



ELSEVIER

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Incentives for early adoption of carbon capture technology

Stephen Comello ^{a,b,*}, Stefan Reichelstein ^{a,b}^a Graduate School of Business, Stanford University, 655 Knight Way, Stanford, CA 94305, USA^b Steyer-Taylor Center for Energy Policy and Finance, Stanford University, 559 Nathan Abbott Way, Stanford, CA 94305, USA

HIGHLIGHTS

- Study the cost effects of a CO₂ emission standard for natural gas power plants.
- The standard requires the deployment of carbon capture technology.
- Future compliance costs are reduced through learning effects.
- Identify tax incentives that induce early technology adoption.
- Early adoption results in relatively modest electricity cost increases.

ARTICLE INFO

Article history:

Received 5 February 2014

Received in revised form

2 September 2014

Accepted 3 September 2014

Available online 18 September 2014

Keywords:

Tax incentives

Carbon capture

Learning effects

Levelized cost

ABSTRACT

We analyze a policy proposal for regulating the next generation of baseload electricity generation facilities in the United States. The cornerstone of this regulation is a (hypothetical) EPA mandate for an emission standard of 80 kg of CO₂ per MWh of electricity generated. The mandate would go into effect at the end of 2027 for all power generating facilities that come into operation after 2017. Fossil-fuel power plants could meet the standard by capturing between 80 and 90% of their current CO₂ emissions. While the initial cost of complying with this standard is relatively high for first-of-a-kind facilities, learning effects are projected to reduce this cost substantially by the end of 2027, provided new facilities consistently adopt carbon capture technology in the intervening years. We identify a combination of investment- and production tax credits that provide the required incentives for new facilities to be willing to comply with the standard ahead of the mandate. Due to the anticipated learning effects, the incremental cost associated with the stricter emission limit is projected to about 1.2¢ per kWh of electricity in the long run.

© 2014 Elsevier Ltd. All rights reserved.

1. Introduction

In September 2013, the U.S. Environmental Protection Agency (EPA) promulgated a new standard for the emission of carbon dioxide (CO₂) by stationary power sources. If adopted, this standard will limit CO₂ emissions to 500 kg per MWh generated. Commentators have been split in their assessment of the significance of this regulation for limiting future U.S. carbon emissions from the electricity generating sector; see, for instance, Richter (2013) and Fowlie (2013). While the new standard would render traditional coal-fired power plants infeasible, it has been pointed out that, even in the absence of the standard, new coal-fired power plants would be unlikely to emerge because electricity generating units that rely on

natural gas already have a cost advantage, at least at recent natural gas prices.

This paper analyzes the costs and benefits of a policy proposal that would sharply limit the emissions of future fossil-fuel fired power plants to 80 kg of CO₂ per MWh. Current engineering assessments suggest that this limit is technically feasible (NETL, 2014, 2012, 2013a). The “clean coal” and “clean natural gas” facilities currently at the planning stage are projected to achieve this limit.¹ We envision an EPA requirement that all facilities that come into operation after 2017 must become compliant with the proposed standard by the end of 2027. Current natural gas combined cycle (NGCC) plants emit about 360 kg CO₂ per MWh and therefore could meet the standard by capturing about 80% of their current emissions.

* Corresponding author at: Graduate School of Business, Stanford University, 655 Knight Way, Stanford, CA 94305, USA. Tel.: 1.650 714 8753.

E-mail addresses: scomello@stanford.edu (S. Comello), reichelstein@stanford.edu (S. Reichelstein).

¹ With respect to coal facilities in the United States, these projects include NRG Energy's Petra Nova Carbon Capture Project and the Texas Clean Energy Project. Royal Dutch Shell's Peterhead Project in northern Scotland is an example of a natural gas facility that could meet the 80 kg per MWh standard.

Similarly, coal-fired power plants would have to reduce their current emissions by about 90%. In anticipation of the stricter emission standard, new facilities that come online during 2017 and thereafter would face the following tradeoff: adopt carbon capture capabilities at the outset, or start with a ‘conventional’ facility that will then require retrofitting in 2027 so as to comply with the EPA standard just in time. We identify a schedule of tax credits that provides sufficient incentives for newly built power plants to invest in carbon capture immediately. While this incentive structure would be applicable to any carbon abatement technologies that meet the strict mandate, we examine the economics of the mandate in connection with NGCC facilities that adopt post-combustion carbon capture technology.

Carbon Capture and Storage (CCS) has the potential to achieve deep reductions in greenhouse gas emissions worldwide while maintaining the economic advantages of fossil-fuel energy resources for several decades to come; see, for instance, [Chu and Majumdar \(2012\)](#) and [Moniz \(2013\)](#). While the technological feasibility of the individual components required for CO₂ capture is generally well understood, one of the remaining challenges for deployment is the integration of such components through commercialization ([GCCSI, 2013](#); [IEA, 2013](#); [DECC, 2013](#)). At the same time, there is potential for cost reductions below the current engineering estimates through increased deployment ([Rubin et al., 2007](#); [IEA, 2013](#); [NETL, 2013c](#)). Evidence from other environmental control technologies, such as flue gas desulfurization, suggest that these cost reductions will be realized through learning effects associated with cumulative experience ([Rubin et al., 2007](#); [NETL, 2013b](#); [Nemet, 2012](#); [van den Broek et al., 2009](#)). Facing an effective first-of-a-kind cost premium, however, firms will be reluctant to invest in such new technologies absent either a mandate or compensatory subsidies. Accordingly, [Nordhaus \(2013\)](#) sees carbon capture technology being stuck in a “vicious cycle.”² We view the proposal analyzed in this paper as a mechanism for breaking out of this cycle.

From a carbon emissions perspective, the benefits of our policy proposal are straightforward. Using electricity generation data for the year 2012 as the benchmark, CO₂ emissions from the U.S. electricity sector would be reduced by about 84% in the long run, once incumbent fossil-fuel power plants currently in operation have been phased out.³ This projection assumes that fossil fuels will not expand their overall share of generation capacity (70% in 2012) and nuclear power and renewable energy would together account for at least 30%.⁴ The long-term reduction in emissions would not depend on the actual mix between coal and natural gas, as all electricity generating units would be subject to the same emission limit.⁵

We measure the cost associated with a particular regulation by the increase in the so-called *Levelized Cost of Electricity* (LCOE). This lifecycle cost measure includes all applicable electricity generation expenditures, including plant, equipment, operating expenses and a required return for investors. The LCOE concept is widely used by analysts, academic researchers and government institutions to

compare the cost-effectiveness of alternative electricity generation sources which differ substantially in terms of upfront investment cost and periodic operating costs ([Lazard, 2009](#)). In a competitive wholesale market, the LCOE serves as a benchmark for the expected equilibrium price for electricity generated by a particular technology. Put differently, if the electricity to be produced by a new facility is sold under a power purchasing agreement, the contractual (average) price would have to cover at least the LCOE in order for investors in the facility to break even.

For a hypothetical NGCC plant that goes into operation in 2017, adds a carbon capture unit in 2027 and thereafter captures 80% of its previous CO₂ emissions, our calculations project a cost increase of 0.6¢ per kWh, relative to the base scenario of a ‘conventional’ NGCC facility that emits 360 kg per MWh throughout its useful life.⁶ This estimate is based on current engineering estimates provided in [NETL \(2014\)](#), assuming the same operating conditions, efficiencies and performance.⁷ In contrast, the increase in LCOE would be about 2.7¢ per kWh for a new NGCC facility that immediately adopts carbon capture technology and consistently limits its CO₂ emissions to 80 kg per MWh. To bridge that gap, a 23% investment tax credit combined with a five-year accelerated tax depreciation schedule would be sufficient for newly constructed facilities in 2017 to prefer investing in a carbon capture unit immediately. Furthermore, a production tax credit of 1.8¢ per kWh would be sufficient to compensate the early technology adopters for the incremental operating cost of actually capturing the CO₂.

The tax incentives required for new NGCC plants to be willing to adopt and implement carbon capture technology immediately will diminish rapidly in years past 2017. The main reason is that the adoption of such technology is most expensive for first-of-a-kind facilities, yet these costs are projected to decrease with cumulative experience. Such learning effects have been documented for natural gas power plants in earlier studies, including ([Rubin et al., 2007](#); [EPRI, 2013](#); [van den Broek et al., 2009](#)). Our calculations rely on the familiar *constant elasticity learning model*. It postulates that for a particular type of NGCC facility with carbon capture capabilities, the cost in different categories, e.g., carbon capture unit, will be reduced by a certain percentage with every doubling of the total number of megawatts of capacity deployed for this type of facility.⁸

The magnitude of the learning effects anticipated in connection with carbon capture is most readily seen by examining the LCOE of an electricity generating facility with carbon capture that comes into operation by 2027. Assuming that in the intervening decade all new NGCC plants have consistently opted for carbon capture technology, we project that the incremental cost associated with the 80 kg per MWh standard will decrease to about 1.2¢ per kWh by the end of 2027, thus reducing the anticipated cost increase for first-of-a-kind facilities in 2017 by over 50%.⁹ The linchpin of this dynamic, though, is the initial prospective emission standard combined with tax incentives to motivate early adoption of this

² On page 165, [Nordhaus \(2013\)](#) summarizes: “like many other large-scale and capital intensive technologies, CCS is caught in a vicious cycle. Firms will not invest in CCS on a large scale because it is financially risky; it is financially risky because public acceptance is low and there are big hurdles to large-scale deployment; and public acceptance is low because there is so little experience with CCS at a large-scale. Breaking out of this vicious cycle is a major dilemma for public policy in this as in other and new, large-scale energy systems.”

³ This reduction coincides with the Obama Administration goal for an overall emission reduction of 83% by the year 2050, relative to 2005 levels.

⁴ [EIA \(2013\)](#) projects fossil-fuel electricity generation to account for about a 70% share between 2010 and 2040.

⁵ Given the projection of prices for natural gas in the United States, the electricity mix in the future is likely to move away from coal, even in the absence of any further carbon regulations.

⁶ In anticipation of the 2027 standard, such a facility would be built ‘capture ready’. Capture readiness is already required for new large-scale electricity generating units in the European Union.

⁷ In comparison to other studies ([Rubin et al., 2007](#); [EPRI, 2013](#); [van den Broek et al., 2009](#)), the NETL cost estimates for the construction of carbon capture units and their subsequent operation are generally conservative.

⁸ Appendix A, contained in the Supplementary Data, describes the constant elasticity learning model we use in detail.

⁹ Our analysis focuses on baseload NGCC power plants. The addition of new NGCC plants for the time period 2017–2027 is assumed to follow the trajectory forecast by [EIA \(2013\)](#). If during those years there also were to be new deployments of coal-fired power plants with post-combustion capture carbon capabilities, either in the United States or abroad, our learning model would yield a forecast for lower costs by end of 2027 due to indirect knowledge spillovers.

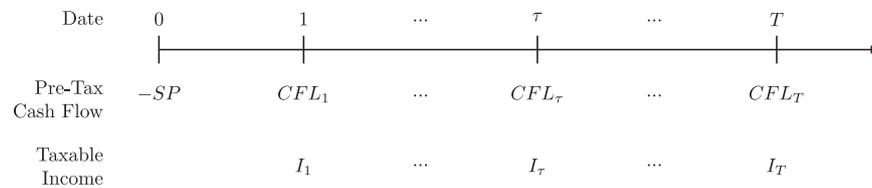


Fig. 1. Single upfront capital investment: cash flows and taxable income.

technology. Such a ‘demand-pull’ policy generates the experience required for cost improvements (Nemet, 2012).

Our calculations ignore any revenues or costs associated with the transport and ultimate sequester of CO₂. We do so because the financial impact of these steps is likely to depend on the location of the generation facility. Future work on this aspect will have to take into account that purified CO₂ is a valuable resource in several industrial applications, most importantly enhanced oil recovery. In parts of the United States, CO₂ currently trades in the range of \$25–40 per tCO₂. For this reason, the expected revenues from enhanced oil recovery are a substantial component of the overall business model for the “clean coal” projects mentioned above. NETL (2013b) provides an estimate in which the purified CO₂ has no industrial use and therefore the power generating facility would have to incur a cost of \$5–10 per tCO₂ for transportation and permanent sequestration.

To summarize, this paper formulates and analyzes the economic consequences of a policy proposal that is centered around a substantially tighter CO₂ emission standard for future U.S. power plants. Provided the proportion of electricity derived from fossil fuel remains constant, the resulting long-run emissions would be reduced dramatically, amounting to an annual reduction of 84% relative to 2012 levels. Generation facilities that come into operation starting in 2017 would anticipate the stringent emission limit of 80 kg of CO₂ per MWh to go into effect by the end of 2027. A combination of investment- and production tax credits would provide incentives for newly built facilities to opt for immediate carbon capture, rather than delay the adoption of this capability until 2027. The consistent adoption of carbon capture technology beginning in 2017 would not only reduce emissions by newly built facilities in the interim, but importantly ensure that the incremental cost associated with the emission standard would effectively be limited to 1.2¢ per kWh by the end of 2027.

The remainder of the paper proceeds as follows. The next section presents the levelized cost concept used to calculate the benchmark scenarios, including base NGCC plants versus those with capture capabilities. Section 3 examines the economics of benchmark scenarios and presents the tax incentives required to motivate new plant constructions to adopt carbon capture capabilities immediately. We summarize the benefits and costs of the proposed regulation and present a sensitivity analysis of our findings in Section 4. We conclude in Section 5. There are two Appendices, the first one of which presents estimated learning rates for different cost categories for NGCC facilities. Appendix B presents a framework for calculating the LCOE of facilities that are retrofitted at some intermediate stage of their useful life. Both appendices are provided as Supplementary Data to this article.

2. Methods

Our analysis of the costs associated with the proposed regulation is based on a levelized cost metric that considers the life-time cost of producing one kilowatt-hour (kWh) of electricity. The Levelized Cost of Electricity (LCOE) is commonly used to aggregate all expenditures required to produce one unit of output (one kWh) into a unit cost measure (Lazard, 2009). In particular, this cost metric includes a share of capital expenditures for the

facility, applicable operating expenses, income taxes, and an acceptable return to investors. The MIT study on the “The Future of Coal” (MIT, 2007) provides the following verbal definition: “...the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors”. The LCOE is a break-even price for electricity that investors would have to receive on average in order to be willing to invest in the facility. Thus if a new plant were to sell its electricity output under a power purchasing agreement, the LCOE would be the minimum average price per kWh that would allow the equity investors in the plant to break even.

Fig. 1 illustrates the relevant cash flows for an NGCC facility that is operated throughout its useful life as initially designed and constructed. This facility incurs the initial capital expenditure, denoted by SP , in connection with plant, property and equipment. In each subsequent year, t , the plant obtains operating cash flows, CFL_t , which we conceptualize as revenues minus current operating costs. In addition, the entity must pay a share of its taxable income, I_t , in corporate income taxes. The LCOE then becomes the ‘plug variable’ in terms of the unit revenue per kWh that must be obtained in order for the net-present value of all after-tax flows, that is, pre-tax cash flows minus income tax payments, to be zero.

The levelized cost of electricity can be expressed in terms of the following principal cost components¹⁰:

$$LCOE = c \cdot \Delta + w + f \quad (1)$$

where

- c is the (levelized) unit cost of capacity per kWh, based on the projected useful life of the facility, the assumed capacity factor and the applicable cost of capital.
- Δ is a scalar that represents the so-called tax factor. It is determined by the firm's corporate income tax rate and the asset depreciation schedule that is allowable for tax purposes.¹¹
- w represents the time-averaged variable operating costs, including fuel, per kWh.
- f denotes the time-averaged fixed operating costs per kWh.

3. Results

3.1. Cost benchmarks for natural gas power plants

Our cost calculations focus on NGCC power plants, as most forecasts project that there will be no new construction of

¹⁰ The LCOE formulation in (1) follows the approach in Reichelstein and Yorston (2013). Appendix B provides the details for calculating the four main LCOE components: c , Δ , w and f . The model formulation in Appendix B considers a generalized setting with sequential capital investments so as to allow for the possibility that the NGCC plant is being retrofitted at a later stage with carbon capture capabilities.

¹¹ In reference to the above quote in the MIT study, suppose the firm's leverage ratio is held constant. Equity holders will receive an “acceptable return” and debt holders will receive “accrued interest on initial project expenses” provided the project achieves a zero net present value when evaluated at the weighted average cost of capital; see, for instance, Ross et al. (2005).

Table 1
LCOE for a conventional NGCC facility.

Input parameters		
Parameter, symbol	Units	Value
Capacity, K	kW	631,620
System price, SP	\$	524,419,016
Annual non-fuel variable operating cost, W	\$	9,658,820
Annual fuel cost, W	\$	224,080,457
Annual fixed cost, F	\$	15,841,986
Capacity factor, CF	%	85%
Emissions intensity, e	kg/kWh	0.355
LCOE calculation		
Tax factor, Δ		1.3161
Unit cost of capacity, c	\$/kWh	0.0099
Average variable cost (incl. fuel), w	\$/kWh	0.0497
Average fixed cost, f	\$/kWh	0.0034
Levelized cost of electricity		
	\$/kWh	0.066

coal-fired generation over the period 2017–2027 (EIA, 2013).¹² The upper portion of Table 1 is based on engineering parameters for a conventional NGCC facility that emits approximately 360 kg per MWh of electricity (NETL, 2014). Such a facility is assumed to operate as a baseload generation plant with a constant capacity factor.^{13,14}

The bottom portion of Table 1 shows the principal levelized cost components c , Δ , w and f for a conventional NGCC facility. We have computed these values using a spreadsheet model which we refer to as the “NGCC+CC Calculator” (Comello and Reichelstein, 2014).¹⁵ The bottom row in Table 1 establishes a benchmark for the cost of electricity associated with baseload NGCC power plants. Since we evaluate the *incremental* cost of carbon capture technology relative to this benchmark, we highlight the finding here as a separate result.

Finding 1. For a conventional NGCC facility that commences operation in 2017, the projected LCOE is 6.6¢ per kWh.

Table 1 indicates that for a conventional NGCC power plant, the levelized capital equipment cost, c , marked up by the tax factor, Δ , accounts for nearly a fifth of the overall LCOE, while the cost of fuel accounts for over half of cost. This point estimate is based on the U. S. average delivery price for natural gas of \$6.13/MMBtu (NETL, 2014). Fig. 2 illustrates the sensitivity of our LCOE projection to unilateral variations in the following variables: (i) system price, (ii) capacity factor, (iii) fuel cost and (iv) cost of capital.¹⁶

¹² An exception to this prediction are the “clean-coal” projects mentioned above. Clearly, this prediction hinges on the persistence of low prices for natural gas.

¹³ Our analysis focuses exclusively on baseload generation plants and ignores the role of intermediate and “peaker” plants. Specifically, we assume that the initial 80 kg standard would apply only to baseload facilities. These power plants are projected to account for the vast majority of new generation and emissions in the coming decades (EIA, 2013).

¹⁴ Conventional NGCC facility is based on the General Electric 7FA.05 turbine configuration, with an efficiency (HHV) of 51.6%. Useful economic life (T)=30 years; weighted average cost of capital (r)=8%; effective corporate tax rate (α)=40%; investment tax credit (i)=0%; production tax credit (s)=\$0/kWh; 150% declining balance depreciation method.

¹⁵ The NGCC+CC Calculator is accessible at URL: <http://tinyurl.com/l8yth6q>. It calculates both present day and future costs for conventional NGCC facilities and those with carbon capture capabilities (new builds and retrofits). Future costs are based on projected capacity deployments and component-level learning rates, as shown in Appendix A and B.

¹⁶ If natural gas prices were to increase sufficiently, coal-fired facilities would become cost-competitive with NGCC plants.

Since NGCC plants with carbon capture have yet to be built at commercial scale, we rely on engineering cost estimates for our analysis. Cost estimates are generally based on equipment, materials and labor required to meet a set of performance specifications, using projected energy- and mass balances. Rubin and Zhai (2012) provide an example of such an engineering-economic model, as does NETL (2011, 2013a). Most recently, NETL (2014) report engineering cost estimates for an NGCC plant with carbon capture technology, capturing 90% of its carbon emissions and thus emitting approximately 40 kg CO₂ per MWh. Since we focus on an emissions limit of 80 kg of CO₂ per MWh, Table 2 has appropriately scaled the factors provided by NETL in connection with a 80% capture rate.¹⁷

The main cost increases from NGCC to a plant with carbon capture are driven by both a substantially higher capital expenditure and higher fixed and variable operating costs. The higher capacity cost stems primarily from the carbon capture unit itself and the balance of system (NETL, 2014). Further, (non-fuel) operational costs nearly double due to increased consumables and additional maintenance charges. In addition to these increments, such a plant experiences an “energy penalty” as a portion of the steam from the steam-cycle is used internally by the carbon capture unit; this has the effect of reducing the net generation output. Higher overall costs and lower net output together result in a substantial LCOE increase.

Finding 2. For an NGCC facility with carbon capture that becomes operational in 2017 and limits its CO₂ emissions to 80 kg per MWh, the projected LCOE is 9.3¢ per kWh.

We emphasize that the cost increase of approximately 2.7¢ per kWh associated with carbon capture is likely to apply only to first-of-a-kind facilities. Based on past observations for fossil-fuel power plants, the literature has established that new technology of this kind is generally subject to learning effects; see, for instance, Rubin et al. (2007), EPRI (2013), van den Broek et al. (2009).¹⁸ Our analysis relies on a component-level application of the *constant elasticity* learning model in which the cumulative volume of capacity installations is viewed as the only driver of learning. Clearly, this variable is merely a proxy for multiple factors that contribute to changes in technology performance, including engineering analysis, research and development, knowledge spillovers and scale economies (Clarke et al., 2008). By construction, our single-factor learning model posits that individual component costs are reduced by a fixed percentage with every doubling of the cumulative capacity deployed.¹⁹ As shown in Table A2 in Appendix A, for the “CO₂ Capture & Compression Unit”, for instance, we assume a learning rate of 9%. This point estimate for the learning rate is somewhat conservative relative to most of the other estimates shown in Table A2.²⁰

The anticipated overall volume of new NGCC facilities with carbon capture is the sum of new NGCC plants in the United States during the

¹⁷ Our scaling approach follows NETL (2014, 2013b), where operational costs scale linearly and capital costs scale by a power law. Otherwise, we assume the same operational conditions as NETL (2014).

¹⁸ The learning rates for NGCC facilities with carbon capture technology are based in part on the comparable technology of flue gas desulfurization.

¹⁹ A constant elasticity learning model has proven descriptive in forecasting the price trajectory of other environmental control technologies such as flue gas desulfurization, selective catalytic reduction and other electricity generation technologies; see for instance (Colpier and Cornland, 2002; Rubin et al., 2007; EPRI, 2013).

²⁰ The electricity generating components of conventional NGCC plants are also subject to learning effects. However, since gas turbines technology has already accumulated considerable experience, the ensuing learning effects for the years 2017–2027 are negligible. Accordingly, the baseline LCOE curve for NGCC plants in Fig. 4 has only a slight downward slope.

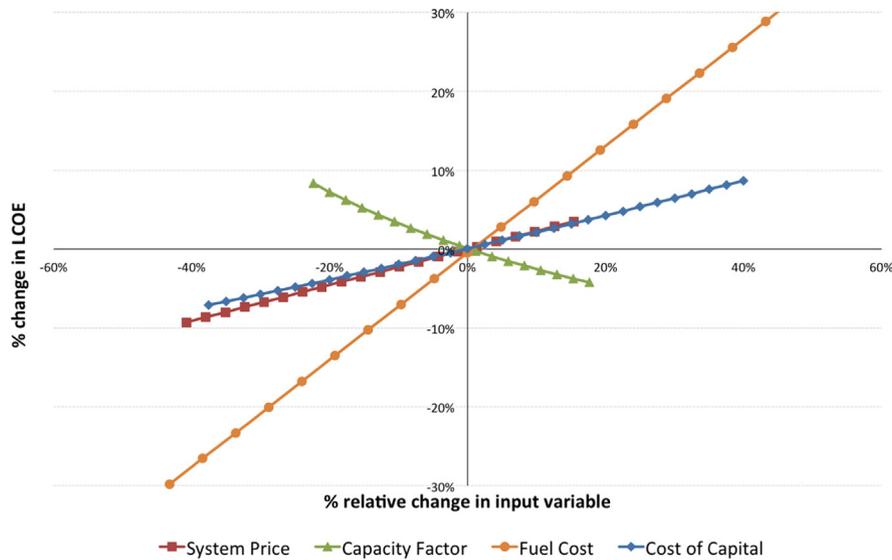


Fig. 2. Sensitivity analysis of LCOE for conventional NGCC generation facilities¹⁶.

Table 2
LCOE for a NGCC facility with carbon capture.

Input parameters		
Parameter, symbol	Units	Value
Capacity, K	kW	559,367
System price, SP	\$	1,016,608,388
Annual non-fuel variable operating cost, W	\$	16,232,840
Annual fuel cost, W	\$	224,096,139
Annual fixed cost, F	\$	27,027,962
Capacity factor, CF	%	85%
Emissions intensity, e	kg/kWh	0.08
LCOE calculation		
Tax factor, Δ		1.3161
Unit cost of capacity, c	\$/kWh	0.0217
Average variable cost (incl. fuel), w	\$/kWh	0.0577
Average fixed cost, f	\$/kWh	0.0065
Levelized cost of electricity	\$/kWh	0.093

period 2017–2027 plus a worldwide projection of post-combustion carbon capture technology deployment during that time. The Energy Information Agency projects approximately 27 GW of NGCC capacity to be installed during this time period, while the Global CCS Institute forecasts approximately 3 GW of post-combustion carbon capture deployments worldwide between 2013 and 2020 (EIA, 2013; GCCSI, 2013). Taken together, approximately 30 GW of cumulative NGCC installed capacity is potentially subject to learning effects during the period 2017–2027.²¹

Finding 3. *If newly built NGCC plants consistently adopt carbon capture technology, a facility that becomes operational by the end of 2027, and thereafter limits its CO₂ emissions to 80 kg per MWh, is projected to achieve an LCOE of approximately 7.8¢ per kWh.*²²

The substantially lower LCOE figure of 7.8¢ per kWh reflects the magnitude of the anticipated learning effects associated with

carbon capture technology. Most of the cost reduction results from lower capital cost for the carbon capture unit and improvements in the balance of system (e.g. integration, controls, and cooling). In order for this cost estimate to materialize by the end of 2027, it will be essential that all new NGCC facilities built in the intervening years embrace carbon capture technology right from the beginning. Since our working hypothesis is that the emission standard only takes effect by the end of 2027, the natural alternative for new builds would be to delay both the construction and the operation of costly carbon capture, with the consequence of higher costs in the year of retrofit. The following section presents calculations on how an EPA mandate would shape the incentives for early adoption.

3.2. The cost of retrofitting

In order to determine the tax incentives required for new NGCC plants to adopt carbon capture capabilities immediately, we first calculate the LCOE for a facility that considers ‘deviating’ from the ‘equilibrium path’. Absent any incentives, it would be advantageous to build a conventional NGCC facility, which would then be retrofitted by the end of 2027, just in time for compliance with the mandate. Such a deviating firm would nonetheless benefit from the learning effects of all other NGCC carbon capture plants built before it. Fig. 3 illustrates the sequence of relevant pre-tax cash flows and annual operating incomes, where the year τ effectively represents the year 2027 when the carbon capture unit is added. The superscript “o” indicates that cash flows and taxable income will be different after the retrofit date.

Appendix B provides the formal details for calculating LCOE values when capital investments are made sequentially. The following result confirms that for a firm that brings a new plant online in 2017 it would be cheaper to defer compliance with the mandate by retrofitting the existing facility on a just-in-time basis.

Finding 4. *For a facility that becomes operational in 2017 as a conventional NGCC plant and is retrofitted in 2027 so as to limit its CO₂ emissions to 80 kg per MWh, the projected LCOE is approximately 7.2¢ per kWh. This estimate assumes that all other new NGCC facilities consistently adopt carbon capture technology.*

For new facilities constructed after 2017, the incentive to deviate from the ‘equilibrium path’ will continually decrease as time progresses. This trend reflects that there is an intrinsic ‘retrofit

²¹ It is typical for cost estimates to increase during early commercialization of large-scale energy related technologies, as such estimates are updated with “as-built” data. We follow the approach in Rubin et al. (2007) and allow for the effects of learning to commence only after 3 GW of cumulative NGCC capacity with carbon capture has been deployed.

²² See the “NGCC+CC Calculator” for details. The sensitivity of the levelized cost figures to changes in the assumed learning rates is examined in Section 4.2.

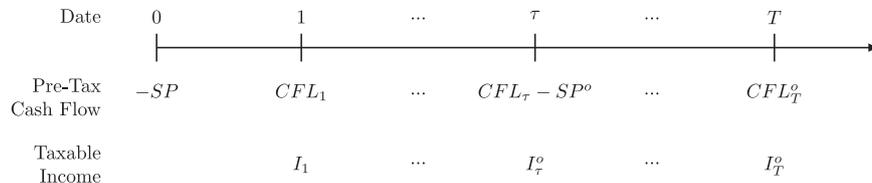


Fig. 3. Two-stage capital investment: cash flows and taxable income.

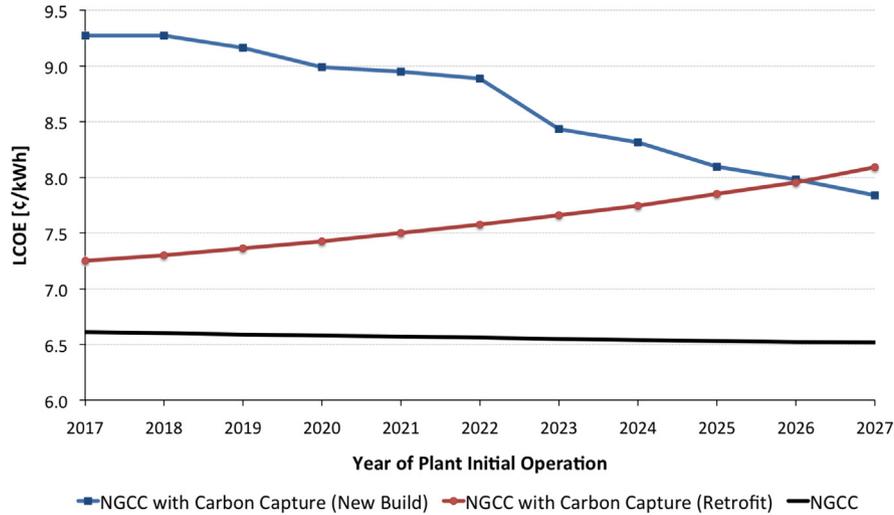


Fig. 4. LCOE for NGCC with carbon capture capabilities accounting for learning effects, “retrofit premium” and time before compliance, as a function of projected capacity deployment (2017–2027): new builds (top), and retrofits, given new build vintage (bottom).

premium” of approximately 9% (NETL, 2014) which effectively penalizes a later addition of carbon capture equipment. As there are fewer years left before the mandate becomes effective at the end of 2027, this premium would have to be paid sooner and the cost advantage of not capturing carbon will apply to a shorter horizon. The bottom line in Fig. 4 shows the LCOE associated with the ‘deviation strategy’ for new NGCC plants that come online during 2017 and thereafter. For example, an NGCC facility built in 2025 and retrofitted in 2027 faces a levelized cost of 7.9¢ per kWh, compared to the 7.2¢ per kWh for an initial built in 2017.

In contrast, the top line shows the ‘equilibrium path’ where every new NGCC facility immediately captures 80% of its emissions. As additional capacity is deployed, subsequent vintages of such facilities are less costly due to learning effects. Cost reductions accelerate in the years after 2022 since in that year a substantial and sustained increase in annual capacity installations is forecasted; see Table A1 in Appendix A.

We now proceed to identify a set of investment- and production tax credits that effectively bridge the gap between the two LCOE values shown in Fig. 4. The tax credits required to incentivize early adoption of carbon capture capabilities are calibrated to the emission standard that would become effective by the end of 2027. The alternative to immediate carbon capture technology adoption thus would not be “business-as-usual”, but rather the prospect of retrofitting in 2027. As with any change in the tax code, these incentives would require Congressional approval. We refer to the entire package as the “Accelerated Carbon Capture Deployment” (ACCD) tax credits. To bridge the gap between the top and bottom lines in Fig. 4, we identify a combination of investment- and production tax credits. We emphasize that these tax credits would apply to any new electricity generating facilities that meet the 80 kg per MWh standard through some carbon abatement technology.

1. During the period 2017–2023, all capital expenditures will be eligible for the five-year accelerated depreciation schedule

according to MACRS. Thereafter, depreciation on all facility capital expenditures will be subject to the current 150% balance, 20-year depreciation schedule.

2. During the period 2017–2025, all capital expenditures will be eligible for the following schedule of Investment Tax Credits (ITC) (Fig. 5):

- 23% ITC for capital expenditures made between 2017 and 2019,
- 13% ITC for capital expenditures made between 2020 and 2023,
- 4.3% linear annual reduction in ITC for capital expenditures made between 2024 and 2025.

3. During the period 2017–2027, all generation from facilities which meet the emissions target will be eligible for the following schedule of Production Tax Credits (PTC) (Fig. 6):

- 1.8¢ per kWh PTC for production between 2017 and 2018,
- 1.1¢ per kWh PTC for production between 2019 and 2022,
- 0.21¢ per kWh linear annual reduction in PTC for production between 2023 and 2027.

Finding 5. The ACCD tax credits provide incentives for all new NGCC facilities that come into operation between 2017 and 2027 to adopt carbon capture technology immediately.

The overall incentive required to keep all new NGCC plants on the ‘equilibrium path’ is determined by the difference between the two lines in Fig. 4. The ACCD tax credits are configured in such a way that the investment tax credit – in conjunction with the accelerated tax depreciation rules – is sufficient to compensate for the additional construction costs associated with the carbon capture unit. The production tax credits are calibrated so that firms have a subsequent incentive to operate the carbon capture unit. Thus payment of the PTC would be tied to a verification requirement that the electricity was in fact generated in compliance with the emission standard.

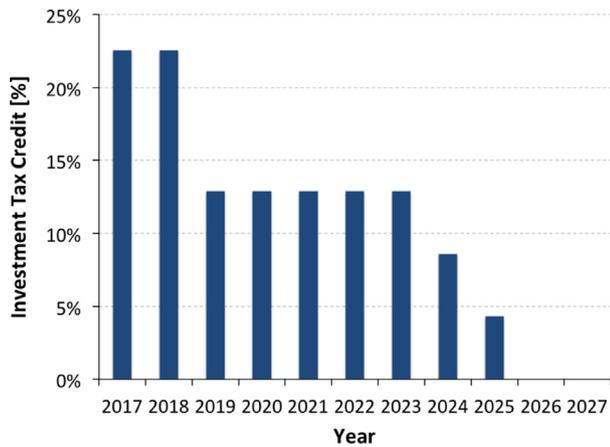


Fig. 5. Investment tax credit schedule.

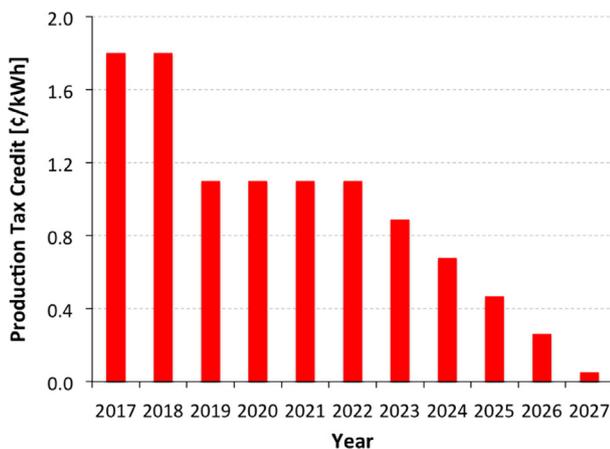


Fig. 6. Production tax credit schedule.

Since cost overruns are quite common during first-of-a-kind large-scale technology commercialization, our tax credits include a “cushion” so that the earliest adopting firms would also have the appropriate incentives if they anticipated that carbon capture related costs would in fact be 10% higher than projected. Our calculations include this premium for the early commercialization phase, namely the first 3 GW of deployment.²³ The two types of tax credits are different insofar as the ITC is paid out fully in the year the facility begins production, while the PTC involves a stream of payments that remains payable for each kWh produced to the end of 2027. While it is conceivable that some firms may attempt to accelerate their deployment schedules due to the decreasing nature of the ACCD, the incentives are designed to make all firms indifferent between early adoption and 2026 retrofit *at any point in time*. Therefore, the long-run impact of the policy proposal would remain intact provided the total deployments by 2027 would be at least as large as assumed in the preceding calculations.

To conclude this section, we note that it is a coincidence that our ACCD tax credits initially call for an ITC that is comparable in size to that of the ITC currently available to solar PV installations. As indicated above, the magnitude of the proposed ITC is derived by the criterion that new NGCC plants are compensated for the higher capital cost associated with the construction of the capture unit.

²³ Rubin and Zhai (2012) also invokes the first-of-a-kind premium concept, however they incorporate this premium through changes in the cost of project finance.

4. Discussion

4.1. Benefits and costs of the proposed regulation

We identify three distinct benefits associated with our regulatory proposal. First, the 80 kg emission limit would lead to a substantial reduction in emissions from the U.S. power sector in the long-run. To quantify this effect, we consider the volume of electricity generated and the generation mix in 2012 as the benchmark. In that year, 39% of all electricity was generated by coal with an emissions rate of approximately 800 kg CO₂ per MWh, while natural gas accounted for 31% of total generation, with an emissions rate of about 360 kg CO₂ per MWh. Holding the volume of fossil-fuel generation volume constant at 70% (irrespective of its particular mix of coal and natural gas) and assuming that zero-emissions generation technologies, i.e. renewable energy and nuclear, continue to account for the remaining 30% of generation, the adherence to the emission standard would reduce total emissions by 84%. We note that our proposal does not account for the specific retirement trajectories of existing plants, rather the future result in the presence of the standard. Obviously, this abatement level would be achieved only when all incumbent facilities have been replaced with either coal or natural gas power plants that comply with the new mandate, say by 2040.²⁴

Second, by the end of 2027, the increase in cost associated with the lower emissions is projected to be below 1.2¢ per kWh at least for NGCC plants. Because learning effects are expected to persist, this cost increment will be reduced further in future years. Third, for the time period 2017–2027, the emissions reduction due to early adoption of carbon capture technology is 54 MMtCO₂, as shown in Fig. 7.

On the cost side, the projected annual revenue foregone by federal government is shown in Fig. 8. The foregone revenues reflect the tax subsidies identified in Section 3, given the projected NGCC capacity deployment schedule. The peak year is 2023, with the majority of the subsidies caused by the ITC due to the relatively large size of anticipated capacity deployments that year. While the size of the ITC expenditure is proportional to the capacity installed in a given year, the cost associated with the PTC increases over time. This feature reflects that the PTC is cumulative in nature, as it remains payable as an annuity to the end of 2027.

Finding 6. *The total (undiscounted) expenditures for the U.S. Treasury associated with the ACCD tax credits are projected to be \$6.6 billion.*

The cost figure reported in Finding 6 ignores the tax consequences related to MACRS. The reason is that an accelerated depreciation schedule merely shifts the tax burden across years and therefore such a change will have no effect on the total *undiscounted* tax revenue.²⁵ We also note that the \$6.6 billion figure includes ‘slack’ since we have chosen a simplified ITC and PTC schedule with relatively few steps, rather than the actual minimal tax credits required each year.

To put the \$6.6 billion figure into context, the total budget authority granted to the Department of Energy for its *CCS Demonstrations Program* and the *Carbon Capture and Storage and Power System Program* between 2005 and 2012 was \$6.9

²⁴ Even without further carbon emission restrictions, total emissions from the electricity sector are poised to decrease to the extent that the share of coal-fired power plants is likely to decline in the coming decades. However, the current 360 kg per MWh emission standard would leave the U.S. power sector far short of the overall Obama Administration’s emission goals for 2050.

²⁵ To be sure, accelerated depreciation is valuable from a leveled cost perspective since this cost is based on present value calculations.

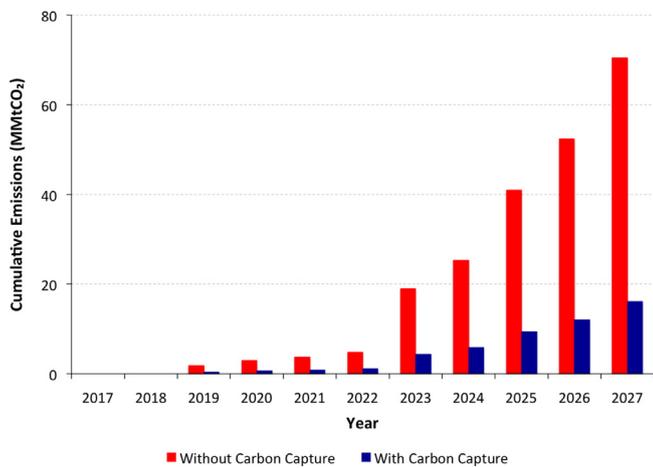


Fig. 7. Cumulative CO₂ emissions of NGCC facilities: with 80% capture rate compared to facilities with no carbon capture equipment.

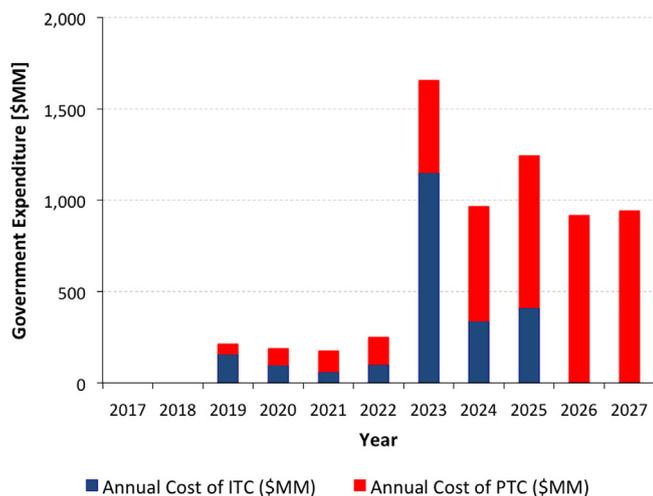


Fig. 8. Schedule of government expenditures associated with ACCD tax credits.

billion²⁶ (CBO, 2012). We note that the ACCD tax credits should not be viewed as a societal cost. In competitive wholesale electricity markets these tax incentives should reduce the increase in electricity prices in the run-up to the 2027 mandate.

Finally, our analysis allows us to calculate the 'shadow price' or implicit cost of capturing CO₂ at NGCC facilities. To meet the emission standard, we established an LCOE of 7.8¢ per kWh by 2027 (Finding 22). Since a conventional plant emits 360 kg CO₂ per MWh and achieves an LCOE of 6.6¢ per kWh (Finding 1), we obtain an implicit cost for CO₂ emission reductions:

Finding 7. *By the end of 2027, the implicit cost of carbon capture for an NGCC facility capturing 80% of CO₂ emissions is approximately \$48 per tCO₂. The implicit cost for such a facility capturing 90% of its CO₂ emissions is \$53 per tCO₂.*

Our study has focused on the emission standard of 80 kg of CO₂ per MWh so as to accommodate coal-fired power plants which would have to capture 90% of their current emissions. Finding 7 shows that the implicit cost associated with a 90% capture rate for NGCC plants (40 kg CO₂ per MWh) would result in a higher average cost per tonne captured. This increase in the implicit cost of

capturing CO₂ essentially reflects greater equipment costs and higher parasitic energy needs.²⁷

Implementation of the policy proposal examined in this paper will require steps that the EPA and Congress would most likely take in sequence. The EPA can impose the emission limit we envision unilaterally under the authority it has under the U.S. Clean Air Act. The use of authority would be similar to that being employed under Section 111(b) of the Act for proposed new source performance standards. The 80 kg emission standard should create an impetus for Congress to change the tax code so as to mitigate the cost of complying with the standard. Firms investing in new NGCC facilities would be likely to lobby for tax breaks that defray the cost of technology development.

It has been pointed out that the credibility of any regulations involving a long lead-time, such as the 80 kg standard that would actually go into effect in 2027, relies on the assumption of commitment. As discussed in Burtraw et al. (2012), there is generally an issue of "dynamic inconsistency" that arises when regulated parties may seek to repeal a regulatory standard for which the cost is still to be borne in the future. In the context of our proposal, this dynamic inconsistency issue appears to be mitigated to the extent that the cost of complying with the 80 kg standard is projected to decrease monotonically in the years leading up to 2027. Nonetheless, commitment on the part of the regulator remains essential to the extent that for new power plants that become operational in 2027, compliance with the standard still imposes an incremental cost of 1.2¢ per kWh (Finding 3). Clearly, the path of cost reductions may differ from the one we forecast for multiple reasons, including delays in policy implementation, unforeseen technological challenges or slower cost improvements (see Section 4.2). If the pace of new carbon capture adoptions were to fall behind schedule, government would still have the option of responding with stronger financial incentives. Adaptations of the California emission standard for vehicles provide a useful illustration in this regard (Hanemann, 2008; Lutsey, 2012).

4.2. Sensitivity analysis

Our calculations have relied on an average of several earlier studies to determine point estimates for the learning rates for each of the components of the NGCC facilities. Table A2 in Appendix A shows the learning rate for each system component derived from the earlier studies we include. Employing the NGCC+CC Calculator and replacing the point estimates with those from each study, we arrive at a range of LCOE values based on alternative learning rates. For example, the LCOE of a newly built NGCC facility that adopts carbon capture technology immediately and becomes operational in 2027 (Finding 3) will range between 7.1¢ per kWh and 8.8¢ per kWh. Further, for an NGCC plant that becomes operational in 2017 as a conventional NGCC plant and is retrofitted in 2027 so as to meet the emission standard (Finding 4), the corresponding LCOE will be in a range between 7.0 and 7.6¢ per kWh. The overall effect of potentially slower learning is shown in Fig. 9, where the trajectories of the 'equilibrium path' and the 'deviation strategy' are plotted based on assumed point estimates (solid lines) and the most conservative learning rates considered in this study (dashed lines).

It is instructive to consider the 'worst-case' learning rate scenario, as the extent of cost reductions due to learning effects remains uncertain. Part of the uncertainty stems from our reliance on a single-factor learning rate model which summarizes, and proxies for,

²⁶ \$3.4 billion in 2009 was appropriated as part of the American Recovery and Reinvestment Act.

²⁷ Our unit cost of carbon capture is lower than the estimate in (Islegen and Reichelstein, 2011), primarily because these authors focused on current costs without incorporating cost reductions over time.

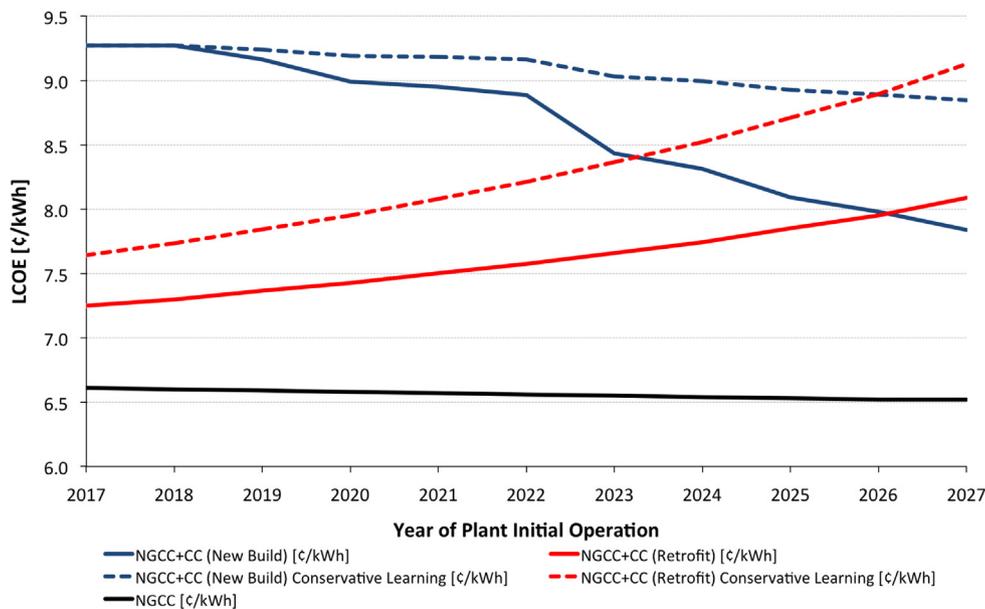


Fig. 9. Comparison of projected LCOE between baseline and conservative learning rates.

several effects such as learning-by-doing, economies of scale and knowledge spillover.

The plot in Fig. 9 shows the extent to which slower learning results in slower cost reductions compared to the baseline scenario, holding the projected capacity deployment schedule and quantity constant. Note that the starting LCOE for the ‘equilibrium path’ remains identical for both scenarios, given that learning has not yet occurred. If policymakers were to anticipate the slower cost improvements for carbon capture shown in Fig. 9, the required tax credits would have to be increased. The required investments tax credits may be lower on a percentage basis since the gap between the ‘equilibrium path’ (top line – dashed) and the ‘deviation strategy’ (bottom line – dashed) is smaller. However, the cumulative PTC would be substantially higher due to higher associated fuel costs (i.e. slower system efficiency increases). As noted in connection with Fig. 2, the LCOE of NGCC facilities is highly sensitive the cost of natural gas. The overall foregone tax revenues to the U.S. Treasury associated with the ACCD tax credits in this conservative (slow) learning scenario would be about \$7.6 billion.

5. Conclusion and policy implications

Our regulatory proposal is aimed at fossil-fuel power plants to be built during the coming decade. The long lead-time we envision for the 80 kg emission standard should mitigate the objection that compliance with the regulatory standard requires technology that has yet to be deployed on a commercial scale. One of the principal challenges for carbon capture technology is that first-of-a-kind implementations are likely to be relatively costly. At the same time, the observed pattern of learning effects in connection with fossil-fuel power plants strongly suggests that these costs would come down rapidly with experience.

Our model identifies a set of tax credits that would apply to any fossil-fuel electricity generating plant and abatement technology that meets the stricter emission standard. In particular, the ACCD tax credits identified in this paper would make it attractive for new NGCC plants to implement carbon capture technology ahead of the anticipated mandate. These temporary subsidies could be instrumental in breaking the vicious cycle frequently associated with the slow adoption of carbon capture technology (Nordhaus, 2013). The

magnitude of the required tax incentives is shown to be relatively moderate, in part because the relevant benchmark would not be the “business-as-usual” scenario for NGCC plants, but rather the prospect of having to retrofit a conventional NGCC facility in 2027. To the extent that the LCOE expresses the long-run marginal cost of electricity, the price increase to consumers is 1.2¢ per kWh, or approximately 10% above the current national average.

There appear to be several promising avenues for extending the analysis in this paper. As indicated in the Introduction, our cost analysis has ignored any revenues and costs associated with the transportation and permanent sequestration of CO₂. The forward-looking nature of our policy proposal should make it easier for newly built electricity generating units to connect to a network of pipelines that are capable of delivering the purified CO₂ to other industrial applications, such as oil fields using CO₂ for enhanced oil recovery.²⁸ Provided the ultimate off-taker is willing to pay for the valuable resource of purified CO₂, the cost estimates presented in this paper are likely to be conservative. Even in the unfavorable scenario where the purified CO₂ gas ultimately has no other industrial use, it appears that the overall cost associated with transportation and geologic storage would merely raise our LCOE forecast by at most another 0.2¢ per kWh.

Our analysis has focused on an emission limit of 80 kg of CO₂ per MWh because that corresponds to a 90% emission reduction for current coal-fired power plants.²⁹ Yet, as indicated in the previous section, the incremental cost for NGCC plants of capturing 90% rather than 80% of their current emissions appears relatively modest. This suggests a possible modification of the policy proposal analyzed here, where the standard remains unchanged, however the PTC credits associated with voluntarily meeting a lower threshold of 40 kg CO₂ per MWh would be made sufficiently attractive so that

²⁸ Current estimates indicate that the demand for enhanced oil recovery is approximately 160 MMtCO₂/year at current prices in the range of \$25–30 per tonne. PB and GCCSI (2011). Fig. 7 shows that this industrial demand could easily absorb the amounts of CO₂ that would be captured annually under our proposal, well past 2030. While we anticipate additional economic industrial uses to emerge given this increase in supply, it is readily conceivable that an appreciable fraction of captured CO₂ could be directed immediately to geologic storage.

²⁹ Four of the five clean coal projects currently underway in the United States anticipate compliance with the 80 kg emission standard. In contrast, the Kemper County project in Mississippi has a designed capture rate of 65%.

new NGCC facilities would immediately aim to meet the even more stringent emission target.

The trajectory of cost reductions associated with increased experience has been taken as exogenous in our analysis. Yet, the actual rate of cost reductions is likely to depend not only on the regulatory policy in place but also a host of other factors including lead-time, predictability of future financial incentives and market competition. The work of Taylor, Rubin and Hounshell (2003) in connection with flue gas desulfurization suggests a number of factors that regulators should consider in order to enhance the rate of learning.

Our calculations on the effects of learning have arguably been conservative insofar as we have focused exclusively on the learning effects associated with new natural gas power plants that are scheduled to come online in the United States between 2017 and 2027. To the extent that fossil-fuel power plants in other countries also invest in carbon capture capabilities, the cost reductions identified in this paper will likely accelerate. This extension would apply to post-combustion capture technologies employed by either natural gas or pulverized coal facilities.

Finally, it would be insightful to contrast the approach in this paper with alternative incentive mechanisms aimed at promoting the adoption of carbon abatement technologies. One such example is the so-called “alternative compliance payment” mechanism outlined in by Burtraw et al. (2012). While we advocate a binding and inflexible standard to be applied in the future coupled with incentives for early adoption, Burtraw et al. (2012) describes a flexible standard based on average emissions over time. Firms that are non-compliant with the average emission target would be required to pay into a public fund that contributes to future abatement investments for the industry. Our proposal would arguably reduce emissions more rapidly at the outset and with fewer industry objections due to the use of subsidies (rather than penalties). In addition to the actual regulatory pathway our proposal may take (and the political forces that may attempt to shape its ultimate form), this supposition should be explored. Further, comparing these two approaches in terms of their overall costs and benefits in the long-run becomes an interesting topic for future research.

Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at <http://dx.doi.org/10.1016/j.enpol.2014.09.003>.

References

- Burtraw, D., Fraas, A., Palmer, K., Richardson, N., 2012. Comments on EPA's Proposed Carbon Pollution Standard for New Power Plants. Technical report, URL: (<http://www.rff.org/RFF/Documents/RFF-DP-12-31.pdf>).
- CBO, 2012. Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide. Technical report, US Congressional Budget Office.
- Chu, S., Majumdar, A., 2012. Opportunities and challenges for a sustainable energy future. *Nature* 488 (7411), 294–303.
- Clarke, L., Weyant, J., Edmonds, J., 2008. On the sources of technological change: what do the models assume?. *Energy Econ.* 30 (2), 409–424 doi:10.1016/j.eneco.2006.05.023 URL: (<http://www.sciencedirect.com/science/article/pii/S0140988306000752>).
- Colpier, U.C., Cornland, D., 2002. The economics of the combined cycle gas turbine—an experience curve analysis. *Energy Policy* 30 (4), 309–316, doi: doi:10.1016/S0301-4215(01)00097-0 URL: (<http://www.sciencedirect.com/science/article/pii/S0301421501000970>).
- Comello, S., Reichelstein, S., 2014. NGCC+CC Cost Calculator, URL: (<http://tinyurl.com/l8yth6g>).
- DECC, 2013. CCS Cost Reduction Taskforce Final Report, May 2013. URL: (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf).
- EIA, 2013. Annual Energy Outlook 2013 with Projections to 2040. URL: (<http://www.eia.gov/forecasts/aeo/pdf/0383%282013%29.pdf>), dOE/EIA-0383(2013).
- EPRI, 2013. PRISM, 2.0: Modeling Technology Learning for Electricity Supply Technologies, 3002000871.
- Fowle, M., 2013. Much Ado About Nothing?. *Energy Economics Exchange*, Haas Energy Institute, October.
- GCCSI, 2013. Global CCS Institute Status of CCS Project Database. URL: (<http://www.globalccsinstitute.com/data/status-ccs-project-database>).
- Hanemann, M., 2008. California's new greenhouse gas laws. *Rev. Environ. Econ. Policy* 2 (1), 114–129. <http://dx.doi.org/10.1093/reep/rem030>, URL: <http://reep.oxfordjournals.org/content/2/1/114.abstract>, <http://reep.oxfordjournals.org/content/2/1/114.full.pdf+html>.
- IEA, 2013. Technology Roadmap Carbon Capture and Storage, 2013 Edition.
- Islegen, O., Reichelstein, S., 2011. Carbon capture by fossil fuel power plants: an economic analysis. *Manag. Sci.* 57, 21–37.
- Lazard, P., 2009. Levelized Cost of Energy Analysis. Technical report, Lazar Capital Markets Report, version 3.
- Lutsey, N., 2012. Regulatory and technology lead-time: the case of US automobile greenhouse gas emission standards. *Transp. Policy* 21 (0), 179–190, doi: doi:10.1016/j.tranpol.2012.03.007 URL: (<http://www.sciencedirect.com/science/article/pii/S0967070X12000522>).
- MIT, 2007. The Future of Coal. URL: (<http://web.mit.edu/coal>).
- Moniz, E.J., 2013. Climate Action Plan testimony, September 18, 2013, before the Committee on Energy and Commerce, Subcommittee on Energy and Power, U.S. House of Representatives. URL: (<http://democrats.energycommerce.house.gov/sites/default/files/documents/Testimony-Moniz-EP-Obama-Administration-Climate-Change-Policies-2013-9-18.pdf>).
- Nemet, G.F., 2012. Subsidies for new technologies and knowledge spillovers from learning by doing. *J. Policy Anal. Manag.* 31 (3), 601–622. <http://dx.doi.org/10.1002/pam.21643>.
- NETL, 2011. Quality Guidelines for Energy System Studies—Cost Estimation Methodology For NETL Assessments of Power Plant Performance, DOE/NETL-2011/1455.
- NETL, 2012. Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases, DOE/NETL-341/082312.
- NETL, 2013a. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: Revision 2a, September 2013, DOE/NETL-2010/1397.
- NETL, 2013b. Quality Guidelines For Energy System Studies—Capital Cost Scaling Methodology. URL: (http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CapitalCostScalingMethodology_Final_20130201.pdf), dOE/NETL-341/013113.
- NETL, 2013c. Quality Guidelines For Energy System Studies—Technology Learning Curve (FOAK to NOAK). URL: (http://www.netl.doe.gov/energy-analyses/pubs/QGESS_FOAKtoNOAK_Final.pdf), dOE/NETL-341/081213.
- NETL, 2014. Cost and Performance of Retrofitting NGCC Units for Carbon Capture. DOE/NETL-341/081213, forthcoming.
- Nordhaus, W., 2013. *The Climate Casino: Risk, Uncertainty and Economics for a Warming World*. Yale University Press, New Haven, CT.
- PB, and GCCSI, 2011. Accelerating the Uptake of CCS: Industrial Use of Captured Carbon Dioxide, URL: (<http://www.globalccsinstitute.com/publications/accelerating-uptake-ccs-industrial-use-captured-carbon-dioxide>).
- Reichelstein, S., Yorston, M., 2013. The prospects for cost competitive solar PV power. *Energy Policy* 55, 117–127.
- Richter, B., 2013. New Clean Air Rules Would Do Little. *New York Times*, October 23.
- Ross, S., Westerfield, R., Jaffe, J., 2005. *Corporate Finance*. McGrawHill Publishers, New York, N.Y.
- Rubin, E.S., Yeh, S., Antes, M., Berkenpas, M., Davison, J., 2007. Use of experience curves to estimate the future cost of power plants with CO₂ capture. *Int. J. Greenh. Gas Control* 1 (2), 188–197.
- Rubin, E.S., Zhai, H., 2012. The cost of carbon capture and storage for natural gas combined cycle power plants. *Environ. Sci. Technol.* 46 (6), 3076–3084. <http://dx.doi.org/10.1021/es204514f>, URL: (<http://pubs.acs.org/doi/abs/10.1021/es204514f>)(<http://pubs.acs.org/doi/pdf/10.1021/es204514f>).
- van den Broek, M., Hoefnagels, R., Rubin, E., Turkenburg, W., Faaij, A., 2009. Effects of technological learning on future cost and performance of power plants with CO₂ capture. *Progr. Energy Combust. Sci.* 35 (6), 457–480.