Turning CO_2 Capture On and Off in Response to Electric Grid Demand: A Baseline Analysis of Emissions and Economics

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Coal consumption accounted for 36% of America's CO_2 emissions in 2005, yet because coal is a relatively inexpensive, widely available, and politically secure fuel, its use is projected to grow in the coming decades (USEIA, 2007, "World Carbon Dioxide Emissions From the Use of Fossil Fuels," International Energy Annual 2005, http://www.eia.doe.gov/emeu/iea/carbon.html). In order for coal to contribute to the U.S. energy mix without detriment to an environmentally acceptable future, implementation of carbon capture and sequestration (CCS) technology is critical. Techno-economic studies establish the large expense of CCS due to substantial energy requirements and capital costs. However, such analyses typically ignore operating dynamics in response to diurnal and seasonal variations in electricity demand and pricing, and they assume that CO_2 capture systems operate continuously at high CO_2 removal and permanently consume a large portion of gross plant generation capacity. In contrast, this study uses an electric grid-level dynamic framework to consider the possibility of turning CO_2 capture systems off during peak electricity demands to regain generation capacity lost to CO_2 capture energy requirements. This practice eliminates the need to build additional generation capacity to make up for CO_2 capture energy requirements, and it might allow plant operators to benefit from selling more electricity during high price time periods. Post-combustion CO_2 absorption and stripping is a leading capture technology that, unlike many other capture methods, is particularly suited for flexible or on/off operation. This study presents a case study on the Electric Reliability Council of Texas (ERCOT) electric grid that estimates CO_2 capture utilization, system-level costs, and CO_2 emissions associated with different strategies of using on/off CO_2 capture on all coal-fired plants in the ERCOT grid in order to satisfy peak electricity demand. It compares base cases of no CO_2 capture and "always on" capture with scenarios where capture is turned off during: (1) peak demand hours every day of the year, (2) the entire season of peak system demand, and (3) system peak demand hours only on seasonal peak demand days. By eliminating the need for new capacity to replace output lost to CO_2 capture energy requirements, flexible CO_2 capture could save billions of dollars in capital costs. Since capture systems remain on for most of the year, flexible capture still achieves substantial CO_2 emissions reductions. [DOI: 10.1115/1.4001573]

1 Introduction

There is a consensus among scientists that climate change is occurring primarily due to carbon dioxide (CO_2) emissions from fossil fuel burning, with over 60% of worldwide emissions coming from power generation systems [1]. Coal-fired power plants account for 60% of electricity sector emissions, 11.4 billion metric tons of CO_2 emitted in 2005, and 2.1 billion in the U.S [2,1]. However, when compared with other fuels used for electricity production, coal is relatively inexpensive, abundant, and politically secure. This advantageous combination indicates that the use of coal for power generation may increase in the coming decades, despite its CO_2 output. In order to continue and expand coal use in an environmentally acceptable manner, it will be essential to implement carbon dioxide capture and sequestration (CCS) systems.

Major barriers to CCS technology are its high capital cost and operating costs associated with the energy requirement of capture systems, which can significantly lower overall power plant thermal efficiency. For a plant using post-combustion (PC) amine absorption, one leading technology, the net output can be 11–40% lower than an equivalent reference plant without CO_2 capture [1,3,4]. A primary portion of this energy requirement is the steam required to heat CO_2-rich solvent to an appropriate temperature where the CO_2 can be liberated for subsequent transport and storage (Fig. 1). In a typical design, steam is diverted from between the intermediate- and low-pressure turbines and directed to a stripper column where the CO_2-rich solvent flows in for regeneration. The other major CO_2 capture energy requirement is the work needed to compress CO_2 to pipeline pressure. The CO_2 compression train could be driven by an electric motor or by expanding the stripping steam in a let-down steam turbine before it reaches the stripper column.

Several techno-economic analyses of CO_2 capture systems exist in the literature, but most take either the bottom-up approach of a single plant analysis or employ a top-down macroeconomic methodology [5,6]. Plant-level studies are necessary to identify detailed plant tradeoffs between performance, economics, and environmental effects, but they typically have limited ability to analyze the implications of dynamic plant operation within the framework of the electric grid. Macroscopic energy analyses are

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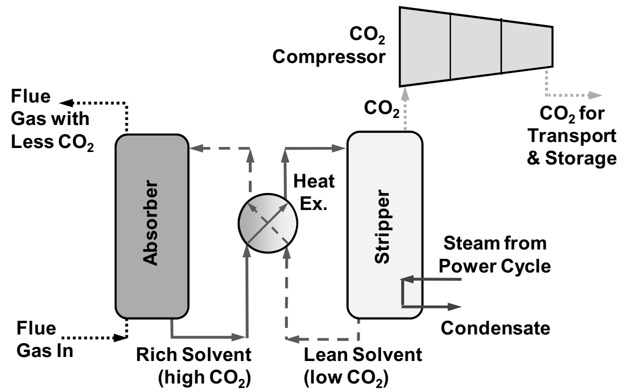

Fig. 1 A Process diagram shows the key features of a typical CO_2 absorption/stripping unit with CO_2 compression

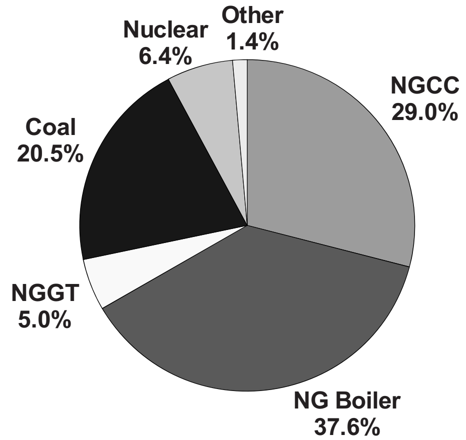

Fig. 2 2006 ERCOT installed capacity of each plant type is shown, demonstrating dominance of natural gas [9,21]

useful for understanding long-term drivers of energy use, but they too have limited capability to capture the short-term implications of dynamic electricity supply and demand.

This study takes an intermediate approach of an electric grid-level perspective in order to make baseline estimates of the implications of turning CO_2 capture systems on and off in response to electric grid demand. While prior analysis investigates plant-level options and implications of flexible CO_2 capture, this study seeks to better understand the effects of on/off operation at a system level [7]. Flexible CO_2 capture operation is particularly suited for PC CO_2 capture systems, which may be designed to allow for the possibility of recovering the energy required for CO_2 capture when it is desirable to increase plant output. PC capture systems can also be more easily retrofitted to current plants, offering a level of flexibility to the electric grid itself. Because of the large body of knowledge surrounding monoethanolamine (MEA) based CO_2 capture systems, PC CO_2 capture using an aqueous MEA solution is considered exclusively in this report.

Turning CO_2 capture "off" does not necessarily refer to bringing all systems associated with CO_2 capture to a full halt, as this practice may be undesirable from an equipment operation and maintenance perspective. In the context of this study, an off configuration refers to the recovery of plant capacity to its base rating without CO_2 capture installed. Full capacity is achieved by redirecting solvent regeneration steam back to the low-pressure turbine where it can be used to generate electricity. In a configuration with sufficient solvent storage, it may be possible to continue to capture CO_2 and hold CO_2-rich solvent in storage tanks for regeneration during periods of lower electricity demand, but a worst-case environmental scenario would assume that CO_2 is vented in a "capture off" configuration. An on/off operation with CO_2 venting can be pictured as a system that cycles between its full-load (on) and zero-load (off) operating points, where maximum specified CO_2 removal is achieved at full-load, and no CO_2 is removed from flue gas at zero-load. As has been identified in prior work, turning off energy intensive CO_2 capture systems during periods of peak electricity demand can eliminate the need for investment in new generation capacity to replace that lost from CO_2 capture energy requirements [8]. If the system response time is short enough, the on/off operation may provide a useful tool for plant operators to better match plant generation with diurnal electricity demand variation. The ability to turn CO_2 capture systems off at the times of the day when electricity is most expensive also offers the opportunity for faster recovery of CCS investment costs relative to a case when CO_2 capture operates continuously at its full-load.

2 Methodology

The purpose of this study is to analyze strategies for on/off CO_2 capture in order to determine baseline estimates of the tradeoffs between power generation performance, economics, and CO_2 emissions. Rather than attempt to optimize on/off operation for specific goals such as minimum cost under a CO_2 emissions limit, the goal of this study is to offer insight into grid-level implications of several on/off CO_2 capture scenarios to better understand how flexible CO_2 capture might affect a widespread deployment of CCS.

2.1 A Case Study of ERCOT Electric Grid. The Electric Reliability Council of Texas (ERCOT) electric grid is examined using grid specifications and performance from the year 2006. This year is chosen because of the completeness of publicly available data from ERCOT and U.S. government agencies. ERCOT is responsible for managing the retail electricity market that accounts for 85% of the total electricity generation in Texas [9]. In 2006, the ERCOT installed capacity was 71,812 MW, and Fig. 2 shows how this capacity is broken down by source [9]. Unlike rated capacity, which indicates the maximum power that could be produced if all generators were online and operating at their optimum conditions, installed capacity shown in Fig. 2 accounts for the expected annual availability of each generation source. NGCC refers to natural gas-powered combined cycle generation, NG boilers are steam cycle power plants using natural gas-fired boilers, and NGGT are open cycle gas turbine-driven generators. For the purposes of this analysis, wind, hydroelectric, and other plant types are lumped into a single "other" category because they comprise a relatively small portion of the generation mix. Because 75% of the actual generation within this category came from wind in 2006, parameters associated with the "other" generation correspond to appropriate values for wind power.

In the ERCOT grid, coal-based and nuclear power operate at a relatively constant output for base load capacity, while natural gas is used both to meet additional base load demand and to balance electricity supply and demand by serving intermediate and peaking load. Thus, higher capacity factors allow coal-fired and nuclear plants to account for 37.4% and 13.6% of the total ERCOT generation in 2006. Lower capacity factor natural gas-fired plants produced 46.3% of the ERCOT electricity in 2006 [10]. Figure 3, taken from a 2005 ERCOT resource update, illustrates the current ERCOT operational strategy for the day in 2005 when electricity demand was at its maximum.

ERCOT uses a reserve margin specification as an important metric to decide whether or not new capacity is required to maintain grid reliability. The reserve margin is defined as the percent of installed capacity that is available during the maximum peak elec-

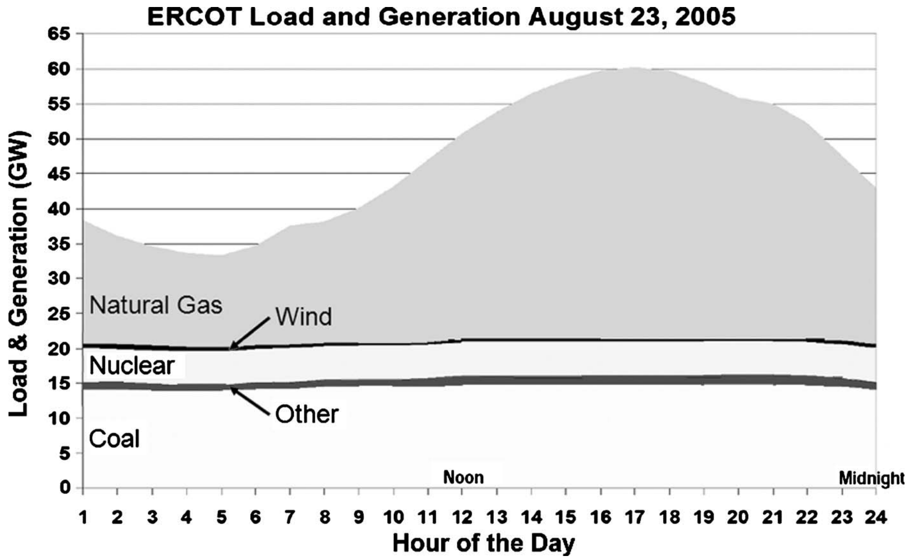

Fig. 3 ERCOT load and generation by plant type on August 23, 2005 demonstrates dependence on natural gas on the maximum peak load day in 2005 [10]

tricity load of the year. ERCOT specifies that it must maintain a 12.5% reserve margin; thus, new capacity installation becomes important when the observed reserve margin approaches this value. The 2006 ERCOT observed reserve margin in 2006 was 14.6%. The projected growth in electricity demand indicates that new capacity will likely be necessary to maintain ERCOT reliability regardless of CO_2 capture installation.

2.2 General Model Assumptions. A MATLAB model is created to compare performance, economics, and emissions of several scenarios. Historical ERCOT hourly load data are taken as inputs, and a decision tree for each scenario determines how much of that load is met by each generation source. Because the lowest ERCOT demand in 2006 never dropped below combined coal-based and nuclear capacity, coal-fired and nuclear facilities are assumed to always run at full capacity. Wind and hydroelectric power are intermittent in reality, but because of their relatively small overall contribution to ERCOT generation in 2006, power output from the "other" category is taken as a constant average value throughout the year. Because different gas-fired generation types vary significantly in efficiency, and by extension, electricity production costs, NGCC, NG boilers, and NGGT are considered separately. The model utilizes natural gas-fired plant types in the order of lowest to highest generation cost, which is calculated, as described in Sec. 2.4.4 below.

Scenarios that implement CO_2 capture consider the operation of the above generation mix if PC CO_2 capture using MEA is installed on all 15 coal-fired power plants in the ERCOT grid. When fully on, the model assumes that CO_2 capture reduces coal-fired generation capacity by a specified percent and captures 90% of plant CO_2 emissions, an often cited CO_2 capture efficiency [1,3,5]. Turning CO_2 capture off allows full recovery of the original plant output and generation cost, and CO_2 is assumed vented to the atmosphere in an off configuration. An actual retrofitted plant incorporating on/off CO_2 capture may not regain its base performance with the CO_2 capture off, but the effect of such a residual energy penalty is not considered in this baseline study.

PC CO_2 capture for natural gas-fired plants is not considered in this study. While such systems are technically feasible and would further reduce emissions, the lower emission rates of natural gas-based plants relative to coal-fired facilities mean that a greater volume of flue gas must be treated to capture a given amount of CO_2. Since the resulting energy requirement and cost per amount of CO_2 avoided is likely to be greater, this option is not included in the model [11].

In practice, the amount of the total installed capacity available for generation varies throughout the year due to factors such as planned maintenance outages, forced outages due to unexpected equipment failures, and discrepancies between design and actual operating conditions. Because much of this variation depends on system planning and unplanned events, and because these events are considered when specifying a reserve margin, predicting and accounting for variation in available capacity is considered to be outside the scope of this study.

2.3 Scenario Descriptions. The specific scenarios analyzed are described below.

2.3.1 BAU: Business as Usual, No CO_2 *Capture*. This case describes the actual 2006 ERCOT configuration, where no power plants utilize CO_2 capture (status quo).

2.3.2 CCS Base: Inflexible CO_2 *Capture*. CO_2 capture operates continuously throughout the year, decreasing the total coal-fired generation capacity by a constant amount. This scenario represents the system configuration in studies that do not consider CO_2 capture flexibility [4,5]. Depending on an ERCOT reserve margin specification or an otherwise defined threshold electricity demand, new generation capacity may be required in this scenario. Because CO_2 capture reduces base load coal-fired generation capacity, this scenario assumes that any new capacity consists of coal-based power generation with CO_2 capture installed. New capacity planning decisions are based on a variety of technical, economic, and political influences, but the above methodology allows for a more direct comparison with studies that assume that the energy requirement of CO_2 capture requires building an equivalent facility with greater gross power output.

2.3.3 FLEX Daily: Flexible CO_2 *Capture Option*. CO_2 capture is turned off every day of the year when demand exceeds the daily peak minus CO_2 capture energy requirements. Thus, CO_2 capture is turned off for some amount of time everyday, regardless of the magnitude of the daily peak. This operational strategy may not be realistic due to additional CO_2 emissions and increased capital recovery time, but it represents a worst-case environmental scenario for flexible CO_2 capture in the event that economics dictate a much more limited use of the "capture on" configuration. Figure

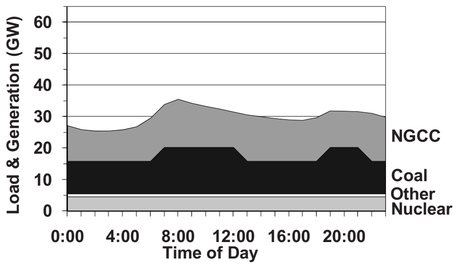

Fig. 4 The *FLEX Daily* load and generation on January 6, 2006 has two CO_2 capture off periods when load nears daily peak load

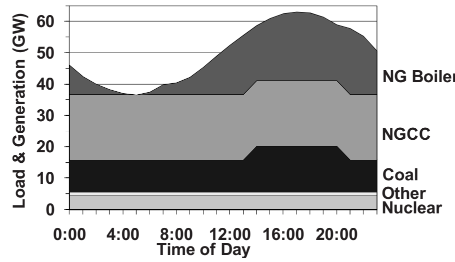

Fig. 6 The *FLEX Hours* load and generation on August 17, 2006 (the maximum peak load day in 2006) has a CO_2 capture off period when load exceeds the threshold load

4 displays how this strategy would utilize the on/off operation, even when demand is relatively low. Times when CO_2 capture is off are indicated by the sudden increases in coal-based power generation when the system load nears the daily peak load.

2.3.4 FLEX Season: Flexible CO_2 *Capture Option*. CO_2 capture is turned off during the entire season between days where electricity demand surpasses a threshold value. This season starts the day prior to the first day a threshold load is exceeded and ends after the last day the system load is above the specified level. The model defines this threshold value based on a grid reserve margin specification. Because the reserve margin is calculated from a single peak load value, a reserve margin specification can be reinterpreted as a threshold load above which CO_2 capture must be turned off. *FLEX Season* represents an extreme case where once CO_2 capture is turned off, difficulty bringing the system back online within a short time frame dictates that it will not be returned to full-load CO_2 capture operation until the peak load season is over. An illustration of this strategy is shown in Fig. 5, which plots the daily ERCOT peak load throughout 2006, along with a potential CO_2 capture "off season."

2.3.5 FLEX Hours: Flexible CO_2 *Capture Option*. CO_2 capture is turned off only during specific hours when electricity demand exceeds the designated threshold value or reserve margin. This case represents the opposite end of the system response time continuum where CO_2 capture can be turned on and off within an hour. Figure 6 demonstrates how this scenario would distribute generation on August 17, 2006, the highest peak load day of 2006.

2.4 Base Case Model Inputs

2.4.1 Reserve Margin. The base case reserve margin is specified at 18.3%. This value is chosen because it corresponds to the requirement to fully replace all capacity lost to CO_2 capture. While the ERCOT minimum reserve margin is 12.5%, using 18.3% allows this study to be compared with those that assume that replacement capacity is required when CO_2 capture is installed. As a result, the new net capacity required in *CCS Base* with base case inputs will be equivalent to the power required to operate CO_2 capture on the entire ERCOT coal fleet.

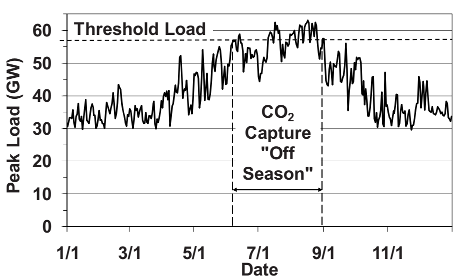

Fig. 5 The seasonal variation in ERCOT daily peak load in 2006 causes a CO_2 capture off season for *FLEX Season*

2.4.2 CO_2 *Capture System*. As stated above, the model assumes that the MEA CO_2 capture system removes 90% of the CO_2 from the coal-based power plant flue gas. Estimates for capture energy requirement vary widely in the literature, but this study assumes that CO_2 capture and compression require 30% of plant output, a value representative of those presented in recent work.

2.4.3 CO_2 *Emissions Rates*. Emissions rates are expressed in metric tons of CO_2 per megawatt-hour (tCO_2/MWh). These values are determined using weighted average CO_2 emission rates for ERCOT plants of each generation type. CO_2 emission rates are calculated using 2004 data, but because the fossil fuel-based power generation in ERCOT did not change significantly from 2004 to 2006, calculated values are assumed to be reasonably accurate. Because this analysis only considers point-of-use emissions, nuclear power and all sources accounted for in the "other" generation are assumed to have negligible CO_2 emissions.

2.4.4 Electricity Production Costs. All cost values in this study are normalized to 2006 dollars. In this study, electricity production costs include fuel costs and other operating and maintenance (O&M) costs, but they do not contain capital charges. While capital charges are important in a single plant analysis that investigates lifetime plant costs in order to make investment decisions, the marginal costs of generating electricity are most important to electric grid operation, because these costs are used to make dispatch decisions. As an approximation, marginal costs are constant throughout the output range of each plant type.

For natural gas-fired plants and coal-fired generating facilities without CO_2 capture, marginal generation costs are determined using published nonfuel O&M costs, 2006 average coal and natural gas prices in Texas, and a weighted average heat rate in the ERCOT grid for each plant type. Fuel prices, particularly natural gas, have been volatile in the recent years, but 2006 fuel prices are used to maintain consistency and for comparison purposes. The average heat rate is calculated using 2004 data, but this methodology is again assumed to yield a reasonably accurate result. Marginal costs for nuclear power are specified directly from literature and do not use a specified heat rate or fuel cost. As indicated above, "other" generation uses the marginal cost for wind power.

The marginal generation cost for coal-based generation with CO_2 capture using MEA absorption was determined using the cost of electricity (COE) for a subcritical pulverized coal-based power plant retrofitted with both a MEA and flue gas desulfurization (FGD) system, reported as 70.40 USD/MWh by Rao and Rubin 2002 (2000 dollars) [5]. Because MEA is more prone to degradation if exposed to SO_2 in flue gas, Rao and Rubin found that a retrofit MEA+FGD will have a lower COE than a MEA retrofit alone, despite higher capital costs. If all ERCOT coal-based plants were retrofitted, several would require SO_2 controls for the efficient use of an MEA-based system. Because the COE reported in Ref. 5 includes capital charges, marginal costs are estimated using another article from the same authors that estimates a 36% contribution of capital charges to the COE for an amine-based CO_2 capture system [12]. Capital cost of the FGD system is assumed to

Table 1 MEA system parameters and 2006 average fuel costs in Texas are used as model inputs [15,16]

Parameters	(%)
CO_2 capture system energy penalty	30%
CO_2 capture efficiency	90%
	(USD/MMBTU)
Coal cost	1.48
Natural Gas cost	6.60

Table 2 Heat rates, marginal generation costs, and CO_2 emission rates are used as model inputs [5,12,15,17–19]

Generation source	Fossil fuel heat rate (MMBtu/MWh)	Generation cost (USD/MWh)	CO_2 emissions rate (tCO_2/MWh)
Coal	11.0	21.68	1.04
Coal+CCS	n/a[a]	52.75	0.15
NGCC	8.98	64.45	0.48
NG boiler	11.8	83.14	0.63
NGGT	13.1	91.83	0.69
Nuclear	n/a[b]	17.15	0
Other	n/a	10.52	0

[a]Heat rate is not included in the estimate of generation costs for coal facilities with CO_2 capture. See 2.4.4 for methodology regarding Coal+CCS capture generation costs.
[b]As stated in 2.4.4, nuclear costs are specified directly rather than using a fuel cost and heat rate.

be a much higher percentage of its contribution to COE, so it is assumed that taking 64% of the full 70.40 USD (2000 dollars) COE is a conservative estimate of the marginal costs of coal-fired generation using CO_2 capture.

Tables 1 and 2 summarize important model assumptions.

3 Results and Discussion

3.1 Model Validation. Table 3 summarizes the comparison of model results for *BAU* with actual data from 2006. While ERCOT reports 305×10^6 MWh of total generation in 2006, the value used for model validation is the sum of the actual ERCOT demand in every hour of 2006. This value of 311×10^6 MWh does not represent a continuous demand variation, but it is more consistent with the model, which calculates generation at hourly intervals. Because CO_2 emissions in ERCOT in 2006 are not available, the model calculation is compared with 2004 emissions. This comparison is reasonable because the total ERCOT generation in 2004, differs from the 2006 generation by less than 2%.

The total generation does not change because the model requires that the actual ERCOT demand is always met. Because the model does not account for varying availability of coal-fired

Table 3 Calculated and actual generation and CO_2 emissions for each plant type are compared for model validation [9,17,20]

Generation source	Model calculation	Actual data	% difference
	2006 Generation (million MWh)		
Coal	129	116	+11
Natural gas	133	144	−7.7
Nuclear	40	42	−5
Other	8.8	8.7	+1.1
Total	311	311	0
	2006 CO_2 Emissions (Mt)		
Coal	133	121	+10
Natural gas	66	73	−10
Total	200	197	+1.3

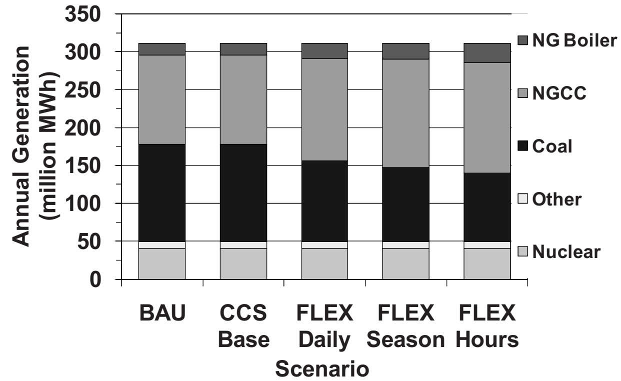

Fig. 7 Annual generation by plant type is compared between scenarios, showing relative changes in coal- and natural gas-based electricity generation

plants, coal-based power generation is calculated 11% higher than the actual value, causing a corresponding 8% underestimate of natural gas-fired generation. This effect produces estimates for coal- and natural gas-based emissions that are respectively higher and lower than the actual quantities, with the net effect being a slight overestimate of total CO_2 emissions. Despite these offsets, calculated values for this first-order model compare well with observed quantities.

3.2 Scenario Comparison. Figure 7 displays the calculated generation mix for each of the five scenarios. The lowest cost nuclear and "other" generation are constant for all scenarios. Because the model does not account for variations in plant availability and specific plant performance constraints, ample NGCC and NG boiler capacity prevent the use of any NGGT units. Since replacement capacity in *CCS Base* is coal-fired generation with CO_2 capture, coal-based generation does not change relative to *BAU*; thus, the entire generation mix remains the same. Among flexible CO_2 capture scenarios, *FLEX Daily* uses the most coal-fired electricity generation, followed by *FLEX Season* and *FLEX Hours*, which simply reflects the order of most to least time CO_2 capture is turned off.

Figure 8 displays the percent of hours throughout the year when CO_2 capture is on at full-load for each scenario. There are very few hours when CO_2 capture must be turned off based on the specified base case reserve margin, so *FLEX Hours* operates CO_2 capture for 99% of the year. Utilization of CO_2 capture is nearly the same between *CCS Base* and *FLEX Hours*; the major difference between these cases is that *CCS Base* requires new replacement capacity, while *FLEX Hours* utilizes existing natural gas-fired facilities when CO_2 capture is on. Off time in *FLEX Hours* amounts to just 99 h in 2006 between June 12 and August 25. Hence, the total off season for *FLEX Season* is June 11 through

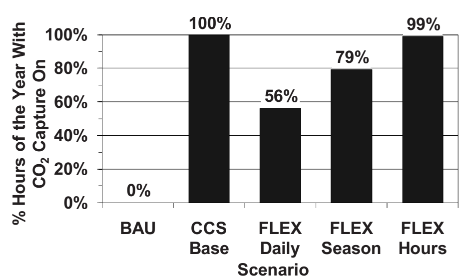

Fig. 8 The percent of hours in 2006 that CO_2 capture is turned on is compared between scenarios, showing the difference between always on CO_2 capture (*CCS Base*) and the flexible CO_2 capture scenarios (*FLEX Daily/Season/Hours*)

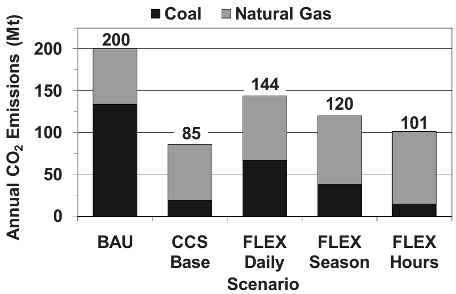

Fig. 9 Annual CO_2 emissions are compared between scenarios, showing relative changes in coal- and natural gas-based CO_2 emissions

August 26, which accounts for 21% of the year. *FLEX Daily*, which uses the on/off operation for peak loads everyday, runs CO_2 capture at full-load for 56% of the year.

As shown in Fig. 9, from a base level of approximately 200 $MtCO_2$, *CCS Base* has the greatest CO_2 emissions reduction at 57% because of its greater use of CO_2 capture at coal-fired facilities. Despite the use of the on/off operation in flexible CO_2 capture scenarios, the system-wide reduction in CO_2 emissions is dramatic. Even *FLEX Daily* reduces emissions by 28%. Despite a 76 day "off season," *FLEX Season* reduces emissions by 40%, and *FLEX Hours* reduces CO_2 emissions by 50%. Though capture systems remove 90% of the CO_2 from coal-fired plant flue gas during full-load CO_2 capture, some of this CO_2 reduction is offset in on/off scenarios by emissions from natural gas-fired plants that operate to replace the base load capacity lost to the energy requirement of CO_2 capture. However, these natural gas-fired plants emit CO_2 at a much lower rate per MWh of electricity, as shown in Table 2. Even in the extreme case of turning CO_2 capture off nearly half of the year, significant CO_2 emissions reductions are still achieved. Because *FLEX Season* and *FLEX Hours* represent maximum and minimum response time of a dynamic CO_2 capture plant, these scenarios indicate the bounds of the CO_2 emissions reduction that may be achieved with full penetration of flexible CO_2 capture into the ERCOT grid under the specified model assumptions.

Using calculated generation data and the marginal generation costs described above, the model determines a system-wide average generation cost and cost per ton of CO_2 avoided. Average generation cost for *BAU* is approximately 40 USD/MWh, and *FLEX Hours* has the highest cost at 55 USD/MWh, a 37% increase. Generation costs for on/off scenarios follow a predictable pattern based on model assumptions; the more often CO_2 capture is used, the more expensive electricity production will be. However, this result is not entirely due to the cost of generation with CO_2 capture; rather, another reason for the cost increase is the greater use of natural gas-based generation for base load when CO_2 capture operates at full-load. High natural gas fuel costs relative to coal are thus a major reason for any increase in average generation costs. Because the marginal cost at coal-fired facilities with CO_2 capture is less than that of natural gas-fired generation, *CCS Base* has a lower average generation cost than *FLEX Hours* at 53 USD/MWh.

The system average cost per ton of CO_2 avoided is 34.91 USD/tCO_2 for *CCS Base* and ranges between 45.44–46.39 USD/tCO_2 for flexible CO_2 capture scenarios. *CCS Base* has a lower CO_2 avoidance cost due to a larger CO_2 emissions reduction at a lower average generation cost. This result indicates that based on generation costs alone, CO_2 emissions can be reduced more economically by operating CO_2 capture continuously rather than using flexible CO_2 capture along with additional natural gas-fired generation when CO_2 capture is on. However, if natural gas-fired units were to be used as replacement capacity in *CCS Base* instead

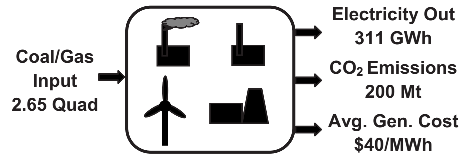

Fig. 10 *BAU* resource flows include annual fuel input, electricity and CO_2 output, and system-wide average generation cost

of coal-fired plants with CO_2 capture, calculated generation, CO_2 emissions, and cost values would be near those of *FLEX Hours*. While *CCS Base* is more attractive on a USD/tCO_2 avoided basis, this result comes at the large expense of building new power plants, whose capital costs are not included in model calculations. *CCS Base*, which assumes replacement of all capacity lost to CO_2 capture, requires over 4400 MW of new installed capacity (approximately four new large-scale power plants). If a new subcritical coal-fired plant with CO_2 capture costs 2900 USD/kW, the on/off operation provides savings of 12.8 billion USD [13]. Furthermore, the amount of time CO_2 capture must be turned off is a very small percentage of the year, so utilization of capitally intense CO_2 capture systems is still high. For comparison purposes, if replacement capacity is instead NGCC at 550 USD/kW or a subcritical coal-based facility without CO_2 capture at 1550 USD/kW, capital cost savings would be 2.44 and 6.84 billion USD, respectively [13].

3.3 Comparison of Resource Flows: *BAU* and *FLEX Hours*. Another way to compare scenarios is to consider resource flows in the system. Primary resource flows for *BAU* and *FLEX Hours* are shown in Figs. 10 and 11 to compare the current ERCOT grid with the best case scenario for CO_2 emissions reduction without a new capacity requirement. These figures demonstrate that another effect of implementing CO_2 capture is increased fuel use for additional natural gas-based electricity generation during full-load CO_2 capture. This increased fuel use reduces the overall electric grid efficiency of fossil fuel use, defined as fossil-based electricity output per coal and natural gas input, which is 34% for *BAU* and 30% for *FLEX Hours*. *CCS Base*, which uses far more coal-fired generation with CO_2 capture than all flexible scenarios, has the lowest grid efficiency at 27%.

Tables 4 and 5 show the base case results from all five scenarios.

3.4 Sensitivity to Reserve Margin. Because the reserve margin specification effectively sets the load threshold above which new capacity must be installed or CO_2 capture must be turned off, it has a strong impact on how a system with CO_2 capture must be planned and operated. Using the same 2006 ERCOT load and initial installed capacity data, *CCS Base* is modeled for various reserve margin specifications, and Fig. 12 shows the amount of new capacity that must be installed. Because reserve margin is determined by the single highest demand of the year, this capacity requirement varies linearly with the reserve margin. The intersection of this plot with the horizontal dotted line represents the base case *CCS Base* described above, where all capacity lost to CO_2 capture must be replaced. The actual 12.5% ERCOT minimum

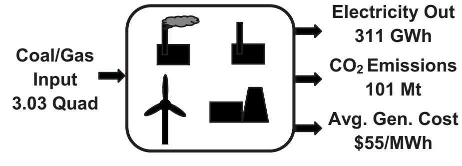

Fig. 11 *FLEX Hours* resource flows include annual fuel input, electricity and CO_2 output, and system-wide average generation cost

Table 4 Summary of generation by source and the number of CO_2 capture "off hours" for each scenario

Scenario	Coal generation (million MWh)	NGCC generation (million MWh)	NG boiler generation (million MWh)	Nuclear generation (million MWh)	Other generation (million MWh)	Total generation (million MWh)	No. of hours with CO_2 capture off
BAU	129	118	15	40.3	8.81	311	8758[a]
CCS Base	129	118	15	40.3	8.81	311	0
FLEX Daily	107	135	20	40.3	8.81	311	3845
FLEX Season	98	143	21	40.3	8.81	311	1824
FLEX Hours	91	146	26	40.3	8.81	311	99

[a]Data set contains 8758 points rather than the full 8760 hours in a year

reserve margin requires only 220 MW of new capacity, but new required capacity increases substantially if future planning indicates that a more stringent value should be used to maintain grid reliability. No new capacity is required below a reserve margin of 12.2%. Requiring only 220 MW with a 12.5% reserve margin suggests that the actual 2006 ERCOT grid could manage a large amount of CO_2 capture retrofitting without new capacity, regardless of flexible CO_2 capture. However, because increasing electricity demand indicates that ERCOT may fail to achieve a minimum 12.5% reserve margin within a few years, it appears beneficial for flexible CO_2 capture to mitigate any additional strain on system capacity [14].

The reserve margin specification also has a strong effect on the on/off operation, as Fig. 13 displays. Increasing the reserve margin increases the chances that *FLEX Season* will find an atypically high demand away from the highest annual peaks. Consequently, there is a rapid increase in the amount of time CO_2 capture is turned off that approaches 23% of the year at a 20% reserve margin. *FLEX Hours* has a much smaller increase in off hours as the reserve margin increases because there are still very few hours throughout the year when the system load nears installed capacity. A plot of off hours versus specified reserve margin for a flexible CO_2 capture system with an intermediate system response time would presumably lie between those of *FLEX Season* and *FLEX Hours*.

The analysis above assumes that flexible CO_2 capture systems are required to turn off when the specified reserve margin is breached. However, if ERCOT considers the energy being used for CO_2 capture to be "available" even during full-load CO_2 capture, the CO_2 capture system may not have to turn off unless a reliability event such as a plant failure occurs. Thus, simply having the ability to operate flexibly may be enough to avoid having to build replacement capacity.

These results indicate that in order for generators using flexible CO_2 capture to effectively plan when capture systems are on or off, it will be essential to clearly define and communicate the reserve margin specification and the availability of the energy being used for CO_2 capture.

4 Conclusions

A grid-level model was created in MATLAB and used to study the implications and tradeoffs of installing flexible CO_2 capture systems on all coal-based power plants in the 2006 ERCOT electric grid. Under base case model assumptions, the ability to turn CO_2 capture on and off in response to electric grid demand prevents the need for over 4400 MW of new capacity, saving approximately 12.8 billion USD in capital costs. Because the highest system loads are very infrequent, on/off capable CO_2 capture systems with a response time of 1 h or less must be off for only 99 nonconsecutive hours of the year to avoid new capacity requirements. If long response times require systems that are turned off to remain so for the entire peak load season, the total "capture off" season is 76 days between June 11 and August 26. Despite the time off, these scenarios achieve 50% and 40% system-wide CO_2 emissions reduction, comparable to the 57% reduction with continuous full-load CO_2 throughout the year. These two on/off scenarios bound the range of possible system response time, so an ERCOT grid with widespread implementation of flexible CO_2 capture may be expected to have CO_2 emissions reduction within this range.

System average generation costs do not change significantly from the use of on/off CO_2 capture. However, the always on scenario has lower CO_2 avoidance costs because it assumes that any required replacement capacity consists of coal-based generation with CO_2 capture, which has lower emissions and lower marginal generation costs than natural gas-based generation with assumed fuel prices. At lower natural gas prices, gas-fired facilities might be used before coal-based generation with CO_2 capture to meet the base load. In all on/off CO_2 capture scenarios, running CO_2 capture requires the increased use of natural gas-fired plants for base load generation, so natural gas fuel prices are the primary determinant of cost variations among scenarios using flexible CO_2 capture.

Electric grid reserve margin specification is important for determining the threshold load above which CO_2 capture must be turned off, so clearly defining this value for plant operators will be essential to ensure proper planning and implementation of flexible CO_2 capture. If the energy used for CO_2 capture is still considered available by the grid operator, simply having the ability to operate CO_2 capture flexibly may be enough to prevent the need for new replacement capacity.

5 Future Work

While this study addresses some key concerns with using on/off CO_2 capture to eliminate the need for replacement capacity, future

Table 5 Summary of fuel use, electric grid efficiency, CO_2 emissions, and costs for each scenario

Scenario	Coal input (Quad)	Natural gas input (Quad)	Electric grid efficiency (%)	CO_2 from coal (Mt)	CO_2 from natural gas (Mt)	Total CO_2 Emissions (Mt) (% reduction)	Average generation cost (USD/MWh; % increase)	Cost of CO_2 avoidance (USD/t)
BAU	1.42	1.24	33.7	134	66.1	200	39.98	n/a
CCS Base	2.03	1.24	27.4	19.1	66.1	85.2 [−57.4]	52.86[+32.2]	34.91
FLEX Daily	1.42	1.44	31.2	66.3	77.3	144 [−28.2]	48.31[+20.8]	45.92
FLEX Season	1.42	1.53	30.3	38.5	81.6	120 [−39.9]	51.65[+29.2]	45.44
FLEX Hours	1.42	1.61	29.5	14.8	86.1	101 [−49.6]	54.78[+37.0]	46.39

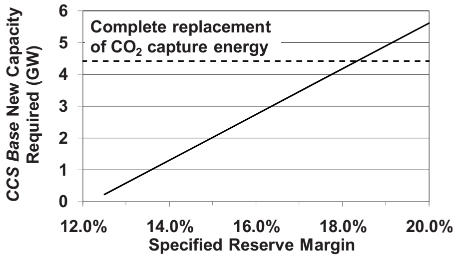

Fig. 12 There is a linear increase of the new capacity required in *CCS Base* with specified reserve margin, and the horizontal line represents the base case where all capacity lost to CO_2 capture is replaced

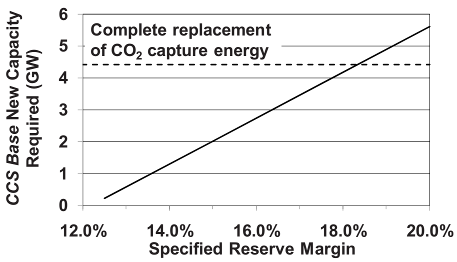

Fig. 13 The number of hours in a year that CO_2 capture is turned off increases the specified reserve margin for *FLEX Season* and *FLEX Hours*, which bound the range of system response time

model development will allow more detailed sensitivity analyses of parameters such as system response time, CO_2 capture energy requirement, and piecewise penetration of CO_2 capture into the electric grid. Examining different options for flexible CO_2 capture may also be useful to better understand the important tradeoffs between dynamically operating CO_2 capture systems. Incorporating actual plant availability, which varies throughout the year from effects such as maintenance schedules and variations in ambient air temperature, may also improve an understanding of how on/off CO_2 capture can be utilized to ensure grid reliability while minimizing costs. Ultimately, a rigorous grid model incorporating individual plant specifications and transmission considerations will be necessary to fully understand the implications of flexible CO_2 capture in the electric grid.

Another potential opportunity to improve the economics of CO_2 capture with flexible operation is by turning capture systems off during daily periods of high electricity price. Selling higher value electricity with the CO_2 capture turned off may improve generator profits relative to an operator that runs CO_2 capture continuously throughout the year. Future studies will investigate this concept in order to better understand the tradeoffs between the value of electricity and the cost of CO_2 emissions in a carbon dioxide constrained electric grid with flexible CO_2 capture. It will be important to understand how the value of CO_2 may affect electricity prices and grid dispatch decisions when flexible CO_2 capture is considered.

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