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Reducing the average cost of CO_2 capture by shutting-down the capture plant at times of high electricity prices

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ABSTRACT

Flexible operation of a CCS plant can lower the cost of foregone electricity sales in competitive wholesale electricity markets but reduces the amount of CO_2 captured over the life-time of a CCS plant and increases the capital cost of CCS systems per unit of emissions captured. Whether the benefits of flexible CCS exceed the increased costs depends on a relationship between capital and operating costs and cyclical electricity price differentials. In this paper we explore these trade-offs, propose a method to quantify them and apply this framework to U.S. data on CCS capital costs and electricity prices.

1. Introduction

Carbon Capture and Storage (CCS) technologies can significantly reduce the amount of CO_2 emitted from coal-fired power plants but high capital and operating costs may limit the role they will play in a carbon constrained world. A significant portion of CCS operating costs is due to their energy penalty which reduces the plant's electricity sales and profits, especially during times of high electricity prices. Most analyses of CCS systems assume continuous operation of the CCS unit and capture of CO_2 when the plant is operating, but cyclical electricity demand and prices have spurred interest in ways to minimize CCS energy usage during times of high electricity prices to reduce average capture cost and maximize profits. A plant with CCS could temporarily shut down the capture unit and vent CO_2 to increase electricity output during times of high wholesale electricity prices. Although temporarily shutting down the capture unit means increasing the plant's emissions, it is possible that by reducing the average cost of capture, this mechanism may facilitate installation of CCS in a greater number of coal-fired power plants and lead to lower national emissions. In this paper we study the costs and benefits of such mechanism in post-combustion CCS systems.

One of the most mature post-combustion capture technologies uses amines to chemically absorb CO_2 from exhaust gases (Rochelle, 2009). In this paper we focus on amine-based CCS systems, where aqueous mono-ethanol amine (MEA) is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber, where CO_2 is removed, and a regenerator, where CO_2 is released and the original solvent is recovered. Providing energy for solvent regeneration and CO_2 compression significantly reduces the plant's net efficiency and net electricity output (Chung et al., 2011). Estimates for the reduction in the plant's electrical output (energy penalty) due to CCS operation range from 20% to 40% (IECM, 2010; Rochelle, 2009). Temporarily shutting down an amine capture unit thus implies avoiding the CCS energy penalty and increasing the plant's output 20–40% during peak price periods if the plant's electrical generators are capable of handling the increased flow of steam that becomes available when the CCS unit is not operating. In this paper we assume no additional capital costs are required for installing a capture unit bypass because this is likely to be included in most plant designs for reliability, availability, and maintenance purposes (Chalmers et al., 2009b). For an existing plant with a CCS retrofit the steam turbines and generators are designed to handle the full steam flow from the boiler when the CCS is shut down so there is no additional capital investment required for flexible operation of retrofit plants. However, new plants with CCS may be designed with lower capacity steam turbines and generators if the plant is designed to operate the CO_2 capture unit continuously. Therefore new CCS plants with flexible CCS systems may require additional capital expenditures to increase the capacity of the steam turbines and generators.

A few studies have looked at the technical feasibility and economics of flexible post-combustion CCS systems. Chalmers et al. (2009b), examined the technical implications of flexible operation

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of CCS plants and concluded that bypassing the capture unit would not face any significant engineering constraints. The same authors (Chalmers et al., 2009a) examined a number of scenarios with varying assumptions on carbon prices and concluded that the ability to bypass the CO_2 capture system at times of high electricity demand has economic value even when CO_2 prices are high (up to \$60/tCO_2 for a peak electricity price that is twice the daytime price, and up to \$100/tCO_2 for a super-peak that is 4 times the daytime electricity price).

In the U.S., the economic and environmental impacts associated with increased electricity output and ramp-rate from bypassing the capture unit have been investigated with an economic dispatch model of ERCOT (i.e. Texas power system) assuming a range of carbon prices (Cohen et al., 2010; Ziaii et al., 2009) and fuel prices (Cohen et al., 2009; Fyffe et al., 2010). These studies conclude that flexible operation of CCS could save up to 12.8 billion in ERCOT from precluding the need of installing over 4400 MW of new generating capacity, while minimally reducing CO_2 capture relative to a scenario of continuous CCS operation.

The studies discussed assume a CO_2 price, but in our judgment, estimating the benefits of temporarily shutting down the CO_2 capture plant is relevant under a variety of climate policy scenarios, including those without a price on carbon. If CO_2 emissions from the electricity sector in the future are constrained with a tax or a cap-and-trade program, the CO_2 price will of course be the primary criteria used by plant operators to decide whether to temporarily shut down a flexible CCS system. But in the context of the New Source Performance Standard (NSPS) rule recently proposed by the U.S. EPA, which requires new coal plants install CCS after 10 years of operation (U.S. EPA, 2012), the economic potential of bypassing the CO_2 capture plant at times of high electricity prices, needs to be assessed without making assumptions on CO_2 prices. This paper intends to fill this gap. Rather than taking a system-wide approach, we look at the capital costs, O&M costs, and performance of new and retrofit base-load CCS plants to explore the possibility of reducing the plant's average cost of CO_2 capture via CO_2 venting. To do so, we develop a method to determine whether the price regime in a wholesale electricity market justifies temporarily shutting down an amine capture plant to reduce the average cost of CO_2 capture and then, focus our analysis on four electricity markets in the U.S. Eastern Interconnect where coal-fired power plants play and will continue to play an important role meeting electricity needs, and where CCS is likely to be implemented.

A parallel analysis of the profitability of amine-storage for increasing the CCS plant generation capacity at times of high electricity prices, without venting any additional CO_2 has also been completed (Patino-Echeverri and Hoppock, 2012).

2. Method

In this paper we propose a method to determine whether flexible operation of CCS will reduce the cost of capture, assuming a base-load plant that is a price taker in the wholesale electricity market, and is not subject to any economic penalties for venting CO_2 over short time periods. Our method consists of characterizing the price regime required for flexible operation profitability in terms of the capital and operating costs of post-combustion amine CCS units. When the capture unit is shut down at times of high electricity prices the variable cost of capturing CO_2 is reduced, but at the same time the capital cost per ton of CO_2 captured increases, as fewer tons are captured over the life-time of the plant. Here we find an expression that summarizes the tradeoff between the increment in the capital cost per ton and the reduction in the variable cost of capture that occurs when the CO_2 bypass is used to vent out CO_2 at times of high electricity prices. This expression depends only on the difference between the average of high electricity prices and the average price, and the capital, and operating and maintenance costs of the CCS system.

One advantage of our method is that we identify the characteristics of price regimes that are favorable to flexible operation of CCS in terms of a price differential that is independent of the electricity price themselves or any assumptions on the future price of carbon emissions. By applying the method to data on CCS costs and electricity prices in competitive markets in the U.S. we provide a preliminary assessment of whether this type of flexible operation may be economically beneficial in these markets.

Throughout this paper we assume the CCS plant is a price taker and therefore by making more electricity generation available to the market it does not affect prevalent prices. Similarly we assume that any additional electricity the plant supplies to the market as a result of bypassing the capture unit, can be dispatched. In reality prices will be affected by any changes in supply and demand, and the ability to dispatch more electricity may be constrained by transmission capacity and reliability considerations. An analysis accounting for all these effects could be attempted with a security-constrained, economic dispatch model representing generation resources, transmission lines, and demand profiles in the system, and accounting for different forecasts of future fuel prices, and power capacity additions and retirements, as well as for forecasts on the adoption of CCS both as a retrofit and in new plants. Such analysis is out of the scope of this paper. Although system wide analysis of CCS economics can reveal interesting insights that may be overlooked from plant-level analysis as demonstrated in the literature (e.g. Wise and Dooley, 2004) we believe that for the objectives of this paper, the benefits of a security-constrained, economic dispatch may be outweigh by the costs of making a wide range of assumptions that ultimately determine prices. Instead we use historical prices to provide a benchmark of the value of a CCS bypass in a system with similar price variability.

2.1. Average price differentials

We characterize the electricity price regimes for which venting out CO_2 during H_v hours in an H hour cycle, reduces the average cost of capture. For this characterization we will use the concept of price differentials. We define:

H: Hours of plant operation in a cycle (e.g. $H = 168$ if a weekly cycle and capacity factor of the plant is 1).
P_k: Kth lowest electricity hourly price in the cycle (\$/MWh) (e.g. If $H = 168$, then P_{168} = highest hourly price in the cycle (week)).

We define the mth *Price Differential* for an H hours cycle denoted as PD_m^H where $m = 1, 2, \ldots, H$, as the difference between the average of the m highest hourly electricity prices in the cycle, and the average electricity price for all hours in the cycle:

$$\mathrm{PD}_m^H = \frac{1}{m}\sum_{k=H-m+1}^{H} P_k - \frac{1}{H}\sum_{k=1}^{H} P_k \tag{1}$$

This definition will become useful when we show that the average cost of capture can be reduced if the market exhibits price differentials (PDs) that exceed a threshold calculated as a function of the capital and operating costs of the CCS plant.

2.2. Average cost of CO_2 capture

As stated in the introduction, if there is a carbon price, the costs of bypassing the capture unit and emitting CO_2 during the H_v hours of highest electricity prices in an H hours cycle, must be compared to the extra revenue due to increased sales of electricity, and a reduction in operating costs of the CCS during those hours.

Regardless of whether there is a carbon price, to minimize the cost of emissions reduction, the number of hours when CO_2 is not captured should be such that the average cost of capture (including capital and fixed O&M costs) is reduced with respect to a situation in which CO_2 is captured continuously (i.e. whenever the plant is operating). In this section we compare the average cost of capture for conventional and flexible operation to determine when flexible operation can be beneficial in the absence of a carbon price.

2.3. Average cost of CO_2 capture: continuous operation of CCS system

We define:

- E: CCS hourly energy use (MWh), also known as the energy penalty of CCS
- T: CO_2 captured when CCS is operating (Ton/h)
- CC: Capital costs of conventional CCS system for a cycle of H hours (e.g. if weekly cycling then CC = levelized annual capital costs/number of weeks in a year) ($)
- VOM: Variable operating and maintenance costs of CCS excluding energy cost ($/h)
- FOM: Fixed operating and maintenance costs from the CCS system during one cycle ($)
- CF: Plant's capacity factor (%), assumed to be constant
- A: Average cost of capture ($/ton CO_2) for a plant with conventional operation of CCS (i.e. CO_2 is captured continuously during the H hours of the cycle)

$$A = \frac{\mathrm{CC} + \mathrm{FOM} + \mathrm{CF} \times H \times \mathrm{VOM} + \mathrm{CF} \times E \sum_{k=1}^{H} P_k}{\mathrm{CF} \times H \times T} \tag{2}$$

2.4. Average cost of CO_2 capture: flexible operation of CCS system

As explained in the introduction we assume that flexible operation of retrofit plants does not require any additional capital investment. In contrast, for a new coal-fired power plant with CCS we assume that enabling flexible operation of the CCS system requires additional investment in a larger capacity low pressure turbine to use the extra steam that will be available when the CO_2 capture unit is shutdown. Most CCS designs use steam drawn from between the Intermediate Pressure and Low Pressure (LP) turbines to supply heat for amine regeneration (Chalmers et al., 2009b). New coal plants with CCS will likely be designed with scaled down LP turbines because of reduced steam flow. With bypass of the capture plant, steam flows to the LP turbines are restored to the equivalent flow of an equivalent plant without CCS, necessitating additional capacity of this LP turbine to take advantage of the increased steam flow (Chalmers et al., 2009b). Instead, an existing coal-fired power plant that is retrofitted with CCS is already capable of utilizing CCS bypass steam flows, because its LP turbines are already sized for pre-CCS flows.

Fig. 1 illustrates a CCS plant with capability of bypassing the capture system.

To represent the additional capital costs to enable flexibility of new CCS plants we define:

CC^{flex}: Additional capital costs that must be incurred to enable flexible operation of a CCS plant; i.e. to enable the CCS system to utilize the additional steam to increase net power output when the capture plant is shut down. These costs are zero for a retrofit plant and are equal to the costs of increased LP turbine capacity in a new CCS plant as discussed above (costs are for a cycle of H hours e.g. if weekly cycling then CC^{flex} = levelized annual capital costs/number of weeks in a year) ($)

We also define:

- H_v: Number of hours the CO_2 capture unit is shutdown (h/cycle) and CO_2 is vented out.
- A_v: Average cost of capture ($/ton) for a retrofit or new plant capable of shutting down the capture unit (and increasing net power output) during H_v hours in a cycle of H hours

The average cost of capture for both retrofit and new plants, when the CO_2 capture unit is shutdown during H_v hours in a cycle is given by:

$$A_v = \frac{\mathrm{CC} + \mathrm{CC}^{\mathrm{flex}} + \mathrm{FOM} + \mathrm{CF} \times (H - H_v) \times \mathrm{VOM} + \mathrm{CF} \times E \sum_{k=1}^{H-H_v} P_k}{\mathrm{CF} \times (H - H_v) \times T} \tag{3}$$

2.5. Price regimes that allow a reduction in the average cost of capture from flexible CCS operation

If green-house gas regulations impose a price on carbon emissions then plant operators will decide whether to shut down the capture plant based on a comparison between the price of CO_2 and the marginal cost of capture. In other words, any savings from reducing the O&M and electricity penalty costs by shutting the capture plant off will be compared against the charges that will be incurred for venting CO_2 to the atmosphere instead of capturing it.

In this paper we argue that regardless of the future regulatory scenario, it is worth estimating the reduction in the average cost of CO_2 capture that can be obtained by venting CO_2 during times of high electricity prices. Information on how the average cost of capture can be reduced with flexible operation should be used to inform regulations governing CCS use.

The value of H_v should be chosen so that the average cost of capture in a cycle with CO_2 venting is lower than the average cost of capture when capturing H hours a cycle. That means that the reduction in the per unit average cost of capture ($/ton CO_2) enabled by flexible operation of the CCS capture unit can be found by subtracting Eq. (3) from Eq. (2):

$$A - A_v = \frac{\mathrm{CF} \times H \times E \sum_{k=H-H_v+1}^{H} P_k - H_v \left(\mathrm{CC} + \mathrm{FOM} + \mathrm{CF} \times E \sum_{k=1}^{H} P_k \right) - H \times \mathrm{CC}^{\mathrm{flex}}}{\mathrm{CF} \times (H - H_v) \times H \times T} \tag{4}$$

Venting out CO_2 during H_v hours in an H hours cycle reduces the average cost of capture in a retrofit or new plant if Eq. (4) is positive, or if:

$$\frac{1}{H_v} \sum_{k=H-H_v+1}^{H} P_k - \frac{1}{H} \sum_{k=1}^{H} P_k > \frac{1}{\mathrm{CF} \times E} \left(\frac{\mathrm{CC} + \mathrm{FOM}}{H} + \frac{\mathrm{CC}^{\mathrm{flex}}}{H_v} \right) \tag{5a}$$

Note that the left hand side of Eq. (5a) is equal to the difference between the average price of the highest priced H_v hours in the cycle, and the average electricity price for all the H hours in the cycle, or in other words is the v^{th} Price Differential as defined in Eq. (1).

So in conclusion, venting out CO_2 during H_v hours in an H hours cycle reduces the average cost of capture if:

$$\mathrm{PD}_V^H > \frac{1}{\mathrm{CF} \times E} \left(\frac{\mathrm{CC} + \mathrm{FOM}}{H} + \frac{\mathrm{CC}^{\mathrm{flex}}}{H_v} \right) \tag{5b}$$

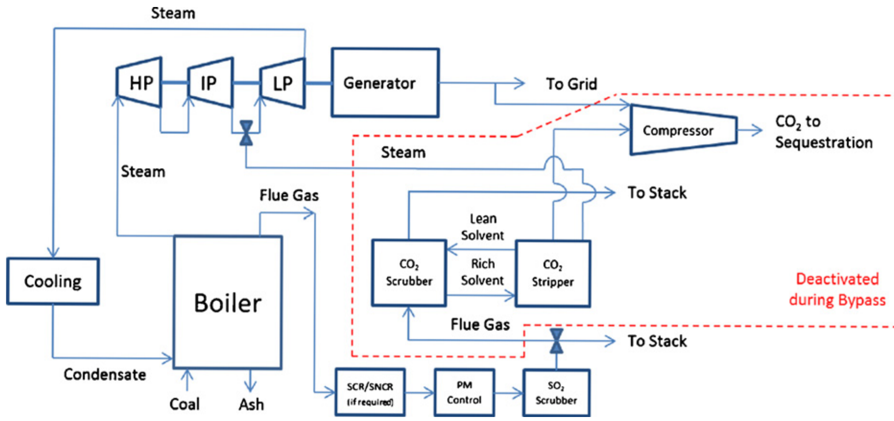

Fig. 1. Simplified schematic of coal plant with post combustion CCS and valves to bypass the CCS system. Equipment within the red dashed line is deactivated when CCS system is bypassed. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

2.6. Implications of assuming a constant capacity factor

A plant's capacity factor depends in part on its availability. By assuming a constant capacity factor we may be underestimating the benefits from price arbitrage that can be obtained from bypassing the CO_2 capture unit at times of high electricity prices. To maximize revenue operators could attempt to maximize output during peak loads and peak seasons when daily price differentials are greatest, and schedule maintenance during the spring and fall when price differentials are lower.

2.7. Feasibility of cycling steam flow for flexible operation of the CCS system in a retrofit plant

Shutting down the CCS system during high wholesale price periods will increase steam flows to the low pressure (LP) turbine to its base case levels (pre CCS retrofit) and decrease/eliminate steam flow to the letdown turbine. Changing steam flow rates through the LP turbine would likely affect the turbine's efficiency, but determining these efficiency losses would require mechanical modeling that is beyond the scope of this paper so we have not included them in our calculations.

Similarly, when the capture unit is shut down, and the LP turbine is operating at full capacity, it is likely that the letdown turbine would require a small amount of steam to maintain the temperature of the turbine and guard against wear, slightly reducing steam flow to the LP turbine (Pike, 2010). This would cause a minor drop in the output of the plant and a minor efficiency penalty. We assume these impacts are negligible.

3. Results

In this section we use Eq. (5b) to determine whether flexible operation of CCS may allow a reduction of the average cost of capture in the U.S. Our results also explore the magnitude of the excess emissions per plant that may result if CCS plants are operated as to minimize the average cost of capture.

3.1. Energy penalty, capital costs, and operating and maintenance costs of a CCS system

CCS capital and operating costs depend on a number of plant characteristics and therefore the right-hand-side of Eq. (5b) will vary with different assumptions. In this paper we use two sources of information for existing and new plants to explore whether price regimes in wholesale markets in the Eastern Interconnect of the U.S. justify shutting down the CCS capture plants to reduce the average cost of capture. For existing plants we use operating parameters and capital and O&M costs from a National Energy Technology Laboratory's (NETL) CCS report (NETL, 2007), for new plants we use the IECM model from the NETL funded Center for Energy and Environmental Studies at Carnegie Mellon University (IECM, 2010). Assumptions for new and existing plants are summarized in Table 1. Note that the CCS energy penalty estimate for the new plant is 40% while for the existing plant is 30%. This discrepancy is due to different assumptions regarding the effect of removing steam from the plant's low pressure turbine for CCS amine regeneration and its impact on plant efficiency.

Using the estimates provided in Table 1, and assuming a weekly cycle (i.e. $H = 168$ h), the right hand side of Eq. (5b) can be calculated for different assumptions on the number of hours CO_2 will be vented per cycle (i.e. H_v). These estimates for different capacity factors and 30% and 40% CCS energy penalties are provided in Table 2.

According to Table 2 we can conclude that venting CO_2 from CCS in retrofit plants during H_v hours a week would reduce the average cost of capture if the corresponding weekly average price differentials $PD_{H_v}^{168}$ exceeded 33–54 $/MWh depending on assumptions about capacity factor and CCS energy penalty. This threshold for $PD_{H_v}^{168}$ would be constant for any number of venting hours H_v. In contrast, for a new plant with flexible CCS, the threshold for $PD_{H_v}^{168}$ that makes venting economical varies widely with the number of venting hours. For example venting CO_2 during one hour a week (i.e. $H_v = 1$), assuming a 90% capacity factor, and 40% energy penalty, would reduce the cost of capture in a new plant if PD_1^{168} exceeded $500/MWh every week, while venting during one day a week (i.e. $H_v = 24$) would be economical if PD_{24}^{168} exceeded $47/MWh every week. As seen in Table 2, assumptions on capacity factor and CCS energy penalty significantly impact the threshold for price differentials. Higher capacity factors and higher energy penalty lower the required price differential. In the following section we use historical electricity prices in the U.S. to calculate the average weekly price differential $PD_{H_v}^{168}$ for a range of venting hours. Throughout this paper we assume the CCS system implies an energy penalty of 30% in an existing plant and of 40% in a new plant as it is assumed in the original studies from which we take cost and performance data for these plants (NETL, 2007; IECM, 2010).

3.2. Average price differentials in U.S. electricity markets

In the U.S. a number of Independent System Operators (ISO)/Regional Transmission Organizations (RTO) were created after the Federal Energy Regulatory Commission FERC orders

Table 1
Estimates of costs, and CCS energy penalty for an existing and new plant with CCS.

	Existing plant	New plant
1. Net power output with CCS (MW)	303	513
2. Net power output without CCS (MW)	434	848
3. Total capital requirement of CCS, $1000	417,952	499,888
4. Total capital requirement of increased LP turbine capacity, $1000	–	65,930
5. CC,[a] $1000	904	1081
6. CCflex,[a] $1000	–	143
7. FOM, $1000/year	2605	14,710
8. VOM, $/hour	8	19
9. E, MW/hour	131	335
10. T, CO_2 Tons/hour (CO_2 removal efficiency is 90% for both plants)	389	686
11. Coal type	Ohio Bituminous, carbon content 63.2%, heat content 11,293 Btu/lb	Illinois #6 Bituminous, carbon content 63.75%, heat content 11,670 Btu/lb

[a] Costs in lines 5 and 6 are calculated equal to the Levelized Annual Capital Cost divided by 52.14 (number of cycles – weeks – in a year). Levelized Annual Capital Cost is calculated by multiplying the Total Capital Requirement by a Fixed Capital Charge Factor of 0.1128 which is the default value in IECM (IECM, 2010) resulting from standard assumptions on economic life-time of the investment, interest rate, tax-rates, debt to equity ratio, etc. For a new plant, a larger LP turbine is needed to enable full increase in net power output when the capture unit is shut-down. New Plant characteristics: 908.9 MW gross capacity, 847.9 MW capacity after subtracting energy penalty of the following environmental controls: NOx Control: Hot-side SCR, Particulates: Cold-side ESP, SO_2 Control: Wet FGD, Mercury: Carbon Injection, Cooling system: Wet Cooling Tower, Wastewater: Ash Pond, Fly ash Disposal: No Mixing. When an amine CCS system operates electricity output drops to 512.9 MW. CO_2 Capture: Amine System. All costs are in $2009. Costs of existing plant were converted to $2009 using the Chemical Engineering Plant Cost Index (2011).

888 and 889 mandated the unbundling of electrical services and required electric utilities to provide open and non-discriminatory access to their power transmission facilities. ISO/RTOs coordinate the power grid and wholesale electricity markets to ensure the balance between electricity demand and supply. In the Eastern Interconnect there are four ISOs that operate two-settlement electricity markets (day ahead and real-time) and determine locational marginal prices (LMP): New York (NYISO), New England ISO (ISONE), MISO and PJM. The marginal fuel in MISO and PJM is coal while in ISONE and NYISO is natural gas. Together, these markets span 29 states, have a peak load of 320 GW and serve a population of about 133 million (NYISO, 2012; ISONE, 2012; PJM, 2012; MISO, 2012).

Using Locational Marginal Prices (LMP) for major trading hubs and load zones in these ISOs during years 2007 and 2008, we calculated the average price differentials for each week (i.e. $H = 168$), assuming the CCS unit is shut down 24, 16, 8, 4 and 1 h a week (e.g. $H_v = 24$, 16, 8, 4 and 1).

Given that new plants require an additional capital expense to enable flexible operation of the capture unit, price differentials during every week of the planning horizon (or average price differentials throughout the planning horizon) should exceed the thresholds found in Table 2 to achieve a reduction in the average cost of CO_2 capture. Table 3 shows that average price differentials in the examined hubs rarely exceeded the required threshold for justifying investment in bypass at new plants. The price differentials of year 2007 would justify an investment to vent out CO_2 at a new plant during 16 h a week in only two nodes. The price differentials of 2008 would have justified investment to enable shutting down the capture plant during 24 h a week in 5 nodes, and during 16 h/week in 2 other nodes.

In contrast, average price differentials exceeded the threshold for justifying venting out CO_2 at existing plants retrofitted with CCS during 1 or more hours per week in 22 out of 35 nodes for year 2007, and 32 out of 35 nodes for year 2008. Price differentials are a function of a number of factors including load patterns, capacity reserve margins, type of generation resources, market design, and power transmission capacity. Although identifying the underlying causes of inter and intra market variations in price differentials would require analysis beyond the scope of this paper, the results in Table 3 suggest that transmission congestion is likely to have played a very important role. For example, persistent transmission congestion in the Wisconsin and the Upper Peninsula of Michigan (WUMS) and Minnesota areas may have caused the high price differentials observed in MISO (FERC, 2012). Similarly the high price differentials observed in the areas of concentrated demand in NYISO such as New York City (NYC) metropolitan area, and Long Island (LI) may also be explained by transmission congestion that occurs at midafternoon and other times of high electricity demand (U.S. EIA, 2012).

Because enabling a bypass system in an existing-retrofitted plant does not require any additional capital investment the interpretation of these results for retrofitted plants is different from the interpretation for a new plant. In the case of retrofit plants, the fact that the average price differential for a particular node did not exceed the threshold for profitability is not indicative of the potential for reducing the average costs of CO_2 capture by flexibly operating the capture unit. In fact there may have been several

Table 2
Required price differentials ($2009) for reducing average cost of CO_2 capture by shutting-down the plant H_v hours in an H hours cycle. Calculated as the Right-Hand-Side of Eq. (5b), assuming a weekly cycle ($H = 168$ h), CCS energy penalties of 30% and 40% as estimated by (NETL, 2007) and (IECM, 2010), and capacity factors (CF) of 1, 0.9 and 0.8[a].

H_v (h)	Existing plant						New plant					
	CCS energy penalty = 30%			CCS energy penalty = 40%			CCS energy penalty = 30%			CCS energy penalty = 40%		
	CF = 1	CF = 0.9	CF = 0.8	CF = 1	CF = 0.9	CF = 0.8	CF = 1	CF = 0.9	CF = 0.8	CF = 1	CF = 0.9	CF = 0.8
1	44	48	54	33	37	42	591	657	739	450	500	562
4	44	48	54	33	37	42	172	191	215	131	145	163
8	44	48	54	33	37	42	102	113	127	77	86	97
16	44	48	54	33	37	42	67	74	83	51	56	64
24	44	48	54	33	37	42	55	61	69	42	47	52

[a] A capacity factor of 1 is not a realistic assumption but is included here as a lower bound estimate of the required price differentials.

Table 3
Average of weekly price differentials observed during 2007 and 2008 in major trading hubs in U.S. electricity markets in the Eastern Interconnect. The left-hand side of Eq. (5b) was calculated for each week. Weekly values for each number of venting hours (H_v) were averaged over the year to find the numbers reported in table. Cells shaded in color indicate cost effectiveness assuming a constant capacity factor of 1, a CCS energy penalty of 30% for the retrofit plant and 40% for the new plant. Cells shaded in green indicate cost effectiveness for existing plants. Cells shaded in dark blue indicate cost effectiveness for both new and existing plants. Cells shaded in orange indicate values that are cost effective for new plants. All price differentials were converted to $2009 using levelized GDP data from the Bureau of Economic Analysis, U.S. Department of Commerce (http://www.bea.gov/national/index.htm#gdp).

		2007 $APD_{H_v}^{168}$					2008 $APD_{H_v}^{168}$				
		H_v=24	H_v=16	H_v=8	H_v=4	H_v=1	H_v=24	H_v=16	H_v=8	H_v=4	H_v=1
NYISO	CAPITL Zone	26.01	28.95	32.98	36.03	39.08	28.57	32.13	37.63	41.42	45.75
	CNTRL Zone	24.34	27.16	31.00	33.84	36.63	27.10	30.82	36.14	40.20	44.90
	DUNWD Zone	35.52	40.40	47.25	52.29	57.70	41.29	47.63	57.43	64.88	71.82
	GENESE Zone	25.66	28.74	32.78	35.78	38.77	26.94	30.55	35.96	39.99	44.77
	WEST Zone	24.57	27.44	31.42	34.33	37.45	24.73	28.03	32.89	36.46	40.76
	HUD VL Zone	32.99	37.34	43.32	47.69	52.40	37.29	42.71	51.02	57.45	63.41
	LONGIL Zone	44.88	53.00	64.09	72.11	83.32	44.71	52.02	63.41	71.86	81.41
	MHKVL Zone	25.20	28.12	32.07	35.05	37.90	27.99	31.74	37.20	41.34	46.16
	MLLWD Zone	35.40	40.24	47.02	51.96	57.38	40.95	47.22	56.87	64.17	71.05
	NYC Zone	36.49	41.27	48.14	53.37	58.87	42.96	48.72	57.48	64.03	70.02
	NORTH Zone	23.61	26.42	30.29	33.11	35.83	25.38	28.81	33.78	37.49	42.30
Midwest ISO	Minnesota Hub	48.57	54.59	63.49	70.27	77.91	43.44	47.96	54.25	59.13	65.75
	Michigan Hub	40.13	45.00	52.04	57.79	64.83	42.37	46.80	52.76	57.36	63.29
	Illinois Hub	39.48	44.31	51.55	57.57	64.64	40.40	44.70	50.43	55.04	60.54
	FE Hub	39.10	43.96	51.06	56.59	63.52	40.47	44.93	50.73	55.15	60.46
	Cinergy Hub	39.05	43.76	50.49	55.90	62.72	40.81	45.30	51.48	56.28	62.51
ISO NE	Connecticut Zone	30.37	34.34	39.96	44.32	48.59	35.43	40.51	47.70	53.13	59.45
	Maine Zone	22.14	25.02	29.02	32.08	35.90	24.34	27.66	32.50	36.52	41.94
	NE MassBost Zone	24.78	28.43	33.81	37.59	43.36	27.95	32.09	38.52	43.42	47.56
	New Hampshire Zone	23.83	26.95	31.36	34.44	38.20	27.38	31.29	37.05	41.12	45.23
	Rhode Island Zone	23.46	26.59	31.08	34.31	37.99	27.18	30.95	36.70	41.13	45.46
	SE MASS Zone	24.83	28.07	32.80	36.28	39.86	29.30	33.11	38.89	43.57	48.17
	WC MASS Zone	24.95	28.14	32.72	36.08	39.73	29.01	33.46	40.32	44.92	49.41
	Vermont Zone	25.78	29.03	33.57	36.77	40.36	28.55	32.73	38.88	43.16	47.41
PJM	AEP GEN HUB	32.22	35.67	40.44	44.06	48.16	33.47	37.04	42.12	45.64	49.58
	AEP-DAYTON HUB	34.04	37.74	42.85	46.79	51.08	35.60	39.46	45.07	48.88	52.98
	CHICAGO GEN HUB	33.65	37.20	42.09	45.66	49.80	36.04	39.64	44.67	48.38	52.55
	CHICAGO HUB	33.65	37.20	42.09	45.66	49.80	36.86	40.55	45.72	49.52	53.79
	DOMINION HUB	37.86	42.52	49.10	53.88	59.56	39.56	44.79	52.80	59.05	66.19
	EASTERN HUB	39.59	44.67	52.19	58.10	64.17	45.62	52.27	62.59	70.74	79.36
	N ILLINOIS HUB	33.96	37.55	42.49	46.11	50.29	36.40	40.05	45.12	48.87	53.07
	NEW JERSEY HUB	39.17	44.12	51.30	57.10	63.01	43.35	49.52	59.40	66.89	73.95
	OHIO HUB	33.76	37.37	42.34	46.11	50.30	35.61	39.38	44.76	48.51	52.63
	WEST INT HUB	32.32	35.93	40.89	44.47	48.58	34.27	38.21	44.01	48.02	52.21
	WESTERN HUB	37.40	42.02	48.41	53.23	58.38	42.94	49.19	59.12	66.52	74.15

weeks when the weekly price differentials were high enough to justify shutting down the capture unit for some hours at plants where the annual average price differential does not exceed the threshold.

To explore the value of the bypass system at an existing plant with a CCS retrofit we looked at the number of weeks in years 2007 and 2008 for which the weekly price differentials would have exceeded the required threshold (assuming a CCS energy penalty of 30% as in (NETL, 2007). As shown in Table 4, each of the nodes had at least one week, when weekly price differentials would have reduced the average cost of CO_2 capture by venting out CO_2 during 24 h in the week (H_v = 24). Shutting down the capture plant for 1 h a week (H_v = 1) would have been justified for at least 10 weeks in 2007 and at least 17 weeks in 2008 at every price node.

Note that since for new plants a bypass system requires additional capital investment it is not possible to explore the bypass profitability with this metric (i.e. number of weeks when weekly price differentials exceed threshold). Although weekly price differentials exceeded the required weekly threshold for new plants for all price hubs during at least one week in 2007 and 2 weeks in 2008, this does not mean venting would have happened during those weeks, since the extra investment in bypass would only be justified if the average weekly price differentials exceeded the threshold.

Table 4
Number of weeks in years 2007 and 2008 when weekly price differentials in major trading hubs in U.S. electricity markets in the Eastern Interconnect exceeded the required threshold for reducing the average cost of CO_2 capture at an existing retrofitted plant by shutting down the capture unit. Calculations assume a CCS energy penalty of 30% as in (NETL, 2007).

	Number of weeks per year when weekly PDs exceeded the required threshold presented in Table 2, for profitability of bypass at an existing plant									
	2007					2008				
	$H_v = 24$	$H_v = 16$	$H_v = 8$	$H_v = 4$	$H_v = 1$	$H_v = 24$	$H_v = 16$	$H_v = 8$	$H_v = 4$	$H_v = 1$
NYISO										
CAPITL Zone	2	4	7	10	10	5	11	15	16	22
CNTRL Zone	1	2	6	7	10	6	8	9	18	22
DUNWD Zone	10	16	20	25	29	14	19	23	26	30
GENESE Zone	1	3	7	9	11	4	7	9	17	23
WEST Zone	1	2	5	7	10	2	3	6	12	20
HUD VL Zone	8	14	18	20	24	13	16	22	25	29
LONGIL Zone	22	28	32	38	41	19	24	30	34	39
MHKVL Zone	2	3	6	8	11	7	9	13	18	23
MLLWD Zone	10	16	20	25	28	14	19	22	26	31
NYC Zone	12	17	22	28	32	17	21	26	28	31
NORTH Zone	2	3	6	8	10	4	6	7	13	18
Midwest ISO										
Minnesota Hub	28	34	42	50	51	18	27	36	41	48
Michigan Hub	17	25	30	38	46	15	22	30	35	43
Illinois Hub	16	22	29	34	43	12	18	26	31	41
FE Hub	13	22	31	36	45	12	21	27	31	39
Cinergy Hub	13	23	27	36	45	12	20	27	34	39
ISO NE										
Connecticut Zone	7	9	12	18	26	15	17	22	29	29
Maine Zone	1	2	7	9	13	4	8	10	12	18
NE MassBost Zone	3	7	12	15	17	8	9	15	17	19
New Hampshire Zone	2	5	10	11	13	7	9	14	16	18
Rhode Island Zone	2	4	9	10	15	7	9	13	15	17
SE MASS Zone	4	6	9	10	13	8	9	15	16	19
WC MASS Zone	2	6	10	12	16	8	9	15	16	19
Vermont Zone	2	7	10	12	17	7	9	14	16	18
PJM										
AEP GEN HUB	5	10	14	20	25	9	10	20	24	27
AEP-DAYTON HUB	8	11	19	22	28	9	13	21	26	30
CHICAGO GEN HUB	8	11	16	21	28	10	13	22	27	30
CHICAGO HUB	8	11	16	21	28	10	13	23	27	33
DOMINION HUB	11	19	24	29	33	16	18	27	32	39
EASTERN HUB	14	18	24	35	40	19	24	31	34	43
N ILLINOIS HUB	8	11	19	22	29	10	13	22	27	31
NEW JERSEY HUB	15	19	24	30	37	15	21	28	29	38
OHIO HUB	8	11	18	22	28	9	13	22	26	30
WEST INT HUB	7	11	14	21	25	10	13	19	23	30
WESTERN HUB	11	15	23	29	33	18	23	28	31	38

3.3. Estimate of potential change in average cost of CO_2 capture with flexible operation in the U.S.

For an alternative look at the economics of flexible operation of CCS, we use the same LMP price data to calculate the decrease in the average cost of CO_2 capture (Eq. (4)) that would be observed if retrofit plants only vented CO_2 during H_v hours during the weeks that the price differential exceeded the required threshold. Table 5 shows what the decrease in the average cost of capture ($2009/ton) would have been for retrofit plants.

Table 5 shows that for an existing plant retrofitted with CCS, shutting down the CCS system during the highest wholesale price hours during weeks when the PD exceeded the required threshold, would marginally reduce the average cost of capture for all hubs for the electricity price differentials observed in 2007 and 2008. The average cost of capture would have decreased by 1–8 cents/ton for 1 h of venting a week ($H_v = 1$). Venting CO_2 during 24 h a week ($H_v = 24$) would have decreased average cost of capture by up to 49 cents/ton for the 2007 price differentials and by up to 58 cents/ton for the 2008 price differentials.

The same analysis for a new CCS plant confirms that incurring the necessary investment to enable flexibility, and venting CO_2 for a set number of H_v hours every week when the price differential exceeded the required threshold would have increased the average CO_2 capture costs for most nodes. This result is consistent with the observation that the annual average of weekly price differentials did not exceed the required threshold for most nodes. Venting CO_2 during the highest priced hour every week ($H_v = 1$) would have increased the average cost of CO_2 capture in a new plant by $1.07–$1.21/ton in 2007 and by $1.08–$1.20/ton in 2008 depending on the hub. Venting CO_2 during the 24 h of highest prices ($H_v = 24$) during weeks when the price differentials exceeded the required threshold would have increased the average cost of capture in most nodes except 2 nodes in 2007 and 9 nodes in 2008. The highest reduction in the average cost of capture in 2007 would have been observed in the Minnesota Hub where the average cost of capture would have decreased by 54 cents/ton in 2007 and in the Eastern Hub in PJM when the average cost of capture would have decreased by 38 cents/ton in 2008.

Note that the calculations of Table 5 assume that venting happens during H_v hours during weeks when the price differential makes it economical. This implies two assumptions: (1) the plant operator can identify in advance the H_v highest priced hours in a week and (2) the plant operator sticks to the plan of either venting

Table 5
Reduction in average cost of capture (\$/ton CO_2 captured) from venting CO_2 H_ν hours per week, during weeks when price differentials exceeded the thresholds of Table 2 for an existing plant retrofitted with CCS. Assumes capacity factor = 1, and a CCS energy penalty of 30% as in NETL (2007). All reductions in average cost of capture are in \$2009.

	Eq. (4) with 2007 LMP price data					Eq. (4) with 2007 LMP price data				
	H_ν = 24	H_ν = 16	H_ν = 8	H_ν = 4	H_ν = 1	H_ν = 24	H_ν = 16	H_ν = 8	H_ν = 4	H_ν = 1
NYISO										
CAPITL Zone	0.02	0.03	0.04	0.03	0.01	0.05	0.07	0.07	0.05	0.02
CNTRL Zone	0.02	0.02	0.03	0.02	0.01	0.05	0.07	0.06	0.04	0.02
DUNWD Zone	0.16	0.19	0.16	0.11	0.03	0.49	0.46	0.34	0.21	0.06
GENESE Zone	0.02	0.03	0.03	0.02	0.01	0.04	0.06	0.05	0.04	0.01
WEST Zone	0.02	0.02	0.02	0.02	0.01	0.02	0.03	0.03	0.02	0.01
HUD VL Zone	0.09	0.13	0.12	0.08	0.03	0.33	0.32	0.25	0.16	0.05
LONGIL Zone	0.49	0.52	0.39	0.25	0.08	0.54	0.54	0.41	0.25	0.08
MHKVL Zone	0.02	0.03	0.03	0.02	0.01	0.07	0.08	0.07	0.05	0.02
MLLWD Zone	0.16	0.19	0.16	0.11	0.03	0.48	0.45	0.33	0.21	0.06
NYC Zone	0.16	0.19	0.16	0.11	0.04	0.49	0.45	0.33	0.21	0.06
NORTH Zone	0.02	0.03	0.03	0.02	0.01	0.05	0.05	0.04	0.03	0.01
Midwest ISO										
Minnesota Hub	0.47	0.45	0.34	0.22	0.07	0.27	0.27	0.21	0.14	0.05
Michigan Hub	0.21	0.22	0.18	0.13	0.04	0.34	0.29	0.20	0.12	0.04
Illinois Hub	0.20	0.22	0.19	0.13	0.04	0.29	0.25	0.17	0.11	0.04
FE Hub	0.16	0.20	0.17	0.12	0.04	0.31	0.27	0.18	0.11	0.04
Cinergy Hub	0.17	0.19	0.16	0.11	0.04	0.31	0.26	0.18	0.12	0.04
ISO NE										
Connecticut Zone	0.08	0.09	0.08	0.06	0.02	0.30	0.28	0.21	0.13	0.04
Maine Zone	0.01	0.02	0.02	0.02	0.01	0.04	0.06	0.06	0.04	0.02
NE MassBost Zone	0.03	0.04	0.05	0.04	0.02	0.14	0.15	0.13	0.09	0.03
New Hampshire Zone	0.02	0.03	0.04	0.03	0.01	0.14	0.15	0.12	0.07	0.02
Rhode Island Zone	0.02	0.03	0.04	0.03	0.01	0.13	0.14	0.11	0.07	0.02
SE MASS Zone	0.03	0.05	0.05	0.04	0.01	0.17	0.17	0.13	0.09	0.03
WC MASS Zone	0.02	0.04	0.04	0.03	0.01	0.18	0.19	0.16	0.10	0.03
Vermont Zone	0.02	0.04	0.04	0.03	0.01	0.16	0.17	0.13	0.08	0.02
PJM										
AEP GEN HUB	0.03	0.05	0.06	0.04	0.01	0.15	0.13	0.10	0.06	0.02
AEP-DAYTON HUB	0.07	0.09	0.08	0.06	0.02	0.21	0.18	0.14	0.08	0.03
CHICAGO HUB	0.05	0.07	0.07	0.05	0.02	0.22	0.19	0.13	0.08	0.03
DOMINION HUB	0.19	0.21	0.17	0.11	0.03	0.34	0.32	0.25	0.16	0.05
EASTERN HUB	0.25	0.25	0.20	0.14	0.04	0.58	0.52	0.38	0.24	0.07
N ILLINOIS HUB	0.06	0.08	0.07	0.05	0.02	0.21	0.18	0.13	0.08	0.02
NEW JERSEY HUB	0.25	0.25	0.19	0.13	0.04	0.49	0.45	0.34	0.22	0.06
OHIO HUB	0.06	0.08	0.08	0.05	0.02	0.20	0.17	0.13	0.08	0.03
WEST INT HUB	0.05	0.08	0.07	0.05	0.02	0.18	0.17	0.13	0.08	0.03
WESTERN HUB	0.21	0.21	0.16	0.11	0.03	0.50	0.46	0.35	0.22	0.07

during H_ν hours or not venting at all. These two assumptions have competing effects. The first assumption may lead to an over estimation of the benefits of flexible operation, since identifying the hours of highest prices in a week in advance may not always be possible. The second assumption may lead to an under estimation of the benefits of flexible operation since the plant operator does not need to stick to a plan of venting H_ν hours but could choose to vent any number of hours. Plant operators could increase revenue and profits from electricity sales by venting CO_2 during more or less hours per week than H_ν during weeks where price differentials where high. Regardless of the final effect of these competing assumptions, this analysis illustrates that under the prices observed during 2007 and 2008 the reduction in the average cost of capture in retrofit plants would have likely been very modest. Similarly, this analysis suggests that it would be unlikely that shutting down the capture system and venting CO_2 during the highest wholesale price hours at a new supercritical CCS plant would reduce its average cost of capture.

Finally, we have estimated the reduction in CO_2 captured that would have occurred during years 2007 and 2008 if the capture plant had been shutdown at the times that would have reduced the average cost of capture. The percentage reduction in CO_2 capture is presented in Table 6.

4. Discussion

Our analysis based on U.S. electricity price data from years 2007 and 2008 suggests the CO_2 venting would occur on exceptional circumstances and almost exclusively from retrofit plants which require no additional capital cost for a bypass, as new CCS plants would require additional capital investment that may not be justified. For the time period and markets observed in this paper, the maximum reduction in CO_2 capture due to venting at retrofit plants would have not exceeded 9.9% (Minnesota Hub in the MISO region).

Although our estimates of the reduction in the average cost of CO_2 capture that can be obtained from bypassing the CCS unit is almost inexistent for new plants and very marginal for retrofit plants, there are several reasons to think that regulations banning CO_2 venting from CCS plants could do more harm than good. On one hand, although there is much uncertainty on how the power system will look when large-scale CCS plants are deployed, it is likely that increased penetration of variable energy sources such as wind and solar, will cause high price differentials. This could imply important reductions in the average cost of CO_2 capture from retrofit plants (and in extreme cases, also from new plants) enabled to vent CO_2 and increase their power output at the times of highest electricity prices. Although it is likely that this type of venting

Table 6
Percent reduction in CO_2 captured from venting CO_2 when doing so reduces the average cost of capture. Reductions are shown for an existing plant assuming a capacity factor of 1, a CCS energy penalty of 30%, and electricity prices as observed in years 2007 and 2008.

	Existing plant	
	2007 LMP price data	2008 LMP price data
NYISO		
CAPITL Zone	1.3%	2.9%
CNTRL Zone	0.9%	2.6%
DUNWD Zone	4.5%	5.3%
GENESE Zone	1.1%	2.3%
WEST Zone	0.9%	1.4%
HUD VL Zone	3.8%	4.8%
LONGIL Zone	7.8%	6.9%
MHKVL Zone	1.1%	2.9%
MLLWD Zone	4.5%	5.3%
NYC Zone	5.0%	6.0%
NORTH Zone	1.1%	1.9%
Midwest ISO		
Minnesota Hub	9.9%	7.7%
Michigan Hub	7.0%	6.4%
Illinois Hub	6.4%	5.5%
FE Hub	6.4%	5.8%
Cinergy Hub	6.3%	5.8%
ISO NE		
Connecticut Zone	2.9%	5.3%
Maine Zone	1.1%	2.2%
NE MassBost Zone	2.2%	3.0%
New Hampshire Zone	1.6%	2.9%
Rhode Island Zone	1.5%	2.8%
SE MASS Zone	1.8%	3.0%
WC MASS Zone	1.8%	3.0%
Vermont Zone	1.9%	2.9%
PJM		
AEP GEN HUB	3.0%	3.8%
AEP-DAYTON HUB	3.7%	4.2%
CHICAGO HUB	3.5%	4.4%
CHICAGO GEN HUB	3.5%	4.5%
DOMINION HUB	5.2%	5.9%
EASTERN HUB	5.7%	7.0%
N ILLINOIS HUB	3.7%	4.4%
NEW JERSEY HUB	5.7%	6.0%
OHIO HUB	3.6%	4.2%
WEST INT HUB	3.3%	4.1%
WESTERN HUB	4.8%	6.5%

would not significantly increase emissions, this could be further controlled instituting a penalty for venting. On the other hand, the value of the increased generating capacity and ramping capability that can be obtained from bypassing the CCS system in a CCS baseload plant could greatly increase in a world with increased penetration of variable energy resources.

Future research could explore methods to optimally set the value of the economic penalties for venting CO_2 to guarantee that this practice is limited to instances when system-wide costs justify doing so. Future studies should also explore to what extent venting CO_2 from CCS plants at times of very high electricity prices may reduce air emissions other than CO_2, since freeing up the capacity of CCS plants at times of high electricity demand, may prevent the need of dispatching other fossil-fired generating resources that are inefficient and do not have air pollution controls. Finally, policy mechanisms to regulate venting should evaluate its economic and environmental impacts in comparison with other alternatives for flexible operation of post-combustion CCS system such as the installation of amine-storage tanks (Patino-Echeverri and Hoppock, 2012).

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Appendix A. Supplementary data

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