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Reduced-order modelling of flexible CCS and assessment using short-term resource scheduling approach

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ABSTRACT

CCS (Carbon Capture and Storage) can allow conventional fuels for electricity generation to be used while achieving deep reductions in GHG (Greenhouse Gas) emissions at the cost, though, of reduced efficiency and capacity relative to an electricity system without CCS. It has been proposed that the deployment of generating units with CCS that are *flexible*—in particular, that can moderate their CO_2 recovery in response to market conditions—would mitigate some of the disbenefit associated with the technology. This paper uses the short-term resource scheduling approach to assess the value of flexible generating units with CCS (Carbon Capture and Storage); generating unit part-load performance, variability of CO_2 recovery, and detailed operation of an electricity system including transmission and reliability constraints are considered simultaneously. A parametric study of the performance of a coal-fired generating unit with CCS is undertaken using an Aspen Plus® steady-state model and a reduced-order model representing the Pareto optimal frontier of the unit is developed using regression analysis. The base economic dispatch underlying the electricity system simulator is extended to accommodate flexible generating units with CCS. The flexible generating unit with CCS is added to the IEEE RTS'96 (Institute of Electrical and Electronics Engineers One-Area Reliability Test System—1996) and the operation of the modified IEEE RTS'96 is simulated for one week. The results are contrasted with results taken from Alie et al. (2015) for the base IEEE RTS'96 and an IEEE RTS'96 with "fixed" CCS. "Flexible" CCS is effective at reducing GHG emissions, though to a slightly lesser extent than was observed via "fixed" CCS. However, with GHG regulation in place, flexibility markedly increases the net energy benefit of the generating unit with CCS and this was achieved not through adjustment of CO_2 recovery in order to moderate output but, rather, by increasing the generating unit's ability to successfully compete to provide reserve power. Performance metrics that do not consider the impact of GHG mitigation options on energy benefit may not correctly rank GHG mitigation options.

1. Introduction

CCS is an important GHG mitigation option. According to assessments undertaken by the IEA (International Energy Agency), if CCS is removed from the list of GHG mitigation options for the electricity generation sector, the capital investment required to meet the same emissions constraint increases by 40%. And, it is the only technology that will allow deep GHG reductions in the industrial sector (Levina et al., 2013).

The primary benefit of CCS in the electricity generation sector is that it allows conventional fuels and technologies to be used while mitigating the emissions of the CO_2 that is generated. In the late 1990s and early 2000s, the use of CCS as a means of mitigating CO_2 emissions from coal-fired generating units is a novel idea. Though technologies for capturing CO_2 from flue gases (*i.e.*, post-combustion CO_2 capture) were commercially-available (*e.g.*, from Fluor Daniel, ABB/Lummus Global), initial evaluations indicated that the tradeoff for meaningful CO_2 abatement from a coal-fired generating unit is reduced generating capacity and/or efficiency relative to a generating unit without CCS:

Abbreviations: ANOVA, Analysis of Variance; CCA, cost of CO_2 avoided; CCS, Carbon Capture and Storage; ERCOT, Electricity Reliability Council of Texas; GHG, Greenhouse Gas; HEP, Hourly Electricity Price; IEA, International Energy Agency; IHR, Incremental Heat Rate; IP/LP, Intermediate Pressure/Low Pressure; LRMC, Long-Run Marginal Cost; MCR, Maximum Continuous Rating; MEA, monoethanolamine; MINLP, Mixed-Integer Non-Linear Programming; NERC, North American Electric Reliability Corporation; PCC, post-combustion capture; IEEE RTS'96, Institute of Electrical and Electronics Engineers One-Area Reliability Test System—1996; SGER, Specified Gas Emitters Regulation; SRMC, Short-Run Marginal Cost.

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Nomenclature

Variables

CCA	cost of CO_2 avoided, *e.g.*, \$/tCO_2e
CEI	CO_2 emissions intensity, *e.g.*, tCO_2e/MWh$_e$
CF	capacity factor
CoE	cost of electricity, *e.g.*, \$/MWh$_e$
C	annual cost, *e.g.*, \$/year
FA	approach to flooding
F	molar flow rate, *e.g.*, kmol/s
HR	heat rate, *e.g.*, kJ/kWh$_e$
L_1/D	reflux ratio in a distillation column
$\mathcal{P}$	pressure, *e.g.*, kPa
$\mathcal{P}_{out}/\mathcal{P}_{in}$	ratio of outlet pressure to inlet pressure across the turbine
P	real power, *e.g.*, MW$_e$
$\Delta\dot{q}$	ramp rate for continuous units, *e.g.*, MW$_{th}$/min
$\dot{Q}$	heat duty, *e.g.*, MW$_{th}$
$\dot{q}$	heat input to boiler, *e.g.*, MJ
RM	reserve market power, *e.g.*, MW$_e$
TCR	total capital recovery, *e.g.*, \$
t	temperature, *e.g.*, °C
TAX	emissions permit price, *e.g.*, \$ per unit mass emitted
u	state of generating unit with respect to start-up (*i.e.*, one if the unit started-up in the time period and zero otherwise)
x	fraction recovered or extracted
z	value of objective function

Greek

τ	length of time, hours
ω	state of generating unit (*i.e.*, one if the unit is off and zero otherwise)

Parameters

EI	fuel emissions intensity, *e.g.*, kg/MJ
d	column diameter, *e.g.*, metres
FC	fuel cost, *e.g.*, \$/MJ
FCF	"Fixed Charge Factor"; for a given interest rate, *i*, and total number of payments, *N*, the annuity as fraction of the present value that must be paid to reduce the future value to zero, *e.g.*, \$/year
h	height of packing, *e.g.*, metres
HPY	hours per year, *e.g.*, 8766 h/year
L	time period duration, *e.g.*, hours
MEA	unit cost of make-up solvent, *e.g.*, \$/tCO_2
TS	unit cost of CO_2 transportation and storage, *e.g.*, \$/tCO_2
T	number of time periods

Superscripts

*	denotes set-point
CO_2	pertaining to CO_2 or CO_2 capture
C	pertaining to continuous units
D	pertaining to discrete units
FOM	pertaining to fixed operating and maintenance component of the cost
fuel	pertaining to fuel
max	indicates maximum value
MEA	pertaining to make-up solvent
min	indicates minimum value
†	pertaining to a situation where a contingency has occurred
R	pertaining to reserve market
S	pertaining to supply
start-up	pertaining to unit start-up
TS	pertaining to CO_2 transportation and sequestration
VOM	pertaining to variable operating and maintenance component of the cost

Subscripts

10^{ns}	pertaining to 10-minute, non-spinning reserve market
10^{sp}	pertaining to 10-minute, spinning reserve market
30^{ns}	pertaining to 30-minute, non-spinning reserve market
abs	pertaining to absorber
aux	pertaining to auxiliary turbine
C	pertaining to continuous units
D	pertaining to discrete units
generator	pertaining to generating unit
lean	pertaining to lean solvent
n	index of generating units
reb	pertaining to *Stripper* reboiler
r	index of reserve markets
ref	pertaining to reference case
steam	pertaining to Intermediate Pressure/Low Pressure extraction point
str	pertaining to Stripper
t	index of time periods

Sets

NG	set of generating units
RM	set of reserve markets

- In a well designed Econoamine FG process, 4.2 GJ of steam per tonne of CO_2 is required (Chapel et al., 1999).
- 400 MW$_e$ coal-fired power plant with 90% CO_2 recovery using MEA (monoethanolamine), has flue gas blower and CO_2 compression duties of 9 and 31 MW$_e$ and a stripper reboiler duty of 351 MW$_{th}$ (Singh, 2001).
- Marion et al. evaluate the retrofit of a 450 MW$_e$ coal-fired power plant with ABB/Lummus Global MEA-based capture process. 94% of the generated CO_2 is recovered and the net plant output is reduced by 40% (*i.e.*, 173 MW$_e$) (Marion et al., 2001).
- Morimoto et al. estimate the performance of post-combustion CO_2 capture using MEA for a 1000 MW$_e$ coal-fired generating unit (effective size of 666 MW$_e$ as only two-thirds of the flue gas is treated). For 90% recovery, flue gas blower and CO_2 compression duties of 9 and 56 MW$_e$ and a stripper reboiler duty of 328 MW$_{th}$ (Morimoto et al., 2002).
- Alie estimates the performance of 500 MW$_e$ coal-fired generating unit retrofitted with an MEA-based post-combustion capture process. Recovering 85% of the CO_2 decreases the net plant output by 31% (*i.e.*, 155 MW$_e$) (Alie, 2004).

Improving the performance of post-combustion CO_2 capture and, in particular, the energy required for solvent regeneration is an active area of research. In the assessment of CCS, a survey of the literature reveals that the basis is most often a generating unit operating at base-load and under steady-state conditions with a *fixed* rate of CO_2 recovery (Singh, 2001; Rao and Rubin, 2002; Ordorica-Garcia, 2003; Elkamel et al., 2009; Ansolabehere et al., 2007; van den Broek et al., 2009; Levina et al., 2013). As early as 2002, Gibbins et al. propose that the design of generating units with CCS should consider more than just steady-state performance at power plant base-load; factors like reliability, availability, maintainability, operability, and "upgradability" should also be taken into account (Gibbins et al., 2002). In particular, Gibbins et al. propose that a generating unit with integrated CCS should be able to:

- operate without capturing CO_2,
- operate with CO_2 capture at part-load,
- be able to change load rapidly, and
- be upgradeable.

Research into the operability of CCS can be categorized into two streams. The first stream investigates the ability of CO_2 capture processes to respond to changing market conditions. Lucquiaud et al. discuss the design of steam cycles such that the generating units are CCS-ready and can operate flexibly post-installation of CO_2 capture (Lucquiaud et al., 2007, 2008). Jayarathna et al. (2013) and Harun et al. (2012) are amongst those that have created dynamic models of MEA-based CO_2 capture process. It is an active area of research. Indications are that generating units with post-combustion can respond in a timely manner to changes in CO_2 recovery set-point over the operating range of the boilers.

The second stream of research has attempted to quantify the benefit that flexible generating units with CCS would realize. Chalmers and Gibbins estimate potential economic benefits of storing rich solvent in order to shift the energy penalty associated with solvent regeneration from periods of high electricity price to periods of low electricity price (Chalmers and Gibbins, 2007).

Cohen (2009) and Cohen et al. (2012) attempt to assess the potential benefits of flexible CCS in ERCOT (Electricity Reliability Council of Texas) and, similarly, Khalilpour (2014) attempts to assess the potential benefits of CCS in an Australian context.

Delarue et al. propose that the increase in power output from turning a CO_2 capture process off could preferentially provide power in the face of a contingency and, thereby, reduce operating costs and the need for new generation capacity (Delarue et al., 2012).

Collectively, the previous attempts to quantify the benefit of flexibility have considered:

1. part-load operation of the boiler and steam cycle,
2. variability in CO_2 recovery, and
3. the detailed operation of the electricity system.

However, no study has simultaneously considered all three of these factors. The last point is of particular importance and for two reasons.

Firstly, assessing the techno-economic performance of a generating unit with flexible CCS—or any generating unit, for that matter—requires some understanding of the utilization of the generating unit: effectively, in each time period, the load at which the boiler operates, the fraction of CO_2 that is recovered and/or the quantity of solvent that is regenerated, and the heat rate of the unit. In the earlier techno-economic assessments of CCS, it is common to assume that the generating unit with CCS operates at base-load in all time periods and/or has utilization identical to the historical performance of the generating units without CCS that are being replaced (Singh, 2001; Rao and Rubin, 2002; Ordorica-Garcia, 2003). Recent techno-economic assessments of flexible CCS have assumed that a generating unit with CCS operates, in every time period, at the load and CO_2 recovery that maximizes its utility (Cohen et al., 2012; Khalilpour, 2014). It implicitly assumes that the presence of a generating unit with CCS would not influence the price of electricity.

Especially in a deregulated electricity system, it may not be reasonable to expect the utilization of dispatchable units to remain constant over time; instead, one would expect utilization to change from one time period to the next as the system operator dispatches units to simultaneously satisfy demand, reliability, transmission, and other constraints. And, as the electricity systems into which CCS will be deployed are expected to be materially different than in the past (*e.g.*, increasingly stringent regulation of GHG emissions and share of capacity from non-dispatchable generating units), the historical performance of units within a system may not be a good proxy for the performance of the system in the future. Alie et al. (2015) demonstrate that GHG regulation and CCS can have a significant impact on the dispatch of units and on the market price of electricity and the indication is that explicit consideration of the detailed operation of the electricity system of interest is likely of value for the assessment of the benefits of flexible generating units with CCS.

Secondly, fundamental to the notion of a flexible generating unit with CCS is that recovery of CO_2 can be curtailed as a means of increasing the net power output of the generating unit. From a planning perspective, this flexibility can provide cost savings by delaying the need to install additional capacity in the face of increasing peak demand (Delarue et al., 2012). From an operating point of view, it is theorized that this flexibility could provide and additional means of reserve power in the face of contingency (Chalmers and Gibbins, 2007; Alie and Douglas, 2008; Cohen et al., 2012). Explicit consideration of the transmission system and the provisioning of reserve power in the electricity system of interest is likely of vale in for assessing the benefits of flexible generating units with CCS.

Collectively, then, the evaluations of flexible CCS referenced above may provide poor insight into the benefit of flexibility in terms of magnitude and the manner in which it is realized (*i.e.*, the source of the benefit).

Alie et al. (2015) proposed a method for assessing the effectiveness of GHG mitigation options: the short-term resource scheduling approach. The advantage of this approach relative to others (*i.e.*, techno-economic assessment and medium- to long-term electricity system planning) is that the utilization and performance of generating units is determined endogenously and the detailed operation of the target electricity system—including the transmission system and reserve power market—is considered. The primary objective of the paper is to describe the use of this methodology to assess the benefit of generating units with CCS that are flexible.

The paper is organized as follows:

- Section 2 provides an overview of short-term resource scheduling approach.
- Section 3 describes the development of reduced-order model of coal-fired generating unit with flexible CCS.
- Section 4 describes the integration of flexible coal-fired generating unit with CCS into electricity system simulator.
- Section 5 presents the key results from the simulation of the IEEE RTS'96 with a flexible generating unit with CCS.
- Section 6 discusses results.
- Section 7 gives concluding remarks.

2. Overview of short-term resource scheduling approach

The short-term generation scheduling approach for assessing the effectiveness of a GHG mitigation option is described in Alie et al. (2015). Advantages of this approach over techno-economic study and medium- to long-term planning include endogenous estimation of utilization and performance of the generating units, assessment of the impact of GHG mitigation options on electricity price and energy benefit, and the direct comparison of GHG mitigation options that are technological and non-technological in

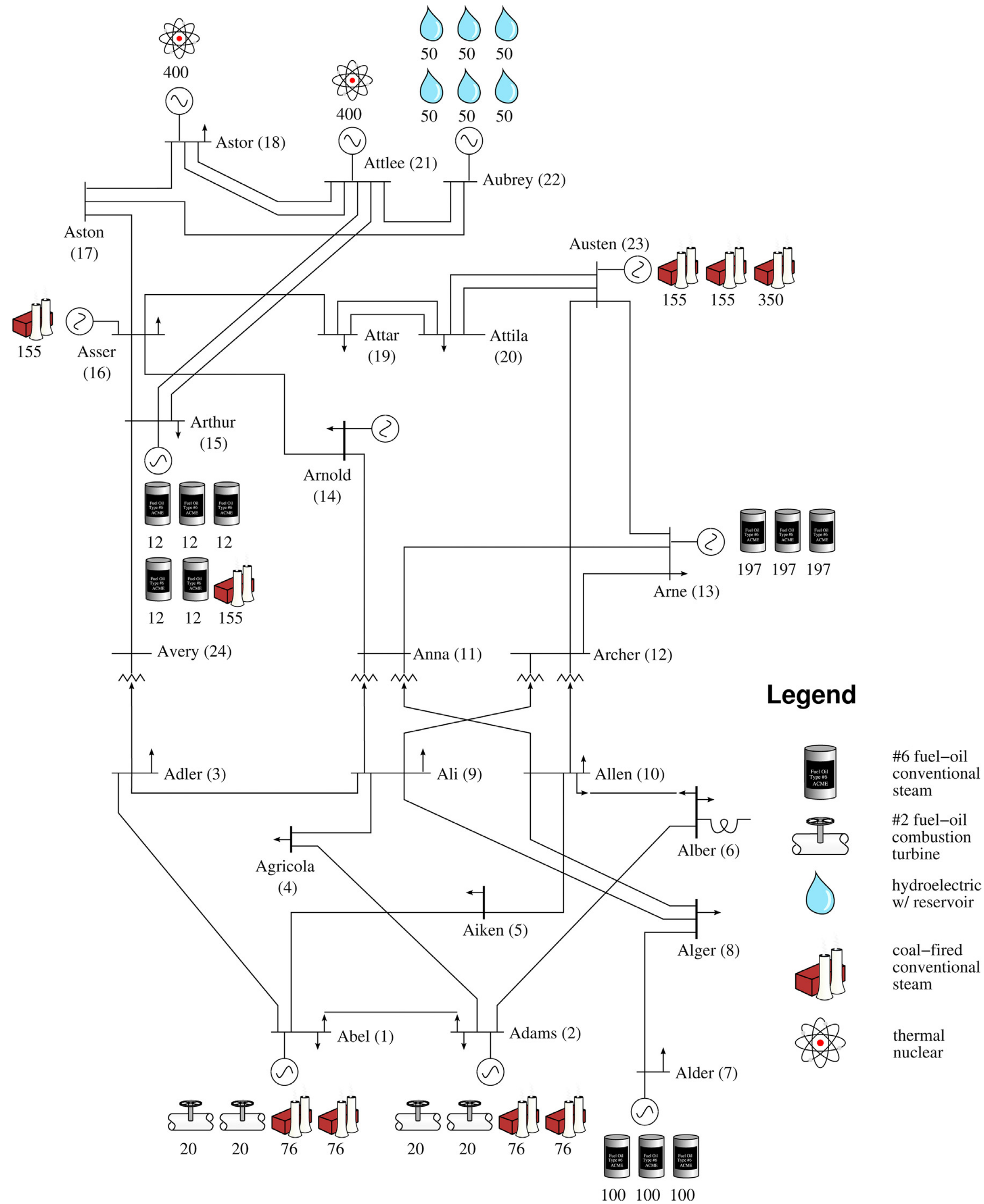


Fig. 1. One-line diagram of IEEE RTS'96. *Note*: "Abel (1)" specifies the name of the bus (*i.e.*, *Abel*) and the bus ID (*i.e.*, *1*); the number below each generating unit symbol represents the unit's capacity in MW_e.

nature. There are five steps in the short-term generating scheduling approach:

Step 1 Model the target electricity grid: the generating units, the loads, and the transmission lines that connect them. For this study, the '1-area' IEEE RTS'96 (Grigg et al., 1999) is selected as the target electricity system. A one-line diagram of the IEEE RTS'96 is shown in Fig. 1. Reasons for selecting the IEEE RTS'96 include:

1. The electricity system contains a diverse set of generating unit types (*i.e.*, fossil fuel, nuclear, hydroelectric) and parameters describing the technical and economic performance of the generation units are provided. Extending the system to include other types of electricity generation or electricity storage is straightforward.
2. In the IEEE RTS'96, the physical layout of the sources and sinks is provided as is the physical properties of the transmission system.

3. The IEEE RTS'96 has been used in other electricity system studies (Chowdhury and Koval, 2003; Ghajar and Billinton, 2006; Zerriffi et al., 2007). Alie et al. (2015) use the IEEE RTS'96 to assess the impact of GHG regulation and CCS with *fixed* CO_2 recovery and a direct comparison to the performance of the system when a generating unit with CCS that is *flexible* can therefore be made.

Step 2 Simulate the operation of the electricity system with and without GHG regulation. The electricity system simulation mimics the operation of the deregulated electricity system in Ontario, Canada (IESO, 2008). There are three phases. The *pre-dispatch* phase occurs a day in advance. Using firm offers to sell power, a forecast of demand, system operating requirements, and energy availability, the system operator commits units for, typically, a 24 hour horizon. In the *real-time operation* phase, the system operator dispatches units in order to balance electricity supply, demand, and reserve power. In the *market settlement* phase, the electricity price is determined is determined for each time period based upon the accepted bids. There is a requirement for 400 MW_e of 10-minute—half of which must be spinning—and 600 MW_e of 30-minute reserve power in each time period.[1]

Each phase has in common the need to solve an economic dispatch problem that seeks to satisfy electricity demand while maximizing the shared economic benefit of producers and consumers. This economic dispatch problem is described in Section 4.

GHG regulation is implemented in the form of a cost borne by the generator for every unit of CO_2 that is emitted. CO_2 prices of \$15/CO_2e, \$40/CO_2e, and \$100/CO_2e are used; these are the same prices used in Alie et al. (2015) which, again, allows direct comparison of *fixed* and *flexible* generating units with CCS to be made.

Step 3 Characterize the techno-economic performance of a flexible generating unit with CCS. A monoethanolamine-based, post-combustion CO_2 capture process is designed to capture 85% of the CO_2 from the flue gas of a 500 MW_e coal-fired generating unit. The capture process is integrated with the generating unit and the performance of the integrated unit is simulated over a range of part-load conditions. The development of the reduced-order model of the generating unit with CCS is given in Section 3.

Step 4 Add CCS to the electricity system model and, again, simulate the operation of the electricity system with and without GHG regulation. In this study, the nominally 500 MW_e *flexible* generating unit with CCS replaces the 350 MW_e at Austen and the operation of the electricity system is again simulated with and without GHG regulation.

Step 5 Contrast the results of the simulations to obtain an estimate of the relative effectiveness of CCS as a mitigation option. In this study, it is the differences in utilization and energy benefit of a *flexible* generating unit CCS and the generating unit with *fixed* CCS that are scrutinized. Additionally, the impacts in terms of aggregate GHG emissions, electricity price, and net energy benefit are examined as proxies for impact to society, consumers, and generators writ large.

[1] According to the rules of NERC (North American Electric Reliability Corporation), upon which Ontario's reserve requirements are based, the 10-minute reserve, half of which must be spinning, should be set equal to the largest contingency. And, the 30-minute reserve is set greater by half of the second-largest contingency. In the IEEE RTS'96, the two 400 MW_e nuclear units operate as 'base' load units and their unexpectedly going off-line are the contingencies used as the basis for defining the reserve requirements.

Table 1
Summary of optimal design of CO_2 capture process.

Variable	Units	Value
h_{abs}	m	10
h_{str}	m	10
d_{abs}	m	11.2
d_{str}	m	7.6

3. Development of reduced-order model of coal-fired generating unit with flexible CCS

In the IEEE RTS'96, power output of generating units is represented using reduced-order models: univariate, stepwise linear functions of heat input to a boiler.[2] The maximum power output of a flexible generating unit with CCS would additionally depend upon CO_2 recovery and a different approach is needed in order to integrate a flexible unit with CCS into the electricity system simulator.

The development of an Aspen Plus® process model of coal-fired generating unit with PCC (post-combustion capture) based upon 30 wt% MEA is described by Alie et al. (2015). Key to note for this study is that steam required for solvent regeneration is extracted from the IP/LP crossover pipe of the steam cycle and let-down through a back-pressure turbine prior to going to the *Stripper* reboiler. Direct coupling of this Aspen Plus® model and the electricity system simulator is considered. While technically feasible, this approach is computationally expensive and deemed impractical for the purposes here. Instead, the approach taken is to develop a reduced-order model of the flexible generating unit with CCS and to embed it within the MINLP (Mixed-Integer Non-Linear Programming) underlying the economic dispatch problems in the electricity system simulator.

The overall flowsheet for the generating unit with integrated CO_2 capture is given in Fig. 2. Integrating the process models for the generating unit and CO_2 capture comes down to managing the extraction and reinjection of steam and condensate from and to, respectively, the generating unit steam cycle.

Nuchitprasittichai and Cremaschi (2011) discuss development of surrogate models of CO_2 capture process; a surrogate model seeks to represent the solution space of a more robust model but with fewer variables (*i.e.*, with reduced order). A surrogate model can be made with fewer variables as it only needs to be accurate in the region of the current point. The reduced form and parameters of the surrogate models are updated at each iteration of the optimization.

New insight is that it is not necessary to reproduce the entire response surface of the Aspen Plus® process model. All that is required is a presentation of the Pareto-optimal frontier for power output as a function of two variables: heat input to boiler and CO_2 recovery. This presumes that the generating unit with CCS is controllable over its defined operating range of these variables which is consistent in the specification of the units in the IEEE RTS'96. The insight confers significant advantages; a single reduced-order model can be developed to represent performance of the unit over the entire solution space and the model parameters only need to be estimated once.

The optimal design of the *Absorber* and *Stripper* columns identified by Alie et al. (2015) for 85% CO_2 recovery at full-load is shown in Table 1. Using this specification, the part-load performance of the generating unit with CO_2 capture is simulated from 50% load (*i.e.*, heat input to boiler of 750 MW_{th}) to 100% load and CO_2 recovery

[2] The hydroelectric generating units are modelled as having a single step with a heat input of zero over their domains.

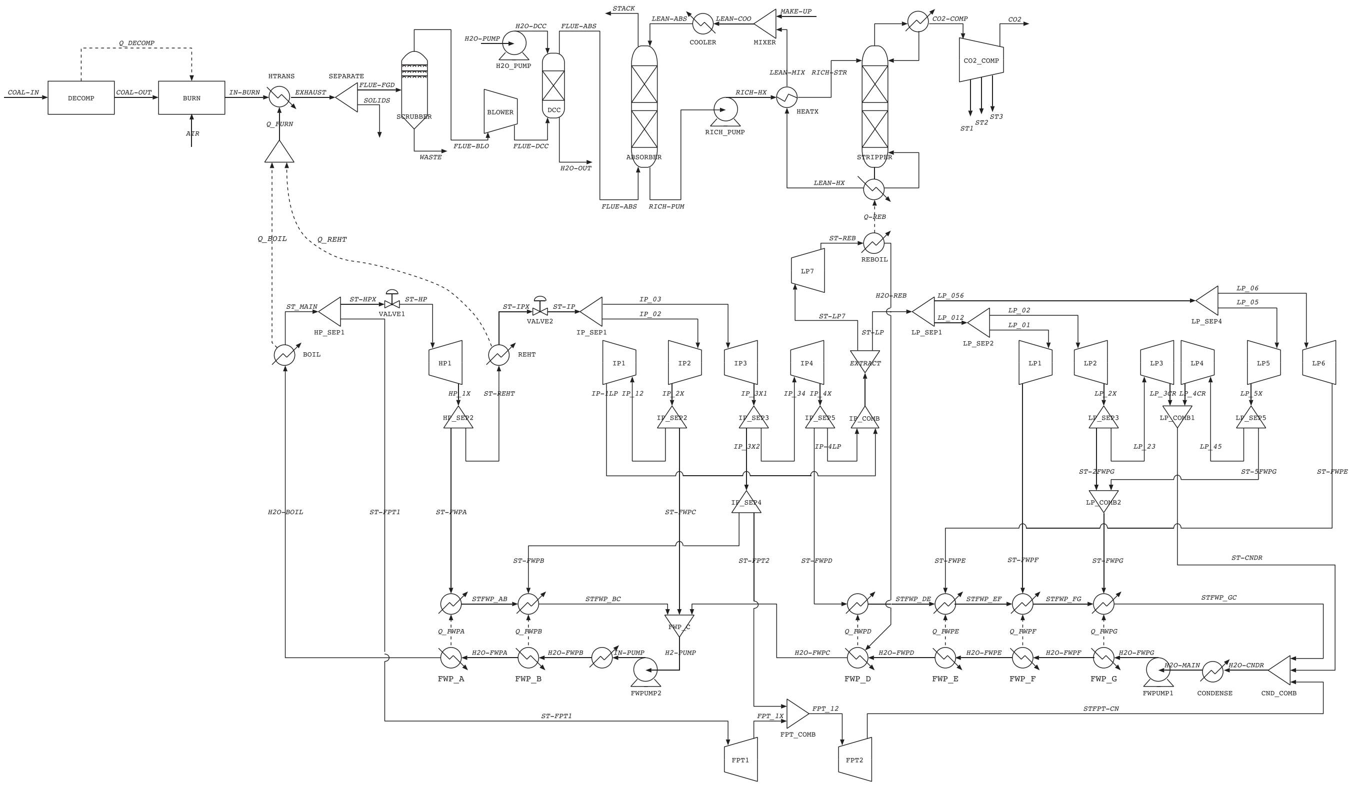


Fig. 2. Flowsheet of integrated generating unit and CO_2 capture process.

ranging from 0% to 95%. The optimization problem that is solved to for each combination of heat input to boiler and CO_2 recovery is shown in (1). The Pareto optimal frontier for power output as a function of unit load and CO_2 recovery is shown in Fig. 3.

$$
\begin{aligned}
&\underset{\substack{x_{steam},\,(\mathcal{P}_{out}/\mathcal{P}_{in})_{aux}\\ \mathcal{P}_{reb},\,F_{lean},\,L_1/D}}{\text{minimize}} && z = P_{generator} - P^{CO_2} + P_{aux}\\
&\text{subject to:} && T_{steam} \geq T_{reb} + 10^{\circ}\mathrm{C}\\
& && \dot{Q}_{steam} \geq \dot{Q}_{reb}\\
& && FA_{abs} \leq FA_{abs}^{max}\\
& && FA_{str} \leq FA_{str}^{max}\\
& && x^{CO_2} \geq (x^{CO_2})^{*} \qquad (1)\\
& && \mathbf{g}(x) = 0\\
&\text{variable bounds:} && 0.00 \leq x_{steam} \leq 0.83\\
& && 0.10 \leq (\mathcal{P}_{out}/\mathcal{P}_{in})_{aux} \leq 1.00\\
& && 0.01 \leq \frac{L_1}{D} \leq 1.00\\
& && 1\,\mathrm{kmol/s} \leq F_{lean} \leq 40\,\mathrm{kmol/s}\\
& && 101.3\,\mathrm{kPa} \leq \mathcal{P}_{reb} \leq 303.9\,\mathrm{kPa}
\end{aligned}
$$

The impetus for the simulations is to obtain the data necessary to develop a reduced-order model of the integrated generating unit and CO_2 capture model. Some interesting ancillary observations are noted:

- 92% of the time, the reboiler temperature is less than 110 °C; 86% of the time it is less than 105 °C. This is in contrast to 'conventional wisdom' which dictates that the *Stripper* reboiler should be operated as hot as practical. Apparently, there is a preference toward maximizing the supplemental power produced in the auxiliary turbine versus lowering the heat duty of the reboiler.
- The loading of the lean solvent ranges from 0.25 to 0.29 with a mean of 0.28 and standard deviation of 0.01.

Fig. 4 shows the input-output characteristic for the generating unit with CO_2 capture for thirteen different values of CO_2 recovery ranging from 0% to 95%. Three observations to mention:

1. At any given CO_2 recovery, there appears to be a first-order, linear relationship between net power output and heat input to the boiler. The idealized representation of the input–output characteristic for a coal-fired generating unit (*i.e.*, heat input to boiler for each unit of net power output) is a smooth, convex curve, often fitted by a second-order polynomial (Wood and Wollenberg,

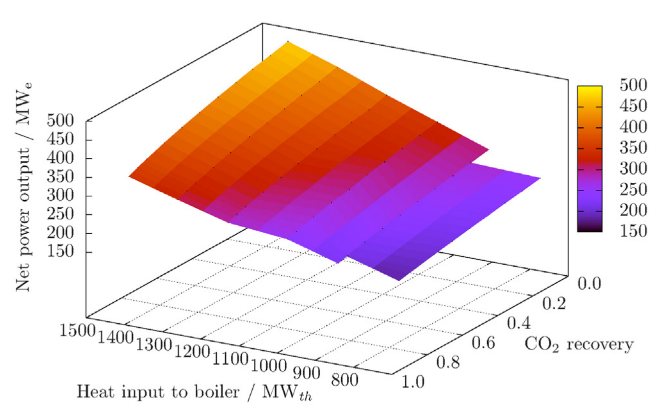


Fig. 3. Net power output versus heat input to the boiler and fraction of CO_2 recovered.

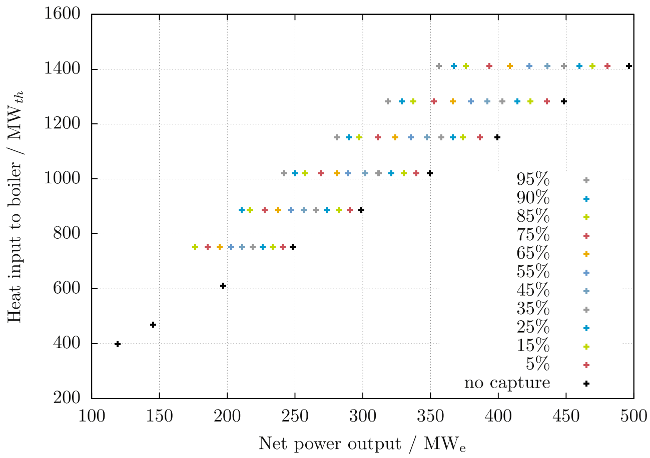


Fig. 4. Heat input to boiler required to achieve power output and CO_2 recovery set points.

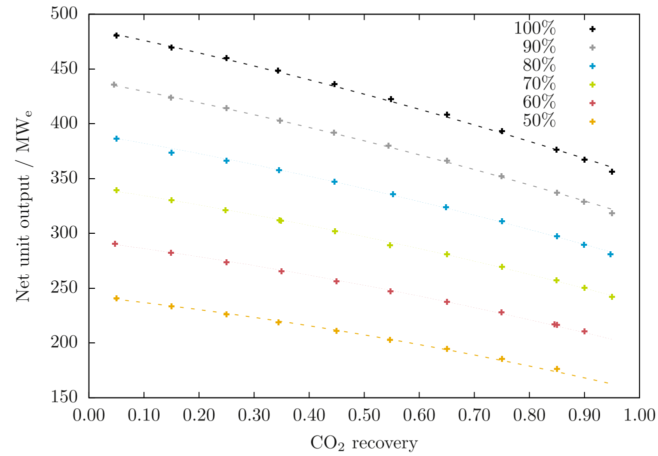


Fig. 5. Comparison of net power output data from Aspen Plus® and reduced-order model.

1996). For the reduced-order model, the terms $a_1\dot{q}$, $a_2\dot{q}^2$, and $a_3(1+\dot{q})^{-1}$ are proposed.

2. At any given heat input to the boiler, there appears to be a first-order, linear relationship between net power output and CO_2 recovery. For the reduced-order model, the terms $a_4x^{CO_2}$ and $a_5(x^{CO_2})^2$ are proposed.
3. There is some interaction between net power output and CO_2 recovery. For example, at 50% load, increasing CO_2 recovery from 5% to 85% reduces net power output by 64 MW$_e$ whereas, at 100% load, increasing CO_2 recovery in this way reduces power output by 104 MW$_e$. Twice as much CO_2 is being recovered at 100% load than is being recovered at 50% load yet the derate is 1.6×. This suggests that it is more energy efficient to capture CO_2 at higher loads than at lower loads. For the reduced-order model, the terms $a_6\dot{q}x^{CO_2}$ and $a_7x^{CO_2}(1+\dot{q})^{-1}$ are proposed.

Collecting all of the above terms yields the *full* model for the generating unit with CO_2 capture is given by (2). Least-squares estimates of the parameters a_0 through a_7 are determined using the GNU R statistical computation software (Venables and Smith, 2012).

$$P = a_0 + a_1\dot{q} + a_2\dot{q}^2 + \frac{a_3}{1+\dot{q}} + a_4x^{CO_2} + a_5(x^{CO_2})^2 + a_6\dot{q}x^{CO_2} + a_7\frac{x^{CO_2}}{1+\dot{q}} \quad (2)$$

Using ANOVA (Analysis of Variance), in particular the t statistic, variations of (2) are proposed in which one or more of these terms are eliminated. The preference is for a reduced-order model that has fewer terms, fits the data reasonably well, and whose partial first derivative with respect to heat input to the boiler depends upon both heat input to the boiler and CO_2 recovery. Nine derivative models are proposed and least-square estimates of the parameters for each is determined using GNU R. Using ANOVA—in particular adjusted-R^2 and P-values—and the decision criteria mentioned above, the reduced-order model in (3) is selected.

$$P = -34.66 + 0.3695\dot{q} - 30.47(x^{CO_2})^2 - 0.07374\dot{q}x^{CO_2} \quad (3)$$

Fig. 5 shows that the fit of the results from the Aspen Plus® simulations with the predicted values from the reduced-order model is reasonable. Fig. 6 is a plot of the residuals; the magnitude of the residuals is relatively small and there is no significant bias in the model as a function of generating unit output.

4. Integration of flexible generating unit with CCS in electricity system simulator

With respect to its integration in the electricity system simulator, the reduced-order model of the flexible generating unit with CCS differs from the units in the IEEE RTS'96 (Grigg et al., 1999) in two important ways. First, the power output of the flexible generating unit with CCS is a function of two variables: heat input to the boiler and CO_2 recovery. Second, these two variables are continuous over their respective domains.

4.1. Changes to the economic dispatch problem formulation

The set NG^C, a subset of NG, is defined and contains the "continuous" generating units. The set NG^D is also defined and contains the "discrete" generating units in the system; note that $NG = NG^D \cup NG^C$. Changes to the economic dispatch problem underlying the electricity system simulator to accommodate "continuous" units are grouped into three categories:

1. Adding constraints to express the power output from continuous units in terms of heat input to boiler and CO_2 recovery.
2. Adding constraints for continuous units specifying the contribution to the reserve market from continuous units.
3. Adding terms for continuous units to the objective function.

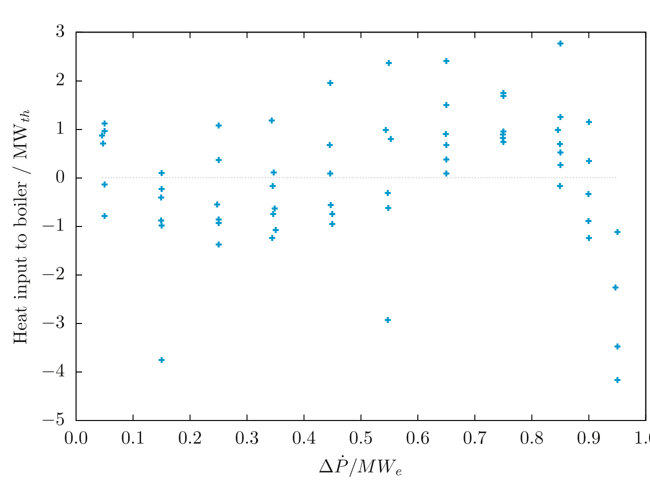


Fig. 6. Residual plot for net power plant output.

4.1.1. Constraints related to real power output

For a flexible generating unit with CCS, real power output is a function of two decision variables: heat input to boiler and CO_2 recovery. There is a minimum heat input to the boiler that must be maintained if the generating unit is on whereas it is assumed that CO_2 recovery is feasible over the range [0, 0.95]. The CO_2 capture process dynamics are assumed to be fast therefore the ramp rate of the generating unit will be constrained by the ramp rate of the boiler. The preceding statements are encapsulated in the following constraints.

Real power output

$$P_{nt}^{S} = a_0 + a_1\dot{q}_{nt} + a_3(x_{nt}^{CO_2})^2 + a_4\dot{q}_{nt}x_{nt}^{CO_2} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Minimum and maximum heat input to the boiler

$$(1-\omega_{nt})\dot{q}_n^{\min} \le \dot{q}_{nt} \le (1-\omega_{nt})\dot{q}_n^{\max} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$
$$(1-\omega_{nt})\dot{q}_n^{\min} \le (\dot{q}_{nt})^{\dagger} \le (1-\omega_{nt})\dot{q}_n^{\max} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Unit ramp rates

$$\dot{q}_{nt} \ge \dot{q}_{n,t-1} - (\Delta\dot{q})_n L_t \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$
$$\dot{q}_{nt} \le \dot{q}_{n,t-1} + (\Delta\dot{q})_n L_t \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

4.1.2. Constraints related to participation in reserve markets

For a flexible generating with CCS, $(\dot{q}, x^{CO_2})$ defines the dispatched real power output and $[(\dot{q})^{\dagger}, (x^{CO_2})^{\dagger}]$ defines the committed power output in case of contingency. As the CO_2 capture process is assumed to have fast dynamics, the maximum amount of power that a unit can provide to each class of reserve is limited by ramp rate of the boiler. The sum of the capacity accepted into the real and reserve power markets from continuous units must be less than the maximum available power. The preceding statements are encapsulated in the constraints shown below.

Capacity utilization

$$P_{nt} = a_0 + a_1(\dot{q}_{nt})^{\dagger} + a_3\left[(x_{nt}^{CO_2})^{\dagger}\right]^2 + a_4(\dot{q}_{nt})^{\dagger}(x_{nt}^{CO_2})^{\dagger} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Maximum real power output in case of a contingency

$$(P_{nt})^{\dagger} = a_0 + a_1[\dot{q}_{nt} + (\Delta\dot{q})_n\tau_r^R] + a_3[(x_{nt}^{CO_2})^{\dagger}]^2 + a_4[\dot{q}_{nt} + (\Delta\dot{q})_n\tau_r^R](x_{nt}^{CO_2})^{\dagger} \quad \forall r \in RM, n \in NG^C, \quad t = 1, 2, \ldots, T$$

Limit on 10-minute, spinning reserve

$$(P_{nt})^{\dagger} \ge P_{nt}^{s} + P_{10^{sp},nt}^{R} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Limit on 10-minute, non-spinning reserve

$$(P_{nt})^{\dagger} \ge P_{nt}^{S} + P_{10^{sp},nt}^{R} + P_{10^{ns},nt}^{R} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Limit on 30-minute, non-spinning reserve

$$(P_{nt})^{\dagger} \ge P_{nt}^{S} + P_{10^{sp},nt}^{R} + P_{10^{ns},nt}^{R} + P_{30^{ns},nt}^{R} \quad \forall n \in NG^C, \quad t = 1, 2, \ldots, T$$

Table 2
Performance summary for generating unit with 85% CO_2 capture.

Parameter	Units	Value
Minimum heat input to boiler	MW_{th}	141
Maximum heat input to boiler	MW_{th}	1411
Minimum reactive power output	MW_e	−50
Maximum reactive power output	MW_e	230
Minimum up-time	h	24
Minimum down-time	h	48
Ramp rate	MWh_e/min	15
Cold start heat input	MWh_e	3929

4.1.3. Objective function

The contribution to the objective function in each time period for a flexible generating unit with CCS in each time period is given by:

$$z_{nt} = \int_0^{P^S} \left(\frac{dC_{nt}^{VOM}}{dP_{nt}^{S}}\right) dP_{nt}^{S} = \Delta C_{nt}^{VOM} = C_{nt}^{VOM}$$

where for a flexible generating unit with CCS, C_{nt}^{VOM} is a function of $u_{nt}, (\dot{q}_{nt})^{\dagger}$, and $\left(x_{nt}^{CO_2}\right)^{\dagger}$. The last step in the above is a consequence of the fact that, by definition, variable operating and maintenance costs are zero when there is zero activity. The additional terms in the objective function for generating units with flexible CO_2 capture is shown in (4).

$$\begin{aligned}
&+\sum_{t=1}^{T}\sum_{n\in NG^C}(\dot{q}_{nt})^{\dagger}FC_nL_t\\
&+\sum_{t=1}^{T}\sum_{n\in NG_C}(\dot{q}_{nt})^{\dagger}EI_n^{CO_2}TAX^{CO_2}L_t\frac{1}{2.205\times10^6}\\
&-\sum_{t=1}^{T}\sum_{n\in NG_C^{CO_2}}(\dot{q}_{nt})^{\dagger}EI_n^{CO_2}TAX^{CO_2}\left(x_{nt}^{CO_2}\right)^{\dagger}L_t\frac{1}{2.205\times10^6}\\
&+\sum_{t=1}^{T}\sum_{n\in NG_C^{CO_2}}(\dot{q}_{nt})^{\dagger}EI_n^{CO_2}MEA_n\left(x_{nt}^{CO_2}\right)^{\dagger}L_t\frac{1}{2.205\times10^6}\\
&+\sum_{t=1}^{T}\sum_{n\in NG_C^{CO_2}}(\dot{q}_{nt})^{\dagger}EI_n^{CO_2}TS_n\left(x_{nt}^{CO_2}\right)^{\dagger}L_t\frac{1}{2.205\times10^6}
\end{aligned} \tag{4}$$

4.2. Changes to the electricity system simulator

Table 2 summarizes the operating parameters of the generating unit with flexible CCS. Is the same as that of the generating unit with fixed CO_2 capture.

In the *market settlement* phase, the marginal cost of generation of generating units with flexible CO_2 capture is computed. For $n \in NG_C^{CO_2}$, the contribution to the objective function is given by:

$$C_{nt}^{VOM} = C_{nt}^{start-up} + C_{nt}^{fuel} + C_{nt}^{CO<ce:inf>2</ce:inf>,start-up} + (1 - x_{nt}^{CO_2})C_{nt}^{CO<ce:inf>2</ce:inf>,fuel} + C_{nt}^{MEA} + C_{nt}^{TS} \tag{5}$$

Taking the partial first-derivative of (5) with respect to P_{nt} yields an expression for the marginal generating cost for this unit:

$$
\begin{aligned}
\frac{dC_{nt}^{VOM}}{dP_{nt}} &= \frac{dC_{nt}^{fuel}}{dP_{nt}} + \left(1 - x_{nt}^{CO_2}\right) \frac{dC_{nt}^{CO<ce:inf>2</ce:inf>,fuel}}{dP_{nt}} + \frac{dC_{nt}^{MEA}}{dP_{nt}} + \frac{dC_{nt}^{TS}}{dP_{nt}} \\
&= FC_n L_t \frac{1}{10^3} \frac{d\dot{q}_{nt}}{dP_{nt}} + \left(1 - x_{nt}^{CO_2}\right) EI_n^{CO_2} TAX^{CO_2} L_t \frac{1}{2.205 \times 10^6} \frac{d\dot{q}_{nt}}{dP_{nt}} + EI_n^{CO_2} MEA_n x_{nt}^{CO_2} L_t \frac{1}{2.205 \times 10^6} \frac{d\dot{q}_{nt}}{dP_{nt}} + EI_n^{CO_2} TS_n x_{nt}^{CO_2} L_t \frac{1}{2.205 \times 10^6} \frac{d\dot{q}_{nt}}{dP_{nt}} \\
&= \left\{ \frac{FC_n L_t}{10^3} + \left[\left(1 - x_{nt}^{CO_2}\right) TAX^{CO_2} + MEA_n x_{nt}^{CO_2} + TS_n x_{nt}^{CO_2} \right] \frac{EI_n^{CO_2} L_t}{2.205 \times 10^6} \right\} \frac{d\dot{q}_{nt}}{dP_{nt}} \\
&= \left\{ \frac{FC_n L_t}{10^3} + \left[TAX^{CO_2} - \left(TAX^{CO_2} - MEA_n - TS_n \right) x_{nt}^{CO_2} \right] \frac{EI_n^{CO_2} L_t}{2.205 \times 10^6} \right\} \frac{d\dot{q}_{nt}}{dP_{nt}}
\end{aligned}
\tag{6}
$$

where $\frac{d\dot{q}_{nt}}{dP_{nt}}$ is the Incremental Heat Rate of the generating unit an expression for which is obtained by taking the partial derivative of $\dot{q}$ with respect to P_{nt}.

4.3. Summary

With the above formulation, no assumptions are made with respect to capacity utilization (*i.e.*, when the generating unit is off and, when on, how much power it generates), heat rate, and CO_2 recovery. Of particular benefit in this study, the formulation allows the optimum combination of heat input to boiler and CO_2 recovery, which depends upon the relative cost of fuel and carbon permits, to be selected to achieve to achieve the target power output in each time period.

5. Key results of simulation of IEEE RTS'96 with flexible CCS

The operation of IEEE RTS'96 with flexible CO_2 capture is simulated for a one-week period with carbon prices of \$0, \$15, \$40, and \$100/tCO_2e. The aggregate demand for the week is shown in Fig. 7. To avoid anomalies in the results during the period of interest, the initial *pre-dispatch* period has a 48-hour time horizon.[3]

Results from the simulation of the IEEE RTS'96 that are key to the primary objective of assessing the benefit of generating units with flexible CCS are presented in this section. Supplemental results from the simulation can be found in Appendix A.

5.1. Capacity utilization

Figs. 8 and 9 indicate the *capacity utilization* and power injected into the grid, respectively, for each type of generating unit, in each time period, and with the carbon price set at \$0/tCO_2e. Capacity utilization refers to the sum of the power successfully bid into the real power market (*i.e.*, injected into the grid) and each of the three reserve markets. There is complete utilization of hydro and nuclear, near complete utilization of intermediate- and large-scale coal, moderate utilization of small-scale coal and intermediate- and large-scale oil, and small-scale oil and combustion turbine are used for peaking. Reserve power comes mostly from intermediate- and large-scale coal and hydro.

Fig. 10 summarizes the change in *capacity factor* for each type of unit in the IEEE RTS'96 with flexible CO_2 capture with CO_2 permit prices of \$15, \$40, and \$100/tCO_2e. Capacity factor is defined as the ratio of the energy output of the plant toits maximum theoretical energy output given the unit's availability over a specified period of time. The trend is as expected. As carbon prices increase, output of coal-fired units decreases, output of oil-fired units goes up (oil, when used for power generation, has a lower CO_2 intensity than coal), and the output of non-fossil fuel units, which was already high, stays the same. This observation reinforces the importance, as is the case in Cohen et al. (2012) and Alie et al. (2015), of being deliberate in terms of the carbon price at which flexible CCS (or any GHG mitigation option, for that matter) is being assessed; Fig. 10 shows that the stringency of the GHG regulation strongly influences the utilization of the generating units and it is this utilization that underlies the assessment of the benefits of a generating unit with flexible CCS.

5.2. Flexible operation generating unit with CCS

Fig. 11 provides a breakdown of the capacity utilization of the coal-fired generating unit with flexible CCS in each time period at carbon prices of \$0, \$15, \$40, and \$100/tCO_2e. The grey area represents the electricity that is injected into the grid; output never goes below 226 MW_e. The blue area represents capacity that is successfully bid into a 10-minute reserve markets and the yellow area represents capacity that is successfully bid into the 30-minute reserve market.

With a zero or \$15/tCO_2e carbon price, the optimal strategy is to operate the boiler at maximum or a relatively high load and to maximize CO_2 recovery. In the case of a contingency, the response is principally to increase output by recovering less CO_2 and, in some cases and to a limited extent, by increasing heat input to the boiler. As the CO_2 capture process is assumed to have fast dynamics, the generating unit with CCS is able to provide 10-minute spinning reserve power which is more difficult to secure than the other classes. Fig. 12 shows the as-dispatched set-point for CO_2 recovery for the generating unit with flexible CO_2 capture at carbon price of

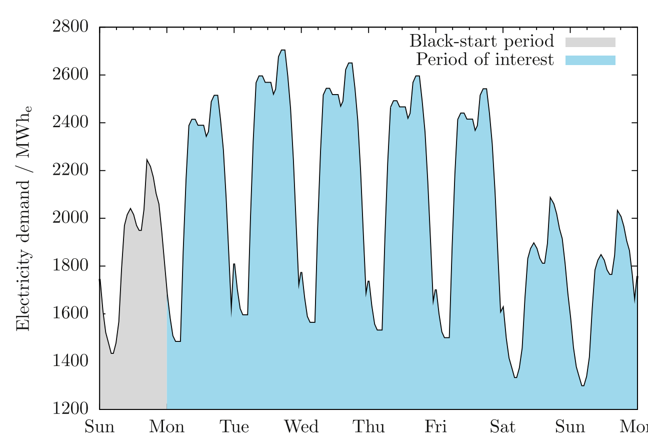


Fig. 7. Electricity demand in IEEE RTS'96.

[3] In practice, this achieved by solving two *pre-dispatch* of 24-hour horizons in sequence starting with the beginning of the day immediately preceding the period of interest.

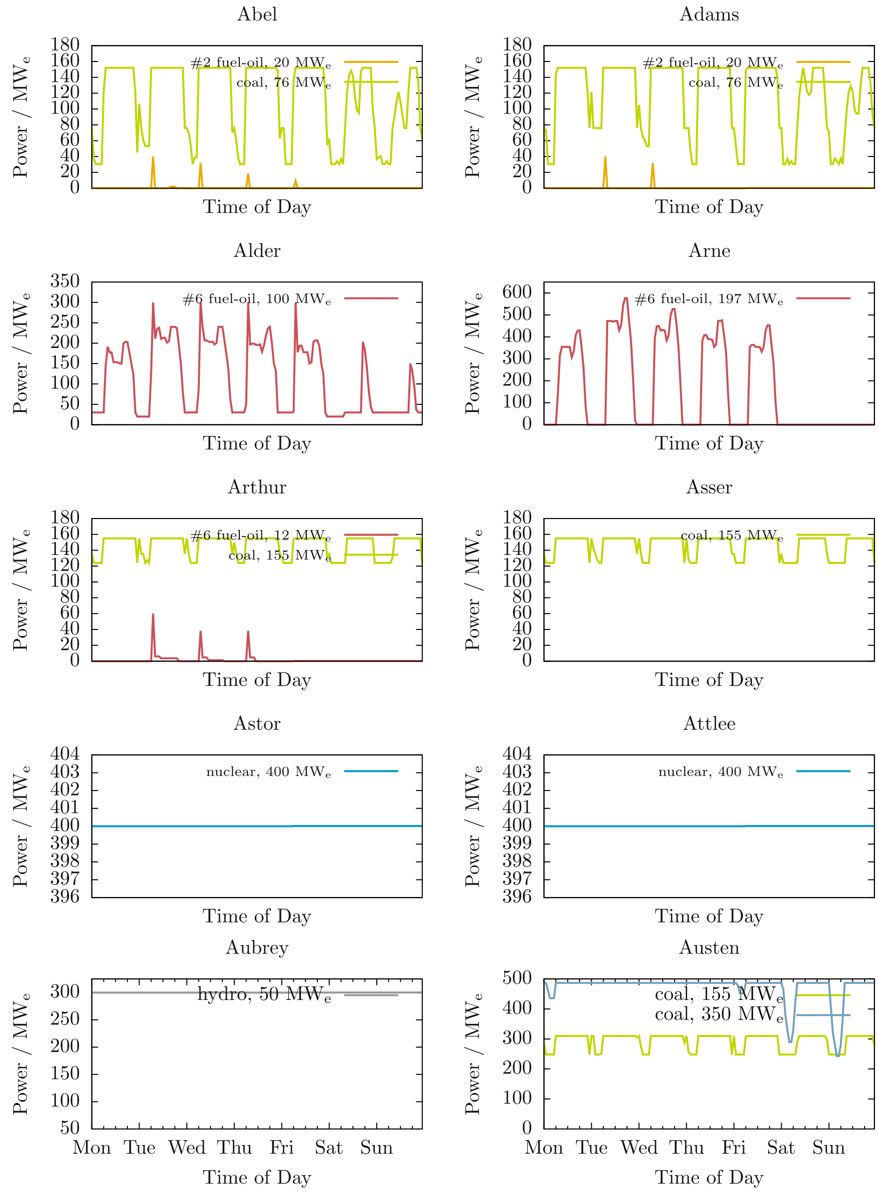


Fig. 8. Capacity utilization of generating units in IEEE RTS'96 with flexible CO_2 capture, without GHG regulation.

\$15/tCO_2e and, also, the CO_2 recovery set-point corresponding to the maximum output in case of a contingency.

Fig. 13 shows the total capacity utilization of the 487 MW_e generating unit with flexible capture over the time period of interest, providing greater detail about how the utilization changes as a function of time. It was already mentioned that the utilization decreases with increasing carbon price and here it is observed that, at \$40 and \$100/tonne CO_2, the capacity utilization has flatlined at 360.4 MW_e.

Prices of \$40 and \$100/tCO_2e provide a strong incentive for low-GHG intensity electricity. Even in the case of a contingency, the generating unit with CCS would be best off maximizing CO_2 recovery. The optimal strategy is to operate the boiler at part-load with maximum CO_2 recovery and to increase output, if and when needed, by increasing the heat input to the boiler while keeping the CO_2 recovery high. In this case, the quantity of capacity that can be used to fulfill the 10-minute reserve requirement is restricted by the ramp rate of the generating unit. Because of relatively high carbon prices, it is uneconomical to reduce the fraction of CO_2 recovered.

Put another way, the flexible generating unit with CCS defines a minimum of three different states in each time period and an example is shown in Table 3. In this time period and under normal circumstances, the unit is operating with a heat input to its boiler of 1027 MW_{th}, recovering 95% of the generated CO_2, and injecting 245.4 MW_e into the grid. In the case of a contingency and at the

Table 3
Operating states for 497 MW_e coal-fired generating unit at Austen during Monday peak period (17:00).

State	P MW_e	$\dot{q}$ MW_{th}	x^{CO_2}
P^S	245.4	1027	0.95
$P^S + RM^S_{10^{ns}}$ [a]	348.8	1177	0.50
$P^S + RM^S_{30^{ns}}$	453.1	1411	0.30

[a] There are many combinations of heat input to boiler and CO_2 recovery that could be used to achieve the target output of 348.8 MW_e within the 10-minute time frame. The example shown corresponds to the maximum increase in heat input to the boiler given the 1.1%/minute ramp rate.

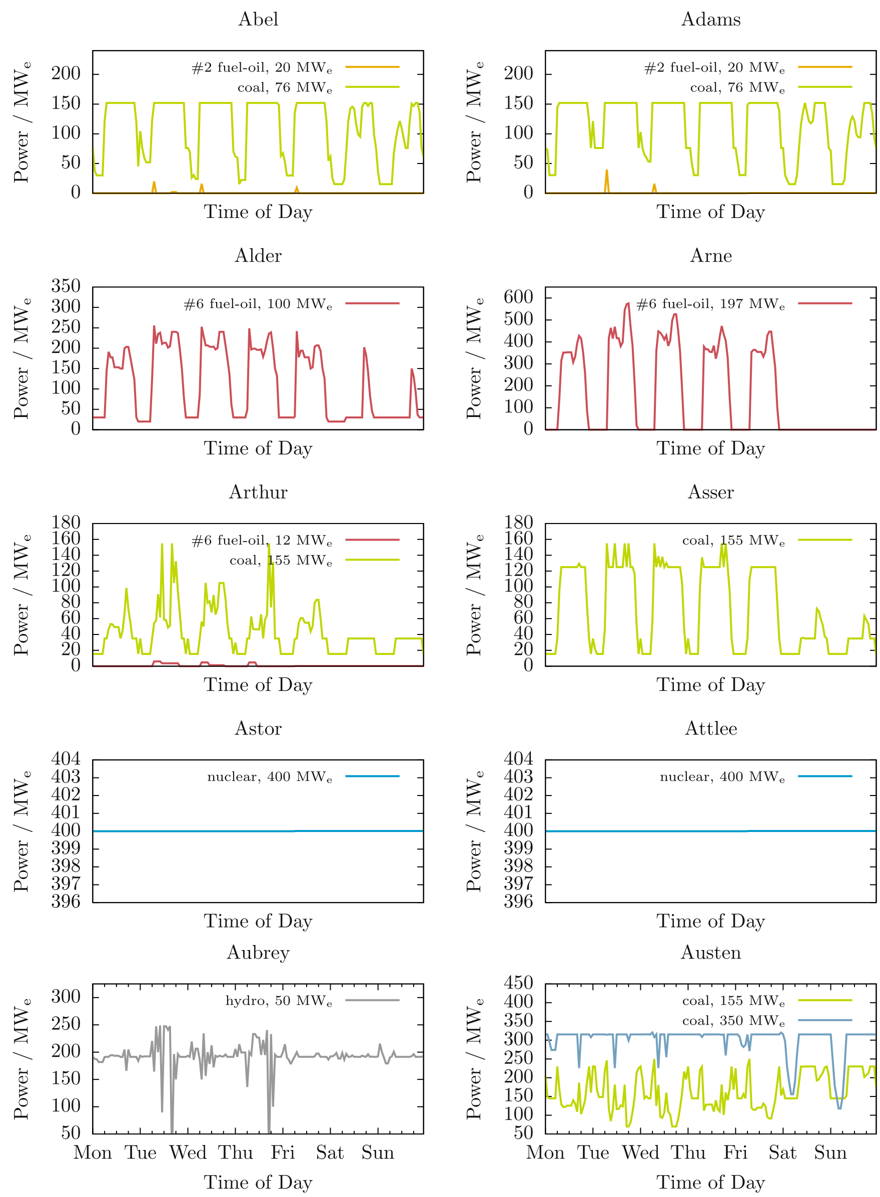


Fig. 9. Real power output of generating units in IEEE RTS'96 with flexible CO_2 capture, without GHG regulation.

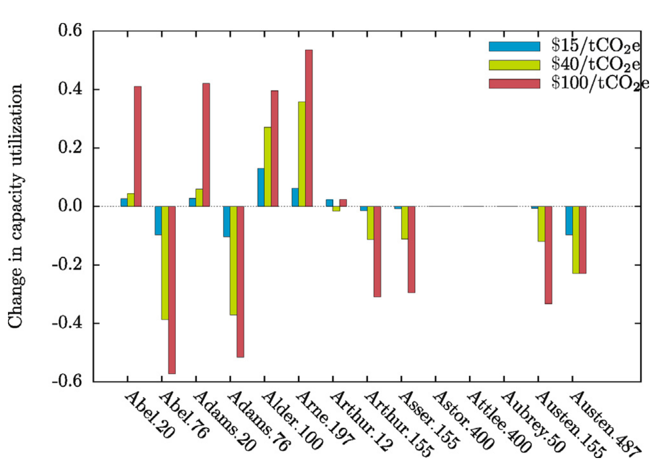


Fig. 10. Impact of GHG regulation on capacity utilization of generating units in IEEE RTS'96 with flexible CO_2 capture.

direction of the system operator, the generating unit is committed to:

1. Within 10 min, increase its output up to 348.8 MW$_e$ by, for example, increasing heat input to its boiler to 1177 MW$_{th}$ (the maximum achievable in 10 min given its ramp rate) and reducing CO_2 recovery to 50%.
2. Within 30 min, increasing its output up to 453.1 MW$_e$ which it would achieve by maximizing the heat input to its (*i.e.*, 1411 MW$_{th}$) and capturing 30% of the generated CO_2.

Fig. 14 shows the operating envelope of the coal-fired generating unit with CCS and the three different operating states described above.

5.3. Congestion

Fig. 15 summarizes the utilization of the 38 transmission lines in the IEEE RTS'96 for case with *flexible capture* and a carbon price of \$15/tCO$_2$e. The blue line at the top represents each line's MCR

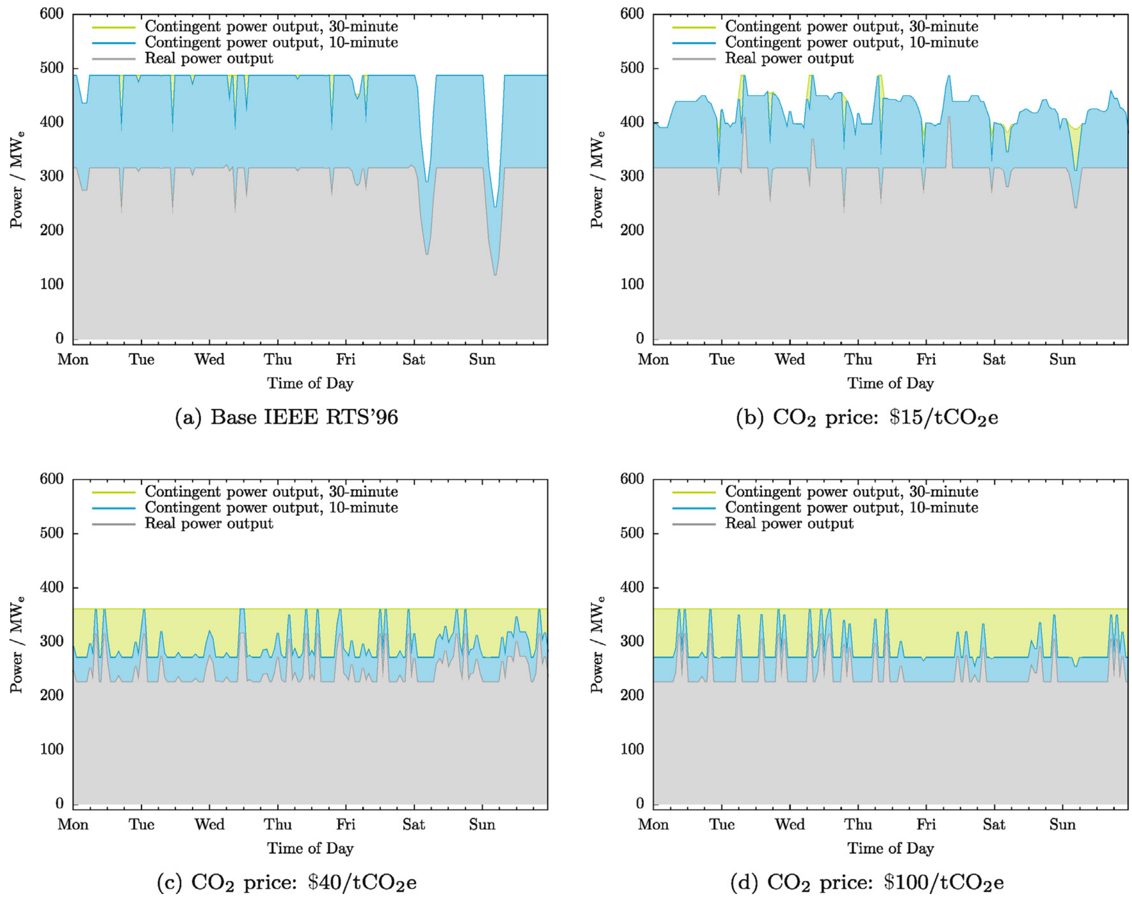


Fig. 11. Comparison of utilization of generating unit with flexible CO_2 capture, with and without GHG regulation. (For interpretation of the references to colour in the text, the reader is referred to the web version of this article.)

(Maximum Continuous Rating), the height of each bar represents the average unused line capacity, and the error bars identify the minimum and maximum values observed during the simulation. In this case, for a few hours during the week of interest, the power flow along the Alder–Alger line exceeds the Maximum Continuous Rating, the only transmission line for which an exceedance is observed in the *flexible capture* scenario. Note that the exceedance is still within the long-time emergency (24 hour) rating of the power line so there may not be a cause for immediate concern.

5.4. Transmission losses

Fig. 16 shows the average transmission losses incurred for each day of the electricity system simulation. With zero carbon price, transmission losses increase on the weekend even though there's a step change reduction in electricity demand. Share of generation from oil fired units at Alder and Arne diminishes which just so happen to be in closer proximity to loads than the cheaper hydro, nuclear, and coal generation. As carbon prices increase, the

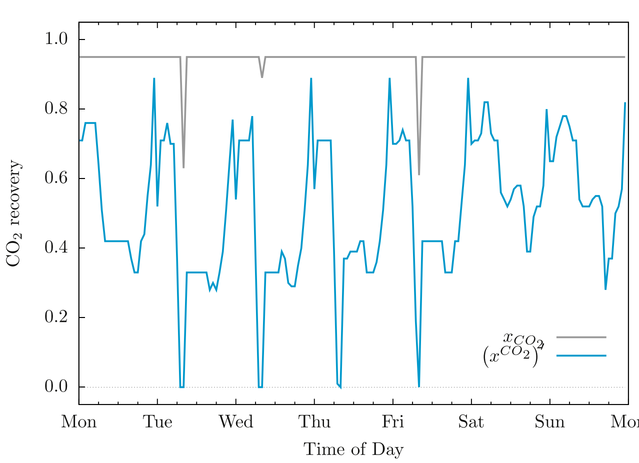


Fig. 12. CO_2 recovery set-points for generating unit with flexible CO_2 capture, \$15/tCO_2e.

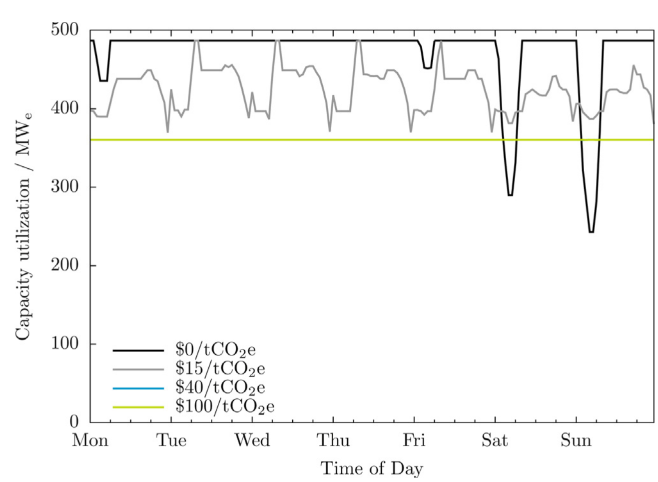


Fig. 13. Capacity utilization for 487 MW_e unit with flexible CO_2 capture at various carbon prices.

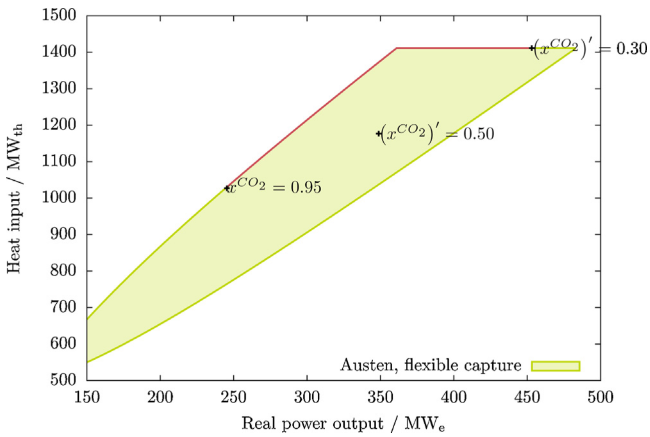


Fig. 14. Operating envelope of generating unit with flexible CCS during Monday peak period (17:00), \$15/tCO_2e.

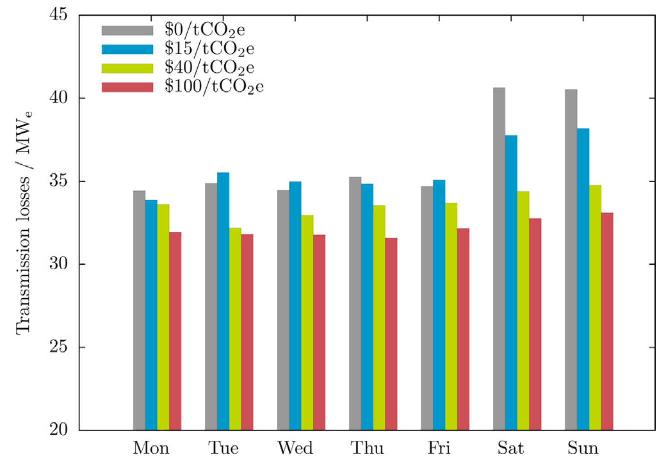


Fig. 16. Summary of daily transmission losses, with GHG regulation.

share of generation from oil-fired units doesn't drop-off during low-demand periods and the quantity of losses observed throughout the week is more uniform. Transmissions losses are 30–45 MW$_e$ or 1–3% of demand and varying over time; this is a significant additional quantity of electricity that must be injected into the grid above demand.

6. Discussion of results

In this work, a *flexible capture* scenario is constructed in which the 350 MW$_e$ coal-fired generating unit described by Grigg et al. (1999) is replaced by a 500 MW$_e$ coal-fired generating unit retrofitted with MEA-based PCC. The CO_2 capture process is designed for 85% recovery of CO_2 at full-load but the generating unit with CCS can reduce its load down to 10% and vary its CO_2 recovery anywhere from 0% to 95%. To understand the impact of this flexibility, the results of this scenario are compared and contrasted with those of two others; the scenarios differ only in terms of the CO_2 capture process installed at the large, coal-fired generating unit at Austen:

- The *no capture* scenario, as per the IEEE RTS'96 (Grigg et al., 1999), has a 350 MW$_e$ coal-fired generating unit without CCS.
- In the *fixed capture* scenario, the 350 MW$_e$ coal-fired generating unit described by Grigg et al. is replaced by a 500 MW$_e$ coal-fired generating unit retrofitted with MEA-based PCC. The new unit is constrained to operate at full-load and recover 85% of the generated CO_2, leading to a net power output of 376 MW$_e$.

Performance of the *no capture* and *fixed capture* scenarios is described by Alie et al. (2015). For each scenario, the operation of the IEEE RTS'96 is simulated for one week at carbon prices of \$0, \$15, \$40, and \$100/tCO_2e.

This section is divided into three parts. In the first part, the focus is the impact of flexible CCS on the IEEE RTS'96 writ large, seeking to establish whether or not flexible CCS is an effective GHG mitigation option. In the second part, the focus narrows to the impact that flexible CCS has at the generating unit level; that is, what benefits accrue to the generator from having a generating unit with *flexible* CCS versus a generating unit with CCS that is constrained to operate at fixed load and fixed CO_2 recovery. Finally, in the third part, the section concludes by reflecting upon

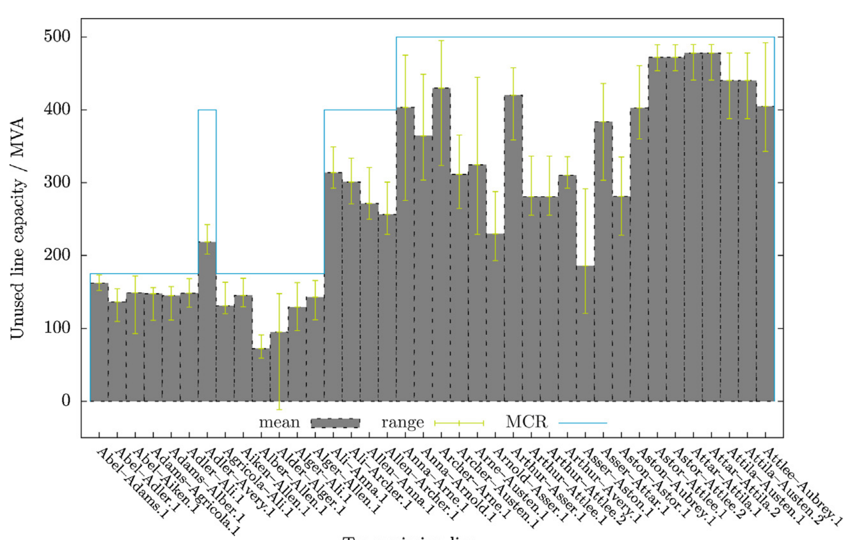


Fig. 15. Mean, maximum, and minimum power flows along each transmission line for IEEE RTS'96 with capture: \$15/tonne CO_2. (For interpretation of the references to colour in the text, the reader is referred to the web version of this article.)

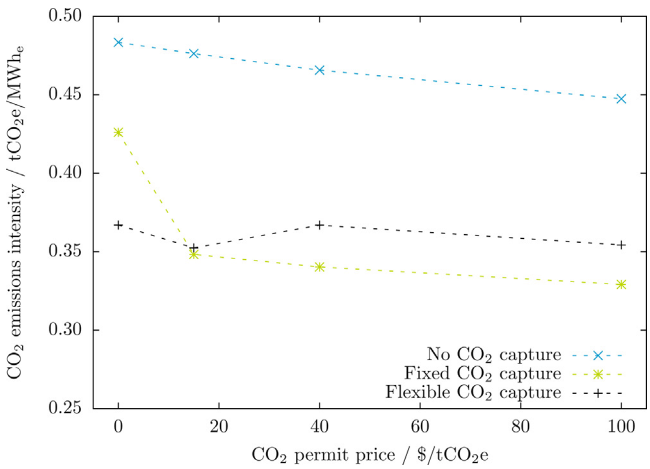


Fig. 17. Comparison of CO_2 emissions intensity in IEEE RTS'96 without, with fixed, and with flexible CO_2 capture.

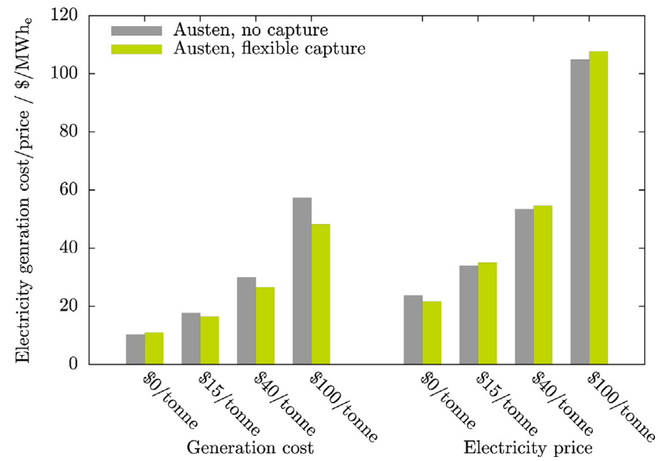


Fig. 18. Impact of adding flexible CCS on cost of electricity generation and electricity price in IEEE RTS'96.

the merits of the short-term resource scheduling approach versus other approaches in the literature.

6.1. *Effectiveness of flexible CCS as a GHG mitigation option*

6.1.1. *Impact of flexible CCS on GHG emissions in IEEE RTS'96*

Fig. 17 compares CO_2 emissions intensity for *no capture* and *fixed capture* scenarios with the CO_2 emissions intensity for the *flexible capture* scenario, from this study. Firstly, one observes that substituting the 350 MW_e unit at Austen with a comparable unit with CCS, flexible or otherwise, significantly reduces the GHG footprint of the IEEE RTS'96.

Secondly, GHG emissions in this study do not decrease monotonically with increasing carbon price as is observed in the *no capture* and *flexible capture* scenarios; in the *flexible capture* case, CO_2 emissions intensity at $\$40/tCO_2e$ is greater than the CO_2 emissions intensity at $\$15/tCO_2e$.

As seen in Fig. 11, the operating paradigm for the generating unit with flexible CO_2 capture changes between \$15 and $\$40/tCO_2e$. The net result is a shift of 75 MW_e of generation from the low-CO_2 intensity generating unit with CCS to higher intensity coal- or oil-fired generating units. This explains the step-change increase in CO_2 emissions intensity in going from \$15 and $\$40/tCO_2e$. The take-away is that it may not be valid to assume that, in a system with flexible CCS, increasing the stringency of GHG regulation necessarily further reduces CO_2 emissions.

Thirdly, at a carbon price of $\$0/tCO_2e$, GHG emissions intensity is lower in the *flexible capture* scenario than in the *fixed capture scenario*. At this carbon price, the capacity factor of the generating unit with CCS is 0.38 in the *fixed capture* scenario versus 0.62 for the unit with CCS in the *flexible capture* scenario. As a rule, the more the generating unit with CCS is dispatched, the lower the GHG emissions.

At CO_2 prices of \$15, \$40, and $\$100/tCO_2e$, CO_2 emissions in the *flexible capture* scenario are higher than in the *fixed capture* scenario. The explanation again goes back to differences in dispatch of the respective units with CCS. At these carbon prices, the capacity factor is unity for the generating unit with CO_2 capture in the *fixed capture* scenario and between 0.49 and 0.64 for the generating unit with CO_2 capture in the *flexible capture* scenario. The take-way is that it may not be valid to assume that either *fixed capture* or *flexible capture* leads to lower GHG emissions intensity; at a minimum, the carbon price would appear to influence which paradigm leads to a lower GHG footprint.

6.1.2. *Impact of flexible CCS on electricity price and cost of generation in IEEE RTS'96*

Fig. 18 compares the cost of electricity generation and electricity price in the *no capture* and *flexible capture* scenarios. Without GHG regulation, the generation costs in the two scenarios are essentially the same. With GHG regulation, generation costs in the *flexible capture* case are lower and the advantage is greater at higher carbon prices. With respect to electricity price, there is little difference between the electricity prices observed in the *no capture* and *flexible capture* scenarios.

6.1.3. *Summary of effectiveness of flexible CCS as a GHG mitigation option*

To summarize, adding CCS to the IEEE RTS'96 reduces GHG emissions by three to ten times more than can be achieved through load-balancing alone. In doing so, electricity generation costs are reduced and electricity price is largely unaffected.

6.2. *Advantages to generator of flexible CO_2 capture*

6.2.1. *Impact of flexible CCS on generating unit utilization*

The presumption is that a *flexible* generating unit with CCS would manipulate its CO_2 recovery to capitalize on (*e.g.*, hourly, diurnal) variations in electricity price relative to carbon price (Chalmers and Gibbins, 2007; Cohen et al., 2012). As the design basis for CO_2 capture processes is typically high (*i.e.*, 90% recovery), value from flexibility is envisioned to be realized from reducing the quantity of CO_2 recovered in order to increase power output during peak demand.

Very little of this behaviour is observed in this study. As shown in Fig. 12, CO_2 recovery is reduced in order to increase power output just three times at a carbon price of $\$15/tCO_2e$. At carbon prices of \$0, \$40, and \$100, the CO_2 recovery of the generating unit is not varied; maximum CO_2 recovery is observed during all time periods. What flexibility does allow the generating unit with CCS to do is shift the allocation of its capacity from the real power market to the reserve power markets. Fig. 19 summarizes the capacity utilization of the largest coal-fired units in each of the *no capture*, *fixed capture*, and *flexible capture* scenarios. As a proportion of the average capacity utilization, more supply is accepted into reserve market(s) in the *flexible capture* scenario than in the *no capture* and *fixed capture* scenarios.

The fact that the flexible generating unit with CCS is capturing CO_2 at a carbon price of $\$0/tCO_2e$ may initially appear counter intuitive. Indeed, it has been taken as a given (Cohen et al., 2012) that it would not be economical for a flexible generating unit with CCS

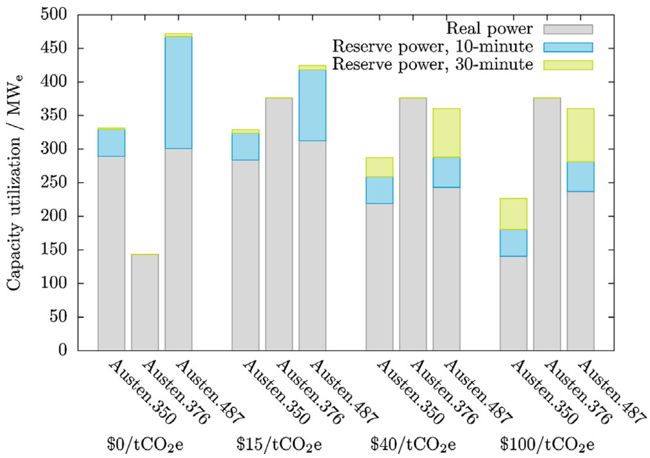


Fig. 19. Summary of capacity utilization of largest coal-fired generating units.

to recover CO_2 at zero or low carbon prices. As shown in Fig. 19, there is also some capacity from the 350 MW_e unit at Austen that is selected for 10- and/or 30-minute reserve, including at a carbon price of $0/t$CO_2$e. It should therefore be anticipated that, in the *flexible capture* scenario, the flexible generating unit with CCS would also have some of its capacity selected for reserve power.

The results indicate that, in the *fixed capture* scenario, it is more advantageous to operate the boiler at (or near) base-load, maximize CO_2 recovery, and increase net power output in the case of a contingency by reducing CO_2 recovery as opposed to either of:

1. Operate the boiler at (or near) base-load and vary CO_2 recovery in order to take advantage of volatility in the difference between the value of electricity and avoided CO_2 emissions.
2. Operate the boiler at part-load, capture no CO_2, and then increase net power output by increasing the heat input to the boiler in the case of a contingency.

The consideration of the detailed operation of the IEEE RTS'96—especially the transmission system and markets for reserve power—embedded within the short-term resource scheduling approach to is what allows the potential importance of flexible CCS to the contribution of system security to be observed on generating unit utilization.

6.2.2. Impact of flexible CCS on generating unit net energy benefit

Energy benefit represents the revenue a unit receives from selling its capacity. This includes payments for bids accepted to satisfy demand and those selected to meet reserve power requirements. *Net energy benefit* represents the difference between the energy benefit and the costs to produce electricity (*e.g.*, fuel both for start-up and power generation, make-up solvent, CO_2 transportation and storage, CO_2 permits). Fig. 20 compares the net energy benefit realized by the largest coal-fired generating unit from the *no capture*, *fixed capture*, and *flexible capture* scenarios at carbon prices of zero, $15, $40, and $100/t$CO_2$e. In every case, the generating unit with flexible CO_2 capture is the most profitable. Now, why is that?

Fig. 21 compares the power injected into the grid in each time period for the largest coal-fired generating unit from the *fixed capture* and *flexible capture* scenarios at a carbon price of zero. At this carbon price, the generating unit with fixed CO_2 capture is disadvantaged. First, it takes an efficiency hit from capturing 85% of its

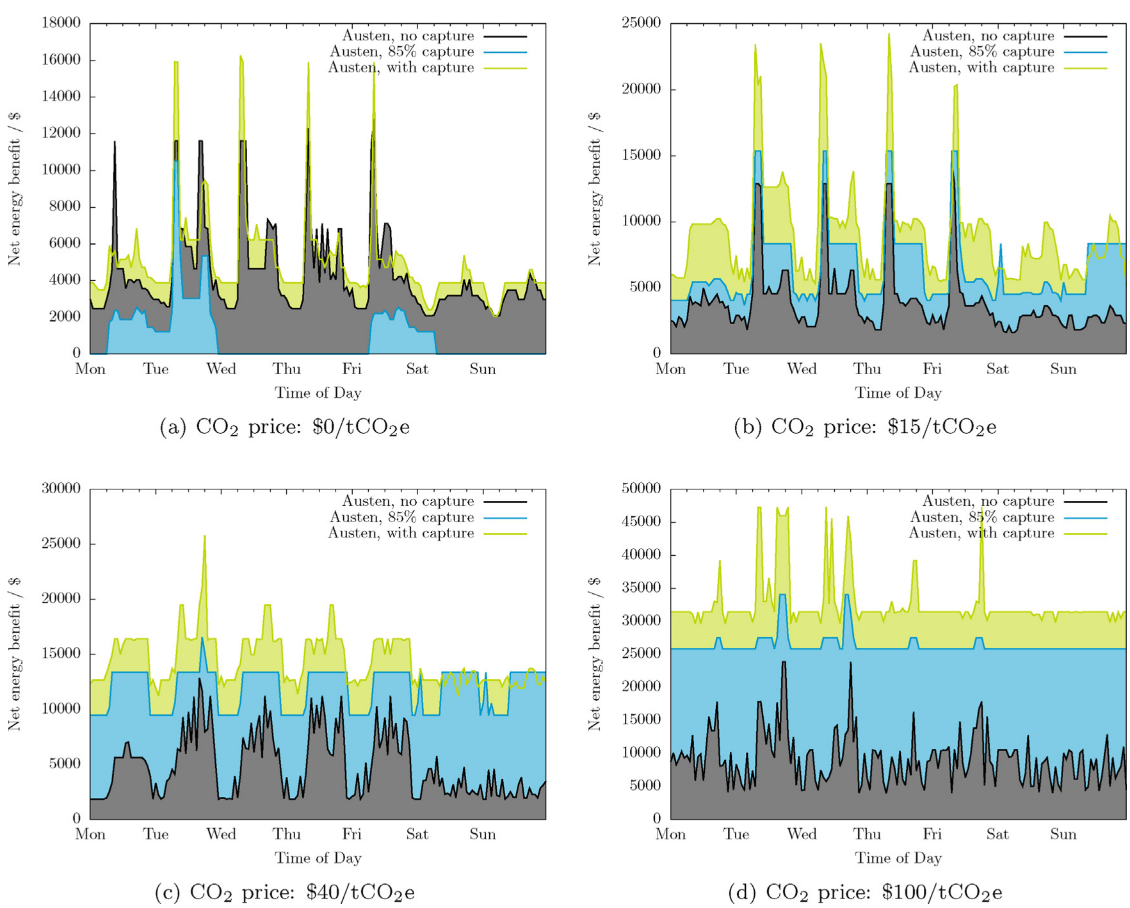


Fig. 20. Comparison of net energy benefit for generating units at Austen, with GHG regulation.

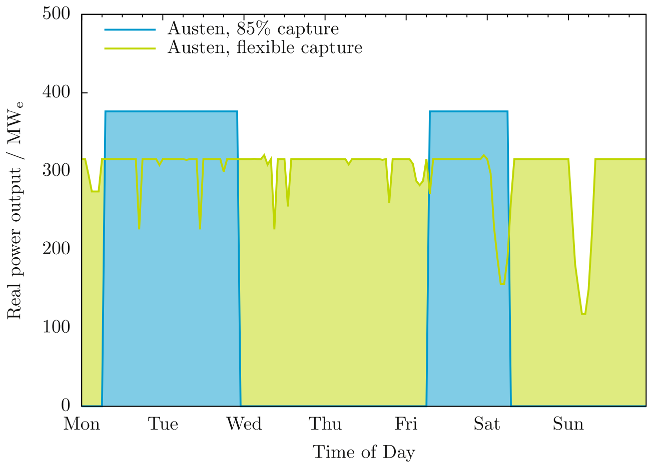


Fig. 21. Comparison of power output for generating units with fixed and flexible CO_2 capture at zero carbon price.

CO_2 but, with a zero carbon price, it garners no favour for its low CO_2-intensity electricity. Second, because its operation is inflexible, it is not able to participate in the reserve markets. It is dispatched just 38% of time over the week of interest. In contrast, the ability to operate at part-load and fast CO_2 capture process dynamics allow the unit with flexible CO_2 capture to achieve a capacity factor of 62%. All things being equal, it should come as no surprise that the generating unit dispatched to a greater extent realizes the greater operating profit in gross terms.

Increased power output alone, though, does not explain the increase in net energy benefit realized by flexible generating units with CCS. In cases with GHG regulation, the generating unit with CCS in the *fixed capture* scenario injects more electricity into the grid than the generating unit with CCS in the *flexible capture scenario*: 376 MW_e in every time period versus averages of 312, 243, and 237 MW_e at carbon prices of \$15, \$40, and \$100/tCO_2e, respectively, in the *flexible capture* scenario. Yet, as seen in Fig. 20b through d, the net energy benefit of the generating unit with CCS in the *flexible capture* scenario is higher than its counterpart in the *fixed capture* one.

Electricity prices that were considerably higher in the *flexible capture* scenario would contribute to the generating unit with CCS in that scenario having a higher net energy benefit. Fig. 22 shows the electricity prices for the *fixed capture* and *flexible capture* scenarios. This is a red herring. The difference in electricity prices is immaterial and would not explain the discrepancy in net energy benefit between the two scenarios.

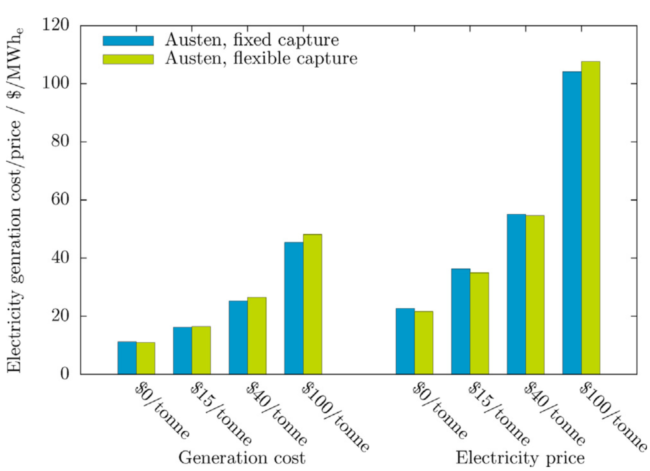


Fig. 22. Cost of generation and electricity price for fixed and flexible capture scenarios.

Net energy benefit is the revenue earned by a generator from leveraging its units' capacity less the units' operating costs. To a first approximation, unless a contingency arises, there are zero operating costs associated with bids accepted into a reserve market yet these bids are a revenue stream for the generator and add directly to the bottom-line. As shown in Fig. 11, 23–35% of the generating unit's capacity is accepted, on average, into the reserve markets. At low carbon prices, reserve power is premised upon reducing the quantity of CO_2 recovered; more power can be made available and more quickly by adjusting CO_2 recovery than by increasing heat input to the boiler. At high prices, reserve power is premised by increasing the heat input to the boiler while keeping CO_2 recovery high; the unit is able to output low-CO_2 intensity power now and also offer low-intensity CO_2 power in case of contingency. In any event, this operability explains the additional net energy benefit realized by the generating unit with CCS in the *flexible capture* scenario, especially with GHG regulation in place.

A key observation in this study is that, at all carbon prices including zero, the generating unit with flexible CO_2 capture is more profitable then the generating unit with fixed capture or, indeed, the generating unit without any CO_2 capture and that this increased profitability is attributable to the flexibility. This is in opposition to the predictions of Cohen (2009), Cohen et al. (2012) and Delarue et al. (2012) that benefits from flexibility would only materialize at intermediate carbon prices: at low carbon prices, CO_2 recovery would collapse to zero and the unit would perform comparable to a unit without CO_2 capture and, at high prices, CO_2 recovery would remain high and the unit would perform comparable to a unit with fixed CO_2 capture. The underestimation of the benefits of flexible CO_2 capture processes is in part due to not explicitly managing market(s) for reserve power, the importance of which is discussed above. Another contributing factor are the simplifying assumptions made around the dispatch of generating units to supply demand and this is discussed next.

6.3. Advantages of short-term resource scheduling approach

There are three areas in which the use of the short-term resource scheduling approach for the assessment of flexible CCS seem to confer particular advantages versus other approaches observed in the literature:

1. Consideration of both revenue and cost impacts of flexible CCS.
2. Endogenous estimation of electricity price.
3. Identification of congestion and consideration of transmission losses.

6.3.1. Consideration of both revenue and cost impacts

CCA (Cost of CO_2 Avoided) is commonly used to measure the performance of GHG mitigation actions including CCS (Singh, 2001; Rao and Rubin, 2002; Ordorica-Garcia, 2003; Elkamel et al., 2009; Ansolabehere et al., 2007; van den Broek et al., 2009; Levina et al., 2013). It compares a generating unit after some mitigation action has been taken (*e.g.*, CCS) to a reference plant and represents the average cost of avoiding a tonne of GHG emissions per unit of output. An expression for *CCA* is shown in (7).

$$CCA = \frac{(CoE) - (CoE)_{ref}}{(CEI)_{ref} - (CEI)} \tag{7}$$

An expression for calculating *CoE* (Cost of Electricity) is given below:

$$CoE = \frac{TCR \times FCF + C^{FOM}}{CF \times P^{max} \times HPY} + C^{VOM} + HR \times FC \tag{8}$$

Table 4
Comparison of *CCA* for fixed and flexible CO_2 capture cases.

Scenario	Cost of CO_2 Avoided (\$/tCO_2e avoided)			
	\$0/tCO_2e	\$15/tCO_2e	\$40/tCO_2e	\$100/tCO_2e
Fixed CO_2 capture	170.92	51.55	40.12	11.27
Flexible CO_2 capture	64.23	60.30	73.51	50.74

Table 5
Increase in net energy benefit from adding CCS.

Scenario	Capacity MW_e	Delta net energy benefit (\$/week/MW_e)			
		\$0/tCO_2e	\$15/tCO_2e	\$40/tCO_2e	\$100/tCO_2e
Fixed capture	487	−1766	374	1798	4610
Flexible capture	487	−344	1285	2677	6837

and *CEI* (CO_2 Emissions Intensity) can be expressed as:

$$CEI = EI^{CO_2} \times HR \quad (9)$$

Using values for capacity factor and heat rate taken from the results of the *no capture*, *fixed capture*, and *flexible capture* scenarios and the same costing basis as Ansolabehere et al. (2007) with an additional 3% premium added to the CCS installed cost to account for the cost of flexibility (*i.e.*, TCR = 978.5 \$/kW_e gross plant capacity for CCS, *FCF* = 0.151, *VOM* = 7.5 \$/MWh_e for unit without CCS, *VOM* = 16 \$/MWh_e for unit with CCS), *CCA* is calculated for the generating units with CCS and are tabulated in Table 4.

The results in Table 4 would suggest fixed CO_2 capture is a better GHG mitigation option than flexible CO_2 capture. This is misaligned with the observations in previous Sections 6.1 and 6.2 that flexible CO_2 capture achieves comparable reductions in GHG emissions to fixed CO_2 capture and with greater net energy benefit to the generating unit of interest. The discrepancy is due to the fact that *CCA* considers only the costs associated with the GHG mitigation option (*e.g.*, capital, fuel consumption, CO_2 permits, CO_2 capture, transportation, and storage). It does not incorporate the impact that the mitigation action may have on revenues from generating electricity and providing ancillary services.

Table 5 shows the increase in average pre-tax, net energy benefit realized per unit of (gross) installed capacity, for the week of interest, from substituting the largest coal-fired generating unit in the IEEE RTS'96 with a generating unit with either fixed or flexible operation. Using the same capital cost assumptions as before, the incremental cost for a flexible generating unit with CCS is \$194/week/MW_e of (gross) installed capacity. At carbon prices of \$15, \$40, and \$100/tCO_2e, this incremental cost is at least five times *less* than the incremental revenue realized by having a flexible generating unit with CCS versus a generating unit with fixed CO_2 capture. So, while *CCA* would indicate a preference for fixed operation (see Table 4), the short-term resource scheduling approach, with its explicit and detailed consideration of the operation of the electricity system, shows a clear preference for flexible generating units with CCS.

6.3.2. Endogenous estimation of electricity price

Predicting a generator's net energy benefit requires an estimate of the electricity price for the time periods of interest and, in a deregulated electricity system, the price formation results from the dispatch of the generating units. It is tempting to assume that dispatch is unaffected by changes in the stringency of GHG regulation, the implementation of a GHG mitigation option (*i.e.*, deployment of CCS, or that units are dispatched strictly in increasing order of SRMC (Short-Run Marginal Cost) as these assumptions make trivial the problem of identifying the marginal unit in any time period.

It was shown by Alie et al. (2015) that adding CCS to the IEEE RTS'96 did change the dispatch of the generating units as did changing the carbon price. The differences in utilization between the generating units with fixed and flexible CO_2 capture has already been discussed. Fig. 23 shows the difference in capacity factor for the other generating units in the IEEE RTS'96 between the *fixed capture* and *flexible capture* scenarios. A unit's output seems to depend upon the type of CCS that is installed and is different depending upon the stringency of the GHG regulation. These findings suggest that it would not be valid to assume that dispatch is insensitive to changes to the generating unit composition in the underlying electricity system.

Although the bids to supply power in the electricity system simulation are based upon SRMC, strict merit-order dispatch is not observed. There are four 155 MW_e coal-fired generating units in the IEEE RTS'96—one at Arthur, one at Asser, and two at Austen—and each has the same performance parameters. In the *flexible capture* scenario, the power each injects into the grid differs significantly from one to the other (see Fig. 9). The electricity system simulator respects the minimum up- and downtime constraints of the generating units, is spatially-aware, models both real and reactive power, and provisions sufficient 10- and 30-minute reserve power to satisfy security considerations; these four aspects result in the power generated by each of the 155 MW_e coal-fired generating units being of different utility. This explains why the dispatch of each unit differs significantly from one to the other whereas a strict merit-order dispatch would predict identical performance.

Also, oil-fired generation represents a major component of electricity supply at a carbon price of \$0/tCO_2e (see Fig. 9) and there are oil-fired units dispatched in all time periods, even during the off-peak periods on weekends. Fig. 24 shows the load–duration curve for the week of interest; off-peak demand in the IEEE RTS'96 is

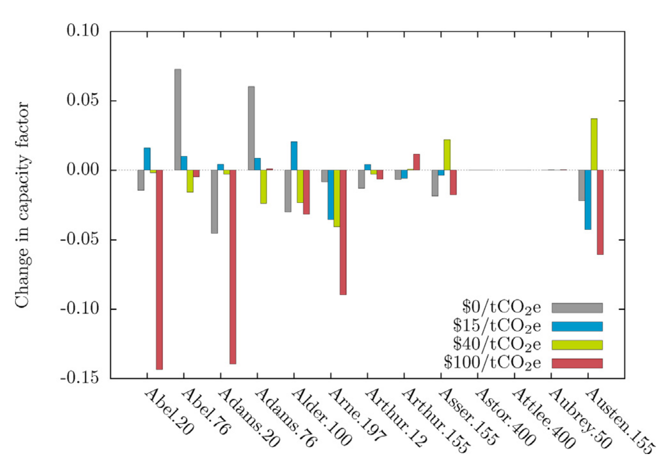


Fig. 23. Impact of making CO_2 capture process flexible on capacity factor of units in IEEE RTS'96 without and with GHG regulation.

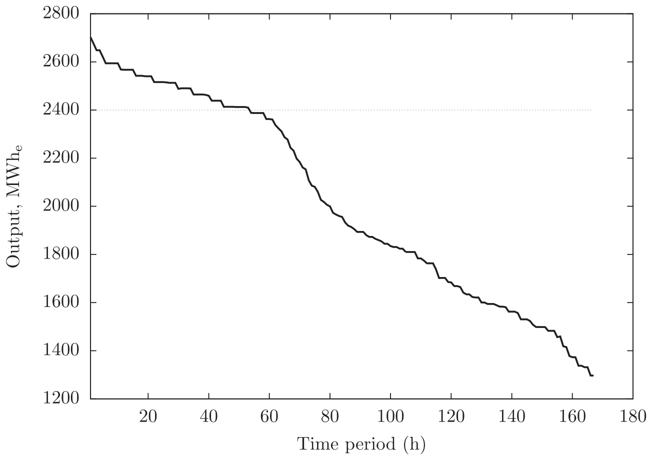


Fig. 24. Load duration curve for first week of operation of IEEE RTS'96.

less than 1594 MW_e during the week and as low as 1297 MW_e on weekends (see Fig. 7). In the composite supply curve for the system at a carbon price of \$0/tCO_2e, oil-fired steam generation comes in at approximately 2400 MW_e. If strict merit-order dispatch were assumed, oil-fired generating units would be dispatched in only one-third of the time periods and contribute marginally to total electrical energy supply. The utilization of the 155 MW_e coal-fired and the oil-fired units in the IEEE RTS'96 suggest that assuming that units are utilized in strict merit-order may not be valid.

6.3.3. Identification of congestion and consideration of transmission losses

The congestion observed in the *flexible capture* scenario (see Fig. 15) is a further example of the importance of explicitly considering the target electricity system. The Alder–Alger transmission line is the only connection between Alder and the rest of the IEEE RTS'96 and its MCR is insufficient to export all of Alder's generating capacity. Without modelling the power flows, it wouldn't be difficult to unwittingly incorporate into one's analysis operating states for the system that are infeasible and lead to incorrect conclusions.

Modelling of the power flows also allows transmission losses to be endogenously incorporated into the assessment of the benefits of flexible CCS. As seen in Fig. 16, transmission losses mean that more power needs to be generated in any given time period than just the demand and that this extra power requirement can vary significantly from one day to the next and for different carbon prices.

7. Conclusion

The primary objective of the paper is to apply the short-term resource scheduling approach to assess the benefit of generating units with CO_2 capture process that are flexible. The IEEE RTS'96 is modified to include a flexible coal-fired generating unit with CCS and the operation of the electricity system is simulated for one week at carbon prices of \$0, \$15, \$40, and \$100/tCO_2e. The results of these cases is compared with comparable cases from a scenario in which the generating unit with CCS is constrained to operate with fixed load and CO_2 recovery and another scenario in which there is no CCS at all.

Flexible CCS provides clear advantage over fixed CCS in IEEE RTS'96. CCS—flexible or otherwise—is effective at reducing GHG emissions in the IEEE RTS'96. With GHG regulation in place, the *flexible capture* and *fixed capture* scenarios emitted fewer GHG emissions and had lower costs of electricity generation than the *no capture* scenario. Flexible generating units with CCS realize a greater net energy benefit that would appear to justify the incremental investment cost for achieving this flexibility.

The greater net energy benefit is principally a result of a flexible generating unit with CCS being able to participate preferentially in the reserve markets. The moderation of electricity output via manipulation of CO_2 recovery set-point is very rarely observed.

The short-term resource scheduling approach is effective in assessing the effectiveness of flexible generating units with CCS for three reasons. First, the short-term resource scheduling approach explicitly takes into consideration the detailed operation of the electricity system including varying demand for real and reactive power; an AC-power flow model to represent electricity transmission; 10- and 30-minute reserve power requirements; and unit ramp, minimum uptime, and minimum downtime constraints. Second, the use of reduced-order model of generating unit with CO_2 capture that represents the Pareto optimal frontier allows the short-term resource scheduling model to consider the trade-off between fuel and carbon prices with a minimum amount of added complexity. Third, the assessment considers the impact to revenues resulting from the implementation of the GHG mitigation option and not just the impacts to costs. These three features allow for precise determination of the costs and benefits of flexible CCS.

The findings in this study are likely sensitive to the unit(s) and, to a greater extent, the electricity system of interest. For example, this study considered consumers to be price takers and that capacity is bid into the market at the SRMC of generation. In ERCOT, where bilateral contracts dominate, it may be appropriate to price bids at the LRMC (Long-Run Marginal Cost) of generation instead. It may also make sense to price bids into the reserve market at a discount (or premium) to capacity bid into the real power market. The recommendation is not to generalize the findings of this study to CCS in general but rather that similar analyses be undertaken to assess the deployment of flexible generating units with CCS—or any other GHG mitigation option, for that matter—in the target electricity systems.

That being said, the additional potential benefit that flexibility confers is contingent upon the flexible generating unit with CCS being able to quickly increase its power output via additional heat input to its boiler or reducing CO_2 recovery. Validation of the dynamic performance of a generating unit with CCS is needed. Recent start-up of commercial-scale coal-fired units with CCS (*i.e.*, Boundary Dam) should facilitate the validation (or invalidation) of assumptions regarding the dynamic performance of the 1st-generation of generating units with CCS.

Appendix A. Supplemental results of simulation of IEEE RTS'96 with flexible CCS

Capacity utilization

Fig. A.1 shows the average capacity utilization and Fig. A.2 shows the capacity factor for the different types of generating units in the IEEE RTS'96 with flexible CO_2 capture at carbon prices of \$0, \$15, \$40, and \$100/tCO_2e.

Heat rate

Fig. A.3 compares the average heat rate observed for each type of generating unit in the IEEE RTS'96 with flexible CCS. The dashed horizontal line indicates the heat rate for that particular unit at its design conditions. For the coal-fired generating unit with CCS, two reference heat rates are shown: the upper one corresponding to the design basis of 100% load and 85% CO_2 recovery and the lower one representing the minimum heat rate of 9969 Btu/kWh_e

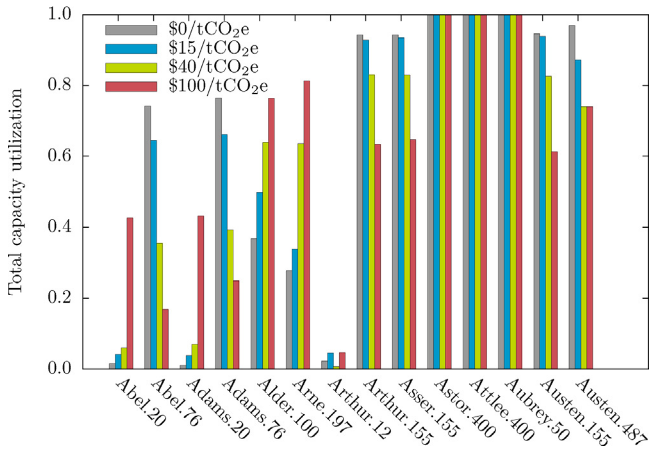


Fig. A.1. Comparison of capacity utilization of generating units in IEEE RTS'96 with flexible CO_2 capture, with and without GHG regulation.

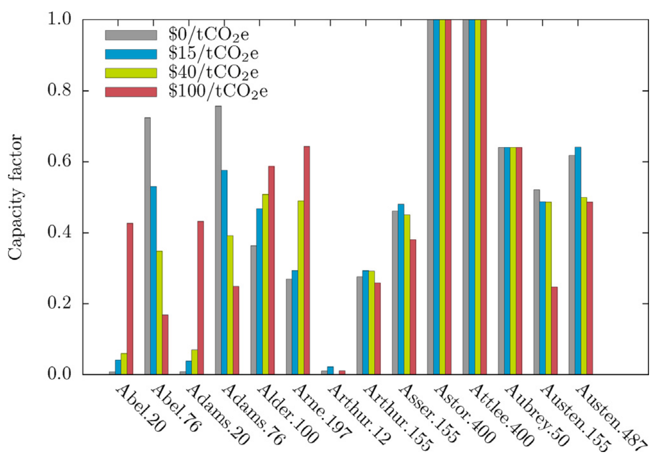


Fig. A.2. Comparison of capacity factor of generating units in IEEE RTS'96 with flexible CO_2 capture, with and without GHG regulation.

corresponding to 100% load and zero CO_2 recovery. Except for the nuclear generating units, the observed heat rate is greater than the design heat rate and is different for each carbon price. In the cases of the small coal- and oil-fired generating units and the generating unit with CCS, not obvious what the correct heat rate value to assume *a priori* would be.

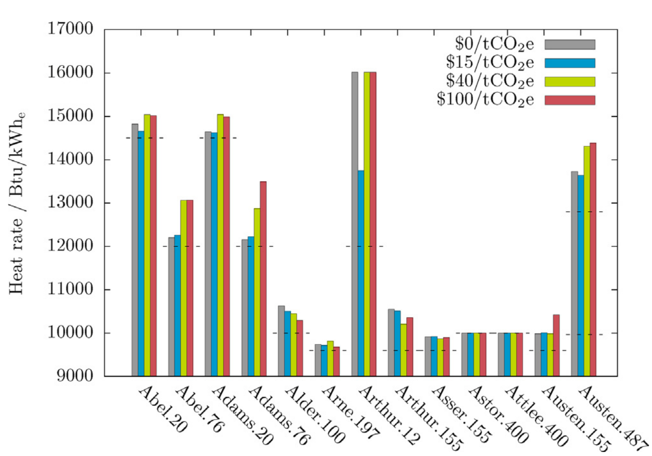


Fig. A.3. Comparison of average heat rates for each type of generating unit, with and without GHG regulation.

Table A.1
Comparison of number of starts for each type of generating unit.

Unit type	Number	Number of starts			
		$0/tCO$_2$e	$15/tCO$_2$e	$40/tCO$_2$e	$100/tCO$_2$e
Abel.20	2	4	10	10	8
Abel.76	2	0	0	0	5
Adams.20	2	3	9	10	9
Adams.76	2	0	0	0	5
Alder.100	3	2	0	0	0
Arne.197	3	15	13	0	0
Arthur.12	5	13	20	2	11
Arthur.155	1	0	0	0	0
Asser.155	1	0	0	0	0
Astor.400	1	0	0	0	0
Attlee.400	1	0	0	0	0
Aubrey.50	6	0	0	0	0
Austen.155	2	0	0	0	0
Austen.487	1	0	0	0	0

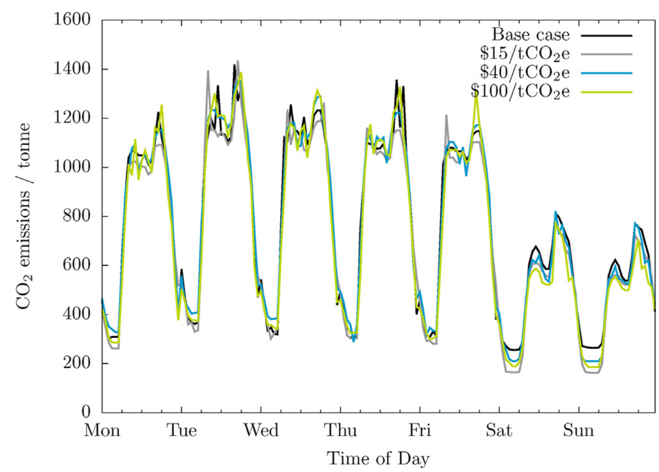


Fig. A.4. CO_2 emissions of base IEEE RTS'96, with and without GHG regulation.

Number of starts (and shutdowns)

Table A.1 indicates the number of starts for each type of generating unit in the IEEE RTS'96 For example, there are three 197 MW_e oil-fired generating units in the system; at a carbon price of zero, these units had thirteen starts amongst themselves and no starts at carbon price of $40/tCO$_2$e.

CO_2 emissions

Fig. A.4 shows the aggregate CO_2 emissions in each time period for the IEEE RTS'96 with flexible CCS for carbon prices of $0, $15, $40, and $100/tCO$_2$e.

The average CO_2 emissions rate and CO_2 emissions intensity of electricity generation for the IEEE RTS'96 with flexible CCS at carbon prices of $0, $15, $40, and $100/tCO$_2$e is summarized in Table A.2. Aggregate CO_2 emissions are 4% lower in the cases with $15 and $100/tCO$_2$e relative to the case with a zero carbon price. When the

Table A.2
Impact of GHG regulation on CO_2 emissions in IEEE RTS'96 with flexible CO_2 capture.

Scenario	$\dot{m}^{CO_2}$	Δ CO_2		*CEI*
	tCO_2/h	tCO_2/h	%	tCO_2/MWh_e
$0/tCO$_2$e	757			0.367
$15/tCO$_2$e	727	30	4.0	0.352
$40/tCO$_2$e	757	0	0.0	0.367
$100/tCO$_2$e	730	27	3.6	0.354

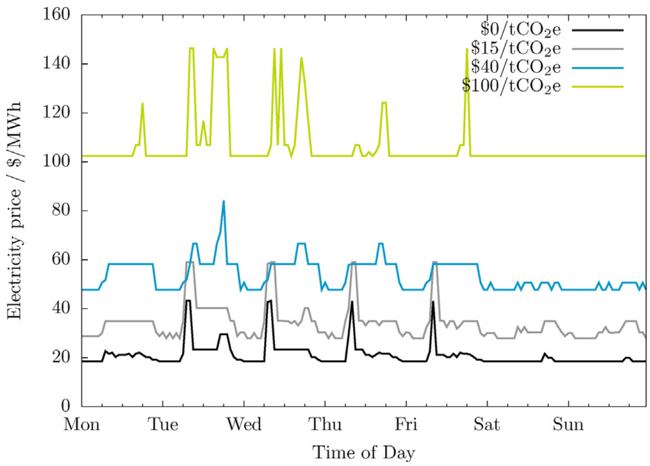


Fig. A.5. Comparison of HEP for IEEE RTS'96 with flexible CO_2 capture with and without GHG regulation.

carbon price is \$40/tCO_2e, though, CO_2 emissions are the same as when there was no GHG regulation.

Electricity price

Fig. A.5 compares the HEP for the IEEE RTS'96 with flexible CO_2 capture at carbon prices of zero, \$15, \$40, and \$100/tCO_2e. Though volatility in the HEP from one time period to the next causes some overlap of the data series, the trend is that increasing the carbon price increases the electricity price. The electricity price and cost

Table A.3
Impact of GHG regulation on electricity price and cost of electricity generation in IEEE RTS'96 with flexible CCS.

Scenario	HEP \$/MWh$_e$	Δ HEP \$/MWh$_e$	*CoE* \$/MWh$_e$	Δ *CoE* \$/MWh$_e$
Base case	21.64		10.98	
\$15/tCO_2e	35.00	13.36	16.49	5.51
\$40/tCO_2e	54.63	32.99	26.49	15.51
\$100/tCO_2e	107.64	86.00	48.18	37.29

of generation are summarized in Table A.3. Both HEP and cost of generation increase monotonically with carbon price, with price being more sensitive.

Fig. A.6 compares the price setting units in each time period for the IEEE RTS'96 with and without GHG regulation. The price peaks are due to small, combustion turbines at Abel and Adams. At zero carbon price, base electricity price is set by oil-fired units at Alder and Arne. As carbon prices increase, it is increasingly the small coal-fired units at Abel and Adams that set the base electricity price.

Energy benefit

Fig. A.7 compares the aggregate net energy benefit realized in the IEEE RTS'96 with flexible CO_2 capture. Start-up costs are significant component of total cost of generation in the time periods in which they are incurred (and are likely a big deal to the generators that are implicated and will influence dispatch) but, on a whole, they are insignificant. Relative to revenues, fuel costs are relatively stable over time. At carbon prices of \$40 and \$100/tCO_2e, generation costs are dominated by the cost to acquire CO_2 permits. What

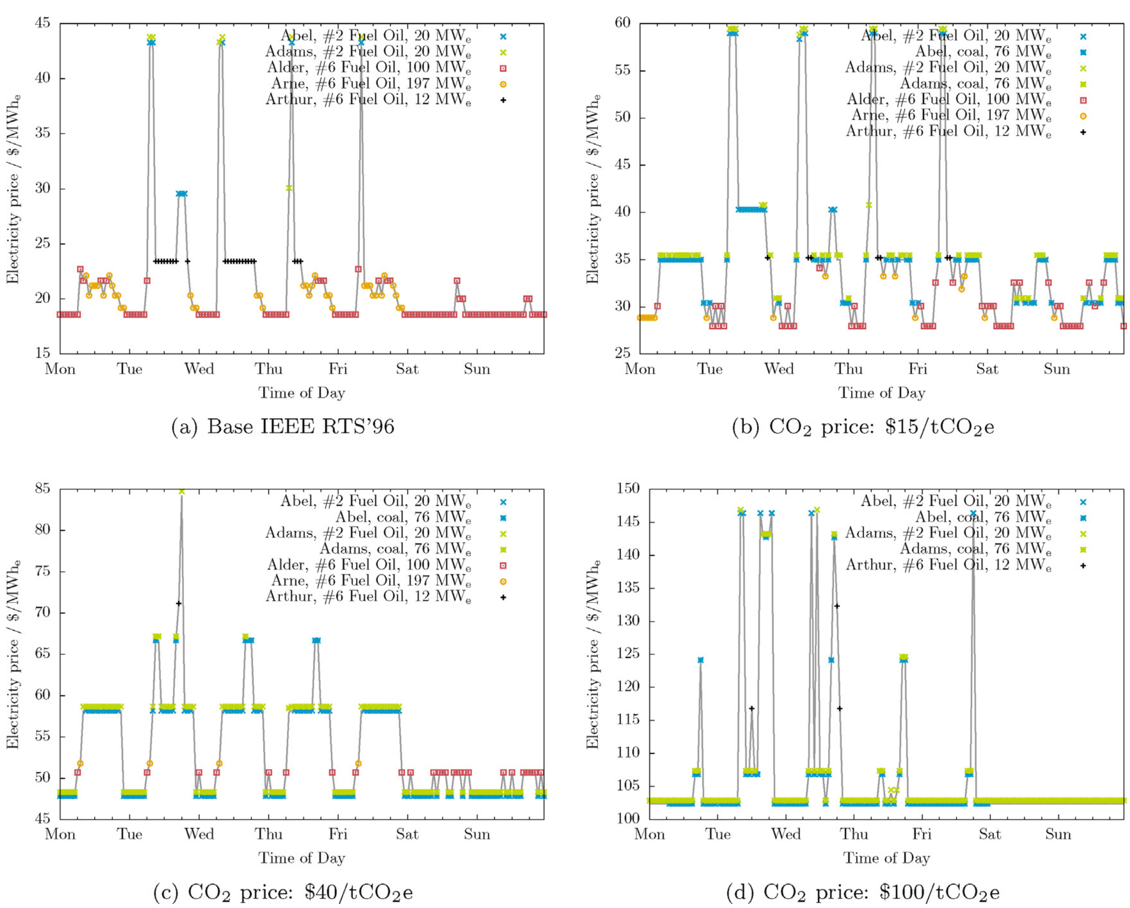
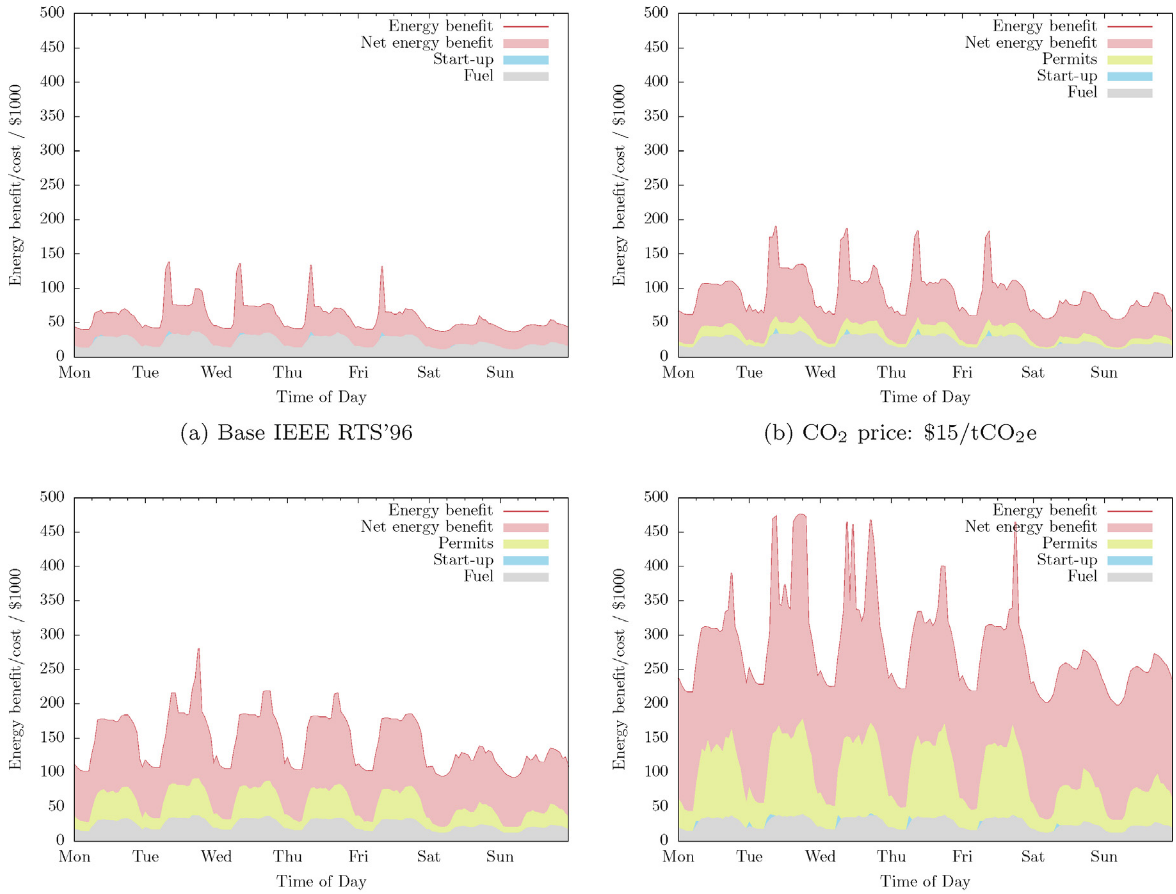


Fig. A.6. Comparison of price setting units in IEEE RTS'96 with flexible CO_2 capture, without GHG regulation.



(a) Base IEEE RTS'96

(b) CO_2 price: \$15/tCO_2e

(c) CO_2 price: \$40/tCO_2e

(d) CO_2 price: \$100/tCO_2e

Fig. A.7. Comparison of aggregate net energy benefit in IEEE RTS'96 with flexible CO_2 capture, with and without GHG regulation.

to do with the revenue generated from selling CO_2 permits is an interesting policy question. Perhaps somewhat counter intuitively, net energy benefit increases by an order of magnitude as carbon prices increase from zero to \$100/tCO_2e. So, the higher the carbon price, no more profitable the electricity generation sector.

Fig. A.8 compares the net energy benefit for each type of generating unit at carbon prices of \$0, \$15, \$40, and \$100/tCO_2e. The small generating units struggle to make money as do the larger oil-fired units in the absence of GHG regulation. This should come as no surprise given that, as shown in Fig. A.6, they are more often than not the price-setting units. And, so, the price is set equal to their marginal cost of generation. The larger oil-fired units and the other units in the system units do better as GHG regulation increases in stringency.

Table A.4 compares the net energy benefit of the different types of generating unit normalized on the basis of capacity. Within the same class of generation, larger units tend to fare better: 197 MW_e oil-fired plants are more profitable than 100 MW_e ones and 155 MW_e coal-fired plants make more money per unit capacity than 76 MW_e units. Note again that the net energy benefit of the 155 MW_e coal-fired generating units can be different the

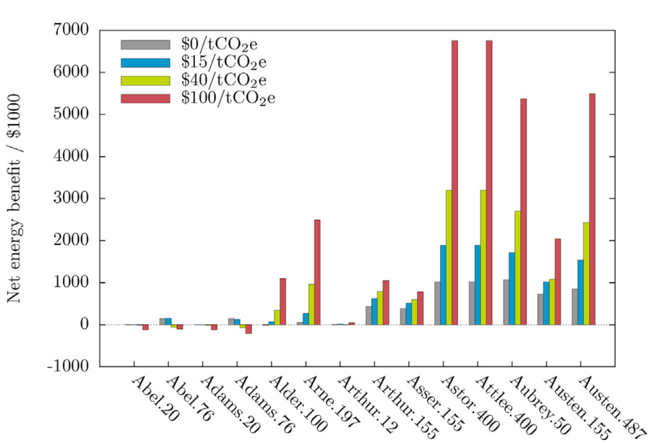


Fig. A.8. Comparison of net energy benefit of each type of generating unit, with GHG regulation.

Table A.4
Comparison of net energy benefit per unit of capacity.

Unit type	Net energy benefit / \$/MW_e installed			
	\$0/tCO_2e	\$15/tCO_2e	\$40/tCO_2e	\$100/tCO_2e
Abel.20	43	−28	−251	−3145
Abel.76	957	987	−436	−695
Adams.20	15	−17	−296	−3169
Adams.76	956	835	−505	−1370
Alder.100	−39	234	1151	3665
Arne.197	93	452	1627	4207
Arthur.12	66	241	68	759
Arthur.155	2781	4016	5096	6755
Asser.155	2446	3302	3867	5044
Astor.400	2538	4712	7984	16883
Attlee.400	2538	4712	7984	16883
Aubrey.50	3546	5720	8992	17891
Austen.155	2328	3274	3492	6583
Austen.487	1741	3157	4986	11270

operating profit realized by the different units responds differently to changes in carbon prices. The energy benefits of the 155 MW_e are similar—these are based upon capacity utilization—but the units' costs are different as the quantity of electricity they produce is different (see Fig. 9).

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