Dynamic Optimization of a Hybrid System of Energy-Storing Cryogenic Carbon Capture and a Baseline Power Generation Unit

Seyed Mostafa Safdarnejad^a, John D. Hedengren^{a,*}, Larry L. Baxter^a

^a*Department of Chemical Engineering, 350 CB, Brigham Young University, Provo, UT 84602, USA*

Abstract

Recently promulgated regulations of the US Environmental Protection Agency (EPA) aggressively limit CO₂ emissions from the US power industry. Carbon capture and increased utilization of renewable energy sources are viable approaches to reduce CO₂ emissions from the power industry. Cryogenic carbon capture considered in this study is a post-combustion CO₂ removal system that separates CO₂ from the flue gas by desublimation. In this investigation, a hybrid system of cryogenic carbon capture and a baseline fossil-fueled power generation unit are optimized with a framework to mathematically represent this hybrid system. Optimization of this hybrid system results in meeting the electricity demand through a combination of coal, gas, and wind power sources with a priority given to wind power for utilization. A comparison of the cost associated with operating the steam turbine as a baseline or load-following unit is also made. A significant decrease in the cycling cost associated with load-following of the coal-fired power plant is observed when it operates as a baseline unit. The decrease in the cycling costs is 82% and 85%, respectively, for when wind power is utilized in meeting the electricity demand and when it is not. The saving in the cycling costs is attributed to the energy storage of cryogenic carbon capture.

Keywords: Cryogenic Carbon Capture, Baseline Power Production, Dynamic

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* Corresponding author. Tel.: +1 801 477 7341, Fax: +1 801 422 0151

Email addresses: safdarnejad@byu.edu (Seyed Mostafa Safdarnejad), john.hedengren@byu.edu (John D. Hedengren), larry_baxter@byu.edu (Larry L. Baxter)

Nomenclature

C	Mass flow rate of the coal combustion
D^{CCC}	Total electricity demand for the CCC facility
D^{LNG}	Total electricity demand of the LNG production facility
$D^{MR,Comp}$	Work of compression of the mixed refrigerant compressor
$D^{NG,Comp}$	Work of compression of the natural gas compressor
$D^{NG,Pipe}$	Work of compression of the pipeline compressor
$D^{plant,max}$	Maximum fraction of the combined electricity demand of the LNG and CCC plants
D^{plant}	Combined electricity demand of the CCC and LNG production facilities
D^{Res}	Electricity demand of the residential users
D^{Tot}	Total electricity demand
FG^C	Mass flow rate of the flue gas produced from coal combustion
$FG^{NG,max}$	Maximum mass flow rate of the flue gas produced from natural gas combustion
FG^{NG}	Mass flow rate of the flue gas produced from natural gas combustion
FOM^{CT}	Fixed operating and maintenance costs of the coal-fired power generation unit
FOM^{GT}	Fixed operating and maintenance costs of the gas-fired power generation unit
GP_{max}^{CC}	Maximum permitted power production in the combined cycle
GT^{cap}	Capacity of the gas turbine
K^{NG}	Gain for the natural gas intake
K^{ST}	Gain for power production in the steam boiler
LNG^{BYP}	Mass flow rate of the LNG bypassing the tank
$LNG^{From\ Tank}$	Mass flow rate of the LNG from the tank
LNG^{Prod}	Mass flow rate of the LNG production
LNG^{Tank}	Mass of the LNG in the tank
$LNG^{To\ Tank}$	Mass flow rate of the LNG directed to the tank
LNG^R	Total mass flow rate of the LNG demand
MR	Mass flow rate of the mixed refrigerant

NG^{CCC}	Mass flow rate of the natural gas coming from the natural gas compressor
$NG^{Conv,max}$	Maximum mass flow rate of the combusted natural gas
NG^{Conv}	Mass flow rate of the natural gas combustion in the gas turbine
NG^{EXPT}	Mass flow rate of the natural gas exported to the pipeline
$NG^{Onephase}$	Mass flow rate of the natural gas coming from the LNG/mixed refrigerant recuperator
$NG^{PL,SP}$	Set point of the natural gas imported from the pipeline
NG^{PL}	Mass flow rate of the natural gas imported from the pipeline
NG^{Tot}	Total mass flow rate of the natural gas for liquefaction
$NG^{Twophase}$	Mass flow rate of the two phase natural gas coming from the CCC plant
p^C	Coal price
p^{CT}	Power generated from the coal-generated flue gas
p^E	Energy price
p^{Ex}	Excess power production
p^{GT}	Power production in the gas turbine
p^N	Natural gas price
p^{NGCC}	Power generated from the natural gas flue gas
$p^{SP,Max}$	Upper bound for the set point of the power output from the coal-fired steam boiler
p^{SP}	Set point of the power output in the steam boiler
p^{ST}	Total power production in the steam boiler
p^{Tot}	Total power generation
p^W	Power generated from the wind
Q^g	Total heat gain in the recuperator
Q^l	Total heat loss in the recuperator
t	Time
VOM^{CT}	Variable operating and maintenance costs of the coal-fired power generation unit
VOM^{GT}	Variable operating and maintenance costs of the gas-fired power generation unit
ΔH_g	Enthalpy of combustion of natural gas
ΔH^1	Enthalpy difference of the cold natural gas across the recuperator
ΔH^2	Enthalpy difference of the cold mixed refrigerant across the recuperator
ΔH^3	Enthalpy difference of the warm natural gas across the recuperator

ΔH^4	Enthalpy difference of the warm mixed refrigerant across the recuperator
ΔH_{FG}^{NG}	Specific enthalpy change of the flue gas from combustion of natural gas
ΔH_{FG}^C	Specific enthalpy change of the flue gas from combustion of coal
ϵ_g	Efficiency of power production in the gas turbine
ϵ^{SB}	Efficiency of the heat exchange in steam reboiler
η^{ST}	Efficiency of the steam turbine
tau^{NG}	Time constant for the natural gas intake
τ^{ST}	Time constant for power production in the steam boiler
CCC	Cryogenic carbon capture
CCCECL	Cryogenic carbon capture with an external cooling loop
CCS	Carbon capture and storage
CHP	Combined heat and power unit
EGS	Enhanced geothermal system
EPA	Environmental Protection Agency
HHV	Higher heating value
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
LCOE	Levelized Cost of Electricity
LNG	Liquefied natural gas
NG	Natural gas
NGCC	Natural gas combined cycle
OCR	Organic Rankine cycle
PC	Pulverized Coal
SAPG	Solar Aided Power Generation

1. Introduction

The power sector is one of the main sources of CO₂ emission. The International Energy Agency (IEA) estimated 42% of the 2012 global CO₂ emissions are derived from power and heat production [1]. There is nearly universal agreement among

5 climatologists that anthropomorphic CO₂ and other greenhouse gases are the main causes of global warming [2]. As a result, more restrictive regulations for CO₂ emissions have been enforced or are under consideration [3, 4, 5]. Recently the US Environmental Protection Agency (EPA) promulgated regulations under Clean Air Act Sections 111(b) and 111(d) for the CO₂ emissions from the US power industry. Existing natural gas and coal-fired power plants can emit up to 1100 and 1400 lbs of CO₂ per *MWh* energy generation. New power plants must reduce CO₂ emissions by 20% from 2014 levels [3]. Current combined-cycle natural gas plants meet these standards and they are about 30% below the emissions of most coal plants. Such large reductions from coal plants lie well beyond the reach of plant efficiency improvements or other modest operational changes and threaten decommissioning of existing plants and curtailing plans for new plants. In fact, coal consumption has declined in the US for many years and there are very few new coal plants planned. These declines, however, stem from low-cost natural gas competition and not from CO₂ emissions controls. Low-cost natural gas is a recent development in the US but is not a global shift in the energy landscape. Globally, coal is by far the most rapidly growing source of primary energy [2]. The trend of the global coal trade is mainly driven by countries in Asia, specifically China and India. For instance, these two countries accounted for 98% of the increase in world coal trade from 2008 to 2013. The increase in the imported coal in China and India is primarily due to an increase in the electricity generation and steel manufacturing [6]. In the US, coal is projected to play a major role in power generation by EPA projections, and shows every sign of continuing a rapidly increasing role in power globally. Global CO₂ emissions must decrease by 60-80% to limit global climate change to a 2 °C increase [7]. This is about twice as much as the total CO₂ emissions from all forms of power generation. Therefore, global climate change critically depends on finding ways to reduce CO₂ emissions from fossil power plants generally and from coal specifically. In this sense, fossil- and specifically coal-based emissions reduction represents one of the most important elements of climate change mitigation. No national or global climate change policy can likely succeed without addressing this issue.

35 Carbon capture and storage (CCS) is a viable approach to achieve the target CO₂

emission level. The literature for CO₂ removal mainly considers three typical CCS technologies: post combustion, pre-combustion, and oxyfuel [2]. The common processes considered in post-combustion technologies are based on using chemical and physical absorption [8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19] or membranes [20, 21]. Pre-combustion technologies are mostly considered in integrated gasification combined cycle (IGCC) power plants, and they are based on removing CO₂ from the fossil fuels before combustion [22, 23]. In oxyfuel technologies, pure oxygen is used to combust the fuel [24, 25]. Cryogenic technologies have also been considered for carbon dioxide removal, and they have several forms such as an inertial carbon extraction system, a thermal swing process, and cryogenic carbon capture with an external cooling loop (CCCECL) [26, 27]. In this investigation, the latter category of cryogenic capture process is considered for removing CO₂ from the flue gas of power plants.

The CCC process is a novel technology for carbon dioxide removal from the flue gas of power generation units [28]. The CCC process cools flue gas from power generation units to the point that CO₂ desublimates. The process then separates solid CO₂ from the remaining gas and melts it. Both the remaining flue gas and pressurized solid CO₂ warm back to higher temperatures. Fast response to fluctuations in electricity demand and renewable energy sources, lower energy consumption and cost, and energy storage are the main advantages of the CCC process. Integration of the CCC capture process with a coal-fired steam boiler that is able to follow the load is considered in [29, 30, 31]. However, many coal-fired generation units operate in a baseline mode and the power output from those generation units is approximately constant over most of the operational lifetime. This investigation considers the integration of a baseline coal-fired steam boiler with a cryogenic capture process. Considering energy storage, the hybrid system is also able to follow the peak demand with a gas turbine without necessarily cycling the coal-fired steam boiler. This is a distinguishing feature of this work from the previous investigation [29]. In addition, the model developed for this hybrid system is applicable to both baseline and load-following generation units. Minor adjustments to the model make boiler output constant or load-following. A comparison is also made between power pro-

duction in simple (scenario 2) and combined (scenario 1) cycles. The simple cycle is a typical peaking unit that is integrated with a baseline steam turbine and the CO₂ emission from both units is mitigated by a cryogenic capture process without energy storage. The results from this comparison highlights the significance of energy storage capability of the CCC process. Finally, the costs associated with cycling a power generation unit are studied, and the impact of the energy storage capability of the CCC process on the cycling costs is quantified. Cycling costs analysis is considered with both presence and absence of the wind power in partially meeting the electricity demand.

This paper is divided into five sections. First, the CCC process is briefly reviewed. Then, the modeling and optimization frameworks to represent the hybrid system are developed. Next, the optimization results obtained for an integrated system of a baseline power generation unit and the CCC process are presented. A comparison between power production in the gas turbine through a simple or combined cycle is also made. Finally, the impact of energy storage of cryogenic carbon capture on leveling the power output from a steam turbine and the associated savings are discussed. It is observed that with the energy storage, a saving of 82% (with wind power) and 85% (without wind power) in the cycling costs associated with the load-following of a steam turbine are obtained.

2. CCC Capture Process

As mentioned, the CCC process separates CO₂ from the power plant flue gas by a desublimation process. Two refrigeration cycles are used to provide the cooling medium for the desublimation process (see Figure 1). The internal refrigeration cycle is operated by a typical refrigerant such as CF₄. Several selections could be made for the refrigerant of the external loop. One selection, liquefied natural gas (LNG), adds significant value and flexibility to the hybrid system. Selection of LNG for the external cooling loop permits the hybrid system to take natural gas from a pipeline and produce LNG in a liquefaction facility. However, the liquefaction process is a very energy intensive process which is of special concern when electricity demand

is high. An insulated tank can time-shift LNG production to off-peak hours. When electricity demand is low, the CCC process produces excess LNG and stores the excess in the insulated tank. Similarly, renewable power sources, even when intermittently available, provide electricity for the liquefaction process. In both cases, low-
100 cost electricity is used to generate carbon capture refrigerant in the form of LNG. During peak hours, the CCC process uses stored LNG for the capture process and delivers the decreased parasitic load to the grid. Removal of heat from the flue gas causes the LNG to become a two phase natural gas stream (stream 9 in Figure 1). This two phase stream completely vaporizes and reaches a higher temperature with
105 further heat gain in the LNG/mixed refrigerant (MR) recuperator. The outlet natural gas from the LNG/MR recuperator (stream 10 in Figure 1) can be partially combusted in a gas turbine. This adds load-following capability to a coal-fired power generation unit equipped with the CCC capture process without necessarily needing to cycle the coal-fired steam boiler. The remaining natural gas from the LNG/MR
110 recuperator (stream 13 in Figure 1) can also be recirculated to the LNG production facilities or be exported to pipeline (stream 1 in Figure 1) to avoid processing it when electricity is expensive. At each time either the storage or a recovery mode is in operation and decision about the operating mode is based on the economical evaluation of the hybrid system. The CCC process and the associated refrigeration cycles are
115 investigated in [26, 32]. Integration of the CCC process with a load-following generation unit is also discussed in [29, 30, 31]. Different designs for the LNG production facilities are presented in [33, 34, 35] and are applicable to a hybrid system of CCC and power generation units.

3. Model Framework

120 3.1. Hybrid System Model

In this section the model developed for the hybrid system of the power generation unit and the CCC capture process is presented. First, relationships for power generation from each source are developed and are all presented in units of *MW*. This is followed by relationships for fuel consumption and flue gas production from

Figure 1: Schematic configuration of the hybrid system of a power generation unit and CCC, [29]

each fuel supply. Next, equations are developed for the calculation of electricity demand for different components of the CCC and LNG plants and mass balance equations for different points in Figure 1. Additionally, details of an energy balance on the LNG/mixed refrigerant recuperator are given along with details of the objective function of this optimization problem. This section concludes with a discussion on the controlled variables, constraints, and optimization framework.

3.1.1. Power Generation From Coal

The power production in the coal-fired steam boiler (P^{ST}) is calculated from a first order differential equation (Eq. (1)) that relates the power output (P^{ST}) to the set point of the power output (P^{SP}). This relation represents the transient response of steam boilers when a change in the power output is required. The set point of the steam boiler power output (P^{SP}) is a decision variable and is optimized based on the economical evaluation of the hybrid system. The range of variation of P^{SP} is considered between 800 and 1800 MW and is assumed based on a maximum residential electricity demand of 2000 MW [29]. When integrating the CCC capture process with existing power generation units, this range should be modified according to

the capacity of the steam turbine.

$$\tau^{ST} \frac{dP^{ST}}{dt} = -P^{ST} + K^{ST} P^{SP} \quad (1)$$

In this case, τ^{ST} and K^{ST} are the time constant and gain, respectively, for power production in the steam boiler. The time constant represents the time it takes to reach 63.2% of the total change in steam boiler power output when there is a change in the set point. Gain is the ratio of total change in the power output from the steam boiler and the magnitude of change in the set point. An assumed value of 2 hours for the time constant represents the slow response of steam boilers to changes in set points in practice. A gain value of 1 is used in Eq. (1) for the steam boiler. It should be noted that reference to the power production in a steam boiler (P^{ST}), in this investigation, is in fact the result of producing power in a turbine that is driven by the steam generated in the boiler. Steam is generated from the heat content of the flue gas produced from coal combustion. Exiting flue gas from a gas turbine can also be introduced to the boiler to produce more steam and achieve the efficiency of a combined cycle. Thus, total power output from the steam turbine (P^{ST}) is the summation of equivalent power from exchanging heat by the flue gas generated from coal and natural gas combustion (Eq. (2)).

$$P^{ST} = P^{CT} + P^{NGCC} \quad (2)$$

P^{CT} and P^{NGCC} are the power generated from the coal and natural gas flue gases, respectively. As presented by Eqs. (4) and (5), P^{NGCC} is dependent on the rate of natural gas combusted in the gas turbine, NG^{Conv} , (or equivalently on the gas power production, P^{GT}). Either P^{CT} or P^{GT} can be selected as the second decision variable and the other variable (as well as P^{NGCC}) is calculated from solving Eqs. (2) and (4) simultaneously. Similarly, mass flow rates of combusted coal (C) and natural gas (NG^{Conv}) can be selected as the second decision variable. In this investigation, flow rate of the natural gas combusted in the gas turbine is selected as the second decision variable.

3.1.2. Power Generation From Natural Gas

Power generated in the gas turbine, P^{GT} , is calculated from Eq. (3):

$$P^{GT} = NG^{Conv} \epsilon_g \Delta H_g \quad (3)$$

where ϵ_g , ΔH_g are the efficiency of power production in the gas turbine and enthalpy of combustion of natural gas, respectively. The values assumed for these two
 170 parameters are 0.3275 and 53.89 MJ/kg, respectively [36]. It should be noted that all equations involving flow rates are presented on a mass basis with units of kg/hr .

Power production from the steam generated from the natural gas combined cycle is obtained from Eq. (4). In deriving this equation, it is assumed that the heat transfer from the flue gas to the boiler feedwater has an efficiency of 88% (ϵ^{SB}). It is
 175 also assumed that the steam turbine is 41.6% efficient (η^{ST}). Ratio of the mass flow rates of the flue gas to natural gas combusted in the gas turbine is presumed to be 42.56 kg/hr (Eq. (5)). These assumptions are based on the simulation studies for a NGCC power plant with a single reheat 16.5 MPa/566 °C/566 °C cycle and an overall combined cycle efficiency of 50.2% [36]. Thus, the overall power production in
 180 the steam turbine is the product of specific enthalpy change of the flue gas (ΔH_{FG}^{NG}), mass flow rate of the flue gas produced from natural gas combustion (FG^{NG}), efficiency of the heat exchange in the boiler (ϵ^{SB}), and efficiency of the steam turbine (η^{ST}):

$$P^{NGCC} = \Delta H_{FG}^{NG} FG^{NG} \epsilon^{SB} \eta^{ST} \quad (4)$$

$$NG^{Conv} = \frac{FG^{NG}}{42.56} \quad (5)$$

As mentioned previously, solving Eqs. (2) and (4) simultaneously returns the
 185 value of P^{CT} . An equation similar to Eq. (4) is also used to calculate the mass flow rate of the flue gas from the combustion of coal (Eq. (6)):

$$FG^C = \frac{P^{CT}}{\epsilon^{SB} \eta^{ST} \Delta H_{FG}^C} \quad (6)$$

where FG^C and ΔH_{FG}^C are the mass flow rate of the flue gas from coal combustion and specific enthalpy change of the flue gas, respectively. It is also assumed that 10.93 kg/hr flue gas is produced from the combustion of 1 kg/hr of coal (Eq. (7)).

$$C = \frac{FG^C}{10.93} \quad (7)$$

190 All these assumptions are based on the simulated results from [36] for a subcritical pulverized coal power plant that uses a single reheat 16.5 MPa/566 °C/566 °C cycle and has an overall plant efficiency of 36.8%. Table 1 summarizes most of the data used in this investigation.

Although flue gas produced in the gas turbine can be completely directed to the
195 boiler, it is assumed that only a fraction of it (stream 18 in Figure 1) is used for excess steam generation in the boiler. This constraint addresses the limitation of the steam boilers in utilization of the flue gas in a combined cycle. The flow rate of the flue gas directed to the steam boiler is limited to a flow rate that can potentially produce sufficient steam to generate power up to 20% of the assumed upper bound for the
200 steam turbine capacity (1800 MW) and is calculated from Eqs. (8) and (9). It should be noted that the numerator of Eq. (8) is normalized with the capacity of the gas turbine to keep the units of both sides on a mass basis.

$$NG^{Conv,max} = \frac{GP_{max}^{CC}}{GT^{cap}} NG^{Conv} \quad (8)$$

$$FG^{NG,max} = 42.56 NG^{Conv,max} \quad (9)$$

$NG^{Conv,max}$ represents the maximum flow rate of combusted natural gas, of which the corresponding produced flue gas, $FG^{NG,max}$, is directed to the steam
205 boiler. The maximum permitted power production in the combined cycle and the capacity of the gas turbine are represented by GP_{max}^{CC} , GT^{cap} , respectively.

3.1.3. Electricity and LNG Demands

Next, electricity demand of the CCC and LNG production facilities and the LNG requirement to treat the flue gas are calculated. The electricity demand for the CCC

Table 1: Summary of the input parameters

Thermal efficiency of boiler, ϵ^{SB}	0.88
Efficiency of the steam turbine, η^{ST}	0.416
Specific enthalpy change of the flue gas from coal combustion, ΔH_{FG}^C (MJ/kg)	2.335
Efficiency of the gas turbine, ϵ_g	0.3275
Enthalpy of combustion of natural gas (HHV), ΔH_g (MJ/kg)	53.89
Specific enthalpy change of the flue gas from natural gas combustion, ΔH_{FG}^{NG} (MJ/kg)	0.587
GP_{max}^{CC} (MW)	360 (20% of the upper bound for the steam turbine power output)
Maximum residential electricity demand (MW)	2000
Overall efficiency of coal-fired power plant	36.8%
Overall efficiency of the NGCC power plant	50.2%
Work of compression for natural gas compressor (kWh _e /(kg inlet)) or (GJ _e /tonne CO ₂)	0.051 (0.1656)
Work of compression for mixed refrigerant compressor (kWh _e /(kg inlet)) or (GJ _e /tonne CO ₂)	0.077 (0.1818)
Work of compression for pipeline compressor (kWh _e /(kg inlet))	0.01
Electricity demand of the CCC for treatment of the flue gas (coal combustion)(GJ _e /(tonne CO ₂ captured))	0.389
Electricity demand of the CCC for treatment of the flue gas (gas combustion)(GJ _e /(tonne CO ₂ captured))	0.428
LNG demand to process the coal flue gas (kg/(tonne CO ₂ captured))	856
LNG demand to process the gas flue gas (kg/(tonne CO ₂ captured))	685
Coal price (\$/ton)	12.65
Natural gas price (\$/1000 ft ³)	5.19
Gas turbine capacity (GT^{cap}) (MW)	1000

210 plant includes the energy requirement for compression of the separated CO₂, com-
pressors in the internal refrigeration cycle, and other auxiliary units not shown in
Figure 1. The total energy requirement for the compression of recirculating natu-
ral gas, mixed refrigerant, and exported natural gas is referred to as the LNG plant
electricity demand. These streams are shown in Figure 1 as stream 12, 15, and 1,
215 respectively.

While the power production from natural gas in a combined cycle is limited, all
the flue gas produced in the gas turbine should be treated in the CCC process. Thus,
total electricity demand of the CCC process and the required LNG to treat the flue
gas resulting from the combustion of natural gas are based on NG^{Conv} and are cal-
220 culated from the re-arrangement of Eq. (5). It is assumed that the treatment of hot
flue gas from the gas turbine and the cold flue gas from the steam boiler requires
the same amount of electricity and LNG. According to [29], 0.389 and 0.428 GJ elec-
tricity are required in the CCC plant to capture one tonne of CO₂ from the flue gases
generated by combustion of coal and natural gas, respectively. Adopting the com-
225 bustion reaction mechanisms used by [9], 851.23 and 545.47 kg/hr CO₂ is produced
from one *MW* power generation from coal and natural gas, respectively. With a 90%
capture rate, the electricity demands of the CCC plant for treatment of the flue gases
generated from coal and natural gas combustion are 0.083 and 0.058 per *MW* gen-
erated power from each source, respectively. The overall electricity demand for the
230 CCC facility is then calculated from Eq. (10):

$$D^{CCC} = 0.083P^{CT} + 0.058P^{NGCC} \quad (10)$$

According to [29], required LNG to process the flue gases from coal and natural
gas combustion are 856 and 685 kg per tonne CO₂ captured. Similar to the calcula-
tion of the CCC electricity demand, LNG demand for treatment of the flue gas from
combustion of coal and natural gas are 656.2 and 336.4 kg/hr per one *MW* generated
235 power from each source, respectively. Thus, the overall LNG demand is calculated

from Eq. (11):

$$LNG^R = 656.2P^{CT} + 336.4P^{NGCC} \quad (11)$$

The work of compression of the natural gas ($D^{NG,Comp}$) and mixed refrigerant ($D^{MR,Comp}$) compressors are 0.1656 and 0.1818 GJ_e per tonne of the captured CO₂ (0.051 and 0.077 kW, respectively, based on kg/hr of the inlet streams). Work of compression of the pipeline compressor is also 0.01 kW per kg/hr of the inlet stream [29]. After unit conversion, these lead to the following equations:

$$D^{NG,Comp} = 5.1 \times 10^{-4} NG^{CCC} \quad (12)$$

$$D^{MR,Comp} = 7.7 \times 10^{-5} MR \quad (13)$$

$$D^{NG,Pipe} = 1 \times 10^{-5} NG^{EXPT} \quad (14)$$

where NG^{CCC} , MR , NG^{EXPT} are the mass flow rates of natural gas coming from the CCC process, mixed refrigerant, and natural gas exported to the pipeline, respectively (Figure 1).

It should be emphasized that the CO₂ removal process is assumed to be a continuous operation. Thus, the CCC plant electricity demand, D^{CCC} , always exists. Regardless of the energy storage, energy requirement for compression of the recirculating natural gas, $D^{NG,Comp}$, also always exists. This is because of the continuous need of the capture plant for LNG which generates a continuous flow of natural gas inside the system, presented by streams 9, 10, 12, and 13 in Figure 1. Energy storage only shifts some of the electricity demand of the mixed refrigerant compressor ($D^{MR,Comp}$).

Total electricity demand for capturing CO₂, D^{plant} , is then calculated by adding up the individual components (Eq. (15)):

$$D^{plant} = D^{CCC} + D^{NG,Comp} + D^{MR,Comp} + D^{NG,Pipe} \quad (15)$$

Figure 2: Actual electricity demand for San Diego, USA, and average energy price for California for the period between September 13, 2014 and September 20, 2014 [29].

255 Total electricity demand is a summation of the CCC and LNG plants, D^{plant} and residential area, D^{Res} , presented by Eq. (16). Residential electricity demand assumed in this investigation is an input to the optimization problem. The data used for the residential demand is shown in Figure 2 and is based on the scaled electricity demand for San Diego, USA for the period between September 13, 2014 and
260 September 20, 2014 [37].

$$D^{Tot} = D^{plant} + D^{Res} \quad (16)$$

3.1.4. Total Power Generation

The overall power generation is also calculated from Eq. (17):

$$P^{Tot} = P^{CT} + P^{GT} + P^{NGCC} + P^W \quad (17)$$

where P^W represents the power generated from the wind and is considered an input to the model. A wind power profile similar to the previous work [29] is adopted
 265 in this investigation and is shown along with the results obtained from other power sources in Section 4.

3.1.5. LNG Production and Storage Facilities

Mass balance equations for different points in the LNG production and storage facilities are presented next. According to Figure 1, the amount of LNG that is pro-
 270 duced in the recuperator (stream 4) is the sum of the natural gas imported from the pipeline (stream 2) and natural gas that comes from the CCC plant (stream 13). From this summation, natural gas exported from the plant (stream 1) should be deducted. Thus, total LNG production (also equals the value of NG^{Tot} on a mass basis) is calculated from Eq. (18):

$$LNG^{Prod} = NG^{PL} + NG^{CCC} - NG^{EXPT} \quad (18)$$

275 Deriving all equations on a mass basis also results in the equality of $NG^{Twophase}$, $NG^{Onephase}$, and LNG^R (Figure 1). This conclusion is used in deriving a relationship between NG^{CCC} , LNG^R , and NG^{Conv} . It is obvious from Figure 1 that natural gas from the CCC plant (stream 13), NG^{CCC} , equals the difference between mass flow rates of the LNG requirement (stream 10), LNG^R , and natural gas combusted in the
 280 gas turbine (stream 11), NG^{Conv} :

$$NG^{CCC} = NG^{Onephase} - NG^{Conv} \quad (19)$$

The LNG production (stream 4) is also equal to the summation of the LNG to the tank (stream 5) and the LNG bypassing the tank (stream 6) (Eq. (20)):

$$LNG^{Prod} = LNG^{To\ Tank} + LNG^{BYP} \quad (20)$$

LNG from the tank (stream 7) is calculated from a mass balance at the tank outlet

Eq. (21):

$$LNG^{From\ Tank} = LNG^R - LNG^{BYP} \quad (21)$$

285 A dynamic mass balance equation is also used for defining the inventory of the tank (Eq. (22)):

$$\frac{d(LNG^{Tank})}{dt} = LNG^{To\ Tank} - LNG^{From\ Tank} \quad (22)$$

3.1.6. Natural Gas Intake

While combustion of the natural gas in the gas turbine is approximately instantaneous, an equation similar to Eq. (1) is considered for the natural gas imported to the plant (Eq. (23)). This equation represents the dynamic response of the system to changes in set point of imported natural gas.

$$\tau^{NG} \frac{dNG^{PL}}{dt} = -NG^{PL} + K^{NG} NG^{PL,SP} \quad (23)$$

where $NG^{PL,SP}$ is the set point of the natural gas imported from the pipeline and is a decision variable. Time constant and gain of the first order model used in this equation are represented by τ^{NG} and K^{NG} , respectively. A time constant of 5 minutes and a gain value of 1 are assumed for the import of natural gas.

3.1.7. LNG/Mixed Refrigerant Recuperator

An energy balance over the recuperator defines the relationship between the natural gas imported (NG^{PL}), exported (NG^{EXPT}), and recirculated in the system (NG^{CCC}). It also defines the trend of variation of mass flow rate for the mixed refrigerant (MR). Total energy gain from the cold streams entering the recuperator is obtained from Eq. (24):

$$Q^g = NG^{Two\ phase} \Delta H^1 + MR \Delta H^2 \quad (24)$$

where ΔH^1 is the enthalpy difference of the two phase gas stream exiting the CCC plant and warm natural gas after the recuperator and is equal to 299 kJ/kg. ΔH^2 is

also the enthalpy difference of the cold mixed refrigerant entering the recuperator
 305 and is equal to 620 kJ/kg.

Total energy loss from the hot streams entering the recuperator is also obtained
 from Eq. (25):

$$Q^L = NG^{Tot} \Delta H^3 + MR \Delta H^4 \quad (25)$$

where ΔH^3 is the enthalpy difference between the warm natural gas that is liq-
 uefied and the LNG produced in the plant and is equal to -582 kJ/kg. ΔH^4 is also
 310 the enthalpy difference of the hot mixed refrigerant entering the recuperator and is
 equal to -9 kJ/kg.

The values assumed for ΔH^1 , ΔH^2 , ΔH^3 , and ΔH^4 are based on the results ob-
 tained at [26] with the assumption that temperature and pressure of the entering
 and exiting streams to and from the recuperator are constant. Results presented in
 315 [38, 39] propose a design for a plate heat exchanger that the temperature and pres-
 sure remain constant despite the fluctuations in inlet and outlet conditions of the
 heat exchanger. Thus, the recuperator considered in this study has a steady state
 performance and is very responsive to fluctuations in the inlet and outlet conditions
 of the recuperator, caused by the variations in electricity demand and wind power.

320 The summation of Q^g and Q^L should be zero, assuming no heat loss to the envi-
 ronment (Eq. (26)).

$$Q^g + Q^L = 0 \quad (26)$$

3.1.8. Economical Evaluation

Finally, the objective function is defined as follows:

$$\begin{aligned} Profit = & (D^{Res} - D^{Plant})P^E - (NG^{PL} - NG^{EXPT})P^N - P^C C \\ & - (FOM^{CT} + VOM^{CT})P^{CT} - (FOM^{GT} + VOM^{GT})P^{GT} \end{aligned} \quad (27)$$

where P^E , P^N , and P^C represent energy price (\$/MWh), natural gas price (\$/kg),
 325 and coal price (\$/kg), respectively. Variable operating and maintainance (VOM)

costs of the coal- and gas-fired power generation units are represented by VOM^{CT} and VOM^{GT} while fixed operating costs (FOM) are presented by FOM^{CT} and FOM^{GT} for the coal- and gas-fired power units, respectively. In this investigation, the same VOM and FOM costs are assumed for both power generation types and are equal
330 to 7.3 and 10.2 dollar per MWh of energy production, respectively [36]. An hourly energy price is also assumed in this work with a trend shown in Figure 2. The credit given to export of the natural gas is considered to be the same as the purchasing price of the imported natural gas and is equal to $\$5.19/1000 \text{ ft}^3$ [29]. A price of $\$12.65/\text{ton}$ is presumed for the coal.

335 It should be noted that the energy storage capability of the CCC process is expected to benefit the wholesale electricity prices in a power grid. However, no impact on the energy price is assumed. The impact of the energy storage on the whole-sale electricity prices is outside the scope of this study.

3.2. Controlled variable

340 The overall power generation from the coal, gas, and wind should always match the sum of the electricity demands for the residential users and the CCC and LNG production facilities, as shown with Eq. (28)

$$P^{Tot} = D^{Tot} \quad (28)$$

To achieve this goal, excess energy production is defined as shown in Eq. (29) and it is considered as a controlled variable with high and low set point values of
345 zero. This also permits to dedicate a higher penalty for underproduction of power. Selection of a value of zero for the high and low set points of excess energy production highlights that neither overproduction nor underproduction of power is an optimal solution in practice.

$$P^{Ex} = P^{Tot} - D^{Tot} \quad (29)$$

3.3. Constraints

350 As mentioned in Section 2, either energy storage or an energy recovery mode is in operation at each time step. This depends on the economic evaluation of each time step. The constraint developed in Eq. (30) helps the optimization algorithm choose between the operational strategy at each time step:

$$LNG^{To\ Tank} LNG^{From\ Tank} = 0 \quad (30)$$

While this constraint assumes that either $LNG^{To\ Tank}$ or $LNG^{From\ Tank}$ is zero
355 at each time step, LNG^{BYP} always has non-zero values. This is because of the continuous demand of LNG to the CCC plant for the treatment of CO₂ produced from the power plant. It is also unlikely that import and export of natural gas occur simultaneously in practice. Thus, a similar relationship is assumed between them:

$$NG^{PL} NG^{EXPT} = 0 \quad (31)$$

Additionally, a capacity of 8 million kg is assumed for the LNG tank in this in-
360 vestigation. At the tank temperature and pressure of -94 °C and 37 bar, respectively, a standard capacity of 28000 m³ can hold 8 million kg of LNG. This capacity is selected based on the performance of the integrated system. However, the overall performance of the hybrid system remains the same with different tank capacities [29]. Thus:

$$LNG^{Tank} \leq 8 \times 10^6 \quad (32)$$

365 Power produced in the gas turbine should always be less than its capacity. The capacity of the gas turbine is presumed to be 50% of the maximum residential electricity demand (2000 MW) considered in this investigation. While the presumed turbine capacity is large and is not a typical capacity size in practice, it should be noted that the assumed electricity demand profile has a large range of variation (838
370 to 2000 MW). Because the gas and steam turbines considered in this work are the main energy sources during peak hours and the steam turbine is anticipated a baseline unit, it is not possible to meet the peak of the residential electricity demand

without a large gas turbine. With current technologies, such a large fluctuation in electricity demand is met through several peaking generation units. Thus the need
 375 for oversized gas or oil turbines is eliminated. With a single power generation unit it is not possible to meet the large gap between maximum and minimum electricity demand. The need to optimize load flowing capacity highlights the importance of simulating a power grid in which the fossil-fueled power generation units are equipped with the CCC process. In this case, peak electricity demand is met through
 380 a combination of power sources. In addition, the energy storage portion of CCC can effectively become the grid spinning reserve by adjusting its parasitic load in time to accommodate the dispatch schedule of the grid. This large-scale energy storage capacity has the potential for significant economic and operational benefit. Study of a large scale power grid system when fossil-fueled power generation units are
 385 equipped with the CCC process is the focus of future work. For the purpose of a single generation unit, it is assumed that a large capacity for the gas turbine is a valid assumption.

$$P^{GT} \leq GT^{cap} \quad (33)$$

From [29], it is also presumed that the combined electricity consumption in the CCC and LNG production facilities is less than 15% of the upper bound for the steam
 390 boiler power output (1800 MW).

$$D^{plant} \leq 270 \quad (34)$$

As stated before, it is presumed that the set point of power production in the steam turbine (P^{SP}) can vary from 800 to 1800 MW. While no economic calculation is considered to size the steam turbine, these values are selected based on the maximum residential demand assumed in this investigation. However, an estimate of the
 395 required nominal power output for the steam turbine is obtained from the results.

3.4. Optimization Framework

After formulating the system, it is necessary to set up an optimization framework to increase the effectiveness of the hybrid system. The optimization framework used

in this system benefits from an objective function in the form of an ℓ_1 -norm because
 400 it permits prioritization of the objective functions and only linear terms are added to
 the problem. An ℓ_1 -norm approach is formulated as shown in Eq. (35) [29, 40, 41].
 In this equation, a desired objective function for the problem (Eq. (27)) is added to
 the expression presented by Eq. (35a) and forms the overall objective function. The
 mathematical equation presented by Eq. (35a) is used for model regularization to
 405 obtain satisfactory results; i.e., in each simulation, variables $c_{\bar{y}}, c_u, c_{\Delta u}$ are adjusted
 such that smooth results are observed in the trend of the decision variables. Thus,
 these variables are the tuning parameters for the model. High penalization factors
 are also assigned for the deviation of the controlled variable from the desired set
 point. The penalization factors are w_{hi} and w_{lo} to penalize over and under produc-
 410 tion of power, respectively. Eqs. (35b) to (35d) represent the model of the system
 developed in Sections 3.1 to 3.3. Eqs. (35e) and (35f) also represent the path that
 the optimization algorithm uses to achieve the desired set point for the controlled
 variable. The expressions presented by Eqs. (35g) and (35h) permit the optimizer to
 keep the controlled variable within a deadband without penalization.

$$\min J = w_{hi}^T \cdot e_{hi} + w_{lo}^T \cdot e_{lo} + y_m^T \cdot c_{\bar{y}} + u^T \cdot c_u + \Delta u^T \cdot c_{\Delta u} \quad (35a)$$

$$s.t. \quad 0 = f\left(\frac{\delta x}{\delta t}, x, \bar{y}, p, d, u\right) \quad (35b)$$

$$0 = g(x, \bar{y}, p, d, u) \quad (35c)$$

$$0 \leq h(x, \bar{y}, p, d, u) \quad (35d)$$

$$\tau_c \frac{\delta y_{t,hi}}{\delta t} + y_{t,hi} = SP_{hi} \quad (35e)$$

$$\tau_c \frac{\delta y_{t,lo}}{\delta t} + y_{t,lo} = SP_{lo} \quad (35f)$$

$$e_{hi} \geq (\bar{y} - y_{t,hi}) \quad (35g)$$

$$e_{lo} \geq (y_{t,lo} - \bar{y}) \quad (35h)$$

415 where the nomenclature for Eq. (35) is found in Table 2.

Table 2: Nomenclature for general form of the objective function with ℓ_1 -norm formulation [29]

Symbol	Description
J	objective function
$\bar{y}$	model values $(\bar{y}_0, \dots, \bar{y}_n)^T$
$y_{t,hi}, y_{t,lo}$	trajectory dead-band for target values
w_{hi}, w_{lo}	penalty factors outside trajectory dead-band
$c_{\bar{y}}, c_u, c_{\Delta u}$	cost of variables y , u , and Δu , respectively
u, x, p, d	inputs (u), states (x), parameters, and disturbances (d)
f, g, h	equation residuals (f), output function (g), and inequality constraints (h)
τ_c	time constant of desired controlled variable response
SP_{lo}, SP_{hi}	lower and upper bounds to final set point dead-band
e_{hi}, e_{lo}	slack variable above or below the trajectory dead-band

The set of equations in Eq. (35) is implemented in the APMonitor Modeling Language [42] and solved either with an interior point solver (IPOPT) [43] or an active set solver (APOPT) [44, 45, 46, 47, 48]. More information about how to implement an optimization in the APMonitor Modeling Language can be found in [40].

420 This optimization problem is solved for eight days of simulation time with hourly time increments. Trends of the variables during the three or four middle days are considered that of an infinite time horizon. This ensures that the performance of the system is not affected by the boundary conditions. More details about this approach are available in [29].

425 As mentioned before, the purpose of this investigation is to integrate the CCC process with a baseline steam turbine. To achieve this goal, a large penalization fac-

tor, $c_{\Delta u}$, is dedicated to the variation of set point of the steam turbine power output, (P^{SP}). In this case, the steam turbine power output does not vary unless there is an improvement in the overall objective function. In addition, the change in steam
430 turbine power output between subsequent time steps is limited to 100 MW/hr to further restrict the variation of the power output in the steam turbine. This maximum change rate is much less than $1\%/min$ of the nominal load-following capacity of the steam turbine.

4. Results and Discussion

435 The results for the integration of cryogenic carbon capture with a baseline coal-fired power plant are presented in this section. These results are divided into four sections; first, the trend of power production from different sources is presented. The total electricity demand is met through a combination of power supplies while steam turbine has the performance of a baseline power generation unit. The net
440 trends of the import of natural gas to the plant and LNG inventory in the tank show that natural gas is imported to the plant when electricity is cheap while it is exported during periods with high electricity prices. LNG inventory in the tank also reflects an excellent transient response to the fluctuations in residential demand, energy price, and wind power availability. Trends of electricity demand for different com-
445 ponents of the CCC and LNG plants show effective time-shifting of the demand of the mixed refrigerant compressor. Finally, the profitability of the baseline hybrid system is compared with a case study for which steam turbine operates as a load-following unit.

4.1. Power Production

450 Figure 3 presents the total power generation in the steam turbine. For comparison, the power generation from a load-following steam turbine is also shown in Figure 3. As it is observed, total power generated in the steam turbine does not vary significantly for most of the simulation time. The minimum output for the steam turbine (820 MW) is close to the selected lower limit (800 MW). Because the steam

455 turbine operates as a baseline unit, the power output from this unit does not cycle during peak hours and gas power is used instead as the peaking unit (shown in Figure 4). The small variations observed in the trend of the steam turbine power output between hours 110 and 160 is because of a high penalization factor, w_{hi} , dedicated to avoid overproduction of power. When wind power is significant (for instance for 460 the period between hours 115 to 150), power output from the steam turbine decreases a few hours before the wind power comes online with the energy storage component of the CCC process making up the difference. Thus, the cost associated with power overproduction is avoided. While this small variation is inevitable to avoid the overproduction penalization cost, the power output remains constant after 465 the change is made as a result of the penalization cost associated with variation of power output in the steam turbine. It is also observed that after hour 156 to the end of the simulation time, wind power has a smaller contribution in meeting the electricity demand and it is found more economical to increase the power output from the steam boiler.

Figure 3: Total power generation from the steam turbine

Figure 4: Electricity demand and power production from coal, wind, and natural gas

From Figure 4, it is also observed that the overall electricity demand is met through a combination of power sources. Whenever wind power is available, it is utilized first to meet the electricity demand while power output in the steam turbine is mostly at a value close to the minimum residential electricity demand. Gas power is mostly produced during peak hours to meet the increasing electricity demand. This is because more LNG is required in the CCC process to treat the higher amounts of flue gas produced during these hours. As LNG from the tank produces excess natural gas inside the plant (after treating the flue gas), this natural gas could be used for power generation in the gas turbine. This is more economical than combusting coal to meet the peak demand. This finding is also compatible with the baseline nature of the steam turbine and permits the optimization problem to avoid the cycling cost of the steam turbine (introduced in Section 6). Production of gas power is a direct impact of using energy storage; i.e. it permits the system to overproduce LNG refrigerant during low power demand or when wind is readily available and to drive the CCC process from the stored refrigerant. The excess warm refrigerant produced during energy recovery is either sent back into the pipeline or used as a fuel source in a gas turbine.

From Figure 3, it seems that a value of 1020 MW, the maximum output from the steam turbine, is reasonable to meet the combined electricity demand of the

residential users and CCC plant. However, economical calculations are needed with
490 consideration of the life time of the steam turbine and the growing need in electricity
demand to accurately size it.

4.2. Net Import of Natural Gas vs. Tank Inventory

Trends of variables for the natural gas imported and exported to the plant are
shown in Figure 5a. Import of natural gas to the plant is mainly observed when
495 electricity is cheap. Export of natural gas from the plant, on the other hand, occurs
when electricity is relatively expensive. This permits the system to avoid liquefying
the circulating natural gas (NG^{CCC}) when demand in electricity is high. Trends of
LNG inventory in the tank (Figure 5b) reflect an excellent transient response of this
optimization problem to fluctuations in residential demand, energy price, and wind
500 power availability. LNG inventory in the tank is dependent on the energy price, cur-
rent inventory in the tank, wind power availability, and the penalization factors used
for the natural gas imported to and exported from the plant. Thus, LNG inventory
is a cumulative effect of these factors and is less intuitive to accurately attribute its
trend to each of these factors. However, it is expected to store LNG when higher
505 electricity price or lower wind availability are anticipated. For instance, when two
peaks in the electricity price are anticipated between hours 86 and 92, LNG storage
starts before actually reaching the peak at hour 86. In this case, LNG storage starts
at hour 71 and ends at hour 79 when it reaches the maximum storage capacity of the
tank. Stored LNG is then recovered from the tank until the tank is emptied at hour
510 124. This period includes the hours for which the peak of electricity price actually
occur. LNG storage is started again after hour 125; however, more wind power is
available from hour 123 to 144 and the tank is not filled completely. This is because
the more availability of wind power is utilized to meet the power demand and less
power is produced from the fossil fuels (consequently less CO_2 is produced). After
515 hour 152, on the other hand, wind power is less available and it is seen that the LNG
tank is fully filled before reaching hour 152. A reasonable cycling in the trend of LNG
inventory is also observed after hour 152 and in the first 72 hours.

While the penalization factors are used to smooth the trends of variations in nat-

Figure 5: Trend of natural gas and LNG inventory

ural gas to and from the plant, the overall trends for these variables and LNG inven-
 520 tory remain the same; i.e. a cyclical trend for the LNG inventory is observed and
 import and export of natural gas occur during off and on peak hours, respectively.

4.3. Electricity Demands of the CCC and LNG Plants

Trends of electricity demand for the mixed refrigerant (*MR*) and natural gas (*NG*)
 compressors are presented in Figure 6. A peak in the electricity demand of the mixed
 525 refrigerant is observed during off-peak hours that is associated with the storage case
 when the LNG tank is filled. The CCC process is then operated with the LNG recov-
 ered from the tank and permits the mixed refrigerant compressor to work at a min-
 imum load when electricity is in high demand. Reduction in the electricity demand
 of the mixed refrigerant compressor can continue for as long as there is LNG in-
 530 ventory in the tank. Decisions on how long either energy storage or recovery should
 continue are economically-driven. In this investigation, inefficiency associated with
 working at non-optimal operating points for the compressor is not considered and
 the compressor is also permitted to turn on and off without any efficiency penalty.
 While these assumptions are acceptable to convey the energy storage concept, they
 535 should be modified when financial decisions are made. This is the focus of future
 work.

Figure 6: Electricity demand for refrigeration compressors and CCC plant in a combined cycle power generation unit with energy storage

4.4. Economic Evaluation

The average profit obtained for a baseline steam turbine over the selected days is \$ 6.5k/hr. This is compared to \$13.6k/hr obtained when the power output from the steam turbine is allowed to vary without penalization. When the steam turbine is allowed to vary, penalization factor for the variation of power output, $c_{\Delta u}$ in Eq. (35a), relaxes; thus, the hybrid system obtains a new optimum. Optimization of the variable steam turbine results in an average profit of \$13.6k/hr. The average hourly revenue obtained from both baseline and variable steam turbines is constant and equals \$58k/hr. This is constant because residential electricity demand and rates are fixed inputs to the optimization problem.

The ratio of total profit and total energy production from all sources considered over the simulation time is 0.43 ¢/kWh for a baseline case while it is 0.91 ¢/kWh for a variable steam turbine. When fixed and variable operating and maintenance costs of the coal- and gas-fired power generation units (VOM and FOM) are ignored in Eq.

(27), the average profit for the baseline case is approximately \$29k/hr which is 20% less than the average profit of a load-following steam turbine (\$35.5k/hr). Similarly, the ratio of the total profit and total energy production when *VOM* and *FOM* are ignored in Eq. (27) is 1.92 ¢/kWh and 2.40 ¢/kWh for baseline and load-following steam turbines, respectively.

5. Comparison between combined and simple cycles

To emphasize on the significance of energy storage, the results obtained in Section 4 (scenario 1) are compared with a case study for which a baseline steam turbine is integrated with a simple cycle gas turbine (scenario 2); i.e. gas turbine exhaust does not generate power in scenario 2. In addition, natural gas supply for the gas turbine in scenario 2 is not the vaporized LNG exiting from the CCC process. In this case, the gas turbine serves as an independent peaking unit. However, it is still assumed that the CCC process treats the flue gas generated from the natural gas turbine. Because a simple cycle is assumed, treatment of the gas turbine exhaust is achieved by adding it to the coal exhaust after the coal superheaters and reheaters. The capacity of the gas turbine in scenario 2 is assumed the same as the analysis discussed in scenario 1 (1000 MW). In scenario 1, the baseline performance is achieved through a combination of the steam generated from the coal and natural gas flue gas; i.e. when coal power in Figure 4 is at a maximum, power from the combined cycle is at a minimum and the reverse trend is also observed. In scenario 2, however, the baseline performance is achieved merely from the steam generated from coal combustion (coal power). Thus, more coal is combusted in the steam boiler in a simple cycle to achieve the same steam flow rate and power output as a combined cycle. To make a fair comparison, it is assumed that the power output obtained in scenario 1 for the steam turbine, P^{ST} , is an input to scenario 2 and it is not varied; i.e. rate of steam production is the same for both scenarios. In addition, it is assumed in scenario 2 that energy storage is not available. This case represents a typical power generation unit that is equipped with a carbon capture technology (without storage capability) and a peaking unit to capture the CO₂ emissions while

580 meeting the electricity demand.

With these assumptions, optimization of the system presented in scenario 2 is implemented and the results are compared with scenario 1. In both scenarios, power production from coal and gas is considered a single generation unit and the power supply is used to meet the electricity demand of residential users and the CCC plant. 585 Figure 7 shows the trend of power production from each source for scenario 1. Figures 8a and 8b also represent the trends of excess power production in each scenario. It is seen in scenario 2 that for most of the simulation time, power supply equals the electricity demand. However, both over production and under production of power occur (Figure 8b) despite the penalization factors applied to balance the demand and supply of electricity. For scenario 1, it is observed that there is no mismatch be- 590 tween electricity demand and power supply over the horizon (Figure 8a). While the observations seen in scenario 2 are rare when a grid analysis is implemented (due to the presence of peaking units), this comparison highlights the importance of energy storage of the CCC process. Energy storage adds flexibility to a single coal-fired 595 generation system to operate as a baseline unit and still be able to meet the peak electricity demand without relying on other generation units in the grid.

The overall mass flow rate of the coal combusted for steam production in a simple cycle is 8% more than a combined cycle, as was expected. Total electricity consumption of the plant is also 8% more in scenario 2. This is because scenario 2 600 produces more flue gas from coal consumption to achieve the same steam flow rate as in scenario 1. Unlike scenario 1, the total flow rate of natural gas imported and exported to the pipeline in scenario 2 is zero because there is no opportunity for arbitrage of electricity without energy storage (see Figure 9) and time-shifting of the electricity demand of mixed refrigerant compressor is not achievable. Thus, natural 605 gas consumption in the simple cycle power generation unit is merely for the purpose of meeting the peak total electricity demand. In contrast, in the case of a combined cycle with energy storage, natural gas has the dual purposes of serving as the refrigerant and a fuel. Thus, natural gas is imported and exported from the plant to take advantage of the arbitrage of electricity (Figure 6). A comparison between the profitability of these two scenarios is meaningless because the primary goal of meeting 610

Figure 7: Electricity demand and power production from coal, wind, and natural gas in a simple cycle power generation unit without energy storage (Scenario 1)

(a) Combined cycle power generation with (b) Simple cycle power generation without energy storage (Scenario 1) energy storage (Scenario 2)

Figure 8: Excess power comparison between combined and simple power generation cycles with and without energy storage, respectively

Figure 9: Electricity demand for refrigeration compressors and CCC plant in a simple cycle power generation unit without energy storage

the electricity demand at all time steps over the horizon is not achieved in scenario 2. Table 3 summarizes the main results obtained from both scenarios.

6. Comparison of cycling costs

An important aspect of power plant operation is the cost associated with ramping, also known as load following or cycling. The changes in operational levels of the plant result in increased thermal, pressure, and mechanical related stress and fatigue [49, 50]. This leads to increased equipment degradation and associated operation and maintenance costs, as well as decreased thermal efficiency.

In general, research done on ramping in power plants has looked at the most fragile part of the plant, the turbine rotor. Historically unit commitment models with economic dispatch have incorporated fixed ramp-rate constraints with the assumption that ramping between the constraints will not cause damage to the turbine rotor [51, 52]. In 2012, a report published by National Renewable Energy Laboratory

Table 3: Comparison between simple and combined cycles: Variables integrated over 8 days of simulation time

Variable	Simple cycle	Combined cycle
Total mass of combusted coal (kg)	70,794,000	65,519,000
Total mass of combusted natural gas (kg)	15,422,000	14,842,000
Total revenue (\$)	11,211,000	1,1211,000
Total CO ₂ production (kg)	197,700,000	184,490,000
Total CO ₂ captured (kg)	177,930,000	166,041,000
Total power production from coal (MWh)	183,810	170,110
Total power production from natural gas (MWh)	75,605	86,336
Total power production from wind power (MWh)	27,291	27,291
Total power production from all sources (MWh)	286,750	283,760

[53] investigated the cost of ramping for an entire plant by considering the cycling costs of several power generation types [54]. This report provides a lower bound for the cycling costs of eight types of generation units. The cycling costs are reported for different cycling scenarios including cold start, warm start, hot start, and load-following cases. Between these cycling scenarios, cold start and load-following have the highest and lowest cycling costs, respectively. For instance, the lower bound for the cold start cycling costs of a typical large-scale subcritical coal-fired power plant is \$ 105/ MW capacity per cold start while load-following cycling cost for the same generation type is \$ 2.45/ MW capacity per load follow [54]. While startup scenarios impose the most expensive cycling costs of the power plants, it is not the scope of this work to investigate them. Consideration of such scenarios requires a longer simulation time (e.g. one year) to be taken into consideration. Instead, just the impact of cryogenic carbon capture on the cycling costs due to load-following of the coal- and gas-fired power generation units is considered. According to [54], the cycling cost of a generation unit varies between individual plants and the numbers provided in this report are generic lower bounds. In this study, estimated multiplicative factors are also provided for faster ramp rate. These multiplicative factors, however,

are not considered in this study and the cycling costs are the median capital and maintenance costs of typical ramping rates. This investigation considers the load-following cycling costs of large scale subcritical coal-fired and natural gas combined cycle (NGCC) power generation units. Accordingly, the cycling cost associated with
645 load-following of a coal-fired generation unit is \$ 2.45/*MW* capacity per load follow while it is \$ 0.64/*MW* capacity for a NGCC power plant. To calculate the number of cycles for power generation from both coal and gas, a post-processing approach is considered; i.e. power outputs from solving the optimization problem are used as input to the rainflow cycle counting algorithm [55] where the output from the al-
650 gorithm is the number of cycles. This calculation assumes that power output from the optimization results has a similar trend to overall stresses in the boiler. The rainflow algorithm allows the application of Miner's rule to assess the fatigue life of a structure subject to complex loading. More details about the rainflow algorithm are available in [56].

655 With the abovementioned assumptions, the cycling costs of the baseline and load-following steam turbines are considered. The power outputs from the coal- and gas- fired generation units, P^{ST} and P^{GT} , for both scenarios are used in the rainflow cycle counting software developed in [57]. Consequently, the number of cycles for the load-following scenario for the coal- and gas- fired generation units
660 are found to be 20 and 17, respectively, over 8 days of simulation time. For a baseline scenario, there are 1 and 21 cycles in the power output from the coal- and gas- fired generation units, respectively. Optimization of the baseline and load-following coal-fired generation units result in a maximum power output of 1020 *MW* and 1210 *MW*, respectively. As mentioned previously, sizing of the genera-
665 tion units is beyond the scope of this study and requires extensive study. However, it is assumed that a capacity of 1800 *MW* is a good estimate for both load-following and baseline coal-fired generation unit for the purpose of cycling costs comparison. With this capacity, the cycling costs of the coal-fired unit for the load-following scenario is $1800 \times 2.45 \times 20 = \$88200$ for 8 days of simulation time while it
670 is $1800 \times 2.45 \times 1 = \$4410$ for a baseline case study. In addition, the cycling cost of the load-following scenario for the gas-fired unit is $1000 \times 0.64 \times 17 = \$10880$ comparing

Table 4: Summary of cycling costs

	With wind		Without wind	
	Load-following boiler	Baseline boiler	Load-following boiler	Baseline boiler
No. Cycles in boiler	20	1	18	1
(Cost)	(\$88200)	(\$4410)	(\$79380)	(\$4410)
No. Cycles in gas turbine	17	21	23	15
(Cost)	(\$10880)	(\$13440)	(\$14720)	(\$9600)
Total cycling costs	\$99080	\$17850	\$94100	\$14010

to a value of $1000 \times 0.64 \times 21 = \$13440$ for a baseline case over 8 days of simulation. In summary, the total costs associated with the cycling of all generation units considered in this investigation are \$99080 and \$17850 for load-following and baseline scenarios, respectively, over 8 days of simulation time. The total costs of cycling for the same power generation units in the absence of wind power are \$94100 and \$14010 for the load-following and baseline coal-fired generation unit, respectively. These costs are based on 1 and 15 cycles for the coal- and gas- fired generation units, respectively, in a baseline case while 18 and 23 cycles are observed for the the same units, respectively, in a load-following case. Table 4 summarizes these results.

The saving in the cycling costs of the baseline generation units, in the presence and absence of wind power, is also a direct result of the energy storage of cryogenic carbon capture. It is well known that coal-fired generation units are mainly designed for baseline operation. Equipping the coal-fired power plant with cryogenic carbon capture enables the power generation unit, as a whole, to follow the load without necessarily varying the steam turbine output. This is achieved by supplying the natural gas required for the peaking unit from the storage system while the carbon dioxide separation from both generation units remains in operation.

It should be emphasized that these costs are the generic lower bounds for cycling
690 of the power generation units, and it does not consider the more expensive practices
of cold, warm, and hot starts. In addition, it is unlikely to have this many cycles in the
boiler in 8 days to follow the load in practice (for both baseline and load-following
power generation units). This is because supplemental peaking units are used to
avoid the variations in power output from the coal-fired generation units. While
695 more accurate analysis of the number of cycles requires longer simulation horizon,
this study demonstrates the potential reduction in cycling costs of a coal-fired power
generation unit by utilizing the energy storage of the CCC process.

7. Conclusion

This investigation considers dynamic integration of a baseline fossil-fueled power
700 generation unit with cryogenic carbon capture. Flue gas cools to the point of CO₂
desublimation to separate CO₂ from the remaining gases. The refrigeration cycles
are energy intensive. However, with the energy storage of the CCC process, the elec-
tricity demand of the refrigeration cycle is shifted to off-peak hours; i.e. refrigerant
required to drive the CCC process, LNG in this investigation, is produced in excess
705 when electricity demand is low or wind power is available. Stored LNG is then used
during peak hours to drive the CCC process. Thus, the compressors of the refrigera-
tion cycles are operating at reduced loads during peak hours. Effective time-shifting
of the electricity demand of the refrigeration compressors is observed from solving
this optimization problem. The total electricity demand of the residential users and
710 the CCC plant is met through a combination of power sources. Wind power, when-
ever available, is first used in meeting the demand. This leads to 100% utilization of
the wind power. With the energy storage of cryogenic carbon capture, a single coal-
fired generation system is able to operate as a baseline unit and still be able to meet
the peak electricity demand. Energy storage also enables a potential 82% and 85%
715 decrease in the costs associated with load-following of power generation units in
presence and absence of wind power, respectively. Consideration of a power grid in
which the fossil-fueled power generation units are equipped with the CCC process

is the focus of future work.

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