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Optimal heat integration in a coal-natural gas energy park with CO₂ capture

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Abstract

Computational techniques are used to optimize the design of an integrated energy park consisting of a coal-fired power plant, a CO₂ capture system, and an auxiliary natural gas combined cycle plant. Emphasis is placed on the design of heat integration in the combined cycle system, as this heat constitutes most of the energy required for temperature-swing CO₂ capture. The facility is constrained to meet a maximum CO₂ emission intensity limit while flexibly capturing CO₂ to maximize profit. The process and capital cost models of the facility include a detailed treatment of the heat recovery steam generator (HRSG). Computational optimization techniques are used to select gas turbine size, CO₂ capture capacity, and the sizes and pressures of HRSG components for HRSG configurations with one, two, and three pressure levels. Facility design is jointly optimized with dispatch using an electricity price-duration curve and natural gas price scenarios of \$3/MMBtu, \$4.50/MMBtu and \$6/MMBtu. System configuration is shown to have a significant impact on economics, with spread in net present value (NPV) among configurations of \$39-54 million (2.6-26% of NPV). Joint optimization of design with optimized flexible dispatch is observed to improve NPV by \$18-56 million (1.2-27%) as compared to optimization with constant dispatch. Gains from optimization increase with higher natural gas price. Optimal capital cost, approximately \$2.1-2.2 billion in all configurations, is higher for configurations with higher number of pressure levels, but does not exhibit strong trends with gas price.

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Keywords: energy park; heat recovery steam generator; optimization; flexible CO₂ capture; system integration; price-duration curve.

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Key abbreviations

CCGT	combined cycle gas turbine
CP	coal-fired power station
GT	gas turbine
HRSG	heat recovery steam generator

1. Introduction

The design of an integrated process facility depends strongly on the way in which the facility will be operated. The allowable range of operation is determined by the design; conversely, in an optimal design, certain components may be sized larger or smaller depending upon whether the component will operate at constant rate or flexibly in time. Given these interdependencies, it is beneficial to jointly optimize facility design and operation.

Consider, for example, electric power generation with CO₂ capture operating under a CO₂ emission limit. The time-varying facility operation can be optimized based on economic criteria, as in [1, 2]. This might include a flexible rate of CO₂ capture, which enables the operator to exploit variation in electricity price while still meeting an overall CO₂ emission constraint. Such operational flexibility requires a greater overall capacity for CO₂ capture than a facility designed for a constant capture rate. Thus, the optimal design and the optimal operation cannot be determined independently.

Previous work has considered optimization of the design of power plants with CO₂ capture [3], and optimization of plant dispatch [1, 2], but full joint optimization of design and dispatch has not been considered. In earlier work we developed an hour-to-hour dispatch optimization model for an energy park consisting of coal-fired power, natural gas-fired power, CO₂ capture, and wind, subject to a CO₂ emission performance standard [2]. We later considered CO₂ taxes and performed a preliminary investigation of the value of variable dispatch and its relationship to the additional investment cost required [4].

Here we extend previous studies to consider joint optimization of dispatch and facility design. This work considers the application of computational optimization techniques for the design of an integrated facility that generates power using coal (with CO₂ capture) and natural gas, and is subject to a CO₂ emission intensity constraint. Optimization is used to determine the continuous design variables in three predefined configurations, as well as the continuous variables that specify facility dispatch. Our focus in this work is on heat integration, since heat represents about 90% of the energy demand for solvent-based temperature-swing CO₂ capture [5], which is the type of capture considered here.

The ‘auxiliary CCS’ concept treated in this work, in which the energy demand for CO₂ capture is provided by a natural gas-fired facility, differs from commonly treated ‘parasitic CCS’ concepts, in which CO₂ capture energy demand is taken directly from the coal plant, without the presence of a gas-fired facility. Bashadi and Herzog [6] discussed different auxiliary CCS configurations, though they did not apply formal optimization techniques for their design.

We begin this paper by describing the process model and capital cost model. The operating modes and the operational dispatch optimization are discussed next. The design problem is then presented, followed by results and discussion. We conclude with suggestions for future work.

2. Process model

The facility treated in this work is an energy park consisting of a baseload coal-fired power plant (CP), a temperature-swing CO₂ capture process, a gas turbine (GT) burning natural gas, and a steam turbine driven by steam generated from GT exhaust using a heat recovery steam generator (HRSG). We include detailed treatment of the HRSG. Figure 1 depicts the overall system. The GT and steam cycle components

are collectively referred to as the combined cycle gas turbine (CCGT) subsystem. The CO₂ capture facility removes CO₂ only from the CP flue gas; the GT flue gas is vented to the atmosphere. The heat requirement for solvent regeneration in the CO₂ capture process is provided by steam drawn from the CCGT subsystem; no steam from the coal plant is used for CO₂ capture. This therefore represents an auxiliary system in which heat integration between the CP and CO₂ capture system is not required.

Solvent regeneration in the CO₂ capture process requires a significant amount of relatively low grade heat (at approximately 400 K). This is the dominant energy demand for this process. Therefore, in this work we focus on optimizing the CCGT steam cycle, which supplies this heat energy. The HRSG portion is treated in detail while the other components are modeled more approximately (parametrically). The CP is represented by its capacity (fixed at 440 MW), coal consumption rate and CO₂ emission rate (emission intensity of 905 kg CO₂/MWh). The CP is assumed to operate at full load at all times. The GT is represented by its (full-load) capacity, fuel consumption rate, flue gas temperature, and CO₂ emission rate. The CO₂ capture process is represented by its capacity for CO₂ removal, per-mass CO₂ solvent regeneration heat requirement, and per-mass CO₂ electrical work requirement. These specifications are taken from the base case in Jassim and Rochelle [5] for an amine-based scheme.

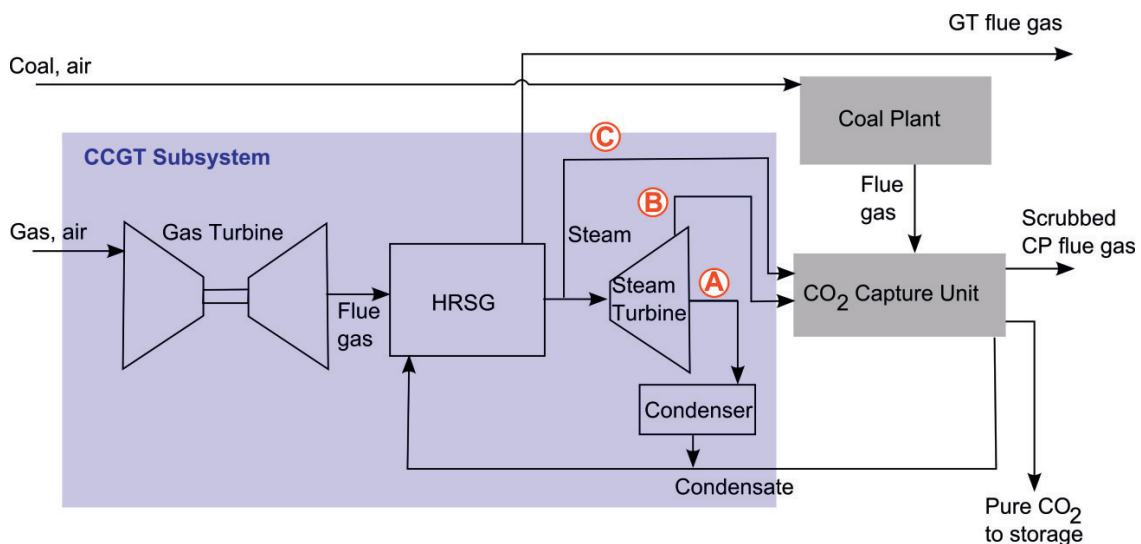


Figure 1. System diagram of the overall energy park

A general steady-state sub-critical HRSG model, based on Casarosa et al. [7] and Franco and Giannini [8], has been developed to allow for the assessment of design choices. The model treats the HRSG as a sequence of discrete heat exchanger elements. (Specific HRSG configurations are shown below.) Water moves in one direction, from element to element, while gas moves in the opposite direction. The model calculates system states, such as the enthalpy of water and flue gas within HRSG elements, given boundary conditions and HRSG component specifications. The other major components in the steam cycle are the steam turbines and condenser. The steam turbines are modeled using isentropic efficiency of 85%, and the condenser is modeled as a water-cooled countercurrent flow heat exchanger with a log-mean temperature difference of 25 K.

2.1. HRSG model

This work treats four kinds of heat exchanger elements: economizers, in which compressed water is heated to near the saturation temperature; evaporators, in which water is boiled; superheaters, in which dry steam is heated; and reheaters, in which steam that has previously been partially expanded in a steam turbine is heated again. Each element operates at a single specified pressure of water, and is characterized by its geometry as well as its thermal transfer size, UA [W/K], which consists of the overall thermal transfer coefficient U [W/(m²-K)] and the contact area of the heat exchanger A [m²].

Figure 2 shows schematics of HRSG configurations with one and two pressure levels. These configurations are used later in optimization. The individual heat exchanger elements are modeled as multipass overall-counterflow heat exchangers with fluids mixed between passes. Each pass is modeled as a cross-flow heat exchanger with the water side mixed and the gas side unmixed. This is consistent with the HRSG modeling in Casarosa et al. [7] (see Kays and London [9] for detailed derivations). This modeling approach is computationally efficient and sufficiently accurate for current requirements.

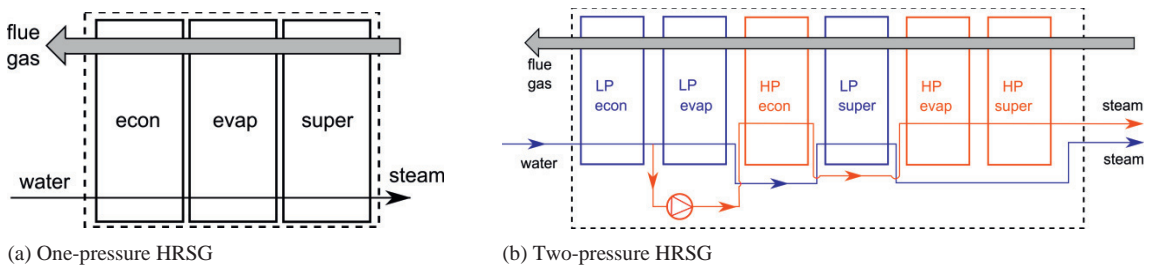


Figure 2. Schematics of two HRSG configurations. LP and HP designate low pressure and high pressure streams

The effectiveness-number of transfer units (ε -NTU) method is used in modeling the heat exchanger elements. The ε -NTU method is described in detail in heat transfer texts such as Kays and London [9] and Nellis and Klein [10]. Equation 1 below expresses the fundamental energy balance within each heat exchanger element, while Equation 2 shows the effectiveness relationship (where $0 \leq \varepsilon \leq 1$ is the effectiveness, which depends upon element size, geometry and fluid states) used to calculate the heat transfer within an element:

$$\dot{Q}_{\text{elem}} = \dot{m}_w \Delta h_w = \dot{m}_g \Delta h_g, \quad (1)$$

$$\dot{Q}_{\text{elem}} = \varepsilon \dot{Q}_{\text{max}}. \quad (2)$$

Here \dot{Q}_{elem} [W] is the actual heat transfer in the element, \dot{Q}_{max} designates the theoretical maximum heat transfer for a perfect counterflow heat exchanger for the given inlet states of the water and gas, \dot{m}_w and \dot{m}_g are the water and gas flow rates, and Δh_w and Δh_g are the changes in water and gas enthalpy across the element. Six state variables (ε , \dot{m}_w , and h_w and h_g at inlet and outlet) are calculated for each element. The gas flow rate is independently specified by the GT model. The elements are coupled to each other (the inlet state of one element is the outlet state of the next element), so it is necessary to solve for all states of the HRSG simultaneously. The governing equations for the HRSG are written in residual form and solved using a damped Newton-Raphson method.

The boundary conditions for the HRSG, including the inlet water temperature, depend on the operating mode of the facility. If the CO₂ capture unit is in operation, then the steam cycle returns liquid water at

the solvent regeneration heat exchanger temperature of 403 K. If the CO₂ capture unit is not in operation, then the steam cycle returns liquid water at the condenser temperature of 330 K. If only a portion of the steam is used for CO₂ capture, then some of the liquid water return is at 403 K and the remainder is at 330 K. In this work these streams are modeled as mixed before returning to the HRSG, which yields a HRSG inlet water temperature between 330 K and 403 K.

For a given HRSG design, the HRSG states are computed for liquid water inlet temperatures of 330 K and 403 K. Behavior at intermediate temperatures is determined by linear interpolation between these two limiting cases. This is an acceptable approximation because HRSG system behavior does not exhibit strong nonlinear dependence on water inlet temperature over this range.

2.2. Capital cost model

The capital cost for the facility is computed at the ‘factored-estimate’ level of accuracy, as described in Perry’s Chemical Engineers’ Handbook [11]. This estimate is based on major equipment items and preliminary energy and material balances, and corresponds to a $\pm 30\%$ margin of error. Because the design is determined algorithmically and not by careful (human) estimation, the actual error is likely to be larger. We nonetheless expect these estimates to be useful for the purpose of comparing capital costs between related system designs, and for approximately quantifying the impact of design modifications.

The capital cost of the coal plant is a fixed quantity taken from the NETL Power Systems Life Cycle Assessment Tool (LCAT) and report [12]. The capital cost of the CO₂ capture system is taken on a per-unit-capacity basis from LCAT, and scaled linearly with size.

For the CCGT subsystem, a more detailed capital cost model, based on the capital cost estimation methodology described by Ulrich and Vasudevan [13, 14], is used. The purchased equipment costs for system components other than the HRSG are scaled according to the power law and reference costs given in [14]. For the HRSG, the purchased equipment cost scales with the area of the heat exchanger elements as given by Casarosa et al. [7]. These purchased equipment costs are then scaled by equipment-specific module factors given in [14]. The purchased equipment cost and module factor of the GT are taken from the Gas Turbine World 2010 Handbook [15]. The overall facility capital cost also includes an additional 18% contingency and fee scaling to account for unexpected events and problems during construction [14]. Other costs, such as working capital and costs associated with the time required to construct the facility, are not included.

3. Operating modes and optimal dispatch

Our previous work treated the facility as being operable along a continuum of possible states (for example, with the GT and CO₂ capture system operating at partial load), and we optimized hour-to-hour facility operations. Thus, in that work, facility states were continuous, while time was discrete. In this work, we take a different approach: facility states are discrete, while time is continuous.

We take this approach because we observed that the optimized dispatch often showed a so-called ‘bang-bang’ behavior, in which facility components were either fully on or off. This type of behavior occurs due to threshold effects – if it was economic at the margin to operate a component, it was typically economic to operate this component at its full capacity. This observation motivates the discrete treatment of operating states used here, in which optimization is applied to determine what portion of time is spent in each operating state (this will depend on the electricity price-duration curve, discussed below). This alternative representation of facility operations captures much of the essential behavior of hour-to-hour dispatch, but at significantly less computational cost.

3.1. Operating modes

The combined system is allowed to operate in four discrete modes: no-extraction CCGT (Mode A); extraction CCGT (Mode B); diversion GT (Mode C); and coal only (Mode D). In all modes, the coal plant operates constantly at full capacity. Operational regimes other than these modes are not treated. Figure 1 indicates the steam streams (flowing out of the HRSG) that correspond to Modes A-C.

The modes are specified as follows:

- **Mode A, no-extraction CCGT.** The GT operates at full capacity and all steam in the steam cycle is expanded to the low temperature reservoir in the condenser. No CO₂ is captured because all heat is used to generate electricity. Mode A has the greatest power generation and total CO₂ emissions of all four modes, and is favored when electricity prices are highest.
- **Mode B, extraction CCGT.** The GT operates at full capacity and steam from the HRSG is expanded in the steam turbine to the extraction steam pressure, at which point steam is redirected to provide heat for CO₂ capture solvent regeneration. Only as much steam as can be used by the CO₂ capture facility is extracted. For a sufficiently large CO₂ capture facility, potentially all of the steam could be extracted, in which case the steam turbine will operate in full back pressure mode. For HRSG configurations with reheat, steam is not extracted from the pre-reheat expansion. Mode B corresponds to less power generation and CO₂ emissions than Mode A (but more than Mode C), and is favored when electricity prices are relatively high but below the peak price.
- **Mode C, diversion GT.** The GT operates at full capacity, and steam generated in the HRSG is diverted to provide heat for regeneration in the CO₂ capture process. Diverted steam is not expanded in the steam turbine. Only as much steam is diverted as can be used by the CO₂ capture facility. If the CO₂ capture facility cannot use all of the steam, the remaining steam is expanded in the steam turbine. For HRSG configurations with reheat, steam is not diverted from the pre-reheat expansion. Mode C corresponds to the least power generation and CO₂ emissions of the three modes in which the GT operates (Modes A, B and C), and is favored when electricity prices are relatively low.
- **Mode D, coal only.** In this mode the gas turbine and CO₂ capture system are inactive. Mode D is favored when electricity prices are lowest. This is because the value of operating the GT and CO₂ capture is negative for very low prices of electricity: the cost of natural gas exceeds the combined value of the electricity generated by the GT and the CO₂ captured.

Modes A, B and C involve tradeoffs between power generation and reduced CO₂ emissions. Given the presence of a CO₂ constraint, there is a clear ordering of which mode is preferred with respect to the price of electricity. The decision process can be thought of as being driven by the relative values of electricity and CO₂ capture: electricity has a clear price, and the CO₂ emission constraint provides an implicit value for CO₂ capture. If the value of electricity exceeds the value of CO₂ capture, then it is favorable to maximize power generation; otherwise, it is favorable to capture CO₂. It is useful to note that more electricity is generated by the CCGT than is consumed within the CO₂ capture process, even in Mode C.

3.2. Optimal dispatch sub-problem

The optimal mode of operation at a point in time depends on the electricity price at that time. Threshold electricity prices – so-called ‘strike prices’ – separate the regimes of operation for each mode. These strike prices can be combined with the price-duration curve (the curve showing the cumulative duration within a set time frame, such as one year, during which electricity prices are above a certain value) to treat optimal facility dispatch and operating economics. In our formulation, the dispatch

optimization decision variables are the strike prices, and the objective function to be maximized is operating profit. The objective function for the overall design optimization is net present value (NPV), but in the dispatch optimization sub-problem maximizing operating profit is equivalent to maximizing NPV because the facility design (and thus capital cost) is fixed. The strike-price based approach is analogous to a simplified form of the hydroelectric dispatch optimization proposed by Lu et al. [16]. Figure 3 shows an example price-duration curve with strike prices.

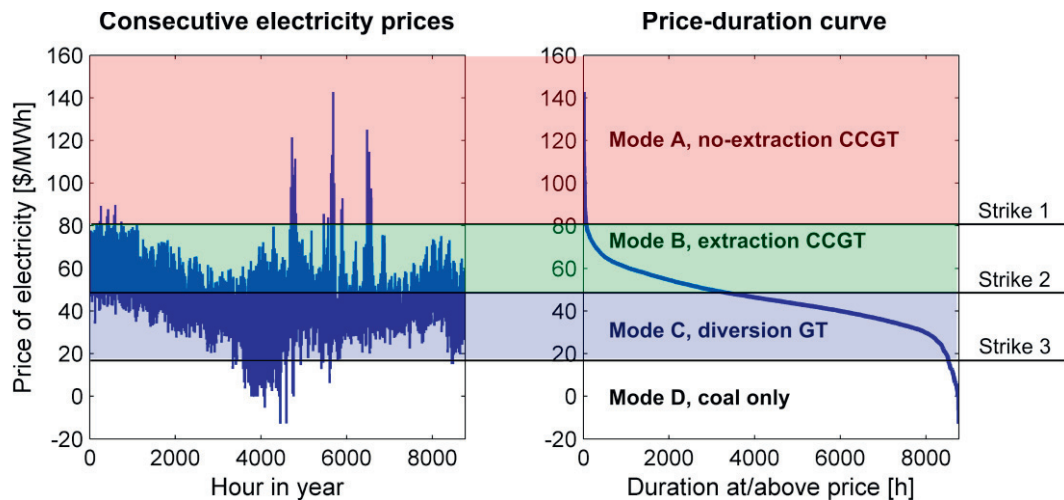


Figure 3. Price duration curve constructed from hourly prices of electricity, with strike prices and operating modes indicated

This treatment does not account for coupling in time in facility operations, but instead is analogous to reordering the hours in one year in terms of electricity price. Therefore, this approach would not accurately represent systems that have substantial operational coupling across time such as those with solvent storage, as treated in our earlier work [2, 4], or hour-to-hour inertia. The strike prices included as decision variables in the dispatch optimization problem are the lower bounds on Mode A, B and C operation. Below the Strike 3 price, the facility operates in Mode D (coal only).

The optimization is subject to CO₂ emission constraints described in Section 4.3. The objective function and constraints of the dispatch optimization problem are smooth, so the problem is amenable to derivative-based methods. We used the `fmincon` function (interior-point algorithm) in MATLAB.

4. Design optimization

4.1. Joint optimization of design with dispatch

The design of the facility is jointly optimized with flexible dispatch. This means that the design is optimized given that the facility will be dispatched optimally in time. As such, the function evaluation for a design calls the dispatch optimization routine described in Section 3.2. Figure 4 shows a flowchart of this methodology. For comparison purposes, cases are also run in which the facility is exclusively operated in the CCGT extraction mode (Mode B); this represents a facility designed with the expectation of constant operation in time. The NOMADm implementation of Mesh Adaptive Direct Search is used to solve the outer design optimization problem [17, 18].

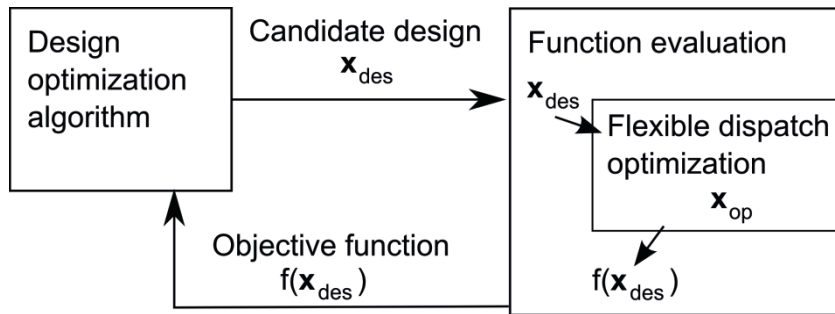


Figure 4. Flowchart of the joint optimization methodology

4.2. Objective function and decision variables

The NPV of the facility is maximized, using a 30 year time window and a 10% discount rate. All calculations are performed using 2010 dollars. The operating profit is calculated from the flexible or constant dispatch scheme, multiplied by 0.85 to account for maintenance and outages.

Table 1. Summary of the problem specifications for the three systems optimized

HRSG configuration	Number of design decision variables	Number of nontrivial nonlinear constraints	Shown in
1-pressure	7	8	Figure 2
2-pressure	11	12	Figure 2
3-pressure	20	17	Figure 5

The decision variables in all cases are the CO₂ capture facility size, GT size, HRSG design pressure(s), HRSG heat exchanger element sizes, and CCGT subsystem steam extraction pressure. Some system parameters, such as the numbers of pressure levels and HRSG elements, and HRSG geometry, are treated by enumerating three different configurations. In future work we plan to treat these as integer and categorical optimization variables. Table 1 shows the number of decision variables for each of the configurations considered.

4.3. Design constraints

Several linear and bound constraints are applied, reflecting a combination of physical limitations and problem simplifications to improve the search:

- HRSG pressures (including reheat pressure if applicable) are all bound between 3 bar and 200 bar
- Steam extraction pressure must be at least 2.72 bar, the pressure of saturated water at the temperature required for regeneration
- Heat exchanger sizes UA are bound between 1 kW/K and 10 MW/K
- GT capacity is bound between 1 MW and 600 MW
- The CO₂ capture capacity is bound between 0% and 90% of coal plant flue gas CO₂
- Steam extraction pressure must be less than the highest steam generation pressure
- For multipressure systems, the pressure design variables must be ordered from smallest to largest

In addition, two types of nonlinear constraints apply: those involving the CO₂ emission limit, and those related to HRSG and steam cycle design requirements. Table 1 shows the number of these nonlinear

constraints for the three configurations. The CO₂ emission constraints are modeled after the US Environmental Protection Agency's proposed rules for CO₂ emissions, which limit emission intensity (I) to 454 kg CO₂/MWh. Here we take $I=E/G$, where E [kg CO₂] is total (cumulative) CO₂ emissions and G [MWh] is total electrical energy generation.

This work treats the emission intensity requirement as three separate constraints. Essentially, the facility as a whole must meet the emission intensity standard along with each of the major subsystems:

- *Overall facility.* The numerator E includes all CO₂ emitted by the facility. The denominator G consists of net electricity exports from the facility; electricity used in CO₂ capture reduces this quantity.
- *Coal plant with CO₂ capture.* The emission intensity numerator includes only the CO₂ in the CP flue gas stream (after CO₂ capture). The denominator of the emission intensity does not include electricity use for CO₂ capture.
- *CCGT subsystem.* The emission intensity numerator includes only CO₂ from the gas turbine. The denominator includes all electric power generated by the GT and CCGT subsystem steam turbine(s), and does not include electricity use for CO₂ capture.

The constraints are formulated in this way to prevent the extreme case of 'diluting' a high-emissions coal plant with large amounts of gas-fired power. Of note is that the CO₂ emission constraints are enforced in the dispatch optimization; the design is feasible with respect to these constraints if and only if the dispatch subproblem is feasible.

In addition to the CO₂ emission constraints, several constraints apply to values of the states in the steam cycle. These constraints represent common design criteria for HRSGs and steam turbines that prevent unfavorable behavior in system components. The constrained quantities listed below are applied specifically to Mode A (i.e., HRSG water inlet temperature of 330 K):

- *Approach temperature.* The water inlet temperature for the evaporators (evaporator steam drums) must be between 10 K and 20 K below the water saturation temperature at the appropriate pressure to avoid economizer steaming or the introduction of excessively cool water into the evaporator steam drums.
- *Pinch temperature.* The temperature of the flue gas in each evaporator must be at least 10 K greater than the operating temperature of the evaporator to maintain a sufficiently large temperature gradient.
- *Condenser steam quality.* The quality of the steam at the outlet of any steam turbine expansion must be at least 0.88 to prevent loss of efficiency and damage in the steam turbine.
- *Reheater inlet steam quality.* Reheaters must have inlet steam in pure vapor form to maintain the validity of the reheater heat transfer representation. This constraint is trivially satisfied for systems without reheaters.
- *Gas outlet temperature.* The flue gas outlet temperature of the HRSG must be greater than 373 K to prevent unwanted precipitation on the gas side of the HRSG.

5. Results and discussion

The three configurations listed in Table 1 and shown in Figures 2 and 5 were treated using the joint optimization methodology. The price-duration curve was constructed from the 2010 prices of a California electricity market node, and multiplied by 1.5 to reflect increased future prices of electricity due to the imposition of CO₂ regulations. This multiplier was chosen to be representative of estimates for the increased cost of electricity with CCS [19], and results in an average electricity price of \$54.60/MWh. The yearly price-duration curve was assumed to be the same over the entire design optimization time frame. Three price scenarios for natural gas were used: \$3/MMBtu, \$4.50/MMBtu, and \$6/MMBtu.

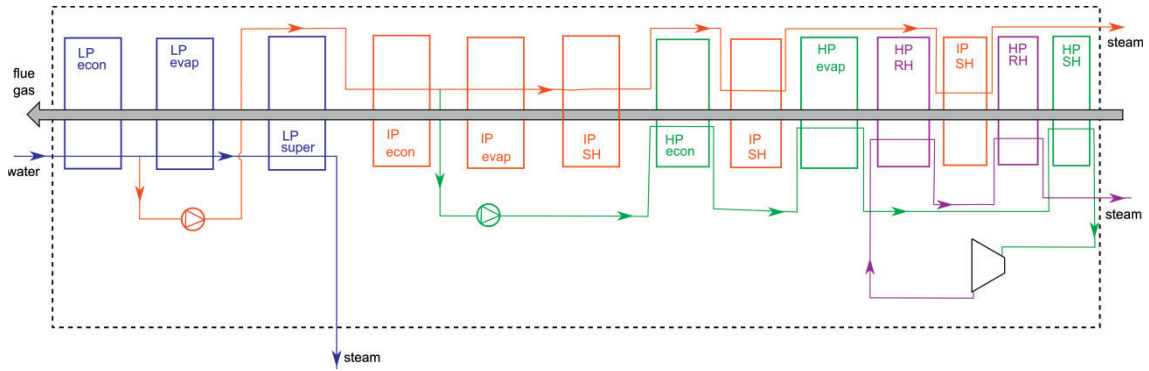


Figure 5. Three-pressure HRSG. LP, IP and HP indicate low pressure, intermediate pressure and high pressure. This configuration includes reheat

Table 2. Net present value and capital cost of optimized designs

Gas price	Configuration	Dispatch scheme	NPV [million US\$]	Capital cost [million US\$]
\$3/MMBtu	1-pressure	constant	1,473	2,139
		flexible	1,477	2,143
	2-pressure	constant	1,490	2,151
		flexible	1,494	2,155
	3-pressure	constant	1,498	2,176
		flexible	1,516	2,174
\$4.50/MMBtu	1-pressure	constant	820	2,137
		flexible	824	2,142
	2-pressure	constant	846	2,152
		flexible	854	2,158
	3-pressure	constant	853	2,176
		flexible	874	2,172
\$6/MMBtu	1-pressure	constant	145	2,137
		flexible	211	2,154
	2-pressure	constant	197	2,156
		flexible	234	2,165
	3-pressure	constant	209	2,175
		flexible	265	2,185

Table 2 shows the NPV and capital cost of the optimized designs. The results show clear patterns in optimized NPV across different cases, and a somewhat weaker pattern in optimal capital cost.

The three-pressure configuration is optimal in all three gas price scenarios, as can be seen by comparing the NPV of the different configurations under flexible dispatch optimization. Similarly, the one-pressure configuration displays the lowest NPV in all three scenarios. In the \$3/MMBtu scenario, the

three-pressure configuration has an NPV that is \$39 million (2.6%) greater than that of the one-pressure configuration. With \$4.50/MMBtu gas, the difference in NPV between the one- and three-pressure configurations is \$50 million (6%); in the \$6/MMBtu scenario this difference is \$54 million (26%).

Joint design optimization with optimized flexible dispatch consistently provides higher NPV than design optimization with constant dispatch, as would be expected. The improvement from flexible dispatch increases with increasing gas price. Specifically, with \$3/MMBtu gas, the NPV improvement in the optimal configuration is \$18 million (1.2%); with \$4.50/MMBtu gas, the NPV improvement is \$21 million (2.5%); and with \$6/MMBtu gas, the NPV improvement is \$56 million (27%). The increasing improvement from joint optimization with increasing natural gas price occurs because flexible dispatch allows the facility to avoid operating the CCGT subsystem when the electricity price is low, and this flexibility provides more benefit when the price of gas is high.

The optimal capital cost increases with increasing number of pressure levels, with the three-pressure configurations having, on average, capital cost that is \$31 million (1.4%) higher than the one-pressure configurations. Capital cost does not, however, exhibit a clear pattern with respect to natural gas price. The return on capital expenditure (ROCE, calculated by dividing annual profit by capital cost) of the optimal designs are 16.4% with \$3/MMBtu gas, 13.5% with \$4.50/MMBtu gas, and 10.7% with \$6/MMBtu gas.

We also performed the optimizations using a price-duration curve constructed by multiplying 2010 electricity prices by 1.25 instead of 1.5. This resulted in substantially reduced optimal NPV and ROCE in all cases. In fact, in the \$6/MMBtu scenario, NPV was negative for all cases, and in the \$4.50/MMBtu scenario NPV was negative for most cases. This demonstrates that, as would be expected, the economic viability of CO₂ capture depends strongly on future electricity prices.

6. Concluding remarks

A process and capital cost model for an integrated energy park consisting of a coal-fired power plant, CO₂ capture capability, and combined cycle gas turbine system was developed. A detailed representation of the heat recovery steam generator was incorporated into this modeling framework. The energy park model was used in the computational optimization of facility design in which the sizes and operating pressures of facility components are selected. This design optimization was conducted in two ways: using constant facility dispatch, and using flexible dispatch determined through an inner optimization. This dispatch optimization was performed using a price-duration curve. Facility economics were observed to depend strongly upon configuration, with variation in optimized net present value of up to \$54 million (26%) between configurations. Joint design and dispatch optimization was observed to yield up to a \$56 million (27%) improvement in NPV over design optimization with constant dispatch. System capital cost, \$2.1-2.2 billion, was higher for configurations with increased number of pressure levels, but did not show clear trends with gas price.

Future work will entail improved representation of CO₂ capture so the design of the entire facility, including the capture process, can be optimized. Joint optimization with true dynamic hour-to-hour dispatch, as opposed to the strike-price-based dispatch used here, will allow for the representation of effects such as solvent storage and ramp rate constraints that couple operation across time. Finally, future work will treat discrete aspects of the design problem, such as the geometry of the heat recovery steam generator, using a mixed integer nonlinear problem formulation. This approach, though computationally more demanding, will enable the more sophisticated optimization of system configuration and can be expected to provide designs that result in even better performance than those identified here.

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