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Abstract: Fossil fuel power plants are one of the major sources of electricity generation, although invariably release greenhouse gases. Due to international treaties and countries regulations, CO_2 emissions reduction is increasingly becoming key in the generators' economics. NGCC power plants constitute a widely used generation technology, from which CO_2 capture through a post-combustion and MEA absorption option constitutes a technological challenge due to the low concentration of pollutants in the flue gas and the high energy requirements of the sequestration process.

In the present work, a rigorous optimization model is developed to address the design and operation of power plants coupled to capture systems. The equations-oriented modeling strategy here utilized can address greenfield designs in which design and operating variables are simultaneously optimized, in order to ensure that the system will be able to meet process requirements at minimum cost. Then, an analysis of the electricity cost, CO_2 avoidance cost, energy penalties, as well as the optimal values of decision variables is thoroughly pursued.

Different economic tradeoffs are comprised at the optimal solutions for the joint project, as given by the different discrete and continuous decisions that the designer needs to weight in order to achieve the desired generation and capture goals, including the number of parallel capture trains, the inherent efficiency of each recovery unit, and the overall emissions reduction rate.

In this context, the joint optimization of the NGCC power plant with the amine-based capture option results in a novel configuration where 731 MW are optimally generated for supplying both the external demand and the

capture plant energy requirements, and achieving an overall CO_2 emissions reduction rate of 82.1% by means of a three capture trains arrangement, where 13.4% of the flue gas stream is bypassed and 94.8% of the CO_2 gets recovered at each unit.

This new generation/capture project features optimal values of its economic performance indicators, with an avoidance cost of 81.7 US$ per tonne of CO_2 captured, which can only be secured by simultaneously optimizing the design and operating variables of both systems on a start-of-the-art optimization algorithm.

To: Editor of *Chemical Engineering Research and Design* Journal

Subject: Submission of manuscript “A NGCC power plant with a CO_2 post-combustion capture option. Optimal economics for different generation/capture goals”

Dear Sir,

Please find annexed with this letter the revised version of the manuscript “A NGCC power plant with a CO_2 post-combustion capture option. Optimal economics for different generation/capture goals” for publication in the *Chemical Engineering Research and Design* Journal.

The authors would like to thank the reviewers for their time and their constructive and valuable comments.

The requested revision has been addressed in this revised version of the manuscript, as discussed in the “Response to Reviewers” file.

The authors state that this paper has not been published previously, it is not under consideration for publication elsewhere, and if accepted it will not be published elsewhere in substantially the same form, in English or in any other language, without the written consent of the Publisher.

I look forward to hearing from you. Yours sincerely,

Ezequiel Godoy

A NGCC combined cycle is coupled to a post-combustion amine-based capture system > The joint project is economically optimized by means of the proposed MINLP model > Electricity costs, mitigation costs, and energy penalties are thoroughly analyzed

A $NGCC$ power plant with a CO_2 post-combustion capture option. Optimal economics for different generation/capture goals

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Abstract

Fossil fuel power plants are one of the major sources of electricity generation, although invariably release greenhouse gases. Due to international treaties and countries regulations, CO_2 emissions reduction is increasingly becoming key in the generators' economics. $NGCC$ power plants constitute a widely used generation technology, from which CO_2 capture through a post-combustion and MEA absorption option constitutes a technological challenge due to the low concentration of pollutants in the flue gas and the high energy requirements of the sequestration process.

In the present work, a rigorous optimization model is developed to address the design and operation of power plants coupled to capture systems. The equations-oriented modeling strategy here utilized can address greenfield designs in which design and operating variables are simultaneously optimized, in order to ensure that the system will be able to meet process requirements at minimum cost. Then, an analysis of the electricity cost, CO_2 avoidance cost, energy penalties, as well as the optimal values of decision variables is thoroughly pursued.

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reduction rate of 82.1% by means of a three capture trains arrangement, where 13.4% of the flue gas stream is bypassed and 94.8% of the CO_2 gets recovered at each unit.

This new generation/capture project features optimal values of its economic performance indicators, with an avoidance cost of 81.7 US$ per tonne of CO_2 captured, which can only be secured by simultaneously optimizing the design and operating variables of both systems on a start-of-the-art optimization algorithm.

Keywords: natural gas combined cycle power plant, post-combustion CO_2 capture system, economic optimization, greenfield design, equations-oriented optimization

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Nomenclature

Acronyms

CP	capture plant
$NGCC$	natural gas combined cycle
PE	process equipment
PP	power plant
PS	process stream

Indexes

$Bypass$	flue gas bypass
Ext	extracted steam
in	inlet stream
out	outlet stream
SA	stand-alone power plant

Process Equipment

AAE	amine-amine exchanger
ABS	absorber
AWE	amine-water exchanger
BLO	blower

$CO2P$	CO_2 pump
COM	CO_2 compressor
CON	stripping gas condenser
CT	cooling tower
GT	gas turbine
$HRSG$	heat recovery steam generator
IC	inter-stage cooler
RAP	rich amine pump
REB	reboiler
REG	stripper
ST	steam turbine
$T1$	MEA tank
$T2$	water tank

Model Variables and Parameters

E	CO_2 emissions per net energy output	tn/MWh
$\dot{m}$	flow rate	kmol/s or kg/s
NTP	number of capture trains in parallel	-
ΔP_{int}	pressure drop at the absorber column	kPa
POT	plant operating time	h/y
$\dot{Q}_{CT}$	cooling tower duty	kJ/s
$\dot{Q}_F$	net fuel consumption	MW
$\dot{Q}_{Reb}$	reboiler energy requirement	kJ/s
$\dot{Q}_{Reb,C}$	reboiler energy requirement - auxiliary steam	kJ/s
$\dot{Q}_{Reb,E}$	reboiler energy requirement - extracted steam	kJ/s
ΔT_{int}	temperature diminution at the cooling tower	K
$\dot{W}_0$	external power demand	MW
$\dot{W}_{BLO}$	power consumption of blower	MW
$\dot{W}_{CO2P}$	power consumption of CO_2 pump	MW
$\dot{W}_{COM}$	power consumption of CO_2 compressor	MW

$\dot{W}_{Ext}$	power equivalent to the extracted steam	MW
$\dot{W}_{loss}$	power consumption of the capture plant	MW
$\dot{W}_{Net}$	net power production in the generation plant	MW
$\dot{W}_{RAP}$	power consumption of rich amine pump	MW
$\dot{W}_{STLP}$	power production at the low pressure steam turbine	MW
η_{CP}	capture train efficiency	%
η_{CO2}	overall capture efficiency	%
$\eta_{T,PP}$	thermal efficiency of the power plant	%
x	molar fraction	-
T	temperature	K
P	pressure	kPa
h	enthalpy	kJ/kmol

Economic Variables and Parameters

a_{PE}	exponential factor for the acquisition cost	-
$CAPEX$	capital expenditures	MUS$/y
C_{Inv}	total equipment acquisition cost	MUS$
C_{Mant}	maintenance cost	MUS$/y
C_{MP}	man power cost	MUS$/y
CRF	capital recovery factor	y
C_{RM}	raw materials cost	MUS$/y
COE	cost of electricity	US$/MWh
C_{PE}	acquisition cost of each piece of equipment	MUS$
F_{Inv}	investment factor	-
F_{Mant}	maintenance factor	-
F_{O1}	man power operating factor	-
F_{O2}	investment operating factor	-
i	interest rate	-
MC	mitigation cost	US$/tn
n	life cycle length	y

$OPEX$	operating expenditures	MUS$/y
TAC	total annual cost	MUS$

Optimization Formulation

f	objective function
$\underline{h}$	sets of equality constraints
$\underline{g}$	sets of inequality constraints
$\underline{x}$	sets of design and operating variables
$\underline{y}$	sets of integer variables

1. Introduction

CO_2 capture by MEA scrubbing is an energy intensive technology, and consequently, it becomes necessary to study how the high thermal and electrical requirements get satisfied with minimum losses on the power plant efficiency. Different authors studied how the operating conditions and/or design parameters impact on the cost of CO_2 recovery aiming at profit maximization (Abu-Zahra et al., 2007a; Nuchitprasittichai and Cremaschi, 2011; Panahi and Skogestad, 2011; Rao and Rubin, 2002, 2006; Ziaii et al., 2011). Total equivalent work and cost of CO_2 avoided are the main parameters reported in the literature to describe the economic implications of coupling a post-combustion process to a power plant, while accounting for the effect of power losses associated to CO_2 capture and compression.

In the post-combustion capture process, the flue gas stream gets directly treated after combustion and heat recovery. Then, CO_2 capture can be studied separately from power generation, by assuming the flue gas conditions (temperature, flow rate, composition and pressure). Gáspár and Cormoş (2011) and Mores et al. (2012a, 2011a,b) presented rigorous mathematical models for the stand-alone post combustion capture plant and analyzed the process performance.

Integration of the generation cycle to the capture plant is essential in order to reduce energy penalties, as several authors (Botero et al., 2009; Cifre et al., 2009; Möller et al., 2007; Pfaff et al., 2010; Popa et al., 2011; Romeo et al., 2008) studied the influence of the coupling instance on the power plant performance. Depending on how the designer deals with the decision variables, problems concerning coupling a capture plant to a power plant can be mainly divided into two groups: retrofit problem and greenfield design. For utility systems, Aguilar et al. (2007a,b) showed that retrofit and grassroots tasks can be addressed inside a common framework, optimizing design and operating variables simultaneously, and considering any additional constraints that may result necessary for defining each case study.

Retrofit design implies improving an existing power plant, by adding the carbon dioxide capture option. There is little scope for making structural modifications in the power plant; hence, it is required to determine size and number of the capture trains to be built, and their interconnections with the current system. Afterwards, the study will be centered in determining the operating conditions of the whole plant, and how the new capture plant affects the existing power plant performance.

Botero et al. (2009) redesigned a $NGCC$ power plant in order to include exhaust gas recirculation and an amine reboiler integrated into the $HRSG$. Möller et al. (2007) modeled the integration of steam production for amine regeneration at a natural gas-fired combined cycle, where the steam is extracted from both the steam turbine and the $HRSG$. Khalilpour and Abbas (2011) showed that the energy penalty burdened by integration of a post-combustion carbon capture plant to a pulverized coal-fired power system can be reduced by heat exchanger network optimization.

Romeo et al. (2008) technically and economically compared different possibilities to overcome the energy requirements when integrating amine scrubbing to a commercial pulverized coal-fired power plant. They found that using a gas turbine to supply compression electrical energy and extracting steam from the steam cycle is the optimum option regarding the efficiency penalty on the power plant performance.

Greenfield problems establish the design of a whole new coupled plant along its operational conditions throughout several scenarios; then, an economic objective is pursued while satisfying the power demand and reducing the CO_2 emissions considering a minimum capture goal.

For a hard-coal fired power plant, Pfaff et al. (2010) focused on waste heat integration by condensate pre-heating and combustion air pre-heating regarding the steam requirements of the capture unit, as they observed that a lot of heat is available for such task, although at very low temperature levels. Every alternative implies a different technological challenge for its implementation, although ultimately, economic profitability will determine which one to deploy at a commercially available plant.

Regarding types of model and their rigorousness, different strategies are introduced in the literature to pursue the modeling and optimization of the integration of power plants with capture technologies. Next, some examples are listed:

- Cifre et al. (2009) and Abu-Zahra et al. (2007a) presented parametric studies for the design and operation of capture plants. In both works, commercial simulators are used to model the studied systems, even though the first comprised the whole plant while the latter centered its study on the stand-alone capture plant.

- Cohen et al. (2011) build a MILP model for a flexible capture system and optimized its economic indicators on GAMS, in order to analyze the plant performance in response to volatile electricity prices.

- Möller et al. (2007) modeled the integration of steam production for amine regeneration, using: a rigorous model for the gas turbine performance deck, simplified correlations for the boiler, empiric relations for the steam turbine calculation and the HEI method for the steam condenser.

- Pfaff et al. (2010) modeled the capture unit as a black box, determining the interface quantities by a detailed overall model in two different commercial software packages.

- Bernier et al. (2010, 2012) used a simple gas turbine model and an ASPEN flow-sheeting of the capture train, obtaining Pareto-optimal solutions aiming mainly at two objectives, levelized cost of electricity and life cycle global warming potential.

1.1. Aim and Outline

In this work, rigorous and flexible mathematical models for a $NGCC$ power plant and a CO_2 post-combustion MEA absorption capture plant are presented, while a comprehensive coupling strategy between both systems is described.

An equations-oriented approach is utilized, in opposition to the modular-sequential simulation or partial optimization methods generally reported in the literature. The proposed methodology allows simultaneously optimizing the design and operating variables associated to both plants. Thus, every solution here discussed is an optimal one, obtained when successfully achieving the resolution of the non-linear programming mathematical optimization formulation.

The discussion of the optimal generation/capture options is organized by solving three case studies when parameterizing practical interest variables at values suggested in the scientific and technical literature:

- At the first case study, the economic optimal values of the project are analyzed, as the joint plant is designed in order to achieve a recovery goal fixed at 90% CO_2 capture. In addition, an economic sensitivity analysis is also introduced, thus identifying which parameters exert the larger impact on the performance of the joint venture. Moreover, the economic benefit of tailoring the $HRSGs$ specifically for the task at hand is discussed when compared with the possibility of using an auxiliary boiler for satisfying the steam requirements of the capture system.

- The second case study discusses the influence of changing the capture system configuration, given by the number of parallel capture trains, over the economic performance of the project. Then, it becomes possible to determine the minimum number of capture trains for achieving a given capture goal.

- The third case study discusses the variation of the economic optimal performance of the joint venture as the CO_2 capture requirement is varied across a wide range, from 80% to 97.5%. This analysis exposes that the greenhouse gases emissions can be further reduced while also improving the economic performance of the project.

The results obtained up to this point provide a first glance at new opportunities for improving the economic performance of capture-ready power plants, which would imply accounting for the simultaneous effect of all these (previously parameterized) variables over the economic optimal performance of the joint project.

Therefore, a fourth case study is set in order to discuss the novel design characteristics and operating policy of an optimal coupled project where the number of capture trains, their inherent efficiency, the overall CO_2 recovery rate, and the alternative of flue gas bypass are all considered as decision variables and their values optimized when solving the proposed formulation. Then, the technical and economic merits of this new obtained alternative are thoroughly discussed, considering the optimal values of the CO_2 mitigation cost, cost of electricity, energy penalties, as well as the decision variables.

2. Process Configuration

The flow diagram for the generation/capture system is presented in Figure 1. A 2 GTs + 1 ST multi shaft $NGCC$ power plant is selected as the generation driver (note that the second gas turbine and its associated steam generator are not presented in this graphic); and the capture plant consists of a parallel recovery units arrangement, while the generated flue gas is evenly distributed between each capture train (note that only one is graphically presented).

A description of the assumptions and technical constraints is presented in Appendix A.

2.1. Modeling Strategy of the Power Plant

The power plant consists of two commercial gas turbines (GTs) (i.e. the design and operating variables have been tuned to reproduce the performance of a GE PG9351FA gas turbine, as reported by GE Power Systems (2013)), its associated three pressure level heat recovery steam generators ($HRSGs$), and a steam turbine (ST) with high, intermediate and low pressure stages. This configuration includes innovative features which enable to obtain high efficiencies, including high gas turbine inlet temperature, multiple pressure levels and parallel heat exchange sections, among others. The detailed mathematical model of this system has been previously introduced at the Appendix A of Godoy et al. (2011, 2010), and includes mass and energy balances as well as design equations for the gas and steam turbines, heat recovery steam generators, pumps, condensers, and others.

2.2. Modeling Strategy of the Capture Plant

In the CO_2 post-combustion capture process based on amine scrubbing, the CO_2 of the flue-gas is chemically absorbed by a 30% MEA solution in an absorption tower (ABS). The resulting rich solvent is regenerated in a stripper unit (REG) by means of its associated reboiler (REB), while the lean solvent is thermally conditioned (AAE, AWE) and sent back again to the absorption process within a closed loop; the stripping gas is condensed (CON) and refluxed to the regeneration column and the CO_2 concentrated gas stream is compressed (COM, IC, $CO2P$) at required levels for transportation. Water and MEA tanks ($T1$, $T2$) are needed in order to supply for the losses due to thermal degradation, evaporation losses and stable salts formation.

Further details have been introduced at Mores et al. (2012a, 2011a,b, 2012b,c), including the mass and energy balances as well as the design equations for the absorbers, regenerators, condensers, heaters, reboilers, pumps and compressors.

2.3. Coupling the Capture Option to the Generation Plant

Coupling Constraints

Exhausted combustion gases $\dot{m}_{PP,out}$ (characterized by $x_{j,PP,out}$, $T_{PP,out}$ and $P_{PP,out}$) leave from the power plant and are fed to the capture plant $\dot{m}_{CP,in}$ (characterized by $x_{j,CP,in}$, $T_{CP,in}$ and $P_{CP,in}$). Then, Eqs. (1-4) are used to relate the power plant outlet gases with the capture plant inlet gases, including its composition, temperatures and pressures. NTP is the number of capture trains and $\dot{m}_{Bypass}$ denotes the flow rate of flue gas released without CO_2 concentration reduction.

$$\dot{m}_{PP,out} = NTP\ \dot{m}_{CP,in} + \dot{m}_{Bypass} \tag{1}$$

$$x_{j,PP,out} = x_{j,CP,in} \quad , \quad j = N_2, O_2, H_2O, CO_2 \tag{2}$$

$$T_{PP,out} - \Delta T_{int} = T_{CP,in} \tag{3}$$

$$P_{PP,out} = P_{CP,in} - \Delta P_{int} \tag{4}$$

As cooling of the gas flow ($\dot{Q}_{CT}$) is needed, a cooling tower (CT) is selected for achieving the temperature diminution ΔT_{int} of each stream departing from the power plant and previous its arrival to the capture plant, according to Eq. (5). This implies the consumption of a given quantity of cooling water $\dot{m}_{CT}$. Moreover, a blower (BLO) is needed to overcome the pressure drop ΔP_{int} in the absorption column.

$$\dot{Q}_{CT} = \dot{m}_{CP,in}\ \Delta h_{CP,in} = \dot{m}_{CT}\ \Delta h_{CT} \tag{5}$$

In addition, technical inequality constraints are established to secure operation of the capture plant within practical operating boundaries:

(1) Eq. (6) sets the largest economic capacity of a single train based on a maximum column diameter of 12.6 m, which secure practical dimensions for such process equipment, as suggested by (Chapel et al., 1999).

$$\dot{m}_{CO_2,CP,in} \leq 2400\ tn/d \tag{6}$$

(2) Eq. (7) circumscribes a feasible range for the operating temperature at the absorption column,

where the chemical absorption is facilitated (Fisher et al., 2005; Rao and Rubin, 2002).

$$313\ K \leq T_{PP,out} \leq 323\ K \tag{7}$$

(3) Eq. (8) limits the operating pressure of the reboiler at typical values recommended in the literature (Abu-Zahra et al., 2007b; Oyenekan and Rochelle, 2007, 2009; Rao and Rubin, 2002), considering the thermal degradation of the amine and the corrosion problems.

$$130\ kPa \leq P_{reb} \leq 200\ kPa \tag{8}$$

Modifications at the NGCC for Powering the Capture System

The reboiler energy requirement $\dot{Q}_{Reb}$ is here supplied by steam extraction ($\dot{Q}_{Reb,E}$) from the low pressure level at the $HRSGs$ (i.e. from the LP/IP crossover pipe), although it can also be satisfied by production of steam ($\dot{Q}_{Reb,C}$) through an auxiliary boiler (as proposed by Romeo et al. (2008)), according to Eq. (9).

$$\dot{Q}_{Reb} = \dot{Q}_{Reb,C} + \dot{Q}_{Reb,E} \tag{9}$$

The first alternative allows optimizing the overall thermal efficiency of the $NGCC$, although implies a reduction of the power available for satisfying the external demand. The latter implies designing and operating an auxiliary boiler for generating the required steam, which does not impact the performance of the power plant, even though it will be inherently less efficient than a large scale steam cycle.

Power equivalent $\dot{W}_{Ext}$ of the energy extracted from the low pressure steam turbine is here computed considering the actual isentropic evolution and expansion efficiency (which define Δh_{STLP}), according to Eq. (10); in opposition to other off-line correlations presented in the literature (Panahi and Skogestad, 2011; Ziaii et al., 2011).

$$\dot{W}_{Ext} = \dot{m}_{ext}\ \Delta h_{STLP} \tag{10}$$

Power consumption of the capture plant $\dot{W}_{loss}$ gets computed by means of Eq. (11), including solvent pumping $\dot{W}_{RAP}$, CO_2 product compression $\dot{W}_{COM}$ and pumping $\dot{W}_{CO2P}$, and flue gas circulation $\dot{W}_{BLO}$.

$$\dot{W}_{loss} = NTP \left(\dot{W}_{RAP} + \dot{W}_{COM} + \dot{W}_{CO2P} + \dot{W}_{BLO}\right) \tag{11}$$

The net energy production $\dot{W}_{Net}$ in the generation plant is given by Eq. (12), computed as the power allocated for satisfying external demand $\dot{W}_0$ plus the electric requirement of the capture plant $\dot{W}_{loss}$.

$$\dot{W}_{Net} = \dot{W}_0 + \dot{W}_{loss} \tag{12}$$

In addition, the thermal efficiency of the power plant $\eta_{T,PP}$ is computed by Eq. (13), where $\dot{Q}_F$ is the net fuel consumption.

$$\eta_{T,PP} = \frac{\dot{W}_{Net}}{\dot{Q}_F} \tag{13}$$

Measures of CO_2 Sequestration Efficiency

Different measures of CO_2 sequestration efficiency are defined aided by Figure 2.

The efficiency of the carbon dioxide removal at each capture train η_{CP} represents the inherent technical performance of such system when facing the task of retaining the CO_2 of the gas flow which passes through the capture unit, as given by Eq. (14) (and also defined at Mores et al. (2012c)).

$$\eta_{CP} = \frac{x_{CO_2,CP,out}\ \dot{m}_{CP,out}}{x_{CO_2,CP,in}\ \dot{m}_{CP,in}} \tag{14}$$

The overall capture efficiency η_{CO2} accounts for the total amount of captured CO_2 with respect to the amount which leaves the power plant (and also considers bypassed gas), as given by Eq. (15).

$$\eta_{CO2} = \frac{NTP\ x_{CO_2,CP,out}\ \dot{m}_{CP,out}}{x_{CO_2,PP,out}\ \dot{m}_{PP,out}} \tag{15}$$

The carbon dioxide emissions per unit of generated energy E becomes given by Eq. (16).

$$E = \frac{(1-\eta_{CO2})\ x_{CO_2,PP,out}\ \dot{m}_{PP,out}}{\dot{W}_{Net}\ POT} \tag{16}$$

3. Economic Performance Evaluation of the Generation/Capture Project

The evaluation of the profitability of different investment options allows selecting the project which yields optimal values of the financial indicators.

Total Annual Cost

The economic performance of the project is here evaluated through its total annual cost TAC, as given at Eq. (17), which includes capital expenditures $CAPEX$ annualized by a given recovery rate CRF, and annual operating expenditures $OPEX$.

$$TAC = \frac{CAPEX}{CRF} + OPEX \tag{17}$$

A description of the equations used for computing the capital and operating expenditures is presented in Appendix B.

Electricity Cost

The cost of the generated electricity COE gets computed according to Eq. (18) as the annualized cost per unit of generated energy.

$$COE = \frac{TAC}{\dot{W}_{Net}\ POT} \tag{18}$$

Mitigation Cost

Cost of electricity in combination with the carbon dioxide emissions can be translated into the cost of CO_2 avoided or mitigation cost MC (Abu-Zahra et al., 2007a), which also represents a normalized measure on the cost of power generation with respect to the amount of CO_2 captured (Rao and Rubin, 2002, 2006), as given at Eq. (19).

$$MC = \frac{COE - COE_{SA}}{E_{SA} - E} \tag{19}$$

where the subscript SA denotes the carbon dioxide emissions and electricity cost of the standalone power plant.

4. Formulation of the Economic Optimization Problem and Definition of Case Studies

Optimizing the economic performance of the coupled plant implies solving the mathematical formulation presented at Figure 3.

In this optimization problem, the mitigation cost (defined at Eq. (19)) is selected as objective function $f\left(\underline{x}\right)$. Thus, optimizing the mitigation cost implies simultaneously minimizing the total expenditures of the project and maximizing the net energy output of the generation plant while achieving the desired overall capture goal.

Here, $\underline{x}$ are the sets of design and operating variables and $\underline{y}$ are the sets of integer variables, which are summarized at Figure 4; while $\underline{h}(\underline{x})$ and $\underline{g}(\underline{x})$ refer to the equality and inequality constraints which configure the power plant and capture system models, as well as the coupling of the capture option to the generation plant, and the economic performance evaluation of the whole project.

4.1. Implementation of the Optimization Problem

This mathematical program is implemented in the optimization software GAMS (Rosenthal, 2008) and solved through the algorithms CONOPT (Drud, 1996) and, where applicable, SBB (Drud, 2001). The proposed model comprises continuous and discrete variables, as well as highly non-linear constraints which configure a non-convex solutions space. Due to such characteristics, global optimal solutions cannot be guaranteed.

The initialization strategy of the optimization problem is outlined at Figure 5. The proposed initialization procedure proved to be efficient, as optimal solutions for the coupled plant are obtained in only a matter of seconds and with a low number of iterations. Moreover, no signs of multiple local solutions were found when using other initialization strategies, although deterioration on the performance of the utilized algorithm (i.e. larger resolution time and number of iterations) was indeed noticed.

4.2. Outline of Case Studies

By these means, four case studies are hereafter solved and discussed, as summarized in Table 1 and briefly outlined below.

Optimal Parametric Designs

Optimal designs for the joint project are obtained and analyzed when parameterizing selected variables by following the findings of previously published works. Even though, the economic optima of the whole system is here improved as the designed and operating variables of both plants are simultaneously optimized, according to:

(1) *Case Study 1*, also referred as *Reference Case*, introduces the optimal design for the amine-based capture plant coupled to the *NGCC*, as the carbon dioxide overall recovery goal is set at 90% (note that the capture unit efficiency of each train is also set at 90%) while maximizing the power output for satisfying the external demand.

In addition, a sensitivity analysis regarding the adopted economic parameters is presented, including fuel cost, investment on process equipment, as well as interest rate and life cycle span.

If a restriction on the amount of extracted steam is imposed, it will become necessary to generate the deficit of steam through an auxiliary boiler. Thus, impact on the project economics is discussed by analyzing the optimal economic indicators of the joint venture.

(2) On every optimal solution previously introduced, a four trains parallel arrangement has been used to treat the whole flue gas stream while achieving the required overall capture goal. Thus, *Case Study 2* discusses the modifications of the optimal economics of the project as the number of parallel units is varied from 2 to 6, while the percentage of captured CO_2 ranges from 40% to 90%.

(3) As general matter, environmental regulations enforce a required level of greenhouse gases emissions reduction (which may differ from the previously fixed 90% overall recovery). Thus, *Case Study 3* discusses the technical and economic implications of varying the intrinsic CO_2 recovery efficiency of the four capture trains from 80% to 97.5%.

Through a comprehensive analysis of the space of optimal solutions, the minimum number of parallel capture trains necessary for achieving a given capture goal is also determined.

Optimal Generation/Capture Designs

Up to this point, several decision variables have been parameterized while optimally designing and operating the coupled plant, since this approach has the advantage of simplifying the resolution strategy of the proposed mathematical model. Even though, different tradeoffs may be excluded from the feasible solutions region, where optimal designs with a better economic performance may reside.

At *Case Study 4*, this issue is overtaken by selecting the overall CO_2 recovery rate, number of parallel capture trains, inherent capture efficiency and flue gas bypass as (free) decision variables. Thus, the obtained optimal project is thoroughly analyzed, observing the improvement of the economic performance indicators, and discussing the necessary modifications of the design and operating variables at the generation and capture plants (respect to the *Reference Case*).

5. Optimal Parametric Designs

5.1. Optimal Economic Design for 90% CO_2 Recovery (Case Study 1 - Reference Case)

Optimal designs for the capture plant coupled to the *NGCC* are here obtained by solving the economic optimization formulation previously discussed at Figure 3. Thus, in the *Reference Case*, the mitigation cost is minimized when using the economic parameters listed at Table 2.

The optimal values of the economic performance indicators of the generation/ capture project are presented at Table 3, including a comparison with the ones associated to a stand-alone power plant designed by minimizing the generated electricity cost.

Total Annual Cost

It is here observed that coupling the capture plant represents an extra 127 MUS$/y total expenditures, driven by a 31.6% increase of the operating expenses and a 50.1% increment on the capital investment. These variations are associated to the construction and operation of the four capture trains, as well as a larger design capacity necessary at the combined cycle.

Electricity and Mitigation Costs

When the capture option is included in the optimization problem, the total generated energy decreases from 6305 GWh/y at the stand-alone plant to 5808 GWh/y at the coupled system. As the total annual expenditures increase (see previous section), it is observed that the electricity cost increases by 49.2% in the latter.

In the *Reference Case*, the CO_2 overall recovery goal is set at 90%. As consequence, the greenhouse gases emissions are reduced from 0.355 tn/MWh at the stand-alone plant to 0.039 tn/MWh at the coupled system. Thus, the cost of implementing the capture option is 84.1 US$ per tonne of CO_2 captured, as computed by Eq. (19).

Optimal Costs Distribution

Table 4 introduces the capital and operating costs distribution for the joint venture. It is here observed that the fuel consumption represents almost 72.0% of the total raw material and utility costs, followed by the expenses on boiler and cooling water (15.6% and 8.8%, respectively).

The construction of the generation system requires 62.5% of the investment on process equipment, whereas 39.3% goes to the gas turbines, 15.3% to the steam turbine, and 7.9% to the $HRSGs$. The main cost components of the capture system are the absorber columns and compressors, which contribute with 13.7% and 9.1% of the required expenses, respectively. On the other hand, the regeneration sub-system (i.e. stripper column, condenser, reboiler, and exchangers) broadens only 10.8% of such category.

5.1.1. Comparison with Other Authors

Table 5 introduces a comparison with results previously presented in the literature by Abu-Zahra et al. (2007a,b); Fisher et al. (2005); Rao and Rubin (2002); Sipöcz and Tobiesen (2012). Note that in order to facilitate this comparison a 90% of CO_2 recovery was here selected as capture goal η_{CO2}, as the inherent efficiency of each capture train η_{CO2} was also set at 90% and no flue gas bypass was allowed. In addition, four parallel capture trains (NTP) were used to treat the whole flue gas stream generated at the power plant.

It is then observed that the optimal values here obtained for these economic indicators are of the same order of magnitude than the ones previously reported in the literature, in spite of the technical modeling differences (hypothesis and reference plant, among others). It is also noted that optimal and up-to-date values of the electricity and avoidance costs are here reported; and that, as consequence of rigorously modeling the design and operating characteristics of both plants and their interconnections, a detailed economic accounting of the joint project is here achieved.

5.1.2. Optimal Design and Operating Variables

Optimal values of the design and operating variables associated to the $NGCC$ are listed in Table 6, along the values of the stand-alone power plant.

Note that the gas turbine characteristic design has been tuned to reproduce the performance of a commercially available one (GE PG9351FA). Thus, its generation capacity is pre-defined (i.e. 522 MW), and does not change when coupling the capture plant, as neither does the fuel consumption. Therefore, the heat available for recovery at the steam cycle also remains constant.

The $NGCC$ needs to be redesigned and optimized when the capture plant gets coupled (i.e. a greenfield type problem). Thus, significant differences are observed for the design and operating characteristics of each piece of equipment at the steam cycle.

Since the low pressure steam is partially derived to the capture plant, the generation capacity of the steam turbines decreases by 23.4%. Thus, the steam production at every pressure level gets redistributed; and consequently, a 13.7% reduction of the thermal efficiency is observed. In addition, the total steam production at the HRSGs increases by 2.7%, which is accompanied by an increment of 12.2% on the required exchange area at the $HRSGs$, and increases on the intermediate and low operating pressures.

Table 7 lists the optimal design and operating variables for the capture system, which is designed for treating the whole flue gas stream originated at the $NGCC$ while recovering 90% of the CO_2. For such purpose, four identical parallel capture trains are necessary, characterized by:

- The CO_2 loading at the absorber falls within the values reported in the literature (0.15 to 0.33, according to Abu-Zahra et al. (2007b); Jordal et al. (2012); Kwak et al. (2012); Ystad et al. (2012)).

- The mass ratio between the solvent and the flue gas flow rates is 0.92. Other authors have reported values between 1.00 and 1.45 (Amrollahi et al., 2012; Jordal et al., 2012; Ystad et al., 2012).

- The amine flow rate per tonne of CO_2 captured is 15.3 m^3/tn, and falls within the range reported by Abu-Zahra et al. (2007b) (15 to 50, for CO_2 recoveries between 80% and 95%).

- As result of the optimization approach, 4.35 GJ of steam are required at the reboiler per tonne of CO_2 captured. A wide range of feasible values (3.6 to 11.2 GJ/tn) has been reported in previous works for a diverse set of operating conditions (Cottrell et al., 2009; Dugas, 2006; Kwak et al., 2012; Mangalapally and Hasse, 2011; Tobiesen et al., 2008). Moreover, Abu-Zahra et al. (2007b); Alie et al. (2005) found that the reboiler duty is critically dependent on the amine flow rate and CO_2 loading.

- Abu-Zahra et al. (2007b) reported higher values for the specific consumption of cooling water (100 to 117 m^3/tn for CO_2 recoveries between 80% and 95%) than the one here obtained (75.1 m^3/tn).

- The electric penalty is 0.650 GJ/tn, which is utilized mainly at the blowers and compressors. Thus, the electric energy consumption is of the same order of magnitude than the values reported by Fisher et al. (2005); Ystad et al. (2012) in spite of the differences on the process configuration (CO_2 content, final disposal pressure, etc.).

5.1.3. Economic Sensitivity Analysis

As expected, the optimal values of the economic performance indicators of the project are critically dependent on the adopted values of the economic parameters. Thus, the sensitivity of the obtained optima is here discussed as several financial parameters are varied across a ±20% range. Then, Figure 6 reflects the relative influence of variations on the economic parameters over the mitigation cost (i.e. the objective function).

As expected, the investment factor exerts the largest negative impact on the mitigation cost, followed in order of importance by the columns cost, interest rate, compressors cost, fuel cost, HRSGs cost and turbines cost. On the contrary, increasing the life cycle length exposes a favorable (quasi) linear trend on the economic performance indicators of the joint project (as the capital expenditures get depreciated across a longer time span).

These economic parameters should then be carefully balanced considering the different available alternatives (turbines manufacturers, fuel sources, type of provision contract, etc.), in order that the newly designed generation/capture project results appealing to the potential investors.

Figure 6 represents the economic sensitivity of the generation/capture project as one economic parameter is varied at a time (while the other ones are kept at their expected values), which intends to configure a "representative, average or expected case". It is noted that the simultaneous increase of all the economic parameters (even including several others here not considered, and except for the life cycle length) would set a "worst case" scenario where the economic performance indicators get severely impacted and the mitigation cost gets increased far beyond the values here reported (a "best case" scenario could be obtained if the economic parameters are varied in the opposite direction, thus obtaining a minimum optimal value of the mitigation cost).

A more rigorous and in-depth economic analysis should consider the uncertainty distribution (in a deterministic or stochastic way) of each economic parameter, which would enable finding the most likely scenarios that the project would have to face; although such analysis is beyond the scope of this work.

5.1.4. Steam Generation at an Auxiliary Boiler versus Steam Extraction from the HRSGs

Up to this point, the *HRSGs* have been tailored for supplying all the steam required at the capture plant. It has been proposed in the literature (Romeo et al., 2008) that such task can also be accomplished by generating the necessary steam at an auxiliary boiler (which has been introduced at Figure 1).

The tradeoff among the two options, generation at the auxiliary boiler versus steam extraction from the low pressure level section at the *HRSGs*, can be considered during the optimization of the project by means of their relative economic weights. Note that the cost of the steam generated at an auxiliary boiler includes the associated operating expenditures (fuel consumption, maintenance, water supply) and the depreciation of the required capital investment.

Then, Figure 7 shows that the mitigation cost increase along the quantity of low pressure steam supplied by the auxiliary boiler. Specifically, if there is no steam extraction, the mitigation cost rises by 30.7%.

It is then concluded that the steam extraction alternative results economically advantageous, as it is generated at the higher operating efficiency of the optimized HRSGs. Even though, the installation of an auxiliary boiler could be considered as a viable option if the designer seeks for increasing the availability of the capture system or when a restriction on the steam extraction becomes active due to maintainability issues at the generation plant.

5.2. Economic Optima for Different Number of Capture Trains (Case Study 2)

A parametric analysis is presented on how modifying the number of parallel capture trains NTP influences the economical performance of the project when the $NGCC$ power plant is jointly designed with a sequestration plant at 90% of CO_2 inherent recovery efficiency per train η_{CP}.

For this porpoise, the mathematical problem defined at Figure 3 is solved by minimizing the mitigation cost, fixing different values for the overall capture efficiency (η_{CO2}, computed according Eq. (15)) from 40% to 90%, and for different number of parallel capture trains NTP fixed at 2, 3, 4, 5 and 6.

Since increasing the overall capture efficiency implies decreasing the percentage of flue gas bypass, the electricity cost presents an increasing trend, as can be seen at Figure 8a. Thus, higher overall CO_2 recovery rates are accommodated by higher expenses on process equipment, as well as larger operating costs for achieving the required capture goal. On the other hand, the mitigation cost (i.e. the objective function) presents a decreasing trend, according to Figure 8b, as consequence of the more efficient utilization of the existing facilities in order to reduce the greenhouse gases emissions.

For a given overall recovery goal, it is observed in Figure 8b that the mitigation cost increases as extra trains are added to the parallel configuration. Such trend indicates that, for achieving a desired overall recovery goal, the number of parallel trains should be kept at the minimum feasible value, thus decreasing the total capital expenditures and securing a better exploitation of the installed capture capacity.

Therefore, Figure 9 presents the minimum required number of parallel capture trains necessary for achieving a desired overall capture goal, as well as the associated percentage of flue gas bypass at each scenario. It is then concluded that for reaching overall recovery values above 54% require at least three parallel trains, while four units are needed when surpassing 80.8% captured CO_2

For configurations with 2, 3 or 4 trains, it is also noted that it becomes necessary to bypass a portion of the flue gas stream if the recovery goal η_{CO2} is set below 90% (as the inherent efficiency of each train η_{CP} is fixed at 90%). As well, it is observed that a four parallel capture trains arrangement allows treating all the exhausted combustion gas (i.e. with null bypass) and achieving an overall recovery goal of 90% at the minimum feasible value of the avoidance cost.

When fixing the capture efficiency of each train as well as their number, a maximum overall recovery capacity gets defined by the equipment sizing restrictions included in the capture system model by Mores et al. (2012a, 2011a,b, 2012b,c). In particular, the absorption column reaches the maximum available design capacity given by the adopted maximum feasible diameter, which is consequence of Eq. (6) becoming an active constraint.

5.3. Influence of Capture Train Efficiency in the Optimal Economic Performance (Case Study 3)

For the greenfield generation/capture project, a parallel configuration with four capture trains NTP is selected for analyzing its optimal economic performance when the inherent capture efficiency η_{CP} is parametrically varied across a wide range.

For this porpoise, the mathematical problem defined at Figure 3 is solved by minimizing the mitigation cost, fixing different values for the capture train efficiency η_{CP} (computed according to Eq. (14)) from 80% to 97.5%. As no flue gas bypass is allowed, note that the overall recovery rate η_{CO2} equals the inherent efficiency of the capture trains.

Amine regeneration and CO_2 compression are energy-intensive, regarding thermal and electrical requirements, respectively; and consequently, their energy penalties are particularly high. Figure 10 shows the distribution of the energy consumed by the capture plant, where its is observed that the average thermal penalty represents about 57.9% of the total energy penalty. Meanwhile, the optimal design implies an average penalty of 0.1814 MWh/tn in order to operate the capture system mechanical drives (i.e. compressors, pumps and blowers).

Figure 11a shows that the specific reboiler duty increases as the amount of CO_2 captured does, which also causes an increment on the amount of steam to be derived from the steam cycle towards such task. As consequence, Figure 11b shows the associated decrement of the net design capacity and thermal efficiency of the power plant.

For the four parallel trains arrangement without flue gas bypass, Figure 12 shows the influence of capture train efficiency in the coupled plant capital and operating expenditures, where it is observed that:

- Higher efficiencies at every capture train implies larger equipment for absorbing an increased amount of CO_2, requiring larger columns at the capture plant and higher consumption of steam and electricity. Thus, larger $HRSGs$ are also necessary at the power plant for accommodating the steam extraction requirements, while the boiler water consumption increases as well. Therefore, the capital and operating expenditures per unit of generated energy present an increasing trend respect to the capture unit inherent efficiency, as seen in Figure 12a.

- Economies of scale imply a decreasing trend of the capital investment per unit of CO_2 captured, as introduced at Figure 12b. It is also observed that the increased amount of CO_2 captured offsets the increased operating expenditures necessary for increasing the capture unit efficiency.

- In all cases, the operating expenditures represent about 2/3 of the total annualized costs. Similar costs distribution were found by Rao and Rubin (2006) at an amine-based capture system with 90% removal efficiency.

- On the average for the whole range of CO_2 recovery values, the gas turbines broaden 39.3% of the investment cost, followed by the steam cycle at the $NGCC$ (23.3%). Regarding the capture plant, 14.2% of the total capital investment goes to CO_2 absorption, 9.8% to CO_2 compression, 9.4% for MEA regeneration, and 4.0% for flue gas conditioning. This costs distribution is similar to the optimal one previously discussed at the *Reference Case*.

Figure 13 shows that the cost of electricity increases as the capture train efficiency does. In contrast, the mitigation cost presents a minimum value of 83.1 US$/tn at 95% of CO_2 recovery. Similar trends have also been observed by other authors (Abu-Zahra et al., 2007a; Rao and Rubin, 2006).

It is here observed that evolution of the total energy penalty originated by the operation of the capture plant strongly impacts on the aforementioned minimum values of the mitigation cost. Increasing the capture unit efficiency beyond the value associated with the minimum attainable carbon dioxide avoidance cost implies a rapidly increasing penalization on such economic indicator, as can be seen at Figure 10.

The increment of the mitigation cost when the capture efficiency is lowered below 95% turns this alternative increasingly economically unattractive from such perspective. Nevertheless, a reduction of the recovery efficiency is also accompanied by a diminution of the generated electricity cost, thus broadening the generator's profit margin.

6. Optimal Generation/Capture Project (Case Study 4)

Advantages and disadvantages of different options need to be economically weighted by the designer in order to determine which alternative to implement when achieving desired generation and capture goals. Thus, different tradeoffs need to be considered during the design stage of a capture-ready generation plant, including:

- Design capacity of capture trains is limited by technological constraints, such as size of commercially available equipment, materials resistance, maximum allowable temperatures for avoiding corrosion, among others. Economies of scale imply a deceleration on the growth of the capital cost of the absorption, desorption and compression stages as the equipment sizes increase.

- The design characteristics of a given capture unit, along the implemented operating policy, determines its inherent recovery efficiency. Thus, the decision variables at the capture plant should be optimized in order to accommodate the required level of CO_2 emissions reduction.

- A parallel arrangement of capture trains needs to be implemented if the volume of flue gas to be treated exceeds the capacity of a single recovery unit. In addition, these active redundancies will increase the system availability when operating at different derated states.

- Flue gas bypass can also be used when the operating capacity of a given parallel configuration has been exceeded, instead of adding an extra recovery train.

For this porpoise, the mathematical problem defined at Figure 3 is solved by minimizing the mitigation cost, selecting the capture train efficiency η_{CP}, CO_2 overall recovery η_{CO2} and the percentage of flue gas bypass as continuous (free) decision variables, as well as the number of parallel capture trains NTP as discrete (integer) decision variable, while also optimizing the design and operating variables of the generation and capture plants.

Flexibility and robustness of the here proposed approach are then highlighted as these previously parameterized variables are now set as decision variables during the economic optimization of the project, with no need of introducing further modifications in the mathematical model of the coupled plant.

At first glance, the optimal capture-ready plant is constituted by three identical trains, with an inherent recovery efficiency of 94.8%, where a portion of the flue gas is bypassed (13.4%), and the overall CO_2 emissions reduction reaches 82.1%.

This configuration of the sequestration system represents an improvement over every other optimal solution previously presented, as it makes better use of the installed capacity and requires lower overall operating expenses. Thus, it is observed in Table 8 that a 2.8% reduction of the mitigation cost is here accomplished when compared with the *Reference Case*, driven by a diminution of the total expenditures of the joint project.

These trends are also reflected in the costs distribution of the project, listed at Table 9. Power law for the costs computation of the absorption, regeneration and compression stages implies a decrease of the capital investment, as fewer capture trains constituted by larger pieces of equipment are necessary. As well, the capture plant incurs in lower operating costs while every recovery unit more efficiently utilizes the available resources.

Tables 10 and 11 report the optimal values of the design and operating variables of the power and capture plants, respectively. It is noteworthy that no penalization is imposed on the amount of emitted CO_2, thus the design of the joint project on its economic optima (driven by the minimization of the avoidance cost) implies an increment on the emissions rate with respect to the *Reference Case*. It is also verified that the design capacity of every piece of equipment at each capture train increases closely up to the maximum commercially available size, while readjusting the flow rate, compositions, pressure drop and temperature level of every process stream.

At the optimal solution, it is observed that different variables reach their lower or upper bound, as their associated inequality constraint becomes active:

- Economies of scale imply a lower capital cost and the better utilization of the installed capacity as the absorption column diameter gets to their maximum allowable size, given by Eq. (6).

- As the flue gas temperature decreases, the chemical absorption rate increases. As consequence, the inlet gas temperature reaches the lower bound (Eq. (7)).

- Increasing the operating pressure of the stripper leads to a reduction in the thermal energy requirement of the stripping process, and implies a lower compression work. Then, the stripper pressure always reaches the upper bound (Eq. (8)).

In order to provide additional sensitivity information for the optimal solution, the KKT multipliers of the critical variable bounds and constraints are reported at Tables 10 and 11. It is observed that the perturbations in the technical bounds that define the operating window (either due to technological developments or inadequate assumption in the cited literature) will cause the optimal solution to change. As a self-consistency check, the KKT multipliers also match the slope of objective function versus the capture efficiency trend for the parameter sweeps in all the case studies.

It is then observed that the equations-oriented optimization model here implemented allows dealing with the large number of degrees of freedom associated with the formulation of a new capture-ready generation project. This complex and rigorous strategy can only be dealt with a mathematical programming approach implemented in state-of-the-art optimization software where the consequences of discrete and continuous decisions associated with the determination of the design characteristics and the operating policy for both plants can be simultaneously weighted.

7. Conclusions

A mathematical model is here formulated aiming at the optimization of the design and operating characteristics when facing the challenge of building capture-ready generation systems from the ground up. While meeting external requirements at minimum cost, greenfield designs constitute a key enhancement when tackling the emissions reduction issue as required by increasingly restrictive international treaties and countries environmental regulations.

Three parametric optimization options for coupling a MEA capture system to a *NGCC* power plant are here thoroughly analyzed. The comprehensive and rigorous models for the generation and capture plants, along the proposed coupling strategy between both systems, allows obtaining a detailed insight on the design characteristics and operating policy which will ultimately secure optimal values of the project economics.

This discussion highlights novel possibilities for further improving the economic performance of the whole project (respect to the simulation or partial optimization approaches previously presented in the literature), which must be pursued through a comprehensive equations-oriented mathematical strategy which simultaneously considers discrete and continuous decisions within the optimization formulation. This proposed strategy thus renders a novel configuration for the option of adding a MEA based capture system to the $NGCC$ power plant, which optimally delivers 731 MW of electric energy while the CO_2 on the flue gas is recovered by three parallel units with a 94.8% of inherent efficiency, 13.4% of flue gas bypass and an overall recovery goal of 82.1%.

While simultaneously considering the different feasible economic tradeoffs, the proposed equations oriented approach delivers a joint project at the preliminary design stage with a minimum value of mitigation cost of 81.7 US$ per tonne of CO_2 captured, thus securing economically attractive values for the financial performance indexes.

Considering the proposed model and using the optimal solutions here obtained as a starting point, further improvement on the technical and economic characteristics of the capture-ready generation plant can be achieved in future works when considering additional features of the problem at hand. Particularly, a continuation of this work will study the influence exerted over the optimal joint plant when considering different availability and maintenance criteria across the whole range of feasible scenarios that the system has to deal with (by means of a state-space approach).

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A. Considerations about the Modelling Strategy of the Coupled Plant

Modeling Aspects

Regarding the power plant, the following modeling aspects are taken into account:

- The design of the power plant implies determining the size and operating characteristics of every exchange section at the HRSGs. A fixed configuration is adopted at both HRSGs (considering the ones used by Bassily (2007); Franco and Casarosa (2002); Franco and Giannini (2006)). Thus, their optimization implies maximizing the recovered heat while considering the pinch and approach temperatures of the system.
- The steam turbine is designed for the flow rate that effectively circulates through every pressure level (once the low pressure steam required by the capture plant has been derived). Performance maps provided by turbines manufacturers are used to correlate the isentropic efficiency and the flow capacity as a function of the compression ratio and rotational speed (Bahadori and Vuthaluru, 2010; Martelli et al., 2011), for given turbine size.

Regarding the capture plant, the following modeling aspects are taken into account:

- Packing for absorber and stripper columns is assumed as "Ceramic Intalox Saddles".
- There is no concentration and temperature gradients in single liquid and gas phases (well-mixed).
- Chemical reactions take place at the liquid phase. Their effect on the CO_2 transfer is considered by an enhancement factor.
- CO_2, MEA and H_2O are the species transferred across the interface.
- The condenser and reboiler are modeled as equilibrium stages. The condenser reflux and stripping gas are fed in the top and the bottom stages respectively.
- The number of compressor stages for CO_2 disposal is assumed to be 4 (based on a 450 K maximum temperature limit and a maximum compression ratio of 3, which are here considered as inequality constraints for designing the required compressor), and the final compression pressure is fixed at 8600 kPa. Then, the CO_2 concentrated stream (dense phase) is pumped to its final disposal pressure fixed at 138.2 atm (Fisher et al., 2005; Rao and Rubin, 2002, 2006).

Technical Constraints

In order to circumscribe a feasible operating region, technical limits and manufacturers recommendations are considered by means of inequality constraints.

Regarding the power plant:

- Minimum and maximum approach point (5 K and 15 K, respectively), to guarantee no water evaporation in the economizers and to avoid thermal shock at evaporator entries, respectively.
- Minimum and maximum pinch point (5 K and 15 K, respectively), to secure reasonable practical values of the $HRSG$ heat transfer area.
- Maximum steam pressure for each operating pressure level at the $HRSG$ (120 atm for high pressure, 45 atm for intermediate pressure, 5 atm for low pressure, 1.5 atm for deaerator, 0.15 atm for condenser), to assure operation within normal parameters.
- Minimum operating pressure of the condenser (0.05 atm), fixed by minimum temperature of available cooling water.
- Maximum gas temperature at $HRSG$ inlet (900 K), to prevent materials deterioration.
- Minimum gas pressure at $HRSG$ discharge (1.005 atm), to assure operation within normal parameters.
- Minimum gas temperature at $HRSG$ discharge (360 K), to prevent corrosion due to water condensation.
- Minimum temperature difference at superheater exit (30 K), to assure operation within normal parameters.
- Minimum temperature difference at condenser (4 K), to avoid excessive cooling water consumption.
- Minimum temperature difference at regenerator exit (40 K), to assure adequate operating parameters.
- Minimum and maximum steam quality at steam turbine discharge (0.92 and 0.97, respectively), to achieve normal operation of the turbine.

Regarding the capture plant:

- Minimum and maximum values for the superficial gas velocity, by considering restrictions on the flooding factors (0.7 and 0.8, respectively) suggested in the technical literature (Kister, 1992; Seider et al., 2009).

- Minimum and maximum permissible column pressure drops per unit of packing height (20 Pa/m and 1000 Pa/m, respectively), to ensure a minimum vapor rate to avoid laminar vapor flow and vapor mal-distribution (Green, 2008; Kister, 1992).

- Minimum amine flow-rate (as a function of fluid properties and packing characteristics, according to the correlations given by Kister (1992)), to ensure a minimum wetting rate recommended for the packing manufacturer.

- Minimum and maximum bounds for the difference between the lean solvent temperature and the rich solvent temperature (5 K and 15 K, respectively). In most papers works, this temperature difference is fixed at a given value, although it is here an optimization variable.

- Maximum reboiler temperature (393 K), to avoid amine degradation and equipment corrosion.

- Minimum columns diameters (10 times the packing nominal diameter) and maximum columns diameters (12.8 m), to secure practical dimensions (Chapel et al., 1999; Seider et al., 2009).

Model Technical Parameters

The technical parameters, necessary for completing the generation/ capture model, are listed in Table 12.

B. $CAPEX$ and $OPEX$ Calculation

A description of the equations used for computing the capital and operating expenditures is here presented.

Capital Expenditures

Total investment cost C_{Inv} is determined as the sum of individual equipment costs $C_{Inv,PE}$ of the power plant (i.e. $PE \subset PP$) and the capture system (i.e. $PE \subset CP$), according to Eq. (B.1).

$$C_{Inv} = C_{Inv,PP} + C_{Inv,CP} = \sum_{PE \subset PP} C_{PE,PP} + NTP \sum_{PE \subset CP} C_{PE,CP} \tag{B.1}$$

The total investment on fix capital $CAPEX$ is also related (besides equipment acquisition) to the design and construction of the necessary facilities and auxiliary services; thus the total equipment acquisition cost is affected by an investment factor F_{Inv} in order to consider such expenditures, as given at Eq. (B.2). Specific values here assumed for the economic indexes when computing capital expenditures are listed in Table 13 according to the guidelines given at Abu-Zahra et al. (2007a); Rao and Rubin (2002).

$$CAPEX = F_{Inv}\, C_{Inv} \tag{B.2}$$

The recovery factor CRF which affects the investment on fix capital is computed by Eq. (B.3), for a given interest rate i and life span n.

$$CRF = \frac{(i+1)^n - 1}{i\,(i+1)^n} \tag{B.3}$$

The acquisition cost of a given piece of equipment $C_{Inv,PE}$ depends upon its size X_{PE} and constructive characteristics, and is computed by Eq. (B.4).

$$C_{PE,j} = C^0_{PE} (X_{PE,j})^{a_{PE}} \quad , \quad j = PP, CP \tag{B.4}$$

where the exponential coefficient (a_{PE}) is assumed equal to one for turbines and equal to 0.6 for the capture plant equipment and $HRSGs$. On the other hand, the reference costs (C^0_{PE}) are computed by correlations reported in the literature (Henao, 2005; Matches, 2013; McCollum and Ogden, 2006; Nye Thermodynamics Corporation, 2013; Seider et al., 2009; U.S. Energy Information Administration, 2010), and Table 14 lists all the pieces of equipment considered in the capital investment computation. Note that unit investment costs have been updated considering the 2012 CEPCI index.

Operating Expenditures

Operating expenditures $OPEX$ get computed as given at Eq. (B.5). The calculation includes raw materials and utilities C_{RM}, maintenance C_{Mant}, man power C_{MP}, and other costs related to these previous ones. Specific values here assumed for the economic indexes F_{O1} and F_{O2} are listed in Table 15 according to the guidelines given at Abu-Zahra et al. (2007a); Rao and Rubin (2002).

$$OPEX = C_{RM} + C_{Mant} + F_{O1}\ C_{MP} + F_{O2}\ C_{Inv} \tag{B.5}$$

Total cost of raw materials and utilities C_{RM} is computed by Eq. (B.6), where POT is the plant operating time; $C_{PS,j}$ refers to the raw material or utility price and $\dot{m}_{PS,j}$ denotes the flow rate (annual basis) of each process stream (PS).

$$C_{RM} = C_{RM,PP} + C_{RM,CP} = \sum_{PS \subset PP} POT\ C^0_{PS} \dot{m}_{PS,PP} + NTP \sum_{PS \subset CP} POT\ C^0_{PS} \dot{m}_{PS,CP} \tag{B.6}$$

The process streams associated to the power plant (i.e. $PS \subset PP$) include fuel, cooling water and boiler water; while the ones associated to the capture plant (i.e. $PS \subset CP$) consider steam, cooling water, process water and MEA.

The nominal loss of MEA is assumed at 1.5 kg per tonne of captured CO_2 (Fisher et al., 2005; Rao and Rubin, 2006). An extra 20% is added in top of that to consider the inhibitor cost (Rao and Rubin, 2002).

Up-to-date fuel cost is obtained from U.S. Department of Energy (2013); MEA cost is taken from Rao and Rubin (2002). On the other hand, utility costs are estimated according to the guidelines introduced by Ulrich and Vasudevan (2006), where unit costs (C_{PS}) are computed from Eq. (B.7).

$$C^0_{PS} = a_{PS} + b_{PS}\ C^0_F \tag{B.7}$$

where C^0_F denotes the fuel cost; while a_{PS} and b_{PS} coefficients are listed in Table 16.

Traditional economic evaluation approach estimates maintenance costs C_{Mant} as a fix percentage F_{Mant} of the capital investment, according to Eq. (B.8).

$$C_{Mant} = F_{Mant}\ C_{Inv} \tag{B.8}$$

Man power costs C_{MP} consider the administrative, technical and operating personnel necessary at both plants, according to Eq. (B.9).

$$C_{MP} = F_{MP}\ N_{MP} \tag{B.9}$$

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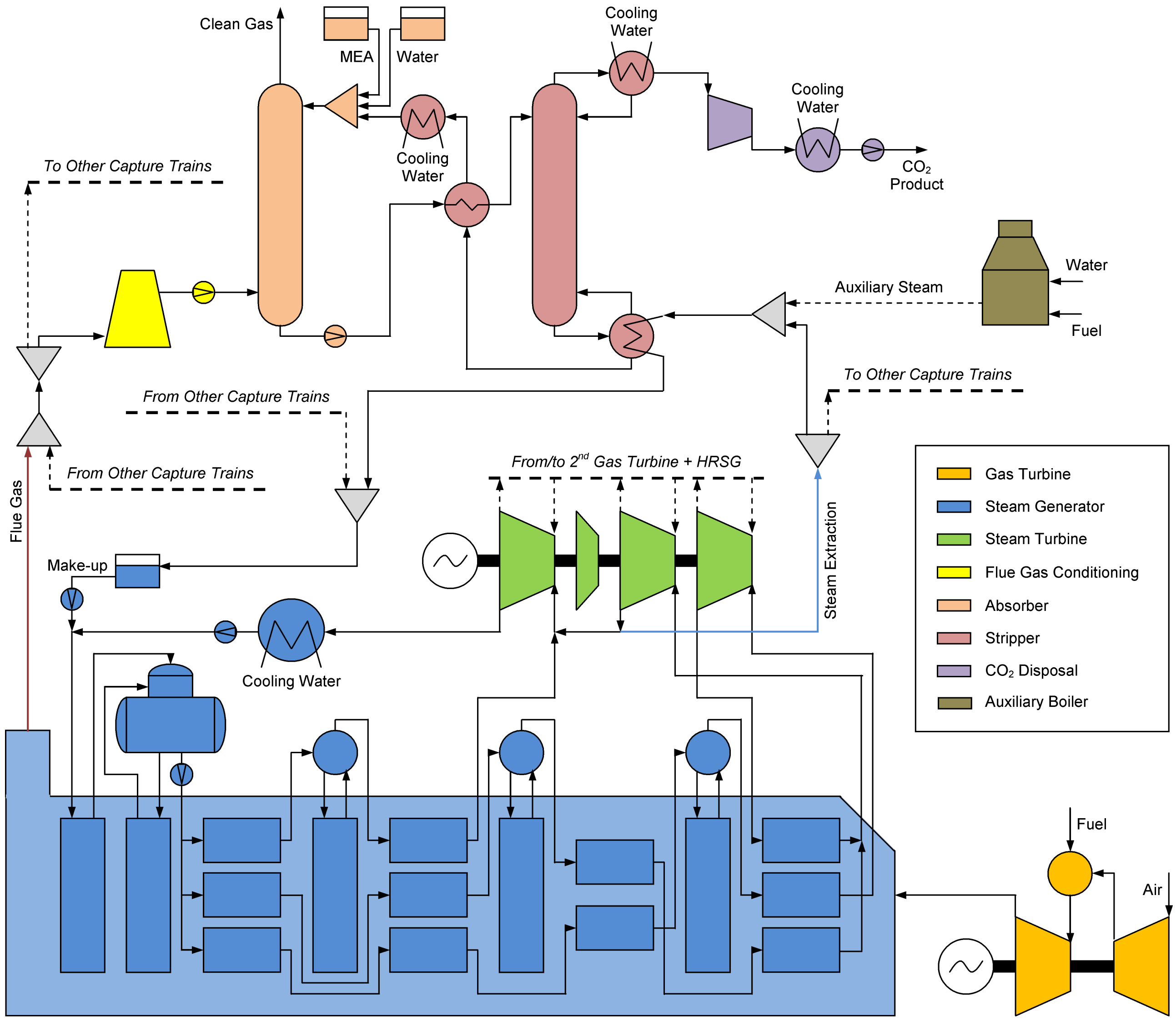


Figure 1: Configuration of the Coupled Plant

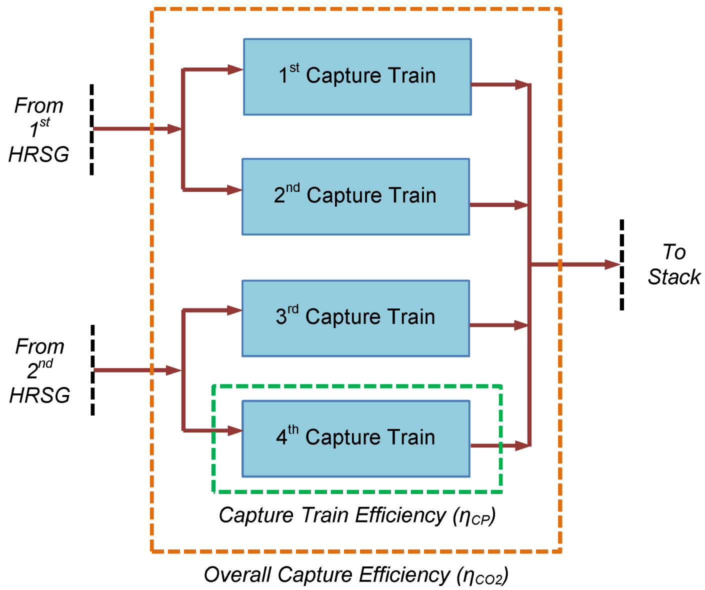


Figure 2: Definition of Recovery Efficiency

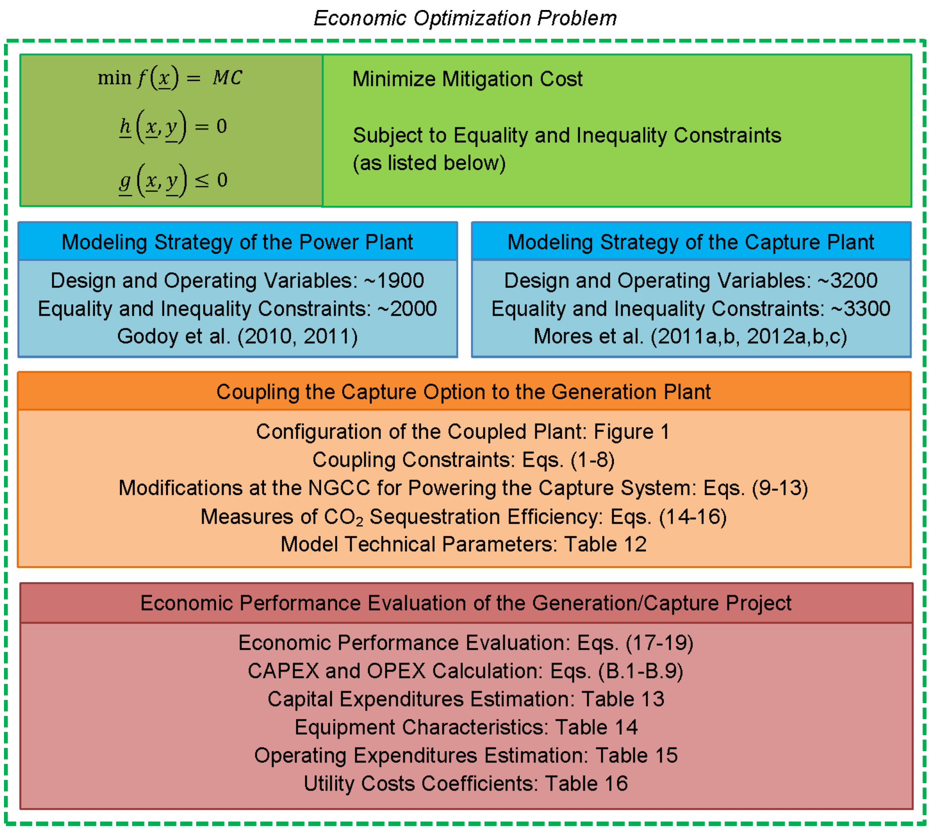


Figure 3: Economic Optimization Problem

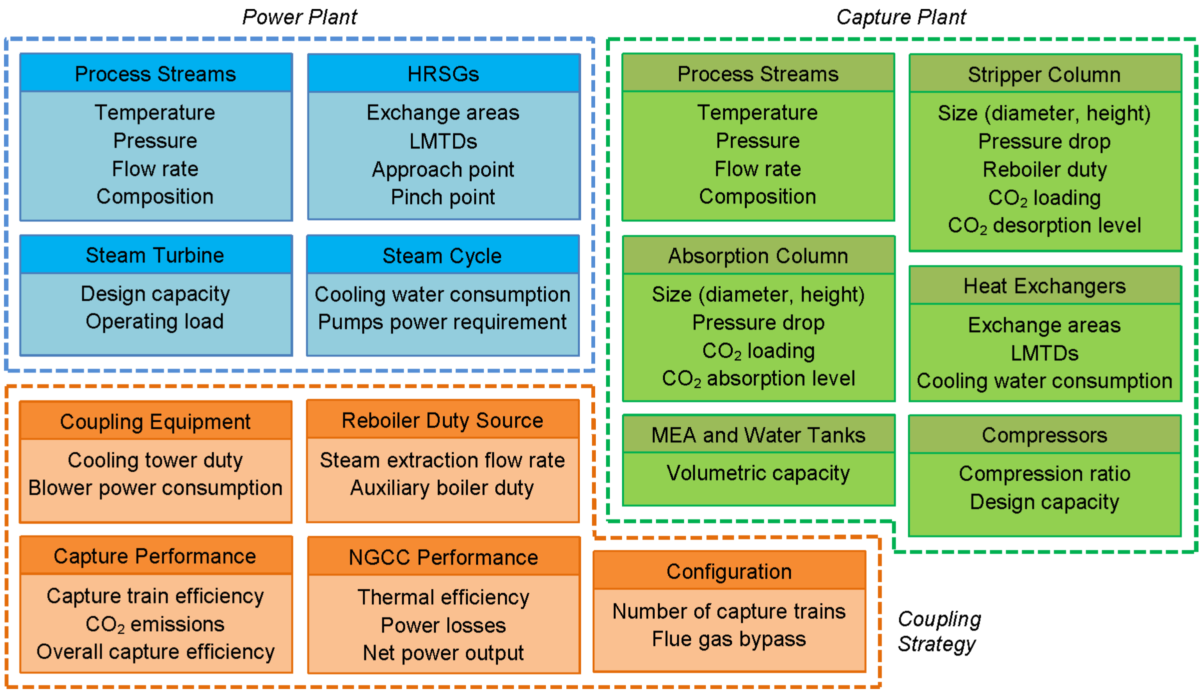


Figure 4: Design and Operating Variables

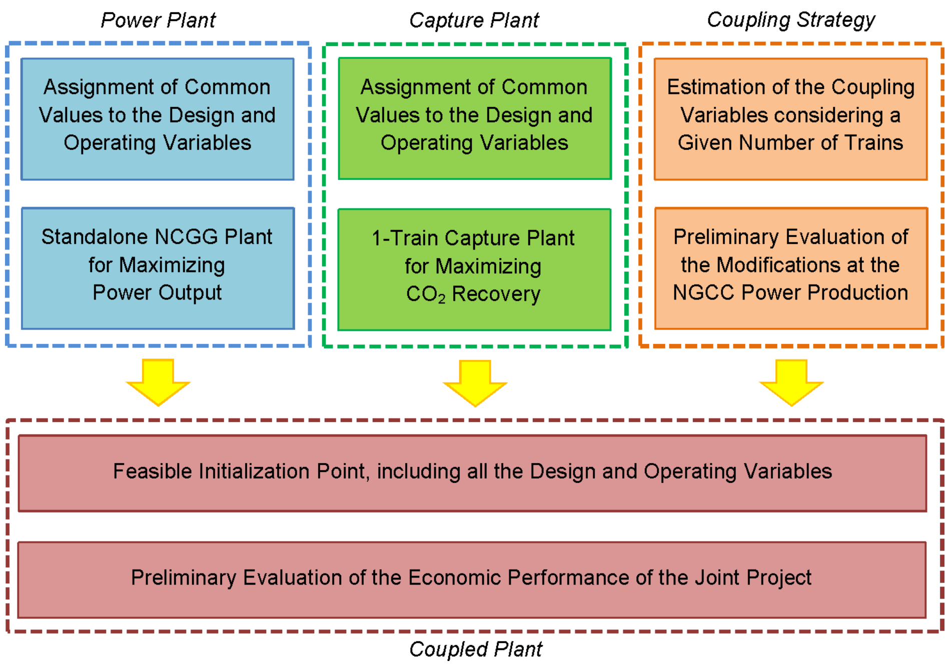


Figure 5: Initialization Strategy

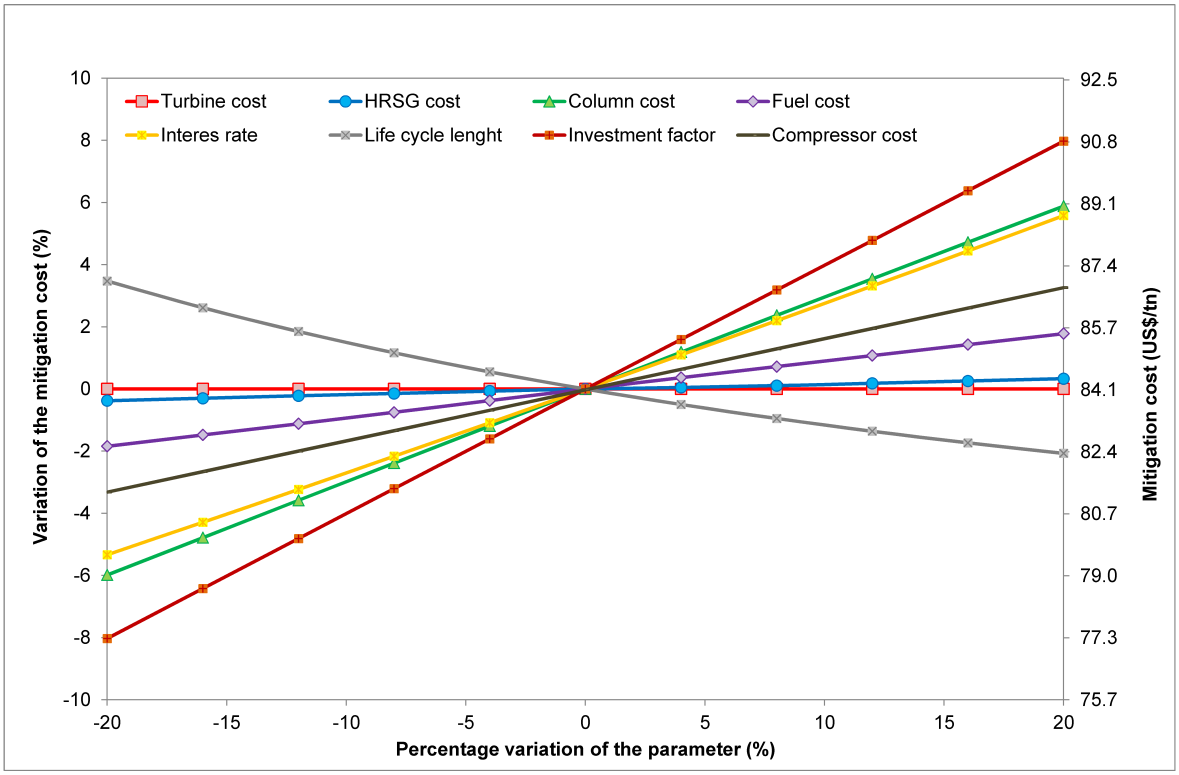


Figure 6: Economic Sensitivity Analysis

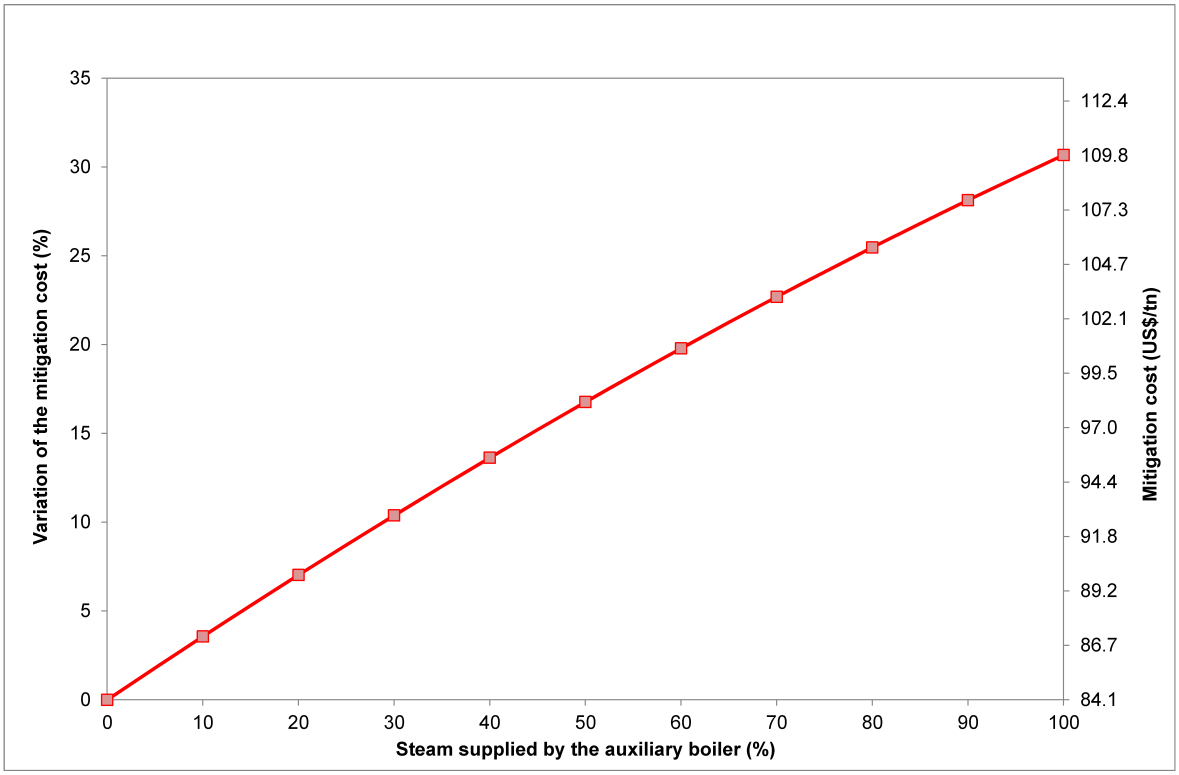
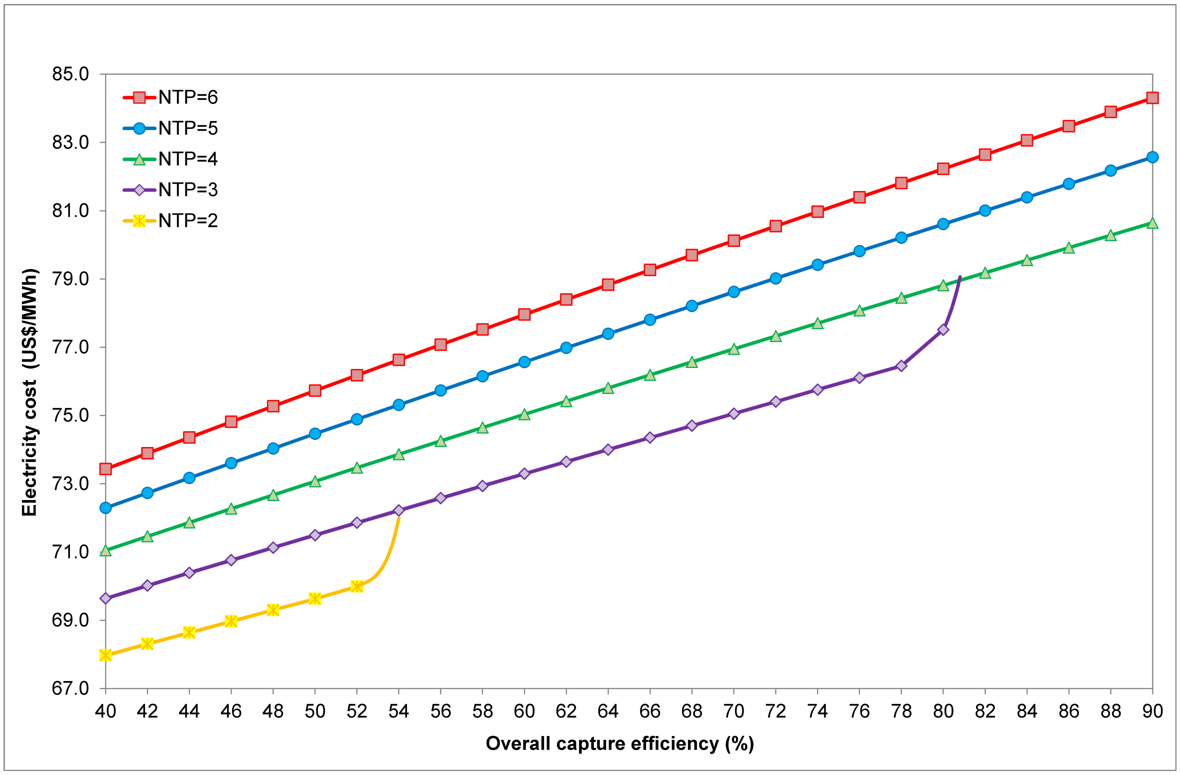
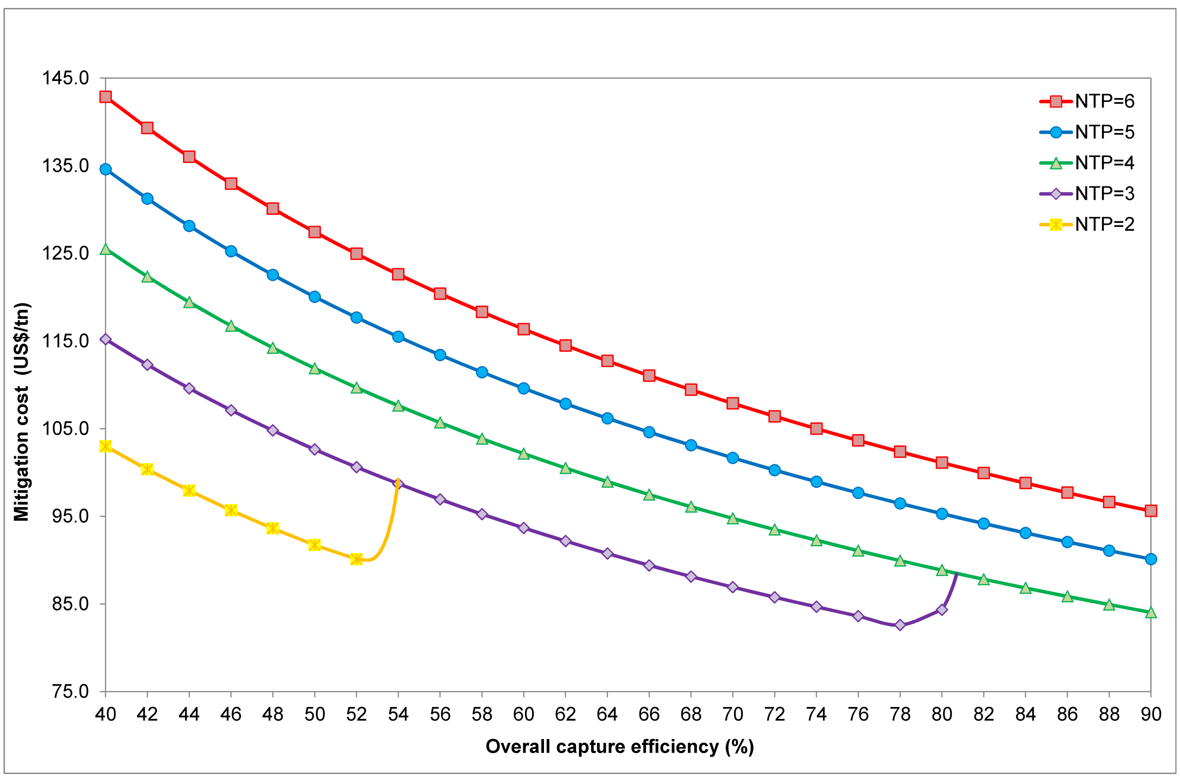


Figure 7: Sensitivity Analysis for the Percentage of Steam Generated at the Auxiliary Boiler



(a) Electricity Cost



(b) Mitigation Cost

Figure 8: Electricity and Mitigation Costs as Function of the Overall Capture Efficiency and Number of Parallel Capture Trains

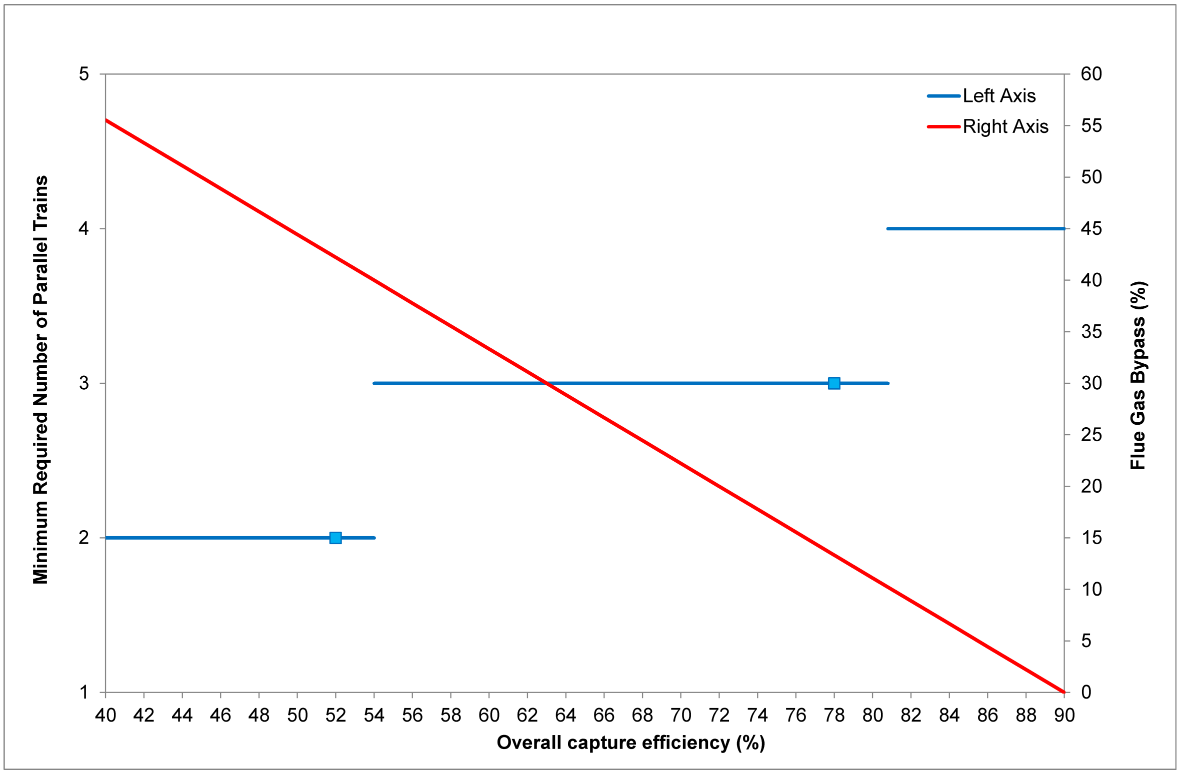


Figure 9: Minimum Required Number of Parallel Trains as Function of the Overall Capture Efficiency

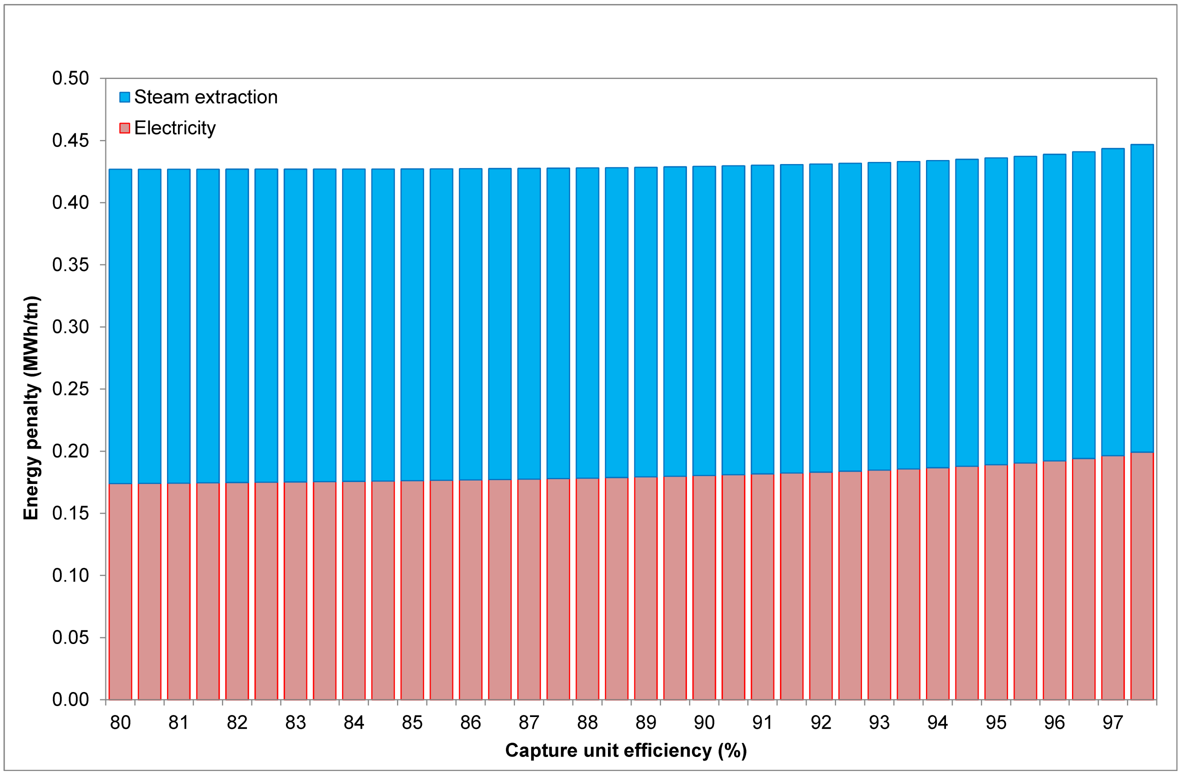
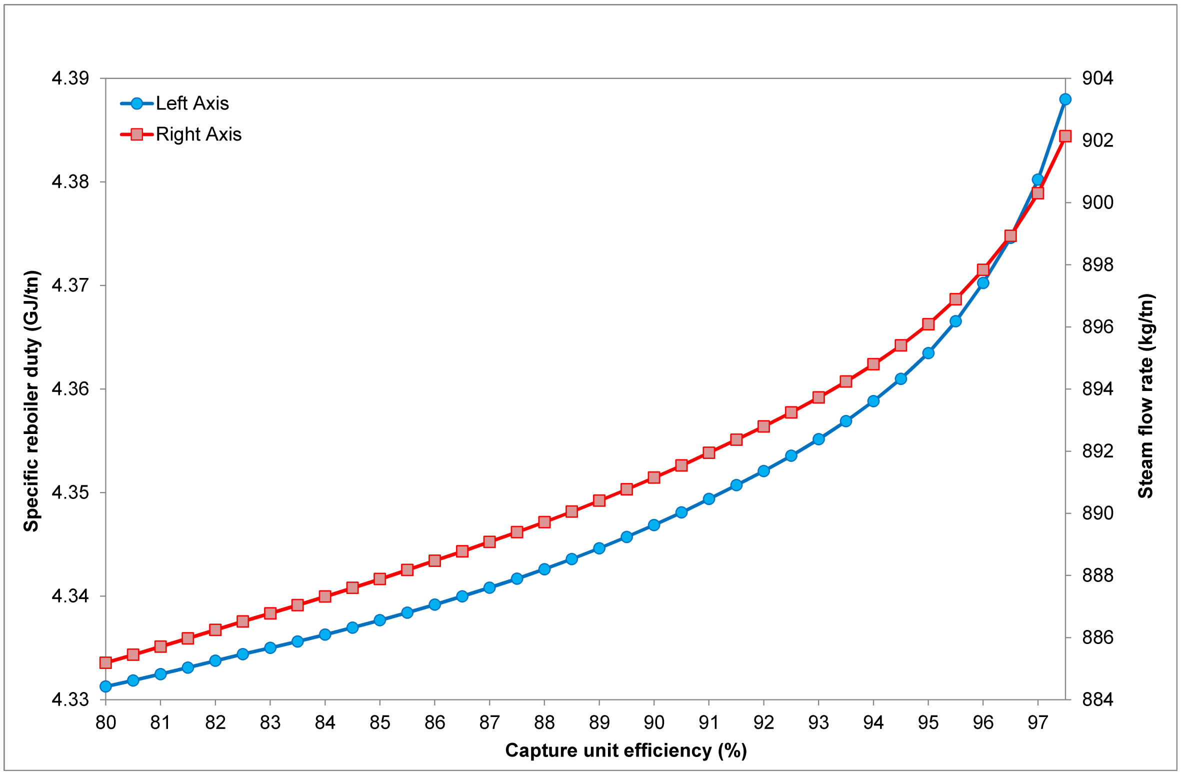
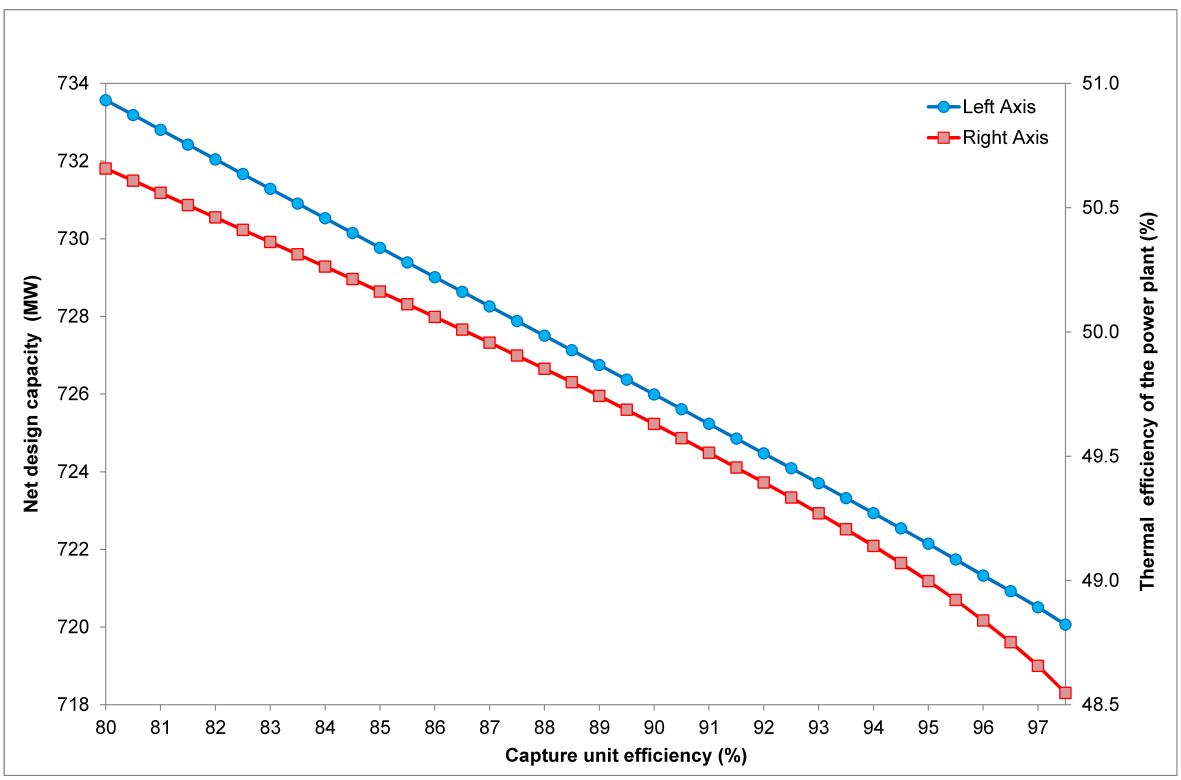


Figure 10: Energy Penalties as Function of the Capture Train Efficiency

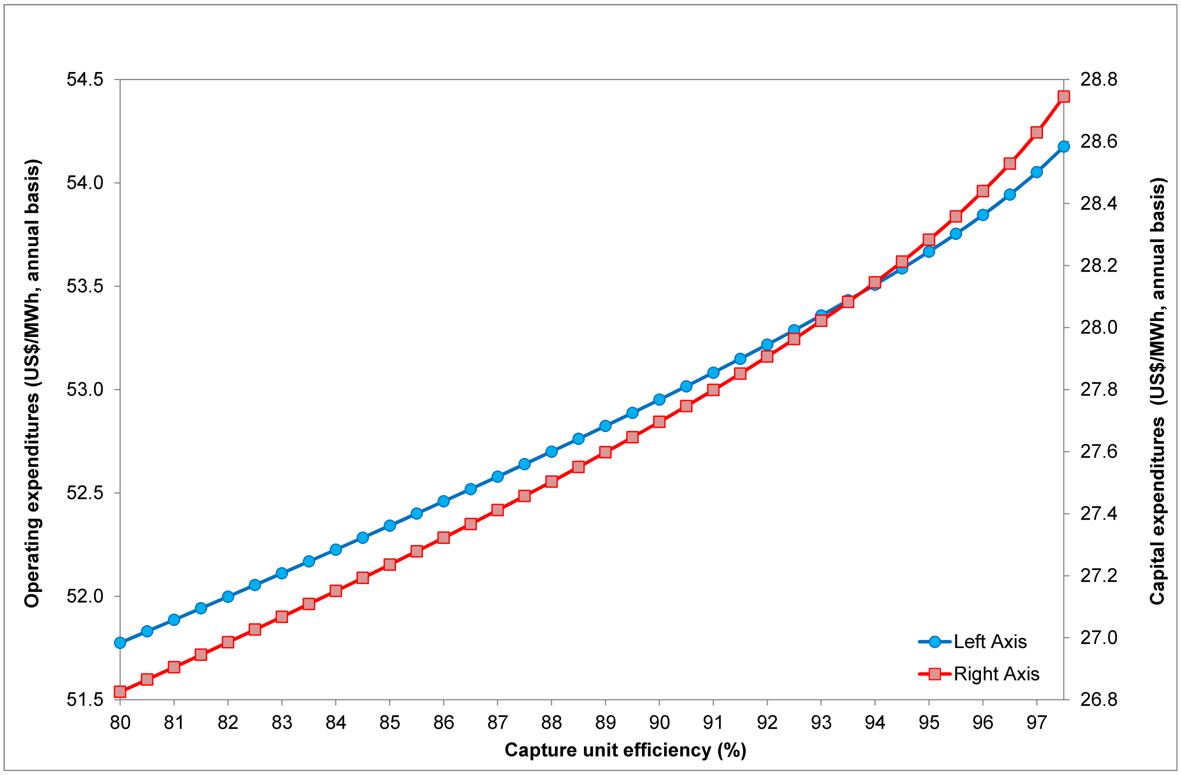


(a) Specific Reboiler Duty and Steam Flow Rate

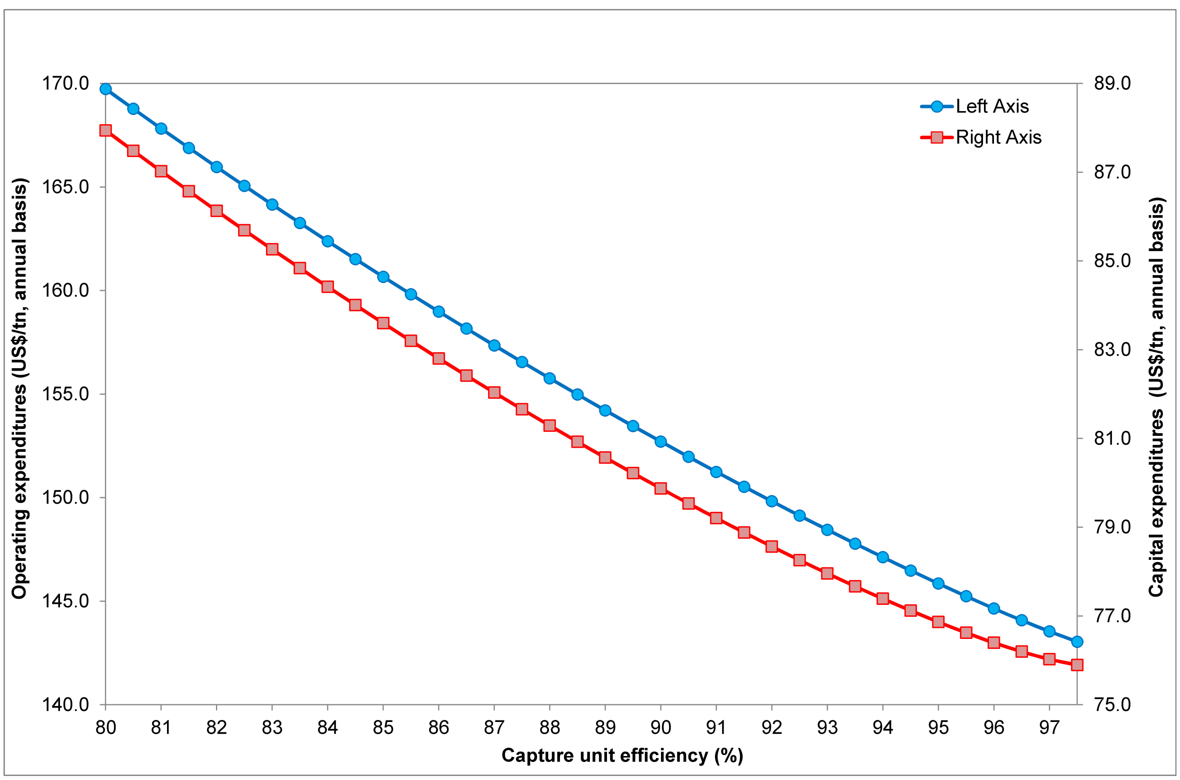


(b) Total Generation Capacity and Thermal Efficiency of the Power Plant

Figure 11: Technical Performance as Function of the Capture Train Efficiency



(a) Per Unit of Generated Energy



(b) Per Unit of CO_2 captured

Figure 12: Capital and Operative Expenditures as Function of the Capture Train Efficiency

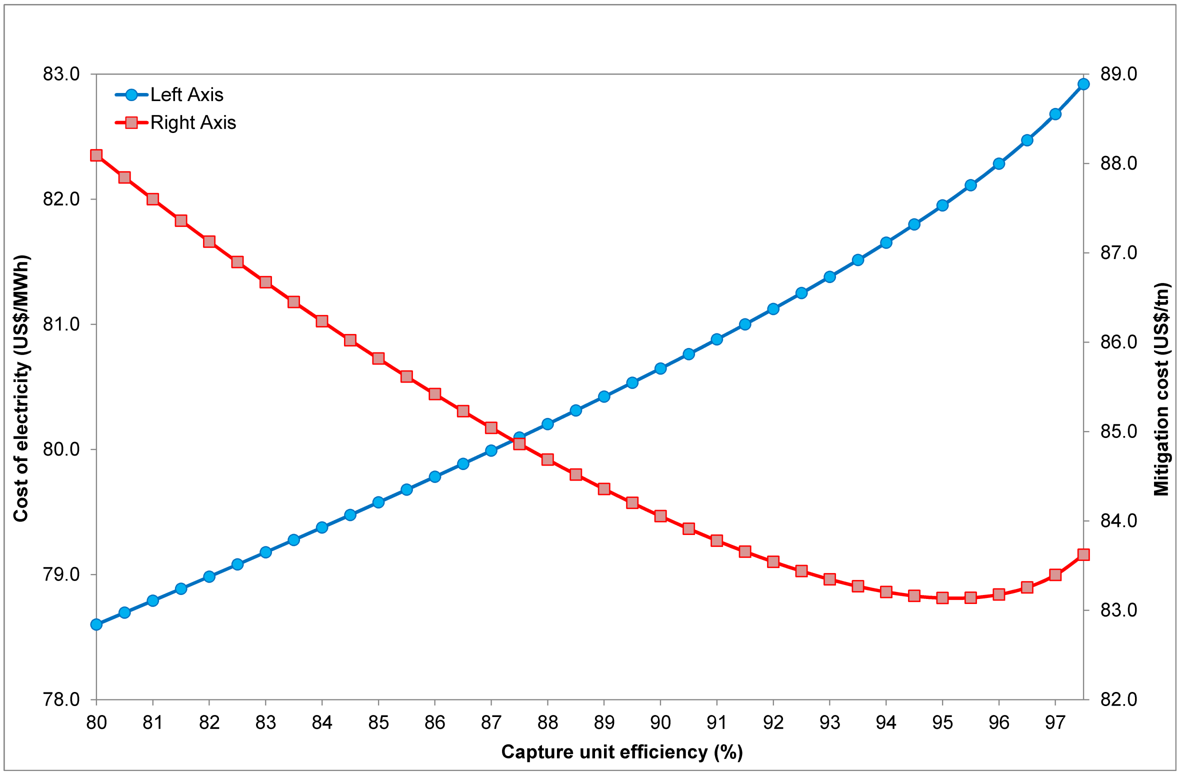


Figure 13: Electricity and Mitigation Costs as Function of the Capture Train Efficiency

List of Tables

Table 1: Definition of Case Studies

		Case Study 1	Case Study 2	Case Study 3	Case Study 4
Type of mathematical problem		NLP	NLP	NLP	MINLP
Number of capture trains (*NTP*)		4	2-6 (parameterized)	4	decision variable (integer)
CO_2 overall capture goal (η_{CO2})	%	90	40-90 (parameterized)	free	decision variable (continuous)
CO_2 capture unit efficiency (η_{CP})	%	90	90	80-97.5 (parameterized)	decision variable (continuous)
Flue gas bypass	%	0	free	0	decision variable (continuous)

Table 2: Economic Parameters for Case Study 1

Interest rate	i	%	8.0
Life cycle span	n	y	25
Total operating time	POT	days/y	8000
Maintenance factor	F_{Mant}	-	0.02
MEA cost	C^0_{MEA}	US$/tn	1858
Fuel cost	C^0_F	US$/GJ	3.318
Manpower equivalent factor	F_{MP}	-	$3.0 . 10^5$
Manpower equivalent number	N_{MP}	-	75.75

Table 3: Optimal Economic Indicators for Case Study 1

		Standalone NGCC	NGCC+Capture at Case Study 1
Total annual cost (*TAC*)	MUS$/y	341	468
Operative expenditures (*OPEX*)	MUS$/y	234	308
Capital expenditures (*CAPEX*)	MUS$	1144	1717
Cost of electricity (*COE*)	US$/MWh	54.1	80.7
Mitigation cost (*MC*)	US$/tn	-	84.1

Table 4: Optimal Costs Distribution for Case Study 1

		Standalone NGCC	NGCC+Capture at Case Study 1
Raw material and utility cost *(C_{RM})*	MUS$/y	150.8	182.3
Fuel	MUS$/y	131.0	131.0
Boiler water	MUS$/y	5.8	28.5
Cooling water	MUS$/y	14.0	16.0
MEA make up and inhibitor	MUS$/y	-	6.7
H_2O make up	MUS$/y	-	0.1
Operating manpower cost *(C_{MP})*	MUS$/y	1.3	2.3
Maintenance cost *(C_{Mant})*	MUS$/y	4.6	6.9
Equipment acquisition cost *(C_{Inv})*	MUS$	228.8	343.4
Gas turbines	MUS$	134.9	134.9
Steam turbine	MUS$	68.6	52.6
Absorber columns	MUS$	-	46.9
Compressors	MUS$	-	31.1
Heat recovery steam generators	MUS$	25.3	27.1
Reboiler	MUS$	-	9.9
Blowers	MUS$	-	9.19
Stripper columns	MUS$	-	9.16
Amine amine exchangers	MUS$	-	7.8
Cooling towers	MUS$	-	4.5
Condensers	MUS$	-	3.6
Amine water exchangers	MUS$	-	2.2
CO_2 pumps	MUS$	-	1.5
Intercoolers	MUS$	-	1.3
H_2O tanks	MUS$	-	1.3
MEA tanks	MUS$	-	0.2
MEA pumps	MUS$	-	0.2

Table 5: Comparison with Other Authors

		Case Study 1 (this work)	**Sipöcz and Tobiesen (2012)**	**Abu-Zahara et al. (2007a,b)**	**Fisher et al. (2005)**	**Rao and Rubin (2002)**
Type of design problem	-	New plant	New plant	NI	Retrofit	New plant
Fuel type	-	Natural gas	Natural gas	Coal	Coal	Coal
Net power of the reference power plant	MW	788	411	575	453	462
Net plant capacity (w/ CO_2 capture)	MW	681	375	426	281	326
Flue gas CO_2 molar fraction	-	0.0399	0.042	0.0812	0.1233	NI
Flue gas flow rate	kmol/s	44.4	22.9	22.4	23.6	NI
CO_2 capture rate	%	90	90	90	90	90
CO_2 captured	10^6 tn/y	2.01	1.08	1.95	3.11	2.58
CO_2 compression pressure	MPa	8.6	6.0	NI	8.6	7.5
CO_2 final disposal pressure	MPa	14.0	20.0	11.0	13.9	13.8
Type of compressor	-	four-stage intercooled	six-stage intercooled	NI	four-stage intercooled	four-stage intercooled
Type of packing	-	Ceramic Intalox Saddles (random)	Sulzer Mellapack 250 (structured)	Mellapak Y125 (structured)	Cascade mini rings #2 (random)	Raschig rings, metallic #1 (random)
Number of capture trains	-	4	NI	NI	4	NI
Capture plant total cost	US$/tn	33.1	NI	24.7 (18.1*)	15.5	NI
Cost of electricity	US$/MWh	80.7	107.7 (80.3*)	76.3 (56*)	63.2	97.0
Mitigation cost	US$/tn	84.1	133.8 (99.7*)	50.4 (37*)	44.9	59.1

* Original reported values in €, converted to US$ considering http://www.xe.com

NI: value not informed

Table 6: Optimal Values of Design and Operating Variables for Case Study 1 - Power Plant

		Standalone NGCC	NGCC+Capture at Case Study 1
Power plant net generation capacity	MW	788	726
Power available for external demand satisfaction	MW	788	681
Electric energy for capture plant powering	MW	-	45
Gas turbine design capacity	MW	522	522
Steam turbine design capacity	MW	266	204
Thermal efficiency	%	57.5	49.6
Gas turbine parameters			
Fuel	kmol/s	0.82	0.82
Compression ratio	-	15.4	15.4
Turbine inlet temperature	K	1547	1547
Steam extraction			
Flow rate	kg/s	-	62.3
Temperature	K	-	408
Equivalent power	MW	-	62.6
Steam turbine flow rate			
Low pressure section	kg/s	98.6	38.3
Intermediate pressure section	kg/s	88.3	88.6
High pressure section	kg/s	67.5	71.9
Specific transfer area	m^2/MW	514	611
HRSG exchange area	dam^2	3907	4382
Deaerator	%	16.9	9.8
Low pressure section	%	18.8	22.8
Intermediate pressure section	%	23.8	21.7
High pressure section	%	40.4	45.7
HRSG operative pressure			
Deaerator section	MPa	0.152	0.152
Low pressure section	MPa	0.244	0.308
Intermediate pressure section	MPa	1.727	2.810
High pressure section	MPa	12.16	12.16
Reheater	MPa	1.727	2.810
Raw material and utility consumption			
Cooling water	kg/s	22.9	13.8
Boiler water	kg/s	0.8	1.6

Table 7: Optimal Values of Design and Operating Variables for Case Study 1 - Capture Plant (per train)

		NGCC+Capture at Case Study 1
Total heat exchange area	dam^2	1631
Reboiler area fraction	%	30.5
Condenser area fraction	%	19.2
Amine-amine exchanger area fraction	%	37.9
Amine-water area fraction	%	8.7
Inter-stage coolers area fraction	%	3.7
Logarithmic mean temperature difference		
Reboiler	K	14.1
Condenser	K	41.7
Amine-amine exchanger	K	13.8
Amine-water exchanger	K	20.7
Absorption column characteristics		
Diameter	m	11.9
Packing height	m	30.6
Gas flow rate	kmol/s	11.1
CO_2 molar fraction (flue gas stream)	-	0.0399
Gases temperature at absorber inlet	K	318
Gases temperature at absorber outlet	K	328
Pressure drop	kPa	15.6
Solvent flow rate	kmol/s	12.41
Amine temperature at absorber inlet	K	316
CO_2 loading	-	0.1587
Stripper column characteristics		
Amine temperature at stripper inlet	K	381
Amine temperature at reboiler outlet	K	395
Diameter	m	4.2
Packing height	m	8.2
Pressure drop	kPa	1.94
Specific reboiler duty	GJ/tn	4.35
CO_2 loading	-	0.4506
Reboiler operating pressure	kPa	200
Compression stage		
CO_2 compression work	MW	5.92
Compression ratio	-	2.57
Flue gas temperature at cooling tower exit	K	303
Process water consumption	m^3/s	1.31
Condenser	%	61.3
Amine water exchanger	%	25.4
Intercoolers	%	10.3
Cooling tower	%	2.9
MEA consumption	kg/s	0.0262
Low pressure steam consumption	kg/s	32.01
Electric energy consumption	MW	11.36
Amine pumps	%	0.3
Blowers	%	45.9
Compressors	%	52.1
CO_2 pumps	%	1.8

Table 8: Optimal Economic Indicators for Case Study 4

		NGCC+Capture at Case Study 4	Difference with Case Study 1 (%)
Total annual cost (*TAC*)	MUS$/y	453	-3.2
Operative expenditures (*OPEX*)	MUS$/y	300	-2.4
Capital expenditures (*CAPEX*)	MUS$	1634	-4.9
Cost of electricity (*COE*)	US$/MWh	77.5	-4.0
Mitigation cost (*MC*)	US$/tn	81.7	-2.8

Table 9: Optimal Costs Distribution for Case Study 4

		NGCC+Capture at Case Study 4	Difference with Case Study 1 (%)
Raw material and utility cost *(C_{RM})*	MUS$/y	181.4	-0.4
Fuel	MUS$/y	131.0	0.0
Boiler water	MUS$/y	28.5	-0.2
Cooling water	MUS$/y	15.7	-1.6
MEA make up and inhibitor	MUS$/y	6.1	-8.8
H_2O make up	MUS$/y	0.1	-1.4
Operating manpower cost *(C_{MP})*	MUS$/y	2.0	-11.1
Maintenance cost *(C_{Mant})*	MUS$/y	6.5	-4.9
Equipment acquisition cost *(C_{Inv})*	MUS$	326.7	-4.9
Gas turbines	MUS$	134.9	0.0
Steam turbine	MUS$	54.0	2.7
Absorber columns	MUS$	39.4	-16.1
Compressors	MUS$	26.2	-15.6
Heat recovery steam generators	MUS$	27.0	-0.1
Reboiler	MUS$	8.6	-13.2
Blowers	MUS$	9.3	1.1
Stripper columns	MUS$	8.0	-13.1
Amine amine exchangers	MUS$	6.3	-19.2
Cooling towers	MUS$	4.4	-1.6
Condensers	MUS$	3.1	-14.7
Amine water exchangers	MUS$	1.8	-21.3
CO_2 pumps	MUS$	1.3	-15.7
Intercoolers	MUS$	1.1	-15.8
H_2O tanks	MUS$	1.1	-15.7
MEA tanks	MUS$	0.2	-15.7
MEA pumps	MUS$	0.1	-20.6

Table 10: Optimal Values of Design and Operating Variables for Case Study 4 - Power Plant

		NGCC+Capture at Case Study 4	Difference with Case Study 1 (%)
Power plant net generation capacity	MW	731	0.8
Power available for external demand satisfaction	MW	683	0.4
Electric energy for capture plant powering	MW	48	6.0
Gas turbine design capacity	MW	522	0.0
Steam turbine design capacity	MW	209	2.7
Thermal efficiency	%	49.8	0.4
Gas turbine parameters			
Fuel	kmol/s	0.82 (3.18E-1)	0.0
Compression ratio	-	15.4 (-2.48E0)	0.0
Turbine inlet temperature	K	1547 (-2.04E-1)	0.0
Steam extraction			
Flow rate	kg/s	56.8	-8.8
Temperature	K	407 (1.86E-1)	-0.1
Equivalent power	MW	57.7	-7.8
Steam turbine flow rate			
Low pressure section	kg/s	43.6	13.8
Intermediate pressure section	kg/s	88.5	0.0
High pressure section	kg/s	71.6	-0.5
Specific transfer area	m^2/MW	607	-0.7
HRSG exchange area	dam^2	4375	-0.2
Deaerator	%	10.2	3.5
Low pressure section	%	22.5	-1.5
Intermediate pressure section	%	21.9	0.9
High pressure section	%	45.5	-0.5
HRSG operative pressure			
Deaerator section	MPa	0.152 (-2.97E-1)	0.0
Low pressure section	MPa	0.306	-0.7
Intermediate pressure section	MPa	2.714	-3.4
High pressure section	MPa	12.16 (-1.96E-2)	0.0
Reheater	MPa	2.714	-3.4
Raw material and utility consumption			
Cooling water	kg/s	16.2	16.7
Boiler water	kg/s	1.6	-0.2

Marginal values reported between brackets

Table 11: Optimal Values of Design and Operating Variables for Case Study 4 - Capture Plant (per train)

		NGCC+Capture at Case Study 4	Difference with Case Study 1 (%)
Total heat exchange area	dam^2	1940	19.0
Reboiler area fraction	%	32.7	7.2
Condenser area fraction	%	20.0	4.1
Amine-amine exchanger area fraction	%	36.0	-4.9
Amine-water area fraction	%	7.9	-8.9
Inter-stage coolers area fraction	%	3.3	-10.1
Logarithmic mean temperature difference			
Reboiler	K	13.5	-4.4
Condenser	K	41.9	0.4
Amine-amine exchanger	K	14.0	1.6
Amine-water exchanger	K	22.6	9.3
Absorption column characteristics			
Diameter#1	m	12.6 (-6.03E0)	5.5
Packing height	m	38.5	25.8
Gas flow rate	kmol/s	12.8	15.5
CO_2 molar fraction (flue gas stream)	-	0.0399	0.0
Gases temperature at absorber inlet	K	324	2.0
Gases temperature at absorber outlet	K	329	0.3
Pressure drop	kPa	22.5	44.1
Solvent flow rate	m^3/tn	14.97	-2.3
Amine temperature at absorber inlet	K	318	0.6
CO_2 loading	-	0.1504	-5.2
Stripper column characteristics			
Amine temperature at stripper inlet	K	381	-0.0
Amine temperature at reboiler outlet	K	395	0.1
Diameter	m	4.7	11.1
Packing height	m	9.9	20.5
Pressure drop	kPa	2.43	25.5
Specific reboiler duty	GJ/tn	4.36	0.3
CO_2 loading	-	0.4506	-0.0
Reboiler operating pressure#3	kPa	200 (-3.87E-2)	0.0
Compression stage			
CO_2 compression work	MW	7.20	21.7
Compression ratio	-	2.57	0.1
Flue gas temperature at cooling tower exit#2	K	303 (2.56E-2)	0.0
Process water consumption	m^3/tn	73.9	-1.6
Condenser	%	63.7	3.9
Amine water exchanger	%	25.2	-1.0
Intercoolers	%	8.7	-16.1
Cooling tower	%	2.5	-16.7
MEA consumption	kg/s	0.0319	21.6
Low pressure steam consumption	kg/s	39.02	21.7
Electric energy consumption	MW	16.06	41.5
Amine pumps	%	0.2	-22.3
Blowers	%	53.5	16.6
Compressors	%	44.8	-14.0
CO_2 pumps	%	1.5	-14.1

#1: Eq. (6); #2: Eq. (7); #3: Eq. (8); Marginal values reported between brackets

Table 12: Model Technical Parameters

Air			
	Temperature	K	298
	Oxygen molar fraction	%	20.59
	Nitrogen molar fraction	%	77.48
	Water molar fraction	%	1.93
Fuel			
	Temperature	K	298
	Pressure	MPa	4.05
	Methane molar fraction	%	91.41
	Ethane molar fraction	%	4.73
	Propane molar fraction	%	0.83
	Butane molar fraction	%	0.29
	Hexane molar fraction	%	0.09
	Nitrogen molar fraction	%	0.07
	Oxygen molar fraction	%	0.89
Fresh MEA stream			
	Temperature	K	298
	Composition	% w/w	30
Temperature of fresh process water		K	298
Cooling water inlet temperature		K	298
CO_2 compression pressure		MPa	14.0
Hold up *MEA* tank		days	30
Hold up water tank		days	1
Packing specifications			
	Type		Intalox saddles
	Specific area	m^2/m^3	118
	Nominal packing size	m	0.05
	Critical surface tension	N/m	0.061
	Void fraction	%	79
	Dry packing factor	m^2/m^3	121.4

Table 13: Capital Expenditures Estimation

Equipment acquisition cost	C_{Inv}	
Installation		0.528 C_{Inv}
Instrumentation and control		0.20 C_{Inv}
Piping		0.40 C_{Inv}
Electrical		0.11 C_{Inv}
Building and services		0.10 C_{Inv}
Yard improvements		0.10 C_{Inv}
Services facilities		0.20 C_{Inv}
Land		0.05 C_{Inv}
Total direct manufacturing cost	*DMC*	2.688 C_{Inv}
Engineering		0.10 *DMC*
Construction expenses		0.10 *DMC*
Contractor's fee		0.005 *DMC*
Contingencies		0.17 *DMC*
Total indirect manufacturing cost	*IMC*	0.375 *DMC*
Investment on fix capital	*IFC*	*DMC+IMC*
Working investment		0.25 *IFC*
Start-up cost + initial MEA cost		0.10 *IFC*
Capital expenditures	*CAPEX*	1.35 *IFC* = 5 C_{Inv}

Table 14: Equipment Characteristics used for Computing Capital Costs

	Type	Material	Capacity	Unit cost	Reference
Gas turbines (*GT*)	GE PG9351FA	Composite	Power (kW)	$2.583 \cdot 10^2$	Nye TC (2013)
Steam turbine (*ST*)	3 Pressure Levels	Composite	Power (kW)	$2.583 \cdot 10^2$	Nye TC (2013)
Steam generators (*HRSG*)	Horizontal, unfired	Composite	Area (m^2)	$1.115 \cdot 10^4$	U.S. EIA (2010)
Column vessels (*ABS*)	Vertical vessel	SS	Superficial area (m^2)	$7.422 \cdot 10^4$	Henao (2005)
Packing columns (*ABS*)	Intalox saddles	Ceramic	Packing volume (m^3)	$1.189 \cdot 10^4$	Henao (2005)
Column vessels (*REG*)	Vertical vessel	SS	Superficial area (m^2)	$5.831 \cdot 10^4$	Henao (2005)
Packing columns (*REG*)	Intalox saddles	Ceramic	Packing volume (m^3)	$7.763 \cdot 10^3$	Henao (2005)
Rich amine pumps and drivers (*RAP*)	Centrifugal	SS	Brake HP (kW)	$5.801 \cdot 10^3$	Henao (2005)
Blowers and drivers (*BLO*)	Centrifugal (turbo)	CS	Brake HP (kW)	$1.351 \cdot 10^4$	Seider et al. (2009)
Exchangers (*AAE*)	Floating head	SS-SS	Area (m^2)	$1.036 \cdot 10^4$	Henao (2005)
Exchangers (*AWE, IC, CON*)	Floating head	CS-SS	Area (m^2)	$7.153 \cdot 10^3$	Henao (2005)
Reboilers (*REB*)	Kettle	SS-SS	Area (m^2)	$1.490 \cdot 10^4$	Henao (2005)
Cooling towers (*CT*)	Induced draft	CS	Thermal load (kJ)	$3.245 \cdot 10^3$	Matches (2003)
Water and *MEA* tanks (*T1, T2*)	Floating roof	CS	Volume (m^3)	$4.515 \cdot 10^3$	Seider et al. (2009)
CO_2 pumps and drivers (*CO2P*)	Centrifugal	CS	Brake HP (kW)	$9.801 \cdot 10^2$	McCollum and Ogden (2006)
Compressors and drivers (*COM*)	Centrifugal	SS	Brake HP (kW)	$4.242 \cdot 10^4$	Seider et al. (2009)

Table 15: Operating Expenditures Estimation

Raw material and utility	C_{RM}	
Operative manpower	C_{MP}	
Maintenance	C_{Mant}	
Local taxes		0.02 IFC
Insurance		0.01 IFC
Supervision and support labor	C_S	0.30 C_{MP}
Laboratory charges		0.10 C_{MP}
Operative supplies		0.01617 IFC
Plant overhead		0.45 $(C_{MP}+C_S)$+0.04851 IFC
Total production cost	PC	$C_{RM}+C_{Mant}+1.985C_{MP}+0.0947\ IFC$
Administrative		0.13 C_{MP}
Distribution and marketing		0.00397 C_{MP}
Research and development		0.0397 C_{MP}
Total additional cost	AC	0.217 C_{MP}
Operative expenditures	$OPEX$	$PC+AC = C_{RM}+C_{Mant}+2.2\ C_{MP}+0.33\ C_{Inv}$

Table 16: Utility Cost Coefficients

		a_{PS}	b_{PS}
Auxiliary steam (1<P<46 barg; 0.06<$\dot{m}$<40 kg/s)	US$/kg	0.0151 $\dot{m}^{-0.9}$	0.0034 $P^{0.05}$
Cooling water (0.01<q<10 m^3/s)	US$/$m^3$	0.5589+0.0168 q^{-1}	0.003
Make-up water (0.01<q<1 m^3/s)	US$/$m^3$	2.7945 +0.1118 $q^{-0.6}$	0.04