Multi-Criteria Optimization of an Advanced Combined Cycle Power Plant including CO_2 Separation Options

Hongtao Li*, François Maréchal, Meinrad Burer, Daniel Favrat

Laboratory for Industrial Energy Systems, Swiss Federal Institute of Technology Lausanne
CH-1015 Lausanne, Switzerland

Abstract

This paper illustrates a methodology developed in order to facilitate the analysis of complex systems characterized by a large number of technical, economical and environmental parameters. Thermo-economic modeling of a natural gas combined cycle including monoethanolamine absorption CO_2 separation option has been integrated within a multi-objective optimizer based on a genetic algorithm in order to characterize the economic and environmental potential of such complex systems within various contexts.

A natural gas combined cycle project in a district of Germany is given as a case study. The results show the influences of the configuration and technical parameter changes on the evolution of electrical efficiency of the combined cycle plant as well as on those of its sub-systems, such as gas turbine cycle and steam cycle. The optimum integrations of such a complex system under different situations are revealed by the Pareto Optimal Frontier obtained through the multi-objective optimization process, which provides information on the relationship between power generation cost and CO_2 emission performances. Such information is of direct relevance for policy makers to define coherent emission tax levels, or for utility owners or project investors to choose the appropriate emission levels to be reached by the new plant, or for power generation technology suppliers to identify the market potential of their products as well as the most appropriate design for a given power unit, under given policies and economic contexts.

Keywords: Multi-criteria, Multi-objective optimization, Thermo-economic modeling, environomic, Combined Cycle, CO_2 separation, MEA, CO_2 tax

1. Introduction

Considering the major role of the power sector in the economy and its contribution to local atmospheric pollution and CO_2 emissions, the development of new cost-effective and environmentally friendly electricity generation systems is of the first priority for a more sustainable society. According to the WEO 2000 Reference Scenario projection, 2294 GW of new generating capacity will be installed worldwide by 2020, with fossil fuel based power plants accounting for 1890 GW, around 86% of the total [1]. In such a context, natural gas combined cycle (NGCC) power plants are among the most adapted options, due to low emission rates and very competitive generation costs. When associated with monoethanolamine absorption (MEA) CO_2 separation alternatives, their impact on climate change can be reduced but at a price which makes this option not economical when pollution costs are not internalized.

In order to facilitate the analysis of such complex systems characterized by a large number of technical, economical and environmental parameters and to find out the optimal solutions, a thermo-economic modularization modelling approach based on generalized superstructure of advanced NGCC plant with MEA option has been developed and integrated into an environomic

* Corresponding author. Tel.: + 41 21 693 5316; Fax: + 41 21 693 3502
Email address: Hongtao.li@epfl.ch (H. Li)

Nomenclature

AAC	Annual total CO_2 abatement cost [US$/year]
ABC	CO_2 abatement cost [US$/ton CO_2]
AP	CO_2 abatement percentage [%]
AQ	Annual CO_2 abatement quantity [ton CO_2/year]
C	Annual cost [US$/year]
c	Specific cost; price [UScents/kWh]
COE	Cost of Electricity [UScents/kWh]
MCO2	Annual CO_2 emissions [ton CO_2/year]
n	Amortization period [year]
P	Power capacity; Power demand [kW]
RCO2	CO_2 emission rate [gCO_2/kWh]
T	Annual operating hours [hours/year]
$\vec{x}$	Set of independent and dependent variables
$\vec{y}$	Set of independent and dependent variables

Subscripts

av	Average
comb	Combustion
grid	Power grid
NG	Natural Gas
O&M	Operation and Maintenance
unit	NGCC unit

Abbreviations

CRF	Capital Recovery Factor
EGR	Exhaust gas recirculation
GOSa	Global optimal solution when there is a CO_2 tax of aUS$/ton CO_2
GT	Gas Turbine
LOSa	Local optimal solution when there is a CO_2 tax of aUS$/ton CO_2
MEA	Monoethanolamine absorption
NGCC	Natural gas combined Cycle
POF	Pareto Optimal Frontier
RH	Reheat
ST	Steam Turbine
SC	Simple combustion
SQC	Sequential combustion

optimization methodology [2]. This methodology allows the internalization of external cost such as that due to CO_2 tax into the single objective aggregated function, i.e. the annual total cost or the cost of electricity (COE). The local and global optima can be found with the help of powerful optimization algorithm like the evolutionary algorithms [2-4]. The developed models proved to be able to reflect the market situation and the methodology itself can effectively deal with such a complex problem.

With the successful development and implementation of a new and fast multi-objective optimizer, a more flexible evaluation is realized in this study with an analysis of the economic

and environmental potential of the NGCC systems within various contexts, taking into account the uncertainty of future CO_2 tax levels. MEA CO_2 separation with exhaust gas recirculation option is modeled as one of the possible options of the studied NGCC plant.

2. Methodology

2.1 Thermo-economic Modelling of Natural Gas Combined Cycle Systems with MEA Option

The thermo-economic modelling is based on a generalized superstructure of advanced NGCC unit with MEA option, composed with 4 sub-systems, shown in Fig. 1.

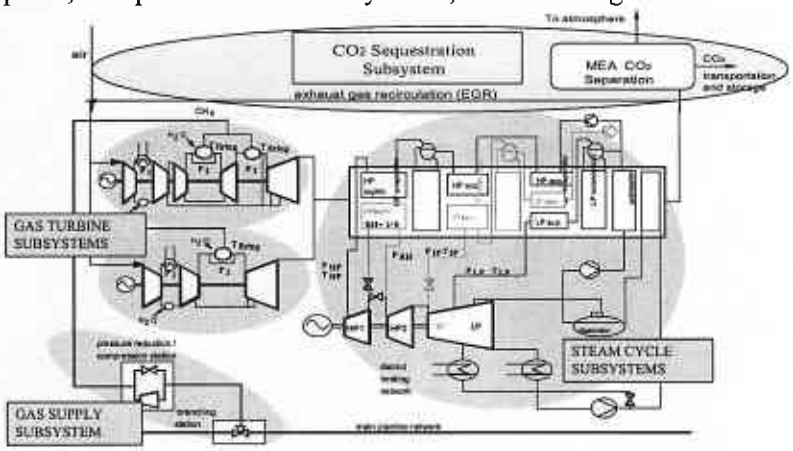

Fig.1. Superstructure of an advanced NGCC with MEA and EGR option [2]

Besides traditional simple combustion (SC) gas turbine (GT), the sequential combustion (SQC) technology that has been successfully implemented in ALSTOM's GT24 and GT26 is also modeled. NOx control technology such as dry low-NOx is included. The steam cycle superstructure model includes two and three pressure level heat recovery steam generators (HRSG) and a steam turbine (ST) cycle with reheat as a possible option. Details can be found in [2,5].

MEA absorption unit can capture up to 90% of CO_2 in the exhaust gas [6]. However it becomes costly if no additional measures are taken due to the relatively dilute concentration in the flue gas. The exhaust gas recirculation (EGR) option can increase the CO_2 content in the flue gas [7] and effectively reduce the size and investment cost of the MEA unit. An optimum oxygen content in the combustion air can minimize the COE under such a situation. The MEA cost function is based on the data from Hendriks [6] and validated by the data from Undrum [8]. Besides the investment cost increase, MEA unit will consume a large amount of steam extracted from NGCC system, which causes electrical efficiency degradation. The fuel cost therefore will increase accordingly.

The cost of CO_2 transportation and storage after CO_2 separation varies in a wide range from 5 to 15 US$/ton CO_2 avoided [9] due to a high site specific uncertainty. A cost of 10 US$/ton CO_2 avoided for CO_2 disposal (transportation and storage) is used in this study. In order to consider the total cost and emissions for a NGCC plant, the natural gas supply system is also modeled [5].

2.2 Multi-criteria Evaluation and Optimization

Evolutionary algorithms have been proven to be robust and effective for the resolution of non-linear, non-continuous, and mixed real integer optimization problems such as those encountered when dealing with NGCC systems. The single objective aggregated function allows a minimization of the overall internalized cost of an energy system, accounting for design, installation, operation as well as pollution through the introduction of pollution cost factors.

However, given the difficulty encountered sometimes when trying to express certain criteria in financial terms due to various reasons, a multi-objective optimization is preferred. As an example, the uncertainty of CO_2 emission tax levels may make it difficult for pre-internalization of CO_2 emission cost into a single COE function. In this work, both the CO_2 emission rate in terms of gCO_2 emitted per kWh electricity produced and the COE are simultaneously optimized before emission cost internalization. The optimization results are in the form of a set of global optima called Pareto Optimal Frontier by contrast with only one as is often shown with single objective optimization. Each of the solution along the Pareto Optimal Frontier (POF) corresponds to the minimum CO_2 emission rate under a given COE, or, in other words, the minimum COE under a given CO_2 emission rate level. The influence of the CO_2 tax level can then easily be evaluated through post-optimization internalization.

For such a purpose, a new multi-objective optimizer based on queuing and clustering genetic algorithm has been recently developed [10], and applied to the analysis of the trade-off between cost and specific fuel consumption or environmental performance associated with the implementation of advanced integrated energy systems within urban areas and the power load dispatching between several pulverized coal plants [11-14]. In this study, it is used to optimize the two objectives of a NGCC project: the CO_2 emission rate and the COE.

3. Supplying Electricity to a Community with 400 MW Demand in a District of Germany

3.1 Case description

The case study of electricity supply to a community has been investigated with the environmental and economic context of Germany. This community has an additional 400 MW power demand in the year of 2005 to be satisfied. Considering the financial and environmental policy situation, the predefined options can be the construction of a 400 MW NGCC plant that may include or not MEA unit to supply the full demand, or the construction of a smaller NGCC unit with/without MEA. For the latter case, the balance of the electricity needed is imported from the power grid at a price defined in a long term contract, which is based on long term projection of the electricity wholesale price. The smallest NGCC capacity is set at 100 MW due to economies of scale consideration. The annual operating hours planned for the NGCC plant is of 7500 hours.

The investment in the NGCC unit is assumed to be satisfied by a bank loan. The natural gas price is of 1 UScents/kWh for power generation activities [15]. The electricity buying price in the long term power importation contract is taken as 3.8 UScents/kWh, which is the projected average electricity wholesale price after 2005 [15].

3.2 Objective Functions and Independent Variables

For the given power demand, the average cost of electricity (COE_{av}) and the average CO_2 emission rate ($RCO2_{av}$) are taken as the two objectives to be simultaneously optimized.

The COE_{av} is calculated with equation (1) :

$$COE_{av} = \frac{COE_{unit} \cdot P_{unit} \cdot T + c_{grid} \cdot (P_{demand} - P_{unit}) \cdot T}{P_{demand} \cdot T} \quad \text{[UScents/kWh]} \qquad (1)$$

Where, C_{grid} [UScents/kWh] is the electricity wholesale price of the grid, or, in another word, electricity buying price in this study, based on a long term contract. P_{unit} [MW] and P_{demand} [MW] are respectively the NGCC unit capacity and total power demand of 400 MW. T [hours/year] is the annual operating period of the NGCC unit (7500 hours). The cost of electricity of the NGCC unit (COE_{unit}) is given be equation (2) :

$$COE_{unit} = \frac{C_{capital} + C_{O\&M} + C_{fuel} + C_{solvent\ \&disposal}}{P_{unit} \cdot T} \times 100 \qquad \text{[UScents/kWh]} \qquad (2)$$

Where, $C_{O\&M}$ [US$/year] , C_{fuel} [US$/year] are the annual operating and maintenance cost (excluding the solvent cost of the MEA unit) and fuel cost of the NGCC unit, respectively. $C_{solvent\&disposal}$ [US$/year] is the solvent and CO_2 disposal (including transportation and storage) cost when there is a MEA unit. The annual capital cost $C_{capital}$ [US$/year] is calculated as follows:

$$C_{capital} = CRF \cdot C_{investment} \qquad \text{[US\$/year]} \qquad (3)$$

Where, $C_{invstment}$ is the total investment cost of the plant, including equipment cost and installation cost. CRF is the Capital Recovery Factor that calculates the equivalent value of a future annuity given the present cash equivalent with the following equation:

$$CRF = \frac{\hat{i} \cdot (1+i)^n}{(1+i)^n - 1} \qquad \text{[-]} \qquad (4)$$

Where, i is the interest rate with a value of 8% used in this study; n is the amortization period of 15 years, which is set the same as the investment depreciation period and the economic lifetime of the plant.

The annual CO_2 emissions due to fuel combustion $MCO2_{comb}$ [ton CO_2/year] is derived according to the carbon content of natural gas as well as the fuel consumption rate, or, in other words, the electrical efficiency of the NGCC, and a CO_2 capture rate of 90% in the exhaust gas is assumed when MEA is introduced. The annual CO_2 emissions due to exploration, production, preparation and transportation of natural gas is estimated at 0.31kg of CO_2 per kg of natural gas delivered [5]. Methane is another important green house gas with a much higher global warming potential (GWP) of about 24.5 using a 100-year time horizon (IPCC, 1997). With a leakage of 0.9% of the total natural gas consumption, the equivalent annual CO_2 emissions are considered in the total annual CO_2 emissions [5]. The average CO_2 emission is given as:

$$RCO2_{av} = \frac{MCO2_{comb} + MCO2_{NG} + MCO2_{grid}}{P_{demand} \cdot T} \times 10^6 \qquad \text{[gCO}_2\text{/kWh]} \qquad (5)$$

Where, $MCO2_{NG}$ [ton CO_2/year] is the annual indirect equivalent CO_2 emissions due to natural gas preparation and leakage and $MCO2_{grid}$ [ton CO_2/year] is the annual total CO_2 emissions due to power importation. The CO_2 average emission rate for the power grid in Germany is of 631gCO_2/kWh [15].

The optimization problem defined by this case study therefore can be written as :

$$Min(COE_{av}, RCO2_{av}) = f(\vec{x}, \vec{y}) \qquad (6)$$

subject to

$$\begin{cases} h_j(\vec{x}, \vec{y}) = 0 & j = 1,.....,J \text{ (equality constraints)} \\ g_k(\vec{x}, \vec{y}) \geq 0 & k = 1,.....,K \text{ (inequality constraints)} \end{cases}$$

Where, $\vec{x}$ and $\vec{y}$ are sets of independent and dependent variables, respectively.

The independent variables can be classified into two categories: 1) integer variables for system configuration design such as gas turbine and steam cycle type, and 2) continuous variables such as NGCC capacity, gas turbine pressure ratio and inlet temperature, which define the important technical and financial parameters. Some of the typical real independent variables and their boundary conditions are given in Table 1.

Table 1. Some important real independent variables and their boundary conditions

	Lower Bound	Higher Bound
Capacity (MW)	100	400
GT Pressure Ratio (for SC or low pressure part of SQC) [-]	10.0	25.0
GT Pressure Ratio for high pressure part of SQC [-]	1.5	3.0
GT Turbine inlet temperature (°C)	1000	1450
GT Excess air ratio [-]	1.5	2.5
GT Desired Oxygen mass content [%]	10	23
ST Live steam pressure (bar)	50	150
Temperature difference between GT exhaust gas and ST life and reheat steam (°C)	50	90
HRSG pinch (°C)	8	20
Condenser Pressure (bar)	0.05	0.06

3.3 Additional Evaluation Criteria

Besides the COE_{av} and $RCO2_{av}$, the following additional criteria are also defined in order to further evaluate the performances of the solutions.

Annual CO_2 abatement quantity

The annual CO_2 abatement quantity (AQ) is the CO_2 annual reduction of the analyzed solution compared to the reference case, and calculated as :

$$AQ = (RCO2_{av} - RCO2_{baseline}) \cdot P_{demand} \cdot T / 10^6 \quad \text{[ton } CO_2\text{/year]} \quad (7)$$

where, $RCO2_{baseline}$ is the CO_2 emission rate of the reference case. The power grid is taken as the reference case in this analysis, and therefore $RCO2_{grid}$(631 gCO_2/kWh) and grid whole sale price COE_{grid}, which is also the electricity buying price for this project, are taken as the baseline.

Annual total CO_2 abatement cost

Similar as AP, the annual CO_2 abatement cost is the additional annual cost compared to the baseline values:

$$AAC = (COE_{av} - COE_{baseline}) \cdot P_{demand} \cdot T / 100 \quad \text{[US\$/year]} \quad (8)$$

CO_2 abatement percentage

The CO_2 abatement percentage is derived by equation (9) :

$$AP = AQ / (RCO2_{baseline} \cdot P_{demand} \cdot T \times 10^6) \times 100 \quad [\%] \quad (9)$$

It represents the CO_2 abatement potential of the given solution compared to the reference case.

CO_2 abatement cost

For the analyzed solution, the specific additional cost for CO_2 reduction compared to the reference case can be evaluated by the CO_2 abatement cost, which is defined as

$$ABC = AAC / AQ \quad \text{[US\$/ton } CO_2\text{]} \quad (10)$$

This is an important criterion both for effective CO_2 tax level design and for the economic feasibility and profitability analysis of the solutions, which will be analyzed in detail later.

4. Results

The POF obtained with the multi-objective optimizer and the typical solutions are given in Fig. 2. The configurations' descriptions and the values of the important independent and dependent parameters of these typical solutions along the POF are listed in Table 2. Fig. 3. gives the evolution of COE_{unit} with a detailed decomposition information of the typical solutions as

well as their associated $RCO2_{unit}$ and $RCO2_{av}$ .The evolution of the electrical efficiency and specific equipment cost for NGCC, GT and ST along the POF is given in Fig. 4.

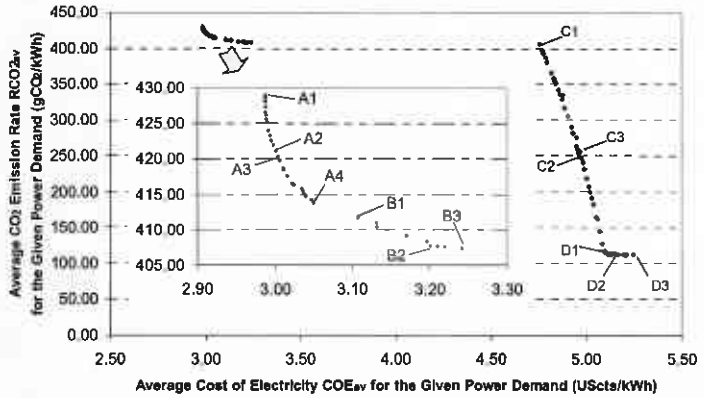

Fig. 2. POF obtained with electricity buying price at 3.8 UScents/kWh

The POF shown in Fig.2. includes 4 segments, which indicates different clustering solutions. A 400MW (maximum capacity for this project) simple combustion 3 pressure level NGCC unit (A1) is shown to be the most economical but the most CO_2 intensive solution in the absence of CO_2 tax with a electrical efficiency of 56.59%, which converges to the current conventional NGCC. This is due to its lower COE_{unit} (2.99 UScents/kWh) than that of the electricity buying price. Along with the increase of NGCC electrical efficiency due to GT cycle and/or ST cycle electrical efficiency improvement, the $RCO2_{unit}$ decreases 5% from solution A1 to B3, with increased COE_{unit}. A maximum COE_{unit} of 3.24 UScents/kWh associated with an electrical efficiency of 59.49% is achieved by solution B3 corresponding to the lowest $RCO2_{unit}$ of 407.4 gCO_2/kWh, within segment A and B. This COE_{unit} is still lower than the electricity buying price. Therefore, no power is imported within these solutions. The COE_{unit} and $RCO2_{unit}$ are then equal to COE_{av} and $RCO2_{av}$, respectively. The solution B3 has the most complex configuration (sequential combustion gas turbine, 3 pressure level steam cycle with reheat) that are available in the market today, which help it reaching a electrical efficiency of around 60%. Its typical physical parameters are also reaching their currently commercially available bound, with a pressure ratio at 31, turbine inlet temperature at 1425 °C, live/reheat steam temperature at 581.8 °C, pinch of HRSG of 8 °C and condenser pressure at 0.05 bar. Further increase of the NGCC electrical efficiency becomes technically and economically unfeasible. The MEA CO_2 sequestration must be introduced in order to reach a lower $RCO2_{av}$, and the solutions therefore jump to segment C, with a significant $RCO2_{unit}$ reduction ($RCO2_{unit}$ is lower than 150 gCO_2/kWh). However, in the meantime, the COE_{unit} of the NGCC also increases dramatically when MEA is introduced (all of the COE_{unit} are higher than 5 UScents/kWh in such a case). These values can be clearly seen from Fig. 3. Therefore, part of the electricity demand will be satisfied by the power grid which has a higher $RCO2_{grid}$ of 631gCO2/kWh, but relatively lower COE_{grid} of 3.8 UScents/kWh. Due to much lower $RCO2_{unit}$ of NGCC with MEA option, further increasing the NGCC unit capacity from 176 MW (C1) to the maximum possible capacity 400 MW (D1) results in a drastic $RCO2_{av}$ reduction, from 405.2 gCO_2/kWh to 114.6 gCO_2/kWh (around 72% reduction). Along with the capacity increase, the COE_{unit} decreases from 5.97 UScents/kWh to 5.1 UScents/kWh mainly due to scale of investment effect, which can be seen from Fig. 3 and Table 2. They are still higher than the COE_{grid}. Therefore, the COE_{av} increases from 4.75 UScents/kWh to 5.1 UScents/kWh due to a lower amount of imported electricity. Starting from solutions D1, further reduction

Table 2. Values of important independent and dependent parameters of typical solutions along the POF

NGCC Performance and Parameters

	COE (UScents/kWh)	CO_2 emission rate (gCO_2/kWh)	Capacity (MW)	Electrical efficiency (%)	Fuel Mass Flow Rate (kg/s)	Specific equipment cost (US$/kW)	MEA	MEA specific equipment cost (US$/kW)	Desired Oxygen mass content [-]
A1	2.99	429.0	400	56.59	15.15	301	no	0.00	0.23
A2	3.00	421.1	400	57.66	14.87	317	no	0.00	0.23
A3	3.00	420.3	400	57.77	14.85	319	no	0.00	0.23
A4	3.05	413.8	400	58.67	14.62	343	no	0.00	0.23
B1	3.11	411.8	400	58.83	14.58	363	no	0.00	0.23
B2	3.20	407.7	400	59.43	14.43	400	no	0.00	0.23
B3	3.24	407.4	400	59.49	14.42	414	no	0.00	0.23
C1	4.75	405.2	176	50.75	7.45	1043	yes	556.67	0.10
C2	4.96	253.4	293	51.46	12.24	883	yes	462.10	0.10
C3	4.98	246.5	298	51.84	12.35	888	yes	456.79	0.10
D1	5.10	114.6	400	52.43	16.36	814	yes	409.65	0.10
D2	5.17	112.4	400	53.35	16.07	851	yes	406.00	0.11
D3	5.25	112.1	400	53.47	16.04	880	yes	405.42	0.11

GT Cycle Performance and Parameters

	Capacity (MW)	Electrical efficiency (%)	Specific equipment cost (US$/kW)	Type	Pressure Ratio [-]	Turbine inlet temperature (°C)	Exhaust gas temperature (°C)	Exhaust gas mass flow rate (kg/s)	Excess air ratio [-]
A1	272.59	37.23	117.49	SC	18	1367	611.2	614.9	2.292
A2	273.20	39.38	124.31	SC	20	1394	605.4	598.6	2.267
A3	270.46	39.06	122.06	SC	20	1392	612.8	593.8	2.254
A4	269.47	39.53	132.49	SC	21	1421	617.6	573.0	2.203
B1	264.41	38.89	145.12	SQC	24	1387	655.3	535.8	2.381
B2	269.36	40.02	184.02	SQC	31	1427	657.5	512.1	2.396
B3	269.18	40.03	182.98	SQC	31	1425	656.3	512.4	2.404
C1	124.30	35.79	196.64	SQC	26	1371	664.7	291.4	1.650
C2	208.30	36.49	176.07	SQC	26	1376	665.1	473.3	1.650
C3	209.96	36.45	172.73	SQC	26	1366	659.2	483.0	1.650
D1	281.99	36.96	166.31	SQC	25	1361	654.7	639.3	1.650
D2	287.27	38.32	203.67	SQC	30	1419	657.0	606.5	1.650
D3	286.60	38.31	203.21	SQC	30	1419	657.0	605.2	1.650

ST Cycle Performance and Parameters

	Capacity (MW)	Electrical efficiency (%)	Specific equipment cost (US$/kW)	Type	Live steam pressure (bar)	Live/reheat steam temperature (°C)	Condenser Pressure (bar)	HRSG pinch (K)
A1	132.26	27.72	125.19	3Pressure	103.69	551.7	0.059	18.84
A2	131.65	30.15	134.20	3Pressure	118.49	557.9	0.053	11.06
A3	134.39	30.70	138.41	3Pressure+RH	98.93	543.0	0.055	11.68
A4	135.37	31.66	152.11	3Pressure +RH	149.97	545.5	0.050	8.03
B1	140.45	32.63	160.11	3Pressure +RH	148.98	566.2	0.050	8.17
B2	135.50	32.36	158.29	3Pressure +RH	150.00	568.5	0.050	8.00
B3	135.68	32.44	173.39	3Pessure +RH	150.00	581.8	0.050	8.01
C1	74.73	23.29	209.90	3Pressure	108.00	574.9	0.051	11.93
C2	122.87	23.57	176.47	3 Pressure	115.38	575.3	0.052	11.85
C3	126.50	24.22	189.85	3Pressure +RH	113.28	570.3	0.051	10.44
D1	168.16	24.54	175.55	3Pressure +RH	150.00	566.4	0.051	9.04
D2	161.81	24.38	178.74	3Pressure +RH	149.94	568.7	0.050	8.06
D3	162.39	24.57	208.50	3Pressure +RH	149.94	587.2	0.050	8.01

of $RCO2_{av}$ can only be achieved by increasing the NGCC electrical efficiency. The lowest $RCO2_{av}$ of 112.1 gCO_2/kWh is reached by solution D3, with similar configuration and physical parameters as solution B3, but at a cost of 6% points electrical efficiency degradation and 62% COE_{unit} increase, due to utilization of MEA.

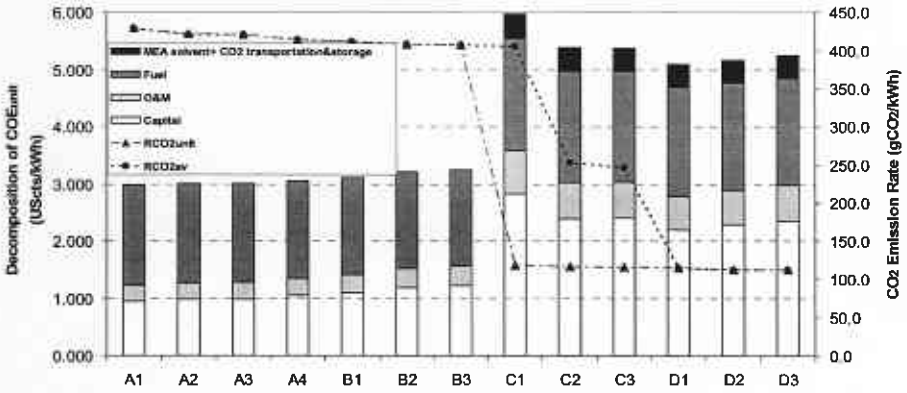

Fig. 3. Evolution of COE with decomposition and CO_2 emission rate of typical solutions

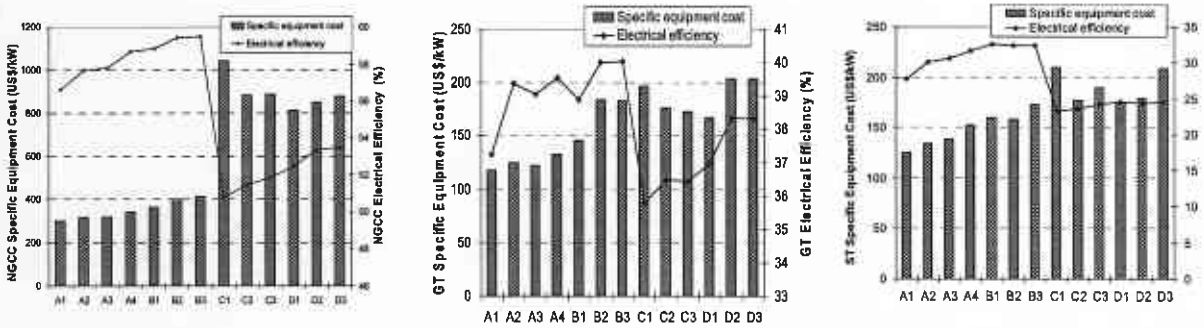

Fig. 4. Evolution of specific equipment cost and electrical efficiency for NGCC, GT and ST of typical solutions along the POF

Fig. 2 and Fig. 3 shows that the driving force for reducing $RCO2_{unit}$ and $RCO2_{av}$ along the POF mainly rely on two different measures: 1) increasing NGCC electrical efficiency, which corresponds solutions in segment A, B and D; and 2) increasing the capacity of NGCC with MEA CO_2 separation, which includes solutions in segment C. A $RCO2_{av}$ reduction potential of 72% (290 gCO_2/kWh) can be achieved through increasing the capacity of NGCC unit with MEA option from solution C1 to D1, with a CO_2 abatement cost of only 12 US$/ton CO_2 for solution D1 when C1 is taken as the reference, or with a with a CO_2 abatement cost of 67 US$/ton CO_2 for solution D1 when A1 (400MW conventional NGCC) is taken as the reference. This potential is much higher than the solutions only relying on efficiency increase (solutions from A1 to B3), by which only a $RCO2_{av}$ reduction of 22 gCO_2/kWh can be achieved at a very high CO_2 abatement cost of 116 US$/ton CO_2 for solution B3 when A1 (400MW conventional NGCC) is taken as the reference case. These distinct characteristics can be classified as the so-called 'efficiency effect' and 'CO_2 sequestration and grid power substitution effect', which are shown in Fig. 5.

It should be noted that the evaluation of the solutions along the 'efficiency effect' segments, (segment A, B and D), clearly show the corresponding relations between NGCC electrical

efficiency improvement and the increase of specific investment cost due to the adoption of additional measures. This relation can be clearly seen from Table 2 and Fig. 4. With an increased pressure ratio and gas turbine inlet temperature, the electrical efficiencies of GT, ST and NGCC increase from A1 to A2. When steam reheat is introduced in solution A3, higher ST cycle electrical efficiency with a higher specific equipment cost results a higher NGCC electrical efficiency. It also allows a lower gas turbine electrical efficiency with lower inlet temperature, which results in a lower GT specific investment. From A3 to A4, GT inlet temperature increases again. The SQC GT is introduced starting from solution B1. Although the overall pressure ratio is of 24, the pressure ratio for low pressure stages is of only 15. This results in a higher exhaust gas temperature and a higher live steam temperature is chosen, compared to solution A4. Therefore a higher ST cycle efficiency is achieved. Therefore, although the GT efficiency decreases due to the utilization of lower gas turbine inlet temperature, the overall NGCC electrical efficiency increased. Meanwhile, a higher GT specific equipment cost is needed due to introduction of SQC with higher overall pressure ratio. Starting from B1, the pressure ratio and GT inlet temperature are increasing. The GT and NGCC electrical efficiency as well as their specific equipment cost therefore increase. When the maximum commercial available pressure ratio of 31 and GT inlet temperature of 1425 °C are reached, further increase of NGCC efficiency from B2 to B3 mainly rely on the live/reheat steam inlet temperature improvement. When the solution jumps in to segment C, the NGCC electrical efficiency is degraded with a much higher specific equipment cost compared to solutions in segment A and B, due to utilization of MEA. When the maximum capacity for this project of 400 MW is reached by solution D1, a similar behavior that appeared in segment B can be observed.

With a natural gas price of 1 UScents/kWh, the COE_{unit} of solution A1 to B3 are lower than that of the baseline – the electricity buying price. Therefore, their CO_2 abatement costs in such a case are negative values. With higher natural gas price or lower electricity buying price, this situation may change dramatically.

When MEA is introduced, the oxygen content in the combustion is also optimized. As seen in Table 2, a value of 10% to 11% can help the system to reach its minimum cost of electricity.

With similar pressure ratios, a lower excess air ratio is needed when GT inlet temperature increases, as happened from solution A1 to A4. However, with an increased pressure ratio and higher temperature of inlet air, a higher excess air ratio is needed to control the NOx formation[1], as happens from B1 to B2. A much lower excess air ratio is used when MEA is introduced due to exhaust gas recirculation (EGR) as shown in Table 2.

The effects of different CO_2 tax levels are shown in Fig. 6. With a CO_2 tax up to 60 US$/ton CO_2, the most economical solution recognized as global optimal solution (GOS) still remains within the segment of A and B. However, a higher efficiency is chosen for the NGCC (from GOS0 TO GOS60 in Fig. 6) when a higher CO_2 tax is imposed. Although the solutions within the segment C and D are never chosen as GOS under the given tax level, its local optimal solution (LOS) moves from C1(LOS30), to a solution in segment D (LOS30) under a 30 US$/ ton CO_2 tax. This means that a maximum capacity NGCC capacity (400MW) will be chosen when MEA must be utilized along with a CO_2 tax of 30 US$/kWh. Meanwhile, LOS30 is even more economical than the baseline in which case all of the electricity is imported form the power grid. This is

1 Dry-NOx technology has been chosen by the optimizer for all of the solutions along the POF in order to reach the NOx emission limitation of 50 mg/N3 set by the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants

because of the CO_2 tax penalization to the grid power due to its higher $RCO2_{grid}$. Under a higher CO_2 tax of 60 US$/ton, a greater efficiency will be chosen for the NGCC as the LOS (LOS 60).

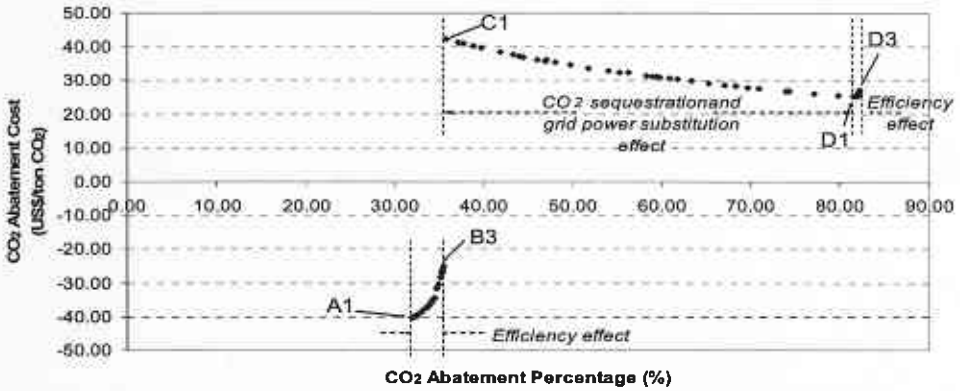

Fig. 5. CO_2 abatement cost VS CO_2 abatement percentage along the POF with the baseline of the power grid

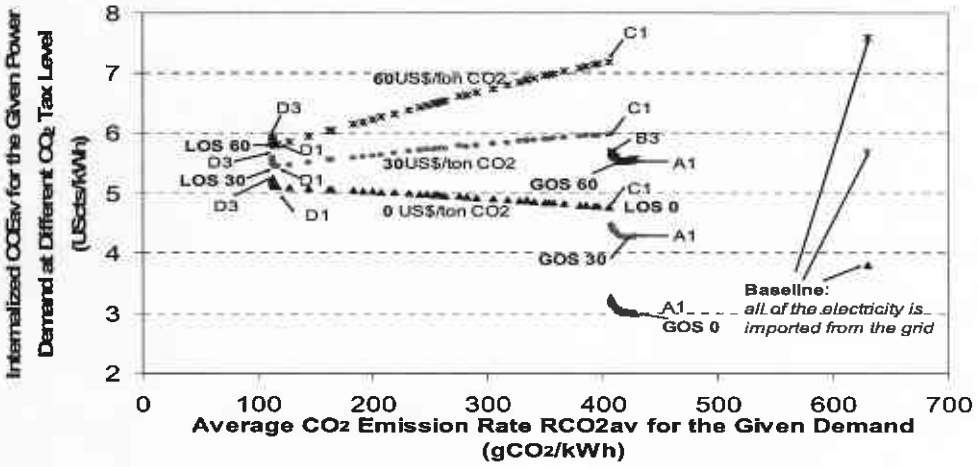

Fig. 6. Internalization of different CO_2 tax levels

5. Conclusions

A NGCC project with the economic and environmental contexts of Germany is studied based on thermo-economic modelling and multi-objective optimization approach. The Pareto Optimal Frontiers (POF) obtained with multi-objective optimization process provides information on the relationship between the cost of the electricity and CO_2 emission rate. The results clearly show the influence of the configuration and technical parameter changes on the evolution of electrical efficiency and the associated specific equipment cost of the combined cycle plant as well as on those of its sub-systems, such as gas turbine cycle and steam cycle. The optimal integrations of such a complex system under different situations can be therefore found with the help of POF. The CO_2 abatement potential through NGCC electrical efficiency improvement is much lower than utilization of MEA in terms of CO_2 abatement quantity and percentage. Meanwhile, when compared to a conventional NGCC with the same capacity, a 400MW NGCC with MEA has a CO_2 abatement cost of 67 US$/ton CO_2. This is lower than that for a current most advanced NGCC without MEA option under developing (116 US$/ton CO_2). The introduction of the CO_2

tax up to 60 US$/ton CO_2 may help higher efficiency NGCC penetrating into the market for the given study. However, it is unlikely to make the MEA option becomes economical although this solution is already cheaper than importing electricity from the power grid when a CO_2 tax of 30 US$/ton CO_2 is imposed in the analyzed case. The cost of electricity of a 400MW NGCC unit without MEA option is cheaper than grid power wholesale price assumed in this study (3.8 UScents/kWh). Their CO_2 abatement costs therefore are negative when the power grid is taken as the baseline. However, given the fact that the natural gas and electricity wholesale price varies in a wide range, this situation may changed dramatically.

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