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CO_2 CAPTURE AND STORAGE IN THE ELECTRICITY GENERATION SECTOR

AN ALTERNATIVE FOR CO_2 EMISSIONS REDUCTION

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The present Working Paper refers to Europe's Fourth Gas Corridor Pipelines and the perspectives, uncertainties and implications for SE Europe and Greece. IENE wishes to thank its author Mr. Spyros Paleoyannis for his valuable contribution.

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CO_2 Capture and Storage in the Electricity Generation Sector -An alternative for CO_2 emissions reduction

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Abstract

The purpose of the work presented in this paper is to examine and evaluate the perspectives of application of CO_2 Capture and Storage (CCS) technologies in the electricity generation sector.

Results from thermodynamic simulations conducted within the framework of various EU-funded projects, both for green-field and retrofit applications of the oxyfuel technology and post-combustion capture with amine scrubbing in typical Greek power plants are used to demonstrate the potential for emissions reduction and evaluate the associated power output and efficiency penalties.

The application of CO_2 capture technologies in a power plant is highly costly in terms of efficiency and net power output reduction. The thermodynamic data, coupled with the investment costs provide an insight on the economics associated to CO_2 sequestration options and the viability of the power plants within the framework of the application of a CO_2 economic penalty, in an electricity generation system based on low-quality coal.

Finally, the discussion tackles the available CO_2 storage options and scenarios in the Greek territory, based on recent surveys for the assessment of CO_2 storage sites in Greece conducted within the framework of EU projects.

1. Introduction

During the last thirty years human activities have increased the CO_2 emissions in the atmosphere by 15%. In the assessment report of the Intergovernmental Panel on Climate Change (IPCC), it is stated that most of the observed global warming over the last 50 years is likely to have been due to the increase in greenhouse gases concentrations in the atmosphere. Stabilisation of the atmospheric CO_2 concentration requires CO_2 emissions to eventually drop well below current levels **[1]**. In analysing measures for reducing CO_2 emissions, the IPCC concludes that none of the following measures alone would be sufficient to stabilise atmospheric CO_2 concentrations: demand reductions and/or efficiency improvements; substitution among fossil fuels; switching to renewables or nuclear energy; CO_2 sequestration; or afforestation. Thus, in identifying strategies climate change mitigation, combinations of multiple technologies in all sectors must be considered. Carbon sequestration can be defined as the capture and secure storage of carbon that would otherwise be emitted to, or remain, in the atmosphere. This is called carbon capture and storage (CCS). The rationale for CCS is to enable the use of fossil fuels while reducing CO_2 emissions into the atmosphere, thereby mitigating global climate change. At present, fossil fuels are the dominant source of the global primary energy demand, and will likely remain so for the rest of the century supplying over 85% of all primary energy. Despite the great efforts and investments by many nations to increase the share of renewable energy to the primary energy demand and to foster conservation and efficiency improvements of fossil fuel usage, addressing climate change concerns during the next decades will likely require significant contributions from CCS.

2. CO_2 Sequestration Technologies

The commercial or under development CCS technologies for thermal power plants are divided into three broad categories: CO2 separation from flue gas (post-combustion capture), combustion in O2 instead of air or oxyfuel combustion and production of a carbon-free fuel (pre-combustion capture) **[2]**.

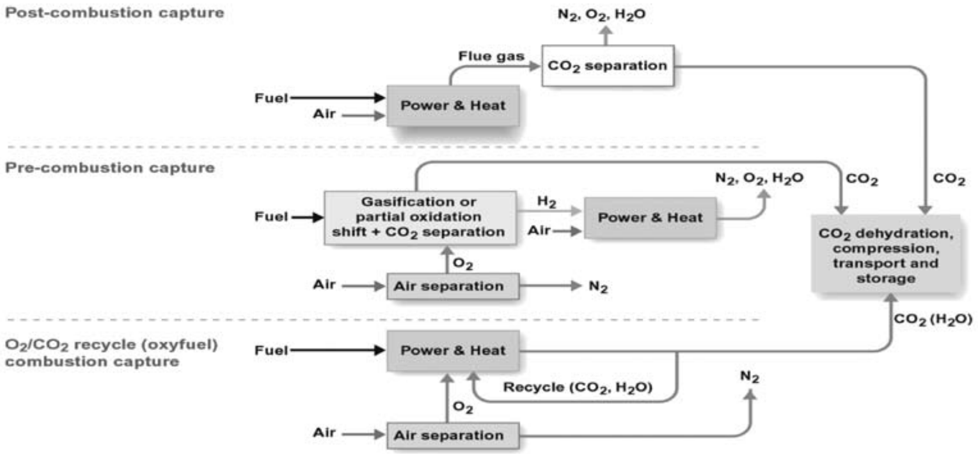


Figure 1: CCS technological options

A. Post-combustion CO2 capture

The following basic processes can be used for large scale CO_2 precipitation from flue gases: absorption (separation in a liquid absorbent via a scrubber), adsorption (separation on a solid), membrane engineering (separation of CO_2 based on the different permeability compared with other gases), and low-temperature technology (freezing or condensing the CO_2). From the above mentioned, absorption is a mature commercially available technology, whereas the other processes are not developed enough to provide an attractive potential. Depending on whether or not a chemical reaction takes place, absorption processes can be classified as chemical and physical. Chemical absorption is suitable for high gas flows (>150 m3/s and low CO_2 partial pressures (<7 bar), while physical absorption is suitable for high gas flows (>150 m3/s) and high CO_2 partial pressures (>7 bar) **[3]**.

The most common solvents used are the alkanoamines. The most commercially successful technique for CO_2 capture from power plants flue gases is the wet scrubbing process with chemical absorption by Monoethanolamine (MEA) (Fig. 1). MEA scrubbing provides CO_2 recovery of 98% and product purity of more than 99%. Most systems use an aqueous solution of 15-25 wt% MEA, mainly due to corrosion issues **[4]**.

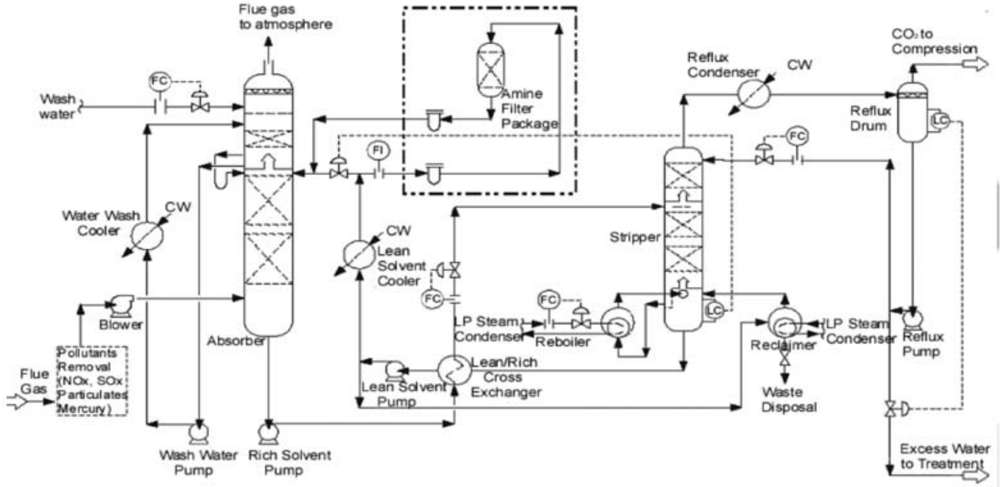


Figure 2: Chemical absorption with amines **[7]**

In the amine gas processing operation, CO_2 is absorbed from the flue gas, which should be free of SO_2, O_2, hydrocarbons and particulates, by the liquid solvent in an absorber operating at 40-60ºC **[4]**. The gas stream and the liquid solvent are contacted in counter-current flow in the absorption tower. The gas to be scrubbed, after being compressed to ca. 1.3 bars, enters the tower at the bottom, flows up and leaves the absorber at the top. The solvent, enters the tower at the top, flows down and leaves at the bottom. In the stripper (regeneration stage) the charged amine solution is heated with steam to 120-150ºC, in order to strip off CO_2 **[2]**. This temperature range is used due to the thermal degradation of the solvent at temperatures higher than 125ºC. The regeneration stage is carried out at low pressures to enhance CO_2 desorption. The hot lean amine solution flows through a heat exchanger, where it is contacted with the charged amine solution flow and then it enters again the absorption tower. The CO_2 stream is cooled, its water content is removed, and it consequently compressed and transported to the storage location (Fig. 2).

The required heat for the regeneration of the absorbent is 3.2-4 MJ per kg of recovered CO_2. In the case of a steam power plant, this heat is covered by steam extraction from the LP steam turbine (4.5-6 bar). The energy for the compression of the flue gases and the pumping of the amine solution is approximately 0.11 MJ per kg of CO_2 captured **[5]**. When applied in coal-fired power plants, wet scrubbing process with chemical absorption reduces the steam flow in the low-pressure steam turbine by approximately 2/3, due to the steam demand of the system for regeneration of the CO_2 charged solvent (back reaction), which equals to approximately 80% of the total energy consumption of the chemical absorption process. As a result, power output is reduced by 20% and the plant efficiency by 11 to 14 percentage points [6]. For a typical plant, the economical recovery is 85% for 3% CO_2 in the flue gas, while it is 90-92% for 8% CO_2 in the exhaust gas.

B. Oxyfuel combustion

The oxyfuel concept is based on the fact that when coal, hydrocarbon or synthesis gas is burned with pure O_2 instead of air, the produced flue gas contains mainly CO_2 and H_2O. By cooling the waste gas, the water content is condensed and an almost pure gaseous CO_2 stream can be achieved, which can be compressed, transported and stored. The method can be applied in steam generation power plants, Gas Turbines or IGCC's and for all fossil fuels (coal, oil or natural gas).

An Air Separation Unit (ASU) is required for O_2 production. Cryogenic air separation is the most suitable technique for N2 separation from air (Fig. 3), which has the following stages: air compression with intercooling, cooling to 11.5 ºC, removal of water vapour and other impurities through molecular sieves, liquefaction of the compressed air (-180ºC) in a heat exchanger to utilise the heat of the outgoing gas streams and separation of N2 from the air in a distillation column **[8]**.

Up to 15% of the power plant's electrical output is consumed by the process **[9]**. The purity of the O_2 produced in the ASU plays an important role regarding power consumption for air separation. Cryogenic air separation can give 99.7% O_2 purity. For purities below 95%, power consumption is reduced due to the lower air pressure required, while for purities higher than 97%, power consumption is sharply increased, since Ar should also be separated. Taking into account the energy required for the air separation, the production of O_2 with purity of 95% is a promising option **[10]**.

Fuel combustion with pure oxygen produces very high combustion temperatures. In order to lower the temperature and attain unchanged combustion conditions, part of the flue gas is recycled in the combustion chamber. In the case of a retrofit design, the temperature as well as the flue gas volume should remain within the same range as for conventional combustion. Several studies propose that when the O_2/CO_2 combustion CO_2 separation technique is applied to a boiler, approximately 2/3 of the boiler exit flue gas mass flow should be recirculated **[11]**, **[10]**.

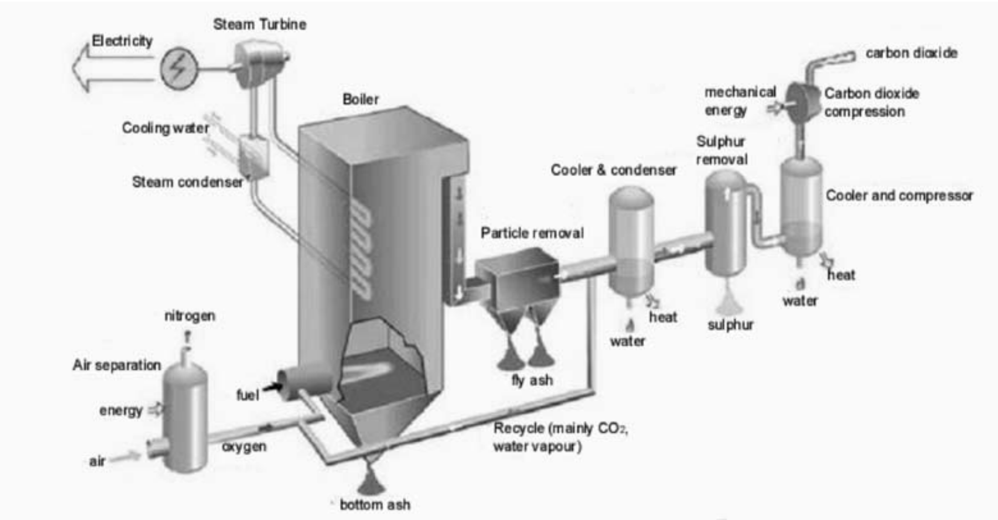


Figure 3: Oxyfuel combustion scheme (Vattenfall)

The typical flue gas treatment for an oxyfuel power plant consists of the following steps **[12]**:

- flue gas condensation with water treatment (to separate the main part of H_2O in the flue gas)
- compression (to transfer the flue gas in liquid state)
- Active dehydration with TEG (Tri-Ethylene Glycol) (to separate the remaining H_2O in order to avoid corrosion and hydrate precipitation during transportation)
- Heat exchanging (to super-cool the gas stream to make sure that it is in the liquid state)
- Removal of non-condensable gases as N_2, O_2 and Ar
- Compression (increase the pressure of the fluid to achieve the transport conditions).

C. Pre-combustion CO2 capture

In the frame of CO_2 pre-combustion capture, carbon is removed from the fuel prior to combustion. In the typical coal gasification process, coal is pulverized and mixed with water to produce a slurry. The slurry is heated with O_2 or air to ca. 1300 K and decomposed, producing a mixture of mainly H_2 and CO. The product undergoes a “CO shift” or “water shift” reaction, where CO is converted to CO_2 and H_2 through an exothermic reaction at 673 K (Fig. 4). After conversion, the synthesis gas consists mainly of H_2 and CO_2. Due to the high CO_2 partial pressure, absorption through physically active solvents (Rectisol) is the most appropriate method for CO_2 separation **[9]**. H_2 permeating membranes can also be used for H_2/CO_2 separation.

Another CO_2 pre-combustion concept proposes that coal gasification, water shift reaction and CO_2 separation can occur under the same operating conditions and integrated into the same reactor. The sorbent suitable for the CO_2 capture is CaO and the reaction takes place at 1100 K. Two bed reactors can be used for this procedure, one for the gasification, shift and capture reactions and one for the regeneration of the sorbent.

The H_2-rich product gas leaves the first reactor and the CO_2 stream leaves the second reactor, after calcination of the sorbent. With application of this proposed technology, the overall energy penalty may be reduced by 20-25%, compared with the standard gasification process **[13]**. The above-mentioned technologies are also applicable for natural gas, where instead of gasification, the reforming reaction takes place, breaking CH_4 into H_2 and CO in the presence of steam.

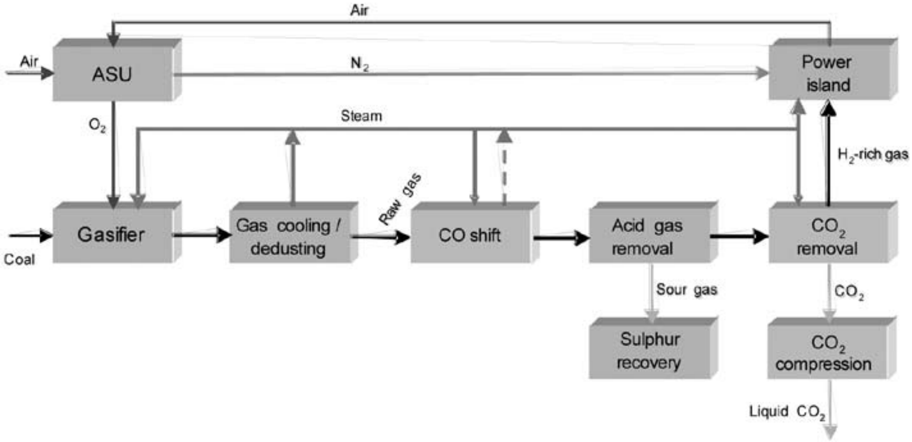


Figure 4: Pre-combustion CO_2 capture **[7]**

3. CO_2 Capture and Storage in the European Market

The European Technology Platform has estimated the effect of implementing the various CCS technologies in the European electricity generation sector in 2020, for typical natural gas, coal and lignite units **[7]**. For the calculations, the following assumptions were made: economic life time and depreciation period 25 years, natural gas costs 5.8 €/GJ, coal costs 2.3 €/GJ and lignite costs 1.1 €/GJ, fuel price escalation 1.5%/year and 7500 annual operating hours at full load. The discount factor is 9%, the tax rate 35% and the loan interest rate 6%.

Table 1 presents the basic calculation figures concerning the power output, efficiency, CO_2 capture rate and the capital cost. In all cases, CO_2 capture is higher than 85%. A significant capital cost increase and efficiency decrease is demonstrated. For the typical coal unit, the capital cost increase varies from 58-72% and the efficiency decrease is 10 percentage points, while for the lignite unit the corresponding figures are 46-58% and 2-4 percentage points (lignite pre-drying is applied for the CO_2 capture units in this case). Finally, for the typical lignite unit, the capital cost increase varies from 81-174% and the efficiency decrease to 10-17 percentage points.

The estimation of the effect of implementing CO_2 capture technologies in the European electricity generation sector in 2020 is shown in Fig. 5, which demonstrates a generation cost increase of the order of 40-50%, while Fig. 6 presents the CO_2 capture cost per ton CO_2, being in the range of 50-60 €/t for solid fuel units and ca. 100 €/t for natural gas units, with a potential of decrease by 20-50% with further development of CO_2 capture technologies.

Coal		**Reference Unit**	**Unit with pre - combustion capture**	**Unit with post - Combustion capture**	**_ xyfuel**
Power output	MW	556	737	460	470
Efficiency	%	46	36	36	36
CO_2 capture	%	-	92	85	91
Capital cost	Euro/kW	918	1577	1446	1447
Lignite		**Reference Unit**	**Unit with pre - combustion capture**	**Unit with post - Combustion capture**	**_ xyfuel**
Power output	MW	920	717	731	760
Efficiency	%	43	41	39	41
CO_2 capture	%	-	85	85	90
EPC Capital cost	Euro/kW	1065	1556	1683	1671
Natural Gas		**Reference Unit**	**Unit with pre - combustion capture**	**Unit with post - Combustion capture**	**_ xyfuel**
Power output	MW	420	755	662	325
Efficiency	%	58	41	47	48
CO_2 capture	%	-	93	85	100
Capital cost	Euro/kW	410	763	742	1124

Table 1: CO_2 in large coal, lignite and natural gas units **[7]**

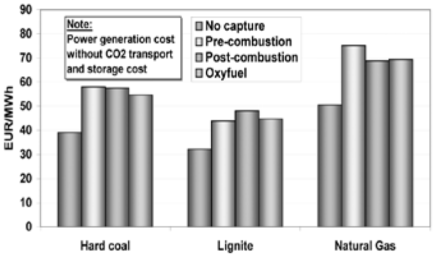


Figure 5: Estimated electricity generation cost from large coal, lignite and NG units in 2020, without and with CO_2 capture **[7]**

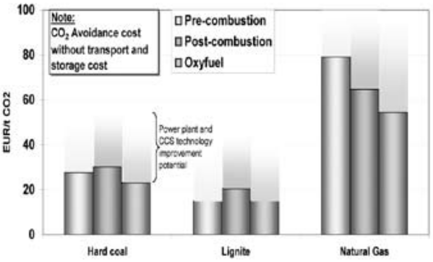


Figure 6: Estimated CO_2 capture cost from large electricity generation units in 2020 (coal, lignite and NG) **[7]**

According to the European Platform for Zero Emission Fossil Fuel Power Plants, a list of 43 large scale demonstration projects for CCS in Europe has been announced, while the first project implementation is foreseen for 2010. Among them, 6 projects are dealing with lignite utilization and CCS technology. All technological options are involved, while the most selected solution is post combustion **[14]**. Furthermore, according to the proposal of the Presidency to the European Council (20/3/2009) related to the European Economic Recovery Plan and call for proposals of May 2009, 13 CCS projects are to be funded with 1050 M€, of which 12 are dealing with coal utilization and include all technological options **[15]**.

The current section aims to assess the effect from implementation of CCS technologies in the Greek electricity generation sector. In this respect, both a green-field oxyfuel power plant based on a typical Greek lignite-fired power plant as well as the retrofit of an existing lignite power plant to oxyfuel and post-combustion capture have been modeled, in order to demonstrate the potential for emissions reduction and evaluate the associated power output and efficiency penalties. The power plant simulations have been performed with the thermodynamic cycle calculation software ENBIPRO (**EN**ergie-**BI**llanz-**PRO**gram), a tool for heat and mass balance solving of complex thermodynamic circuits, calculation of efficiency and exergetic and exergoeconomic analysis of power plants, as well as the commercial thermodynamic cycle calculation software GATECYCLE.

4.1 Green-field Oxyfuel Greek Power Plant

The reference power plant used as a base case for the assessment of the efficiency of a Greenfield oxyfuel power plant is a 360 MWel gross power output plant with reheat and 7 water preheaters with steam extraction from the ST. Since the raw lignite has a high moisture content of 55.4 % w/w, a fuel pre-drying system has been integrated in both the reference power plant and the oxyfuel plant, based on utilisation of the heat content of the moisture removed in the form of steam from the raw lignite, for the drying (WTA drying system) **[16]**. The water content of the raw lignite is while it is reduced to 12 % w/w at the exit of the dryer. In all simulations, the fuel consumption of the power plant is kept the same.

		Ref. PP	**Greenfield oxyfuel PP**
FW pump	MW_{el}	9.17	9.54
Forced Draft fan	MW_{el}	1.43	-
Induced Draft and gas fans	MW_{el}	2.77	3.55
Dryer	MW_{el}	25.21	25.21
Lignite mills	MW_{el}	9.05	9.05
Electrostatic Precipitators (ESP's)	MW_{el}	0.50	0.50
Fly ash transport	MW_{el}	0.85	0.85
Lignite feeding and handling system	MW_{el}	0.78	0.78
Condensate pumps	MW_{el}	0.54	0.56
Circulating and cooling water pumps	MW_{el}	3.74	3.93
Others	MW_{el}	1.14	1.20
ASU	MW_{el}	-	52.39
CO_2 compression	MW_{el}	-	46.35
Raw Fuel flow	kg/s	136.34	136.34
Gross power output	MW_{el}	356.78	392.45
Gross el. efficiency	%	48.30	53.13
Net power output	MW_{el}	301.61	238.53
Net el. efficiency	%	40.83	32.29

Table 2: Main results of the green-field oxyfuel simulations **[18]**

The main results of the simulations, in terms of power output and efficiency, are presented in Table 2. A significant increase in gross power output for the oxyfuel power plant was observed, in the magnitude of 36 MW. That is partially attributed to an increased steam production from the boiler, as well as to the heat integration scheme, which has eliminated the need of some steam extractions for preheating. Nevertheless, the significant demand for auxiliary power arising from the application of the oxyfuel CO_2 capture technology results in a considerable penalty in the power plant performance of ca. 8.5 percentage points. Concerning the CO_2 capture efficiency, this is strongly related to the flue gas composition at the boiler exit. The remaining non-condensable gases in the oxyfuel case consist of O_2, N_2, SO_2 and Ar. Their presence is due to the 95% vol. purity of the O_2 at the exit of the ASU, as well as the air infiltration in the boiler and the ESP. The removal of non-condensable gases is achieved by a flash process and are released to the atmosphere. However, an amount of the condensed CO_2 is released too during this process **[17]**. In the case examined, the calculated CO_2 capture efficiency is limited to 90% of the CO_2 produced from lignite combustion.

4.2 Retrofit of a Greek Power Plant with CCS

From the three basic CO2 capture technological pathways, only post-combustion capture and oxyfuel combustion can be applied in existing power plants. In this framework, the retrofit of a typical 330 MWel power plant with amine scrubbing and oxyfuel combustion has been modelled. The plant has a supercritical boiler and a triple-pressure steam turbine configuration with 8 feed-water preheating stages. The flue gas after the air pre-heater passes through the electrostatic precipitator and the flue gas de-sulphurisation unit.

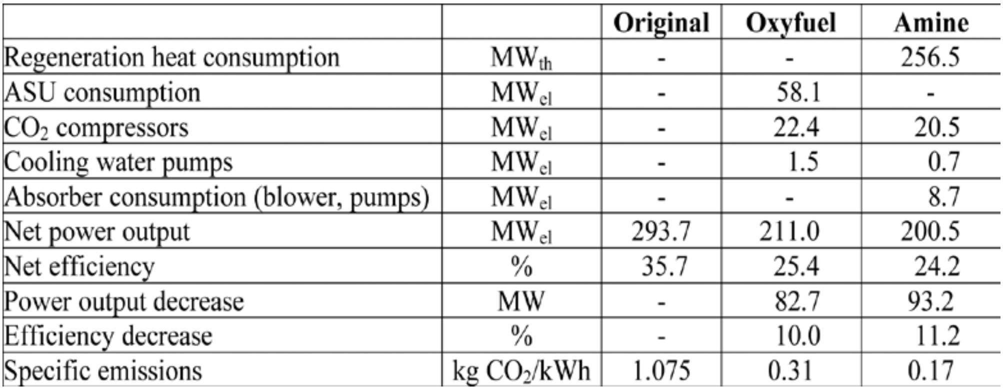
The main energy consuming processes concerning the amine scrubbing technology, for a 90% CO_2 capture rate, are the following:

- Heat consumption for regeneration of the rich-CO_2 solution (4 MJ/kg CO_2), covered by LP steam extraction from the steam turbine at 6 bar/285 oC (1.7 kg steam/kg CO_2) **[19]**.
- Electricity consumption of flue gas blowers used to overcome the system pressure drop, as well as for pumping of the amine solution and of the absorber wash water **[19]**.
- 5-stage compression of the CO_2 stream to 110 bar with inter-cooling to 20 ^oC for transportation and storage and cooling pumps consumption (inlet pressure 2.5 bar).

Under the assumptions of 95% O_2 purity and 3% air infiltration, the oxyfuel combustion process can capture 79% of the CO_2 that is produced from coal combustion **[11]**, since the flue gas contains a significant amount of non-condensable gases (N_2, Ar και O_2) that should be removed. During the removal process, part of the CO_2 is vented to the atmosphere. The main energy consuming processes of the oxyfuel technology are the following:

- Cryogenic ASU: 4-stage air compression to 5.5 bar with inter-cooling to 20 ^oC.
- CO2 compression: 5-stage compression 110 bar with inter-cooling to 20 ^oC.
- Cooling water compression to 2.5 bar, for cooling of the ASU inlet air/CO_2 stream.

The main results of the simulations are presented in Table 3, where the large influence of integration of CO_2 capture technologies on the efficiency of the original power plant is demonstrated. The application of the oxyfuel and the amine scrubbing technology decreases the power plant efficiency by 10.3 and 11.5 percentage points, respectively. The oxyfuel technology has a greater optimization potential, since the flue gas exits the boiler at 305 ^oC, due to the elimination of the air preheater, and a large amount of heat could be recovered for feed-water pre-heating. Due to the increased cost and difficulty of this scheme for retrofit applications, the above mentioned solution can be applied mainly in new power plants with CO_2 capture (section 4.1).



		Original	Oxyfuel	Amine
Regeneration heat consumption	MW_{th}	-	-	256.5
ASU consumption	MW_{el}	-	58.1	-
CO_2 compressors	MW_{el}	-	22.4	20.5
Cooling water pumps	MW_{el}	-	1.5	0.7
Absorber consumption (blower, pumps)	MW_{el}	-	-	8.7
Net power output	MW_{el}	293.7	211.0	200.5
Net efficiency	%	35.7	25.4	24.2
Power output decrease	MW	-	82.7	93.2
Efficiency decrease	%	-	10.0	11.2
Specific emissions	kg CO_2/kWh	1.075	0.31	0.17

Table 3: Basic retrofit simulation results

4.3 Economics of CO_2 capture in the Greek electricity market

In this section, an estimation of the electricity generation cost is provided for the following technologies: conventional lignite power plant, conventional lignite power plant with integrated CO_2 capture with amine scrubbing and oxyfuel combustion, state-of-the art supercritical lignite power plant (clean coal technologies), natural gas-fired combined cycle and Integrated Gasification Combined Cycle (IGCC) power plant. For the calculations, the following assumptions have been made: discount factor 8%, inflation 3%, lignite cost 1.8 €/GJ and natural gas costs 5.5 €/GJ, depreciation for solid fuel units 25 years, for NG and IGCC units 15 years. The operating and maintenance costs is assumed 3% of the investment cost per year and the variable costs 0.01 €/kWh for lignite units and 0.005 €/kWh for natural gas units. The annual operating hours of the units are 7500 at full load. The CO_2 cost, defined by the CO_2 market, has been assumed 18 €/tn. The specific assumptions for each power plant case are provided in Table 4 **[2]**.

Fixed costs include the capital cost depreciation and the operating and maintenance costs, while variable costs include the fuel cost. The natural gas-fired unit demonstrates the lowest fixed cost, due to its low capital cost while, on the other hand, for the units with CO_2 capture and the IGCC unit, the fixed costs are a large percentage of the total kWh costs, due to the increased capital, operating and maintenance costs. Because of the low fuel costs, lignite units have the lowest variable costs with respect to natural gas units. Nevertheless, the variable costs of units integrating CO_2 capture increase significantly, due to their low efficiency. The increased volatility of natural gas price, due to its dependency to oil prices (up to 40% of total costs [206]) contributes in an increased uncertainty concerning the electricity generation cost from natural gas-fired combined cycle units, in contrast to the domestic lignite market which is practically independent of oil prices.

		Convent. lignite fired power plant	Amine scrubbing	Oxyfuel	Clean coal	NGCC	IGCC
Net power output	MWel	293.7	200.5	211	300	380	766
Net efficiency	%	35.4	24.2	25.4	44.0	56.5	43.0
Investment cost	€/kW	1100	1900	1570	1150	600	1370
CO_2 specific emissions	kg/ kWh	1.075	0.17	0.31	0.865	0.37	0.76

Table 4: Specific assumptions for electricity generation cost estimation

For the estimation of the effect of CO_2 emissions on electricity generation costs, the units have been grouped in two categories: current technologies and technologies that will be commercially available in the future. The difference in specific emissions from the reference unit for each category (natural gas unit for the first category and conventional lignite power plant with integrated CO_2 capture with amine scrubbing for the second) multiplied by the CO_2 cost is an estimation of the price risk due to the emitted CO_2.

As concerns the total generation costs, Figures 7 and 8 show that the conventional lignite power plant, the state-of-the art supercritical lignite power plant and the IGCC unit have the lowest kWh costs, while the natural gas unit has the highest generation cost, due to the high fuel prices and the market uncertainty. In addition, the implementation of CCS technologies significantly increases the capital costs and influences negatively power plant efficiency and, as a result, electricity generation costs.

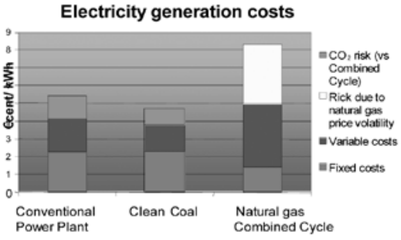


Figure 7: Electricity generation costs - Current technologies

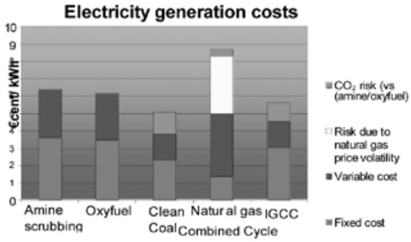
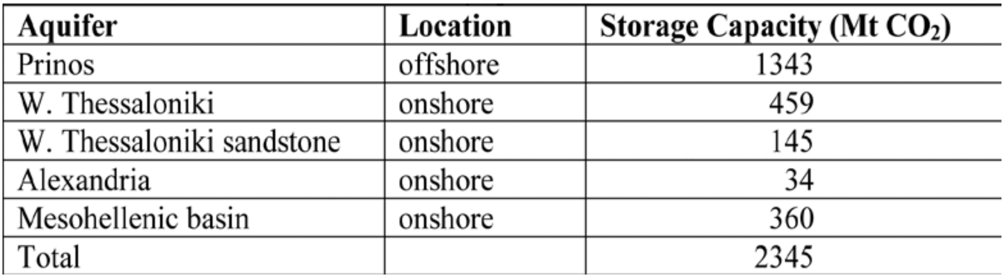


Figure 8: Electricity generation costs - Future technologies

4.4 Storage capacity of geologic formations in the Greek territory

The candidate geologic formations where CO_2 could be stored in the long term are mostly present in Northern Greece. These formations are a part of the Mesohellenic Trough, of the Thessaloniki basin and of the Prinos basin. The total storage capacity is estimated to ca. 2345 Mt CO_2, as presented in Table 5. The locations have been selected due to their proximity to the main sources of CO_2 emissions, namely the lignite-fired power plants situated in Northern Greece, refineries, cement and fertilizer industries. Especially the Prinos basin offers adequate infrastructure, due to the exploitation of hydrocarbon resources conducted in the area. Nevertheless, further research is required for all the candidate areas so that their suitability is confirmed.



Aquifer	Location	Storage Capacity (Mt CO_2)
Prinos	offshore	1343
W. Thessaloniki	onshore	459
W. Thessaloniki sandstone	onshore	145
Alexandria	onshore	34
Mesohellenic basin	onshore	360
Total		2345

Table 5: CO_2 storage potential in Greece **[20]**

5. Conclusions

CCS technologies can contribute significantly in the reduction of atmospheric CO_2 emissions from the electricity generation sector. Nevertheless, the effect of implementation of these technologies in the efficiency decrease of the power plants is pronounced, resulting in a considerable increase of electricity generation costs, in combination with the higher investment costs. In addition, the purchase of CO_2 credits through the CO_2 market under development is expected to further increase electricity costs. From the comparison of the various technological solutions, it is concluded that units utilising local lignite can under these circumstances have a competitive kWh cost with respect to natural gas units, which present a larger cost risk due to the volatility of natural gas prices.

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A detailed list of over 300 publications in scientific journals and conferences, as well as reports for different projects are available upon request. Citations on the published work, based on Scopus and ISI Web of Knowledge databases, are calculated at 535 (excluding self-citations), while the h-Index is estimated at 13. Based on the analysis conducted by the School of Mechanical Engineering of the National Technical University of Athens, the above index is the second higher h-Index among all the academic staff of the School and the highest among those of the academic staff that are active in the field of energy.

Dr. Aggelos Doukelis was born in Athens in 1969 and graduated from the Anavryta High School. He completed his university studies in the National Technical University of Athens with a Diploma in Mechanical Engineering in 1993 and holds a Ph.D. degree in Turbomachinery and Engineering Mechanics from Cranfield University (1999).

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