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IGCC with CCS

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1. Introduction

Integrated gasification combined cycle (IGCC) is a technology where a solid or liquid fuel, such as biomass, coal or heavy oil, is firstly converted into a synthesis gas (syngas). Then all fuel-derived impurities are removed from the gas before it is combusted in a gas turbine. The excess heat from the gas turbine is then passed to a steam cycle, which results in a higher efficiency compared to conventional combustion and steam cycle alone. Sulphur dioxide, particulates and heavy metals are removed from the syngas using effective gas cleaning processes. Even carbon dioxide is less costly to separate from a high-pressure syngas stream than from a flue gas stream. Also the carbon monoxide of the syngas can be converted by shift conversion to hydrogen and carbon dioxide before final CO_2 removal.

The objective of this work was to identify the most promising IGCC concepts that would be particularly suitable for Finland for further development. To achieve this goal, various IGCC concepts and projects, existing and in development, were screened. Considering the Finnish market conditions, the most potential concepts were evaluated in more detail using process modelling tool Aspen Plus.

In this report, a short overview of IGCC technology status is given followed by a description of operating IGCC plants and on-going IGCC projects. Performance and cost evaluations for a coal-based IGCC concept with and without CO_2 capture is presented and compared to those of conventional technologies (pulverized coal power plants and natural gas fired combined cycle power plants). Finally, relevant IGCC concepts for Finland as well as their performance and cost evaluations are presented and discussed.

2. IGCC – overview

2.1 IGCC plant description

Integrated gasification combined cycle (IGCC) is an attractive option for power generation because it offers a relatively high efficiency and it enables co-production of other valuable products, such as SNG, hydrogen or chemicals. In recent years, as environmental regulations are driving power producers to adopt CCS technology to reduce CO_2 emissions, IGCC concept has become an even more viable alternative. Contrary to conventional power plants where CO_2 is separated from the flue gas after combustion (post-combustion technology), IGCC plants enable CO_2 capture from the syngas before combustion (pre-combustion technology) which is less costly.

IGCC technology combines gasification with a combined cycle power system. A simplified block flow diagram of a typical coal-based IGCC plant is presented in Figure 1. Carbon-containing feedstock, such as coal, petcoke or residual oil, is gasified to produce a combustible gas mixture, syngas, which contains mainly H_2, CO, CO_2 and impurities, such as fly ash, alkali and sulphur species. Gasification is followed by gas cleaning units to separate the impurities before the cleaned gas is combusted in a gas turbine. Gas clean-up units include particulate removal, COS hydrolysis, mercury (Hg) and acid gas removal (AGR).

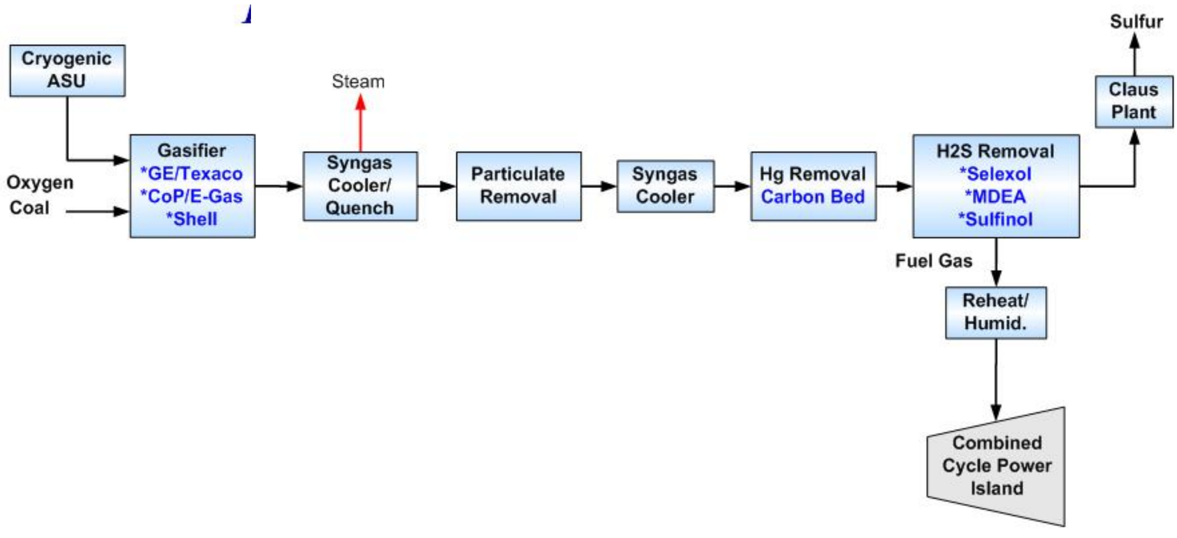


Figure 1. Coal-based IGCC power plant concept without CO_2 capture [1].

In a coal-based IGCC plant, syngas is first cooled down by heat exchangers or quenched with water after which particulates are removed in a water scrubber and/or a cyclone/filter unit. Water scrubbing also removes hydrogen chloride (HCl) and ammonia (NH_3). Particulate-free gas enters a COS hydrolysis unit where carbonyl sulphide (COS) is converted into hydrogen sulphide (H_2S) which is later removed in the AGR unit. After further cooling, carbon beds are applied for mercury adsorption. The remaining acid gases, such as H_2S, are separated in the AGR unit typically by absorption into chemical (e.g. MDEA, Methyldiethanolamine) or physical solvents (e.g. Selexol, Rectisol). The separated H_2S is recovered from the sour gas leaving the AGR unit and converted into elemental sulphur or sulphuric acid (H_2SO_4). Most commonly, H_2S is retrieved as liquid sulphur by using a catalytic Claus process. [2] The cleaned syngas is fired in a gas turbine to produce electricity. To reduce NO_x emissions, syngas is first diluted with nitrogen. The flue gases are passed through a heat recovery steam generator (HRSG) to generate steam which is further applied in a steam turbine for power generation.

Incorporation of CO_2 capture to an IGCC power plant requires certain modifications to the basic process scheme. A water gas shift reactor is needed prior to AGR for converting CO to CO_2. CO_2 can then be removed in a conventional AGR unit simultaneously with H_2S. Rectisol and Selexol processes are favoured for parallel H_2S and CO_2 removal in CO_2 capture cases. CO_2 and H_2S are released from the AGR unit separately after which H_2S is led to sulphur recovery and CO_2 for further processing. [2] A simplified block flow diagram of a coal-based IGCC plant with CO_2 capture is presented in Figure 2.

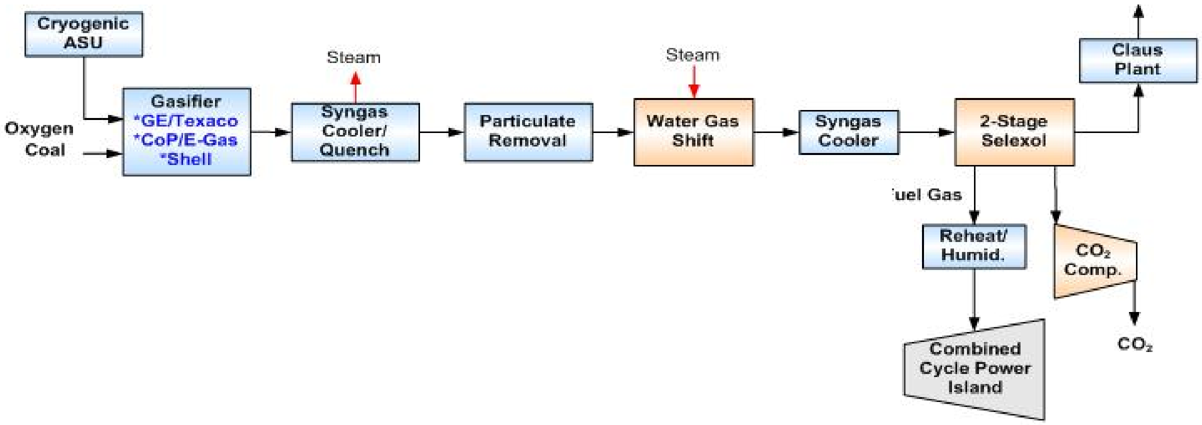


Figure 2. Coal-based IGCC power plant concept with CO_2 capture [1].

Biomass-based IGCC power plant concept differs from the coal-based concept described above mostly due to the different gas quality, especially the presence of tars in the syngas. Biomass can also be gasified in air-blown fluidized-bed gasifiers operating at relatively low temperatures, while less reactive coal must be gasified at higher temperatures using oxygen as the gasification agent. A detailed description of a biomass-based IGCC is presented in Chapter 4 where IGCC concepts suitable for Finnish conditions are highlighted.

2.2 IGCC technology status

The first IGCC power plants that are currently in commercial operation were commissioned in the 1990's. The existing IGCC power plants are either based on solid feedstock, mostly different types of coals or petcoke, or residual oils from refineries. High-temperature and high pressure entrained-flow gasification technology is well suited for coal/petcoke/residual oil gasification and is preferred over fixed-bed and fluidized-bed gasification technologies in IGCC applications. Most operating and planned IGCC plants are based on oxygen-blown entrained-flow gasification. Entrained-flow gasification technology providers include Shell, GE, Siemens, ConocoPhillips and Mitsubishi all of which have commercial references. [2] Comparison of the different gasification technologies as well as examples of technology providers is given in Figure 3. Furthermore, the main entrained-flow gasifier types are illustrated in Figure 4.

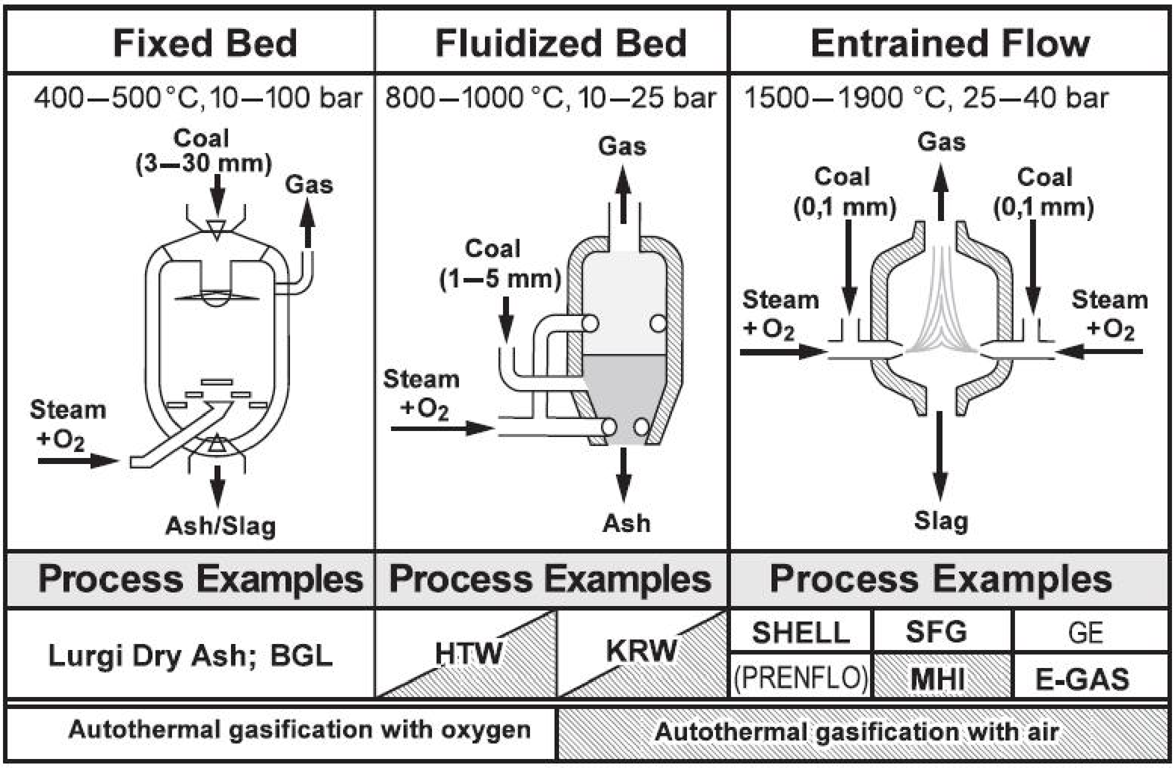


Figure 3. Comparison of gasification technologies [2].

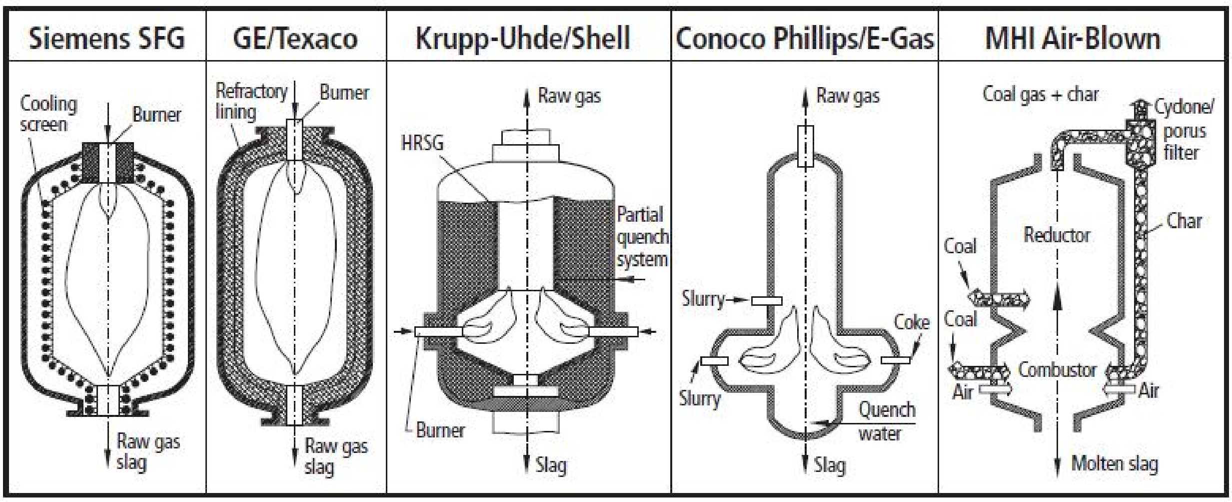


Figure 4. Entrained-flow gasifier types [2].

Due to the gained experience from operating plants, coal-based IGCC technology can be considered commercially proven and available. However, high capital costs and challenges related to plant availability have hindered its market penetration. Current R&D activities are focused on improving the efficiency and reliability as well as reducing the costs of coal-based IGCC power plants to make them more competitive against conventional power plants. R&D areas include e.g.: [3]

- development of alternative air separation methods, such as ion transport membranes (ITM), to replace the conventional cryogenic air separation unit (ASU)

- development of warm syngas clean-up methods to replace low temperature AGR which would reduce heat losses

- development of more advanced gas turbines suitable for H2-rich syngas (e.g. to allow higher firing temperatures)

Biomass-based IGCC process was developed in Finland in the late 1980's and early 1990's and it was demonstrated at a small CHP plant (6 MW_e/9 MW_{th}) in Värnamo Sweden in 1993-1999. This project showed that this so called simplified-IGCC process was technically feasible [4]. The Värnamo plant was based on Foster Wheeler CFB gasification followed by hot gas filtration. Similar concept was also tested on 20 MW_{th} scale in Tampere using Carbona's BFB gasifier. However, no commercial-scale plants have been built so far. The smallest economical plant size for this simplified biomass-IGCC has been estimated to be in the range of 20-30 MW_e.

2.3 Operating IGCC plants

The first IGCC power plants that are still in operation started as demonstration plants in the 1990's and have later switched into commercial operation. They mostly use coal or petcoke as feedstock. Two plants are located in the US (Wabash River and Polk County IGCC power stations) and three in Europe (Buggenum, Puertollano and Vresova IGCC plants). These IGCC plants have obtained availabilities of approximately 80 % [5]. The development of plant availability in the Polk County IGCC power station after being commissioned in 1997 is illustrated in Figure 5. The plant efficiencies (LHV basis) range between 39-44 % (see Appendix A).

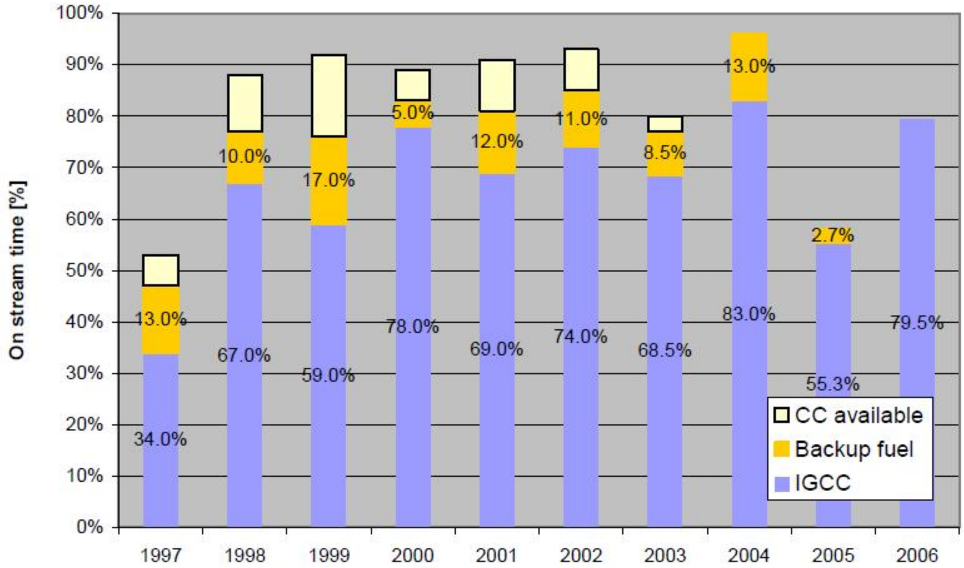


Figure 5. Polk County IGCC power station availability in 1997-2006. In 2005 the gas turbine compressor unit caused a 100-day outage. The share between IGCC and back-up fuel availabilities is not given for 2006.[6]

In 1999-2008, new IGCC plants utilizing typically residual oils from refineries were commissioned. E.g. the Sarlux IGCC plant was integrated to the SARAS refinery in Italy. The plant uses visbreaker residue as feedstock to produce hydrogen and steam to the refinery as well as electricity to the Sardinian power grid [7]. In Czech Republic, the Vresova IGCC plant received an additional Siemens gasification block in 2007. The original coal-based IGCC plant, which was commissioned in 1996, employs a Lurgi fixed-bed gasification technology which produces liquids, such as coal tars and phenol concentrates, as by-products. These by-products are gasified in the new unit to produce more electricity. [8]

Most recently the Clean Coal Power R&D Ltd constructed a 250 MW IGCC demonstration plant in Nakoso, Japan. The plant, which is based on the Mitsubishi air-blown gasification technology, started operation in 2007. [8] After successful tests with coal, the demonstration programme was terminated at the end of March 2013 and the plant will continue operation as a commercial plant [9]. A full list of operating IGCC plants is given in Appendix A.

2.3.1 CO_2 capture at operating IGCC plants

None of the existing IGCC plants is equipped with full-scale CO_2 capture facilities. In recent years, however, pilot-scale CO_2 capture tests have been carried out at the Buggenum and Puertollano IGCC plants [10, 11, 12]. Additionally, a CO_2 capture demonstration unit is under construction at the Polk County IGCC plant [13, 14].

The Buggenum IGCC plant (253 MW) in the Netherlands was commissioned in 1994 with coal as feedstock (Figure 6). The plant has been in commercial operation since 1998. [15] Various fuels, such as automotive shredder fibres, petcokes and biomass, have been tested as secondary feedstock. Biomass up to 30 % input has been co-gasified at the Buggenum plant since 2005. [16] Furthermore, a pilot-scale CO_2 capture unit with 90 % capture rate was constructed to take a 20 MW slipstream from the plant. Tests were started in May 2011. [17]

In the 335 MW Puertollano IGCC plant in Spain, pilot-scale CO_2 capture and H_2 production tests were carried out in 2010-2011. A block flow diagram of the test facility is presented in Figure 7. The pilot facilities (14 MW_{th} slipstream from the plant) included a shift reactor with subsequent CO_2 and H_2 separation and H_2 purification in a PSA (pressure swing adsorption) unit. The CO_2 capture rate was approximately 91.7 %. [10, 11, 18]

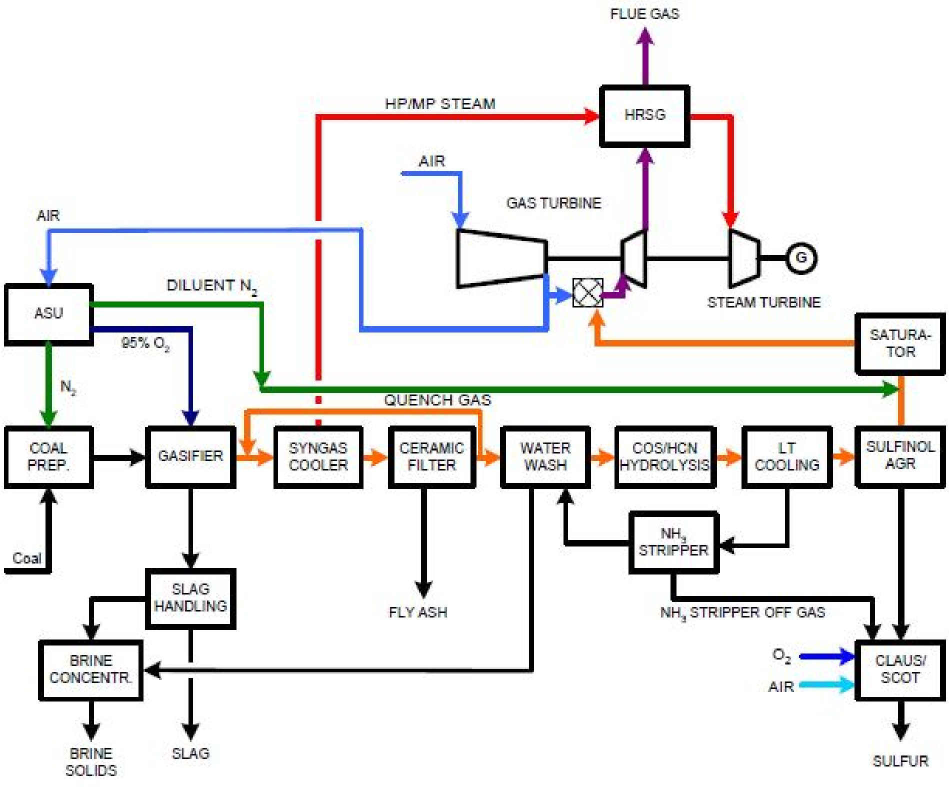


Figure 6. A block flow diagram of the Buggenum IGCC plant [6].

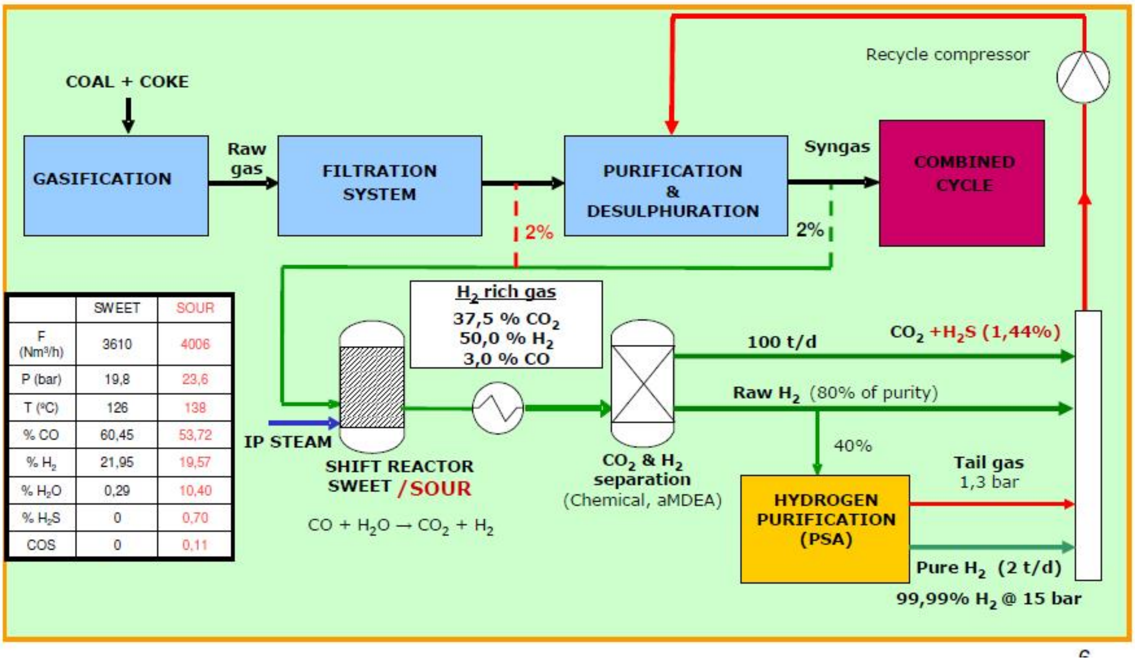


Figure 7. A block flow diagram of the Puertollano CO2 capture and H2 production pilot unit [18].

A new 50 MW_e CO_2 capture demonstration facility (Figure 8) is currently being constructed at the Polk County IGCC plant. The demonstration facility combines RTI's warm syngas clean-up technology with a shift unit and CO_2 capture based on an advanced activated amine process (aMDEA). The capital cost of the combination is assessed to be 15-30 % lower compared to the conventional syngas cleaning technologies with CO_2 capture (Rectisol, Selexol). Demonstration tests are expected to start in July 2015. [13]

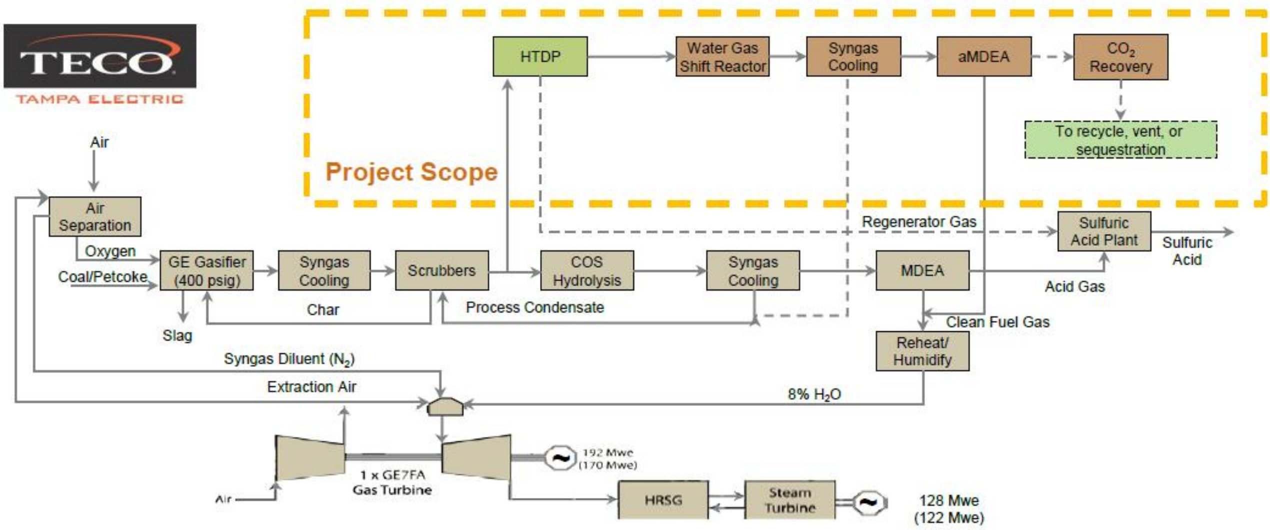


Figure 8. 50 MW_e demonstration unit at the Polk County IGCC plant [13].

2.4 IGCC projects

Currently, there are a few on-going IGCC projects in planning/preplanning phase but only a few are pushing forward towards realization. Issues related to project financing, permits and legislation are causing delays and projects have been cancelled or postponed until IGCC technology becomes economically more viable. In some cases the original plans have been dropped and the plant is realized as a natural gas fired combined cycle power plant which enables incorporation of IGCC and CCS technologies at a later stage. At the moment (date: 31.3.2013) a total of four IGCC power plants are under construction (one in China, one in Japan, one in South Korea, one in the US), one is under commission (in the US) and one is already partly in operation (in China). A detailed IGCC project list as well as plans for incorporating CCS is presented in Appendix B.

The proposed IGCC projects are primarily greenfield plants based on coal or petcoke gasification. Only two suggested IGCC concepts include co-gasification of biomass, typically up to 30 % share. Fully biomass-based on-going IGCC projects were not identified. Most projects include CCS technology with CO_2 capture rates up to 90 %. The separated CO2 is either used for enhanced oil recovery (EOR) or stored.

The planned IGCC plants are mainly designed for power generation but some of them feature co-production of hydrogen, SNG or chemicals, such as ammonia. The most advanced IGCC plant is the GreenGen IGCC project in China which includes CO_2 capture and production of hydrogen and power. Electricity is produced by firing H_2-rich syngas in a hydrogen turbine and also by using part of the produced hydrogen in fuel cells. Rest of the hydrogen is used as a commercial product. The first stage of the plant started operation 2012. [19, 20, 21]

A brief description of recent/planned IGCC projects worldwide is presented in this chapter.

2.4.1 Asia

The GreenGen IGCC Project in China aims at demonstrating a polygeneration concept (Figure 9): coal-based power generation, hydrogen production, hydrogen power generation via fuel cell technology as well as CO_2 capture and sequestration. The project is carried out in three stages. The first stage includes construction of a 250 MW IGCC power plant with a pilot scale CO_2 capture unit. Stage 2 is dedicated to R&D of the key technologies for improving the process concept i.e. smaller scale H_2 production, fuel cell power production and CCS. In stage 3, a 400 MW IGCC demonstration plant will be constructed with H_2 production, H_2 turbine combined cycle power generation, fuel cell power production and a full scale CO_2 capture unit that will produce around 2 Mt/a CO_2 for enhanced oil recovery. The 250 MW IGCC plant (stage 1) started operation in early 2012 [20] and the construction of a small pilot-scale CO_2 capture and fuel cell power production unit is currently under way. Stage 3 is expected to be in full operation in 2016 and the CCS technology in 2020. [19, 20, 21]

Another project under construction in China is the Dongguan IGCC Retrofit Project which will convert a 120 MW natural gas fired combined cycle power plant into an IGCC plant running with coal. [22, 23, 24]

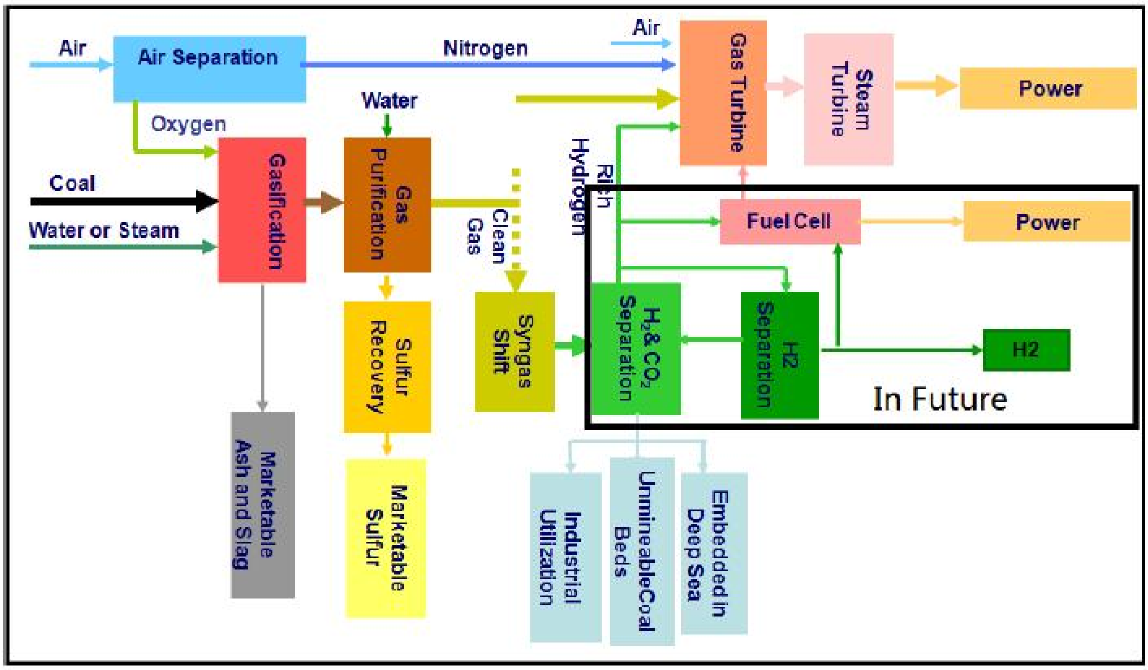


Figure 9. The planned GreenGen IGCC plant [19].

In Japan, construction of an oxygen-blown coal-based IGCC power plant was started in March 2013. The Osaki CoolGen demonstration plant with a power generation capacity of 170 MW is expected to be completed in 2017. [25] The plant is based on the Japanese EAGLE gasification technology (a two-stage, pressurized entrained-flow gasifier) which was first demonstrated in a pilot-scale test facility (150 tpd) commissioned in 2001 [26]. The ultimate goal is to demonstrate the integrated coal gasification fuel cell combined cycle technology (IGFC) in parallel with CO_2 capture and storage. The 170 MW IGCC plant will be used as a basis for this technology development which will be carried out in consequtive steps: first, the implementation of CCS facilities and second, the fuel cells. [27]

In South Korea, three coal-based IGCC plants corresponding a total power generation capacity of 900 MW are planned to be in operation by 2019. The first 300 MW unit is currently under construction in Taean. No plans of implementing CCS have yet been announced. Furthermore, the potential for retrofitting decommissioning power plants with IGCC technology in South Korea by 2020 has been assessed to equal 10 GW. [28]

Reliance Industries Limited (RIL) in India has announced its plans to build a 1000 MW IGCC plant into the world's largest refinery complex in Jamnagar. In May 2012, Phillips 66 agreed to license the E-GAS gasification technology to RIL [29]. The plant would use a mixture of petcoke and coal as feedstock to produce power, steam, hydrogen, SNG and chemicals, such as acetyl chemicals, for the refinery (Figure 10). H_2 production would replace the existing H_2 plant at the site and SNG would substitute liquefied natural gas (LNG) which is currently used as refinery fuel gas. Furthermore, syngas would be used to run the existing gas turbine for power generation. The IGCC plant was planned to start operation in 2015 but the current project status is unknown. [30]

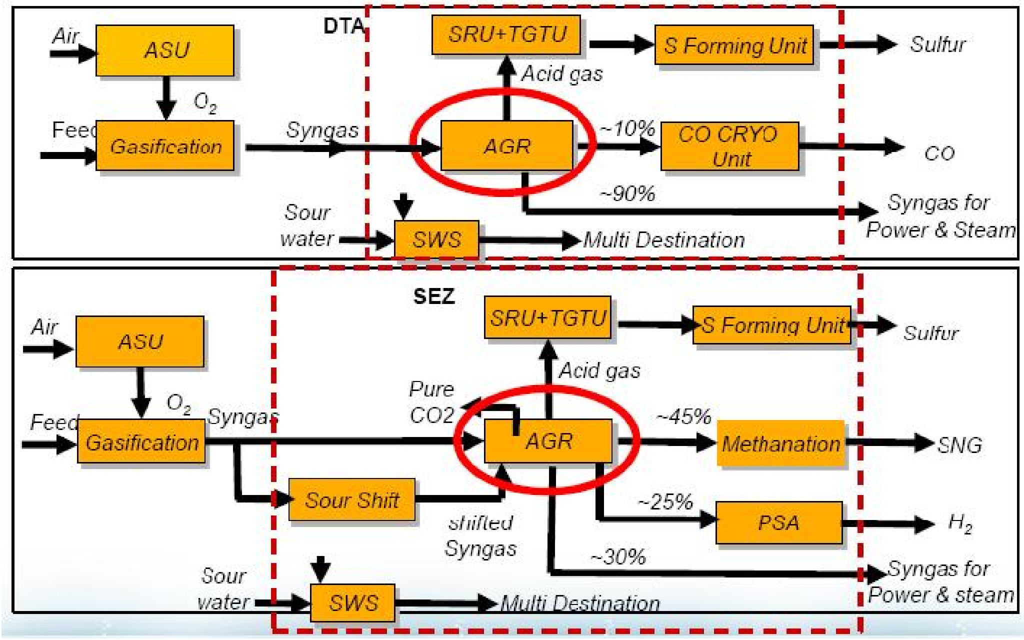


Figure 10. The planned Jamnagar IGCC plant [30].

2.4.2 Australia

In Australia, the proposed IGCC projects have not yet progressed to implementation. The ZeroGen IGCC+CCS project which aimed at constructing a 530 MW IGCC plant with CCS was cancelled in December 2010 [31, 32]. The Surat Basin project with plans to build a coal-based 340 MW IGCC plant with CCS is currently waiting for funding decisions and approvals before proceeding with feasibility studies [33, 34].

2.4.3 Europe

In the Netherlands, 1200 MW Nuon Magnum multi-fuel IGCC power plant is being constructed in two phases. In phase I, the plant is be operated as a natural gas fired combined cycle plant (NGCC). The first phase was expected to be in operation at the end of 2012. In phase II, the plant will be converted into an IGCC plant with CO_2 capture. The plant would ultimately use a mixture of coal and biomass as feedstock. However, due to the rise in raw material prices and pending negotiations with environmentalists, Nuon has postponed phase II. [35, 36].

In the UK, there are three IGCC projects which all plan to employ CCS: the Don Valley Power Project, the Killingholme Project and the Teesside Low Carbon Project. All three projects are currently struggling with financing after they applied for the European Union's NER300 funding and failed to receive it (December 2012) [37].

The Don Valley Power Project by 2Co Energy Ltd would first be constructed as a natural gas fired combined cycle plant and later converted to run on syngas. 2Co Energy is currently seeking financial support from the UK government in order to proceed with the project. [38, 39, 40] The Killingholme Project by C.GEN was originally planned as an IGCC power plant with CCS and possible co-production of hydrogen (Figure 11). The fuels include coal, petcoke and biomass, such as woodchips, up to 30 % share. The front-end engineering design (FEED) is currently under way. However, C.GEN has later announced that the plant will be operated either as a combined cycle gas turbine (CCGT) or as an IGCC plant which would allow retrofitting of CCS at a later stage. [41, 42, 43, 44]

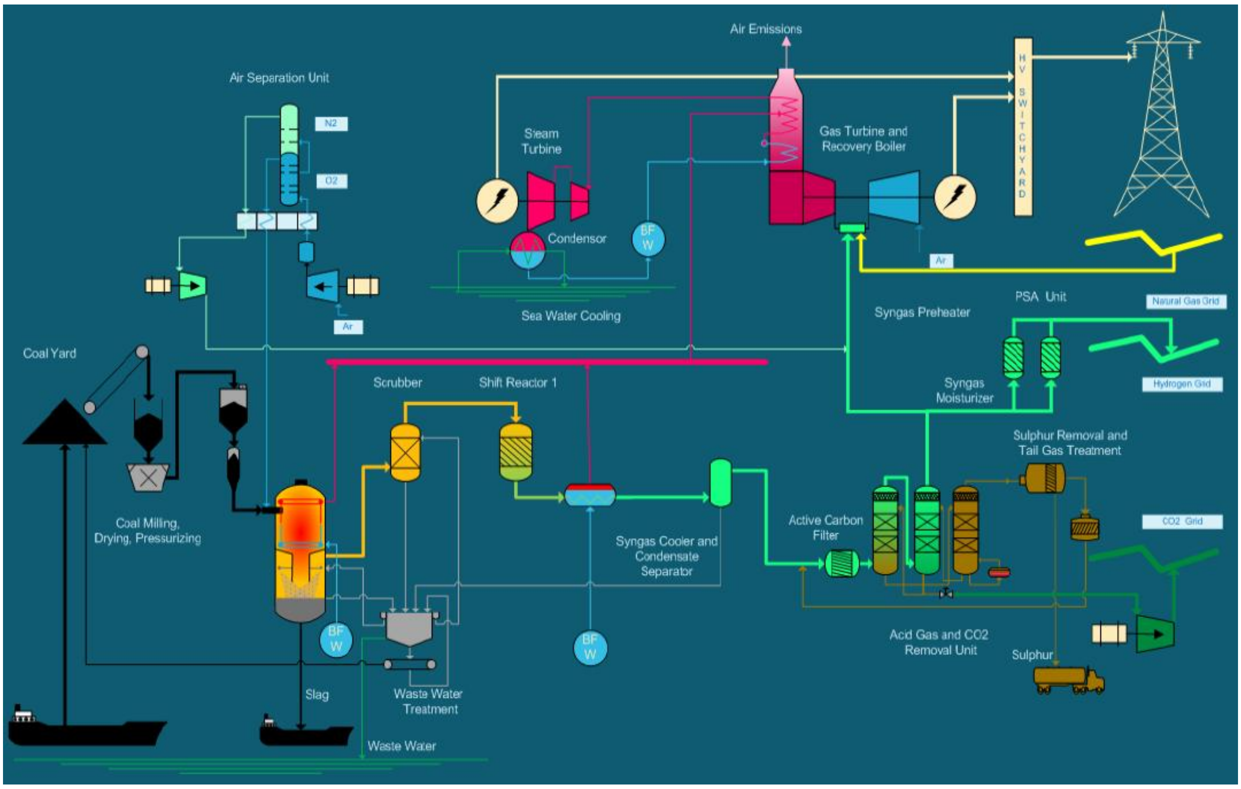


Figure 11. The original Killingholme IGCC power plant concept [42].

The Teesside Low Carbon project aims at constructing a coal-based IGCC plant with CCS and co-production of decarbonized hydrogen. The project did not receive funding through the UK government's £1 billion CCS Commercialisation Program but was put on the reserve list in March 2013. Potential financers are still being searched for. [45, 46, 47]

In Germany, RWE was planning to build a lignite-based IGCC plant with CCS. The project was, however, discontinued after the German Carbon Storage Law (KSpG) was tightened which made CO_2 storage seem difficult. [48, 49]

2.4.4 North America

Out of the many planned IGCC projects in the US, only two are currently progressing: the Edwardsport IGCC in Indiana and the Kemper County IGCC in Mississippi. The coal-based 618 MW Edwardsport IGCC plant is under commissioning and is expected to start commercial operation in mid-2013 [50]. CO_2 capture and sequestration facilities are not included at this phase but a space is already reserved at the site. Duke Energy has mabe preliminary assessments of the possibility to incorporate CCS at a later stage. [51, 52, 53] The Kemper County project includes a coal-based 582 MW IGCC power plant with co-production of sulphuric acid and ammonia (Figure 12). The CO_2 capture facility will separate 3.5 Mt/a CO_2 for enhanced oil recovery. The construction of the plant is under way and expected to be finalised in 2014. [54, 55]

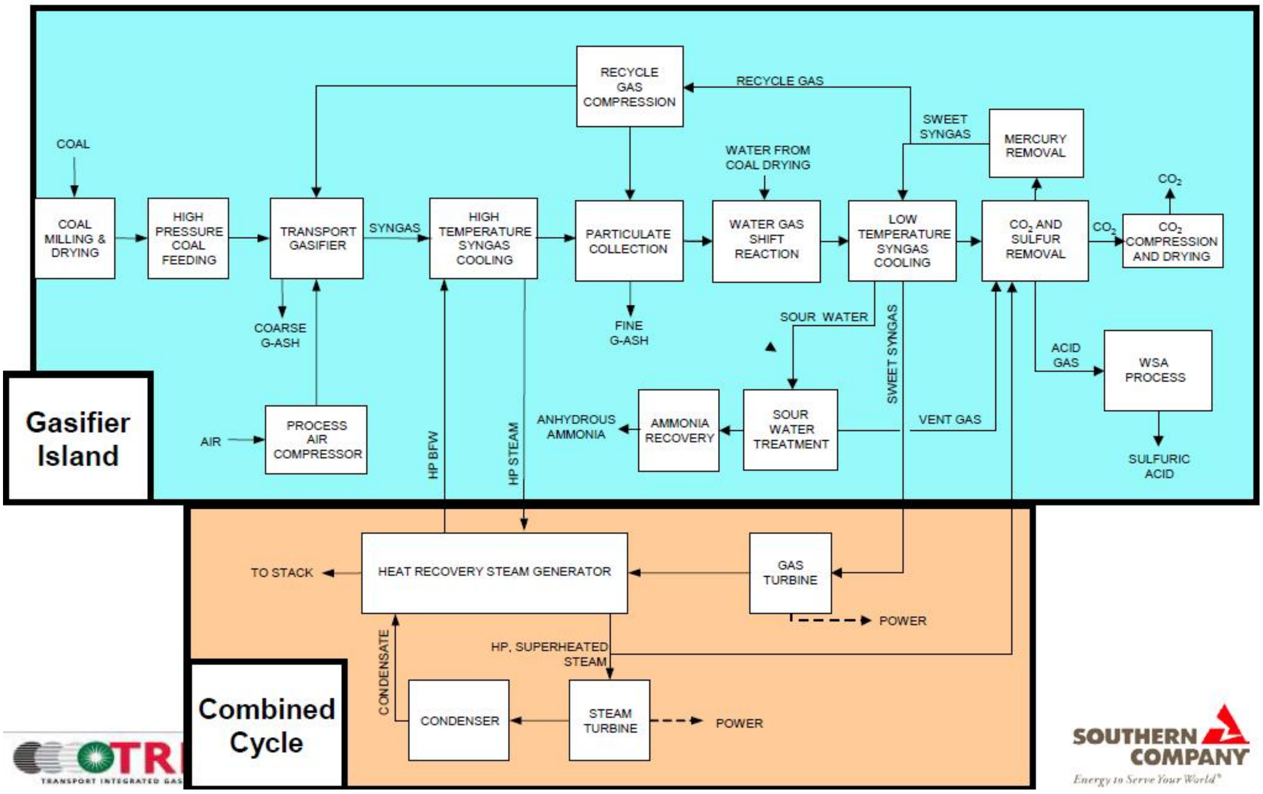


Figure 12. The Kemper County IGCC plant [54].

Other IGCC projects in the US, most of which also employ CCS, are either pending for a final investment decision or are on hold/have been cancelled. E. g. the Taylorville Energy Center project aimed at building a 600 MW IGCC power plant with parallel SNG production and CCS (Figure 13). The concept was based on coal gasification and intermediate SNG production. Part of the SNG was aimed for commercial use and the rest to run the gas turbine. However, after failing to receive the construction permit, Tenaska Energy proposed to build a 611 MW natural gas fired combined cycle which could incorporate the coal gasification block and CCS facilities at a later stage, under better market conditions. [56, 57, 58] The Good Spring IGCC project was also suspended in 2012 and EmberClear made a decision of constructing a 300 MW natural gas fired combined cycle power plant instead [59].

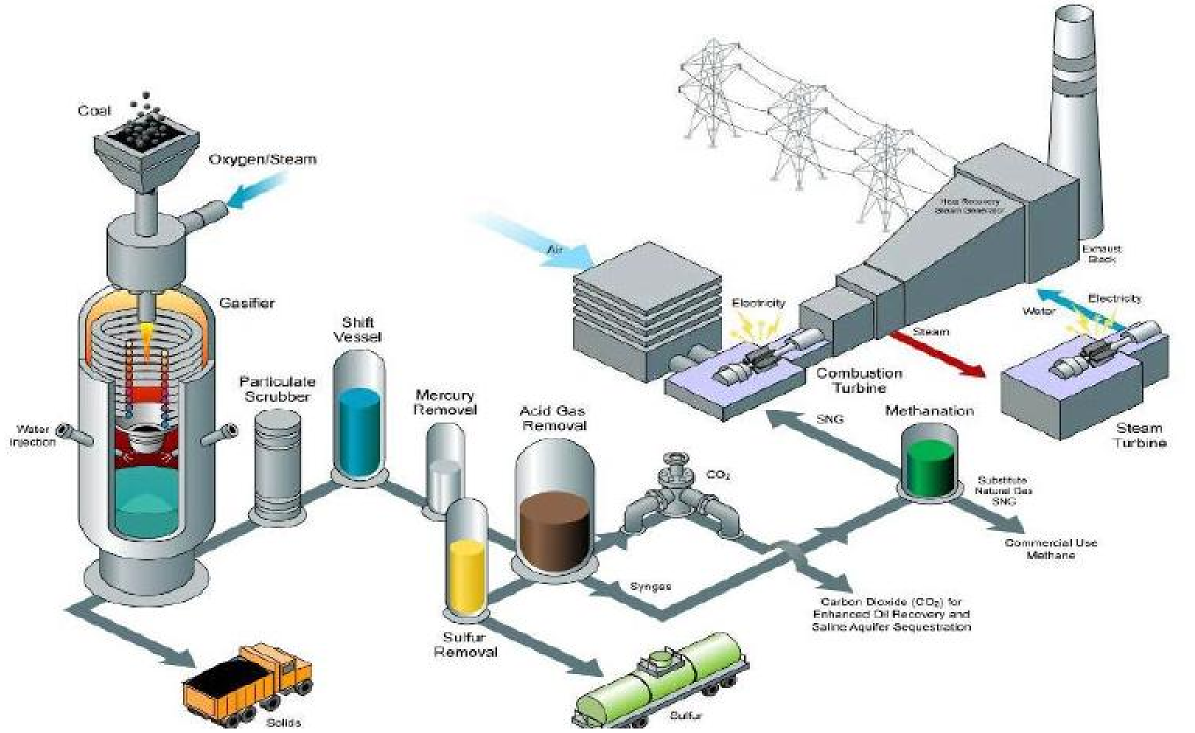


Figure 13. The Taylorville Energy Center project concept [58].

3. Performance and cost of IGCC systems

3.1 Coal-based IGCC plants with and without CCS

In general, coal-based IGCC power plants have high efficiencies which can compete with pulverized coal power plants. In a comprehensive study carried out by NETL in 2010 [60], coal-based IGCC power plant concept was compared to pulverized coal combustion (PC, supercritical and subcritical) and natural gas combined cycle (NGCC) power plant concepts. Performance and cost evaluations based on Aspen Plus simulation modelling were performed both for cases with and without CO_2 capture. Schematic diagrams of the evaluated IGCC concepts (representing current technology) were already presented in Chapter 2, in Figure 1 and Figure 2.

In the NETL study [60], coal-based IGCC plant efficiency (HHV basis) was estimated at approximately 40 % whereas PC plant efficiencies for supercritical and subcritical cases are about 39 % and 37 %, respectively (Figure 14). NGCC plant efficiency is significantly higher, approximately 50 %. NETL study also compared the performance of three available coal gasification technologies: General Electric Energy (GEE), ConocoPhillips (CoP) and Shell Global Solutions (Shell). IGCC power plant based on Shell gasification technology has the highest efficiency, approximately 42 %. GEE and CoP IGCC cases showed 39 % and 40 % efficiencies, respectively. With 90 % CO_2 capture, IGCC power plant efficiency was evaluated to be about 31-32 % which is markedly higher than that of coal-based PC plants, approximately 26-28 %. The difference may be explained by the fact that pre-combustion CO_2 capture technology applied for IGCC plants is less energy intensive than the post-combustion technology in PC and NGCC plants. This is mostly because CO_2 is in a more concentrated form in syngas and is therefore easier to be separated [61].

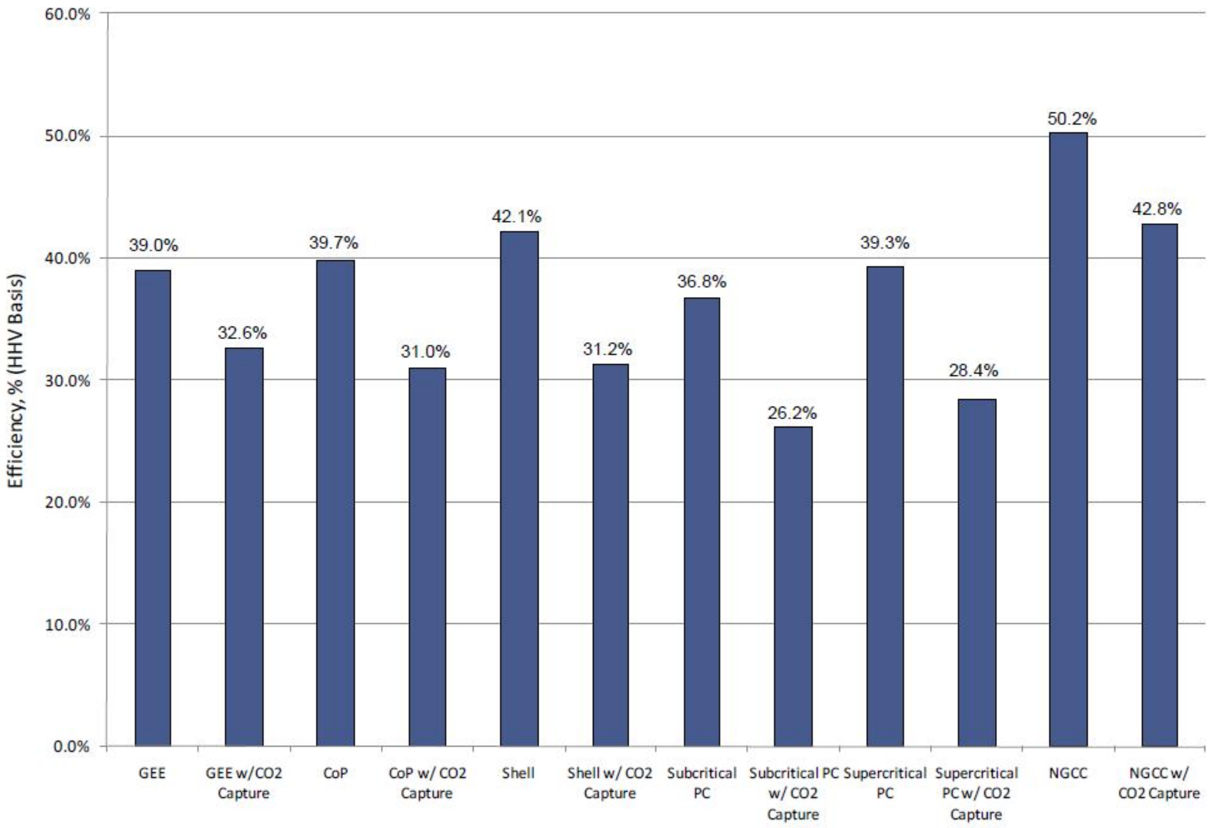
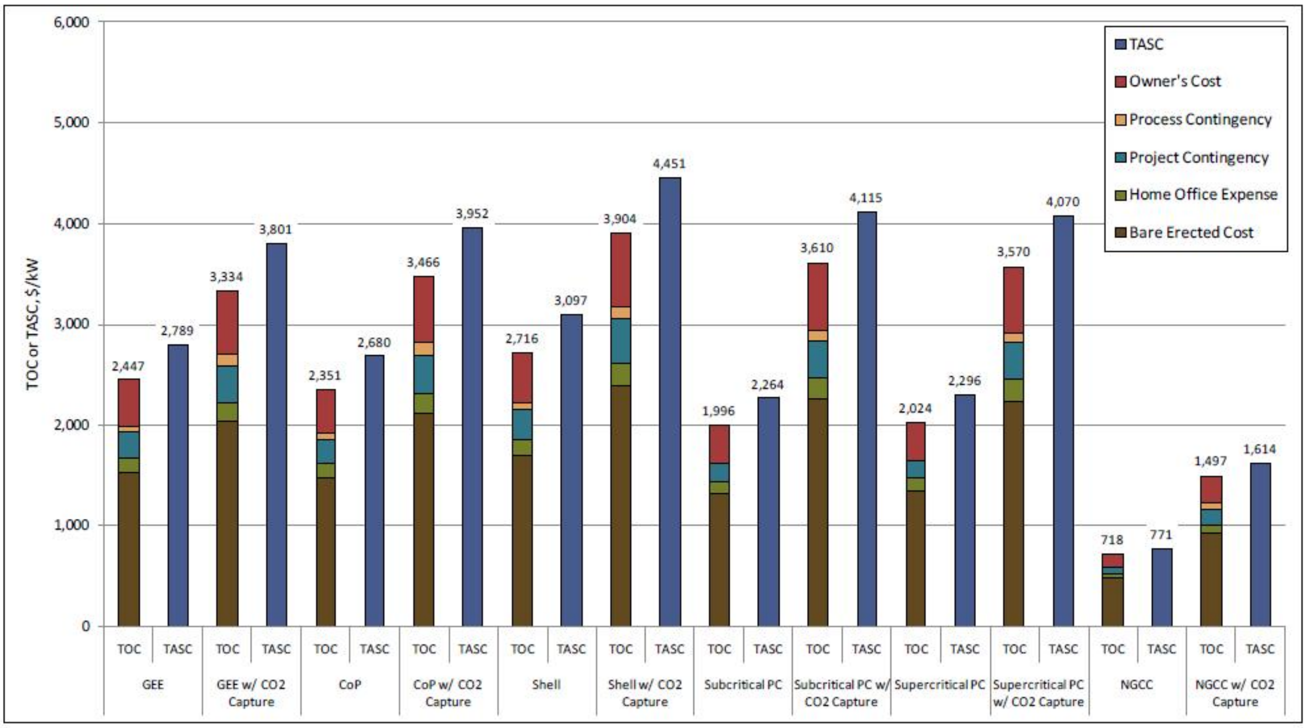


Figure 14. Net plant efficiencies (HHV basis) in the NETL study [60].

NETL cost analysis of the selected cases was performed considering the US market conditions. The Total Overnight Cost (TOC) and the Total As-Spent Cost (TASC) of the plants are illustrated in Figure 15 and the Cost of Electricity (COE) in Figure 16. The economic assumptions used in the study are presented in Appendix C. Although the figures cannot be directly adapted to Finland or other countries, the NETL study [60] clearly shows that coal-based IGCC plants have the highest capital costs. With CO_2 capture, however, the TOC of IGCC plants and PC plants is somewhat similar. Cost of electricity is the lowest with PC and NGCC plants but incorporation of CO_2 capture facility causes a significant increase in the COE. With CO_2 capture, the cost of electricity was estimated to be in the same range for PC and coal-based IGCC plants.



Note: TOC expressed in 2007 dollars. TASC expressed in mixed-year 2007 to 2011 year dollars for coal plants and 2007 to 2009 mixed-year dollars for NGCC.

Figure 15. Plant capital costs in the NETL study [60].

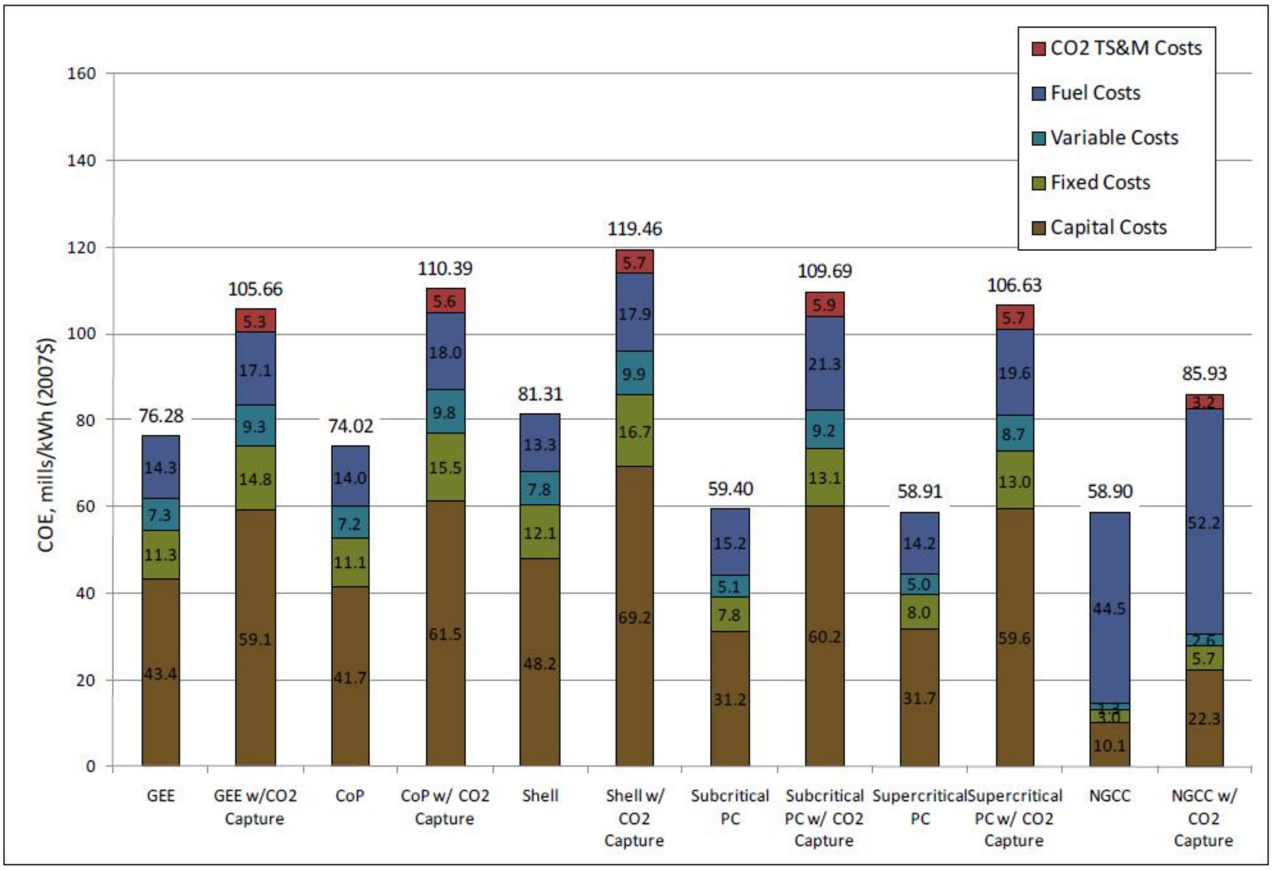


Figure 16. Cost of electricity in the selected cases [60].

3.2 Advanced coal-based IGCC plants with and without CCS

R&D effort is currently put into improving the economics of coal-based IGCC concepts e.g. through more advanced gas turbine, air separation and syngas cleaning technologies. NETL evaluated the impact of such improvements on the performance and cost of coal-based IGCC power generation in a study carried out in 2010 [3]. The reference case without CO_2 capture is a coal-based IGCC power plant employing conventional technologies: a single-stage slurry feed gasifier with syngas cooling and acid gas removal by Selexol followed by a 7FA syngas turbine and typical steam cycle. The reference case with CO_2 capture includes a water gas shift unit combined with two-stage Selexol for acid gas removal and CO_2 separation, CO_2 compression and a modified 7FA-based gas turbine suitable for H_2-rich syngas. In addition, the capacity factor is increased from 75 % to 80 % in the CO_2 capture case as it is assumed to be realistic by the time CO_2 capture technology is incorporated into IGCC plants. [3]

The cumulative effect of the following technology improvements on the coal-IGCC cases is given in Figure 17: [3]

- advanced F-turbine (e.g. higher firing temperature)
- dry coal feed pump to replace slurry feed
- improved capacity factor (CF) through equipment design and operating experience: 75 → 85 %
- warm gas clean up (WGCU) coupled with Selexol for CO_2 capture
- warm gas clean up (WGCU) coupled with hydrogen membrane for CO_2 capture
- advanced hydrogen turbine (AHT-1)
- ion transport membrane (ITM) to replace cryogenic air separation unit for oxygen production

- advanced hydrogen turbine (AHT-2)
- improved capacity factor (CF) through equipment design and operating experience: 85 → 90 %
- advanced integrated gasification fuel cell: gas turbine replaced by a pressurized solid oxide fuel cell

NETL study shows the future potential of improving plant efficiency and reducing costs by new developments. These new technologies are not yet considered commercially available but will require further R&D. NETL estimated that the described technology pathway from the reference case to fuel cell integration represents 18 years of development work in total [3].

Based on the study [3], the plant efficiency could be raised from around 35 % to 46 % in the non-CO_2 capture case and from 30 to 40 % in the CO_2 capture case with the described technology advancements, excluding fuel cell integration. The levelized cost of electricity could be reduced roughly by 30 % and 40 %, respectively. Advanced gas turbines especially seem to have a markedly effect on both the plant efficiency and the cost of electricity. E.g. the advanced F-turbine technology already increases the plant efficiency (HHV basis) by 2.5 %-points in the non-CO_2 capture case and 1.3 %-point in the CO_2 capture case. It also reduces the levelized cost of electricity roughly by 7 % and 11%, respectively.

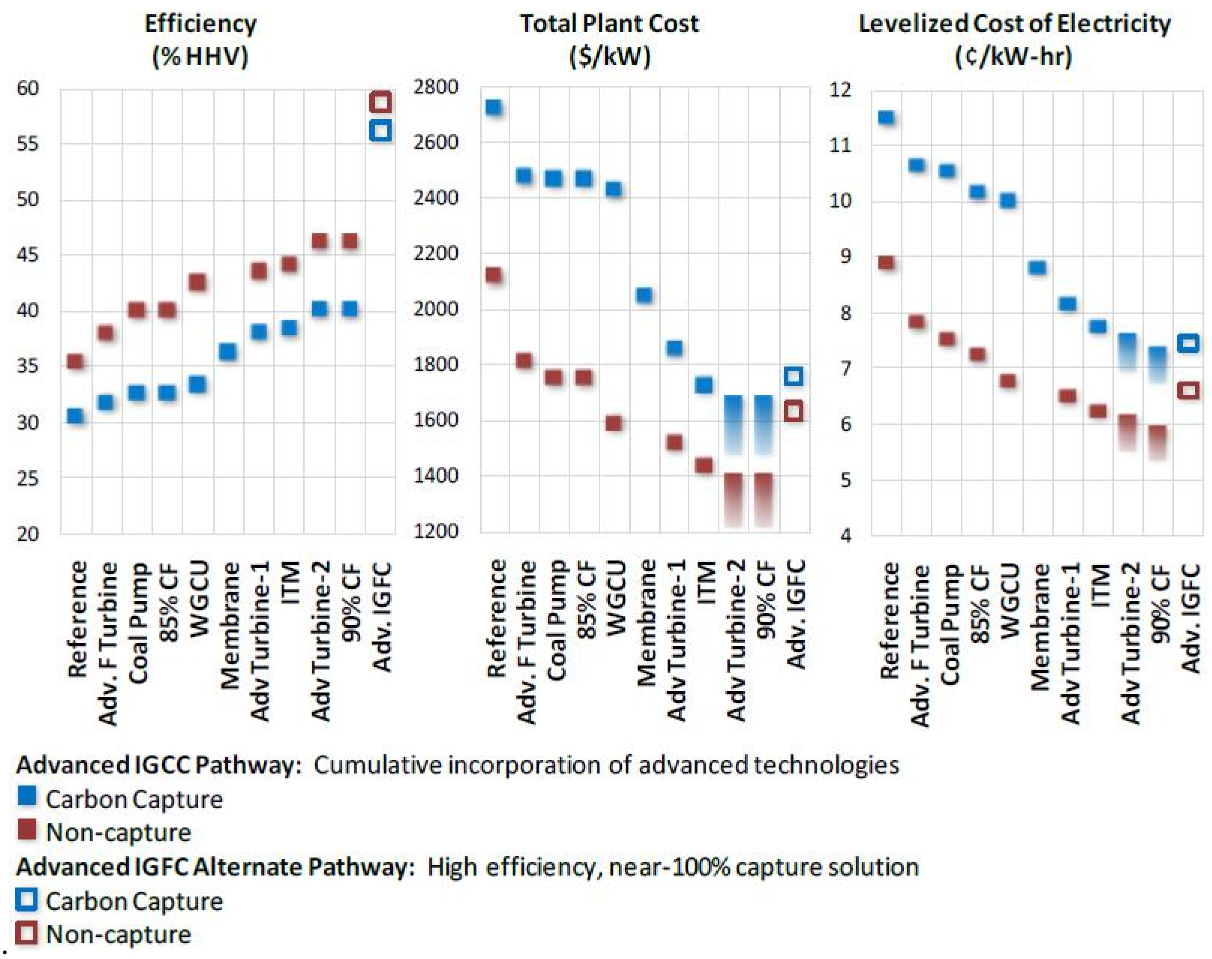


Figure 17. NETL study: performance and cost analysis of advanced IGCC pathways with and without CO_2 capture [3].

4. Prospects of IGCC in Finland

4.1 General

When the possible role of IGCC technlogy is evaluated in Finnish energy production conditions, the following qualitative conclusions can be made. Coal-based IGCC with CCS as a baseload electricity production method may not be very attractive for the Finnish conditions as CHP technologies have a better overall efficiency and are naturally suitable to large cities and major part of the baseload electricity will be produced by nuclear power. IGCC with refinery residues could be one alternative in improving the CO_2 balance of oil refining. In this case the driving force should probably come from NESTE Oil.

In Finland, the most potential IGCC technology would still be combined heat and power within pulp and paper industry or at district heating power plants. Potential feedstocks are solid wood residues, black liquor and peat. The most economical process concepts are based on the simplified IGCC utilising air-blown pressurised gasification followed by hot gas filtration carried out at ca. 550 ^{o}C.

The potential of implementing biomass IGCC (without CCS) in Finland was earlier studied in an EU project which focused on evaluating the performance and cost of IGCC in combined heat and power production as a stand-alone plant and as a retrofit to an existing natural gas fired combined cycle CHP plant [62]. These concepts were also compared to a concept where biomass IGCC is used as a compound cycle in an existing large coal-based condensing power plant without heat production. The main results from this previous study are summarised in Chapter 4.2. The technology is ready for industrial-scale demonstration and this could be supported also by national and EU level investment subsidies. Andritz-Carbona has made several pre-engineering studies around different gas turbines and they would probably be ready for a rapid realisation project. The biggest advantage for this technlogy is the high power-to-heat ratio in CHP plants, which would make it possible to increase the CHP electricity production capacity in Finland by an additional 1000-2000 MWe according to studies made in early 1990's.

However, the air-blown IGCC is not attractive from CCS point of view because the product gas is diluted by 50 % nitrogen and the process concept does not require any wet gas cleaning or shift conversion steps. Thus, the benefits are related to the use of renewable feedstocks and to the high electric efficiency.

Pressurized steam-oxygen blown gasification followed by deep gas cleaning has been recently developed in Finland for the production of transportation fuels, hydrogen and synthetic natural gas (SNG). This process includes shift conversion and the removal of acid gases before final synthesis unit and it is in this respect similar to coal-IGCC processes. Thus, CO_2 removal is anyhow included in the process and the additional costs of bio-CCS are rather small and do not dramatically decrease the biomass conversion efficiency.

The steam-oxygen gasification technology creates possibilities for two different type of applications: a) biomass/peat-IGCC plants preferably as CHP units, and b) integrated production of liquid tranportation fuels, power and heat. These alternatives are examined in detail in Chapters 4.3 and 4.4.

4.2 Biomass IGCC without CCS – earlier studies

The potential of biomass IGCC (without CCS) in Finland was studied as a part of an EU project “BiGPower” (“Advanced Biomass Gasification for High-Efficiency Power” project) in 2005-2008. The performance and techno-economic feasibility of the most promising IGCC-based cases were evaluated by Carbona. The deployment of CCS was out of the scope. [62]

Considering the Finnish market conditions, the following three cases in the size range of 50-60 MWe were selected for detailed techno-economic calculations: [62]

1) New biomass IGCC as a stand-alone CHP plant
2) Biomass IGCC retrofit to an existing natural gas fired combined cycle CHP plant
3) Biomass IGCC as a compound cycle with an existing large condensing power plant using coal as the main feedstock

In all cases, the gasification island was based on the Carbona concept with integrated fuel drying: pressurized air-blown gasification (BFB) with subsequent syngas cooling and hot gas filtration. Typical Nordic woody biomass consisting of forest residues, bark and waste wood was used as feedstock. Carbona also made a survey of existing gas turbines suitable for syngas operation (with reasonable efficiency) in the size range of 10-50 MW_e. The amount of readily available gas turbine types was very limited: GT10 (11,5 MW_e) and GE Frame-6B (43 MW_e). GE Frame-6B was found to be technically and economically more feasible in Finnish conditions and was selected for the case studies. The cost evaluation basis for calculations is given in Table 1. [62]

Table 1. Cost evaluation basis for the Finnish biomass IGCC case studies [62].

Price of biomass	€/MWh	15
Price of electricity	€/MWh	45
Feed-in tariff subsidy	€/MWh	6.9 *)
Price of heat	€/MWh	35
Annual labour costs per person	€/a	35 000
Investment support	% of investment	30 (demo) *)
Annuity factor	10%, 15 a	0.132
Annual full power operation time	h/a h/a	7 000 5 500

*) availability to be discussed with authorities for power generation capacity class > 10 MWe

Based on the techno-economic evaluations, it was concluded that biomass IGCC in Finland is economically attractive only with combined heat and power production (cases 1 and 2). The condensing power plant option was not considered economically very interesting. More detailed results of the case studies are given below: [62]

- New biomass IGCC as a stand-alone CHP plant

  The first case is a large-scale greenfield CHP plant based on biomass IGCC. The results are given both for the heating season (denoted as “cold”) and the warm season (denoted as “warm”) when only a small amount of heat is produced.

- power production by GT: 47.5 MW (cold), 43.3 MW (warm)
- power production by ST: 20.4 MW (cold), 29.2 MW (warm)
- total net power production: 62.9 MW (cold), 67.4 MW (warm)
- district heat supply: 67.1 MW (cold), 8.0 MW (warm)
- power generation efficiency (LHV): 40.1 % (cold), 45.8 % (warm)
- total efficiency: 83.0 % (cold), 51.3 % (warm)
- estimated total investment cost: 84.7 M€ (1 350 €/kWnet)

o Biomass IGCC retrofit to an existing natural gas fired combined cycle CHP plant

The second case is a retrofit CHP plant with an existing GE Frame-6B gas turbine which is already suitable for syngas operation. Besides power, the plant produces process steam for the neighbouring industry as well as district heat for the local heating network. The results are compared to those of the original natural gas fired combined cycle CHP plant (denoted as “orig.”).

- total net power production: 51,6 (orig.) → 59,7 MW
- district heat supply: 12.1 (orig.) → 12.1 MW
- power generation efficiency (LHV): 37.4 (orig.) → 38.6 %
- total efficiency: 67.9 (orig.) → 66.0 %
- estimated total investment cost: 45.3 M€

o Biomass IGCC as a compound cycle with an existing large condensing power plant using coal as the main feedstock

The third case is originally a large-scale (169 MW_e) condensing steam power plant designed for base load operation. In this specific case the GE Frame-6B gas turbine capacity is approximately ¼ of the steam turbine capacity which enables an optimal integration at the plant. The results are compared to those of the original coal fired power plant (denoted as “orig.”).

- renewable fuel share: 0 (orig.) → 29.6 % (of total fuel input)
- district heat supply: -
- total net power production: 162 (orig.) → 230 MW
- power generation efficiency (LHV): 44.5 (orig.) → 46.8 %
- total efficiency: 43.0 (orig.) → 44.3 %
- estimated total investment cost: 74.6 M€ (1 100 €/kWnet)

4.3 Production of transportation fuels and power & heat

Production of transportation fuels and heat via biomass gasification in Finnish conditions was studied in a recently published report [63]. Techno-economic evaluations for the production of methanol, dimethyl ether (DME), Fischer-Tropsch (FT) liquids and synthetic gasoline were carried out for a 300 MW (biomass input at 50 % moisture, LHV) stand-alone plant using forest residue as feedstock. Main results from the techno-economic evaluations are summarized in this chapter. A more detailed description of the process design and Aspen Plus simulation calculations can be found from the report.

4.3.1 Process description

A simplified block flow diagram of the evaluated biomass-to-liquid (BTL) plant is presented in Figure 18. The BTL plant is based on pressurized fluidized-bed steam/O_2-blown gasification of biomass followed by hot gas filtration and catalytic reforming to decompose high-molecular-mass tars and C_2-hydrocarbons to light gases. All the evaluated plants employ this same front-end design, which is based on the Ultra-Clean Gas (UCG) gasification process developed at VTT. After reforming, the H_2/CO ratio of the gas is adjusted for synthesis in a shift reactor after which the gas is cooled down and scrubbed with water in order to remove any residual tars and ammonia. After scrubbing, the near-ambient temperature gas is dried and compressed to a high pressure prior the acid gas removal step. Rectisol, a commercially proven physical washing process, was chosen for removing the sulphur species and CO2. Finally, the cleaned gas undergoes synthesis and upgrading steps. In the case of CCS, CO_2 and H_2S, separated by the Rectisol process, are pressurized to 150 bar in three steps with intercooling to 30 °C. [63]

The plants also include auxiliary equipment: air separation unit for oxygen production, biomass dryer, auxiliary boiler and a steam cycle. The plants are designed as self-sufficent in terms of steam and heat. Electricity is consumed on-site and surplus electricity is sold to the power grid or acquired from the grid in the case of electricity deficit. [63]

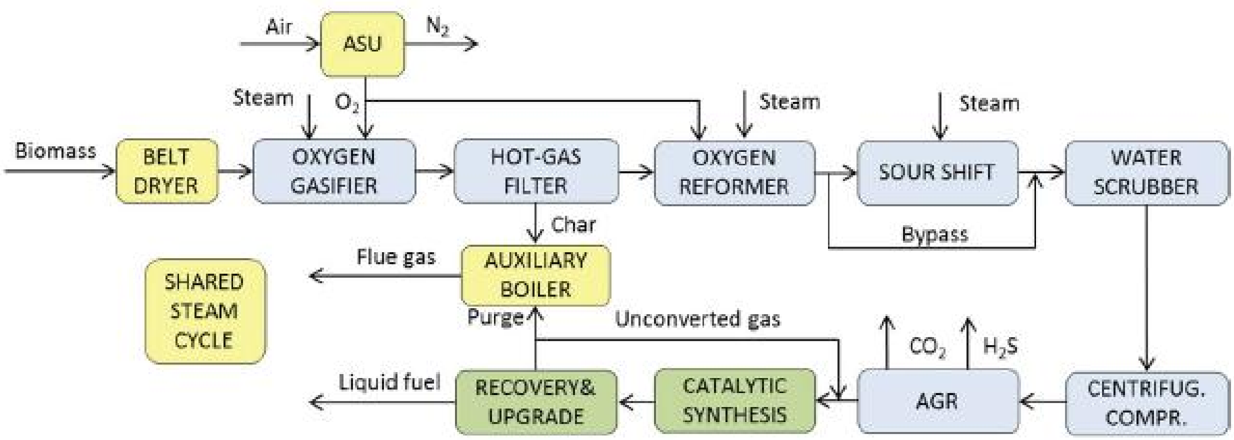


Figure 18. A simplified block flow diagram of a stand-alone BTL plant [63].

4.3.2 Case designs

Five separate case designs (presented in Table 2) were calculated for each end-product option. Cases 1 and 2 are based on the currently proven VTT's UCG process design, which has already been demonstrated on a pre-commercial scale. Besides the transportation liquid production, Case 1 produces power (condensing steam turbine) and Case 2 both power and district heat (CHP mode). In both cases, the separated CO_2 is vented. Cases 3-5 require further R&D to be fully realised but they show the future potential. The steam cycle is operated in CHP mode in all cases. Case 3 is similar to Case 2 but filtration temperature is increased from 550 to 850 °C. Case 4 features both, higher filtration temperature and higher gasification pressure (22 bar). Case 5 is otherwise identical with Case 4 but it incorporates CCS technology instead of CO2 venting. [63]

Table 2. Studied BTL case designs [63].

CASE	1	2	3	4	5
Front-end	Currently proven		Further R&D required		
Steam system	Condensing	CHP	CHP	CHP	CHP
Filtration	550 °C	550 °C	850 °C	850 °C	850 °C
Gasification	5 bar	5 bar	5 bar	22 bar	22 bar
CO2	Vent	Vent	Vent	Vent	CCS

4.3.3 Simulation results

Overall efficiencies from biomass (LHV basis) to fuel and district heat for all evaluated cases are presented in Figure 19. Liquefied petroleum gas (LPG), which is a byproduct of the methanol-to-gasoline (MTG) process, was excluded from the MTG fuel efficiency calculation. [63]

As shown in Figure 19, the efficiency from biomass to fuel ranges between 50-67%. Highest fuel efficiencies are obtained with methanol and DME production. The production of district heat (CHP cases) further increases the overall efficiency by 11-29 %-points compared to Case 1 with a condensing steam turbine. For methanol and DME cases, the overall efficiencies for combined fuel and district heat production vary in the range of 74-80 %. The highest overall efficiencies are obtained in Case 3 where filtration temperature would be increased from 550 to 850 °C. However, Case 2, which represents the current technology with district heat production, also seems to yield promising overall efficiencies. [63]

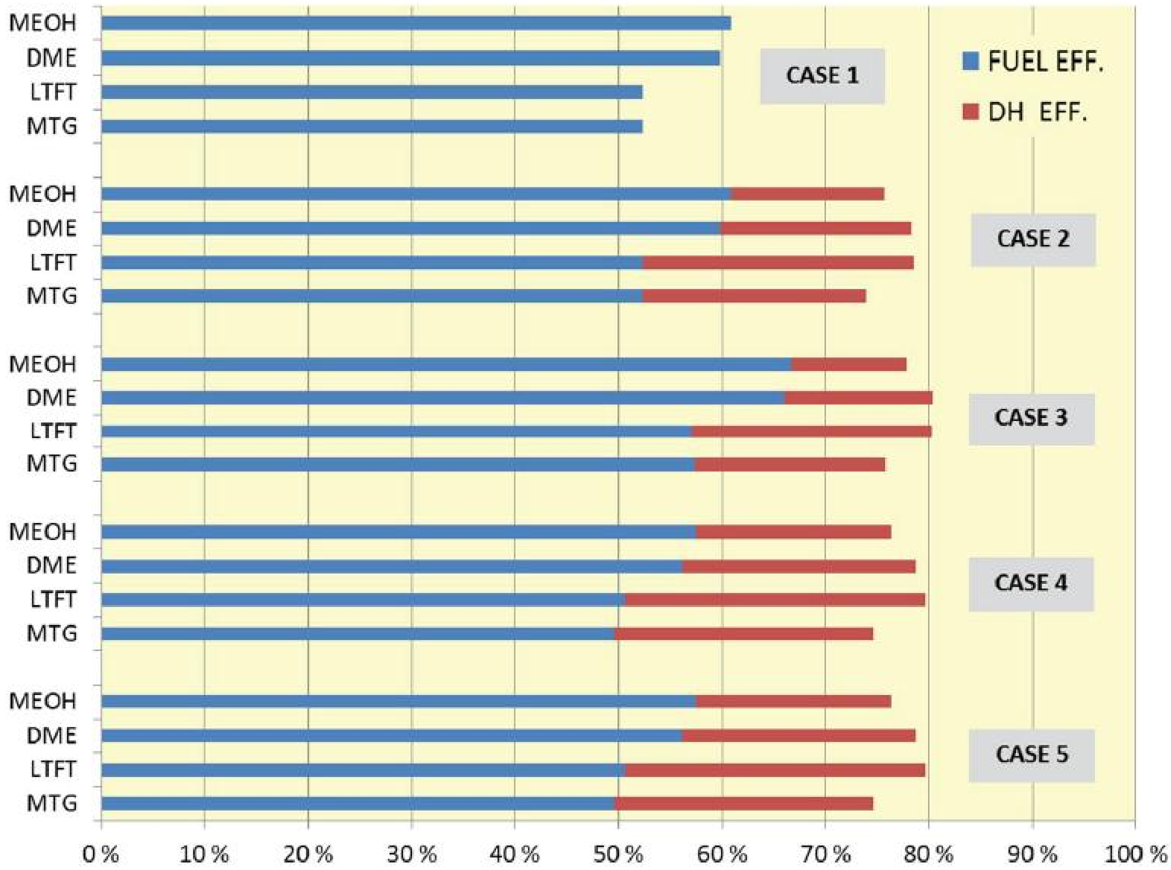


Figure 19. Overall efficiencies from biomass to fuel and district heat [63].

4.3.4 Process economics

Cost estimates were generated for an N^th plant design. Levelised production cost estimates of fuel (LCOF, €/MWh) for the evaluated cases are given in Figure 20. Investment support, CO2 credits and tax assumptions were excluded from the calculations. In each case, the lowest costs are obtained for methanol (58-65 €/MWh) and DME production (58-66 €/MWh) and the highest for FT liquids (64-75 €/MWh) and synthetic gasoline (68-78 €/MWh). Cases which include district heat production have lower costs than Case 1 producing only fuel. Lowest production costs are obtained in Case 3 which would require some R&D effort to raise the filtration temperature from 550 to 850 °C. In the CCS-case (Case 5), transportation and underground storage costs of CO_2 were not taken into account in the production cost calculations which explains the relatively small increase in LCOF in Case 5 compared to CO_2 venting in Case 4. [63]

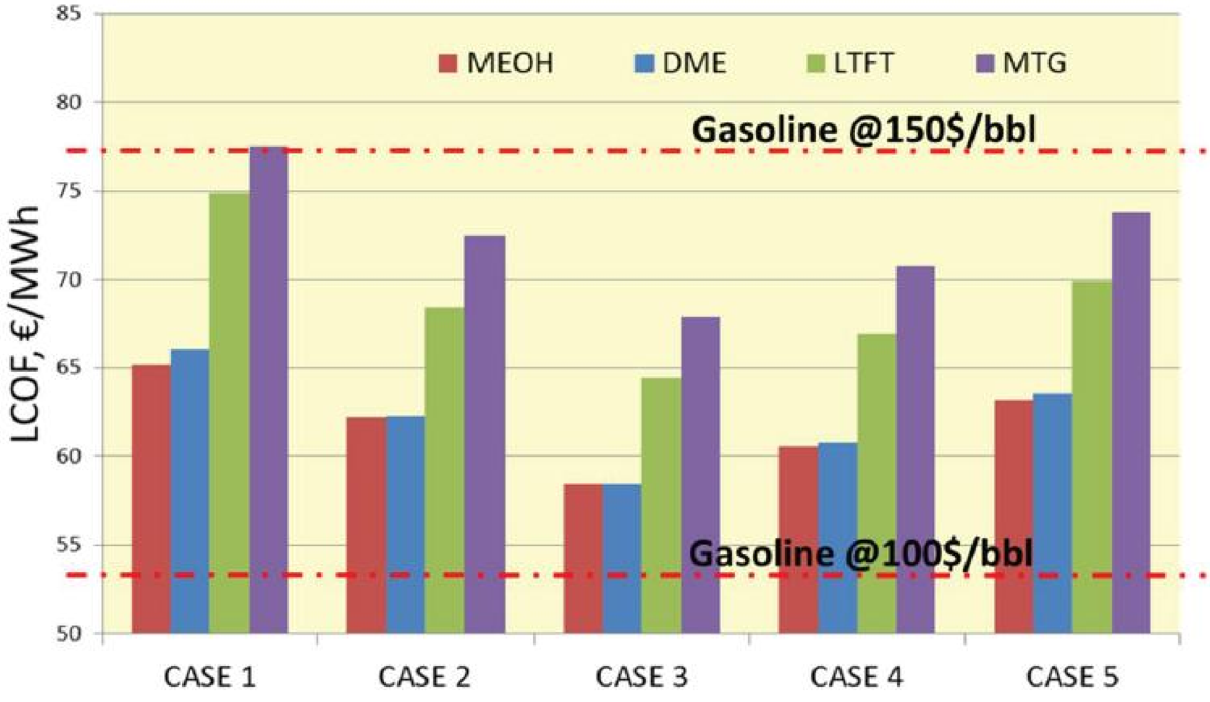


Figure 20. Levelised production cost estimates of fuel (LCOF, €/MWh) for the evaluated cases [63].

4.4 Biomass IGCC with CCS

New calculations were carried out for two biomass IGCC plant cases with CCS. The cases are named as:

1) “Power Only”, which involves dedicated production of carbon-negative electricity

2) “Power & Fuels”, which involves co-production of carbon-negative synthetic fuels and electricity.

The scale of both plants was set to 300 MWth (LHV, before drying) of biomass feed. A simplified block flow diagram of the “Power Only” case is presented in Figure 21. The equipment-wise design of the biomass-based IGCC-CCS plant is very similar to the BTL plant described in Chapter 4.3.1. The main exception is, of course, that in the IGCC design the synthesis island is replaced by a combined cycle power module. The examined cases are differentiated from each other by the stoichiometry of the synthesis gas produced. As co-production of fuel requires that the molar H_2/CO ratio of the syngas is around 2, in dedicated power production, syngas can be shifted much further (in our design H_2/CO ~6) to maximise the amount of captured carbon.

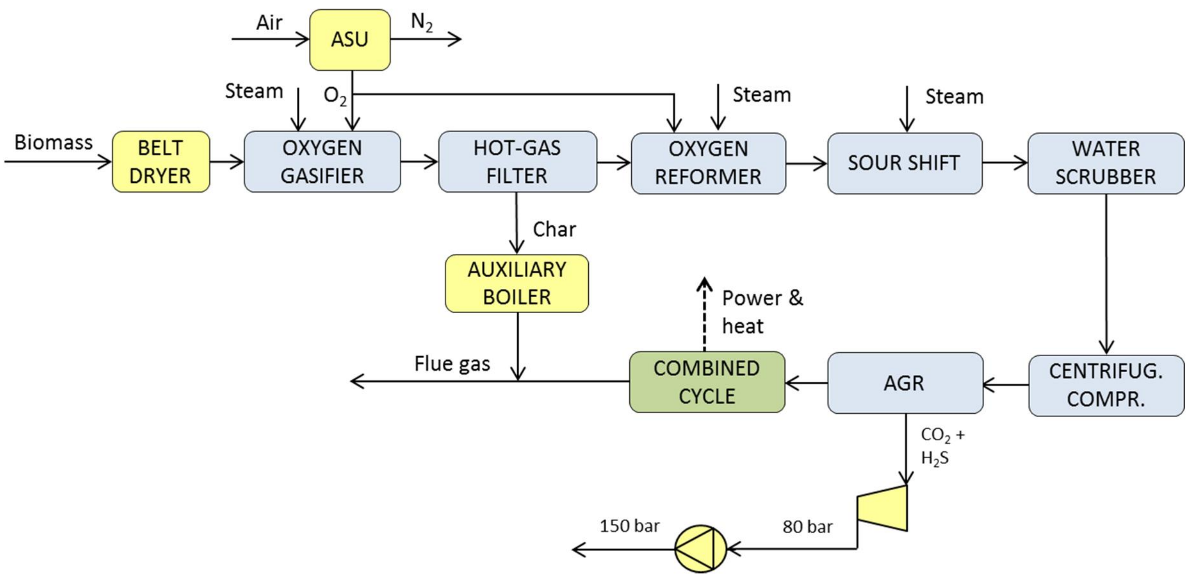


Figure 21. A simplified block flow diagram of a biomass IGCC power plant with carbon capture.

Also, in a design where fuels are co-produced, the conversion of CH_4 in the reformer needs to be maximised in order to prevent excessive build-up of inerts in the synthesis loop. However, in the “Power Only” case the methane conversion can be much lower as it works as fuel for the gas turbine just as carbon monoxide and hydrogen. This less stringent methane reforming requirement also works for the benefit of the “Power Only” process as less reforming brings savings in oxygen and steam use and leads to higher thermal efficiency. These main differences in these two designs are also summarised in

Table *3*.

Table 3. Key differences of the simulated IGCC-CCS plant designs.

CASE	Power & Fuels	Power Only
H2/CO target	2	Max.
CH4 reforming	Max.	Min.

In contrast to a dedicated BTL plant, the extraction steam turbine becomes a part of the combined cycle, causing changes in scale and operation. However, the basic principle of the steam system design, i.e. extracting steam from the turbine to satisfy the needs of the gasification process, remains the same. Steam that is raised by cooling the hot syngas, auxiliary boiler flue gases and synthesis reactor are also fed to the steam turbine to take part in electricity generation.

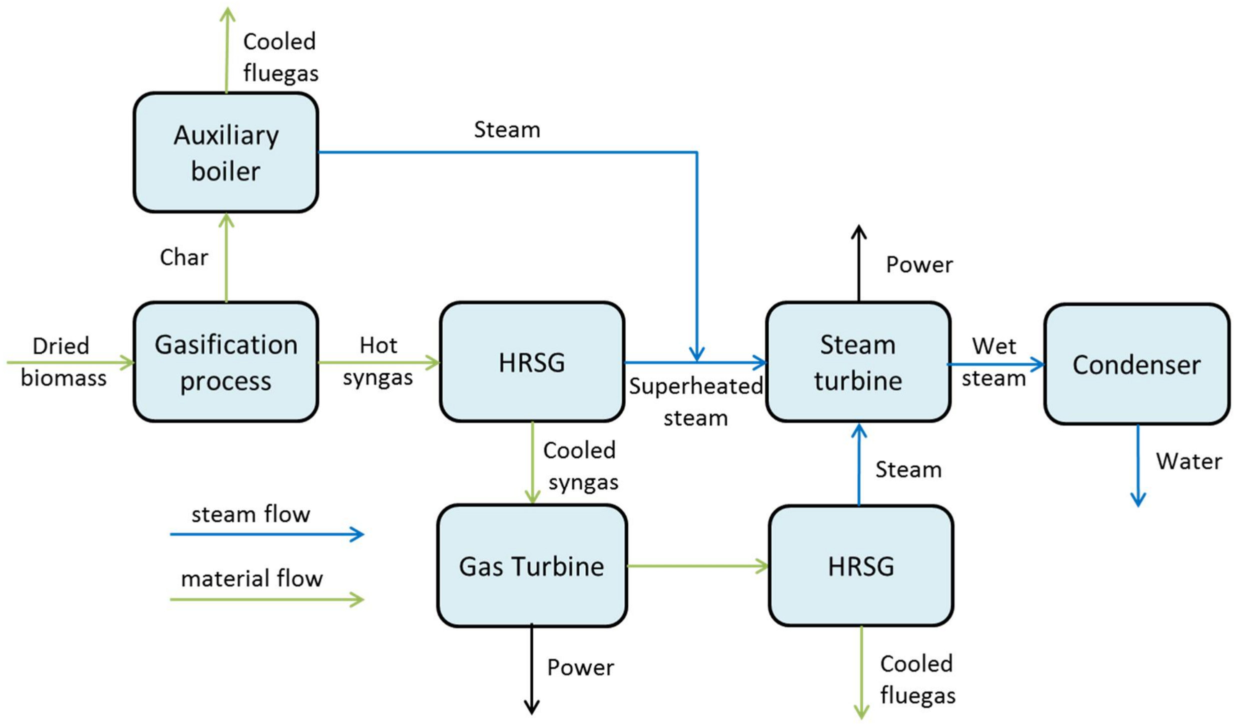


Figure 22. Possible steam system layout for a biomass IGCC plant.

The highest pressure steam for the gasification process is extracted at 31 bar pressure level and used to preheat feed water of the syngas HRSG to 220 °C. Process steam is extracted at a 6 bar pressure and used for the gasifier, reformer, shift and solvent regenerator of the Rectisol unit. Lastly, some steam is extracted also at 1 bar pressure to provide heat for drying (if needed) or district heat in CHP mode. Condenser pressure for the power only design is 0.02 bar and 17.5 °C.

4.4.1 Simulation results

The mass and energy balances of the above-described plants were calculated with Aspen Plus chemical process simulation software. The detailed results are included as a separate appendix (Appendix D) while main findings are discussed in the following text. We start by examining the normalised energy distribution of the produced syngas for the examined cases, as illustrated in Figure 23. For the “Power Only” case, 66 % of the syngas energy content is contained in hydrogen, 12 % in carbon monoxide and 22 % in methane. In the “Power & Fuels” case this distribution is: 61 % H_2, 36 % CO and only 3 % CH_4. The observed differences in gas compositions are a direct consequence of maximal shifting and minimal CH_4 reforming approach employed in the “Power Only” IGCC-CCS plant design.

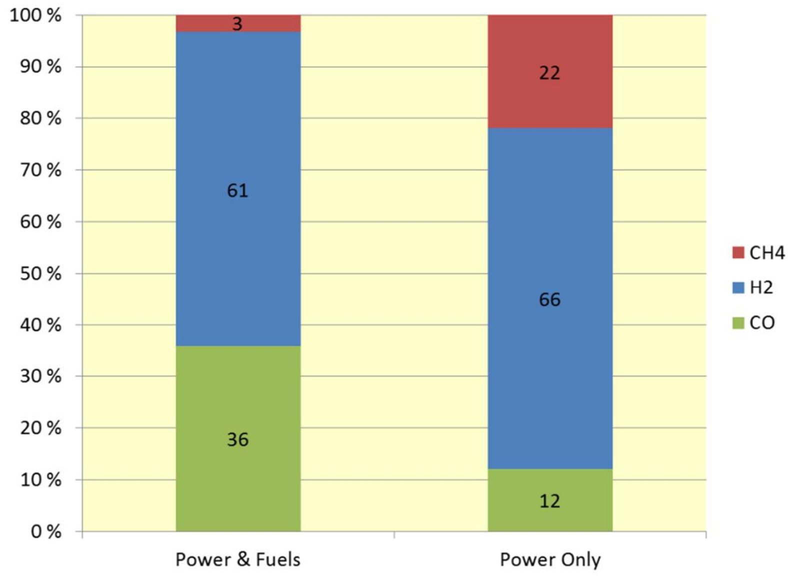


Figure 23. Comparison of the normalised synthesis gas energy distribution for the simulated cases.

We then turn to examine the absolute energy flows of the generated syngas. From the 300 MW_{th} (LHV) of biomass that is fed to the plant’s dryer, about 240 MW worth of conditioned and ultra-cleaned gas is generated with the proposed designs. The “Power Only” plant produces 244 MW of of ultra-clean decarbonated gas, while for the “Power & Fuels” design the amount is slightly lower, 239 MW.

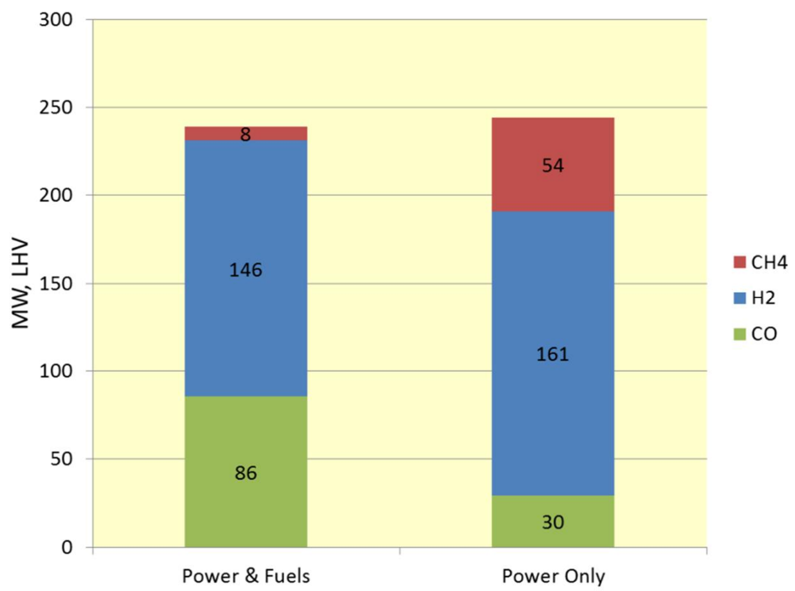


Figure 24. Comparison of the synthesis gas energy distribution for the simulated cases using 300 MW (AR, LHV) biomass input.

Interpreting these results in terms of cold gas efficiency (1), we get that CGE is 81.3 % for the “Power Only” design and 79.7 % for the “Power & Fuels” design. The explanation for the higher CGE of the “Power Only” plant is in the minimal CH_4 reforming approach where lower methane conversion leads to less syngas being oxidised to provide heat for the endothermic reactions.

$$CGE = \frac{\dot{m}_{gas} * H_{gas}}{\dot{m}_{biom} * H_{biom}}, \qquad (1)$$

Table 4 aggregates key simulation results of CO_2. In the “Power Only” case, 2131 metric tonnes per day (TPD) is separated from the synthesis gas and compressed to 150 bar to be ready for transportation. This amount of CO_2 represents 75% of the input carbon contained by the biomass and 97 % of the CO_2 that was available for separation in the acid gas removal unit. In the same manner, 1597 tonnes of CO_2 is captured daily in the “Power & Fuels” plant, which represents 56 % of the carbon input to the process. The explanation for the lower capture rate lies in lesser shifting ($H_2/CO = 2$ instead of maximal), which also results in lesser by-product CO_2 formation. The capture efficiency in the AGR unit is the same 97 % for both designs.

Table 4. Key parameters for the simulated plant designs.

INPUT/OUTPUT	CASE	Power & Fuels	Power Only	CHP
Total biomass input (AR, LHV)	MW	300	300	300
Compressed CO_2 (150 bar)	TPD	1597	2131	2131
Share of input carbon captured	%	56	75	75
Share of CO_2 captured	%	97	97	97
Gross power output	MW	133	136	113
Net power output	MW	122	121	99
Net heat output				111
Power efficiency	%	40.7	40.4	32.8
Power + DH efficiency	%			69.9

From the 300 MW_{th} of biomass input, a biomass-IGCC plant based on the “Power & Fuels” design generates 133 MW of electricity. For the “Power Only” design the gross power output is 136 MW and for combined heat and power design 113 MW. Due to the larger amount of captured CO2, the on-site power consumption is higher in the “Power Only” and “CHP” plants than in the less-capturing “Power & Fuels” plant. As a result, the net power output of the “Power Only” plant (121 MW) is actually little lower than that of the “Power & Fuels” plant (122 MW). For the “CHP” design the net power output is 99 MW. The calculated power efficiencies are 40.4 %, 32.8 % and 40.7 % for the “Power Only”, “CHP” and “Power & Fuels” plants, respectively. In the CHP mode the overall efficiency to power and heat is 69.9 %.

4.4.2 Process Economics

Investment cost estimates were generated for the examined plant designs. The costing is based on reference equipment costs from the VTT's cost database most recently published in reference [63]. The database is assembled and constantly updated based on information from literature sources, vendor quotes, discussions with industry experts and in-house engineering judgement. Individual cost scaling exponents (k) are used to scale these reference capital costs (C_o) to the capacity that corresponds with simulation results (S) by the following relation:

$$C = C_0 * \left(\frac{S}{S_0}\right)^k, \qquad (2)$$

where S_o is the scale of reference equipment and C the cost of equipment at the size suggested by simulation results. All reference costs have been escalated to constant 2010 euros using Chemical Engineering's Plant Cost index[1] (CEPCI).

A summary of the assumed investment cost factors are given in Table 5. The installation is 30 % on top of the equipment cost and includes instrumentation and controls, electrical connections, piping, insulation and site preparation. The Indirect costs are 22 % on top of the equipment cost and contain engineering & head office costs (15 %), start-up costs (5 %) and royalties & fees (2 %). The annual Operating & Maintenance costs are 4 % of the Total Plant Cost and include personnel costs (0.5 %), maintenance and insurances (2.5 %) as well as catalysts & chemicals (1 %).

Table 5. Financial parameters assumed for all investigated plant designs.

FINANCIAL PARAMETERS	
Investment factors	
Installation	27 %
Indirect costs	22 %
Contingency for standard components	20 %
Contingency for less mature components	30 %
Interest during construction, fraction of *TOC*	5 %
Capital charges factor, (10%, 20a)	12 %
O&M costs factor, fraction of TPC/a	4 %
Annual availability of a BTL plant, h	7889
District heat peak-load demand, h	5500
Investment support, M€	0
Costs, €/MWh	
Biomass feedstock (150 MW / 300 MW)	13.7 / 16.9
District heat	30

The annual availability of all plants was assumed to be 90 %, corresponding to 7889 annual runtime. The solids handling equipment is expected to be the most important availability limiting factor.

[1] Chemical Engineering; Apr 2012; 119, 4; ABI/INFORM Complete pg. 84, *www.che.com/pci*

4.4.3 Capital and production cost estimates

Based on the above-described costing methodology, detailed capital cost estimates were generated for a biomass-IGCC-CCS plant based on the "Power Only" design at two different scales. The results are shown in Table 6, which shows the costs breakdown to main equipment areas. According to the results, the Total Capital Investment (TCI) is 360 M€ for the 300 MW_{th} and 221 M€ for the 150 MW_{th} plant. The share of auxiliary equipment of the Total Overnight Cost (TOC) is 28 %, Gasification Island is 45 % and Power Island 27 %.

Table 6. Capital cost estimates for "Power Only" IGCC-CCS designs at 150 MW and 300 MW biomass input (as received, LHV).

BIOMASS INPUT	150 MW	300 MW
Auxiliary equipment	60.6	91.6
Buildings	10.4	18.8
Oxygen production	29.5	41.8
Feedstock pretreatment	20.6	31.1
Gasification island	95.0	152.9
Gasification	29.7	49.9
Hot-gas cleaning	22.5	35.8
CO shift	4.0	6.4
Syngas cooling	6.0	9.5
Compression	9.7	15.4
Acid gas removal	23.1	35.8
Power island	54.4	98.0
HRSG from syngas	8.1	14.1
Aux. boiler + fluegas	3.1	4.8
Gas turbine + HRSG	43.9	79.1
TOTAL OVERNIGHT CAPITAL	211	343
TOTAL CAPITAL INVESTMENT	221	360

Based on the investment cost estimates production cost estimates were generated using assumptions given in Table 5. We use 13.7 €/MWh for the cost of biomass in the smaller plant and 16.9 €/MWh for biomass in the larger plant. The district heat is valued at 30 €/MWh. We levelise the total capital investment over the period of 20 years using capital charge factor 0.12 which corresponds with 10% return on investment. The operating and maintenance costs are valued at 4% of the capital investment.

Figure 25 illustrates the levelised annual costs associated with the operation of the plant. We have also added the levelised cost of electricity production (LCOE) as a separate dot on the same graph. The value of the columns can be read from the primary vertical axis on the left, while the value of LCOE can be read from the secondary vertical axis on the right. According to the results, annual costs for the 150 MW scale plant are 51 M€ and 97 M€ for the 300 MW scale plant. Dividing these costs by the amount of electricity produced annually, we reach production cost estimates that are 126 €/MWh for the 150 MW and 104 €/MWh for the 300 MW scale plant.

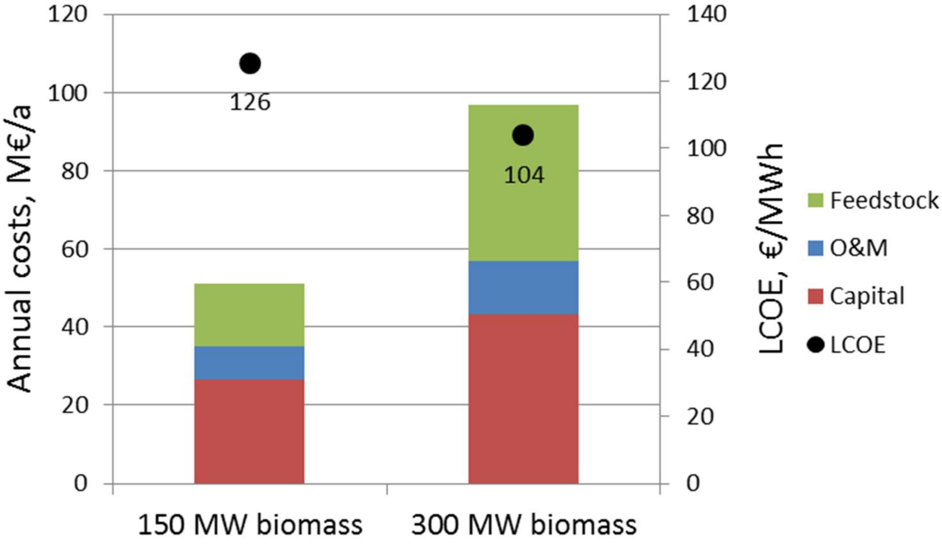


Figure 25. Annual cost estimates (columns) and levelised cost of electricity (dots) for an IGCC-CCS "Power Only" plant at 150 MW (biomass @13.7 €/MWh) and 300 MW (biomass @16.9 €/MWh) feedstock input.

We also generate production cost estimates for a case where the steam system is operated in CHP mode. In this design, the lower electricity output is balanced by district heat that can be sold to a nearby grid. Like in the previous figure, the costs are denoted as positive, while incomes from the district heat sales are considered as negative costs and drawn below the horizontal axis. In these CHP cases we estimate the levelised production cost of electricity to be 115 €/MWh and 91 €/MWh, for the 150 MW and 300 MW scale plants, respectively.

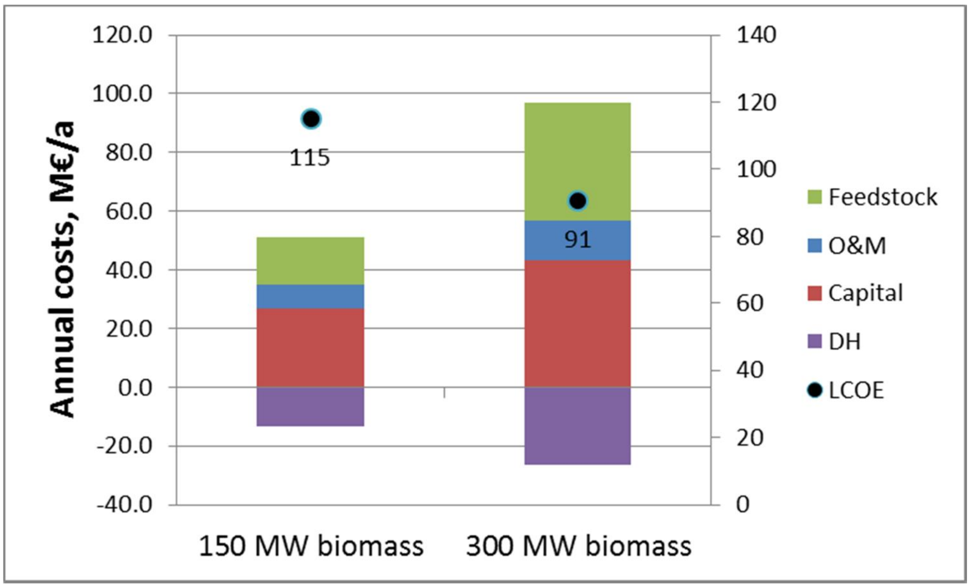


Figure 26. Annual cost estimates (columns) and levelised cost of electricity (dots) for an IGCC-CCS "Power Only" plant operated in CHP mode at 150 MW (biomass @13.7 €/MWh) and 300 MW (biomass @16.9 €/MWh) feedstock input.

5. Conclusions and final remarks

IGCC is an attractive option for power generation due to the high plant efficiency. It also enables co-production of other valuable products, such as SNG, hydrogen or chemicals. In addition, CO_2 removal from syngas is less costly than from fuel gas in conventional power plants.

Coal-IGCC technology based on high temperature and high pressure entrained-flow gasification is commercially available. However, high capital costs and challenges related to plant availability have hindered its market penetration. Current R&D activities are focused on improving the efficiency and reliability as well as reducing the costs of coal-based IGCC power plants to make them more competitive against conventional power plants. Biomass-IGCC technology has been demonstrated but so far no commercial plants have been built.

Considering the Finnish conditions, ***biomass-based IGCC concepts with combined heat and power production*** show the most potential. CHP mode increases the overall plant efficiency compared to condensing power production. The plants could be integrated to existing pulp and paper industry or realized as district heating power plants. Potential feedstocks include solid biomass residues, black liquor and peat.

Biomass-IGCC technology has already been demonstrated and proven technically feasible in Värnamo, Sweden, at 6 MW_e/9 MW_{th} scale. This ***simplified biomass-IGCC concept based on air-blown fluidized-bed gasification*** and hot gas filtration is ready for demonstration in commercial scale. The benefits of this concept is the high power-to-heat ratio in CHP plants. The smallest economical plant size has been estimated to be in the range of 20-30 MW_e.

The simplified IGCC concept is not, however, a feasible option for the IGCC-CCS case. Firstly, the gas is diluted with nitrogen due to the use of air as gasifying agent. Secondly, the process concept does not include gas cleaning and shift conversion steps required for the capture of CO_2. When we consider ***biomass-IGCC with CO_2 capture***, the most attractive concept would be ***based on pressurized steam-oxygen blown fluidized-bed gasification*** followed by gas cleaning, shift conversion and acid gas removal which are similar to those in coal-IGCC concepts. This process was initially developed for the production of transportation fuels, hydrogen and synthetic natural gas (SNG) and has already been demonstrated on a pre-commercial scale in Varkaus, Finland. The benefit of this concept, from IGCC-CCS point of view, is the fact that CO_2 removal is already included in the basic process design. Therefore, the additional costs related to incorporating CCS are rather small. Additionally, this concept allows the ***co-production of liquid transportation fuels*** in addition to power and heat at any given ratio.

Our analysis shows that it is possible to produce electricity from biomass, having strongly negative carbon emissions, with efficiency close to 40 %. In CHP mode, the electrical efficiency is lowered to 33 % while overall efficiency to power and heat increases to 80 %. In continuous operation (90 % on-stream factor) the estimated production cost of electricity for a CHP design is 115 €/MWh at 150 MW_{biom} and 91 €/MWh at 300 MW_{biom} scale.

APPENDIX A - *Operating IGCC plants*

	Plant type	*Plant name*	*Location*	*Owner*	*Feedstock*	*Gasifier*	*Gas turbine*	*Plant output, MW*	*Other products*	*Plant efficiency, % (LHV)*	*In operation since*	*Ref.*
1	commercial	Puertollano IGCC Plant	Spain (Puertollano)	Elcogas SA	coal, petcoke (50/50 %)	ThyssenKrupp Uhde: PRENFLO (oxygen-blown, dry feed)	Siemens: V 94.3	335	-	42	1998	2, 64
2	commercial	Buggenum IGCC Plant	the Netherlands (Haelen)	Nuon Power Buggenum	coal, biomass (up to 30 %)	Shell: oxygen-blown, dry feed	Siemens: V 94.2	253	-	43	1994	2, 15, 16, 17
3	commercial	Polk County IGCC Project	US (Mulberry, Florida)	Tampa Electric Co.	coal/petcoke	GE: Texaco, oxygen-blown	GE 7FA	250	-	41	1996	2, 65
4	commercial	Wabash River Gasification	US (West Terre Haute, Indiana)	SG Solutions LLC	petcoke	ConocoPhillips: E-GAS (oxygen-blown, slurry feed)	GE 7FA	262	-	39	1995	2, 66
5	commercial	Vresova IGCC power plant	Czech Republic (Vresova)	Sokolovska Uhelna, A.S.	lignite coal	26 x Lurgi fixed-bed gasifiers	GE 9E	350	sulphuric acid	44	1996	2, 8, 67
6	commercial	Nakoso IGCC	Japan (Nakoso)	Clean Coal Power R&D Co., Ltd.	coal	Mitsubishi: air-blown, dry feed	Mitsubishi: D-type	250	-	42.9	2007	8, 68
7	commercial	ISAB Energy IGCC Project	Italy (Priolo Gargallo)	ISAB Energy	ROSE asphalt	GE	Siemens: V94.2K	512	-	na	1999	69

APPENDIX A - *Operating IGCC plants (continued)*

	Plant type	*Plant name*	*Location*	*Owner*	*Feedstock*	*Gasifier*	*Gas turbine*	*Plant output, MW*	*Other products*	*Plant efficiency, % (LHV)*	*In operation since*	*Ref.*
8	commercial	SARLUX IGCC Project	Italy (Sarroch)	SARLUX srl	visbreaker residue	GE: Texaco, oxygen-blown	GE MS9001E	551	steam and 60 000 m3n/h H2 for the refinery	44.6	2000	7, 70, 71
9	commercial	api Energia S.p.A. IGCC Plant	Italy (Falconara Marittima)	api Energia S.p.A.	vac. visbreaker residue	GE	ABB 13E2	287	-	na	2001	72
10	commercial	Agip IGCC	Italy (Sannazzaro)	AGIP Raffinazione S.p.A.	visbreaker residue	Shell	Siemens: V94.2K	250	-	na	2006	70, 73
11	commercial	Thermoselece Vresova	Czech Republic (Vresova)	Sokolovska Uhelna, A.S.	tars and oils	Siemens SFG	GE 9E	175 MWth	-	na	2008	74
12	commercial	Chawan IGCC Plant	Singapore (Pulau Ayer Chawan)	Esso Singapore Pty. Ltd.	residual oil	GE	GE 6FA	173	-	na	2001	75
13	commercial	Negishi IGCC	Japan (Yokohama)	Nippon Petroleum Refining Co.	vac. residue	GE	Mitsubishi: 701F	342	-	na	2003	76
14	commercial	Americentrale Fuel Gas Plant	the Netherlands (Geertruidenberg)	EPZ	demolition wood	Lurgi	?	46	-	na	2000	77

APPENDIX B - *IGCC projects in Asia*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
1	stage 1 in operation	new	GreenGen IGCC Project	China (Tianjin)	GreenGen Co	coal	HCERI	Siemens: 1 x SGT5-2000E (stage 1)	250 (stage 1), 400 (stage 3)	H2 production, fuel cell power production, sulphur	55-60 (by 2020)	2012 (stage 1), 2016 (stage 3)	19, 21, 78, 79, 80
2	under construction	retrofit	Dongguan IGCC Retrofit Project	China (Dongguan)	Dongguan Tianming Electric Power Co., Ltd	coal	KBR: TRIG	GE (existing)	120	-	-	2013	81, 82
3	under construction	new	Osaki CoolGen Project (demo plant)	Japan (Hiroshima)	Osaki CoolGen Corporation	coal	Babcock-Hitachi: EAGLE gasifier	Hitachi	170	-	40.5 (HHV)	2017	24, 27, 83
4	early planning stage	new	Dongguan Taiyangzhou IGCC	China (Dongguan)	Dongguan Taiyangzhou Power Corporation	coal	KBR: TRIG	?	800	-	-	2015	22, 23
5	under construction	new	300 MW demonstration IGCC Plant in Korea	South Korea (Taean)	KOWEPO	coal	Shell: SCGP, dry feed	GE 7F	300 (net)	-	42 (HHV)	2016	28, 84
6	?	partly retrofit	RIL's Gasification Project at Jamnagar	India (Jamnagar)	RIL (Reliance Industries Ltd.)	petcoke 65%, coal 35%	Phillips 66: E-GAS	?	1000	steam, H2, SNG and chemicals, such as acetyl chemicals	-	Q2 2015	29, 30, 85

APPENDIX B - *IGCC projects in Australia*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
1	pre-feasibility studies completed	new	Surat Basin CCS Project (formerly Wandoan)	Australia (Surat Basin, Queensland)	Wandoan Power	coal	GE	GE	340 (net)	-	-	2017/2018	33, 34
2	cancelled	new	ZeroGen IGCC+CCS Project	Australia (Queensland)	ZeroGen Pty Ltd.	Australian hard coal	Mitsubishi: air-blown, dry feed	Mitsubishi: M701G2 GT (J-type)	530 (gross)	-	-	October 2015	31, 32

APPENDIX B - *IGCC projects in Europe*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
1	phase 1 (NGCC) completed in 2012, phase 2 (IGCC) postponed	new	Nuon Magnum multi-fuel power plant	the Netherlands (Eemshaven)	Nuon	hard coals and partial petcoke, biomass, sewage sludge, refuge	Shell: 3 x SCGP	Mitsubishi : 3 x F-class GT	1200 (net)	-	42 (LHV, phase 2)	2012 (phase 1), 2020 (phase 2)	35, 86, 87, 88
2	on hold, final investment decision expected in 2013	new	Don Valley Power Project	UK (Stainforth, South Yorkshire)	2Co Energy Ltd	coal	Shell	GE	920 (gross)	-	-	2016	38, 39, 40
3	front-end engineering design (FEED) under way (expected to be completed in 2013)	new	Killingholme Project	UK (North Killingholme, North Lincolnshire)	C.GEN NV	coal, petcoke (up to 30%) and sustainable biomass (e.g. woodchips up to 30%)	ThyssenKrupp Uhde: PRENFLO, PDQ	F-class GT	470	possibly 5-7 t/h pure H2	-	2016-2017	41, 42, 43, 44

APPENDIX B - *IGCC projects in Europe (continued)*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
4	final investment decision expected in 2014	new	Teesside Low Carbon	UK (Teesside)	Progressive Energy Ltd, BOC, International Power, National Grid, Fairfield Energy and Premier Oil	bituminous coal	?	?	450	possibly decarbonised H2 (40 t/h)	-	2016	45, 46, 47, 89
5	feasibility study complete	new	Kedzierzyn Project (polygeneration plant with CCS)	Poland (Kędzierzyn-Koźle)	ZAK-PKE consortium	coal	?	?	300	517 000 t/y methanol	-	2015	90
6	discontinued until further notice	new	RWE IGCC Plant in Hürth	Germany (Hürth)	RWE	lignite	entrained flow (40 bar), quench mode	F-class GT	450 (gross), 360 (net)	-	36	by 2014	48, 49, 91

APPENDIX B - *IGCC projects in North America*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
1	under comissioning	new	Edwardsport IGCC Plant	US (Knox County, Indiana)	Duke Energy	Indiana coal	GE	2 x GE 7F	618 (net)	-	38.5 (HHV)	mid-2013	50, 52, 53
2	under construction	new	Kemper County IGCC	US (Kemper County, Mississippi)	Missisippi Power	coal (lignite)	KBR: 2 x TRIG, air-blown	Siemens: 2 x SGT6-5000F	582	135 000 t/a sulphuric acid, ammonia 20 000 t/a	28.1 (HHV, with CCS)	May 2014	54, 55
3	final investment decision expected in mid-2013	new	Texas Clean Energy	US (Penwell, Texas)	Summit Power	coal	Siemens: 2 X SFG-500	Siemens: SGT6-PAC 5000F	400	710 000 t/y ammonia/urea	-	2015	92, 93, 94
4	final investment decision expected in 2013	new	Hydrogen Energy California	US (Kern County, California)	SCS Energy LLC	petcoke 25 % / coal 75 %	Mitsubishi: oxygen-blown	Mitsubishi: MHI 501GAC	400 (gross)	1 Mt/a urea and ammonia	-	2017	95, 96, 97

APPENDIX B - *IGCC projects in North America (continued)*

	Project status	Plant type	Project name	Location	Owner	Feedstock	Gasifier	Gas turbine	Plant output (electricity), MW	Other products	Plant efficiency, % (target)	Planned start	Ref.
5	on hold / suspended, feasibility study complete	new	Taylorville Energy Center	US (Taylorville, Illinois)	Tenaska Energy	Illinois coal #6	Siemens: 2 x SFG-500	Siemens: 2 x SGT6-5000F	600 (net)	SNG for commercial use	-	2016	56, 57, 58
6	on hold	new	Sweeny Gasification Project	US (Sweeny, Texas)	ConocoPhillips	petcoke	ConocoPhillips: E-GAS	?	683 (net)	-	-	2014	98, 99, 100
8	cancelled, switched to 300 MW NGCC plant without CCS	new	Good Spring IGCC	US (Pennsylvania)	EmberClear Corporation	anthracite coal	HCERI	?	270	-	-	4th quarter 2015	59, 101
9	front-end engineering design (FEED) completed	new	Genesee IGCC Facility	Canada (Edmonton)	Capital Power Corporation	coal	Siemens: SFG	?	270 (net)	-	-	2015	102, 103, 104

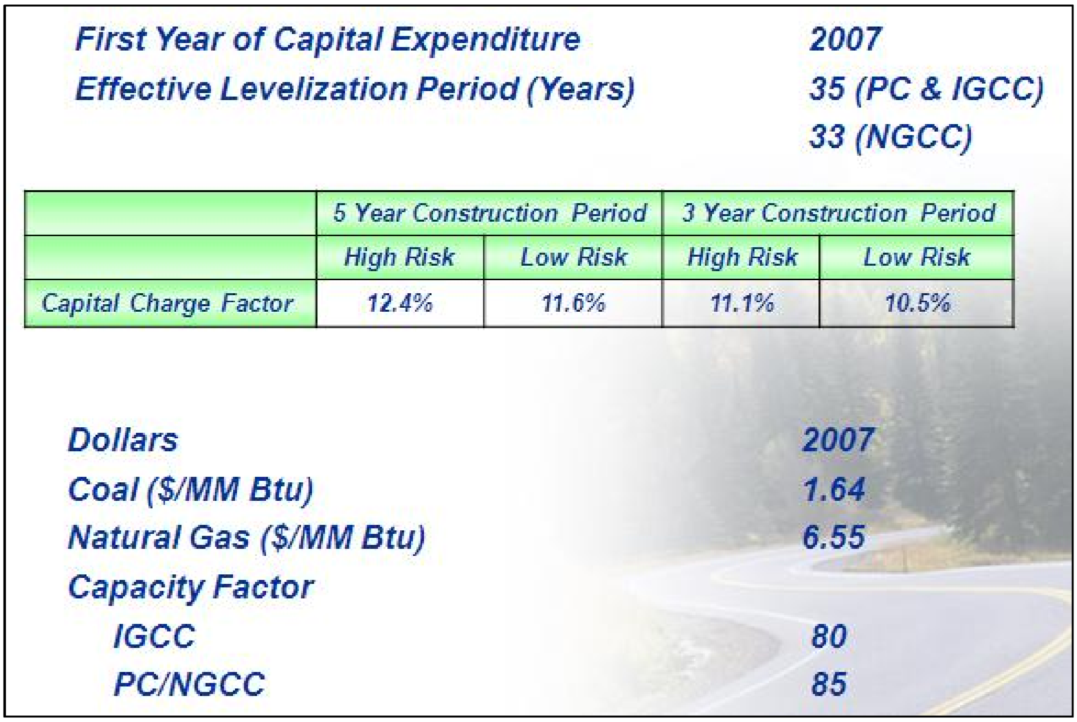
APPENDIX B - *IGCC projects and plans for incorporating CCS*

	Project name	Location	CCS	CO2 capture technology	CO2 capture, %	CO2 capture, Mt/a	CO2 fate	Ref.
ASIA								
1	GreenGen IGCC Project	China (Tianjin)	yes	pre-comb.	> 80 (target after stage 3)	up to 2 (stage 3), 0.1 for the food and beverage industry (stage 1)	sequestration and potential EOR	19, 21, 78, 79, 80
2	Dongguan IGCC Retrofit Project	China (Dongguan)	no	-	-	-	-	81, 82
3	Osaki CoolGen Project (demo plant)	Japan (Hiroshima)	under consideration	-	-	-	-	24, 27, 83
4	Dongguan Taiyangzhou IGCC	China (Dongguan)	yes	pre-comb.	?	1	depleted onshore oil and gas reservoirs	22, 23
5	300 MW demonstration IGCC Plant in Korea	South Korea (Taean)	no	-	-	-	-	28, 84
6	RIL's Gasification Project at Jamnagar	India (Jamnagar)	under consideration	?	?	8	?	29, 30, 85
AUSTRALIA								
7	Surat Basin CCS Project (formerly Wandoan)	Australia (Surat Basin, Queensland)	yes	pre-comb.	90	up to 2.5	onshore deep saline formations storage	33, 34
8	ZeroGen IGCC+CCS Project	Australia (Queensland)	yes	pre-comb.	65-90	2-3	storage	31, 32
EUROPE								
9	Nuon Magnum multi-fuel power plant	the Netherlands, Eemshaven	yes	pre-comb.	in phase 2: 30-80 % in subsequent steps	?	sequestration in North Sea oil and gas fields	35, 86, 87, 88
10	Don Valley Power Project	UK (Stainforth, South Yorkshire)	yes	pre-comb.	90	4.9	EOR offshore, North Sea oil fields	38, 39, 40
11	Killingholme Project	UK (North Killingholme, North Lincolnshire)	yes	pre-comb.	-	2.5	offshore storage in deep saline aquifers	42, 43, 44

APPENDIX B - *IGCC projects and plans for incorporating CCS (continued)*

	Project name	Location	CCS	CO2 capture technology	CO2 capture, %	CO2 capture, Mt/a	CO2 fate	Ref.
EUROPE								
12	Teesside Low Carbon	UK (Teesside)	yes	pre-comb.	85	2.5 (400 MW slipstream)	offshore storage in depleted oil field	45, 46, 47, 89
13	Kedzierzyn Project	Poland (Kędzierzyn-Koźle)	yes	pre-comb.	90	2.5	?	90
14	RWE IGCC Plant in Hürth	Germany (Hürth)	yes	pre-comb.	92	2.6	sequestration in saline reservoir	48, 49, 91
N. AMERICA								
15	Edwardsport IGCC Plant	US (Knox County, Indiana)	possibly in the future	-	-	-	-	50, 52, 53
16	Kemper County IGCC	US (Kemper County, Mississippi)	yes	pre-comb.	65	3.5	EOR	54, 55
17	Texas Clean Energy	US (Penwell, Texas)	yes	pre-comb.	90	2.5	EOR	92, 93, 94
18	Hydrogen Energy California	US (Kern County, California)	yes	pre-comb.	90	3	EOR (87 %), the rest will be used in the production of urea	95, 96, 97
19	Taylorville Energy Center	US (Taylorville, Illinois)	yes	pre-comb.	> 50	up to 3	sequestered or used for EOR	56, 57, 58
20	Sweeny Gasification Project	US (Sweeny, Texas)	yes	pre-comb.	85	5.6	sequestration in neighboring deep saline aquifers and/or EOR	98, 99, 100
22	Good Spring IGCC	US (Pennsylvania)	yes	pre-comb.	> 50	1	onshore deep saline formations storage	59, 101
23	Genesee IGCC Facility	Canada (Edmonton)	under consideration	?	?	?	?	102, 103, 104

APPENDIX C - *Economic assumptions used in the NETL study [1]*



	5 Year Construction Period		3 Year Construction Period	
	High Risk	Low Risk	High Risk	Low Risk
Capital Charge Factor	12.4%	11.6%	11.1%	10.5%

APPENDIX D - *Detailed simulation results*

Table 1. Simulated biomass and oxygen inputs related to the case designs.

CONSUMABLES		Power & Fuels	Power Only
Biomass			
Biomass to dryer	MW (LHV)	300	300
Biomass to gasifier	MW (LHV)	335	335
Biomass to dryer (moist. 50 wt%)	kg/s	34.9	34.9
Biomass to gasifier (moist. 15 wt%)	kg/s	20.5	20.5
Oxygen consumption	**kg/s**		
Gasifier	kg/s	5.5	5.5
Reformer	kg/s	4.0	2.4

Table 2. Detailed set-up of the solid biomass conversion equipment.

BIOMASS CONVERSION		Power & Fuels	Power Only
Gasifier			
Pressure	bar	5	5
Temperature	°C	850	850
Heat loss	%	1.2	1.2
Steam/O_2	-	1.0	1.0
Carbon conversion	%	98	98
S/O_2 inlet temp	°C	203	203
Filter			
Temperature	°C	550	550
Reformer			
Outlet temperature	°C	945	850
Heat loss	%	0.8	0.8
Steam/O_2	-	1.0	1.0
Methane in (dry)	mol%	8.8	8.8
Methane out (dry)	mol%	0.8	5.6
Methane conversion	%	90	30
S/O_2 inlet temp	°C	207	207

Table 3. Detailed set-up for the synthesis gas conditioning equipment.

GAS CONDITIONING	CASE	Power & Fuels	Power Only
Sour shift			
H_2/CO at inlet	-	1.4	1.4
Steam/CO at inlet	-	1.8	1.8
Sulphur at inlet (dry)	ppm	86	91
T_{in}	°C	275	296
T_{out}	°C	420	421
By-pass/syngas	mol/mol	0.70	0.00
H_2/CO after shift	-	2.0	6.4
Scrubber			
Inlet temperature	°C	200	200
T_{out} at stage 1	°C	60	60
T_{out} at stage 2	°C	30	30
Pressure at outlet	bar	3.8	3.8
Water removal	kg/s	10.6	6.2
NH_3 at inlet	ppm	90	688
Upstream AGR			
CO_2 + sulphur removal	%	100	100

Table 4. Power consumption for the simulated plant designs.

POWER CONSUMPTION	CASE	Power & Fuels	Power Only
Oxygen production	MW	-9.0	-7.5
Oxygen compression	MW	-1.9	-1.6
Drying and feeding	MW	-2.0	-2.0
Syngas scrubbing	MW	-0.2	-0.1
Syngas compression	MW	-7.5	-7.8
Acid gas removal	MW	-0.8	-1.1
CO_2 compression	MW	-6.6	-8.8
Blowers and pumps	MW	-0.5	-0.5
Miscellaneous	MW	-1.5	-1.5
SUM	**MW**	**-30.0**	**-30.9**

Table 5. Steam consumption for the simulated plant designs.

STEAM CONSUMPTION	CASE	Power & Fuels	Power Only
Drying	kg/s	5.5	8.5
Gasifier	kg/s	5.5	5.5
Reformer	kg/s	4.0	2.4
WGS	kg/s	0.1	0.5
AGR	kg/s	2.9	3.9
Synthesis	kg/s	0.0	0.0
Deaerator	kg/s	3.8	3.5
Economiser	kg/s	4.7	4.4
SUM	kg/s	26.5	28.7

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