The Economy of Large Scale Biomass to Substitute Natural Gas (bioSNG) plants

G. Aranda
A. van der Drift
R. Smit

January 2014
ECN-E--14-008

Acknowledgement

The work described in this report was performed as part of the EDGaR-project SNG-impact with ECN project number 51244.

Abstract

In this work, an economic assessment of large-scale production of Synthetic Natural Gas from biomass (bioSNG) has been carried out. With the aim of estimating the total capital investment of a large-scale bioSNG facility, different commercial plants based on gasification technology, including Gas-to-Liquids (GTL), Coal-to-Liquids (CTL), Coal-to-methanol (CTM), Coal-to-SNG (CSNG), and Integrated Gasification Combined Cycle (IGCC) have been used as references. The layout for SNG production from biomass is based on MILENA indirect gasification (technology developed by ECN). The average Total Capital Investment (TCI) for a large bioSNG plant (1 GW thermal input) has been determined as ~1530 USD_{2013}/kW_{input}. Technology learning could further decrease the TCI of a bioSNG plant with about 30% to 1100 USD_{2013}/kW_{input} after a cumulative number of 10 GW installed capacity. A TCI of 1100 USD_{2013}/kW_{input} results in an overall bioSNG cost price of 14-24 USD_{2013}/GJ, largely depending on the price of biomass feedstock. From three scenarios considered (wood chips in Europe and United States, or cheap agricultural residues from Brazil/India), the latter is the best in terms of cost price of SNG. However, Europe offers several advantages for the deployment of SNG from biomass, e.g. existing natural gas infrastructure, and an existing SNG market based on incentives and obligations. Internalization of CO_2 emissions in the 2030 untaxed price of SNG reveals that bioSNG can be competitive with SNG produced from coal, with a cost of 25 USD_{2013}/GJ. Even so, medium-term bioSNG prices are expected to remain higher than future natural gas prices. However, the implementation of concepts such as the co-production of bioSNG/bioLNG and chemicals/biofuels, the capture and storage of CO_2, or power-to-gas systems will contribute to enhance the business case of bioSNG production. ECN is working on all these topics.

Contents

Summary

In this work, an economic assessment of large-scale production of Synthetic Natural Gas (SNG) from biomass is carried out. With the aim of estimating the total capital investment of a large-scale bioSNG facility, different commercial plants based on gasification technology have been used as references, including Gas-to-Liquids (GTL), Coal-to-Liquids (CTL), Coal-to-methanol (CTM), Coal-to-SNG (CSNG), and Integrated Gasification Combined Cycle (IGCC). Due to the uncertainty of the reported investment of plants (caused by differences of scale and start-up year, cost escalation, co-production, reporting policies, etc.), a large number of references has been used in order to obtain a credible, realistic average value. The reference layout for SNG production from biomass is based on MILENA indirect gasification (technology developed by ECN).

In addition, a systematic comparison between technologies has been carried out in order to incorporate the technical differences of bioSNG technology into the estimated total capital investment. Analysis has shown that biomass-to-SNG ranges from +5% to +30% compared to the selected commercial reference technologies.

Based on absolute cost references of operating or under construction large-scale plants, and taking into account the technical differences with respect to a bioSNG plant, the averaged Total Capital Investment (TCI) for a large (1 GW_{input}) bioSNG plant has been determined as ~1530 USD_{2013}/kW_{input}.

The effect of technology learning, also considered in the study, has been assumed to be able to further decrease the TCI of a bioSNG plant with about 30% to 1100 USD_{2013}/kW_{input} after a cumulative number of 10 GW installed capacity (medium-term, e.g. in 2030).

A TCI of 1100 USD_{2013}/kW_{input} results in an overall bioSNG cost price ranging between 14-24 USD_{2013}/GJ or 0.45-0.77 USD_{2013}/Nm^3 (Groningen quality gas). The cost price for 1 GJ of bioSNG largely depends on the price of the biomass feedstock (2-9 USD_{2013}/GJ), and therefore, on the plant location. Using medium-term projections of prices of biofuels, it has been found that bioSNG has a lower cost in terms of energy content than liquid biofuels. However, untaxed prices cannot be competitive with current fossil natural gas prices. From the three scenarios considered (wood chips in Europe and United States, or inexpensive agricultural residues from Brazil/India), the latter is the best in terms of cost price of SNG. However, Europe offers several advantages for the deployment of bioSNG, such as a developed natural gas infrastructure, and the current existence of a market based on incentives and obligations.

Finally, in order to take into account the cost of CO_2 emissions during the cycle life of SNG, cost of CO_2 emissions has been added into the medium-term price of natural gas and SNG produced from coal and biomass. Results of internalization of CO_2 emission cost in the 2030 untaxed price of SNG have shown that bioSNG can be competitive with SNG produced from coal, with a cost of 25 USD_{2013}/GJ. Even so, medium-term bioSNG prices are expected to remain higher than future natural gas prices. However, the implementation of concepts such as the co-production of bioSNG/bioLNG and chemicals/biofuels, the capture and storage of CO_2, or power-to-gas systems will contribute to enhance the business case of bioSNG production. ECN is working on all these topics.

Nomenclature

ASU: Air separation unit.
bbl/day: Barrels/day.
bcf/y: Billion cubic feet/year.
bcm/y: Billion cubic meter/year.
bioLNG: Liquefied Natural Gas produced from biomass gasification.
bioSNG: Synthetic Natural Gas produced from biomass gasification.
BTL: Biomass to liquids.
CCS: Carbon Capture and Storage.
CNY: Chinese yuan renminbi (1 CNY = 0.163 USD).
CTL: Coal to liquids (diesel and naphtha transportation liquid fuels).
CTM: Coal to methanol.
CSNG: Coal to SNG.
DME: Dimethyl ether.
EUR: Euro (1 EUR = 1.359 USD).
F-T: Fischer-Tropsch.
HC: Hydrocarbons.
HDS: Hydrodesulphurization.
ISBL: Inside battery limits.
IGCC: Integrated gasification combined cycle.
LHV: Lower heating value (MJ/kg or MJ/Nm^3).
LPG: Liquefied petroleum gases.
MDEA: Methyl diethanolamine.
MeOH: Methanol.
Mscf: Million standard cubic feet.
O & M: Operation and maintenance.
P2G: Power-to-gas.
SNG: Synthetic natural gas.
TCI: Total Capital Investment.
USD: American dollar.
USD_{2013}: 2013 American dollar.
WGS: Water-gas shift.

1

Introduction

1.1 Synthetic Natural Gas (SNG) as energy carrier

SNG (Substitute Natural Gas, or Synthetic Natural Gas) is defined as a gas containing mostly CH_4 (> 95% vol.), with similar properties to natural gas, which can be produced from thermochemical gasification of fuels (e.g. coal, biomass) coupled to subsequent methanation. Conversion efficiency of coal/biomass to SNG is higher than the efficiency to liquid fuels [1]. Overall efficiency of conversion from biomass to SNG can be up to 70% in energy basis [2][3].

Due to its interchangeability with natural gas, the use of SNG has a number of advantages. SNG can be efficiently converted in a number of well-established end-use technologies. It can be cheaply produced at large scale, and is a storable energy carrier, thus enabling whole year operation independently of fluctuations in demand. Moreover, SNG can be injected into the existing grid and easily distributed for transport, heat, and electricity applications. As well as natural gas, SNG has a high social acceptance compared to coal [1][4][5][6].

SNG not only can be considered as an attractive, versatile energy carrier for bioenergy, but also can be used for storage of surplus power from renewable sources (e.g. solar, wind). This is the so-called “power-to-gas” concept where excess power produces H_2 that is added to an existing SNG-plant to convert additional CO_2 into CH_4.

Addition of CO_2 storage technology into the SNG process in coal-to-SNG plants is crucial in order to reduce its environmental footprint. Biomass-based SNG could also be combined with CO_2 storage to further reduce emissions, even making negative CO_2 emissions possible [7].

1.2 SNG production from carbonaceous fuels

Thermochemical production of SNG from coal or biomass includes the following steps:

- Feedstock pre-treatment: drying, crushing, etc.
- Gasification stage.
- Syngas cooling, cleaning and conditioning: gas produced in the gasification stage must be cleaned from contaminants (sulphur compounds, nitrogen compounds, heavy metals, etc.), and its composition (H_2/CO ratio, CO_2 content) must be adjusted prior to the synthesis stage.
- Methanation: syngas is converted into CH_4 through an exothermic reaction.
- SNG conditioning: in order to comply with grid requirements, SNG composition might be adjusted.

There are several possible criteria for the classification of gasification processes. Depending on the method of heat supply, gasification technologies can be classified in direct and indirect. In direct gasification, the heat required for the endothermic devolatilization and gasification reactions is provided by the combustion of a fraction of the feedstock. On the contrary, in indirect gasification processes, gasification and combustion stages are physically separated, and heat is transferred between both reactors via a heat carrier (e.g. bed material). Indirect gasification allows the production of a N_2-free product gas without the need for an expensive air separation unit. As a result, syngas contains a high concentration of CH_4. These advantages make indirect gasification an attractive option for SNG production. In particular, ECN has developed the MILENA indirect gasification technology, described in more detail in section 1.5 of this document.

1.3 Scope and outline of this report

Although bioSNG is considered an interesting energy carrier, there are no operating plants available yet that can be used to estimate the costs of a bioSNG plant. This report aims to present an estimation of the costs of a large-scale plant in a future where bioSNG production is conventional technology. A realistic estimation of the Total Capital Investment (TCI) of a bioSNG plant is crucial for calculation of the bioSNG cost price.

With this background, this report presents the estimation of the Total Capital Investment (TCI) of SNG produced from biomass from the basis of reference technologically large-scale commercial plants which use gasification as the first process step. Section 2 of this document presents the results of specific costs in USD_{2013}/kW referred to a 1 GW thermal input capacity plant for each one of the reference technologies based on the absolute TCI of the facilities selected, and taking into account their different size and start-up date. The technical differences between the reference technologies and a bioSNG plant have been analysed and incorporated into the cost of a bioSNG plant in Section 3. The effect of technology learning on the TCI costs is analysed in Section 4. Finally, based on the estimated TCI after technical learning, a cost price for bioSNG is derived and discussed in Section 5. A number of appendices provides additional information on data and methodology used in this work, as well as on some reference plants.

1.4 Methodology for TCI estimation

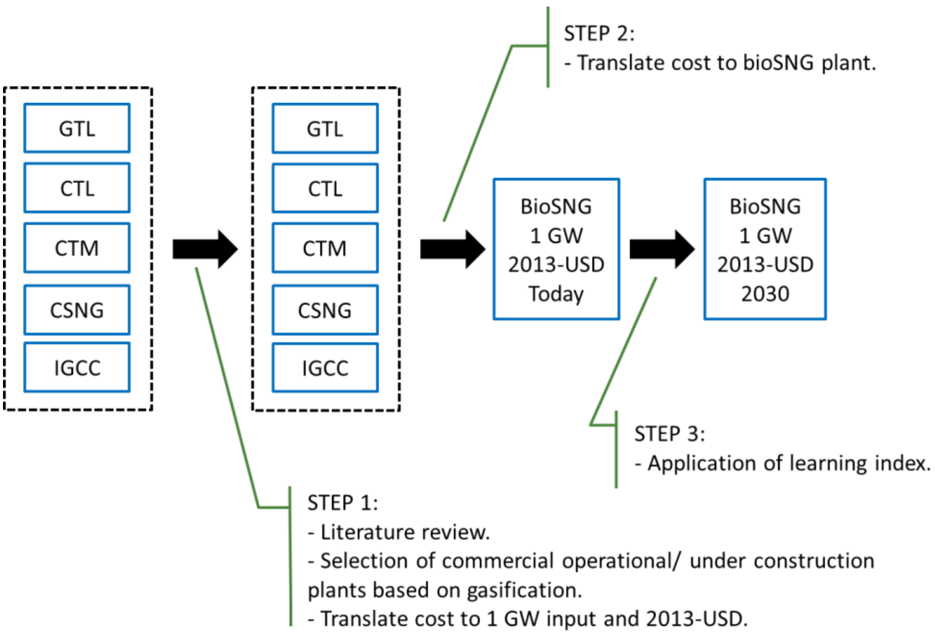
There are two approaches for estimating the Total Capital Investment of a bioSNG plant:

a) From reference data of technologically similar facilities, applying different factors to cope with different scale, start-up year, etc.

b) Bottom-up method, where basic engineering is carried out for the plant and cost estimations are based on a process flow diagram, energy and mass balances, and quotes for major equipment.

In this report, method a) has been selected for a first estimation of costs due to lower complexity, and to the high uncertainty of results from method b).

Figure 1: Methodology for estimation of Total Capital Investment of a large bioSNG plant used in this work.



The TCI for a large-scale and technically mature bioSNG plant has been estimated by using a 3-step methodology (Figure 1):

- Step 1. A list of reference gasification plants has been collected from an extensive literature review. The following technologies have been selected for the study due to its maturity and commercial status:

- Gas to liquids (GTL).
- Coal to liquids (CTL).
- Coal to methanol (CTM).
- Coal to SNG (CSNG).
- Integrated Gasification Combined Cycle (IGCC).

From the available references, only large-scale operational or under construction plants have been considered in order to get a realistic and credible estimation of costs. Moreover, a large number of references has been selected in order to get a realistic average value by reducing the uncertainty of the reported investment costs of plants. The absolute TCI of the facilities selected has been used to derive the specific cost in terms of USD_{2013}/kW for a 1 GW input capacity plant, thus taking into account the different size and start-up date of the facilities considered. This step is presented in section 2 of this report.

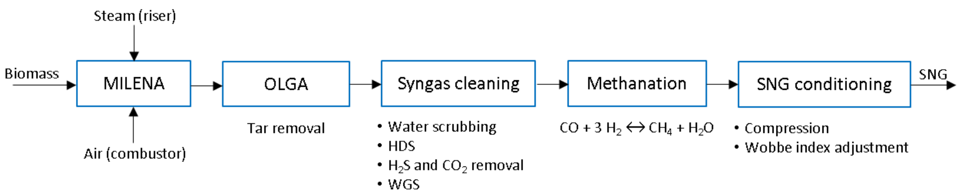
- Step 2. The reference technologies have also been systematically compared with a bioSNG process in order to take into account the technical differences between processes, and translate them into the plant cost of a bioSNG plant. The procedure and results of this analysis are shown in Section 3.

- Step 3. Finally, for a future projection, the TCI updated in step 2 is adjusted to take into account learning effects, resulting in a TCI value that can be expected after implementing 10 GW bioSNG capacity cumulatively (i.e., building 10 units of 1 GW each). The results are presented in Section 4.

1.5 MILENA indirect gasification for SNG production

For a proper comparison of the different technologies considered in this work, a layout for a bioSNG plant has been proposed (Figure 2). MILENA indirect gasification and OLGA tar removal system, technologies developed by ECN, have been selected due to the high potential efficiency for SNG production [3].

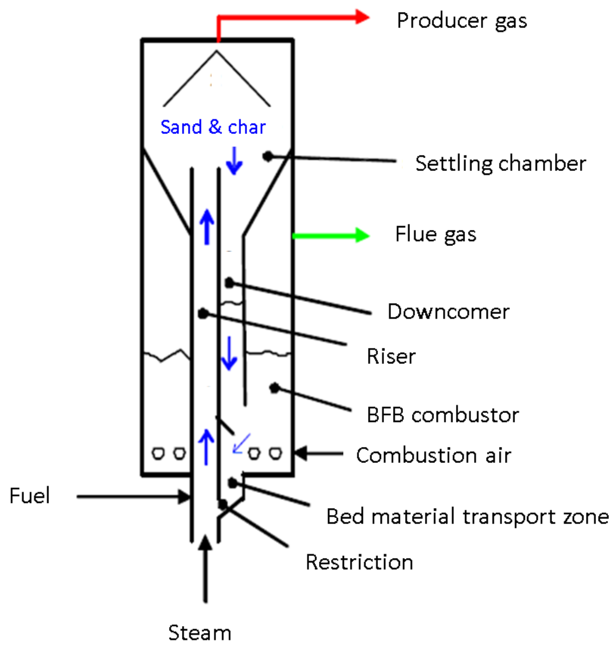
Figure 2: Schematic layout of proposed bioSNG plant based on MILENA indirect gasification.



MILENA technology (shown in Figure 3), incorporates several improvements with respect to existing indirect gasification concepts. Firstly, gasification and combustion reactors are placed in one single vessel for both reactors. This makes the system cheaper, easier to pressurize, and with less heat loss. Moreover, there is only a single bed material circulation mass flow restriction to avoid imbalances. MILENA offers higher efficiency due to a minimum amount of gas/steam for the gasification reactor. The implementation of a settling chamber instead of cyclone for gas/bed material separation allows reducing start-up issues and increasing the ability to cope with flow disturbances. In MILENA gasification, biomass undergoes devolatilization in the riser, whereas the remaining char descends through the downcomer and is combusted in the fluidized bed. Therefore, complete conversion of the feedstock is achieved.

The net overall efficiency for SNG production from MILENA indirect gasification is reported to be ~70% (LHV basis) [3]. MILENA gasification could be scaled up to 1 GW. This 10 m diameter, 20 m height reactor would be operated at a pressure of 7 bar. ECN is currently performing research and development activities on gas cleaning mainly based on catalytic removal of trace components, high temperature reforming of hydrocarbons, hydrogenation of unsaturated hydrocarbons and removal of sulphur and chlorine components.

Figure 3: MILENA gasification technology [3].



2

TCI of reference plants

As described in Section 1, the first step for the estimation of the Total Capital Investment (TCI) of a bioSNG plant is the gathering of data from literature corresponding to large-scale commercial gasification plants in operation or under construction. The reported investment of plants may vary from case to case not only because of differences of scale and start-up year of plants, but also due to cost escalations, co-production, greenfield/brownfield projects, and reporting policies. Therefore, in order to reduce this uncertainty and obtain a credible average value, it is necessary to use a large number of references.

Table 1-Table 5 summarize the performance and cost data of the different facilities considered in this study, categorized as a function of the technology (GTL, CTL, CTM, CSNG, and IGCC). Each reference plant includes start-up year, plant scale, and total capital investment (TCI, expressed in American dollars, USD). Values of specific costs obtained from literature are not comparable with each other, since the plant scale and start-up year are different. For this reason, specific costs have been normalized to a plant size of 1 GW thermal input. An average value of 0.7 has been selected in this work for the scaling factor applied [8]. The normalized costs have also been adjusted to inflation. In this work, 2.65% annual inflation has been assumed, value corresponding to the average inflation in United States in the period 2000-2013 [9][10]. Specific investment costs shown in Table 1-Table 5 are thus expressed in terms of million USD_{2013}/kW_{input}.

Appendix A of this document summarizes the assumptions made for the calculations, including efficiencies of technologies, conversion factors, and formulae used for calculations. Appendix B reviews the state of the art of selected technologies. Moreover, due to the possible distortion of the calculated investment costs, neither biomass-to-liquids nor biomass-to-SNG facilities have been included in this analysis. Nevertheless, a brief review of BTL and bioSNG European projects is presented in Appendix C of the document.

Table 1: Performance and cost data of reference gas-to-liquids (GTL) plants.

Code	Project name	Location	Plant output (bbl/day)	Plant output (GW)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/ 1 GW_{input})	Reference
GTL.1	Petrosa, Mossel Bay GTL	Mossel Bay, Western Cape, South Africa	45 000	2.70	1.5	1992	910	[11][12][13][14][15][16][17][18]
GTL.2	Shell Bintulu SMDS	Bintulu, Sarawak, Borneo, Malaysia	14 700	0.88	0.85	1993	1100	[19][20][21][22]
GTL.3	Qatar Petroleum/ Sasol, Oryx GTL	Ras Laffan Industrial City, Qatar	34 000	2.04	1	2006	510	[22][23][24][25][26][27][28]
GTL.4	Shell Pearl GTL INITIAL	Ras Laffan Industrial City, Qatar	140 000	8.39	5	2003	1025	[22][29][30][31]
GTL.5	Shell Pearl GTL ACTUAL	Ras Laffan Industrial City, Qatar	140 000	8.39	19	2011	3160	
GTL.6	Sasol/ Chevron/ NNPC. Escravos GTL INITIAL	Lagos, Nigeria	34 000	2.04	3	2010	1380	[22][32][33][34][35][36][37]
GTL.7	Sasol/ Chevron/ NNPC. Escravos GTL ACTUAL	Lagos, Nigeria	34 000	2.04	8.4	2013	3570	
GTL.8	Sasol/Uzbekneftegaz/Petronas GTL	Qarshi, Uzbekistan	38 000	2.28	2.5	2016 - 2017	980	[38][39]
GTL.9	Sasol, Lake Charles	Lake Charles, Louisiana, USA	96 000	5.75	16	2018 - 2019	3290	[40][41][42][43][44][45]

Table 2: Performance and cost data of reference coal-to-liquids (CTL) plants.

Code	Project name	Location	Plant output (bbl/day)	Plant output (ton/year)	Plant output (GW)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/ 1 GW_{input})	References
CTL.1	Sasol, Sasolburg CTL	Sasolburg, South Africa	15 600	-	0.96	0.45	1955	1280	[46][47][48]
CTL.2	Sasol, Secunda CTL	Secunda, South Africa	160 000	-	9.29	5.7	1980 / 1984	1720	[46][47][48][49][50][51][52]
CTL.3	Shenhua Group Co. Ltd., Inner Mongolia CTL	Ordos, Inner Mongolia, China	-	3 200 000	4.43	2.76	2010	640	[53]
CTL.4	Shenhua Ningmei Group / Sasol Synfuels, Ningxia Hui CTL Plant	NingDong chemical base, Ningxia, China	80 000	3 200 000	4.65	8.7	2010	1950	[53][54][55][56][57][58]
CTL.5	Shenhua Direct Coal Liquefaction Project	Ordos, Inner Mongolia, China	24 000	-	1.39	1.5	2008	820	[53][58][59][60][61][62][63][64][65]
CTL.6	Yankuang Shaanxi Future Energy Chemical Co., Ltd.	Yulin, Shaanxi, China	-	1 000 000	1.38	2.4	2013	1160	[53][58][66][67][68]
CTL.7	Yi'tai Group	Ganquanpu or Yili, Xinjiang, China	-	5 400 000	7.47	10.3	2013	1530	[53][58]
CTL.8	American Lignite Energy CTL	McLean county, North Dakota, USA	32 000	-	1.86	4	-	1570	[69][70]
CTL.9	Fox Creek CTL	Fox Creek, Alberta, Canada	40 000	-	2.32	4.5	2014 -15	1510	[71][72][73][74]
CTL.10	H&WB CTL Facility	Bataan, Philippines	60 000	-	3.48	2.8	2013	710	[75][76]
CTL.11	Likuen Coal Liquefaction Project	La Guajira / Santander / Cundinamarca and Boyacá, Colombia	50 000	-	2.90	2	2013	580	[77][78][79]

Table 3: Performance and cost data of reference coal-to-methanol (CTM) plants.

Code	Project name	Location	Plant output (ton/year)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/ 1 GW input)	References
CTM.1	Durban Methanol Plant	Sasolburg, South Africa	140 000	0.021	1998	110	[48][80][81]
CTM.2	Air Products Kingsport Methanol Plant	USA, Kingsport, Tennessee	96 000	0.21	1997	1495	[82][83]
CTM.3	Henan Kiaxiang Complex	Yima, Henan, China	400 000	0.26	2008	510	[53][84][85][86][87]
CTM.4	Dongneng Chemical	Hulunbeier, Inner Mongolia, China	200 000	0.15	2008	490	[53][88]
CTM.5	Sinopec, Puyang Chemical Plant	Puyang, Henan, China	600 000	0.24	2008	355	[53]
CTM.6	Jinye Group	Gujiao, Shanxi, China	300 000	0.15	2009	350	[53][89]
CTM.7	Jiangsu Sopo Group	Zhenjiang, China	540 000	0.33	2009	510	[90]
CTM.8	Shanxi Qinpeng Coal Science Development Co,, Ltd,	Yangcheng County, Jincheng, Shanxi, China	200 000	0.31	2009	960	[53]
CTM.9	Xinsheng Coal Chemical Corp	Yuncheng, Shanxi, China	200 000	0.085	2009	260	[53]
CTM.10	Asia New-Energy (Xinyang) Holdings Pte, Ltd	Xinyang, Henan, China	300 000	0.46	2009	1080	[53]
CTM.11	China Gas/Shanxi Tiancheng Dayang	Fenyang, Shanxi, China	400 000	0.431	2010	800	[53]
CTM.12	China Oceanwide Holdings Group	Baotou, Inner Mongolia, China	1 800 000	3.7	2010	2410	[53][91][92][93][94]
CTM.13	Jingde Energy & Chemicals Co,, Ltd	Xingyi, Guizhou, China	600 000	0.54	2010	760	[53][95]
CTM.14	Datang International Power Generation Co,, Ltd	Duolun County, Inner Mongolia	1 680 000	2.97	2010	2030	[53][96][97]
CTM.15	SES/Golden Concord Energy	Xilinguole, Inner Mongolia,China	225 000	0.12	2010	335	[53][98]
CTM.16	Shaanxi Provincial Investment Group Co,	Xianyang, Shaanxi, China	600 000	0.44	2010	620	[53][99][100][101]
CTM.17	Shenhua Group	Baotou, Inner Mongolia, China	1 800 000	2.8	2010	1820	[53][58][97][102] [103][104][105]

Table 3: Performance and cost data of reference coal-to-methanol (CTM) plants (continued).

Code	Project name	Location	Plant output (ton/year)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/1 GW_{input})	References
CTM.18	Shenhua Ningmei Group	NingDong, Ningxia, China	1 670 000	2.8	2010	1920	[53][58][97][106][107][109][110]
CTM.19	Xishan Coal Electricity Group/Shilin Chemical	Ordos, Inner Mongolia, China	300 000	0.19	2010	430	[53][111]
CTM.20	Wei-he Coal Chemical Group	Weinan, Shaanxi, China	400 000	0.53	2010	990	[53][112][113]
CTM.21	Shenhua Ningmei Group	NingDong, Ningxia, China	600 000	0.41	2010	580	[53]
CTM.22	Huating Zhongxu Coal Chemical Corp.	Huating, Gansu, China	600 000	0.44	2010	620	[53][114][115][116][117]
CTM.23	Shaanxi Yanchang Petrochemical Xinghua Company	Xingping, Shaanxi, China	300 000	0.75	2011	1670	[53][118]
CTM.24	Guizhou Jinyuan Group / Chitianhua Group	Tongzi, Guizhou, China	300 000	0.65	2012	1410	[53][119][120][121]
CTM.25	Fengfeng Group	Handan, Hebei, China	1 000 000	2.61	2008	2700	[53][122]
CTM.26	Chongqing Wansheng Coal Chemical Co., Ltd.	Chongqing, China	300 000	0.44	2013	930	[53]
CTM.27	Bohai Chemical Industry Group Corporation	Tianjin, China	500 000	1.93	2014-15	2850	[53]
CTM.28	Chia Tai Energy Chemical Group/Shaanxi Coal Chemical Group/Shaanxi Provincial Investment Group/Shaanxi Xinxing Coal Chemical	Yulin, Shaanxi, China	1 800 000	3.19	-	1920	[53]
CTM.29	Chongqing Kabeile Chemicals	Chongqing, China	850 000	0.39	2012	410	[53][123][124]
CTM.30	Daban Coal Chemical Corp.	Chifeng, Inner Mongolia, China	300 000	0.97	2012	2100	[53]
CTM.31	East Hope Group	Wansheng, Chongqing, China	200 000	0.43	2010	1300	[53][125][126][127]
CTM.32	Guizhou Shuicheng Coal Mining (Group) Co., Ltd	Liupanshui, Guizhou, China	200000	0.26	2011	770	[53][128][129][130]

Table 3: Performance and cost data of reference coal-to-methanol (CTM) plants (continued).

Code	Project name	Location	Plant output (ton/year)	Investment (billion USD)	Start-up date	TCI (million USD_{2013} / 1 GW input)	References
CTM.33	Hangtian Huayuan Chemicals Corp.	Shuangyashan, Heilongjiang, China	300 000	0.24	2011	530	[53]
CTM.34	Hemei Group	Hebi, Henan, China	600 000	0.58	2010	815	[53]
CTM.35	Huaneng Hulunbeier Energy Development Co Ltd.	Manzhouli, Inner Mongolia, China	600 000	0.67	2010	940	[53][131]
CTM.36	HuaYi Group/Yili Resources	Ordos, Inner Mongolia, China	1 200 000	0.24	2011	200	[53]
CTM.37	Inner Mongolia Donghua Energy Co., Ltd.	Ordos, Inner Mongolia, China	600 000	0.57	-	740	[53][132][133]
CTM.38	Jizhong Energy Fengfeng Group/Luneng Group	Xilinguole, Inner Mongolia, China	1 200 000	4.21	-	3370	[53][134][135]
CTM.39	Liye Tianfu Energy Co., Ltd.	Shihezi, Xinjiang, China	300 000	0.22	2011	490	[53][136]
CTM.40	Shanghai Huayi Group, Anhui Huayi Chemicals Co.	Wuwei county, Anhui, China	600 000	1.19	2012	1590	[53][137][138][139]
CTM.41	Ningxia Baota Petrochemicals/Huadian Power International Corporation Limited	NingDong, Ningxia, China	600 000	0.33	-	430	[53]
CTM.42	Northwest Energy & Chemicals Co., Ltd.	Ordos, Inner Mongolia, China	300 000	0.98	-	2070	[53]
CTM.43	Pucheng Clean Energy Chemical Co. Ltd.	Weinan, Shaanxi, China	1 800 000	2.92	2013	1760	[53][140][141]
CTM.44	Shaanxi Yanchang Petroleum Group Yulin Coal Chemical Co., Ltd.	Yulin, Shaanxi, China	600 000	0.86	2011	1180	[53][142]
CTM.45	Shaanxi Yulin Natural Gas Chemical Industry Co., Ltd.	Yulin, Shaanxi, China	600 000	0.66	2011	900	[53][143]
CTM.46	Shandong Xinwen Mining Group Co., Ltd.	Xilinguole, Inner Mongolia, China	300 000	0.33	-	700	[53]
CTM.47	Shanxi Huayun Coal Electricity Co., Ltd.	Lvliang, Shanxi, China	600 000	0.86	2012	1150	[53][144]
CTM.48	Shenhua Group	Hulunbeier, Inner Mongolia, China	1 800 000	2.61	-	1570	[53]

Table 3: Performance and cost data of reference coal-to-methanol (CTM) plants (continued).

Code	Project name	Location	Plant output (ton/year)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/1 GW_{input})	References
CTM.49	Shenhua Group	Yulin, Shaanxi, China	1 800 000	1.42	-	855	[53]
CTM.50	Town Star Industry	Linfen, Shanxi, China	200 000	0.09	-	250	[53][145]
CTM.51	Shenhua Group	Urad Middle Banner, Inner Mongolia, China	480 000	1.53	2012-2013	2320	[146]
CTM.52	Xinjiang Guanghui Industry Co., Ltd.	Yiwu County, Xinjiang, China	1 200 000	1.81	2011	1520	[53][147][148][149]
CTM.53	Yongmei Zhongxin Chemical Corp.	Xinxiang, Henan, China	250 000	0.49	2011	1240	[53]
CTM.54	Yunnan Pioneer Chemical Co., Ltd.	Xundian County, Kunming, China	500 000	0.735	2012	1110	[53]
CTM.55	Zhongtian Hechuang Energy Co., Ltd.	Ordos, Inner Mongolia, China	4 200 000	7.02	2012	2400	[53]
CTM.56	Yankuang Group/ Xinjiang Energy & Chemical Corp.	Urumqi, Xinjiang, China	300 000	0.82	2011	1820	[53]

Table 4: Performance and cost data of reference coal-to-SNG (CSNG) plants.

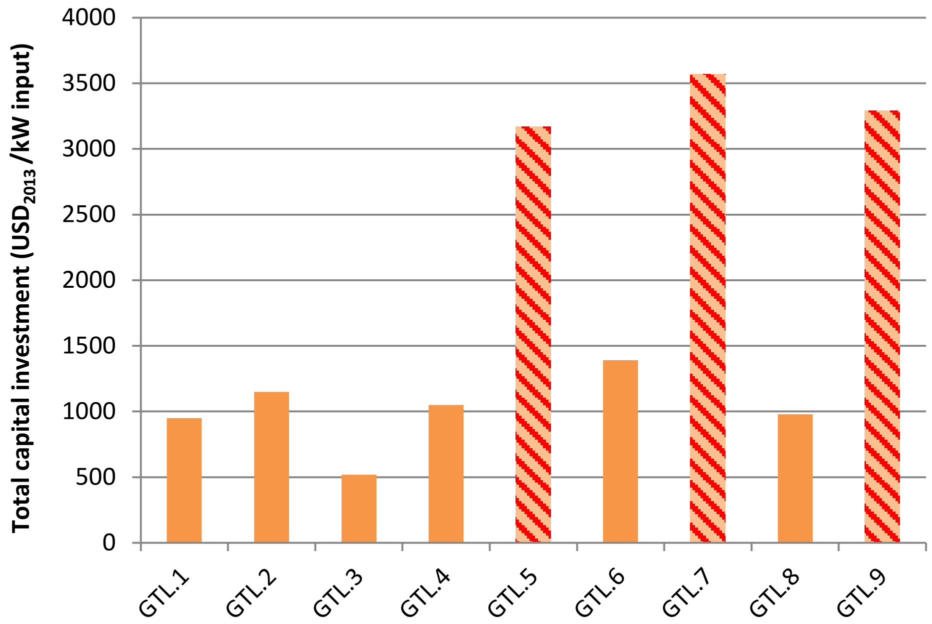
Code	Project name	Location	Plant output (bcm/y)	Plant output (GW)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/ 1 GW input)	References
CSNG.1	Great Plains Synfuels plant	North Dakota, USA	1.53	1.70	2.1	1984	2160	[6][150][151]
CSNG.2	CPIC / Shandong Xinwen Mining Group	Yili, Xinjiang, China	6	6.66	4.41	2014	800	[53][97] [151][152]
CSNG.3	Datang Energy Chemicals Corp.	Fuxin, Liaoning, China	4	4.44	4.02	2013	990	[53][151][153]
CSNG.4	Datang Group/ Beijing Gas Group/Tianjing Jinneng	Chifeng, Inner Mongolia, China	4	4.44	4.2	2012	1060	[53][151][154]
CSNG.5	Datang International Power Generation Co., Ltd.	Kesheketeng Qi, Inner Mongolia, China	4	4.44	3.76	2012	950	[53][151][154]
CSNG.6	Huineng Coal Chemical Co., Ltd.	Ordos, Inner Mongolia, China	2	2.22	2.21	2013	880	[53][151][154]
CSNG.7	Shenhua Group Co., Ltd.	Ordos, Inner Mongolia, China	2	2.22	2.29	2014	890	[53][154]
CSNG.8	Xinjiang Guanghui Industry Co., Ltd.	Yiwu county, Xinjiang, China	0.5	0.55	1.47	2011	1640	[53][148][155][156]
CSNG.9	CPIC	Yili, Xinjiang, China	6	6.66	4.57	2012	870	[53][151]
CSNG.10	China Huaneng Group	Changji, Xinjiang, China	1.3	1.44	1.12	2013	610	[53][148]
CSNG.11	Yili Xintian Coal Chemical Co., Ltd.	Yili, Xinjiang, China	2	2.22	1.96	2013	780	[152]
CSNG.12	China Guodian Corporation	Xing'an, Inner Mongolia, China	2	2.22	2.12	2014	830	[53][151]
CSNG.13	Qinghua Group	Yining County, Yili, Xinjiang, China	1.3	1.44	0.82	2012	460	[53][152][156]
CSNG.14	Shendong Tinanlong Group	Changji, Xinjiang, China	1.3	1.44	1.12	2013	610	[53]
CSNG.15	China Huadian Corporation	Changji, Xinjiang, China	4	4.44	4	-	985	[53]
CSNG.16	Xinjiang Guanghui Group	Aletai, Xinjiang, China	4	4.44	3.27	2013	810	[53]
CSNG.17	CNOOC, Datong Coal Mine Group Company	Datong, Shanxi, China	4	4.44	4.9	2013	1210	[53][151][157]

Table 5: Performance and cost data of reference Integrated Gasification Combined Cycle (IGCC) plants.

Code	Project name	Location	Power output (MW)	Investment (billion USD)	Start-up date	TCI (million USD_{2013}/1 GW_{input})	References
IGCC.1	Nuon Buggenum	Haelen, Limburg, The Netherlands	253	0.443	1994	1060	[158][159][160][161][162][163][164][165][166]
IGCC.2	Wabash River Power Station	Terre Haute, Indiana, USA	262	0.438	1995	940	[158][159][161][165][166][167][168][169]
IGCC.3	Sokolovska Uhelna AS, Vresova IGCC	Vresova, Czech Republic	351	0.440	1996	800	[158][159][161][165][166][170][171][172][173][174]
IGCC.4	Tampa Electric Company, Polk Power Station	Tampa, Florida, USA	250	0.448	1996	990	[158][159][161][165][166][175][176][177]
IGCC.5	Elcogas	Puertollano, Ciudad Real, Spain	310	0.996	1998	1820	[158][159][161][165][166][178][180][181]
IGCC.6	Duke Energy	Edwardsport, Indiana, USA	618	3.55	2013	2620	[182][183][184][185][186][187][188][189][190]
IGCC.7	Southern Company Services / Mississippi Power Kemper County IGCC	Kemper County, Mississippi, USA	582	2.9	2014	2170	[158][159][161]

Results of updated specific costs in terms of USD_{2013}/kW for a 1 GW input plant are shown in Figure 4 to Figure 8.

Figure 4: Specific TCI costs for gas-to-liquids (GTL) plants translated to 2013-USD and normalized to 1 GW input scale.



In Figure 4 it can be observed that plants GTL.5 (Shell's Pearl), GTL.7 (Sasol's Escravos), and GTL.9 (Sasol's Louisiana), highlighted with red stripes, show dramatically higher investment costs than other plants such as Mossel Bay (GTL.1), Shell's Bintulu (GTL.2) or Shell's Oryx (GTL.3). Despite the high interest and recent developments in GTL industry, progress has been restrained by the huge cost of building GTL plants, due to cost overruns, as well as by the swing in the price of oil [22][37]. Even though it has been reported that a 35000 bbl/day GTL plant can cost about 1 billion USD [37], reality has shown cost escalations in some commercial plants. It is generally accepted that such escalation is an over-reaction forced by constraints in materials availability and engineering capacity [191]. GTL plants have to compete for scarce engineering talent and raw materials such as high-strength corrosion resistant steels with the enormous number of LNG projects launched over the last ten years. Engineering and construction costs for oil and gas exploration and production projects rose 41% between early 2006 and early 2009. The result has been a high pressure on the relatively scarce engineering companies and suppliers capable of delivering advanced GTL plants on this sort of scale [37]. It is expected that escalations will re-dress itself in the next few years, but it is unlikely to return to the low investment costs such as those at the Sasol ORYX project in 2002 [191].

In 2003, before construction began, the project cost of the Shell's Pearl Project (GTL.4 and GTL.5 in Table 1) was estimated at 5 billion USD. However, the real costs of this project are much higher, up to 18-19 billion USD, which is about four times the original estimate. Chevron and Sasol's Escravos plant (GTL.6 and GTL.7 In Table 1) has seen even worse cost inflation, and is years behind schedule. This 34000 bbl/day plant was initially budgeted at 3 billion USD. the cost of project had escalated to 8.4 billion USD. As for the case of the Louisiana GTL project (GTL.9 in Table 1), cost has already jumped up to 16 billion USD from the initial estimate of 8 billion USD. The high price tag of GTL plants is largely due to capital costs of building GTL facilities. Even with the 2 billion USD tax credits and other incentives from the state of Louisiana, the final cost of the project may be higher [192].

Figure 5: Specific TCI costs for coal-to-liquids (CTL) plants translated to 2013-USD and normalized to 1 GW input scale.

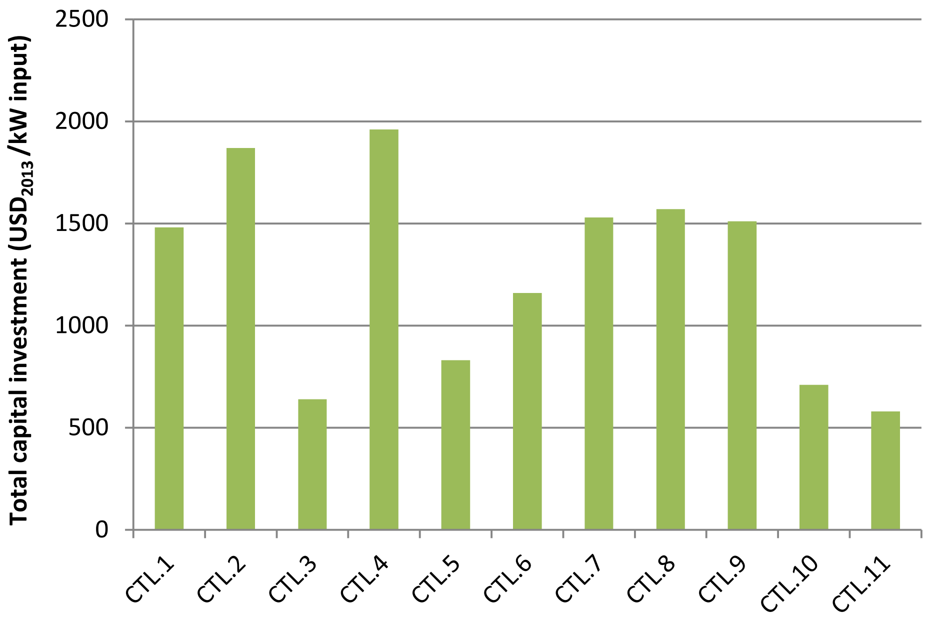
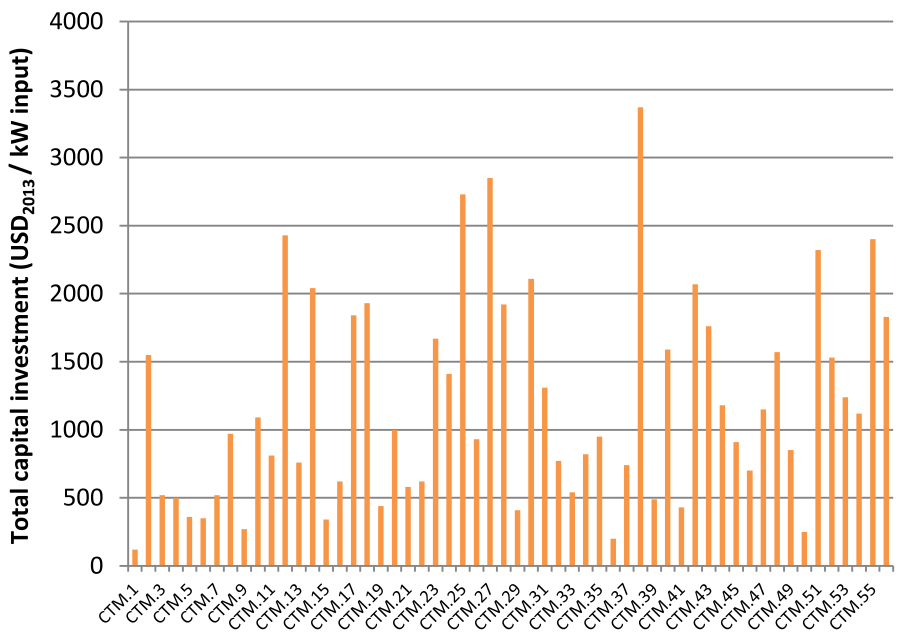


Figure 6: Specific TCI costs for coal-to-methanol (CTM) plants translated to 2013-USD and normalized to 1 GW input scale.



It is worth noticing in Figure 7 that there are two specific cases far from the average. In these cases (corresponding to the Great Plains plant and the Xinjiang Guanghui facilities, respectively), the higher investment costs might be explained by the co-production of other chemicals (see Section D.3 in Appendix D for the description of the Great Plants SNG facility).

Figure 7: Specific TCI costs for coal-to-SNG (CSNG) plants translated to 2013-USD and normalized to 1 GW input scale.

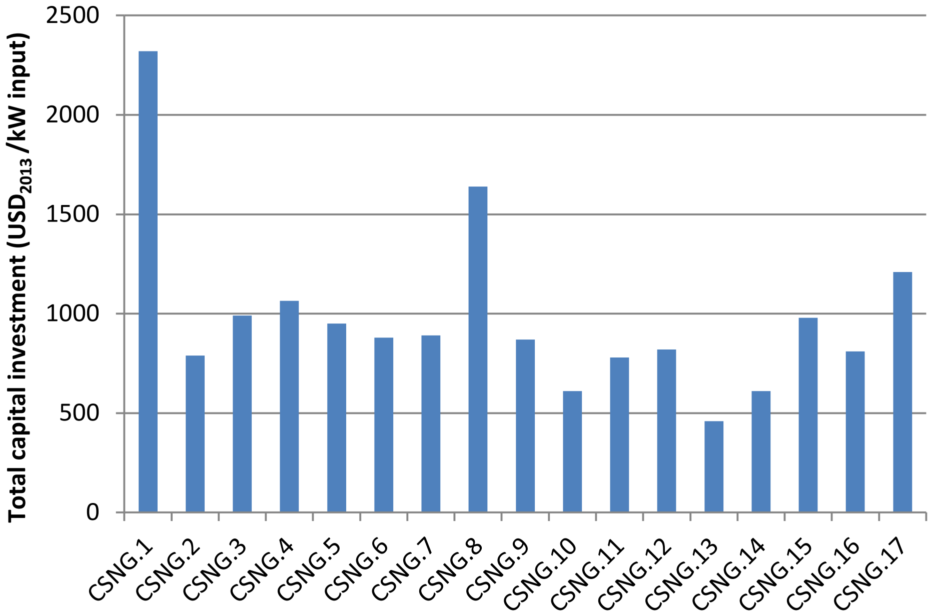
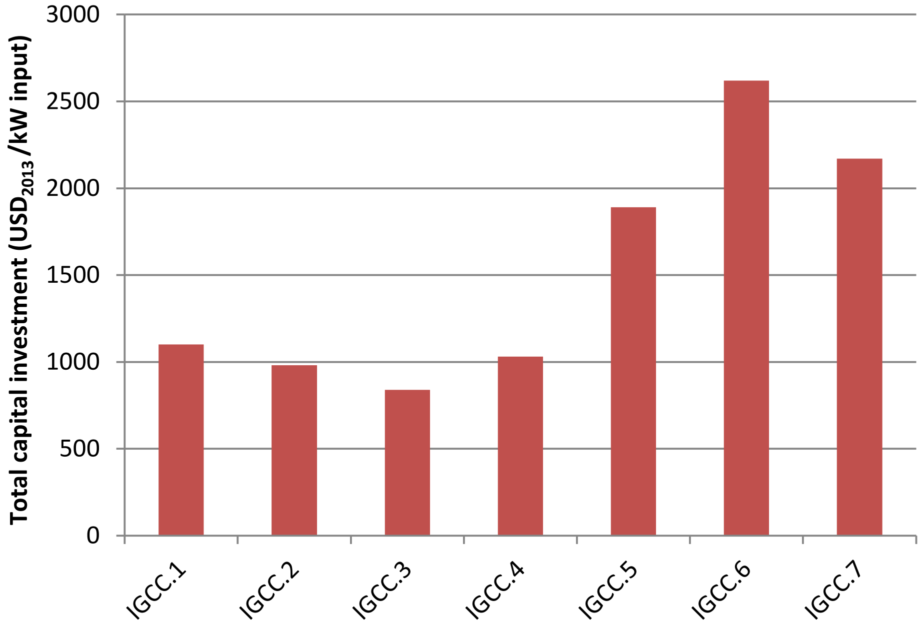


Figure 8: Specific TCI costs for Integrated Gasification Combined Cycle (IGCC) plants translated to 2013-USD and normalized to 1 GW input scale.



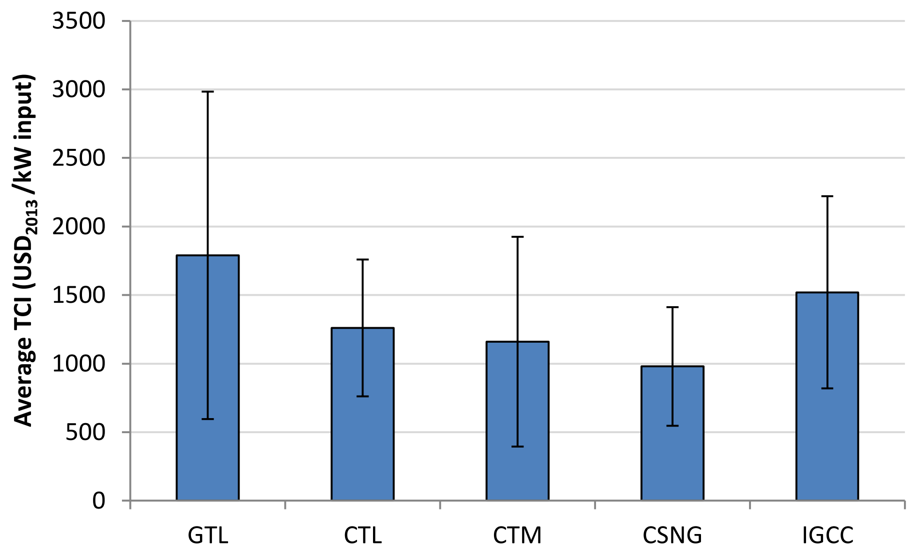
The average values of the specific TCI costs in terms of USD_{2013}/kW for a 1 GW thermal input plant are summarized in Table 6 and Figure 9. As can be seen, GTL is the technology with highest average specific investment costs (~1800 USD_{2013}/kW input) and highest deviation of values. Moreover, literature values for GTL investment costs are significantly lower than the actual ones. The reason of the discrepancy and the high dispersion of data values is the effect of cost escalations, discussed previously in this section. On the contrary, coal-to-SNG technology shows the lowest average (~ 970 USD_{2013}/kW input) and standard deviation values. In this study, the average values will be used, not excluding any of the input values. This is assumed to be the most reliable estimation for the estimation of the TCI of a large scale bioSNG plant.

Table 6: Summary and comparison of average values of TCI of reference plants.

Technology	TCI (USD_{2013}/kW_{input})	Comparison with literature references TCI (USD_{2013}/kW_{input})
GTL	1770	551.4 [193] 627.5 [194] 428.5 [22]
CTL	1220	1286 [195]
CTM	1160	-
CSNG	970	-
IGCC	1490	1184 – 1714 [196]

Values shown are the input for the next step in the cost estimation of a large-scale bioSNG plant, analysed in Section 3 of this document.

Figure 9: Summary of average values and standard deviation for the specific TCI of reference plants translated to 2013-USD and normalized to 1 GW input scale.



3

Normalized equipment cost of a bioSNG plant

The cost-share of each main process block of the reference plants is compared with the main process blocks (e.g. gasification island, or gas cleaning) of a bioSNG plant. As mentioned in the introduction, the reference plants are GTL, CTL, CTM, CSNG, and IGCC. The difference in the level of technical complexity gives an estimation of the cost difference in these process blocks.

For each reference plant, the system layout is briefly described and a simplified process flow diagram is provided. The differences in terms of components and equipment cost-share of these components are given in a separate table. All equipment or Inside Battery Limits (ISBL) costs of the reference plants have been normalized at 100 units. The division of cost shares of the different equipment is different for each case. This analysis results in the relative equipment cost for a bioSNG plant.

In order to perform a rigorous, consistent analysis, the following units have been considered in each one of the cases studied:

A. Air separation unit.
B. Gasifier island. This includes feedstock pre-treatment and feeding, gasifier and syngas cooling.
C. Syngas cleaning and conditioning (tar removal, acid gas removal, adjustment of composition, compression).
D. Synthesis and product upgrading. This unit is not applicable to IGCC plants.
E. Steam plant / power block (only applicable to IGCC plants). Also including plant balance.

The configuration of biomass-to-SNG used in this work for the analysis, based on MILENA indirect gasification and OLGA tar removal, has been described in section 1.5 of this document.

3.1 Gas-to liquids vs. biomass-to-SNG

A simplified layout of a GTL plant is shown in Figure 10. More details on the ORYX GTL plant as an example of the technology can be found in Section D.1 of Appendix D.

Figure 10: Schematic layout of a gas-to-Liquids plant

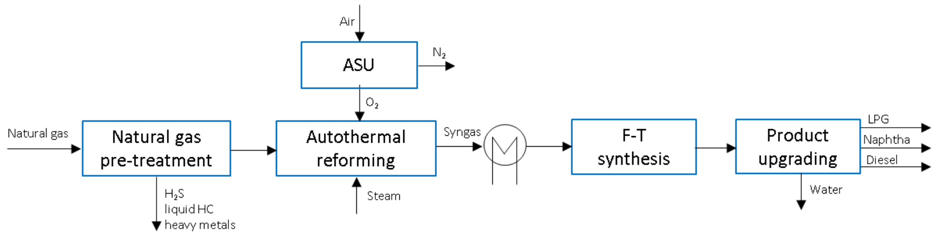
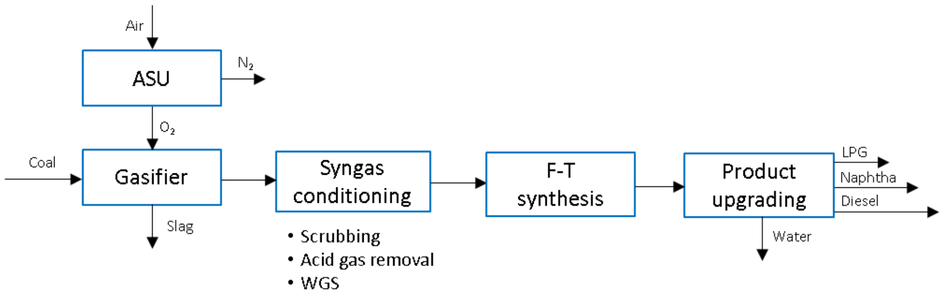


Table 7 summarizes the cost-share differences of a GTL plant with a bioSNG plant.

3.2 Coal-to-liquids vs. biomass-to-SNG

For the analysis presented in this work, CTL process based on gasification of the solid feedstock and subsequent Fischer-Tropsch synthesis has been considered. Figure 11 plots a simplified configuration of a CTL process.

Figure 11: Simplified layout of a coal-to-liquids plant.



In principle, coal-to-liquid plants show a number of similar features as compared to SNG production. Both processes use gasification of a solid material, contain extensive cleaning of the syngas produced (e.g. sulphur, CO_2), and include a catalytic process (methanation vs. Fischer Tropsch) in the end. More details on an example of CTL facility (Sasol Synfuels plant in Secunda, South Africa, see CTL.2 in Table 2) can be found in Appendix D of the document.

Table 8 summarizes the comparison of the distribution of investment costs of a CTL and a bioSNG plant.

Table 7: Comparison of cost distribution of gas-to-liquids and biomass-to-SNG plants.

Main equipment blocks	Cost GTL plant [% of ISBL] [21]	Gas-to-liquids vs. biomass-to-SNG	Relative cost of biomass-to-SNG plant [% of ISBL compared to GTL]
A. Air separation unit	25	Not required in the bioSNG plant because of the use of indirect gasification.	0
B. Gasifier island	32	- Biomass pre-treatment: grinding and drying. Lock hoppers required for pressurized feeding into the gasifier. - Natural gas pre-treatment: removal of liquid hydrocarbons, sulphur compounds (H_2S, COS, mercaptans), heavy metals, etc. - Gasifier: bioSNG concept uses MILENA indirect gasification. GTL uses steam reforming /partial oxidation/autothermal reforming. Partial oxidation and autothermal reforming require the use of oxygen, which imposes more strict requirements to materials. Steam reforming operates at high pressures, and requires of catalysts. - Operating temperature: MILENA indirect gasification operates at lower temperatures (700-900°C) than partial oxidation (1300-1500°C). This makes the material requirements less stringent, and simplifies the design (less refractory). - Operating pressure: MILENA indirect gasification operates up to 7 bar (due to limited possible solid circulation). Partial oxidation units can operate at higher pressures (up to 70 bar).Therefore, for the same output, MILENA equipment has a larger size, and is thus more expensive.	45
C. Syngas cleaning and conditioning	0	- BioSNG plant: physical tar removal (OLGA system), HDS, adjustment of H_2/CO ratio via WGS, acid gas removal (e.g. amine scrubbing unit + adsorption bed). More compression requirements and larger equipment size, because of the lower operating pressure of the MILENA gasifier (up to 7 bar). - GTL plant: Syngas cleaning not required.	50
D. Synthesis and product upgrading	43	- Synthesis: Fischer-Tropsch and methanation reactors operate at similar pressures (20-30 bar) and temperatures ~ 300°C. However, F-T unit adds complex recycler and reformer, which moreover increases flow, and thus equipment size. - Product upgrading: Complex and costly upgrading of F-T crude. SNG upgrading is relatively easy (adjustment of Wobbe index and pressure).	25
Total ISBL	**100**		**120**

Table 8: Comparison of cost distribution of coal-to-liquids and biomass-to-SNG plants.

Main equipment blocks	Cost coal-to-liquids plant [% of ISBL] [197][198]	Coal-to-liquids vs. biomass-to-SNG	Relative cost of biomass-to-SNG plant [% of ISBL compared to CTL]
A. Air separation unit	10	ASU is not required in the biomass-to-SNG case because of the use of indirect gasification.	0
B. Gasification island	26	- Pre-treatment and feeding: Grinding and drying of biomass is more costly than for coal (biomass has a relatively high moisture content, and is fibrous). In both cases, lock hoppers are required for pressurized feeding into the gasifier. - Gasifier: biomass-to-SNG concept uses MILENA indirect gasification. CTL uses fixed-bed gasification (Sasol). The latter requires the use of oxygen, which poses more strict requirements to materials. - Operating temperature: MILENA indirect gasification operates at lower temperatures (700-900°C) than oxygen-blown gasification. This makes the material requirements less stringent, and simplifies the design (less refractory required). - Operating pressure: MILENA indirect gasification (bioSNG) operates up to 7 bar (due to limited possible solid circulation). Lurgi fixed-bed gasification (CTL) operates at ~ 24 bar. Therefore, for the same output, MILENA equipment has a larger size, and thus more expensive.	45
C. Syngas cleaning and conditioning	22	- Tar removal: physical tar removal (OLGA system) and recirculation of tar to gasifier in bioSNG plant. Condensation and further processing for extraction of phenol and other products in CTL. - Adjustment of H_2/CO ratio: similar in both cases (WGS unit). - Acid gas removal: CTL plants use complex, costly physical absorption (e.g. Rectisol) for CO_2 and contaminants removal. Biomass-to-SNG concept might use less costly amine scrubbing unit + adsorption bed for CO_2 and H_2S removal. - Compression: more compression requirements and larger equipment size in bioSNG plant, because of the lower operating pressure of the MILENA gasifier (up to 7 bar).	45
D. Synthesis and product upgrading	32	-Synthesis: F-T and methanation reactors operate at similar pressures and temperatures. However, F-T unit adds complex recycler and reformer, which increases flow, and thus equipment size. -Product upgrading of F-T crude requires complex and costly equipment. On the contrary, SNG upgrading is relatively easy (adjustment of Wobbe index, compression).	15
Total ISBL	**100**		**105**

3.3 Coal-to-methanol vs. biomass-to-SNG

Figure 12 shows a simplified configuration of methanol synthesis. The process consists of gasification of coal. Syngas produced is cleaned and conditioned prior to methanol synthesis. Products from synthesis stage are separated and upgraded in order to comply with the product methanol requirements.

Figure 12: Schematic layout of a coal-to-methanol plant.

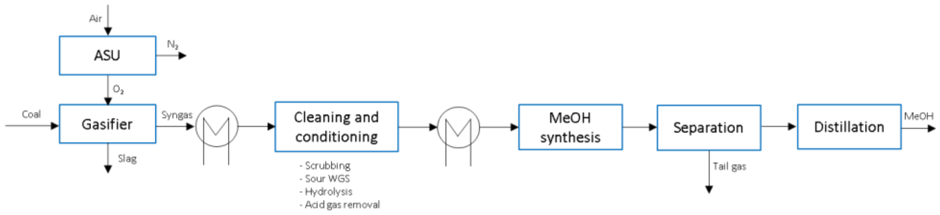


Table 9 summarizes the comparison of cost distribution of coal-to-methanol and biomass-to-SNG plants.

Table 9: Comparison of cost distribution of coal-to-methanol and biomass-to-SNG plants.

Main equipment blocks	Cost CTM plant [% of ISBL] [197][199]	Coal-to-methanol vs. biomass-to-SNG	Relative cost of bioSNG plant [% of ISBL compared to CTM]
A. Air separation unit	20	ASU not required in bioSNG plant because of the use of indirect gasification.	0
B. Gasification island	31	- Feedstock pre-treatment and feeding: Grinding and drying of biomass is more costly than for coal. In both cases, lock hoppers required for pressurized feeding into the gasifier. - Gasifier: biomass-to-SNG concept uses MILENA indirect gasification. CTM uses fixed-bed or entrained-flow gasification. Both require the use of oxygen, which poses more strict requirements to materials. -Operating temperature: MILENA indirect gasification operates at lower temperatures (700-900°C) than oxygen-blown gasification. This makes material requirements less stringent, and simplifies the design (less refractory / no membrane walls required). -Operating pressure: MILENA indirect gasification operates up to 7 bar (due to limited possible solid circulation). Fixed-bed / entrained-flow gasifiers can operate at much higher pressures, which leads to more compact equipment, and thus to cost savings in construction materials. Therefore, for the same output, MILENA equipment has a larger size, and is thus more expensive.	45
C. Syngas cleaning and conditioning	27	- Tar removal: physical tar removal (OLGA) and recirculation of tar to gasifier in bioSNG. Condensation and further processing for extraction of phenol and other products in CTL. - Adjustment of H_2/CO: similar (WGS unit). - Acid gas removal: CTL plants use complex, costly physical absorption (e.g. Rectisol) for CO_2 and contaminants removal. Biomass-to-SNG might use less costly amine scrubbing unit + water scrubbing + adsorption bed. Upstream HDS required in the bioSNG concept. - Compression: more compression requirements and larger equipment size in bioSNG plant, because of the lower operating pressure of MILENA (up to 7 bar).	50
D. Synthesis and product upgrading	22	- Synthesis: Due to the most stringent pressure conditions of methanol synthesis (50-70 bar) and gas recycle, cost of methanol synthesis unit expected to be slightly higher than methanation reactor (~ 30 bar). -Product upgrading: Both upgrading of methanol (distillation), and of SNG (adjustment of Wobbe index, compression) are relatively simple. Therefore, costs are assumed to be in a similar range.	20
Total ISBL	**100**		**115**

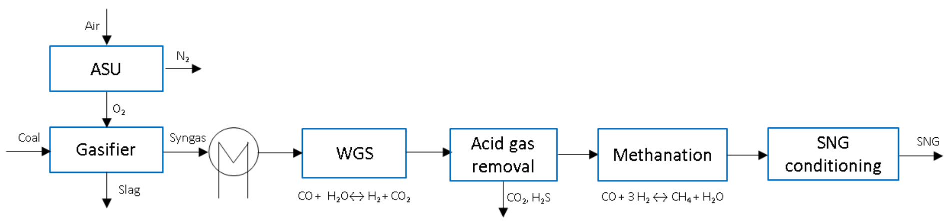
3.4 Coal-to-SNG vs. biomass-to-SNG

The coal-to-SNG plant, in principle, can be considered similar to a bioSNG plant. A generic, conventional SNG facility from coal gasification, shown in Figure 13, is composed by the following units:

- Gasifier (the most usual technologies used for large-scale coal gasification are fixed-bed and entrained-flow gasification).
- Cooling and tar removal.
- Sour water-gas shift (WGS) for adjustment of H_2/CO ratio.
- Acid gas removal unit (e.g. Rectisol, Selexol).
- Methanation unit.
- SNG conditioning: water and CO_2 removal, cooling and compression.

A detailed description of an example of commercial CSNG plant (Great Plains Synfuels, CSNG.1 in Table 4) can be found in Section D.3 of Appendix D of this document.

Figure 13: Simplified configuration of a coal-to-SNG plant.



Comparison analysis is presented in Table 10.

Table 10: Comparison of cost distribution of coal-to-SNG and biomass-to-SNG plants.

Main equipment blocks	Cost of CSNG plant [% of ISBL] [197]	Coal-to-SNG vs. biomass-to-SNG	Relative cost of bioSNG plant [% of ISBL compared to CSNG]
A. Air separation unit	11	ASU is not required in the biomass-to-SNG case because of the use of indirect gasification.	0
B. Gasification island	31	- Feedstock pre-treatment: Grinding and drying of biomass is more costly than for coal. In both cases, lock hoppers are required for pressurized feeding. - Gasifier: biomass-to-SNG concept uses MILENA indirect gasification. CSNG uses fixed-bed or entrained-flow gasification (e.g. Lurgi fixed-bed gasification in the Great Plains Synfuels plant). Both require the use of oxygen, which poses more strict requirements to materials. - Operating temperature: MILENA indirect gasification operates at lower temperatures (700-900°C) than O_2-blown gasification (1200-1500°C). This makes the material requirements less stringent, and simplifies the design (less refractory /no membrane walls required). - Operating pressure: MILENA indirect gasification operates up to 7 bar (due to limited possible solid circulation). CSNG gasifier operates at ~30 bar (Great Plains plant). Therefore, for the same output, MILENA equipment has a larger size, and thus more expensive.	45
C. Syngas cleaning and conditioning	16	- Tar removal: physical tar removal (OLGA) and tar recirculation to gasifier in bioSNG plant. Tar condensation and separation/recovery of products (e.g. phenol, cresylic acid) in CSNG. The latter option is considered more complex. - Acid gas removal: coal-to-SNG uses costly physical absorption processes (e.g. Rectisol). Biomass-to-SNG concept might use less costly processes (e.g. water scrubbing + amine scrubbing unit + adsorption bed) for CO_2 and H_2S removal. BioSNG concept adds HDS prior to acid gas removal. - Adjustment of H_2/CO ratio: similar in both cases (WGS unit). - Compression: more compression requirements and larger equipment size in bioSNG plant, because of the lower operating pressure of the MILENA gasifier (up to 7 bar).	45
D. Synthesis and product upgrading	42	- Synthesis: Similar technology. Biomass-to-SNG process might be slightly less costly due to the higher CH_4 content of syngas, which results in a smaller methanation plant and ideally no gas recycle for temperature control. - Product upgrading: similar (same specifications for pipeline injection).	40
Total ISBL	**100**		**130**

3.5 Integrated gasification combined cycle vs. biomass-to-SNG

Results of the comparison of distribution costs between a reference IGCC plant and a biomass-to-SNG process are summarized in Table 11. More details on an example of commercial IGCC plant (Elcogas, IGCC.5 in Table 5) can be found in Section D.4 of Appendix D.

Table 11: Comparison of cost distribution of IGCC and biomass-to-SNG plants.

Main equipment blocks	Cost of IGCC plant [% of ISBL] [200]	IGCC vs. biomass-to-SNG	Relative cost of bioSNG plant [% of ISBL compared to IGCC]
A. Air separation unit	12	ASU not required in bioSNG plant (indirect gasification).	0
B. Gasification island	26	- Feedstock pre-treatment: Grinding and drying more costly for biomass than for coal. Lock hoppers required in both cases for pressurized feeding. - Gasifier: MILENA indirect gasification for bioSNG plant. Entrained-flow gasification in IGCC plant. The latter requires the use of oxygen (more strict material requirements). - Operating temperature: lower temperatures in MILENA (700-900°C) than entrained-flow gasification (1200-1500°C). Less stringent material requirements and less complex design in bioSNG plant. - Operating pressure: up to 7 bar in MILENA. ~25-30 bar in IGCC plant. Therefore, MILENA equipment has a larger size and is more expensive.	40
C. Syngas cleaning and conditioning	8	- Tar removal: OLGA tar removal and recirculation of tars to gasifier in bioSNG plant. Tar condensation in IGCC (no products recovery, less complex). - Acid gas removal: less stringent specifications of syngas for IGCC applications than for synthesis. Therefore, gas cleaning is less severe, and less costly cleaning systems (e.g. amine scrubbing) can be used. BioSNG plant can also use amine scrubbing, but previous HDS is required. - Adjustment of H_2/CO: not required in IGCC. - Compression: More compression requirements and larger equipment size in bioSNG due to lower operating pressure of MILENA gasifier.	40
D. Synthesis and product upgrading	N.A.	BioSNG plant: Methanation at 30 bar and 300°C. SNG upgrading relatively easy.	30
E. Steam plant / power block	54	IGCC plant: steam turbine, heat recovery steam generator (HRSG), and gas turbine.	N.A.
Total ISBL	**100**		**110**

3.6 Results on normalized equipment cost

Results of the analysis performed in the previous sections of this chapter are summarized in Table 12. Differences between costs of biomass-to-SNG process and reference plants are displayed. As can be seen, based on the analysis proposed in this work, biomass-to-SNG ranges from +5% to +30% compared to the selected commercial reference technologies.

Table 12: Summary of estimated change in equipment cost for a biomass-to-SNG plant compared to reference plants.

Reference plant	Estimated cost difference for biomass-to-SNG plant
GTL	+ 20 %
CTL	+ 5%
CTM	+ 15%
CSNG	+ 30%
IGCC	+ 10%

4

Total Capital Investment for a bioSNG plant

In Section 2, an average total capital investment (TCI) for each reference technology based on costs of commercial plants was determined. In this chapter, technical differences between processes quantified in Section 3 are applied to the TCI estimated. Results are summarized in Table 13.

Table 13: Average TCI of a 1 GW biomass-to-SNG plant.

Reference plant	Average TCI (USD_{2013}/kW_{input})	Estimated cost difference respect to bioSNG plant	Average TCI of bioSNG plant (USD_{2013}/ kW_{input})
GTL	1770	+ 20 %	2120
CTL	1220	+ 5%	1280
CTM	1160	+ 15%	1330
CSNG	970	+ 30%	1260
IGCC	1490	+ 10%	1640
		AVERAGE	1530

Therefore, after accounting for inflation rates and differences in technologies, the average TCI for a biomass-to-SNG plant results in ~ **1530 USD_{2013}/kW_{input}**. This is the overall specific cost of a large-scale (1 GW thermal input) bioSNG plant.

Although the estimated TCI value is based on data from large-scale commercial operational and under construction plants, the value obtained must be extrapolated in order to take into account learning effects.

The value of 1530 USD_{2013}/kW input is therefore the TCI of a 1 GW bioSNG plant that would be the first or second of its kind. Because parts of this process are not yet upscaled to 1 GW, this 1^{st}-2^{nd} of a kind bioSNG plant can only be built in about 10 years from now. The question is which value of TCI is realistic for a bioSNG plant on the longer term. For this, it is assumed that 10 GW capacity is installed cumulatively, that is, after copying a 1 GW plant ten times. This may be the case in 20-25 years from now, approximately in 2030.

Learning usually occurs at two levels: 1) during the construction of the plant and 2) during operation of the plant. It is important that lessons learned are incorporated in the next plants. This could lead to capital cost-reductions and increased operational hours and less downtime of the plant. An important condition is that subsequent plants are constructed and/or operated by the same company. Too much time between construction could result in an effect called “forgetting by not doing” instead of “learning by doing”.

The progress and learning rates strongly depend on the type of technology [201]. Since biomass-to-SNG technology is relatively new, a learning rate of 10% has been assumed in this work. By applying the equations presented in Section A.5 of Appendix A, it can be checked that increasing the capacity from 1 to 10 GW would reduce the costs with 30%. So, the TCI for a complete biomass-to-SNG facility results in **~ 1100 USD_{2013}/kW_{input}** after 10 GW of cumulative installed plants.

5

BioSNG cost price

In this chapter the cost price of bioSNG is calculated for large-scale production. This price is based on the capital cost for a large bioSNG plant which has been estimated in Sections 2-4.

5.1 Assumptions

A capital cost of **~ 1100 USD_{2013}/kW_{input}** has been used for the calculation of the bioSNG price. The technology selected in this work for SNG production from biomass is briefly described in section 1.5 of this document. A 1 GW input biomass-to-SNG plant is assumed. This plant produces about 21 million GJ or 655 million Nm^3 of Groningen-quality SNG per year. Table 14 displays the assumptions used in the economic analysis for the calculation of the bioSNG price.

Table 14: Input parameters for estimation of the cost price of bio-SNG (2013).

Plant parameters		
Plant size (input)	1	GW
Specific plant cost	1100	USD_{2013}/kW input
Net electricity consumption	2%	of thermal input
Plant efficiency biomass-to-SNG	70%	(LHV based)
Plant availability	90%	of the year [202]
Economic parameters		
O&M cost	3	% of the TCI per year [202]
Other fixed cost	2	% of the TCI per year
Interest	5	% per year
Capital charges	10	years, annuity
Cost of biomass	See Table 15	USD_{2013}/GJ
Cost of electricity	0.09	USD_{2013}/kWh [203]

The price of bioSNG is expected to dramatically depend on the cost of biomass feedstock. Table 15 shows the price of biomass feedstock in different geographical areas.

Table 15: Price of biomass feedstocks in different geographic areas [203].

Region	Biomass feedstock	Cost (USD/ton)	Cost (USD/GJ)
Europe	Industrial wood pellets (CIF Rotterdam)	166	9.8
	Wood chips from local energy crops	60-94	5.2 – 8.2
	Wood chips from Scandinavian forest residues to continental Europe	98 - 115	8.6 – 10.1
	Local agricultural residues	55 - 68	4.8 – 6.0
	Imported pellets from United States to continental Europe	157 - 182	9.3 – 10.8
United States	Energy chips / residuals North-East		3.7
	Forest residues	15-30	1.3 – 2.6
	Wood waste	10-50	0.5 – 2.5
	Agricultural residues (corn stover and straw)	20-50	1.7 – 4.3
	Energy crops (poplar, willow and switchgrass)	39-60	4.5 – 6.9
Brazil	Wood chips	71	9.3
	Bagasse	11 - 13	1.3 – 2.3
India	Rice husk	22 - 30	0.7 – 2.3
	Bagasse	12 - 14	1.4 – 2.5

For the determination of the cost price of bioSNG, three cases have been considered in this work:

a) Case 1. The plant is located in Europe (e.g. in the Rotterdam area, the Netherlands), and uses wood chips shipped from Scandinavia/Baltic area as feedstock.
b) Case 2. The plant is located in United States, and uses wood chips as feedstock.
c) Case 3. The bioSNG facility uses cheap agricultural residues (e.g. Brazil or India).

In all cases, it is assumed that the values include the transportation costs to the plant.

5.2 Results

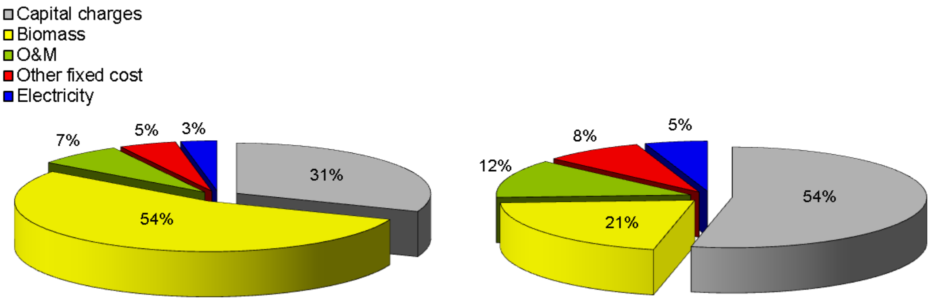
Results obtained are summarized in Table 16. The cost price of bioSNG ranges between **14-24 USD$_{2013}$/GJ**, and strongly depends on the biomass feedstock, and therefore, on the plant location. This price is equivalent to ~ **0.45– 0.77 USD$_{2013}$/Nm^3**, based on the LHV of Groningen gas (32 MJ/Nm^3). Figure 14 compares the distribution of costs of bioSNG production for cases 1 and 3. Biomass price amounts to 54% of total costs in case the bioSNG plant is located in Europe. This fraction is only 21% in case inexpensive agricultural residues are available.

Table 16: Summary of results of bioSNG cost price produced in a 1 GW input plant.

Scenario	Biomass feedstock	Cost of biomass* (USD_{2012}/GJ)	Cost of bioSNG (USD_{2013}/GJ)
Case 1	Wood chips	9	24
Case 2	Wood chips	4	17
Case 3	Agricultural residues	2	14

* Cost at plant gate.

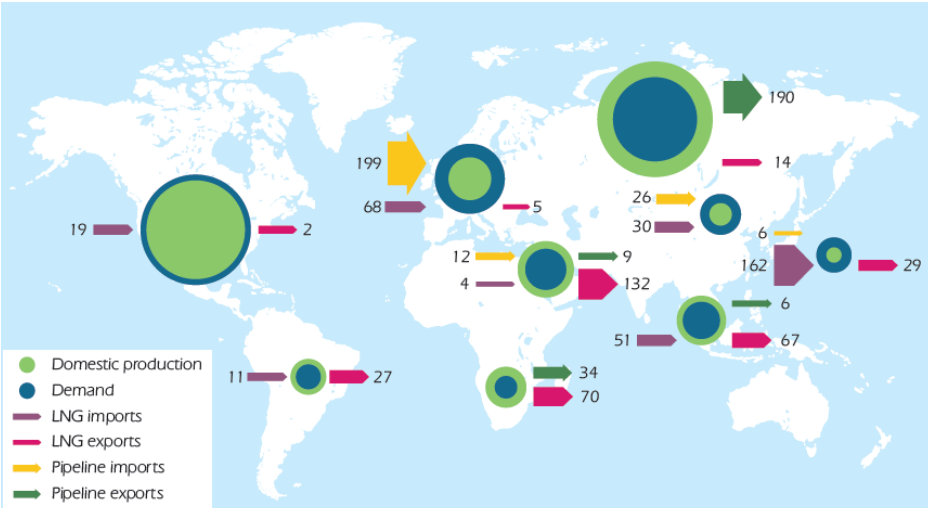
Figure 14: Distribution of costs of bioSNG production. Comparison of most expensive (case 1) and least expensive (case 3) scenarios.



Case 1: 24 USD_{2013}/GJ | Case 3: 14 USD_{2013}/GJ

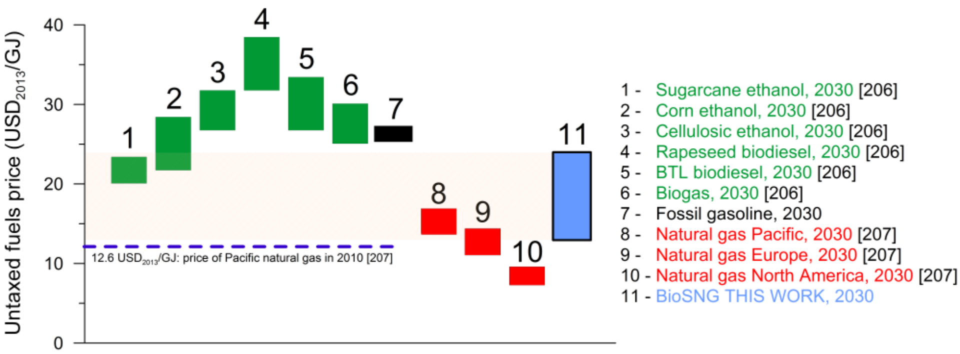
Even though it has been shown that the price of bioSNG is largely determined by the price of biomass feedstock, this is not the only factor that must be taken into account in the decision of a bioSNG location. Other economic/political factors must also borne in mind. BioSNG must compete with fossil natural gas, or even also with SNG produced from coal. In this sense, the recent changes in the energy scenario, particularly concerning the development of non-conventional natural gas production, affect decisively on the investment decisions of production of bioSNG. For additional information, Appendix B briefly reviews the status of some coal-based technologies in the United States and China. Figure 15 displays the map of global natural gas trade in 2013. As can be seen, bioSNG plants only make sense in areas in which the demand of natural gas is higher than the production. Therefore, in principle, Europe and the Asia-Pacific region (China, Korea, Japan) are the geographical areas in which bioSNG production might be in principle most attractive. China has recently focused on SNG production from autochthonous coal (see Section B.1 in Appendix B), and therefore, production of SNG from biomass might not be economically competitive.

Figure 15: Natural gas trade in 2013 [205]



Looking at bioSNG as biofuel, projection of price of biofuels up to 2050 can be found in reference [206], whereas estimations of natural gas prices up to 2035 are reported in reference [207]. Prices have been translated in terms of energy content and corrected with the inflation rate, in USD_{2013}/GJ. Results can be found in Figure 16. As can be seen, even at its highest value (corresponding to production in Europe), bioSNG has a lower cost per energy content unit than most biofuels, including BTL diesel. However, bioSNG is in general more expensive than fossil natural gas, and therefore should be labelled as biofuel in order to be competitive. The projected cost of fossil natural gas cost ranges between 7.3 – 9.6 USD_{2013}/GJ in North America, 13.8 – 16.9 USD_{2013}/GJ in Pacific, and 11.1 – 14.4 USD_{2013}/GJ in Europe [207][1], whereas bioSNG has estimated in this work as 14-24 USD_{2013}/GJ (see Table 16).

Figure 16: Comparison of 2030 forecasted prices of fuels in terms of energy content (data 1-7 adapted from [206], data 8-10 adapted from [207]).



[1] A conversion factor of 1 GJ = 0.95 MBtu, and an inflation rate of 2.65% (average in United States in 2000-2013 [9][10]) have been applied for the calculation of prices in USD_{2013}/GJ from USD_{2010}/MBtu.

5.3 Internalization of CO_2 emissions costs in bioSNG price

Prices compared in Figure 16 do not take into account the cost of CO_2 emitted during the cycle life of SNG. Actually, reduction of greenhouse gases is one of the main advantages of using biomass instead of coal for SNG production. The internalization of CO_2 emissions into the fuel cost increases the economic feasibility of bioSNG. In order to quantify this effect, three gaseous fuels have been compared:

1. Fossil natural gas, as reference (NG).

2. SNG produced from coal (CSNG).

3. SNG produced from biomass gasification (bioSNG).

For the comparison, the following assumptions have been taken:

- The cost of CO_2 emissions in 2030 is 40 USD_{2010}/ton CO_2 in Europe (Current Policies and New Policies scenarios), 23 USD_{2010}/ton CO_2 in China (New Policies scenario) and 30 USD_{2010}/ton CO_2 in United States [207][2].

- The price of natural gas in 2030 corresponds to the IEA New Policies scenario [207], i.e. between 11.7 USD_{2010}/GJ in Europe, 13.9 USD_{2010}/GJ in Asia-Pacific, and 7.9 USD_{2010}/GJ in North America [207].

- SNG from coal is assumed to be produced from steam coal (109.3 USD_{2010}/ton in 2030 according to the New Policies scenario [207]). Using the average 980 USD_{2013}/kW_{input} obtained in Section 2 of the document as input value for the TCI of a CSNG plant, and the same methodology applied to estimate the cost price of bioSNG, this results in a cost price of SNG from coal of 14.8 USD_{2013}/GJ.

- BioSNG cost, 24 USD_{2013}/GJ, has been taken from the result of the European scenario (conservative case) obtained in this work.

- CO_2 sequestration has not been considered in any case.

- Costs have been updated to USD_{2013} by assuming an inflation rate of 2.65% (average of United States in 2000-2013 [9][10]).

- CO_2 emission values, expressed in ton/MJ SNG or NG, have been calculated from data found in literature. In each case, combustion of CH_4 produced, and production of CO_2 during the SNG synthesis process have been considered. Calculated values are summarized in Table 17.

[2] United States is considered in the New Policies scenario to adopt a 'shadow price' for CO_2 ranging between 15 USD_{2010}/ton in 2015 to 35 USD_{2010}/ton in 2035 [207].

Table 17: CO_2 emissions for the process cycles considered.

Case	CO_2 emission (ton CO_2/m^3 SNG or NG)	CO_2 emission (ton CO_2/MJ SNG or NG)	Reference
Natural gas	0.0020	$5.7\ 10^{-5}$	[7]
SNG from coal	0.016	$2.7\ 10^{-4}$	[151]
BioSNG	0.000625	$1.8\ 10^{-5}$ *	[7]

* In agreement with the values of CO_2 emissions of biomass [208], and applying a factor of 70% efficiency (LHV basis) for the conversion of biomass to SNG.

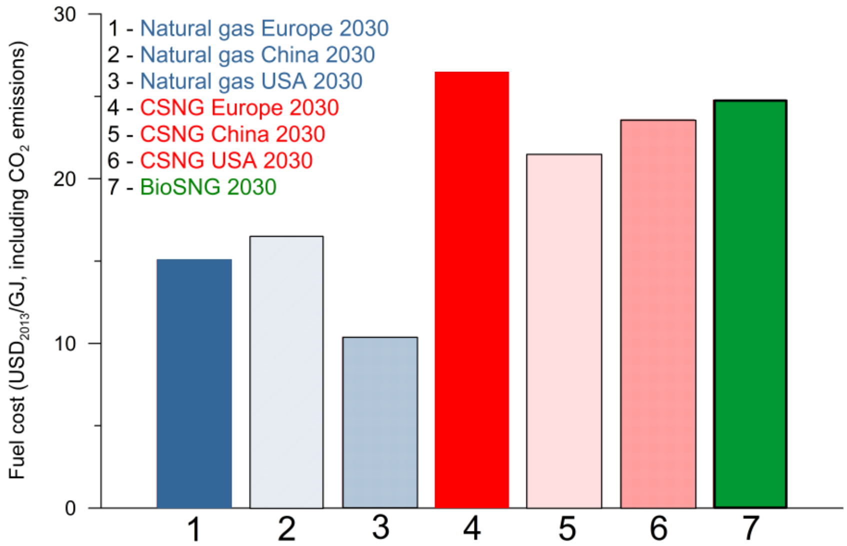
Costs of natural gas and SNG from coal have been calculated for three scenarios, Europe China, and United States (USA), in order to take into account the different expected cost of natural gas and CO_2 emissions. Results of calculations are displayed in Table 18 and Figure 17.

Table 18: Effect of cost of CO_2 emissions on cost of natural gas and SNG from coal and biomass.

Fuel	Scenario	Base price in 2030 (USD_{2013}/GJ)	CO_2 emission cost (USD_{2013}/ton CO_2)	CO_2 emission cost (USD_{2010}/GJ)	Total cost (USD_{2013}/GJ)
NG (Reference)	Europe	12.7	43.3	+ 2.5	15.1
	China	15.0	24.9	+ 1.4	16.4
	USA	8.5	32.4	+ 1.8	10.4
CSNG	Europe	14.8	43.3	+ 11.7	26.5
	China	14.8	24.9	+ 6.7	21.5
	USA	14.8	32.4	+ 8.8	23.6
BioSNG		24	43.3	+ 0.8	24.8

As can be seen, the internalization of the cost of CO_2 emissions makes bioSNG competitive with SNG produced from coal. It is interesting to observe in Table 18 the significant penalty of CO_2 emission in the increase of CSNG cost with respect to natural gas, which in the end makes it the most costly gaseous fuel.

Figure 17: Summary of results of addition of CO_2 emission cost on 2030 untaxed price of natural gas, and SNG from coal and biomass.



6

Outlook

This report has dealt with the estimation of the investment cost of a bioSNG plant and the cost price of bioSNG. As analysed in Section 5.2, the cost of bioSNG in terms of energy content is expected to be competitive with other biofuels in the medium term. However, bioSNG is in general more expensive than fossil natural gas, and should be labelled as biofuel in order to be competitive. Therefore, the question that must be addressed is how to reduce the cost price of bioSNG to become economically attractive. In this section, some key topics that might enhance the economy of bioSNG are briefly discussed.

Co-production of SNG and chemicals/biofuels

Producer gas from fluidized bed gasification contains high amounts of methane, which is good for the efficiency to bioSNG, but it also contains significant amounts of other hydrocarbon molecules like benzene and ethylene. These molecules are converted into methane in the conventional configuration of bioSNG plant (see Figure 2). Benzene and ethylene require special attention due to their tendency to form coke on the methanation catalysts. At the same time, benzene and ethylene are valuable chemicals, which add up to more than 25% of the heating value of the raw producer gas. Therefore, separation of benzene and ethylene rather than conversion to methane might be an attractive option. ECN is currently developing technology for the recovery of valuable hydrocarbons from producer gas. At the same time, research is ongoing to increase the yield of valuable chemicals in gasification to further improve the business case of co-production bioSNG and chemicals.

Besides hydrocarbons, almost half of the producer gas from fluidized bed gasification consists of H_2 and CO. This syngas can be used to produce liquid biofuels or biochemicals like diesel, jetfuel, or methanol, where the unconverted gases and all the hydrocarbons subsequently are converted into SNG. This combination brings economic benefits because of the high value liquid biofuels, but also has several technical synergies that may reduce the costs of the plant.

Another attractive option involves the co-production of LNG and chemicals/biofuels. The production of LNG through cryogenic separation offers the additional advantage possibility of delivering ultra-clean syngas (H_2 and CO) for subsequent synthesis of bio-methanol or other biofuels.

BioCCS

BioSNG production will always result in a large flow high-purity CO_2. The volume of CO_2 roughly equals the bioSNG production on a volume basis. Contrary to Carbon Capture and Storage (CCS) applied to reduce CO_2-emissions from fossil fuel processes, CCS combined with bioSNG production hardly involves an energy penalty, since CO_2 separation is an integral part of the bioSNG process. Implementation of capture and storage of CO_2 in bioSNG plants is therefore a relatively efficient and cheap method to reduce CO_2 concentrations in the atmosphere, allowing negative CO_2 emissions. Moreover, costs of bioSNG might be reduced in cases where there is a market for the produced CO_2.

Power-to-Gas

The production of large quantities of CO_2 in the bioSNG process offers another opportunity through the implementation of the so-called power-to-gas (P2G) concept. Hydrogen produced from excess renewable power production in regions with high shares of solar or wind power can be added to an existing bioSNG plant to produce additional methane while consuming CO_2 that otherwise would be lost as a carbon source. This concept involves limited additional costs in the bioSNG process, since it only requires additional capacity in the last part of the process. The combination of bioSNG and power-to-gas therefore creates a cost benefit that might improve the economics of bioSNG production.

7 Conclusions

- The total capital investment for 1 GW bioSNG plant has been estimated as ~1530 USD_{2013}/kW_{input}, based on the absolute cost references for GTL, CTL, CTM, CSNG and IGCC plants, and taking into account the technical differences with respect with a bioSNG plant.
- Cost of biomass-to-SNG plant ranges from +5% to +30% compared to the selected commercial reference technologies.
- Technology learning could decrease the TCI for a bioSNG plant with about 30% to ~1100 USD_{2013}/kW_{input} after 10 GW of cumulative installed capacity in the medium-term (2030).
- The cost price for 1 GJ of bioSNG largely depends on the biomass feedstock used. Three scenarios (wood chips in Europe and United States, or inexpensive agricultural residues from Brazil/India) have been analysed. A TCI of 1100 USD_{2013}/kW_{input} results in an overall bioSNG cost price ranging between 14-24 USD_{2013}/GJ or 0.45- 0.77 USD_{2013}/Nm^3 (Groningen quality gas).
- Despite the highest bioSNG costs compared with the rest of scenarios considered, Europe offers several advantages for the deployment of SNG from biomass, e.g. existing natural gas infrastructure, and a developed SNG market based on incentives and obligations.
- In the medium term (2030), bioSNG is expected to have a lower cost in terms of energy content than other liquid biofuels. However, it cannot be competitive with fossil natural gas prices.
- Internalization of CO_2 emissions in the medium-term final cost of SNG reveals that bioSNG could be competitive with SNG produced from coal. Even so, medium-term bioSNG prices are expected to remain higher than those of natural gas.
- The implementation of concepts such as the co-production of bioSNG/bioLNG and chemicals/biofuels, the capture and storage of CO_2, or power-to-gas systems will contribute to enhance the business case of bioSNG production. ECN is working on all these topics.

Appendix A. Assumptions for calculation of TCI costs

A.1 Efficiency of reference plants

- Efficiency GTL plants: 60% [194][195][209]
- Efficiency CTL plants: 49% [195]
- Efficiency CTM plants: 55% [210][211]
- Efficiency CSNG plants: 60% (LHV based) [197][212]
- Efficiency IGCC plants: 42% [161][165]

A.2 Distribution of products

- CTL plants: 4% LPG, 48% diesel, 48% gasoline (% wt.) (high-temperature Fischer-Tropsch) [213].
- GTL plants: 70% diesel, 25% gasoline, 5% LPG [37][193].

A.3 Heating value of fuels

- LHV diesel: 43.1 MJ/kg
- LHV gasoline: 43.95 MJ/kg
- LHV LPG: 46.61 MJ/kg
- 1 bbl = 5.7 GJ LHV diesel = 4.75 GJ LHV gasoline = 0.015 GJ LHV LPG
- LHV methanol = 19.9 MJ/kg
- LHV SNG: 35 MJ/Nm^3
- LHV Groningen natural gas: 32 MJ/Nm^3

A.4 Economic analysis

The total investment cost normalized to a 1 GW plant, TCI_2, is calculated by applying equation (Eq. 1):

$$TCI_2 = TCI_1 \left(\frac{P_1}{P_2}\right)^F \qquad \text{(Eq. 1)}$$

where:

TCI_2: Total Investment Cost normalized to 1 GW input (USD).

TCI_1: Total Investment Cost given at P_2 input power (USD).

P_2: Input size of reference plant (GW).

P_2 : Normalized power input (equal to 1 GW).
F : Scale-up factor (William's factor): 0.7 [8].

The total investment cost updated to 2013-USD TCI_3 is obtained after applying (Eq. 2):

$$TCI_3 = TCI_2 \left(1 + \frac{I}{100}\right)^{2013-Y} \quad \text{(Eq. 2)}$$

where:
I : Inflation rate, taken as 2.65% (average inflation rate in the United States in the period 2000 - 2013) [9][10].
Y : Start-up year of reference plant.

In case of plants under construction with start-up data beyond 2013, or plants with no available start-up date in literature, 2013 is assumed as reference year for calculations.

In case that the investment costs are provided in a currency different than American Dollars, the following exchange rates are applied:

1 CNY = 0.163 USD; 1 EUR = 1.359 USD

A.5 Learning effects

Learning effects are analysed in Section 4 of this document. Learning curves are often expressed as (Eq. 3):

$$C_t = C_0 \left(\frac{P_t}{P_0}\right)^{-\alpha} \quad \text{(Eq. 3)}$$

where C_t is the cost of the plant at time *t*, C_0 is the cost of the plant at *t* = 0, P_t the cumulated installed capacity (in GW) at time *t*, P_0 the number of plants installed at time *t* = 0 and α the learning index. The α is related to the Progress Ratio PR, as shown in (Eq. 4), which expresses the percentage to which costs are reduced by doubling the installed capacity:

$$PR = 2^{-\alpha} \quad \text{(Eq. 4)}$$

The PR is related to more commonly known Learning Rate (LR) by $LR = 1 - PR$. The progress and learning rates strongly depend on the type of technology. Typical values for progress ratios are 0.8 – 0.9 [201].

Since biomass-to-SNG technology is relatively new, a learning rate of 10% has been assumed in this work. By applying (Eq. 4), this means a learning index α of 15%. Therefore, according to (Eq. 3), increasing the capacity from 1 to 10 GW would reduce the costs with 30%.

Appendix B. Status of reference technologies

For a realistic, credible estimation of total investment costs of reference technologies, only operational or under construction plants have been considered. However, in the recent years there is a large number of coal-based projects that have been shelved or delayed, especially in the United States. In this Appendix, some background information on the status of some reference technologies, as well as a review of some coal commercial projects delayed or shelved, is presented.

B.1 Coal-to-SNG in China

Economic development is a key priority in China, and energy is needed for that purpose. However, China has growing import dependency on oil and gas. Coal is the main hydrocarbon resource of China, and the Chinese coal industry is the largest in the world. Therefore, SNG allows both objectives by substituting imported gas and oil products for heating and cooking applications. China is now building the largest SNG industry in the world [151]. Although it is still unclear the role of SNG in the future energy scenario of China, SNG could provide a significant contribution to the country's gas supply, which may outstrip shale gas in both quantity and timing [156].

In 2012 there were more than 30 proposed SNG projects with a combined capacity of 120 billion m^3/y. In 2013, the central government has approved nine large-scale SNG plants with a total capacity of 37 billion m^3 of natural gas per year. Total planned capacity of nearly 200 billion m^3/y exceeds by far China's total natural gas demand [151].

If full target capacity of the under construction projects is reached, coal gasification could supply 89-96 billion m^3/y [156]. The first two commercial coal gasification projects are Qinghua Coal Group's project in Yili, Xinjiang (1.38 billion m^3/y in first phase, rising eventually to full potential capacity of 5.5 billion m^3/y). The second project is Xinjiang Guanghui (0.5 billion m^3/y). Four more projects are expected to be completed in 2013, two in Inner Mongolia and two more in Xinjiang [156].

Operating or under construction commercial CSNG plants in China are summarized in Table 4 of Section 2. Planned CSNG plants can be found in Table 19.

B.2 Coal-to-liquids in China

China is also looking to coal as an alternative to oil, and proposals for over 60 million tons of coal-to-liquids (CTL) capacity (about 1.2 million bbl/day) have been submitted for review [214]. Operating or under construction commercial CTL plants in China are summarized in Table 2 of Section 2.

B.3 Coal-to-methanol in China

Methanol can be used as liquid fuel or as feedstock for DME plants and methanol-to-ethylene or methanol-to-propylene plants. In 2007, total consumption of methanol in China was ~ 10 million ton, of which 65% was produced from coal. Since China has a lack of oil and gas, but is rich in coal resources, it is expected that the country will focus on coal-to-methanol processes for a long period of time in the future [60].

B.4 Coal-to-SNG in United States

Beginning 2000, in response to increases in natural gas prices, American utilities began a renewed push to build new coal-fired electricity generating plants. By the spring of 2007, approximately 150 such projects were either under construction or in various stages of planning. Since then, scores of coal-fired power plants have been cancelled, but others have been proposed.

By 2009, there were at least 15 CSNG plants proposed in United States in different stages of development [215]. The prospects of coal-to-SNG technology seemed promising, due to the abundance of coal supply, a rise of prices of oil and natural gas, the interest in energy independency and environmental considerations, and financial incentives (long-term SNG purchase agreements with energy utilities, which removed commodity risks; 80% debt/equity ratio with virtually all long-term debt covered by federal loan guarantee) [216].

However, new developments in horizontal drilling and hydraulic fracturing have greatly expanded shale gas and oil production in North America. As a consequence, shale gas production in the United States has increased by around five times from 2006 to 2010. This increase is over 20% of the dry natural gas production volume in the US. Shale gas has caused the Henry Hub spot price to drop from 12 USD/Mscf in June 2008 to less than 4 USD/Mscf in January 2012 [217]. This boost in unconventional natural gas production is expected to continue to expand over the medium term [205].

Low gas prices associated with the shale gas revolution have caused a marked decrease in coal use in the United States, the world's second-largest consumer. In 2005, when the first shale well was fractured, coal produced almost three times as much power in the United States as gas. By 2017 it is expected that coal and natural gas have similar contribution. The abundance of natural gas has reduced the economic viability of SNG plants [151][205][218]. Table 20 shows the status of some planned CSNG projects in United States.

B.5 Coal-to-liquids in United States

United States is the largest oil importer in the world. Petroleum imports accounts for 60% of total, with a cost of 265 billion USD in 2006. The need for fulfilling the increased demand for transportation fuels, as well as the abundant coal reserves, are the main drivers for the development of the CTL industry in United States[219].

However, there are several barriers to the creation of US CTL industry, including oil price volatility, technical uncertainty in terms of integration of plant components, need for incremental investment in coal mining infrastructure, availability of materials and resources, and environmental concerns (CO_2 emissions, water availability) [219]. These factors have influenced the large number of projects delayed or shelved, as shown in Table 21.

B.6 Coal-to-liquids in Australia

Some of the CTL projects being investigated in Australia include [220]:

- Linc Energy: commercial underground coal gasification to liquids in the Arckaringa Basin.
- Carbon Energy.
- Cougar Energy.
- Blackham Resources.
- Altona Resources Arckaringa Coal-to-Liquids and Power Project.
- Monash Energy – a joint venture between Shell and Anglo American.
- FuturGas Project, by Hybrid Energy Australia.

Nevertheless, environmental concerns together with high capital costs are likely to limit development and expansion of the CTL industry in Australia in the immediate future. If CCS technology and deployment matures, this may provide the economic conditions under which CTL could become viable [221].

Table 19. Data of some planned commercial-scale coal-to-SNG projects in China.

Project name	Location	Plant output (bcm/y)	Plant output (GW)	Investment (billion USD)	Start-up date	Reference
China Guodian Corporation	Xing'an, Inner Mongolia	2	2.22	2.12	2014	[53]
Beijing Holding Group	Hohhot, Inner Mongolia	4	4.44	4.9	-	
Shaanxi Coal and Chemical Industry Group	Yulin, Shaanxi	3	3.33	5.23	-	
CNOOC, Datong Coal Mine Group Company	Datong, Shanxi	4	4.44	4.9	-	
Shanxi International Power Group, Wison Engineering	Shuozhou, Shanxi	4	4.44	3.92	-	
Qinghua Group	Yining County, Yili, Xinjiang	1.3	1.44	0.82	2012	
Shendong Tinanlong Group	Changji, Xinjiang	1.3	1.44	1.12	2013	
China Huadian Corporation	Changji, Xinjiang	4	4.44	4	2013	
Kailuan Group	Changji, Xinjiang	4	4.44	2.86	-	
Xinjiang Guanghui Group	Aletai, Xinjiang	4	4.44	3.27	2013	
Xuzhou Coal Mining Group	Tacheng, Xinjiang	4	4.44	3.59	-	
Anhui Province Energy Group, State Development & Investment Corporation (SDIC)	Fengtai County, Huainan, Anhui	2	2.22	2.45	-	

Table 20. Data of some commercial-scale coal-to-SNG projects in the united States.

Project name	Location	Plant output (bcf/y)	Investment (billion USD)	Projected start-up date	Status	Reference
Secure Energy Inc.	Decatur, Illinois	20	0.8	2009	On hold/ delayed	[6][222][223]
Power Holdings of Illinois LLC	Rend Lake, Illinois	50	2	2013	Delayed / on hold	[6][222] [224][225]
Indiana Gasification LLC (Leucadia / E3 Gasification / Johnston & Associates)	Indiana	40 (+ 134 MW electricity)	2.65	2015	Shelved / delayed	[6][214][222] [226][227]
Oswego SNG Project / TransGas Development Systems	Scriba, New York	3.9	2	2010	Shelved	[6][222][228]
South Heart Coal Gasification Project (Great Northern Power Development, L.P. / Allied Syngas Corporation)	Stark County, North Dakota	36.5	1.4	2012	On hold	[6][222][229]
Leucadia's Mississippi Gasification	Moss Point, Mississippi	120	2	2015	On hold	[6][222][226] [230]
Leucadia Illinois Plant	Cook County, Illinois	-	3	-	On hold	[6][222][231]
ConocoPhillips/ Peabody Energy	Muhlenberg County, Kentucky	50-70		2014	On hold	[6][222][232]
Hunton Energy	Freeport, Texas	-	2.4	2012	Shelved	[6][222][233]

Table 21. Data of some commercial-scale coal-to-liquids projects in the United States [222].

Project name	Location	Plant output (bbl/day)	Investment (billion USD)	Projected start-up date	Status	References
DKRW Energy / SNC-Lavalin	Medicine Bow, Wyoming	20 000	2	2014	On hold	[234][235][236][237]
Rentech Mingo County CTL Project	Mingo County, West Virginia	20 000	4	2015	Shelved	[238]
Rentech Natchez CTL Project	Natchez, Mississippi	25 000	2.75	2014	Cancelled	[239][240][241]
TransGas Adams Fork Energy Plant	Mingo County, West Virginia	18 000	4	2013	On hold	[242]
Australian-american Energy / Great Western Energy, Many Stars Plant	Big Horn County, Montana	50 000	7.4	2016	Shelved	[243]
Ambre Energy	Southwestern Montana	1 600 000	0.375	2011	Shelved	[244]
Clean Coal Power Operations	Paducah, Kentucky	40 000 (+ 300 MW electricity)	7.6	2013	Shelved	[245]
Drummond Coal Company	Montgomery County, Illinois	48 000	3.6	-	Shelved	[246]
Waste Management & Processors	Gilberton, Pennsylvania	5034 (+ 41 MW electricity)	1	2010	Shelved	[247]
Baard Energy	Wellsville, Ohio	35 000 (+ 200 MW electricity)	5	2013	On hold (no longer coal-based)	[248]

Appendix C. Brief overview of BTL and bioSNG projects in Europe

In this work, TCI of bioSNG plants has been estimated from references of operational or under construction large-scale facilities. The inclusion of biomass-to-liquids or biomass-to-SNG plants would have distorted the analysis, given the much lower scale of the first demonstration facilities of this type. However, in the last years, a number of initiatives for production of SNG, liquid transportation fuels and chemicals from biomass has been developed.

The development of bioenergy industry in Europe is driven by the need for fulfilling the EU 20/20/20 targets, as well as the security of energy supply. Four main value chains of bioenergy can be identified [249][250]: synthetic fuels, bio-SNG, high-efficiency CHP, and intermediate energy carriers (bio-oil, torrefaction). Among them, this Appendix briefly summarizes the state-of-the-art of demonstration facilities of biomass-to-fuels and SNG in Europe.

Table 22 and Table 23 summarize the status of some current European BTL and bioSNG projects, respectively.

Table 22. Performance and status data of some current demonstration-scale biomass-to-liquids projects in Europe.

Project name	Location	Plant input (MW_{th})	Plant output (ton/y)	Investment (million EUR)	Projected start-up date	Products	References
Metsa Group / Vapo, Forest BtL plant	Kemi, Finland	320	115 000	530	2016	92000 ton/y diesel, 32000 ton/y naphtha	[250][251][252]
Karlsruhe Institute of Technology, Bioliq project	Karlsruhe, Germany	2	608	-	2013	DME, gasoline	[250][251][253]
Chemreq, BioDME Project	Pitea, Sweden	3	1460	~ 22	2011	DME	[250][251][253][254][255][256]
Chemrec, Domsjo and Vallvik Projects	Sweden	200	100 000	49	2015	Methanol (140000 ton/y) to DME (100000 ton/y)	[250][251][257][258][259]
UPM, demonstration plant	Strasbourg, France	300	105 000	170	2014 investment decision	80% diesel, 20% naphtha	[250][251]
Woodspirit Project	Netherlands		200 000	199	2016 - 2017	Methanol	[250][251]
BioTfueL Project	France	12	-	112.7	2014	F-T products	[250][251][260]
Värmlandsmetanol AB	Hagfors, Sweden	111	92 000	300-380	2015-2017	Methanol	[250][251][256][261]
Gussing FT pilot	Gussing, Austria	8	0.2[3]	-	2005	Heat and power. Test site for F-T, SNG, alcohols and H_2	[250][251][253][256]

[3] Pilot plant (slipstream from produced gas).

Table 23. Performance and status data of some current demonstration-scale biomass-to-SNG projects in Europe.

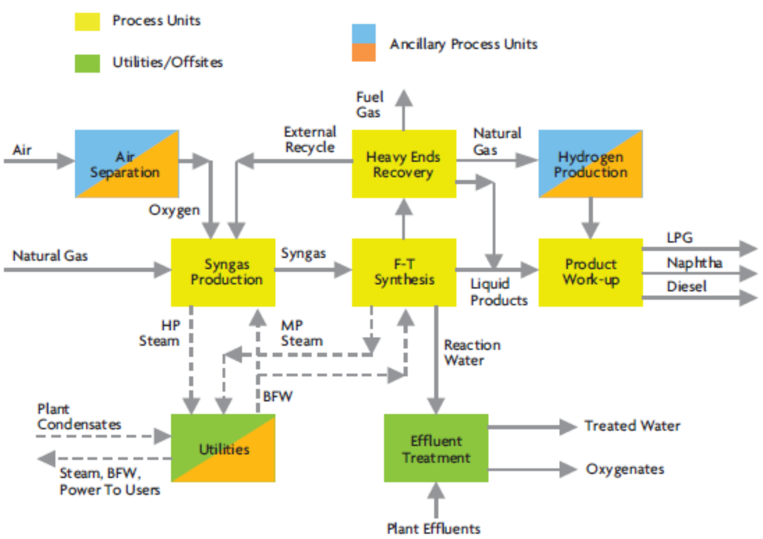
Project name	Location	Plant output (MW_{th})	Investment (million EUR)	Projected start-up date	References
ECN/HVC project	Alkmaar, Netherlands	12 $MW_{th\ input}$ heat and power (1st demo plant) 50-100 MW SNG (2nd demo plant)	-	2014	[250][253][262] [263] [264]
E.On Bio2G Project	Landskrona or Malmo, Sweden	200	450		[250][262][264] [265]
Goteborg Energi/ E.On, GoBiGas Project	Goteborg, Sweden	20 (1st phase) 80 – 100 (2nd phase)	140 (1st phase) 59 (2nd phase) ~ 220 total	2016 (2nd phase)	[250][253][262][264] [266][267][268]
GAYA Project	France	20-60	-	2017	[250][256] [262][269][270]
Gussing FT pilot	Gussing, Austria	1	-	2002	[250][262]

Appendix D. Examples of reference plants

D.1 Example of GTL plant: Sasol ORYX

The Sasol ORYX GTL plant (GTL.3 in Table 1 of Section 2) has been selected as reference example for comparison purposes in Section 3.1. The process flow diagram of the plant is shown in Figure 18.

Figure 18: Simplified process flow diagram of the ORYX GTL plant [26].



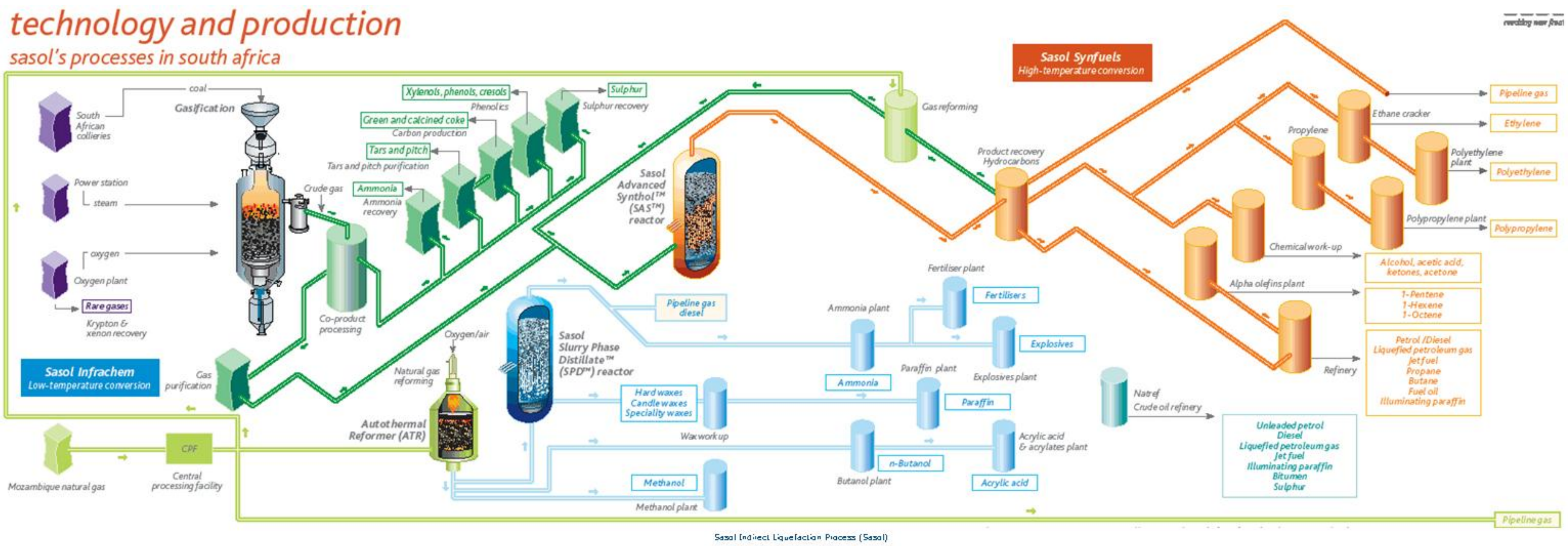
Natural gas feedstock from the Qatar's North Field is routed to LNG facilities in Ras-Laffan. After desulphurization, natural gas is fed to the GTL plant. 96% is used as feedstock for syngas production, whereas 4% is used as fuel [24]. An air separation unit produces oxygen which is sent to the autothermal reforming unit. Methane reacts with oxygen and steam in order to produce synthesis gas. After cooling, syngas produced is fed to the Fischer-Tropsch unit. ORYX GTL uses Sasol low-temperature slurry bed reactors with proprietary catalysts. The long-chain paraffin hydrocarbons produced are cooled and separated into tail gas, wax, hydrocarbon condensate and reaction water. Tail gas is sent for further hydrocarbon recovery, whereas hydrocarbon condensate and wax are sent to the hydrocracking unit (which uses Chevron catalysts). Water is treated and exported for irrigation applications. Product from hydrocracking is routed to a series of flash vessels to separate liquid and vapour phases. Vapour is recycled and liquid is fractionated and treated into final products (naphtha, diesel, LPG, etc.). Hydrogen used in the hydrotreating unit is produced from steam reforming of natural gas, shift conversion, and purification via pressure swing absorption [24].

D.2 Example of CTL plant: Sasol Secunda

For the analysis presented in Section 3.2, Sasol Secunda plant (see CTL.2 in Table 2 of section 2) has been selected as reference CTL facility.

Construction of Sasol II began in the mid-1970s, with operation of the two plants commencing in the early 1980s. The two plants contain 80 Sasol-Lurgi Fixed Bed Dry Bottom (FBDB) gasifiers. The feedstock for the plants is sub-bituminous coal supplied by Sasol Mining, a sister company of Sasol Synfuels. Natural gas is also used as a supplemental feedstock. Sasol Synfuel plant uses HTFT technology in the Sasol Advanced Synthol (SAS) process to convert synthesis gas from coal into automotive and other fuels, as well as a wide range of light olefins. The coal is converted in the gasifiers into a raw product gas with the addition of steam and oxygen. The produced syngas is then cooled, cleaned and conditioned as it leaves the gasifier, producing the first level of co-products as they condense or are recovered from the stream: tars, oils and pitches, ammonia, sulphur and phenols. Once purified, the syngas is sent to a suite of nine Sasol Advanced Synthol (SAS) reactors where it is reacted in the presence of a fluidized iron based catalyst at elevated pressure (~ 24 bar) and a temperature of about 350°C, producing hydrocarbons along with reaction water and oxygenated hydrocarbons. The hydrocarbons from the SAS reactors are cooled until most of the components are liquefied before fractionation is used to separate the various hydrocarbon-rich fractions. Methane rich gas is also produced in this process and is converted to syngas via autothermal reforming for internal processing and sale as pipeline gas. The C_2 rich stream is split into ethylene and ethane. Ethane is cracked in a high temperature furnace, yielding ethylene which is then purified. C_3H_6 or propylene from the light hydrocarbon gases is purified and used in the production of polypropylene. Alpha olefins pentene (C_5), hexene (C_6) and octene (C_8) are recovered, while the longer-chain olefins (C_7 - C_{11}) are introduced into the fuel pool. Oxygenates in the aqueous stream from the SAS process are separated and purified in the chemical work-up plant to produce alcohols, acetic acid and ketones including acetone, methyl ethyl ketone and methyl iso butyl ketone [46][49].

Figure 19: Process flow diagram of Sasol Synfuels plant [49]

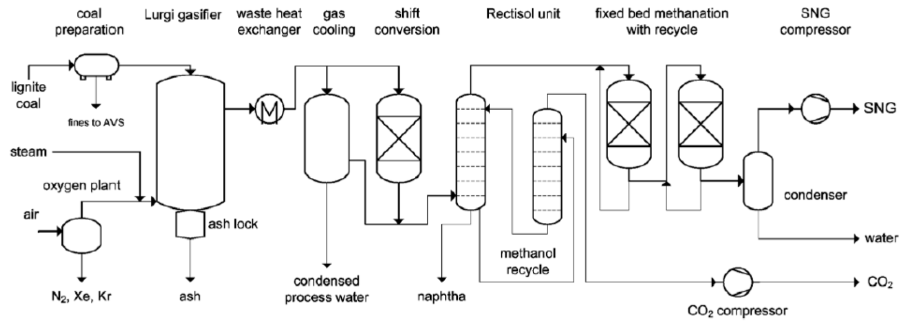


D.3 Example of CSNG plant: Great Plains Synfuels

For the comparison analysis presented in Section 3.4, the coal-to-SNG plant of Great Plains (CSNG.1 in Table 4 of Section 2) has been taken as a reference.

The Great Plains plant was commissioned in 1984 in North Dakota (USA) and has a production of $4.8{\cdot}10^6$ m^3 SNG/day and 98.7% availability [2][150]. The facility is operated by the Dakota Gasification Company and consists of 14 Lurgi fixed-bed updraft gasifiers followed by a WGS conversion unit (1/3 of the total stream) and CO_2 and sulphur removal via Rectisol® scrubbing (Figure 20). In the pressurized gasifiers, 18000 ton/day of lignite coal are contacted in counter-current with oxygen (delivered by an air separation unit, ASU) and steam. The resulting producer gas is cooled. After the Rectisol scrubbing only traces of hydrocarbons and sulphur compounds were found [1]. After the methanation unit, the product gas is compressed and dried, CO_2 is removed and the resulting SNG is distributed to end users via the national gas grid. In addition to SNG, other compounds are co-produced: CO_2 (for enhanced oil recovery), Kr, Xe and liquid N_2 (from the air separation unit), naphtha, phenol and cresylic acid are produced (from the gas liquor separation unit), ammonium sulphate and ammonia.

Figure 20: Simplified process flow diagram of the Great Plains coal-to-SNG plant [2].



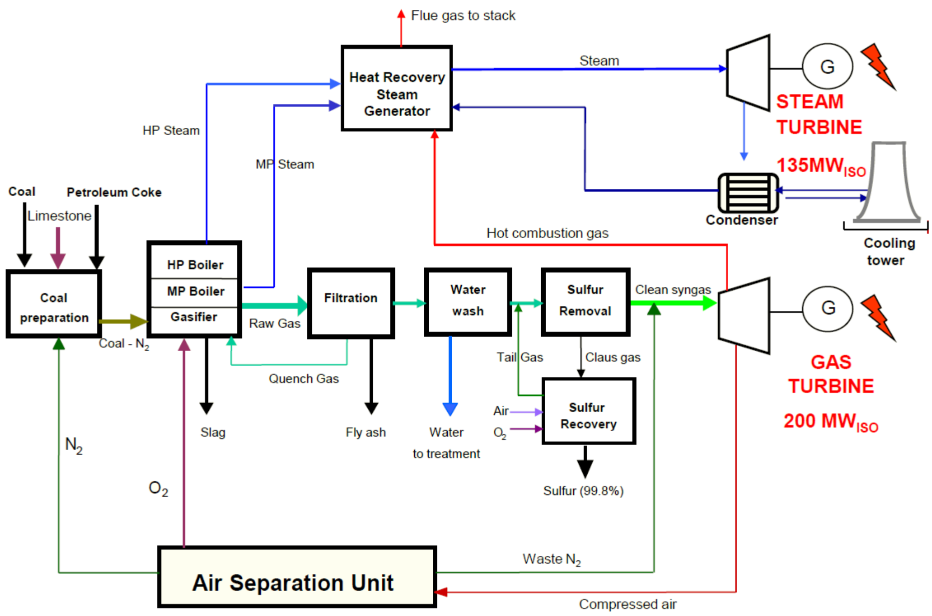
D.4 Example of IGCC plant: ELCOGAS

Elcogas plant in Puertollano, Spain (see IGCC.5 in Table 5 of Section 2) has been selected as an example of commercial IGCC plant for comparison purposes in Section 3.5. Figure 21 displays a simplified scheme of the process.

The 300 MW Elcogas plant uses a mixture of 50% wt. subbituminous high-ash coal and 50% petroleum coke from a nearby oil refinery. Coal is ground to < 50-60 μm in two roller mills. The coal is partly dried in the mills and further dried to less than 2 % wt. via medium pressure steam and natural gas combustion. An Air Liquide air separation unit produces 85% pure oxygen for the gasifier. The dried coal is then sent through a lock hopper before being conveyed pneumatically to four side-mounted burners using nitrogen from the ASU as a carrying medium [169].

Syngas is produced in a pressurized entrained-flow Krupp Koppers Prenflo gasifier at 1200-1600°C and 24 bar. Raw syngas is quenched with recycled syngas to 900°C, and further cooled in water-tube syngas coolers to 240°C. Particles are removed with a ceramic candle filter, and syngas is scrubbed with water at 165°C to remove NH_3 and halides. Acid gas removal is carried out with an hydrolysis unit and MDEA amine scrubbing. Sulphur is recovered in a Claus unit. Clean syngas is sent to a Siemens gas turbine, where it is fired with N_2 for NO_x reduction. The heat recovery steam generator (HRSG) produces steam from the gas turbine exhaust gases. The high-temperature and pressure steam produced is fed to a steam turbine to produce additional electricity [169].

Figure 21: Process layout of the Puertollano IGCC plant [180].



References

[1] M. Gassner, F. Marechal. *Thermo-economic optimization of the polygeneration of synthetic natural gas (SNG), power and heat from lignocellulosic biomass by gasification and methanation*. Energy and Environmental Science 5 (2012) 5768-5789
http://infoscience.epfl.ch/record/174475/files/c1ee02867g_ownlayout.pdf

[2] J. Kopyscinski, T.J. Schildhauer, S.M.A. Biollaz. *Production of synthetic natural gas (SNG) from coal and dry biomass – A technology review from 1950 to 2009*. Fuel 89 (2010) 1763-1783

[3] C.M. van der Meijden. *Development of the MILENA gasification technology for the production of Bio-SNG*. Doctoral Thesis. Eindhoven University of Technology, 2010. ISBN: 978-90-386-2363-4.
http://www.ecn.nl/docs/library/report/2010/b10016.pdf

[4] B. van der Drift. *SNG: A new biomass-based energy carrier*, 2006

[5] R.W.R. Zwart. *Synthetic Natural Gas (SNG). Large-scale introduction of green natural gas in existing gas grids*. ECN-L--07-069, 2007
ftp://ftp.ecn.nl/pub/www/library/report/2007/l07069.pdf

[6] M. Sudiro, A. Bertucco. *Synthetic Natural Gas (SNG) from coal and biomass: a survey of existing process technologies, open issues and perspectives*. In: *Natural gas*, Ed.P. Potocnik, ISBN 978-953-307-112-1, 2010
http://cdn.intechopen.com/pdfs/11472/InTech-Synthetic_natural_gas_sng_from_coal_and_biomass_a_survey_of_existing_process_technologies_open_issues_and_perspectives.pdf

[7] C.M. van der Meijden, H. Veringa, B.J. Vreugdenhil, A. van der Drift, R.W.R. Zwart, R. Smit. *Production of bio-methane from woody biomass*. ECN-M—09-086, 2009
http://www.ecn.nl/docs/library/report/2009/m09086.pdf

[8] M. Sciasko, T. Chmielniak. *Cost estimates of coal gasification for chemicals and motor fuels*. In: *Gasification for practical applications*. Ed. Y. Yun, InTech, 2012

[9] Trading Economics. *United States inflation rate*
http://www.tradingeconomics.com/united-states/inflation-cpi

[10] *Historic inflation United States – CPI inflation*
http://www.inflation.eu/inflation-rates/united-states/historic-inflation/cpi-inflation-united-states.aspx

[11] PetroSA. *Operations and refinery*
http://www.petrosa.co.za/innovation_in_action/Pages/Operations-and-Refinery.aspx

[12] Aveng. Engineering & Projects Company. *Mossel Bay Refinery.* http://www.e-pc.co.za/projects/mossel-bay-refinery

[13] BarryOnEnergy. *PetroSA's Mossel Bay GTL refinery*
http://barryonenergy.wordpress.com/2012/03/24/petrosas-mossel-bay-gtl-refinery/

[14] *PetroSA appoints CSIR for Mossel Bay environmental study*. November 7, 2012 http://www.engineeringnews.co.za/article/petrosa-appoints-csir-for-mossel-bay-environmental-study-2012-11-07
[15] G. Shaw. *Gas to liquid technologies*, 2012 http://www.energy.gov.za/files/IEP/presentations/GasToLiquidTechnologies_30March2012.pdf
[16] Petroleum Africa. *PetroSA contemplates LNG terminal investment* http://www.petroleumafrica.com/petrosa-contemplates-lng-terminal-investment/
[17] J. Taylor. *Scramble to replenish feedstock for Mossel Bay refinery*. Mining Weekly, December 2, 2011 http://www.miningweekly.com/article/scramble-for-stock-replenishing-2011-12-02
[18] T. Creamer. *Group Five appointed to oversee PetroSA refinery shutdown*. Engineering News, July 25, 2013 http://www.engineeringnews.co.za/article/group-five-appointed-to-oversee-petrosa-refinery-shutdown-2013-07-25
[19] R. Rapier. *Inside Shell's Bintulu GTL plant.* Energy Trends Insider, November 14, 2010 http://www.energytrendsinsider.com/2010/11/14/inside-shells-bintulu-gtl-plant/
[20] Shell. *Shell MDS technology and process* http://www.shell.com.my/products-services/solutions-for-businesses/smds/process-technology.html
[21] A.M. Samsam Bakhtiari. *Gas-to-liquids: much smoke, little fire* http://www.greatchange.org/bb-GTL_limitations.html
[22] B. White. *Can gas-to-liquids technology get traction?* Alaska natural gas transportation projects, 2012 http://www.arcticgas.gov/can-gas-liquids-technology-get-traction
[23] H. Boerrigter. *Economy of biomass-to-liquids (BTL) plants. An engineering assessment*. ECN-C—06-019, 2006.
[24] QP – Sasol. *Oryx GTL* http://www.oryxgtl.com.qa/
[25] International Gas Union. *ORYX GTL and the GTL sector.* http://www.igu.org/gas-knowhow/publications/igu-publications/mag/apr07/p126-150.pdf
[26] Technip. ORYX GTL. *How Technip delivered Middle East's first GTL plant* http://www.technip.com/sites/default/files/technip/publications/attachments/Oryx_GTL.pdf
[27] GastechNews. *Gas-to-liquids – on the threshold of a new era?* http://www.gastechnews.com/processing-technology/gas-to-liquids-on-the-threshold-of-a-new-era/
[28] C. Brown. *Gas-to-liquid: A viable alternative to oil-derived transport fuels?* The Oxford Institute for Energy Studies, University of Oxford, 2013. http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/05/WPM-50.pdf
[29] Shell Global. *Pearl GTL* http://www.shell.com/global/aboutshell/major-projects-2/pearl.html
[30] S. Pfeifer. *Pearl crowns Shell's Qatari gasoil hopes*. Financial Times, June 5, 2011 http://www.ft.com/cms/s/0/615ade02-8f92-11e0-954d-00144feab49a.html#axzz2fEF7miHc
[31] J.M. Broder, C. Krauss. *A big, and risky, energy bet.* The New York Times, December 17, 2012 http://www.nytimes.com/2012/12/18/business/energy-

environment/sasol-betting-big-on-gas-to-liquid-plant-in-us.html?pagewanted=all&_r=0

[32] B. Reddall. *Cost of delayed Chevron Nigeria plant now $8.4 bln*. Reuters, February 24, 2011 http://www.reuters.com/article/2011/02/25/chevron-idUSN2428474120110225

[33] O. Oredein. *Hopes of monetizing GTL resources in Nigeria are again delayed*. E & P Exploration & Production, January 22, 2013 http://www.epmag.com/Production-Field-Development/Hopes-Monetizing-GTL-Resources-Nigeria-Again-Delayed_112000

[34] Unidro. *Escravos GTL – Nigeria* http://www.unidro.net/index.php/progetti/escravos-gtl-nigeria

[35] Vanguard. *Escravos GL shutdown, by citizen Okon* http://www.vanguardngr.com/2012/12/ecravos-gtl-shut-down-by-citizen-okon/

[36] Hydrocarbons Technology. *Escravos gas-to-liquids project, Niger delta, Nigeria* http://www.hydrocarbons-technology.com/projects/escravos/

[37] J. Kemp. *Extreme project risk still holds back GTL*. Reuters, November 26, 2012 http://www.reuters.com/article/2012/11/26/column-kemp-natural-gas-idUSL5E8MQ79E20121126

[38] U. Izundu. *Sasol to establish GTL plant in Uzbekistan*. Oil & Gas Journal. July 17, 2009 http://www.ogj.com/articles/2009/07/sasol-to-establish.html

[39] Downstream Today. *China's Citic to help build Uzbek gas-chemical facilities*. May 20, 2011 http://www.downstreamtoday.com/news/article.aspx?a_id=26672

[40] Sasol. *Sasol Louisiana projects*. http://www.sasollouisianaprojects.com/page.php?page=projects

[41] B. DuBose. *GTL'13: Sasol eyes diversified product slate for Louisiana GTL plant*. Hydrocarbon Processing, July 20, 2013 http://www.hydrocarbonprocessing.com/Article/3237485/GTL-13-Sasol-eyes-diversified-product-slate-for-Louisiana-GTL-plant.html

[42] Chemicals Technology. *Sasol's Lake Charles gas-to-liquid and ethane cracker complex, United States of America* http://www.chemicals-technology.com/projects/sasol-lake-charles-gas-liquid-ethane-cracker/

[43] Sasol. *US mega projects* http://www.sasol.com/innovation/us-mega-projects

[44] W.R. True. *Sasol to start design work on Louisiana GTL, ethane cracker plants*. Oil & Gas Journal, March 12, 2012 http://www.ogj.com/articles/2012/12/sasol-to-start-design-work-on-louisiana-gtl-ethane-cracker-plants.html

[45] Louisiana Economic Development. *Sasol. New investment opportunities emerge as natural gas prices fall* http://www.louisianaeconomicdevelopment.com/page/sasol

[46] J.L. Anastai. *Sasol: South Africa´s oil from coal story. Background for environmental assessment*. US Environmental Protection Agency, 1980 http://www.fischer-tropsch.org/DOE/DOE_reports/600_8-80-002/epa-600_8-80-002.pdf

[47] *Historical overview of the South African chemical industry: 1896 – 1998*. Chemistry International 21 (3), 1999 http://www.iupac.org/publications/ci/1999/may/other3.html#six

[48] *Sasol. Historical milestones* http://www.sasol.com/about-sasol/company-profile/historical-milestones

[49] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia*. Operating facilities – Sasol http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/sasol.html

[50] *Sasol´s Secunda CTL plant: costly to build, but now it´s a cash cow*. High Beam, January 1, 2005 http://www.highbeam.com/doc/1P3-793476071.html

[51] A. Eberhard. *The future of South African coal: market, investment, and policy challenges*. Stanford University, Program on Energy and sustainable Development, 2011 http://iis-db.stanford.edu/pubs/23082/WP_100_Eberhard_Future_of_South_African_Coal.pdf

[52] S. Mangena. *Coal gasification and liquefaction. Sasol experiences and opportunities*. 4th EU-South Africa Clean Coal Working Group Meeting, 2012 http://www.energy.gov.za/files/4thEUSouthAfricaCleanCoalWorkingGroup/SJ%20Mangena%20-%20SA-EU%20Clean%20Coal%20Working%20Group%20Meeting%20-final.pdf

[53] AsiaChem. *ChinaCoalChem Monthly Report*, 2010 http://www.chinacoalchem.com/en/Sample.pdf

[54] Foster Wheeler. *Coal-to-liquids. Specialist skills secure win with Sasol and Shenhua Ningxia* http://www.fwc.com/GlobalEC/pdf/Ningxia%20Sasol%20CTL.pdf

[55] Downstream Today. *China to spend $13B on liquefied coal base*. March 9, 2007 http://www.downstreamtoday.com/news/article.aspx?a_id=1934&AspxAutoDetectCookieSupport=1

[56] T. Creamer. *Sasol pulls back from China CTL, reallocates capital and people*. Engineering News, September 12, 2011 http://www.engineeringnews.co.za/article/sasol-pulls-back-from-china-ctl-reallocates-capital-and-people-2011-09-12

[57] F. Tan. *Shell, Shenhua study Ningxia coal-to-liquids plant*. ICIS, 11 July 2006 http://www.icis.com/Articles/2006/07/11/1074095/shell-shenhua-study-ningxia-coal-to-liquids-plant.html

[58] O. Yang. *Development and trends of modern coal-to-chemicals in China*. CPIC, 2012 http://www.docin.com/p-702536603.html

[59] Hydrocarbons Technology. *Shenhua coal to liquids plant, China* http://www.hydrocarbons-technology.com/projects/shenhua/

[60] L. Ma. *WP2 – Future Energy Technology Perspectives. 2.2 Coal technology assessment*. http://www.nzec.info/en/assets/Reports/NZECWP2.2-Technology-Assessment-Coal-TechnologiesFinal-report.pdf

[61] X. Ren. *Shenhua CTL (clean coal) projects and CO_2 sequestration*. 2nd US-China CO_2 Emissions Control Science & Technology Symposium, 2008 http://www.netl.doe.gov/publications/proceedings/08/CO2E/PDF/session%201/2008.5.Hangzhou%20CO2%20forum-EN.pdf

[62] Y. Zhang. *Shenhua coal conversion technology and industry development.* http://gcep.stanford.edu/pdfs/wR5MezrJ2SJ6NfFl5sb5Jg/16_china_zhangyuzhuo.pdf

[63] Q. Sun. *CTL development in China based on Shenhua CTL projects*. US-China Energy Center. http://files.asme.org/asmeorg/Communities/Technical/Energy/16089.pdf
[64] T. Si. *Shenhua shows the way to make gas from coal*. January 22, 2009 http://www.chinadaily.com.cn/business/2009-01/22/content_7419616.htm
[65] S. Dubey. *Coal-to-liquids (CTL). Misplaced solution for oil starved world*. http://www.kosid.org/wp-content/uploads/2012/09/SasolCtL.pdf
[66] EnergyAsia. *Yankuang Group, US Accelergy to conduct feasibility study for coal-to-liquids plant*. October 10, 2011 http://energyasia.com/public-stories/china-yankuang-group-us-accelergy-to-conduct-feasibility-study-for-coal-to-liquids-plant/
[67] China Daily. *Yankuang gains approval of coal-to-oil project in Shaanxi*. January 12, 2008 http://en.sxcoal.com/NewsDetail.aspx?cateID=165&id=15300&keyword=Yankuang
[68] Xinhua News Agency. *Yankuang´s indirect CTL project likely to aprroved by NDRC*. iStockAnalyst, August 30, 2010 http://www.istockanalyst.com/article/viewiStockNews/articleid/4450823
[69] Energy Justice Network. *American Lignite Energy CTL* http://www.energyjustice.net/map/displayfacility-74062.htm
[70] Great River Energy. *North Dakota coal-to-liquids project establishes 'American Lignite Energy' for development effort*. http://www.greatriverenergy.com/aboutus/pressroom/052507_american_lignite_energy.html
[71] Downstream Today. *Fox Creek coal-to-liquids project*. September 10, 2008 http://www.downstreamtoday.com/projects/project.aspx?project_id=44
[72] *Alter NRG proposing Canada´s first coal-to-liquids project*. Green Car Congress, July 23 2008 http://www.greencarcongress.com/2008/07/alter-nrg-propo.html
[73] Alter NRG Corp. *Alter NRG announces Canada´s first CTL project*. Downstream Today, July 22 2008.http://www.downstreamtoday.com/News/ArticlePrint.aspx?aid=11985
[74] L Flint. *Fox Creek coal to liquids project: green fuels for the future*. APEGGA Professional Development Days, 2009 http://www.apega.ca/members/Presentations/2009/conference/02-05-Flint.pdf
[75] H &WB Asia Pacific (Pte Ltd) Corporation. *Coal-to-liquids beginning in the Philippines*. http://www.hwbasiapacific.net/features.html
[76] *US firm gets licensing deal for coal-to-liquid plant*. Mobility Tech zone, April 22, 2007 http://www.mobilitytechzone.com/news/2007/04/22/2539260.htm
[77] H. Beltrán. *Govt, Likuen sign coal liquefaction plants deal*. BN Americas, July 19, 2005 http://www.bnamericas.com/news/mining/Govt,_Likuen_sign_coal_liquefaction_plants_deal
[78] H. Beltrán. *Likuen liquefaction project secures 600 Mt of coal*. BN Americas, December 13, 2005 http://www.bnamericas.com/news/mining/Likuen_liquefaction_project_secures_600Mt_of_coal
[79] Likuen. *The coal liquefaction process*. January 16, 2008 http://likuen.co/spip/spip.php?article11

[80] Business Wire. *New methanol production plant at Sasol*. September 16, 1997 http://www.thefreelibrary.com/New+Methanol+Production+Plant+at+Sasol.-a019765189
[81] ICIS. *Sasol gets green light for high purity methanol plant*. September 22, 1997 http://www.icis.com/Articles/1997/09/22/45079/sasol-gets-green-light-for-high-purity-methanol-plant.html
[82] Eastman Chemical Company, Air Products and Chemicals Inc. *Project data on Eastman Chemical Company´s chemicals-from-coal complex in Kingsport, TN.* US Department of Energy, National Energy Technology Laboratory, 2003 http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/Eastman%20Chemicals%20from%20Coal%20Complex.pdf
[83] E.C. Heydorn, B.W. Diamond, R.D. Lilly. *Commercial-scale demonstration of the liquid phase methanol (LPMEOHTM) process.* US Department of Energy, National Energy Technology Laboratory, 2003 http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/estmn/LPMEOHFinal.pdf
[84] China Chemical Reporter. *Methanol project in Henan Yima approved*. High Beam Research, November 6, 2004 http://www.highbeam.com/doc/1G1-125713147.html
[85] Asian Chemical News. *Henan Kaixiang scales down methanol project capacity*. October 25, 2004 http://connection.ebscohost.com/c/articles/15004468/henan-kaixiang-scales-down-methanol-project-capacity
[86] F. Tan. *China´s Kaixiang to build two methanol plants in Henan*. March 23, 2004 ICIS. http://www.icis.com/Articles/2004/03/24/568180/chinas-kaixiang-to-build-two-methanol-plants-in-henan.html
[87] ICIS. *Kaixiang plans Henan methanol.* March 22, 2004 http://www.icis.com/Articles/2004/03/19/566364/kaixiang-plans-henan-methanol.html
[88] H. Hui. *China´s Hulunbeier Dongneng runs methanol plant at 100%.* ICIS, August 17, 2009 http://www.icis.com/Articles/2009/08/17/9240332/chinas-hulunbeier-dongneng-runs-methanol-plant-at-100.html
[89] CCR. *Shanxi Jinye launches 300000 T/A methanol project*. June 3, 2008 http://www.knak.jp/china/china-12.htm
[90] *Sopo methanol plant* http://sopo.l303.bizcn.com/en/about.php?cid=110&id=42&sid=97
[91] Alestron. *Towngas mulls Fenyang methanol and DME project*. HighBeam Business, February 1, 2008 http://business.highbeam.com/436093/article-1G1-174097755/towngas-mulls-fenyang-methanol-and-dme-project
[92] China Chemical Reporter. *Signing for dimethyl ether project in Shanxi*. EBSCO Host Connection, February 26, 2008 http://connection.ebscohost.com/c/articles/31130661/signing-dimethyl-ether-project-shanxi
[93] China Oceanwide Holdings Group Co., Ltd. http://www.cohg.com.cn/eng/doc/jtcy-energy.asp
[94] China Chemical Reporter. *China Oceanwide Holdings Group launches coal chemical project*. HighBeam, October 26, 2007 http://www.highbeam.com/doc/1G1-170455418.html

[95] China Chemical Reporter. *Chan and Chang Group launches coal chemical project in Guizhou*. HighBeam Research, June 16, 2007 http://www.highbeam.com/doc/1G1-165691766.html
[96] Datang International Power Generation Co., Ltd. 2011 *Annual Report. Achieving sustainable development through the synergy in diversity* http://www.dtpower.com/en/content/attach/site2/20120516/0023aeaa58bd111d901455.pdf
[97] HSBC Global Research. Sinopec Engineering (2386 HK) https://www.research.hsbc.com/R/20/p0X2LIS
[98] Synthesis Energy Systems. *SES and Golden Concord sign joint venture contract to build coal gasification, methanol and DME plant in Inner Mongolia, China*. Market Wire, June 6, 2007 http://www.marketwired.com/press-release/ses-golden-concord-sign-joint-venture-contract-build-coal-gasification-methanol-dme-739510.htm
[99] China Chemical Reporter. *Xianyang chemical to finance methanol project*. EBSCOHost Connection, October 16, 2007 http://connection.ebscohost.com/c/articles/27082338/xianyang-chemical-finance-methanol-project
[100] Siemens AG. S*hanxi Xian yang Chemicals Industry Co., Ltd. Methanol Products* – Xi an, China, 2008 http://a.gongkong.com/customer/siemens/Operationd/pdf/1735-E.pdf
[101] Shaanxi – Guangdong – Hong Kong Economic Cooperation. *Cooperation projects of Shaanxi province.* http://www.shaanxi.gov.cn/portal/www4.shaanxi.gov.cn/tjxm/en/mydoc088.htm
[102] F + L Weekly. *China´s MEP orders Shenhua to suspend operations of its coal-to-olefins plant in Baotou*. http://fuelsandlubes.com/flw/chinas-mep-orders-shenhua-to-suspend-operations-at-its-baotou-cto-plant/
[103] Shenhua Group Corp. Ltd. *The first and largest coal to olefin project in the world is built up in Baotou. The construction of the project makes many records in China's chemical and petrochemical industry*, December 16, 2010 http://www.csclc.com.cn/ens/xwygg/gsgg/2010-12-16/275.shtml
[104] China Coal Resource. *Shenhua´s Baotou CTO project ordered to halt*. January 25, 2013 http://en.sxcoal.com/NewsDetail.aspx?cateID=615&id=84850&keyword=order
[105] Y. Zhang. *Shenhua coal conversion technology and industry development*. http://gcep.stanford.edu/pdfs/wR5MezrJ2SJ6NfFl5sb5Jg/16_china_zhangyuzhuo.pdf
[106] W. Lang, C. Ingraham. *New drive for China´s coal industry*. Siemens, 2012 http://www.energy.siemens.com/hq/pool/hq/power-generation/fuel-gasifier/downloads/New-Drive-for-Chinas-Coal-Industry.PDF
[107] J. Wang. *China´s Shenhua Ningxia eyes MTP project start-up in end ´10*. ICIS, June 11, 2010 http://www.icis.com/Articles/2010/06/11/9366962/chinas-shenhua-ningxia-eyes-mtp-project-start-up-in-end-10.html
[108] Shenhua Ningxia Coal Industry Group. *Ningdong profile* http://www.nxmy.com/MagneticNingdong/index.htm
[109] Wuxi An Activity Pneumatic Sets Co., Ltd. *Building the world´s largest coal chemical base*. October 29, 2009 http://wuxianhuo.com/english/SingleNews.aspx?i=2

[110] Industry overview
http://www.hkexnews.hk/listedco/listconews/sehk/2012/1213/02236_1503430/E114.pdf
[111] Our Chemical http://www.ourchemical.com/catalogs_14/142733-20-8.html
[112] D. Wu. *China´s Shaanxi Weihe Group starts up methanol plant.* ICIS, September 15, 2011
http://www.icis.com/Articles/2011/09/15/9492522/chinas-shaanxi-weihe-group-starts-up-methanol-plant.html
[113] F. Shen. *China´s Shaanxi Weihe shuts methanol and DME plants on 9 April*. ICIS, April 10, 2012 http://www.icis.com/Articles/2012/04/10/9548494/chinas-shaanxi-weihe-shuts-methanol-and-dme-plants-on-9-april.html
[114] H. Hui. *China's Huating Zhongxu eyes restart of methanol plant in July*. ICIS, June 29, 2011 http://www.icis.com/Articles/2011/06/29/9473402/chinas-huating-zhongxu-eyes-restart-of-methanol-plant-in.html
[115] China Chemical Reporter. *600000 T/A coal-based methanol project launched in Gansu*. HighBeam Research, October 26, 2005
http://www.highbeam.com/doc/1G1-138861471.html
[116] China Chemical Reporter. *Coal chemical base established in Huating*. HighBeam Research, July 26, 2005 http://www.highbeam.com/doc/1G1-135119732.html
[117] Puworld. *Huating 600 ktpa coal-based methanol project proceeds smoothly*. October 15, 2009 http://en.puworld.com/html/20091015/8486.html
[118] D. Wu. *China's Xinghua chemical runs coal-chemical units at full rates*. ICIS, December 9, 2011 http://www.icis.com/Articles/2011/12/09/9515252/chinas-xinghua-chemical-runs-coal-chemical-units-at-full-rates.html
[119] V. Pan. *China´s Guizhou Jinchi starts regular production at Tongzi project*. ICIS, February 4, 2013
http://www.icis.com/Borealis/Article.asp?p=1&q=BFB3C6D1D8BDE2B6CCAD8DB96EB0D9CAAFDCC1D48DAEE7B281AED7B8E0B4D5D6B0EC&id=B28494A49882AA
[120] *GE demonstrates scale and fuel flexibility of its gasification technology at two major projects in China*. March 5, 2012 http://www.genewscenter.com/Press-Releases/GE-Demonstrates-Scale-and-Fuel-Flexibility-of-Its-Gasification-Technology-at-Two-Major-Projects-in-China-36c1.aspx
[121] http://www.china-automation.net/html/20090907.php
[122] China Chemical Reporter. *Fengfeng Group kicked off coal chemical project phase II*. EBSCO Host Connection. September 6, 2009
http://connection.ebscohost.com/c/articles/44127586/fengfeng-group-kicked-off-coal-chemical-project-phase-ii
[123] Sinopec Tenth Construction Company. *Coal to chemical project*
http://en.sinopecten.com/comcontent17_detail.html
[124] R. Qian. *China´s Chongqing Kabeile may delay methanol plant start-up*. ICIS, August 21, 2012 http://www.icis.com/Articles/2012/08/21/9588521/chinas-chongqing-kabeile-may-delay-methanol-plant-start-up.html
[125] D. Wu. *China´s East Hope to start up new methanol unit by late Aug*. ICIS, August 23, 2010 http://www.icis.com/Articles/2010/08/23/9387196/chinas-east-hope-to-start-up-new-methanol-unit-by-late-aug.html
[126] Our Chemical. http://www.ourchemical.com/catalogs_85/850411-17-5.html

[127] 21 Chemnet. *Dongting Lake will be built southwest of modern coal chemical base model*. August 24, 2010 http://www.21chemnet.com/News_2010-8-24/12197.html
[128] HighBeam Business. *East China Engineering signed EPC contract*. October 9, 2007 http://business.highbeam.com/436093/article-1G1-169629081/east-china-engineering-signed-epc-contract
[129] CCTV. *Guizhou takes aim at new energy*. July 8, 2010 http://english.cntv.cn/program/china24/20100708/100583.shtml
[130] TMC News. *East China Engineering signed EPC contract*. October 8, 2007 http://www.tmcnet.com/usubmit/2007/10/08/2997549.htm
[131] China Chemical Reporter. *Huaneng Hulunbeier launches its first phase large methanol project*. HighBeam Research, September 16, 2008 http://www.highbeam.com/doc/1G1-186225978.html
[132] Sinopec Tenth Construction Company. Coal chemical project http://en.sinopecten.com/comcontent17_detail/&FrontComContent_list01-1330402094967ContId=d8f4db3b-2144-4c01-976c-965e5e79bdf1&comContentId=d8f4db3b-2144-4c01-976c-965e5e79bdf1.html
[133] http://www.knak.jp/china/china-16.htm
[134] China Coal Resource. *Fengfeng, Luneng to jointly develop Inner Mongolia project*. January 10, 2009 http://en.sxcoal.com/NewsDetail.aspx?cateID=165&id=19977&keyword=Fengfeng
[135] China Coal Resource. *Jizhong Energy advances coal coking project*. November 23, 2009 http://en.sxcoal.com/26357/NewsShow.html
[136] China Chemical Reporter. *Xinjiang Liye tianfu kicks off large methanol project*. HighBeam Research, April 26, 2009 http://www.highbeam.com/doc/1G1-199463949.html
[137] H. Lee. *China's Shanghai Huayi's delays Anhui acetic acid plant start up*. ICIS, March 12, 2012 http://www.icis.com/Articles/2012/03/12/9540480/chinas-shanghai-huayis-delays-anhui-acetic-acid-plant-start.html
[138] F. Tan. *Shanghai Huayi to build $4 bn Anhui coal-chem base*. ICIS, November 20, 2007 http://www.icis.com/Articles/2007/11/20/9079747/shanghai-huayi-to-build-4bn-anhui-coal-chem-base.html
[139] Eruera. *China: Shanghai Huayi Group to invest 600 kt/y MEG project in Anhui province*. Every China, May 20, 2011 http://news.everychina.com/wz4014ca/china_shanghai_huayi_group_to_invest_600kt_y_meg_project_in_anhui_province.html
[140] AsiaChem. *China CTO industry. New opportunities for polyolefin process & equipment suppliers*. June 18, 2010 http://www.chemweekly.com/release/2010/2010CTO.pdf
[141] Petrochemical News. *Pucheng selects Unipol technology*. November 8, 2010 (Vol. 48, No. 45) http://www.petrochemical-news.com/P-V48N45.pdf
[142] The people's government of Shaanxi province. *Yulin: Making a new city, conceiving great-leap forward development*. June 11, 2008 http://english.shaanxi.gov.cn/articleInvestment/investment/environment/onyulin/200806/6202_1.html
[143] ICIS. *China's Shaanxi Yulin building 300 kt/yr methanol plant*. April 21, 2005 http://www.icis.com/Articles/2005/04/21/670779/chinas-shaanxi-yulin-building-300-ktyr-methanol-plant.html

[144] http://www.doc88.com/p-741827818233.html
[145] China Chemical Reporter. *Town Star starts 200000 t/a methanol project*. HighBeam Research, January 26, 2007 http://www.highbeam.com/doc/1G1-158736358.html
[146] China Mining. *Shenhua Group construction on Urad Middle Banner project begins*. April 7, 2011 http://www.chinamining.org/Companies/2011-04-07/1302162934d44362.html
[147] China Color Website. *The country's largest coal methanol to dimethyl ether project will be put into operation in Xinjiang Yiwu*. April 6, 2012 http://color.yanliao.net/youji_1/content/?119.html
[148] The Economist Intelligence Unit Limited. Access China. Xinjiang, 2012 http://www.izvoznookno.si/Dokumenti/xinjiang_ACProvinceReport.pdf
[149] Our chemical. http://www.ourchemical.com/catalogs_35/35144-25-3/
[150] National Energy Technology Laboratory. *Gasifipedia. Great Plains Synfuels plant* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/great-plains.html
[151] C. Yang, R.B. Jackson. *China's synthetic natural gas revolution*. Nature Climate Change, Vol. 3, 2013 http://people.duke.edu/~cy42/SNG.pdf
[152] *Xinjiang SNG industry analysis*. Policies, November 30, 2011 http://blog.sina.com.cn/s/blog_90e5c49c01011kl9.html
[153] China Gas. *China kicks off construction on largest SNG project*. March 29, 2012 http://www.chinagasholdings.com.hk/siteen/aspx/News_Infor.aspx?id=649
[154] The Economist Intelligence Unit Limited. *Access China. Inner Mongolia*, 2012 http://www.izvoznookno.si/Dokumenti/innermongolia_ACProvinceReport.pdf
[155] *Guanghui coal chemical project put into operation in Hamilton*, January 26, 2012 http://www.crusherzy.com/machineblog/2012/01/26/guanghui-coal-chemical-project-put-into-operation-in-hamilton/
[156] R. McCracken. *Test year for Chinese coal-based SNG*. Platts Energy, 2012 http://www.platts.com/IM.Platts.Content%5Caboutplatts%5Cmediacenter%5Cpdf%5Cinsight-nov12-sng.pdf
[157] The Economist Intelligence Unit Limited. *Access China. Shanxi*, 2012 http://www.izvoznookno.si/Dokumenti/shanxi_ACProvinceReport.pdf
[158] J. Karg. *IGCC experience and further developments to meet CCS market needs*. Coal-Gen Europe. Katowice, Poland, 2009 http://www.energy.siemens.com/mx/pool/hq/power-generation/power-plants/integrated-gasification-combined-cycle/Igcc-experience-and-further-developments.pdf
[159] *IGCC technology and operating experience* http://belfercenter.hks.harvard.edu/files/igcc%20financing%20chapter%202.pdf
[160] Global Energy Observatory http://globalenergyobservatory.org/geoid/41985
[161] W.G. Rosenberg, D.C. Alpern, M.R. Walker. *Deploying IGCC in this decade with 3party covenant financing*. Harvard University, 2004 http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/Financing%20IGCC%20Volume%201.pdf
[162] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia, power: IGCC project examples*

http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/nuon.html

[163] Electric Power Research Institute. *Integrated Gasification Combined Cycle (IGCC) design considerations for high availability. Volume 1: Lessons from existing operations*, 2007 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001012226

[164] N.A.H. Holt. *IGCC technical status, trends and future improvements*. American Chemical Society Meeting, San Francisco, CA, 2000 http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/45_1_SAN%20FRANCISCO_03-00_0098.pdf

[165] *IGCC state-of-the-art report*. Department of Mechanical & Structural Engineering & Material Science. University of Stavanger, Norway, 2010 http://www.h2-igcc.eu/Pdf/State-of-the-art%20IGCC%20_2010-04-29.pdf

[166] J.B. Tennant. *Overview of DOE's gasification program*. National Energy Technology Laboratory, US Department of Energy, 2010 http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/DOE%20Gasification%20Program%20Overview%202010%2001-25%20v1v.pdf

[167] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia. Power: IGCC project examples* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/wabash.html

[168] US Department of Energy, Wabash River Coal Gasification Project Joint Venture. *The Wabash River coal gasification repowering project*, 2000 http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical20.pdf

[169] US Department of Energy, National Energy Technology Laboratory (NETL). *Gasification plant cost and performance optimization*. Contract No. DE-AC26-99FT40342, 2003 http://www.netl.doe.gov/technologies/coalpower/fuelcells/publications/fuelcell/fc-cleanup/Gasification%20Plant%20Cost-Perf%20Optimization_9-01-03.pdf

[170] Sokolovska Uhelna. *Performance report 2006* http://www.suas.cz/uploads/82051783947b5627405155_Vyrocni_zprava_06_AJ.pdf

[171] Modern Power Systems. *Report from Vresova: 12 years of operating experience with the world's largest coal-fuelled IGCC*, 2008 http://www.modernpowersystems.com/features/featurereport-from-vresov-12-years-of-operating-experience-with-the-world-s-largest-coal-fuelled-igcc

[172] Gasification Technologies Council. *World Gasification Database* http://www.gasification.org/database1/gasifier.aspx?GasId=274

[173] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia. Power: IGCC project examples* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/project-examples.html#duke

[174] Z. Bucko, J. Engelhard, J. Wolff, H. Vierrath. *400 MWe IGCC power plant with HTW gasification in the Czech Republic*. 1999 Gasification Technologies Conference, San Francisco, CA, 1999

http://citeseerx.ist.psu.edu/viewdoc/download;jsessionid=D4C5F1062085E7066AF293DB805EC6B8?doi=10.1.1.168.59&rep=rep1&type=pdf

[175] TECO Energy. *Polk Power Station IGCC.* The Second DOE/UN International Conference and Workshop on Hybrid Power Systems. Charlotte, NC, 2002 http://www.netl.doe.gov/publications/proceedings/02/Hybrid/Hybrid2Hornick.PDF

[176] US Department of Energy. *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle project*, 2002 http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/bibliography/demonstration/pdfs/tampa/TampaFinal.pdf

[177] US Department of Energy. *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle project*, 2004 http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/bibliography/demonstration/pdfs/tampa/TampaPPA8%20Final080904.pdf

[178] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia. Power: IGCC project examples* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/tampa.html

[179] Elcogas IGCC power plant. *Economic history* http://www.elcogas.es/en/who-are-we/history/economic

[180] P. Coca. *Puertollano IGCC R&D plan: towards zero emissions power plants*. 10th European Gasification Conference. Amsterdam, The Netherlands, 2010 http://www1.icheme.org/gasification2010/pdfs/puertollanoigccpilarcoca.pdf

[181] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia. Power: IGCC project examples* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/elcogas.html

[182] Duke Energy. *Project overview* http://www.duke-energy.com/about-us/edwardsport-overview.asp

[183] S. DiSavino. *Duke's Edwardsport coal-fired plant enters service*. Reuters, June 10, 2013 http://www.reuters.com/article/2013/06/10/utilities-operations-duke-edwardsport-idUSL3N0EM2G720130610

[184] National Energy Technology Laboratory, US Department of Energy. *Gasifipedia. IGCC project examples* http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/project-examples.html#duke

[185] M. Bandyk. *Duke's Edwardsport IGCC still dealing with technical problems*. Institute for Energy Economics and Financial Analysis, August 2, 2013 http://www.ieefa.org/dukes-edwardsport-igcc-still-dealing-with-technical-problems/

[186] Power Engineering. *Duke's Edwardsport IGCC plant operating intermittently*. August 2, 2013 http://www.power-eng.com/articles/2013/08/dukes-edwardsport-igcc-plant-operating-intermittently.html

[187] Emerson Process Management. *Integrated Gasification Combined Cycle (IGCC) at Duke Edwardsport.* http://www.emersonprocessxperts.com/2013/06/integrated-gasification-combined-cycle-igcc-at-duke-edwardsport/

[188] Indiana Distribute Energy Alliance (IDEA) blog. *IndyStar: Duke Energy Indiana customers owe $2.5 billion-plus for Edwardsport plant*, 2012

http://indianadg.wordpress.com/category/duke-energy/edwardsport-igcc-plant/

[189] J.B. Tennant. *Gasification systems overview*. National Energy Technology Laboratory, US Department of Energy, 2013 http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/DOE%20Gasification%20Program%20Overview.pdf

[190] D.M. Zupan. *Edwardsport IGCC – Moving forward*. http://www.gasification.org/uploads/downloads/Conferences/2009/15ZUPAN.pdf

[191] R. Peterson, P. Tijm. *An Alaska North Slope GTL option.* ANRTL, 2008 http://lba.legis.state.ak.us/proposals/doc_log/2008-06_anrtl_presentation.pdf

[192] S. Berdikeeva. *Can Qatar's success with gas-to-liquids fuels be repeated in the U.S.?* Oil Price, March 10, 2013 http://oilprice.com/Energy/Natural-Gas/Can-Qatars-Success-with-Gas-to-Liquids-Fuels-Be-Repeated-in-the-U.S.html

[193] M.J. Economides. *The economics of gas to liquids compared to liquefied natural gas*. World Energy Vol. 8 (1), 2005. http://www.arcticgas.gov/sites/default/files/documents/2005-gtl-vs-lng.pdf

[194] B. Patel. *Gas monetisation: A techno-economic comparison of gas-to-liquid and LNG*. 7th World Congress of Chemical Engineering, Glasgow, 2005 http://www.fosterwheeler.com/publications/tech_papers/files/IChemE%20WCCE%2005%20LNG%20versus%20GTL.pdf

[195] M. Blesl, D. Bruchof. *Liquid fuels production from coal & gas*. IEA-ETSAP Technology Brief S02, 2010 http://www.iea-etsap.org/web/e-techds/pdf/s02-ctl&gtl-gs-gct.pdf

[196] C. Chen, E.S. Rubin, M. Berkenpas. *CO_2 control technology effects on IGCC plant performance and cost.* Proceedings of 23rd International Pittsburgh Coal Conference, 2006 http://repository.cmu.edu/cgi/viewcontent.cgi?article=1077&context=epp

[197] D. Gray, D. Challman, A. Geertsema, D. Drake, R. Andrews. *Technologies for producing transportation fuels, chemicals, Synthetic Natural Gas and electricity from the gasification of Kentucky coal.* University of Kentucky, 2007 http://www.caer.uky.edu/newsroom/news2007/HB299-Report-CTL-SNG-Technologies2007.pdf

[198] R.H. Williams, E.D. Larson, H. Jin. *F-T liquids production from coal and coal + biomass with CO_2 capture and alternative storage options: Aquifer CO_2 storage vs. CO_2-enhanced oil recovery*

[199] D.S. Moulton, N.R. Sefer. *Costs to convert coal to methanol*. EPA 460/3-84-012.

[200] National Energy Technology Laboratory, US Department of Energy. *Shell gasifier IGCC base cases*. PED-IGCC-98-002.

[201] A. McDonald, L. Schrattenholzer. *Learning rates for energy technologies*. Energy Policy 21 (2001) 255-261.

[202] Association for the Advancement of Cost Engineering (AACE). *Conducting Technical and Economic Evaluations: as applied for the Process and Utility Industries*. AACE International Recommended Practice No. 16R-90, Rev. April 1991

[203] European Commission, Eurostat. *Energy price statistics*, 2012 http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Energy_price_statistics#Electricity_prices_for_industrial_consumers

[204] International Renewable Energy Agency. *Biomass for power generation*. IRENA Working Paper, 2012 http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-BIOMASS.pdf
[205] International Energy Agency. *Gas medium-term market report 2012* http://www.iea.org/publications/freepublications/publication/MTGMR2012_web.pdf
[206] IEA-ETSAP, IRENA. *Production of liquid biofuels*. Technology Brief P10, 2013 http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20P10%20Production_of_Liquid%20Biofuels.pdf
[207] International Energy Agency. *World Energy Outlook 2011* http://www.iea.org/publications/freepublications/publication/WEO2011_WEB.pdf
[208] European Commission. *Report from the Commission to the Council and the European Parliament on sustainability requirements for the use of solid and gaseous biomass sources in electricity, heating and cooling*. COM(2010)11 final http://www.emissions-euets.com/attachments/259_Report%20from%20the%20Commission%20of%2025%20February%202010%20COM(2010)11%20final.pdf
[209] F.T. Al-Saadoon. *Economics of GTL Plants*. SPE Projects, Facilities & Construction 2 (1): 1-5. SPE-94380-PA , 2007http://www.spe.org/ejournals/jsp/journalapp.jsp?pageType=Preview&jid=EFC&mid=SPE-94380-PA
[210] T.B. Reed. *Efficiencies of methanol production from gas, coal, waste or wood* http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/21_2_NEW%20YORK_04-76_0037.pdf
[211] P. Cheng, H. Chiu, Y. Chyou, C. Yu. *Processes simulation study of coal to methanol based on gasification technology*. World Academy of Science, Engineering and Technology 41, 2010 http://www.waset.org/journals/waset/v41/v41-178.pdf
[212] L. Chen, R. Nolan, S. Avadhany. *Thermodynamic analysis of coal to Synthetic Natural Gas process*, 2009 http://www.mit.edu/people/leichen/Thermodynamic_Analysis_of_the_coal_to_SNG_process.pdf
[213] P. Gibson. *Coal to liquids at Sasol.* Kentucky Energy Security Summit, 2007 http://www.caer.uky.edu/podcast/Gibson-KESummitOct2007r.pdf
[214] Source Watch. *Coal-to-liquids in China*. http://www.sourcewatch.org/index.php/Coal-to-Liquids_in_China
[215] M. Chandel, E. Williams. *Synthetic Natural Gas (SNG): Technology, environmental implications, and economics*. Climate Change Policy Partnership, Duke University, 2009 http://www.nicholas.duke.edu/instituteold/climate/carbon-capture-and-storage/natgas
[216] Leucadia National Corporation. *Indiana coal to SNG* http://www.purdue.edu/discoverypark/energy/assets/pdfs/CCTR-12-06-06-JClark.pdf
[217] E. Salehi, W. Nel, S. Save. *Viability of GTL for the North American gas market*. Hydrocarbon Processing, January 2013, 41-48 http://www.hatch.ca/Oil_Gas/Articles/Viability_GTL_NA_Gas_Market.pdf

[218] International Energy Agency. *Medium-term coal market report 2012* http://www.iea.org/W/bookshop/add.aspx?id=436
[219] D.C. Cicero. *Coal-to-liquids in the United States. Status and roadmap*. CTLtec Americas 2008, 2008 http://www.netl.doe.gov/technologies/ccbtl/refshelf/presentations/CTL%20Tec%20Cicero%20June%2008.pdf
[220] Source Watch. *Coal-to-liquids in Australia* http://www.sourcewatch.org/index.php/Coal-to-Liquids_in_Australia
[221] J. Styles. *Liquid fuel from coal*. Parliament of Australia, December 19, 2008 http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BN/0809/LiquidFuel#_ftn32
[222] Source Watch. *Proposed coal plant in the United States*. http://www.sourcewatch.org/index.php/Category:Proposed_coal_plants_in_the_United_States
[223] Source Watch. *Secure Energy Decatur gasification plant* http://www.sourcewatch.org/index.php/Secure_Energy_Decatur_Gasification_Plant
[224] Power Holdings of Illinois. *Southern Illinois coal to SNG*, 2009 http://www.powerholdingsllc.com/SouthernIllinoisCoaltoSNGPresentation.pdf
[225] Source Watch. *Power Holdings Company plant* http://www.sourcewatch.org/index.php/Power_Holdings_Company_plant
[226] Source Watch. *Leucadia* http://www.sourcewatch.org/index.php/Leucadia
[227] Source Watch. *Indiana SNG* http://www.sourcewatch.org/index.php/Indiana_SNG
[228] Source Watch. *Scriba coal gasification plant* http://www.sourcewatch.org/index.php/Scriba_Coal_Gasification_Plant
[229] Source Watch. *South Heart Power Project* http://www.sourcewatch.org/index.php/South_Heart_Power_Project
[230] Source Watch. Mississippi Gasification http://www.sourcewatch.org/index.php/Mississippi_Gasification
[231] Source Watch. *Leucadia Illinois Plant*. http://www.sourcewatch.org/index.php/Leucadia_Illinois_Plant
[232] Source Watch. *NewGas Energy Center*. http://www.sourcewatch.org/index.php/NewGas_Energy_Center
[233] Source Watch. *Freeport plant* http://www.sourcewatch.org/index.php/Freeport_Plant
[234] Source Watch. *Medicine Bow plant* http://www.sourcewatch.org/index.php/Medicine_Bow_Plant
[235] A. Hanna. *Taxpayer-backed loan guarantees for liquid coal: Medicine Bow, Wyoming* http://www.taxpayer.net/images/uploads/downloads/Medicine_Bow_CTL_Facility_Fact_Sheet_September_2012.pdf
[236] J. Fugleberg. *Wyoming coal-to-gasoline plant one of only two under way in U.S.* March 25, 2012 http://trib.com/news/state-and-regional/wyoming-coal-to-gasoline-plant-one-of-only-two-under/article_506b7b4c-1748-50cc-9f4c-9c9daae20b5a.html
[237] R. Edward. *The Medicine Bow coal to gasoline plant comes at too great a risk, too high a cost*. April 9, 2013 http://www.foe.org/news/archives/2013-04-the-medicine-bow-coal-to-gasoline-plant-comes-at-too

[238] Source Watch. *Mingo Project*
http://www.sourcewatch.org/index.php/Mingo_Project
[239] Source Watch. *Rentech Energy Midwest Corporation*
http://www.sourcewatch.org/index.php/Rentech_Energy_Midwest_Corporation
[240] Source Watch. *Belwood coal-to-liquids*
http://www.sourcewatch.org/index.php/Belwood_Coal-to-Liquids
[241] Source Watch. *Rentech's Coal-to-Liquids projects*
http://www.sourcewatch.org/index.php/Rentech#Rentech.27s_Coal-to-Liquids_Projects
[242] Source Watch. *Adams Fork Energy Plant*
http://www.sourcewatch.org/index.php/Adams_Fork_Energy_Plant
[243] Source Watch. *Many Stars coal-to-liquids*
http://www.sourcewatch.org/index.php/Many_Stars_Coal-to-Liquids
[244] Source Watch. *Ambre Energy plant*
http://www.sourcewatch.org/index.php/Ambre_Energy_plant
[245] Source Watch. *Clean Coal Power Operations Coal-to-Liquids plant*
http://www.sourcewatch.org/index.php/Clean_Coal_Power_Operations_Coal-to-Liquids_Plant
[246] Source Watch. *Drummond Coal-to-Liquids plant*
http://www.sourcewatch.org/index.php/Drummond_Coal-to-Liquids_Plant
[247] Source Watch. *Gilberton coal-to-clean-fuels and power project*
http://www.sourcewatch.org/index.php/Gilberton_Coal-to-Clean-Fuels_and_Power_Project
[248] Source Watch. *Ohio River Clean Fuels*
http://www.sourcewatch.org/index.php/Ohio_River_Clean_Fuels
[249] I. Landälv. *Thermochemical developments in Europe*. TCBiomass 2013, Chicago, 2013 http://www.gastechnology.org/tcbiomass2013/tcb2013/01-Landalv-tcbiomass2013-presentation-Thur.pdf
[250] I. Landälv. *Status report on demonstration plants for advanced biofuels production*. 5th Stakeholder Plenary meeting. Brussels, 2013
http://www.biofuelstp.eu/spm5/pres/landalv.pdf
[251] European Biofuels Technology Platform. *Status update of selected demonstration plants*. http://www.biofuelstp.eu/btl.html
[252] *Kemi / Ajos. Second generation biodiesel plant*.
http://www.forestbtl.com/wp-content/uploads/2011/02/Kemi-Ajos-plant-brochure-2.4.2012.pdf
[253] D. Bacovsky, N. Ludwiczek, M. Ognissanto, M. Worgetter. *Status of advanced biofuels demonstration facilities in 2012.* IEA Bioenergy Task 39, 2013
http://demoplants.bioenergy2020.eu/files/Demoplants_Report_Final.pdf
[254] P. Salomonsson. *Final report of the European BioDME Project.* 5th International DME Conference, 2013 http://www.biodme.eu/wp/wp-content/uploads/DME5_BioDME_Salomonsson.pdf
[255] I. Landälv. *Two years experience of the BioDME Project – A complete wood to wheel concept*. TCBiomass 2013, Chicago, 2013
http://www.gastechnology.org/tcbiomass2013/tcb2013/03-Landalv-tcbiomass2013-presentation-Wed.pdf
[256] http://web.abo.fi/fak/tkf/spk/costfp0901/biorefinery_activities_two_tables_-_Table_2_(2).pdf

[257] P. Salomonsson. *BioDME. From wood to wheel*. 7th Asian DME Conference, 2011 http://www.biodme.eu/wp/wp-content/uploads/15Per-Salomonsson.pdf

[258] Chemrec. *The Domsjo Fabriker project* http://www.chemrec.se/Page294.aspx

[259] E. Kempemo. *Domsjo Fabriker to build a gasification plant with Chemrec technology* http://www.chemrec.se/Domsjoe_Fabriker_producing_green_fuels_with_Chemrec.aspx

[260] BioTfueL project. *Targeting the development of second-generation biodiesel and biojet fuels*. www.ifpenergiesnouvelles.com

[261] VärmlandsMetanol AB. *World's first commercial scale biomethanol plant in Hagfors Sweden*, 2012 http://www.varmlandsmetanol.se/dokument/History%20March%2012.pdf

[262] European Biofuels Technology Platform. *Bio-SNG and gasification technologies*. http://www.biofuelstp.eu/bio-sng.html

[263] C.M. van der Meijden, J.W. Konemann, W. Sierhuis, A. van der Drift, G. Rietveld. *Wood to bio-methane demonstration project in the Netherlands*. ECN-M—13-009, 2013 http://www.ecn.nl/docs/library/report/2013/m13009.pdf

[264] A. van der Drift, S. Biollaz, L. Waldheim, R. Rauch, C. Manson-Whitton. *Status and future of bioSNG in Europe*. ECN-L—12-075, 2012 https://www.ecn.nl/publicaties/PdfFetch.aspx?nr=ECN-L--12-075

[265] B. Fredridsson Moller, A. Molin, K. Stahl. *Bio2G. A full-scale reference plant in Sweden for production of bio-SNG (biomethane) based on thermal gasification of biomass.* TCBiomass2013, Chicago, 2013 http://www.gastechnology.org/tcbiomass2013/tcb2013/04-Moller-tcbiomass2013-presentation-Wed.pdf

[266] Goteborg Energi. *GoBiGas builds in two phases* http://gobigas.goteborgenergi.se/En/The_plant

[267] Repotec. *GoBiGas* http://www.repotec.at/index.php/97.html

[268] Goteborg Energi. *Gothenburg biomass gasification project, GoBiGas* http://www.goteborgenergi.se/English/Projects/GoBiGas__Gothenburg_Biomass_Gasification_Project

[269] M. Perrin, O. Guerrini, G. Peureuz, J. Duclos, Y. Kara, B. Marchand, W. George, J. Nguyen. *Green gases from solid biomass. How they could boost the bioenergy applications with a decentralized vision*. TCBiomass2013, Chicago, 2013 http://www.gastechnology.org/tcbiomass2013/tcb2013/07-Perrin-tcbiomass2013-presentation-Wed.pdf

[270] B. Marchand, M. Perrin, Y. Kara, O. Guerrini, G. Peureux, E. George, J. Nguyen. *Gaya Project: 2nd generation biomethane through gasification*. Biomass Valorisation for Energy production, Turin, 2013 http://www.envipark.com/wp-content/blogs.dir/1/files/4-GDF-SUEZ-Marchand.pdf

ECN

Westerduinweg 3
1755 LE Petten
The Netherlands

P.O. Box 1
1755 LG Petten
The Netherlands

Tel + 31 88 515 49 49
info@ ecn.nl
www.ecn.nl