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Performance, cost and emissions of coal-to-liquids (CTLs) plants using low-quality coals under carbon constraints

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HIGHLIGHTS

- ▶ Coal-to-liquids plants using low-quality coals are modeled for performance and cost.
- ▶ Dry-feed and slurry-feed gasifiers modeled in liquids-only and co-production plants.
- ▶ Best option based on performance – dry-feed for both liquids-only and co-production.
- ▶ Performance and cost characteristics deteriorate with coal quality.
- ▶ Performance and cost of CTL vary significantly with coal type and technology choice.

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ABSTRACT

Prior studies of coal-to-liquids (CTLs) processes that produce synthetic transportation fuels from coal have focused mainly on designs using bituminous coal with no or limited constraints on carbon emissions. In this study, plant-level techno-economic models are applied to evaluate the performance, emissions and costs of CTL plants using low quality sub-bituminous coal and lignite as feedstock for both a slurry-feed and dry-feed gasification system. The additional cost of carbon dioxide capture and storage (CCS) is also studied for two plant configurations—a liquids-only plant and a co-production plant that produces both liquids and electricity. The effect of uncertainty and variability of key parameters on the cost of liquids products is also quantified, as well as the effects of a carbon constraint in the form of a price or tax on plant-level CO_2 emissions. For liquids-only plants, net plant efficiency is higher and CO_2 emissions and costs are lower when sub-bituminous coal is used. For both coals, performance of plants with a dry-feed gasifier is better compared to plants with slurry-feed gasifiers, but the costs are comparable to each other, with slurry-feed plants having a minor advantage. A major concern for CTL plants is the high level of CO_2 emissions, the major greenhouse gas linked to global climate change. However, this study shows that for the liquids-only plant most of the CO_2 emissions can be avoided using CCS, with only a small (<1%) increase in capital cost. Depending on the coal type, gasifier type and CO_2 constraint (up to \$25/tonne CO_2), the nominal cost of liquid product ranges from \$75 to \$110/barrel. Parameter uncertainties increase this range to \$50–140/barrel (90% confidence interval). With or without CCS, co-production plants are found to have higher capital costs than liquids-only plants, but produce cheaper liquid products when the electricity is sold at a sufficiently high price (\$50–120/MWh, depending on plant design and carbon constraint). For co-production plants, net plant efficiency, which depends both on coal consumption as well as electricity generation, is higher for plants with a dry-feed gasifier while CO_2 emissions are lower from plants with a slurry-feed gasifier. For both coals, capital cost is lower for plants with dry-feed gasifier, with plants using sub-bituminous coal being cheaper than the ones using lignite. A CO_2 tax of \$25/tonne is not enough to make CCS more economical when the electricity price exceeds about \$80/MWh.

1. Introduction

Coal-to-liquids (CTLs) is a process for producing synthetic transportation fuels from coal, to replace or supplement conventional

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supplies of diesel oil and gasoline derived largely from petroleum. In a commonly used CTL technology, coal is first gasified to produce synthesis gas (or syngas) which is subsequently converted to liquid hydrocarbons like gasoline and diesel in a catalytic Fischer–Tropsch (FT) process [1]. These fuels are very clean in terms of aromatic hydrocarbons and criteria air pollutants such as nitrogen and sulfur oxides. Two general configurations of CTL plants are shown in Fig. 1. In a typical commercial CTL plant (called "liquids-only" in this paper) shown in Fig. 1a, the unconverted syngas from the FT reactor is recycled to the reactor to increase the production of liquids. An alternate "co-production" configuration, shown in Fig. 1b, is possible but not yet commercial. Here unconverted syngas from the FT reactor, instead of being recycled, is combusted in a combined cycle power plant to generate electricity that is sold to the grid. Thus, besides providing liquid fuels, CTL technology can also be used for large-scale electricity generation.

There have been a few recent studies dealing with techno-economic evaluation of CTL plants, analyzing both liquids-only and co-production configurations [2–7]. The general agreement is that CTL plants are highly capital intensive but they can be economically feasible if the crude oil prices remain sufficiently high. Most of these studies considered high-quality bituminous coal as the feedstock while a few of them considered low rank coals, mainly for a liquids-only configuration [8]. More than half the coal used in the US consists of lower quality coals such as sub-bituminous coal and lignite [9]. If CTL plants are built on a large scale, there is likelihood that these lower quality coals would be used (or considered) in addition to bituminous coals. Low rank coals differ significantly from bituminous coals in terms of their composition, properties as well as price. It is important to understand the effect of coal type on the performance, emissions and cost of CTL plants with both liquids-only and co-production configurations.

Previous work by the authors showed that the performance and cost of a CTL plant is also sensitive to the gasification technology used [10]. Thus, two kinds of gasification technologies also are considered in this paper. They differ in the method in which coal is fed to the gasifier – a slurry-feed system (modeled on a GE gasifier design), introduces additional water into the gasifier, while the dry-feed system (modeled on a Shell gasifier design) has less water. Along with differences in gasifier temperature and pressure, the resulting composition of the syngas differs for the two gasifier types.

CO_2 emissions from CTL plants also are a cause of major concern. Coupled with the CO_2 emissions resulting from the combustion of coal-derived liquids (when used as a transportation fuel), liquids derived from coal emit almost twice the CO_2 over the life cycle compared to conventional liquid fuels derived from crude oil [11]. Carbon capture and storage (CCS) technology, in which the captured CO_2 is compressed and transported to a deep geological formation, where it is sequestered, can mitigate most of the plant-level CO_2 emissions. CCS also can be economically feasible if there is a sufficiently high price on carbon emissions. Previous studies have quantified the cost of CCS and the effects of carbon prices for CTL plants using bituminous coals [7,10]. However, there is little work available, on the effects of CO_2 emission constraints on the cost of co-production plants using low-rank coals. Also, there is a lack of detailed economic assessments of a CTL plant which systematically analyze the uncertainties in key parameters affecting the cost of coal liquids, including the effects of possible future carbon constraints.

2. Objectives of this study

In this study, the plant-level techno-economic models are developed to evaluate the performance, emissions and costs of CTL plants using low quality sub-bituminous coal and lignite as feedstock for both a slurry-feed and dry-feed gasification system. The additional cost of CCS, including the effects of carbon constraints, in the form of a price or tax on plant-level CO_2 emissions, is also studied for each plant configuration and fuel type noted above.

3. Methodology

In the techno-economic models, all major components of a CTL plant, including gasification, gas cleanup, FT synthesis and power generation are modeled using the Aspen Plus process simulation software [12]. For a given capacity of plant and specified operating

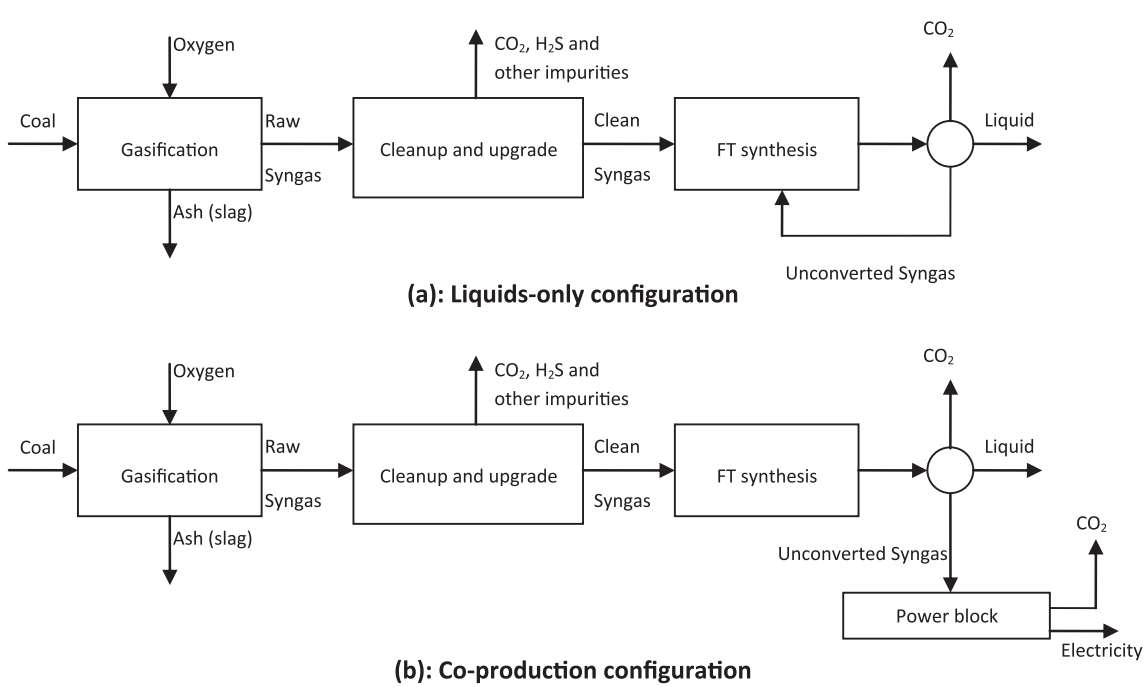

Fig. 1. Two configurations of coal-to-liquids plant: (a) liquids-only, and (b) co-production.

conditions of different components the performance model calculates the mass and energy balances of various streams in the process. The results from the performance model are then input to a cost model which calculates the capital cost (US $/barrel/day) and annual operating costs (US M$/year). These results are combined to calculate the total cost of the liquid product (US $/barrel). A levelized capacity factor of 80% is assumed for base case deterministic calculations. Models for the direct cost of all the process sections except the FT process are obtained from the Integrated Environmental Control Model (IECM) for an IGCC plant [13]. New cost models for the FT process were developed through a regression of cost data from recent literature [4,6]. In this model, the cost of liquid product is calculated as a single value, which simplifies the comparison with crude oil in order to evaluate the economic feasibility of coal-derived liquids. In reality, however, FT liquids are composed of hydrocarbon components in the range of naphtha (heating value 44.5 MJ/kg, density 0.68) and diesel (heating value 44 MJ/kg, density 0.77). The FT cost models are based on the product distribution comprising of roughly 45/55% ratio of naphtha/diesel components. It may also be noted that FT liquids are found to be superior to crude-derived liquids in both combustion performance as well as pollutant emissions [13]. To deal with the uncertainty associated with cost models, which are derived from data in open literature, and also to account for inherent uncertainty and variability in key parameters, an uncertainty and sensitivity analysis, is also performed. Probabilistic uncertainty analysis is used to study the key factors that affect the cost of liquid product, including the price of coal, economic assumptions, technical factors and carbon constraints. All costs in the model are expressed in constant (levelized) 2010 US dollars.

Table 1 shows the ultimate analyses and properties of the two coals used in this study (as-received basis). One is a Wyoming Powder River Basin coal, the other is North Dakota lignite. These coals are selected based on their widespread use for studies of coal-based power generation. The main difference between these coals and higher quality bituminous coals is the large amounts of moisture and/or ash, which lowers the heating value of the coal. For deterministic calculations, a delivered price of $15/tonne is assumed for both coals.

The slurry-feed GE gasifier operates at 1,316 °C and 5.6 MPa and is supplied with oxygen of 95% purity, such that the molar ratio of O_2 to carbon in coal is 0.47 [14]. The remaining 5% is N_2 and Argon. For this gasifier, the concentration of dry solids in coal slurry feed was fixed at 56% for sub-bituminous and 50% for lignite, based on slurryability criteria for different coals [16]. In contrast, the dry-feed Shell gasifier operates at a higher temperature of 1427 °C and a pressure of 4.3 MPa. Oxygen with 95% purity is supplied to the gasifier such that the molar ratio of O_2 to carbon in coal is 0.42. Nitrogen from the air separation unit (ASU) is used to transport pulverized coal to the gasifier [15]. For these dry-feed cases, sub-bituminous and lignite coals are assumed to be dried using waste heat to achieve moisture levels of 6% and 12% respectively, as suggested by the gasifier manufacturer [17]. It may be noted that the commercial use of GE gasifier with low quality coals is not widely found because of problems with the feeding system. However, GE is developing a new coal-feeding system for low quality coals [18].

Table 1
Ultimate analysis (as-received) of low-rank coals used in this study.

Coal Rank	Wyoming PRB Sub-bituminous	ND Lignite Lignite
Ultimate analysis (weight%)		
Ash	5.3	16.0
C	48.2	35.0
H_2	3.3	2.7
N_2	0.7	0.8
Cl	0.0	0.2
S	0.4	1.3
O_2	11.9	11.0
Moisture	30.2	33.0
Higher heating value (MJ/kg)	19.4	14.0

3.1. Modeling of different process areas

This section gives a brief overview of the process models and assumptions used in performance models.

3.1.1. Gasification

The gasification process involves reactions of coal with water (steam or slurry) and oxygen supplied from an air separation unit (ASU). The hot syngas is first cooled in a radiant cooling section to produce high-pressure steam, which is used for electricity generation. Considering the products in a typical gasifier product gas, the following reactions are assumed to take place in the gasifier, for equilibrium thermodynamic calculations [18]:

$$C + 2H_2 \rightarrow CH_4 \quad (1)$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (2)$$

$$2CO + 2O_2 \rightarrow 2CO_2 \quad (3)$$

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad (4)$$

$$S + H_2 \rightarrow H_2S \quad (5)$$

$$N_2 + 3H_2 \rightarrow 2NH_3 \quad (6)$$

$$CO + H_2S \rightarrow COS + H_2 \quad (7)$$

These equations are solved in Aspen Plus for conditions of thermodynamic equilibrium. The gasifier model was then calibrated to match actual syngas composition for each gasifier, as reported by DoE/NETL [15], using the "approach temperature" function in Aspen Plus.

The syngas from each gasifier is cooled and then cleaned using a high-efficiency dual-stage Selexol^{TM} process, combined with a polishing step, to separate H_2S and CO_2 from syngas [4,20]. This clean-up step, combined with polishing, is necessary since FT catalysts are sensitive to sulfur poisoning and the presence of CO_2 is detrimental to FT reactions. Because of this, CO_2 capture is an intrinsic part of a CTL process, although normally the captured CO_2 is vented to the atmosphere [1].

3.1.2. Fischer–Tropsch synthesis

The clean syngas is next fed into a low-temperature (250 °C) slurry-based FT reactor (LTFT) using a Fe-based catalyst to convert the syngas to hydrocarbons of different chain-lengths (Eq. (8)).

$$CO + 2H_2 \rightarrow \frac{1}{n}C_nH_{2n} + H_2O \quad (8)$$

From Eq. (8), it can be seen that the H_2/CO ratio of the FT reactants should be 2. Although coal-derived syngas has a H_2/CO ratio lower than 2, this ratio can be raised via the water gas shift (WGS) reaction (Eq. (2)) that also takes place in the LTFT reactor, producing the additional H_2 required for the FT reactions [5]. It has been reported that for slurry-based LTFT reactors, the minimum H_2/CO ratio required for the syngas input stream is 0.67 [19]. Thus, the extent of the required WGS reaction depends on the inlet H_2/CO ratio, with lower H_2/CO ratio leading to a higher WGS reaction rate [21]. The CO_2 produced in the FT reactor by the WGS reaction is then separated from the unconverted syngas and other gaseous

products using a single-stage Selexol™ system. The temperature of FT reactor is maintained by generating medium pressure steam which is used for power generation.

Though these reactors are more suitable for producing hydrocarbons with higher carbon numbers, a suitably designed refining step can produce liquids in a desired range. The distribution of chain lengths in the products of FT reactor depends on a parameter called the chain growth probability (α) and can be represented by the Anderson–Schulz–Flory (ASF) equation as shown in Eq. (9). The chain growth probability depends on the operating parameters of the FT reactor such as temperature and the catalyst used.

$$W_n = n(1-\alpha)^2\alpha^{n-1} \tag{9}$$

LTFT reactors using Fe-based catalysts are known to have a bimodal product distribution, which means that the value of α changes after a certain carbon number. In this study, for the purposes of modeling, the chain growth probability is assumed to change from $\alpha_1 = 0.85$ to $\alpha_2 = 0.95$ after carbon number 10 [1]. The FT reactor is modeled in Aspen Plus to solve the FT and WGS reactions for a given composition of inlet syngas, fixing the overall CO conversion to 80% per pass. Using the α-values described above, the distribution of carbon numbers in the product stream is determined using Eq. (9) [22].

The gaseous products from the FT reactor include unconverted syngas, CO_2 and lighter hydrocarbons (C1–C4). In the liquids-only configuration, these gases are separated from the liquids and recycled back to the FT reactor after separating CO_2 and reforming the light hydrocarbons to CO and H_2. Some amount of gas is purged to the atmosphere as part of Selexol™ tail gas or from the H_2-recovery section in order to maintain the quantity of inert species in the recycle loop (shown as CO_2 stream after the FT section in Fig. 1). In the liquids-only plant with CCS, a small release of carbon emissions occurs because of this purge gas.

3.1.3. Power generation block

The unconverted syngas from the FT reactor is either recycled back to the reactor (liquids-only configuration) or combusted in a gas turbine (co-production configuration) to generate electricity. The gas turbine modeled here is a GE 7FB design, which operates at a pressure ratio of 18.5 and a firing temperature of 1395 °C (2550 °F). The gas turbine performance model is first calibrated to match the outputs from simple cycle and combined cycle power plants operating on natural gas, as reported by the manufacturer [23]. Calibration of the model involved calculating the isentropic efficiencies of gas turbine and air compressor, as described by Zhu and Frey [24]. Before the gas is combusted, it is mixed with nitrogen from the ASU in order to control NOx emissions while also increasing the mass flow rate through the turbine. After dilution with N_2, the fuel entering the gas turbine combustion chamber has a lower heating value between 4.5 and 4.8 MJ/m^3, as in an IGCC plant [15].

The hot exhaust gases from the gas turbine are cooled in a heat recovery steam generator (HRSG) which generates high pressure superheated steam (9.8 MPa, 538 °C). The HRSG also reheats the intermediate pressure (2.1 MPa) steam to 538 °C. This steam is expanded in a 3-stage (9.8 MPa, 2.1 MPa and 0.28 MPa) steam turbine with intermediate reheating to generate additional electricity. As noted earlier, steam also is generated from raw gas cooling at the gasifier exit and from cooling of the FT reactor. For the co-production cases, steam from this waste heat recovery is sent to the HRSG and used to generate electricity. After supplying all auxiliary load requirements (i.e., power for the ASU, CO_2 capture unit, and in the CCS case, CO_2 compression), net electricity generated is sold to the grid.

In the liquids-only plant, high-pressure and medium-pressure steam from waste heat recovery is sufficient to generate power for all auxiliary load requirements of the plant, including the compressor requirements in the CCS case.

3.1.4. CO_2 capture and sequestration

For both the liquids-only and co-production configurations, concentrated CO_2 streams are available from the gasification and FT synthesis sections. When CCS is employed, this CO_2 is compressed to 150 bar and transported via pipeline for deep geological storage. Since CO_2 is captured as part of the process, the energy penalty for CCS is the additional compressor energy. In a co-production configuration, however, combustion of unconverted syngas in the gas turbine results in additional CO_2 emissions, which are captured using an amine-based post-combustion capture process. For this configuration, the energy penalty of CCS thus includes the energy required for post-combustion CO_2 capture, which includes low-pressure steam needed for solvent regeneration, plus electricity for pumps and other equipment [25]. The two concentrated CO_2 streams from the plant are then combined, compressed and transported to a geological sequestration site.

For the liquids-only configurations, electricity is produced from waste heat in an amount that is just sufficient to meet the internal requirements of the plant (including the compressor energy requirements in the CCS case), with no export to the grid. For the liquids-only plant without CCS, the option of generating additional steam power from waste heat as a co-product for export was not included in our results because the amount of such power is small compared to the net power generated in a co-production plant and thus would not have a significant effect on key results. Although there is potential to generate additional electricity by combusting the gases in the FT recycle loop, this would incur additional costs for a combined cycle power plant. Since sufficient steam power is available to meet all plant requirements, this option is not considered in this paper, consistent with current commercial practice. Since only waste heat is used, the efficiency of the liquids-only plant is not affected, although the capital cost of the plant increases in the CCS case, as discussed below.

4. Case studies results

Both the liquids-only and co-production plant configurations are modeled for a plant producing 50,000 barrels/day of liquid products using LTFT reactor technology, which operates at around 250 °C and 2.5 MPa. Plants with and without CCS are considered.

As noted earlier, the composition of syngas depends on the type of coal and the technology used to gasify it. Table 2 shows the performance model results for the composition of syngas at the gasifier exit for different gasifier and coal combinations. Here, the slurry-feed GE gasifier has a significant fraction of CO_2 while only a small amount of CO_2 is produced in the dry-feed Shell gasifier. The difference in CO_2 concentration is due to the differences in temperature, which affects the CO_2 formation both directly and

Table 2
Composition of syngas at the gasifier exit for different coal types and gasifiers (vol.%).

Coal	Wyoming PRB		ND lignite	
Gasifier	GE	Shell	GE	Shell
CO	25.6	53.4	16.6	48.5
H_2	31.2	26.7	28.8	25.6
CO_2	19.1	5.2	19.7	6.6
H_2O	22.6	6.1	33.1	8.2
Others	1.5	8.6	1.8	11.1

through the WGS reaction. Also, the moisture content in the gasifier products is much higher for slurry-fed systems than the dry-fed systems. As a result, the combined fraction of "FT useful" components – CO and H_2 – is higher in the products of the dry-feed Shell gasifier than in the slurry-feed GE gasifier. As seen in Table 2, about 50% (by volume) of the syngas products from the slurry-feed gasifier are therefore not useful for FT synthesis. This fraction is much lower (20–26%) for the dry-feed system.

Syngas from the gasifier is dried and cleaned to remove CO_2, H_2S and other impurities before sending it to the FT reactor. It can be observed that for both coals, CO content is higher and H_2 content is lower for the higher gasification temperature. In a GE gasifier, more H_2 is produced than CO because of the presence of excess H_2O in the reactants. On the other hand, in the dry-feed Shell gasifier, the volume fraction of CO is higher than that of H_2. For both the gasifiers, the H_2/CO ratio increases with decreasing coal quality. This is because of the higher moisture content in the reactants. For the Shell gasifier cases, raw gas from the gasifier is shifted to bring the H_2/CO ratio up to 0.67, the minimum required for LTFT synthesis [17].

4.1. Analysis of liquids-only plants

Table 3 shows the performance and cost results of using different coals and different gasifiers in a 50,000 barrels/day liquids-only plant. We briefly summarize results for each coal type. Net plant efficiency is defined as the energy output (liquids and electricity) divided by the coal energy input, on a HHV basis.

4.1.1. Sub-bituminous coal cases

Coal consumption of the liquids-only plant using sub-bituminous coal in the GE gasifier is 27.1 kilotonnes/day and CO_2 emissions without CCS are 27.7 kilotonnes/day. Most of this CO_2 can be mitigated using CCS. The overall plant efficiency is 53.2%. The capital cost of the plant without CCS is close to $110,100/barrel/day. This increases marginally by 1.2% with the addition of CCS ($110,500/barrel/day). The cost of liquid product is $75/barrel without CCS, increasing to $82/barrel with CCS. It was observed that the capital cost component is the major contributor to the cost of liquid product. In the future, it is likely that there will be an implicit or explicit cost (or tax) associated with CO_2 emitted into the atmosphere. To illustrate the effect of a carbon price on the product cost, a price of $25/tonne CO_2 was considered. With this price on CO_2 emitted the cost of liquid product increases to $89/barrel, which is higher than the case when CCS is used ($82/barrel).

A liquids-only plant using the dry-feed Shell gasifier uses about 7% less coal (25.4 kilotonnes/day) and emits about 9% less CO_2 (25.3 kilotonnes/day) than the one using the slurry-feed GE gasifier. The overall plant efficiency is 56.8% (HHV), which is higher than the GE case. The main reason for the better performance and economics of a Shell system is the much greater amount of FT-useful components (CO and H_2) produced in the dry-feed gasifier. This translates into lower coal requirements for the production of same amount of useful syngas (CO and H_2). However, the capital cost is slightly higher (2%) compared to the GE case – $112,300/barrel/day without CCS and $113,500/barrel/day with CCS – owing to the much higher unit cost of the dry-feed Shell gasifier. The cost of liquid product is almost the same as with a GE gasifier. Thus, even though the dry-feed system has better performance compared to the slurry-feed system, the costs of both the systems is more or less the same.

4.1.2. Lignite cases

Compared to the sub-bituminous coal, lignite has higher ash and moisture contents. The fraction of solids in the coal slurry is also lower and the moisture content of the dried coal fed to Shell gasifier is higher.

For a liquids-only plant with a GE gasifier, lignite consumption is 40% higher than the sub-bituminous coal case. But CO_2 emissions without CCS increase by less than 2% compared to PRB. This is because of the lower carbon content of lignite. With CCS, CO_2 emissions are even lower than the corresponding sub-bituminous case. The overall plant efficiency using lignite decreases marginally compared to the sub-bituminous coal cases. Capital cost is about 27% higher with lignite, with and without CCS. The cost of liquid product for the plant without CCS is approximately $87/barrel with no CO_2 tax and $101/barrel with a CO_2 price of $25/tonne. Adding CCS increases the cost of liquid product to $93/barrel, which is still cheaper than paying $25/tonne CO_2 without CCS. The cost of liquid products with lignite is much higher than the corresponding costs with sub-bituminous coal because of the predominance of the capital cost component.

Similar to the sub-bituminous cases, the liquids-only plant with Shell gasifier using lignite has better performance but higher costs compared to plants with gasifier using lignite, while both performance and cost are better compared to the corresponding sub-bituminous case. For all cases, it was found that CCS becomes economical at CO_2 prices above about $12/tonne.

Thus, of the two coals studied, the efficiency is higher and CO_2 emissions and costs are lower when sub-bituminous coal is used. For both coals, performance of plants with a dry-feed gasifier is better compared to plants with slurry-feed gasifiers, but the costs are comparable to each other, with slurry-feed plants having a minor advantage.

4.1.3. Uncertainty and sensitivity analysis

In addition to the deterministic results shown above, a probabilistic analysis was conducted to examine the effects of uncertainty and/or variability in key capital and operating cost parameters. The ranges and probability distributions assigned to each cost parameter are shown in Table 4. These distributions reflect the authors' judgment based on data available in the literature, as described in [2]. The uncertainty analysis employed a Monte Carlo simulation technique [26], implemented within the Matlab code for the CTL plant model. Using the random number generator within Matlab,

Table 3
Performance and cost results for a 50,000 barrels/day liquids-only plant using Wyoming PRB and ND lignite as feedstock and GE and Shell gasifier technologies.

Coal type		Sub-bituminous		Lignite	
Gasifier		GE	Shell	GE	Shell
Coal consumption (10^3 tonnes/day, as received)		27.1	25.4	37.6	35.5
Net plant efficiency (% HHV)		53.2	56.8	53.1	56.3
CO_2 emissions (10^3 tonnes/day)	Without CCS	27.7	25.3	28.1	26.0
	With CCS	0.2	0.2	0.1	0.2
Capital cost (10^3 $/barrel/day)	Without CCS	110.1	112.3	133.0	137.4
	With CCS	111.5	113.5	134.4	138.6
Cost of liquid product ($/barrel)	Without CCS + no CO2 tax	75.1	75.8	91.4	93.3
	Without CCS + $25/t CO_2	88.9	88.4	105.5	106.3
	With CCS	81.5	81.7	97.9	99.3

Table 4
Assumed ranges of uncertainties in selected model parameters.

Parameter	Base case value	Distribution
Capital cost parameters		
Direct capital cost (DC)	Calculated from cost model	Triangular (−50%, base case, 50%)
General facilities capital (GFC)	15% of DC	Triangular (10%, 15%, 20%)
Engg and home office (EHO)	10% of DC	Triangular (7%, 10%, 12%)
Process contingency	25% of DC	Triangular (10%, 25%, 40%)
Project contingency	15% of DC	Triangular (10%, 15%, 20%)
Royalty charges	10% of DC	Triangular (7%, 10%, 12%)
Operating cost parameters		
Coal price	\$ 15/tonne	Uniform (10, 20)
CO_2 transport cost	\$ 5/tonne CO_2	Uniform (1.3, 10.4)
CO_2 storage cost	\$ 5/tonne CO_2	Uniform (0.65, 10.4)
Sequestration monitoring cost	\$ 0.25/tonne CO_2	Uniform (0.13, 0.39)
Financial parameters		
Capital recovery factor (CRF)	0.15	Triangular (5%, 15%, 20%)
Plant operation		
Capacity factor	0.80	Triangular (0.75, 0.80, 0.85)

20,000 simulations were performed for each case to generate cumulative probability distributions for cost results.

Fig. 2 shows the effect of uncertainties on the product cost for both coals. These results apply to both the gasifier cases since the product cost is almost the same for both the cases. The overall variation of product cost is almost by a factor of two, showing how important the economic assumptions are in estimating the profitability of a CTL plant. The 90% confidence interval for liquid product cost varies over a large range – \$50–120/barrel for sub-bituminous and \$60–120/barrel for lignite. Unless crude oil prices are consistently higher than this range, investment in CTL plants is fraught with financial risk.

The overall uncertainty was disaggregated to understand the contribution of financial parameters (capital cost and CRF), capacity factor and coal price. Since capital cost contributes most to the cost of liquid products, uncertainties in capital cost parameters, together with the wide variation in the capital recovery factor (CRF reflecting a range from private to public financing), were found to be the cause of most of the variation in product cost.

The effect of plant size on the cost of liquid product from liquids-only plants with CCS using different gasifier and coal combinations is shown in Fig. 3. The size of the plant also has a

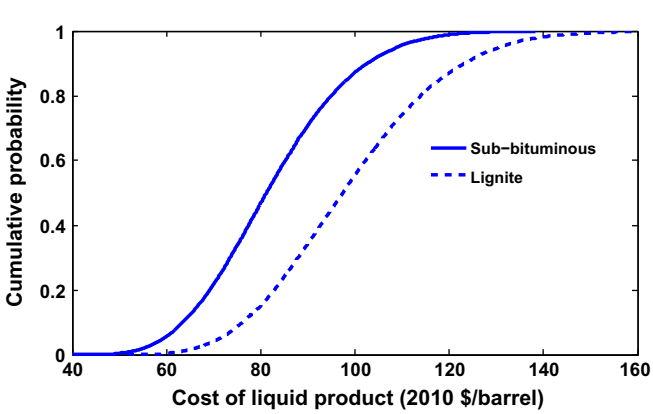

Fig. 2. Effects of uncertainties in different parameters on the cost of liquid product with two coal types. This behavior is the very similar for both gasifiers.

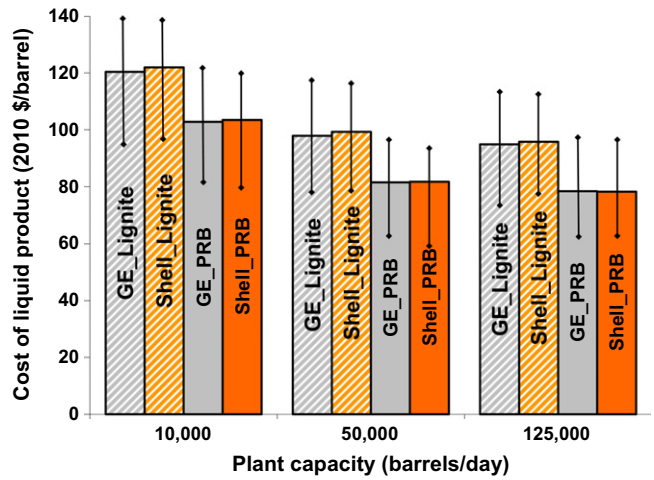

Fig. 3. Graph showing the economy of scale of the cost of liquid products with plant size, for a liquids-only plant with CCS. Error bars show 90% confidence intervals in the cost of liquid products for the uncertainties in Table 4.

notable effect on the cost of liquid products, with the largest plant (125,000 barrels/day) producing liquid products at costs roughly 30% less than the smallest plant (10,000 barrels/day) for the same gasifier and coal type. The variation (90% confidence interval) in the cost of liquid product for the assumed uncertainty ranges is also shown for each plant size. Depending on the plant size, coal and gasifier types, the results show that there can be a wide variation in the cost of liquids produced from coal. Thus, the choice of gasifier technology, coal type, plant size, parameter uncertainties and CO_2 constraints have an effect on the cost of liquid product and hence on the economic feasibility of CTL plants.

4.2. Analysis of the co-production configuration

Here, the techno-economic models are applied to a co-production plant, which generates electricity for sale in addition to producing 50,000 barrels/day of liquid fuel products. Table 5 shows the results for the co-production plant configuration using sub-bituminous coal and lignite.

4.2.1. Sub-bituminous coal results

A co-production CTL plant using sub-bituminous coal in a slurry-feed GE gasifier uses 27% more coal than the corresponding liquids-only plant. In a liquids-only plant, recycling of unconverted syngas to the FT reactor increases the overall efficiency and decreases the coal input required to produce the same amount of liquid products. The CO_2 emissions also increase accordingly, to 42.1 kilotonnes/day, most of which can be mitigated using CCS. In addition to 50,000 barrels/day of liquids, this co-production plant generates a net power output of 875 MW without CCS and 745 MW with CCS. The overall efficiency of this plant is 48.8% without CCS and 47.2% with CCS. These efficiencies are much lower than the corresponding liquids-only cases. The capital cost of the plant without CCS is \$145,500/barrel/day, 30% higher than the corresponding liquids-only case. With CCS, the capital cost increases further by 10%. This is a much greater increase than the liquids-only plant because here a more costly post-combustion capture MEA unit is needed to capture CO_2 from the power plant flue gases. Because of the CH_4 and other hydrocarbon content (C1–C4 gases from the FT reactor) of the feed gas to the power plant, post-combustion CO_2 capture is preferred.

The co-product electricity can be sold to the grid. Assuming an electricity price of \$80/MWh, which reflects average current

Table 5
Performance and cost results for a co-production plant producing 50,000 barrels/day of liquids using Wyoming PRB and ND lignite as feedstock and different gasifier technologies.

Coal type		Sub-bituminous		Lignite	
Gasifier		GE	Shell	GE	Shell
Coal consumption (10^3 tonnes/day, as received)		34.4	31.6	48.0	44.2
Net power output (MW)	Without CCS	875	645	945	650
	With CCS	745	535	815	540
Efficiency (% HHV)	Without CCS	48.8	49.9	49.4	49.5
	With CCS	47.2	48.3	47.7	47.9
CO_2 emissions (10^3 tonnes/day)	Without CCS	42.1	37.2	43.2	38.1
	With CCS	0.9	1.0	0.8	1.0
Capital cost (10^3 \$/barrel/day)	Without CCS	142.5	140.6	173.4	171.4
	With CCS	156.0	152.4	187.6	183.2
For electricity price of \$80/MWh					
Cost of liquid (\$/barrel)	Without CCS no CO_2 tax	62.5	69.3	80.6	89.8
	Without CCS + \$25/t CO_2	83.5	87.9	102.3	108.9
	With CCS no CO_2 tax	84.4	88.7	103.3	109.5
	With CCS + \$25/t CO_2	84.9	89.2	103.7	110.0

market prices in the US, the cost of liquid product is \$63/barrel without CCS. This increases to \$84/barrel when there is a CO_2 tax of \$25/tonne. The addition of CCS increases the cost of liquid product to over \$84/barrel, with a very small rise (<\$1/barrel) with a CO_2 tax, since nearly all of the CO_2 is captured and sequestered. Without CCS, these liquid product prices are lower than the corresponding liquids-only cases because the revenue from co-product electricity sales drives down the cost of liquid products. With CCS, the liquid product costs are higher than the case of a liquids-only plant with CCS. Unlike in the liquids-only plant case, CCS option is more expensive than paying a CO_2 price of \$25/tonne, though only marginally. Higher carbon prices are needed to make CCS much more economical in terms of the cost of liquid product.

Similar to the liquids-only plants, a co-production plant using the dry-feed Shell gasifier is slightly more efficient than the slurry-feed GE case, though the electricity generated is much lower. However, the CO_2 emissions are slightly higher. The capital cost of a Shell-based plant with or without CCS is about 2% lower than the GE-based plant, unlike the trend in the liquids-only cases. In a liquids-only plant, recycling of unconverted syngas to the FT reactor increases the overall efficiency and decreases the coal input required to produce the same amount of liquid products. However, the cost of liquid products from Shell-based co-production plants is higher than the corresponding GE cases, because of the much smaller revenues from electricity sales in the Shell cases.

4.2.2. Lignite results

The results for the plants using lignite as fuel are also shown in Table 5. Compared to the corresponding sub-bituminous cases, efficiency increases marginally for a GE-based plant while it decreases slightly for the Shell-based plant. The marginal increase in the GE case can be attributed to the lower auxiliary load required for CO_2 capture and compression in the FT synthesis section. Because of the high H_2/CO ratio of syngas (Table 2), much lower CO_2 is produced in the FT reactor, thus decreasing the auxiliary energy required to capture and compress CO_2 in the FT synthesis section. This is also the reason for lower overall CO_2 emissions from the GE-based plant compared to the Shell-based plant with CCS. Even though the coal consumption is much higher than the sub-bituminous cases, the CO_2 emissions do not increase correspondingly because of the lower carbon content in lignite compared to sub-bituminous coal. The plant with GE-gasifier produces more electricity compared to the plant using the Shell gasifier, as well as corresponding plant using sub-bituminous coal. However, the Shell-based plant produces nearly the same amount of electricity with lignite as with sub-bituminous coal.

For both the gasifier cases, the capital cost of the lignite-fed plant is approximately 20% higher than the plant using sub-bituminous coal, which can be attributed to the substantial increase in coal consumption. Similar to the sub-bituminous case, the Shell-based plant is cheaper than the GE-based plant with or without CCS. The effect of higher capital costs for lignite-fuelled plants can be seen in the increased cost of liquid products, which are much higher than in the sub-bituminous coal cases. Similar to the sub-bituminous cases, CCS is costlier than paying a CO_2 price of \$25/tonne for the GE case but approximately the same for the Shell case.

Thus for co-production plants, net plant efficiency, which depends both on coal consumption as well as electricity generation, is higher for plants with a dry-feed gasifier while CO_2 emissions are lower from plants with a slurry-feed gasifier. For both coals, capital cost is lower for plants with dry-feed gasifier, with plants using sub-bituminous coal being cheaper than the ones using lignite. On the other hand, plants with slurry-feed gasifier produce cheaper fuels than plants with dry-feed gasifiers, with the sub-bituminous cases cheaper than the lignite cases.

4.3. Co-production vs. liquids-only

As seen above, co-production plants produce significant amounts of electricity which can be sold to the grid. This additional revenue reduces the cost of the primary liquid product. The higher the price at which electricity is sold, the lower is the cost of liquid product. The effect of electricity selling price and CO_2 price on the cost of liquid product is shown in Fig. 4 for the combination of PRB coal and GE gasifier, with and without CCS. Electricity prices at which co-production breaks even with the liquids-only plant (based on the cost of liquid product) are indicated by arrows. With or without CCS, and with or without a CO_2 tax, co-production plants become cheaper than liquids-only plants when the selling price of electricity is in the range of \$50–90/MWh. This range corresponds to current market prices for electricity in the US Those prices can be expected to rise in the future when there are expected to be carbon constraints. Co-production becomes increasingly favorable when the electricity prices are higher. This range, however, is different for other coal and gasifier combinations. Co-production becomes cheaper than the corresponding liquids-only plant when the selling price of electricity is in the range of \$50–100/MWh for a GE-based plant with lignite, \$50–110/MWh for a Shell-based plant with sub-bituminous coal and \$60–130/MWh for a Shell-based plant with lignite.

It can also be seen from Fig. 4 that CCS option is cheaper than paying a CO_2 tax of \$25/tonne only when the electricity price does not exceed about \$80/MWh. For higher electricity prices, the loss of

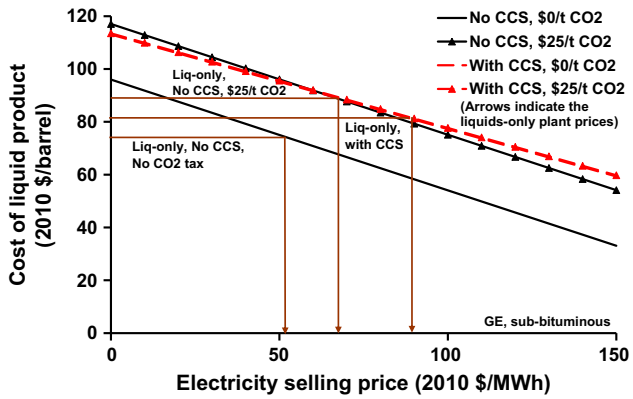

Fig. 4. Effect of electricity selling price on the cost of liquid product for a co-production CTL plant using GE gasifier, with sub-bituminous coal, with and without CCS. Effect of a $25/tonne CO_2 tax on emissions also is shown.

revenue from electricity sales (because of the CCS energy penalty for post-combustion capture) makes CCS uneconomical. This is the case with other gasifier-coal combinations also.

Thus, in general it can be ascertained that though co-production plants produce cheaper liquid products than corresponding liquids-only plants for a sufficiently high electricity price, the breakeven electricity price depending on the gasifier technology and coal combinations. For a particular gasification technology, the breakeven price is lower for the sub-bituminous coal cases compared to the lignite-based plants. For both the coals, the breakeven electricity price is lower for the plant using a slurry-feed gasifier compared to the plant using a dry-feed gasifier. This result is in contrast with the plants using bituminous coal as feedstock, where co-production plants using dry-feed gasification technology is cheaper than the plant using slurry-based gasifier [8]. The electricity price range at which co-production plants using bituminous coal break even (in terms of the cost of liquid product) with the corresponding liquids-only configurations is also much lower than the ranges seen here. This shows that co-production configuration using lower quality coals does not offer the same advantages as when high quality bituminous coal is used. Thus it is clear that the type of coal as well as technology choice significantly affect the performance and cost characteristics of CTL plants.

5. Conclusion

Comprehensive techno-economic models have been developed and applied to evaluate the performance, emissions and costs of CTL plants using low quality sub-bituminous coal and lignite as feedstock, to slurry-feed and dry-feed gasification systems. The results show that performance, cost and emissions of CTL plants vary significantly with the choice of coal and gasification technology.

For liquids-only plants, net plant efficiency is higher and CO_2 emissions and costs are lower when sub-bituminous coal is used. For both coals, performance of plants with a dry-feed gasifier is better compared to plants with slurry-feed gasifiers, but the costs are comparable to each other, with slurry-feed plants having a minor advantage. The case studies presented here showed that the capital requirement for a 50,000 barrels/day liquids-only CTL plants using different coal and gasifier combinations is on the order of $5.0–7 billion, the higher range corresponding to plants using lignite. Depending on the coal type, gasifier type and CO_2 constraint (in the form of CCS or CO_2 tax), the cost of liquid product is in the range of $75–110/barrel. Based on the same fuel price for both coals ($/tonne), the liquid product cost is much higher for lignite-based plants because of the predominance of the capital cost component in the cost of liquid product. CCS becomes the more economical if the CO_2 price/tax is greater than $12/tonne. Plant size also has a significant effect on the cost of liquid products, with the larger plants producing cheaper liquid products because of economies of scale. It was also seen that when uncertainties or variability in cost parameters were considered, the cost of liquid product can vary by nearly a factor of two. Thus, site-specific factors and circumstances can have a large effect on the cost of liquid product and hence on the economic feasibility of CTL plants.

For co-production plants, net plant efficiency, which depends both on coal consumption as well as electricity generation, is higher for plants with a dry-feed gasifier while CO_2 emissions are lower from plants with a slurry-feed gasifier. For both coals, capital cost is lower for plants with dry-feed gasifier, with plants using sub-bituminous coal being cheaper than the ones using lignite. On the other hand, plants with slurry-feed gasifier produce cheaper fuels than plants with dry-feed gasifiers, with the sub-bituminous cases cheaper than the lignite cases. Because of the additional revenue from electricity sales, despite their higher capital costs, co-production plants produce cheaper liquid products compared to liquids-only plants when the electricity is sold at sufficiently high prices ($50–120/MWh, depending on coal type, gasifier technology and carbon constraints). Also, in a co-production plant, a CO_2 tax of $25/tonne is not enough to make CCS more economical when the electricity price exceeds about $80/MWh. Thus it is clear that the type of coal as well as technology choice significantly affect the performance and cost characteristics of CTL plants.

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