

Economics of global gas-to-liquids (GtL) fuels trading based on hybrid PV-Wind power plants

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Abstract

With growing demand for transportation fuels such as diesel and concerns about climate change, this paper introduces a new value chain design for transportation fuels and a respective business case taking into account hybrid PV-Wind power plants. The value chain is based on renewable electricity (RE) converted by power-to-gas (PtG) facilities into synthetic natural gas (SNG), which is finally converted to mainly diesel in gas-to-liquid (GtL) facilities. This RE-diesel can be shipped to everywhere in the world. The calculations for the hybrid PV-Wind power plants, electrolysis and methanation are done based on annual full load hours (FLh). A combination of 5 GW_p single-axis tracking PV and wind power have been applied. Results show that the proposed RE-diesel value chain is competitive for crude oil prices within a minimum price range of about 121 - 191 USD/barrel (0.67 – 1.06 €/l of diesel production cost), depending on assumptions for cost of capital, available oxygen sales and CO₂ emission costs. RE-diesel is competitive with conventional diesel from an economic perspective, while removing environmental concerns. The cost range would be an upper limit for the conventional diesel price in the long-term and RE-diesel can become competitive whenever the fossil fuel prices are higher than the level mentioned and the cost assumptions expected for the year 2030 are achieved. A sensitivity analysis indicates that the RE-PtG-GtL value chain needs to be located at the best complemented solar and wind sites in the world combined with a de-risking strategy and a special focus on mid to long term electrolyzer efficiency improvements. The substitution of fossil fuels by hybrid PV-Wind power plants could create a PV-wind market potential in the order of terawatts.

Keywords: *Hybrid PV-Wind, Power-to-gas (PtG), SNG, Gas-to-liquids (GtL), Power-based fuels, Economics, business model, Argentina*

1. Introduction

The demand for transportation fuels is high in the world and it is growing (IEA, 2014), but fossil fuel resources are limited and we do not know how much affordable crude oil is available for transportation fuels in the long-term (EWG, 2013). Besides, it is still impossible to use electricity in some sectors, like aviation. On the other hand, our planet is facing a dramatic climate change problem (IPCC, 2014), thus even with adequate fossil fuel reserves, CO₂ emissions still would be a limiting constraint in the long-term (Carbon Tracker, 2013; 2015). Methanation (PtG) plants (Breyer et al., 2015) converting electricity into synthetic natural gas (SNG) and Gas-to-Liquids (GtL) plants (Wood et al., 2012) converting natural gas (NG) to liquid fuels (with higher heating value and easier transportation) already exist on a commercial scale.

By using solar photovoltaic (PV) and wind energy based renewable electricity (RE) for PtG and GtL plants, RE-SNG and then RE-diesel can be produced, respectively, to overcome the constraints of resource limitation and CO₂ emissions in the conventional diesel value chain. Figure 1 shows the simplified value chain of the whole process. The main components are: hybrid PV-Wind plants, electrolyzer and methanation plants, CO₂ from air scrubbing units, syngas production unit, Fischer-Tropsch synthesis plant, products upgrading plant and fuels shipping. The integrated system introduces some potentials for utilization of waste energy and by-products. This will also result in the elimination of some sub-components of the major components of the integrated system, such as gas treatment facilities and oxygen production units, which will increase the overall efficiency and will decrease the costs.

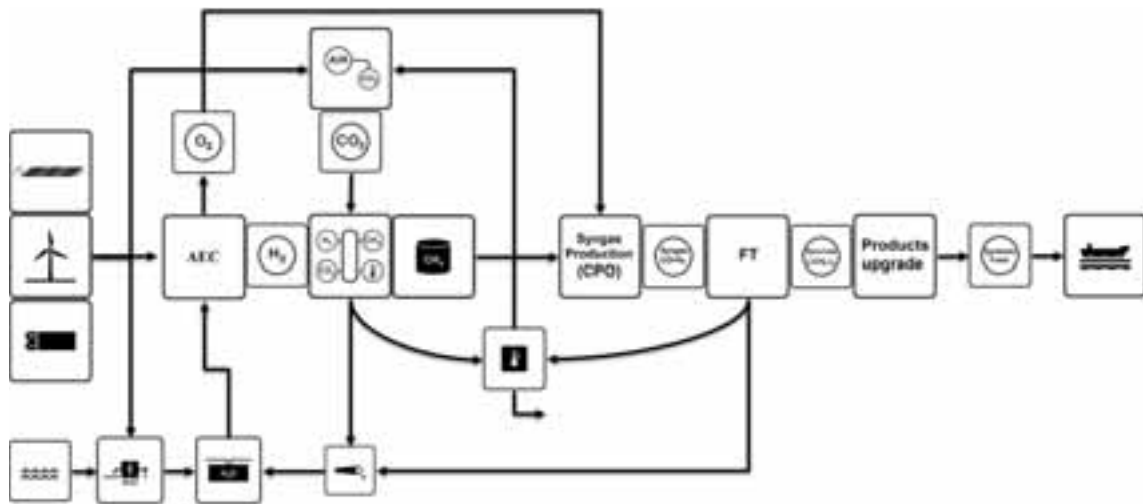


Fig. 1: The hybrid PV-Wind-PtG-GtL value chain. The main components are: hybrid PV-Wind plants, electrolyser and methanation units, CO₂ from air scrubbing units, syngas production unit, Fischer-Tropsch synthesis unit, products upgrading unit and fuels shipping. Abbreviations: alkaline electrolysis (AEC), catalytic partial oxidation (CPO), Fischer-Tropsch (FT) and reverse osmosis desalination (RO).

There are several technical options to produce hydrocarbon fuels based on hybrid PV-wind plants for the transport and mobility sector: mainly RE-PtG, RE-PtG-LNG (Fasihi et al., 2015), RE-power-to-liquids (PtL) and RE-PtG-GtL. All options can be used to buffer and store intermittent renewable electricity. This paper is focused on the RE-PtG-GtL option. Some mobility sectors like aviation, maritime transportation or heavy vehicles cannot be easily operated by batteries or natural gas (NG). Thus even in the long term, liquid hydrocarbon fuels will have a high demand. PtL is the technology to produce liquid fuels directly from renewable electricity, water and CO₂, but this technology is still under development. On the other hand, PtG and GtL technologies are well known and already run on an industrial scale. Thus, in the short term, PtG-GtL seems to be the applicatory method to produce RE-liquid fuels. This paper is an attempt to investigate the costs of this value chain.

2. Methodology

The RE-diesel production system has been divided into two main parts: RE-based SNG production and the GtL downstream value chain. In this paper, two models are used for describing the SNG production for considerations on an annual, but also on an hourly, basis.

The Annual Basis Model represents a hybrid PV-Wind power plant with 5 GW capacity for both single-axis tracking PV and Wind energy. The cost assumptions are based on expected 2030 values and that highly cost competitive components can be sourced for such very large-scale investments. No fixed tilted PV or battery is considered to be part of the plant and the produced electricity and respective calculations are based on annual full load hours (FLh) of the hybrid PV-Wind plants, which can be seen in **Table 1**. The estimate on an annual FLh basis can be surprisingly accurate if applied carefully (Breyer et al., 2011; Pleßmann et al., 2014). The annual basis plants' specification can be seen in **Table 2**. An important piece of information is the level of curtailment, or so-called overlap FLh, i.e. an equivalent of energy which cannot be used. For the special case of hybrid PV-Wind plants, a conservative estimate is 5% (Gerlach et al., 2011). This model will give a rough estimation of a system working with equal PV and wind power capacity.

The Hourly Basis Model uses the optimised combination of PV (fixed-tilted or single-axis tracking), wind power and battery capacity based on an hourly availability of the solar and wind resources to minimize the levelized cost of electricity (LCOE) and cost of SNG. Low cost batteries are added to harvest the excess electricity during overlap times to increase the FLh whenever it is beneficial. More detailed information for this approach is provided by Fasihi et al. (2015).

The full GtL value chain is only analyzed within the annual basis model because with gas storage for output SNG, the GtL plant can work on baseload conditions, which is the cost optimal solution for the GtL value chain.

The equations below have been used to calculate the LCOE of hybrid PV-Wind power plants and the subsequent value chain. Abbreviations: capital expenditures, *capex*, operational expenditures, *opex*, full load hours, *FLh*, fuel

costs, $fuel$, efficiency, η , annuity factor, crf , weighted average cost of capital, $WACC$, lifetime, N , performance ratio, PR , overlap FLh , $overlap$.

$$LCOE_i = \frac{Capex_i \cdot crf + Opex_{i,fix}}{FLh_i} + Opex_{i,var} + \frac{fuel}{\eta_i} \quad (\text{Eq. 1})$$

$$crf = \frac{WACC \cdot (1+WACC)^N}{(1+WACC)^N - 1} \quad (\text{Eq. 2})$$

$$FLh_{PV,el} = PV_{irradiation} \cdot PR \quad (\text{Eq. 3})$$

$$LCOE_{gross} = \frac{Wind_{FLh} \times Wind_{LCOE} + PV_{FLh} \times PV_{LCOE}}{(Wind_{FLh} + PV_{FLh})} \quad (\text{Eq. 4})$$

$$LCOE_{net} = \frac{LCOE_{gross}}{1 - overlap} \quad (\text{Eq. 5})$$

2.1. Power-to-SNG

2.1.1. Hybrid PV-Wind power plant and battery

In this research, hybrid PV-Wind power plants are taken into account as the resource of renewable electricity. The hybrid PV-Wind power plants should be located in the regions of very high FLh to reduce LCOE of power production and subsequently the LCOE of electrolysis and methanation. **Figure 2** shows the FLh for hybrid PV-wind power plant sites in the world, where the best sites are indicated by a red colour coding. In this study, the plant is located in Patagonia, Argentina, which is among the best places in the world for solar and wind resources. The produced RE-based hydrocarbons are assumed to be shipped to Rotterdam in the European Union.

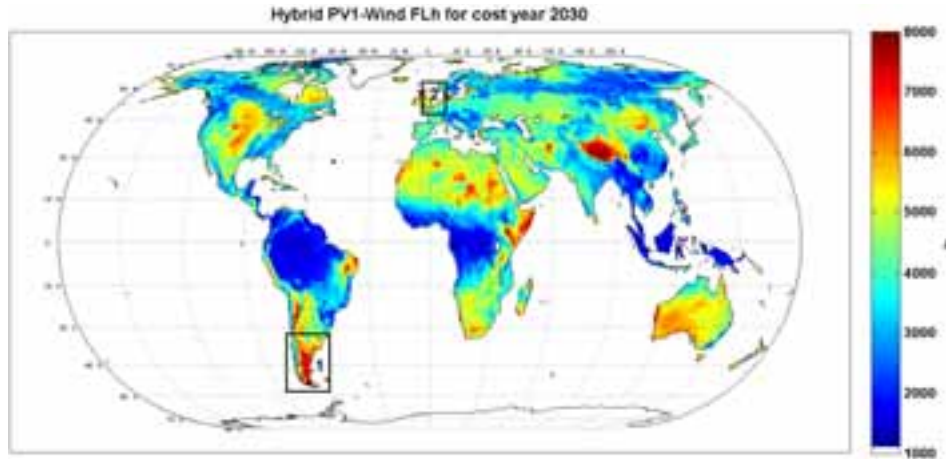


Fig. 2: World's hybrid PV-Wind power plant FLh map. The numbers refer to the place of RE-diesel production (1) and diesel demand (2).

Tab. 1: Hybrid PV-Wind power plant specification. Abbreviations: capital expenditures, $capex$, and operational expenditures, $opex$.

	Unit	Amount		Unit	Amount
<i>PV fixed-tilted</i>			<i>Wind energy</i>		
Capex	€/kWp	500	Capex	€/kW	1000
Opex	% of capex p.a.	1.5	Opex	% of capex p.a.	2
Lifetime	years	35	Lifetime	years	25
<i>PV single-axis tracking</i>			<i>Battery</i>		
Capex	€/kWp	550	Capex	€/kWh _{el}	150
Opex	% of capex p.a.	1.5	Opex	% of capex p.a.	6
Lifetime	years	35	Lifetime	years	10
			Cycle efficiency		90

Tab. 2: Hybrid PV-Wind power plant specification for annual analysis scenario

	Unit	Amount		Unit	Amount
Irradiation (<i>single-axis</i>)	kWh/(m ² ·a)	2410	PV single-axis FLh	h	2000
PV performance ratio (PR)	%	83	Wind FLh	h	5200
PV yield	kWh/kWp	2000	PV and Wind overlap	%	5
			Hybrid PV-Wind FLh	h	6840
<i>Installed capacities</i>					
PV single-axis installed capacity	GWp	5			
Wind installed capacity	GW	5			

2.1.2. *Electrolysis and methanation*

SNG production consists of two main steps: hydrogen production (Eq. 6) and methanation (Eq. 7), which are shown in **Figure 3**. Water and electricity are the inputs for the electrolysis plant, while electrical power converts water to H₂ and O₂ as products of this endothermic process. Generated H₂ and CO₂ obtained from CO₂ from ambient air capture plants are used in the exothermic process of methanation based on the Sabatier reaction to produce SNG (Bandi et al., 1995; Specht et al., 2009; Sterner, 2009).

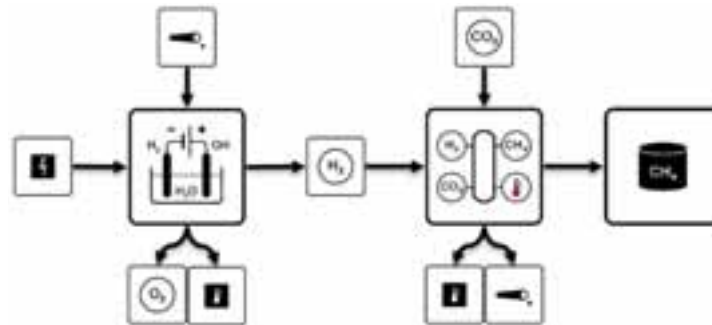


Fig 3: Power-to-Gas (electrolysis and methanation) process.



The alkaline electrolysis cell (AEC) is the well-known and a mature technology for water electrolysis (Millet and Grigoriev, 2013), while the proton exchange membrane electrolysis cell (PEMEC) (Millet and Grigoriev, 2013; Millet, 2015) and solid oxide electrolysis cell (SOEC) (Millet and Grigoriev, 2013; Elder et al., 2015) are technologies in the commercialization phase or still under development. PEMEC shows a slightly better efficiency and shorter startup time in comparison to AEC, which is an advantage while using fluctuating RE as a source of power. SOEC operates at higher temperatures and pressure. The higher temperature offers the chance to replace a part of the electricity needed for the reaction by heat. Furthermore, the produced hydrogen is at a high pressure, which decreases the required energy and cost for compressing hydrogen for the methanation process. However, the startup time of SOEC is higher than AEC and PEMEC. The reported costs for PEMEC and SOEC are higher and in a wider range than those for AEC in 2030. The projected specifications for these three types of electrolyzers and the methanation process are shown in **Tables 3 and 4** (Agora Energiewende, 2014; Breyer et al., 2015; Energinet.dk, 2012; ETOGAS, 2015; FCH JU, 2015; Götz et al., 2015). In addition, there are more uncertainties about the achievement of techno-economic targets for 2030. Therefore, alkaline high pressure electrolysis has been used in our model. Moreover, the lower capex for AEC is very important in achieving optimized SNG cost.

Tab. 3: Electrolyzers' specification. Abbreviations: electricity-to-hydrogen, *EtH₂*, efficiency, *eff*.

	Unit	AEC	PEMEC	SOEC
Capex	€/kW _{el}	319	250-1270	625-100
Opex	% of capex p.a.	3	2-5	2-5
Lifetime	years	30	20	20
EtH ₂ eff. (HHV)	%	86.3	74-89	91-109
Heat demand	% of inlet E	-	-	18-20

The Sabatier reaction is applied in the methanation process and the methanation plant's specification can be seen in **Table 4**.

Tab. 4: Methanation process specification

	Unit	Amount
Capex	€/kW _{H2}	215
Opex	% of capex p.a.	3
Lifetime	years	30
H ₂ -to-SNG eff. (HHV)	%	77.9
H ₂ -to-Heat eff. (HHV)	%	14

2.1.3. CO₂ from ambient air scrubber

CO₂ can be supplied from different sources such as large power plants, or ambient air. To have a sustainable energy system with carbon neutral products, CO₂ needs to be obtained from a sustainable CO₂ source such as a biomass plants with carbon capture and utilization (CCU) or it can be captured from ambient air, which is assumed in this work. The chosen CO₂ source is independent of the location, thus carbon supply would not restrict the best places for the PtG plant.

The CO₂ capture from ambient air approach from Climeworks (Climeworks, 2015a) has been used for the energy system in this work, since between 80-90% of energy needed for this plant can be supplied by heat, rather than electricity (Wurzbacher, 2014). In this case the output heat of the methanation and electrolysis units can be used to fulfill this heat demand, which will increase the overall efficiency of the system. The output heat of alkaline electrolysis and methanation processes, via a heat exchanger with 90% efficiency, perfectly matches the heat demand of the CO₂ capture plant of the required capacity. To capture 1 ton of carbon dioxide out of ambient air, this system requires 1300-1700 kWh_{th} of thermal energy at 100-110°C and 200-250 kWh_{el} electricity (Climeworks, 2015b). The average numbers which have been used in our calculations can be seen in **Table 5**. In case of a lack of internal heat, the heat from the GtL section or heat pumps could be used to deliver the heat needed for the CO₂ capture plant.

Tab. 5: CO₂ capture plant specification

	Unit	Amount
Capex	€/(tCO ₂ ·a)	356
Opex	% of capex p.a.	4
Lifetime	years	30
Electricity demand	kWh _{el} /tCO ₂	225
Heat demand	kWh _{th} /tCO ₂	1500

2.1.4. Water desalination

The steam output of methanation goes through the heat exchanger first, providing the heat for the CO₂ capture plant and the condensed water can be reused in electrolysis. In addition, the output water of the Fischer-Tropsch (FT) process in the GtL section can be recycled and reused in the electrolysis, but these water sources are not enough to supply all the water needed for electrolysis. Thus, a part of water needed for the electrolyzers has to be supplied from an external source. In some regions there might not be enough clean water available for electrolysis. The plant is located along a sea shore, thus seawater reverse osmosis (SWRO) desalination is used, whenever clean water demand for any other activity in the region is more than half of sustainable clean water available in the region (water stress higher than 0.5). Water desalination plant specifications can be found in **Table 6**. More details on RE-powered SWRO desalination plants are provided by Caldera et al. (2015).

PtG and liquefaction plants are built along the sea shore and electricity from hybrid PV-Wind plants is transmitted to the site. In this case, there would be no cost for water piping and pumping from the coast, where the seawater is desalinated. In addition, the GtL plant is located just beside the PtG plant and thus no SNG transportation cost has to be taken into account and the liquid fuels transportation cost to the port will be minimized as well.

Tab. 6: Water desalination and storage plants' specification (Caldera et al., 2015)

	Unit	Amount		Unit	Amount
<i>SWRO Desalination</i>			<i>Water storage</i>		
Capex	€/m ³ ·a)	2.23	Capex	€/m ³ ·a)	0.0074
Opex	% of capex p.a.	4.3	Opex	% of capex p.a.	1.5
Lifetime	years	30	Lifetime		50
Electricity consumption	kWh/m ³	3.0			
Water extraction efficiency	%	45			

2.1.5. Oxygen

Oxygen as a byproduct of electrolysis, has a very important role in the technology used in the GtL process, particularly in the syngas production. The downstream GtL plant needs about 25% of generated oxygen in the PtG plant. This is explained in more detail in Section 2.2.1. *Syngas production*. In case of a potential market, it can also have a very important role in the final cost of produced SNG. The market price of oxygen for industrial purposes can be up to 80 €/t_{O₂} (Breyer et al., 2015). It might be too optimistic to assume that all the produced oxygen could be sold for this price. Moreover, in case of a potential market, oxygen storage and transportation costs have to be applied. To have a rough assumption, considering all these effects, there is no benefit from oxygen in the base scenario. The projection of a maximum 20 €/t_{O₂} benefit from oxygen is assumed in another study for RE-PtG-LNG (Fasihi et al., 2015), when all the produced oxygen was for sale. In the PtG-GtL case, only 75% is available for the potential market. Thus, to have the same impact by the selling of oxygen, the projection of a maximum 30 €/t_{O₂} benefit from unused oxygen has been assumed in the PtG-GtL model.

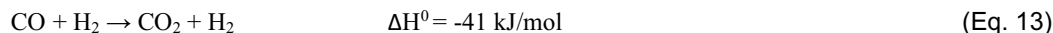
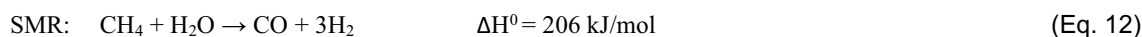
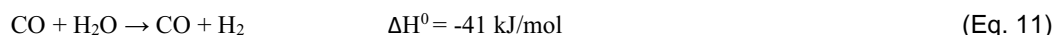
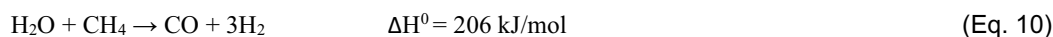
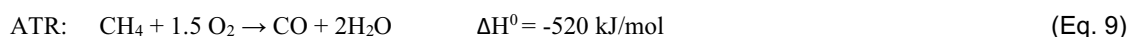
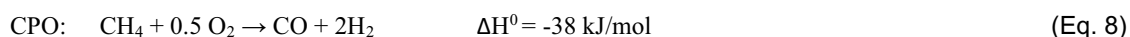
2.2. Gas-to-Liquids

The GtL process provides the opportunity to convert NG or SNG to liquid fuels through a series of chemical reactions. The liquid products are easier and cheaper to transport to remote regions but also internationally, and offer new applications. The GtL process consists of three main steps: *syngas production*, *Fischer-Tropsch Synthesis (FTS)* and *products upgrading* (Wood et al., 2012). Although these process steps are well-known, at the same time, the combined technology is complex and well-protected by limited companies developing them. GtL plants are typically capital intensive and, so far, have been affected by economies of scale which have made them viable only at large scales. Thus, the GtL plants should be built near large scale reserves of NG on a low price level. Recently some companies, such as *Velocys* (Velocys, 2015a), have developed new technologies which have made GtL viable for a lower range of capacities (1500 – 15,000 barrels of crude oil equivalent per day). Until now, there has been a limited number of actual GtL plants in operating mode, which makes it even harder to have good, publically accessible information about these systems on an industrial scale. On the other hand, the quality of input gas, selectivity of the desired products and the regional conditions have led to a development of different minor technologies.

In our model, the feedstock of the GtL plant is RE-SNG produced in a PtG system. This pure and fixed feedstock can decrease the number of determinative variables in this process. This can result in focus on a unique method, which can result in a faster improvement of the technology and decrease in the cost of the system. As an example, no gas treatment would be required in the very first step, which can decrease the cost of the system. The new companies working on affordable, small scale GtL plants can also be a big help for further applications and development of GtL plants.

2.2.1. Syngas production

SNG, as the output of the PtG plant, is the feedstock for the GtL plant. In the first step, SNG needs to be converted to syngas (mixture of CO and H₂) as the feedstock for the FT section. The desired CO:H₂ ratio for FT process is 1:2. There are different reforming technologies to produce syngas from natural gas, including catalytic partial oxidation (CPO) (Eq. 8), auto thermal reforming (ATR) (Eq. 9-11), steam methane reforming (SMR) (Eq. 12, 13) or a combination of these technologies. The main reactions of these processes are as follow (Rostrup-Nielsen, 2000):



Catalytic partial oxidation provides the syngas with the desired CO:H₂ ratio for the FT process, but air separation units (ASU) are needed to produce the required oxygen for this reaction. The cost of an air separation unit is reported to be at least 8% of the capital cost of GtL facilities (Maitlis and Klerk, 2013). Thus, other technologies have also been developed and used by industrial companies in syngas production from natural gas. In our model, pure oxygen is already available as the by-product of electrolysis in the PtG plants. Thus, partial oxidation is the technology that makes the most sense for syngas production within the approach of this paper. The real model would not be this simple and efficient. CO₂ would be produced in the following side reaction (Eq. 14):



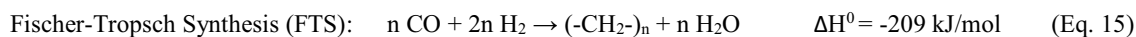
Nothing can be done about the inherent energy loss through water made in the CPO main reaction, but there is a potential to increase the thermal energy efficiency by further advances in technologies to reduce CO₂ formation in the side reaction. This technology is used by the Shell middle distillates synthesis (SMDS) plant in Bintulu, Malaysia, and the carbon to CO conversion is reported to be 94% (Hoek, 2006). The CPO reaction happens at high temperatures, about 1000 °C, and the released heat in this reaction is used to keep it in an autothermal mode (Al-Sayari, 2013) and cannot be used for other purposes.

Table 7: GtL capital expenditures breakdown (Maitlis and Klerk, 2013)

Unit	%
Air Separation Unit	8
Syngas Unit	18
Hydrogen Unit	6
FT Synthesis Unit	24
Upgrading Units	5
Water Disposal Unit	3
Utilities	16
Offsites	20

2.2.2. Fischer-Tropsch synthesis

The Fischer-Tropsch process converts syngas to different chains of synthetic hydrocarbons (-CH₂)_n, which is also known as syncrude (Eq. 15). This reaction is highly exothermic (Graves et al., 2011). In our model, the water produced in this reaction is recycled and reused in the water electrolysis at the PtG section. Also, the released heat can be used for any purpose through a heat exchanger.



This reaction is mainly based on cobalt (Co) or iron (Fe) catalysts, which are operated at different temperatures. The properties of produced syncrude are mainly defined by the chosen catalyst and process conditions. Table 8 shows the different options and their specifications (Klerk, 2014; 2008).

Tab. 8: Characteristics of different types of Fischer-Tropsch synthesis practiced industrially (Klerk, 2014; 2008). Abbreviations: Low Temperature Fischer-Tropsch, LTFT, and High Temperature Fischer-Tropsch, HTFT.

Description	Fe-LTFT	Co-LTFT	Fe-HTFT
Operating temperature (°C)	200-270	170-230	320-360
Operating pressure (MPa)	2-2.5	2-2.5	2-2.5
Water gas shift active	Yes	No	No
Synthetic products composition (mass %):			
Light gas (C ₁ -C ₂)	6	7	23
Liquid petroleum gas (C ₃ -C ₄)	8	5	24
Naphtha (C ₅ -C ₁₀)	12	20	33
Distillate (C ₁₁ -C ₂₂)	20	22	7
Paraffin wax	50	44	-
Aromatic residue	-	-	3
Water-soluble oxygenates	4	2	10

The major products of low temperature Fischer-Tropsch (LTFT) and high temperature Fischer-Tropsch (HTFT) are mainly paraffin and olefin hydrocarbons, respectively. In addition, the products of HTFT contain aromatics which are not desired. HTFT produces a large amount of light gas (C₁-C₂) which is not favourable. In conclusion, although any FT syncrude can be refined to gasoline, jet fuel, diesel fuel and petrochemicals, LTFT seems to be a better option, when aiming for fuels with a longer chain of hydrocarbons, such as diesel.

2.2.3. Products upgrade

The syncrude contains hydrocarbons of different lengths. By adding hydrogen and hydrocracking of long chain syncrude, the hydrocarbons with a desired length can be produced as products in the upgrading unit. Equation 16 shows the simplified reaction at this step. If needed, the hydrogen used in this step can be supplied by water electrolyzer units in the PtG plant.



The GtL final products can include up to 30% wax. Maximizing wax configuration in the output will increase profit, but the demand for wax is much less than diesel. Thus, in a global model, the aim is to maximize the diesel share in the output. The outputs of GtL in some publications are shown in Table 9.

Tab. 9: GtL final products composition (vol%). Abbreviations: liquefied petroleum gas, LPG.

Source	LPG	Naphtha	Middle distillates		Lubes & Wax	Comment
			Jet fuel / Kerosene	Diesel		
Fleisch et al. (2002)		15-25	65-85		0-30	typical GtL
Brown (2013)	5	20	75			
Velocys (2015b)		20	80			
Chedid et al. (2007)	6	26			68	
NPC (2007)		25		70	5	
Khalilpour, Karimi (2012)	5	20		75		
Bao (2010)	3	30		67		
FVV (2013)		15	25	60		Diesel mode
		25	50	25		Kerosene mode

Aiming for the maximum middle distillates share, the numbers provided by (FVV, 2013) have been used for the model of this paper, and represent naphtha, jet fuel and diesel with a share of 15%, 25% and 60%, respectively.

Considering diesel and jet fuel as the target products of this process, the potential revenue of sold by-products from the total costs and therefore the levelised cost of fuel (LCOF) of the target products in the value chain should be investigated. Paraffin wax, as a potential product of the GtL process has a higher financial value than crude oil (Jensen et al., 2013), but it is not in the slot of final products in our model. All products of the GtL process are

a function of the crude oil price, as they compete with refinery products of crude oil. Naphtha has approximately the same market value as crude oil, thus it has no additional effect than the crude oil price on the results (Globova, 2013).

GtL plants benefit a lot from economies of scale, meaning that larger plants would be lower in specific cost. The capex for a typical GtL plant with a capacity of 50,000 barrels per day (bpd) is reported to be 110,000 USD/bbl (Wood et al., 2012). The plant assumed in this paper with an approximate capacity of 26,000 bpd, is on the edge between small scale and large scale plants. *Velocys*, as a manufacturer of small scale GtL plants, reports a capex of 100,000 USD/bbl which is in the range of capex of large scale plants (Velocys, 2015a). As explained in *Section 2.2.1.*, the availability of oxygen for zero marginal cost can reduce the total costs by 8%. Thus, with a USD/€ exchange rate of 1.35 (Tab. 12), the capex of the GtL plant would be about 68 k€/bbl and it is expected to be at the same level for the year 2030.

A lifetime of 25, 25, 30 and 25 years have been reported by Udaeta et al. (2007), Velasco et al. (2010), Wood et al. (2012), (Velocys, 2015b) and FVV (2013) for GtL plants, respectively. According to the project timing (2030), and due to unfailing RE-SNG reserves as the feedstock of the GtL plant, the higher reported lifetime of 30 years should be acceptable. Table 10 shows all the assumptions for the specifications of the GtL plant in the model used in this paper.

Tab. 10: Base case specification of a hypothetical GtL plant assumed for this paper

	Unit	Amount	
Capex	k€/bpd	68	
Opex	% of capex p.a.	3	
Lifetime	years	30	
Availability	%	96	
Energy efficiency	%	65	
Products	naphtha	%	15
	jet fuel	%	25
	diesel	%	60
Heat release	% of inlet SNG	22	

2.2.4. Products shipping

GtL products can be shipped by a product tanker fleet. The deadweight (DW) of large range vessels (LR2) is between 80,000 to 120,000 tons. The ship can carry a weight of approximately 90% of its DW (EIA, 2014b). The shipping specifications are shown in Table 11, assuming a shipping from Patagonia to Rotterdam. The data have been taken from Konovessis (2012), MAN (2013), Sea distances (2015), UNCTAD (2009) and Khalilpour (2012).

Tab. 11: Shipping specification

	Unit	Amount
Capex	m€/ship	48
Opex	% of capex p.a.	3
Lifetime	years	25
Availability	%	95
Ship type	large range 2 (LR2)	-
Ship size	ton (deadweight)	100,000
Speed	knots	14
Charge and discharge time total	days	2
Marine distance	km	13,400

3. Results

3.1. RE-PtG-GtL case study, annual basis model

Integrating all the system's elements offers some chances to increase the overall efficiency. Figure 4 shows the Sankey diagram of the entire system, depicting the energy and material flows within the entire RE-PtG-GtL value chain. The figure is the sample of a system with 1 MWh_{el} specific annual electricity input. As can be seen, the alkaline electrolyzer, at 97%, is the main electricity consuming element, while the excess heat by-product of the electrolyzer and the methanation plant is the main source of energy for the CO₂ capture plant. The heat released in the FT process accounts for 14% of initial electricity and 22% of energy content of inlet SNG to the GtL system. The overall PtG-GtL efficiency of this system, without FT heat utilization, would be 42.5%, while 65% of inlet SNG is converted to liquid fuels in the GtL plant. The 15% naphtha share is finally not available for transport fuels. However, this is no financial burden since it can be sold on the market for an attractive value which should be cost neutral.

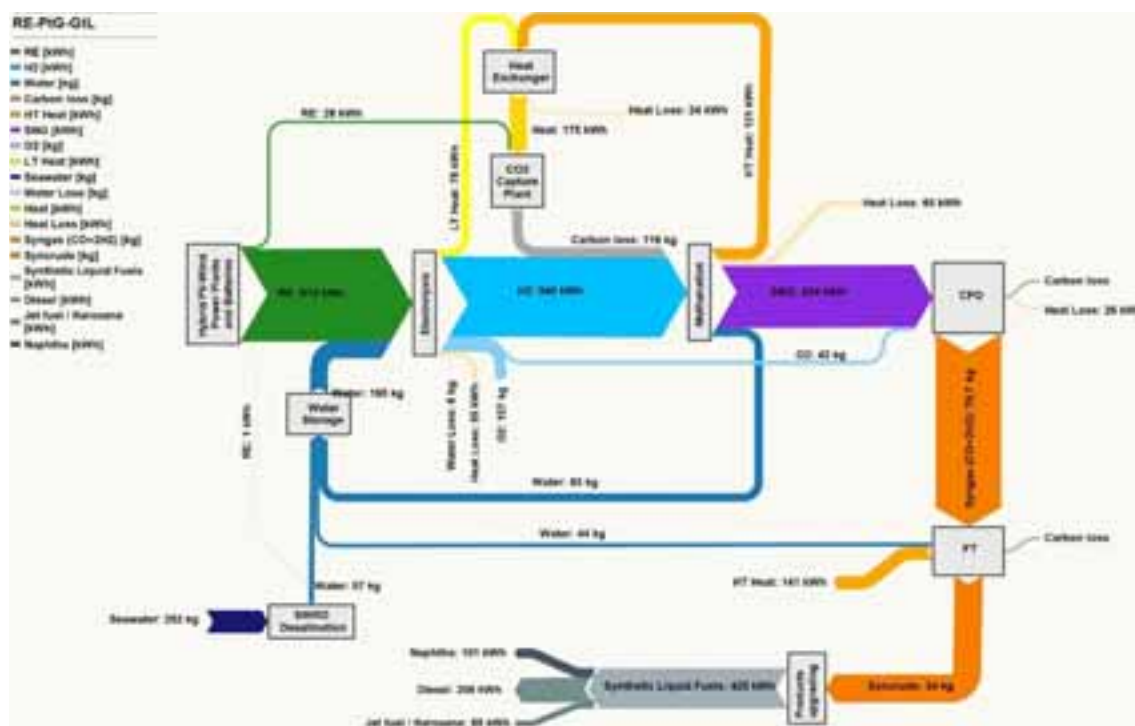


Fig. 4: RE-PtG-GtL energy and material flow diagram.

Unlike RE-SNG, RE-diesel production cost can be a function of crude oil price if there are by-products for selling on the market. All the general assumptions in the calculations of the base case can be found in **Table 12**.

Tab. 12: General assumptions in base case calculations

	Unit	Amount
WACC	%	7
Exchange rate	USD/€	1.35
Brent crude oil price	USD/bbl	80

The LCOE of wind energy and solar PV are 20.35 €/MWh and 25.36 €/MWh, respectively. The hybrid PV-Wind power plant of 5 GW produces 34,688 GWh of electricity per year and the weighted average cost is 22.89 €/MWh. The CO₂ captured from ambient air and the desalinated water cost 40.42 €/tCO₂ and 0.52 €/m³, respectively. A summary of all production costs for the base scenario can be found in **Table 13**.

The diesel produced in the FT-process has different characteristics than the conventional diesel produced by a

petroleum refinery. The term "FT-diesel" is used to emphasize the quality of final product. Although the quality of FT-diesel can differ from plant by plant, in this paper the density (at 20 °C) and higher heating value (HHV) of FT-diesel are assumed to be 766 kg/m³ and 45.471 MJ/kg, respectively (Glebova, 2013; GREET, 2010). On the other hand, the term RE-diesel is used to emphasize the source of primary energy (PE) in diesel production, while referring to the same product.

Table 13: Production cost in base scenario

	Unit	Amount
Renewable Electricity (RE)	€/MWh _{el}	22.89
CO ₂	€/tCO ₂	40.42
Desalinated water	€/m ³	0.52
RE-SNG	€/MWh _{th, gas}	53.31
RE-SNG	USD/MMBtu	20.85
RE-SNG	USD/bbl	120.95
RE-SNG	€/m ³	0.55
RE-PtG-GtL average product at production site	€/MWh _{th}	98.94
FT-diesel at destination	USD/MMBtu	39.13
FT-diesel at destination	€/MWh _{th}	100.03
FT-diesel at destination	€/l	0.97

Figure 5 shows the levelized costs in the RE-diesel value chain with two scenarios for the weighted average cost of capital (WACC): 7% and 5%. RE-diesel cost distribution as a share of the total is not dependent on the WACC. GtL and methanation have the highest share (45.6% and 30.4%, respectively) in the total cost. At 1.1%, shipping has the lowest share in this process. Thus, it is more important to have the plants located in regions of the highest solar and wind potential than in regions close to the target market in order to reduce the final cost.

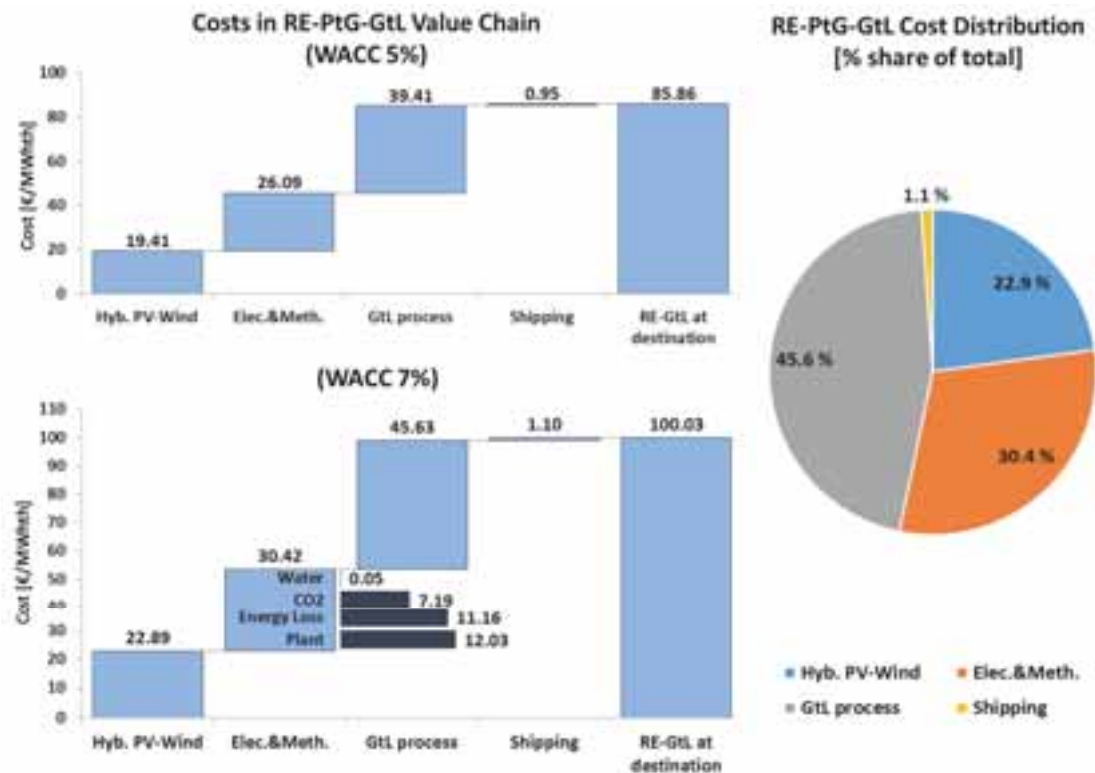


Fig. 5: RE-diesel production cost breakdown for WACC of 5% (top) and 7% (bottom).

Water and CO₂ costs are included in the electrolysis and methanation part of the value chain. With 12.03 €/MWh_{th, gas}, the share of the PtG plant itself in the final cost of methanation is 39.5%, while energy losses in the

electrolysis and exothermic reaction of methanation account for 36.7% of the cost of this process. At 7.19 €/MWh_{th, gas}, the cost of CO₂ has only a 23.6% share in the methanation plant cost, which is due to internal heat utilization for the CO₂ scrubbing process (Fig. 5).

For the assumptions of the base case scenario, the final cost of RE-diesel in Rotterdam would be 100.03 €/MWh_{th}, which is equal to 204.38 USD/bbl, 39.13 USD/MMBtu or 0.97 €/l of diesel. The RE-diesel cost is a function of the crude oil price and refining cost. **Figure 6** shows the historical trends for the crude oil price, refining cost, diesel cost and crude oil cost to diesel price ratio in percentage.

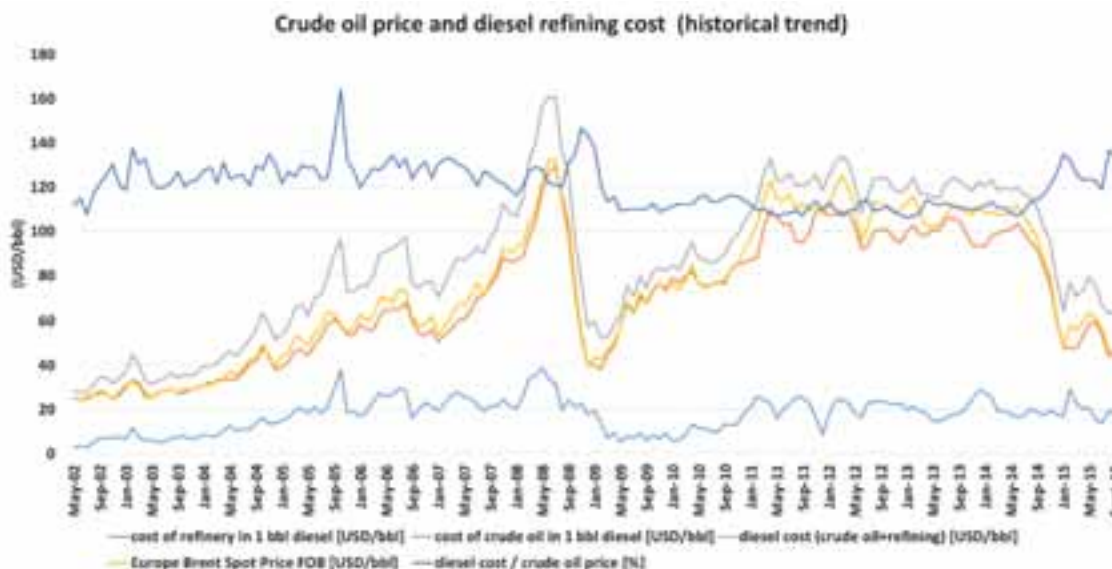


Fig. 6: Crude oil price, diesel refining cost and ratio diesel cost to crude oil price. Data taken from (EIA, 2015).

The long term (13 years) average ratio of one barrel diesel cost (crude oil consumption and refinery cost) to crude oil price is 118.76% and has been taken in this work. The ratio for the full year 2014 was 113.5%. With a crude oil price of 80 USD/bbl, the cost of conventional diesel would be equivalent to 95.01 USD/bbl, 16.38 USD/MMBtu or 0.44 €/l. Thus, the base scenario, accounting for a RE-diesel of 227 USD/bbl, is not directly competitive to the conventional diesel price, but there are some potential game changers:

A) WACC: For a WACC of 7% in the base scenario, the cost of debt and return on equity are 5% and 12%, respectively, for a debt to equity ratio of 70:30. For a WACC of 5%, the corresponding numbers would be 4% and 7%, which could be realized for a risk minimized business case. With this scenario the cost of RE-diesel in Rotterdam could be decreased by 14.2% to 85.86 €/MWh_{th}, 33.59 USD/MMBtu, 194.8 USD/bbl or 0.83 €/l of diesel equivalent. Figure 7 shows the effect of WACC on the final cost.

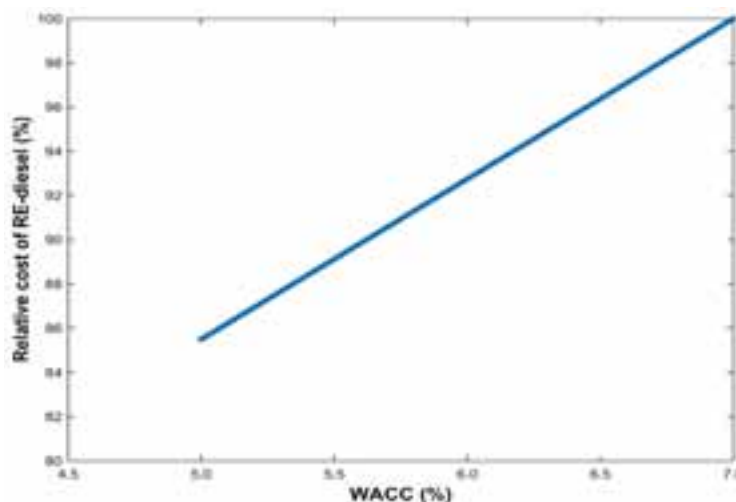


Fig. 7: Effect of WACC on final product's cost in comparison to base case scenario.

B) CO₂ emission cost: CO₂ emission cost for fossil fuels can have a huge impact on the competitiveness of RE-diesel and conventional diesel, as it increases the total cost of fossil fuels. The conventional diesel carbon emissions are 20.2 t/TJ (ton carbon per tera joule) (IPCC, 1996), which is equal to 74.02 t_{CO2}/TJ. The additional cost of CO₂ emissions with a maximum price of 50 €/t_{CO2} on the conventional diesel price can be seen in **Figure 8**. Assuming a crude oil price of 80 USD/bbl and 101.44 USD/bbl as the corresponding price for diesel for the base case (including the cost for refinery), a CO₂ price of up to 50 €/t_{CO2} is equivalent to a price increase of the diesel of 13.48 €/MWh_{th}, 5.27 USD/MMBtu, 30.57 USD/bbl and 0.14 €/l.

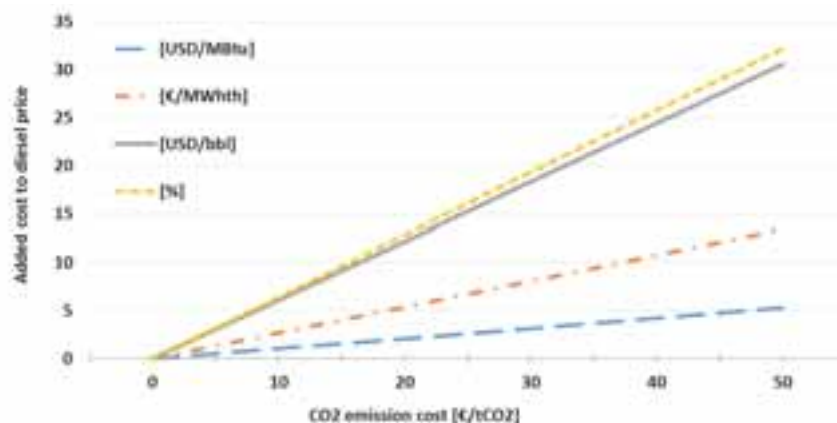


Fig. 8: The additional cost of CO₂ emissions on the conventional diesel price for a CO₂ price of up to 50 €/t_{CO2} in absolute numbers and relative for a basis crude oil price of 80 USD/bbl.

C) Oxygen: 25% of the produced oxygen by the electrolyzer units is used in the syngas production unit, but there is no financial benefit assumed from the rest of oxygen in the base scenario. The projection of a maximum average benefit of 30 €/t_{O2} is shown in **Figure 9**. An oxygen price of up to 30 €/t_{O2} is equivalent to a cost decrease of the RE-diesel of 9.00 €/MWh_{th}, 3.52 USD/MMBtu, 20.42 USD/bbl and 0.08 €/l of diesel, which is equal to a 9.00% decrease in the final cost.

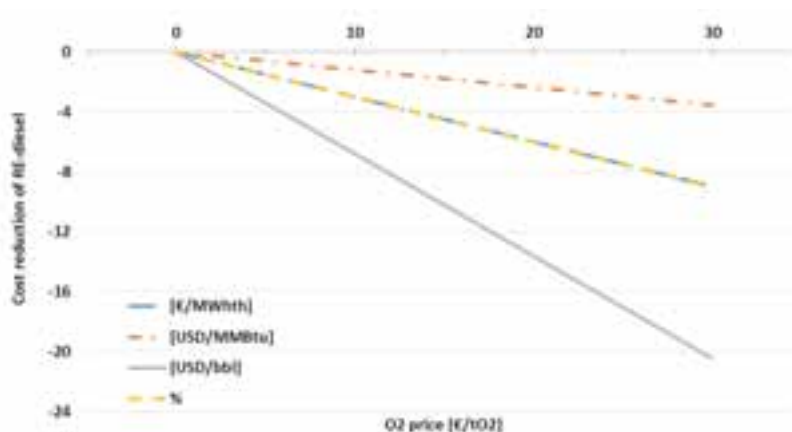


Fig. 9: Effect of oxygen benefit for an oxygen price of up to 30 €/t_{O2} on RE-diesel in absolute numbers and relative ones for the base scenario cost.

As a conclusion, an increase in crude oil price or CO₂ emission cost will increase the cost of conventional diesel, while a profitable business case for O₂ or a reliable business case at a de-risked 5% WACC level can lead to lower cost for RE-diesel cost. The effects of all these potential game changers have been summarised in **Figure 10**. The price of diesel in the EU is based on:

- the global crude oil price as depicted in Figure 10 for a price range of 40 – 200 USD/barrel,
- three scenarios for CO₂ emission cost,
- three scenarios for benefits from O₂ sales, and
- the cost of delivered RE-methane based on two different WACC levels

All projections are for the year 2030.

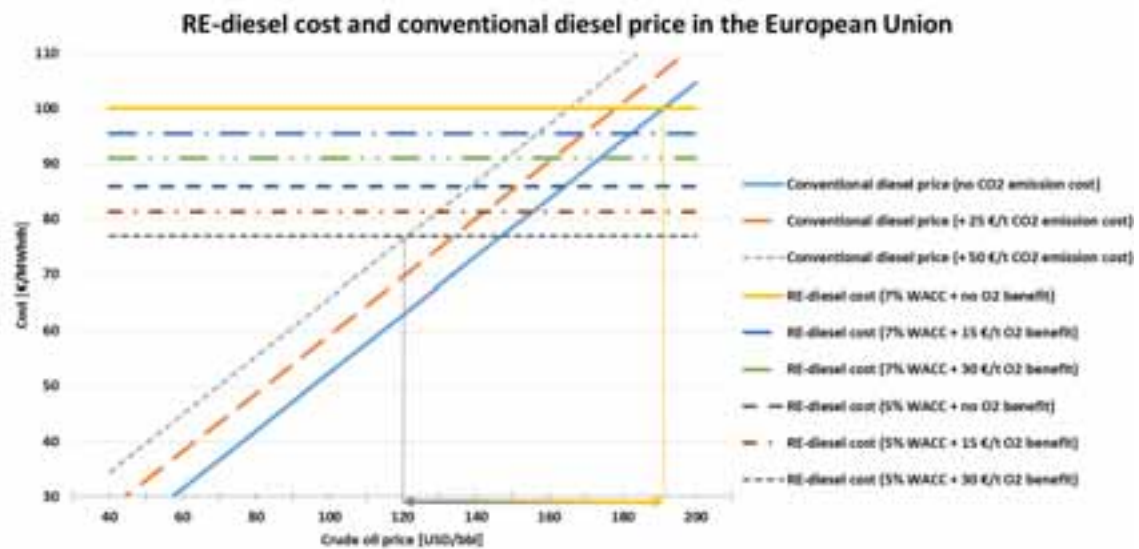


Fig. 10: All possible scenarios for the RE-diesel price in the EU based on the production costs in Patagonia. Reading example: For a crude oil price of 100 USD/bbl the conventional diesel price varies from 66 – 52 €/MWh_{th} (depending on the CO₂ emission costs), while the RE-diesel cost varies from 77 – 100 €/MWh_{th} (depending on WACC and O₂ benefit), i.e. for 121 USD/bbl, 50 €/t_{CO₂}, 5% WACC and 30 €/t_{O₂} the RE-diesel is competitive to the conventional one without any further assumptions.

The first breakeven point can be expected for a produced RE-diesel with a WACC of 5%, CO₂ emission cost of 50 €/t_{CO₂}, accessible oxygen price of 30 €/t_{O₂} and a crude oil price of about 121 USD/bbl. While RE-diesel produced under the base case (WACC of 7%, no CO₂ emission cost and no O₂ sales) can compete with conventional diesel whenever the crude oil price is higher than about 191 USD/bbl. This represents a very high difference and the base case may not easily match with market prices. But the additional assumptions are not far from reality, since a CO₂ emission cost is already applied in some countries (OECD, 2013).

To have a better understanding about the scale of the project, **Table 14** lists the physical and economic aspects of the 5 GW case assumption.

Tab. 14: The annual consumption/ production and economic aspects of the 5 GW case assumption.
Abbreviations: million ton per annum, *MMTPA*, barrel per day, *bpd*.

	Unit	Amount		Unit	Amount
<i>Hybrid PV-Wind power plant</i>			<i>GtL plant</i>		
PV single-axis installed capacity	GW _p	5	Capacity	bpd GTL	27,720
Wind installed capacity	GW	5	Capital expenditure	bn€	1.885
Capital expenditure	bn€	7.8	Diesel production	bbl/year	5,767,900
Hybrid PV-Wind, generation	GWh _{el}	36,000	Jet fuel/ Kerosene production	bbl/year	1,442,000
Hybrid PV-Wind, used	GWh _{el}	34,670	Naphtha production	bbl/year	2,403,300
<i>CO₂ capture plant</i>			<i>Electrolysis and methanation plants</i>		
Capacity	MWh _{el}	131	Capacity	GWh _{el}	4.87
Capital expenditure	m€	36	Capital expenditure	bn€	2.43
CO ₂ production	MMTPA	4.030	SNG production	GWh _{th}	2270
External heat utilization	GWh _{th}	6900	SNG production	MMTPA	1.47
<i>Desalination plant</i>			<i>Shipping</i>		
Capacity	MWh _{el}	5	Shipping volume	bbl/year	9,613,100
Capacity	m ³ /h	505	number of ships	-	1.56
Capital expenditure	m€	10	Capital expenditure	m€	75
Water production	mio m ³	3.5			

The capital expenditure breakdown of the total value chain has been shown in Figure 11. The total capital cost is 13.31 bn€, while the electricity generation solely requires 59% of the capital expenditure. With 0.6% and 0.04% respectively, the capital expenditures of ships and the desalination plant are almost negligible.

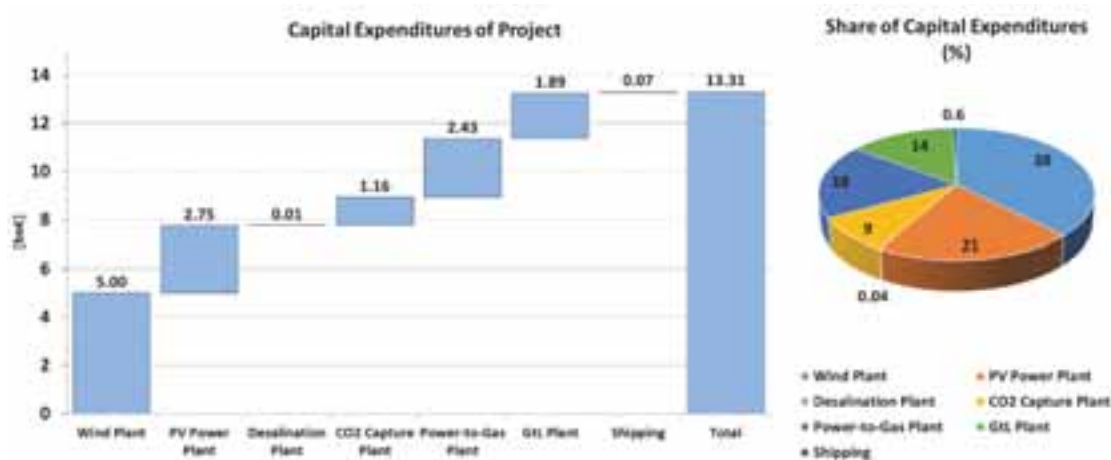


Fig. 11: The capital expenditure breakdown of hybrid PV-Wind-PtG-GtL value chain.

To have an overview on the data available to the public, one should take it into consideration that not even two GtL plants designed by one company are the same. The quality of feedstock, applied technology and desired outputs and the corresponding costs could be quite different case by case. In response to these uncertainties, a series of sensitivity analyses have been done for $\pm 10\%$ change in the capex, efficiency and other inputs of major elements. Figure 12 illustrate these analyses in the categories of economic changes, geographical changes and changes in plant efficiency.

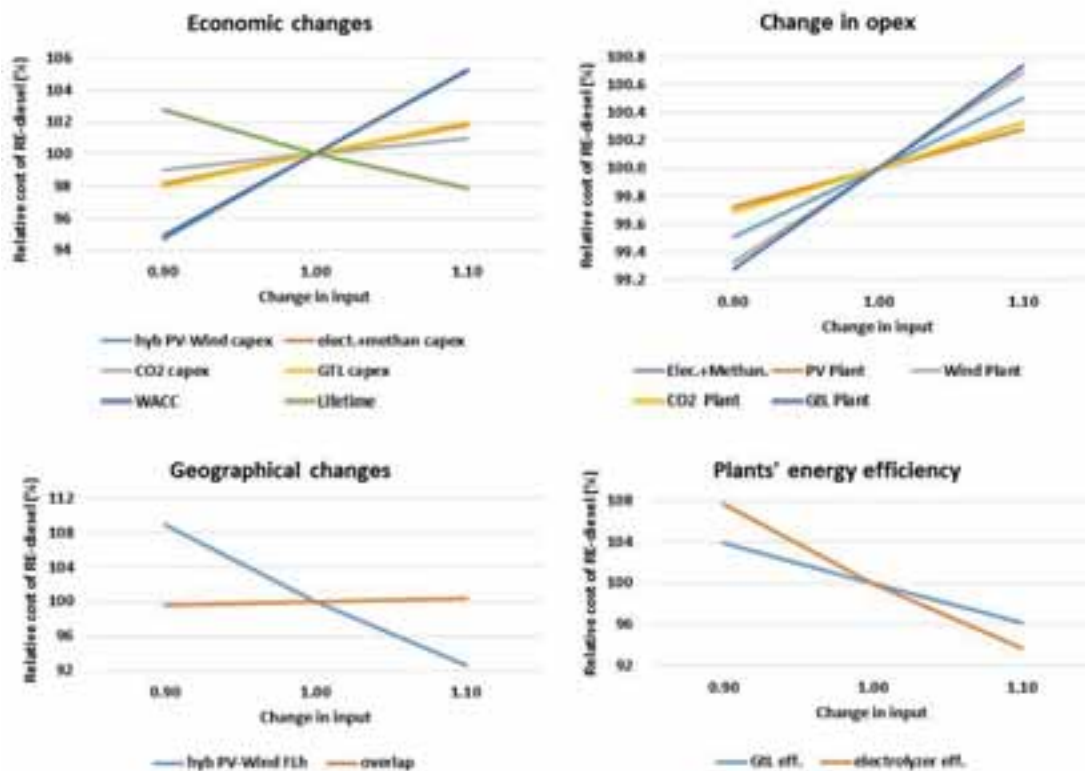


Fig. 12: Sensitivity analysis of input data based on economic changes (top, left), change in plants' opex (top, right), geographical changes (bottom, left) and plants' energy efficiency (bottom, right).

The economic changes graph illustrates that a 10% decrease in the capex of a hybrid PV-Wind power plant will result in a 5.5% decrease in the final LCOF of diesel, which is 2.5 times more than the effect of changes in the capex of the electrolysis or GtL plant. On the other hand, changes in opex shows that no single plant can cause more than a 1% change in the final production cost if the opex divergence is up to 10%. The geographical changes graph shows that a 10% decrease in the FLh of hybrid PV-Wind plant will increase the final LCOF by 9%, while a 10% increase in the efficiency will just result in a 7.5% decrease in the final products' cost. A 10% change in the amount of overlap is a very small number and it does not bring any significant change to the system. As it is expected, plants' energy efficiency analysis shows that a 10% increase in the efficiency of electrolysis and GtL plants would decrease diesel production cost by 6% and 11%, respectively. Thus, while there is no difference in the LCOF of the GtL plant, electrolysis and methanation capex, the GtL plant efficiency has a higher effect on the final product's cost. Summing up, the three final RE-diesel LCOF influencing factors are the full load hours of the hybrid PV-Wind power plant, the electrolyzer efficiency and the WACC for the entire investment. As a consequence, the RE-PtG-GtL value chain needs to be located at the best complemented solar and wind sites in the world combined with a de-risking strategy and a special focus on mid to long term electrolyzer efficiency improvements.

3.2. Optimal RE-PtG-GtL global potential, hourly basis model

The global RE-SNG generation potential has been studied by Fasihi et al. (2015) on an hourly basis. The hourly model enables the best combination of PV (fixed-tilted or single-axis tracking), wind energy and battery capacities based on an hourly availability of the solar and wind resources to minimize the levelized cost of electricity (LCOE) and cost of SNG. Low cost batteries are added to harvest the excess electricity during overlap times to increase the FLh whenever it is beneficial. Applying this approach on all regions in the world with a minimum of 6000 FLh for hybrid PV-Wind power plants and setting an upper limitation of maximum 10% area use by both PV and wind power plants, the global map of optimal electricity and SNG generation potential and the corresponding prices have been shown in Figure 13 (Fasihi et al., 2015).

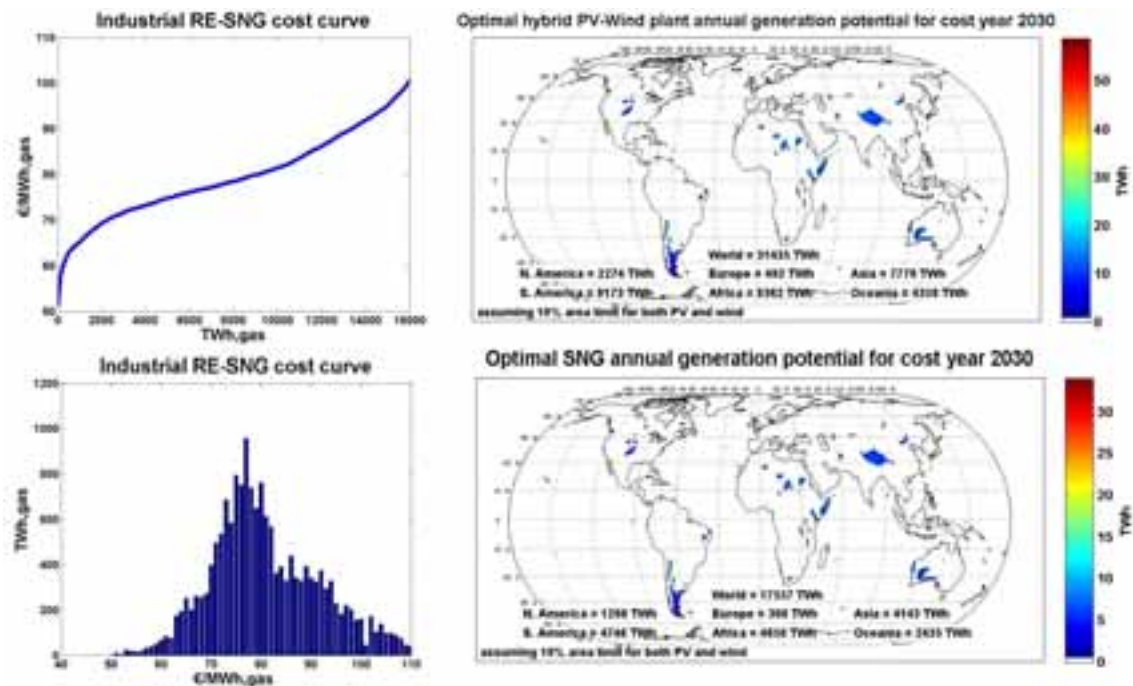


Fig. 13: Optimal hybrid PV-Wind plant annual electricity generation potential (top, right), optimal PtG plant annual SNG generation potential (bottom, right) and SNG cost curve for cost optimized SNG generation in a cumulative (top, left) and a spectral (bottom, right) distribution for the cost year 2030.

Figure 13 illustrates that the generation potential for PtG is less than the electricity generation, which is due to the electricity consumption in the desalination and CO₂ capture plant, and efficiency losses in the PtG plant and power transmission lines. The global annual optimal electricity and SNG production potential are about 31,400 TWh_{el} and 17,600 TWh_{th, gas}, respectively. More SNG could be produced in South America (4,750 TWh_{th, gas}), while the hybrid PV-Wind power plant generation in Africa (8,360 TWh_{el}) is comparable to the potential of South

America (8170 TWh_{el}). Europe has the lowest electricity and SNG production. But with 62.6%, it has the highest electricity to SNG conversion rate among all continents. With respect to global production numbers in the figure, the average electricity to SNG conversion rate can be estimated to be about 56%.

Based on Figure 13, the global optimal SNG potential is about 17,560 TWh_{th,gas}, which results by applying a GtL efficiency of 65% at a production of about 11,410 TWh_{th,fuel} GtL products. This is equal to about 7,540 million barrel GtL products. Figure 14 illustrates the GtL industrial cost curve for global optimal SNG production as feedstock.

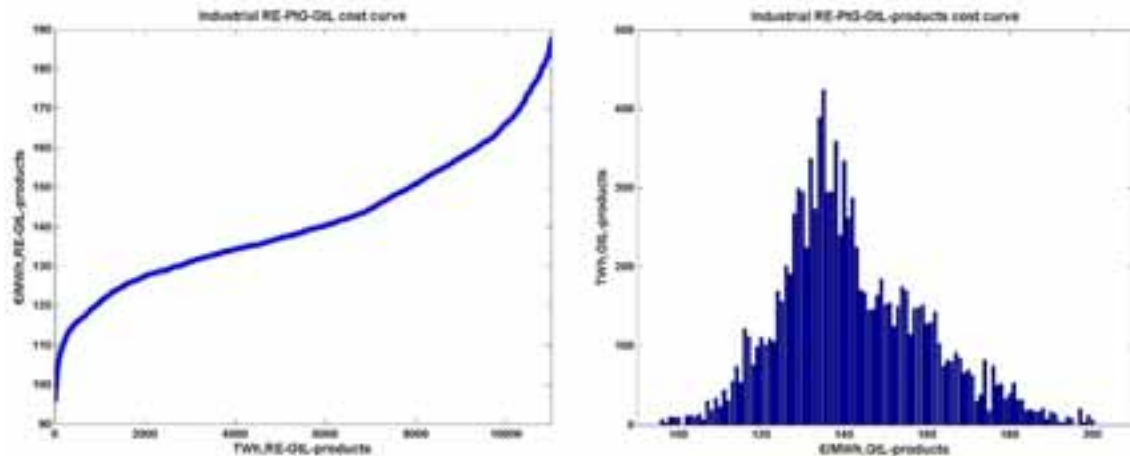


Fig. 14: GtL industrial cost curve for cost optimized GtL production based on RE-PtG in a cumulative (left) and a spectral (right) distribution for the cost year 2030.

The global GtL plants with an inlet SNG cost range of 50 to 100 €/MWh_{th,gas} will result in production costs of RE-diesel in the range of 93.8 to 170.8 €/MWh_{th,fuel}, equal to 212.9 to 387.5 USD/bbl or 0.91 to 1.66 €/l.

4. Conclusion

Due to their emissions, there is no place for fossil fuels in a fully sustainable energy system. On the other hand, a full substitution of fossil fuels by renewable electricity is not possible, as electricity cannot be directly used in some sectors such as aviation or heavy vehicles in all cases. Thus, renewable electricity based fuels are essential to fulfill this demand. The RE-SNG can be further converted to RE-diesel and other fuels in a liquid phase in GtL plants. Modelling an energy system without fossil fuels, the carbon source of this process cannot be from the flue gas of power plants fired by fossil fuels. Moreover, in a global scale energy system, the carbon source should be accessible wherever the renewable power is available. To have a carbon neutral product, CO₂ needed for this process should be captured from ambient air and water desalination should be applied whenever there is a certain levels of water stress in the region. All the technologies for this energy system already exist on a commercial scale and it can become operational whenever investors decide to go for it. All this being said, the system cannot run if the final product is not cost competitive.

This study shows that, with about a 191 USD per oil equivalent barrel, RE-diesel (produced in the RE-PtG-GtL chain) costs more than conventional fossil diesel in today's market. But this price difference is not like a dead end for this energy system. There are different factors which can improve the competitiveness of RE-diesel with conventional fossil diesel in the long term and not all of these factors are internal issues related to this energy system.

- The crude oil price is the very first factor. The long term change in the crude oil price is a function of production cost, production and consumption rate, reserves and political issues. On the other hand, in the short term and as long as production cost of RE-diesel is higher than the production cost of conventional fossil diesel, RE-diesel can be kept away from the market if the crude oil price is set less than RE-diesel production cost. But in the long term, when the crude oil reserves are not sufficient to cover the demand, then the market is likely to follow the RE-diesel production cost.
- Environmental concerns and fuel quality will put additional costs on the conventional fossil diesel price.

CO₂ emission cost has been already set in some countries. Moreover, the standards for fuel quality may rise to a limit at which conventional diesel cannot be produced at that quality anymore. In that case, carbon-neutral and sulphur-free RE-FT-diesel can be considered as one of the main substitutions, also for a production cost 50-100% higher than conventional fossil diesel.

- The by-products of the RE-PtG-GtL value chain can play a significant role in some regional cases, if not globally. A RE-PtG-GtL plant located in a region with high demand for oxygen can decrease the production cost of diesel by 20%. Thus, this system can still run for some special cases, if not globally.
- The other regional effect would be the risk of investment. The impact of de-risking measures have been found to be of high relevance for the economics, since reduced risks which could decrease the WACC from 7% to 5% would reduce the production cost throughout the entire value chain by about 14.2%.
- The heating value of released heat in the FT process is equal to 14% of inlet electricity to the system. A permanent (not seasonal) plan for monetizing this heat can significantly increase the overall efficiency and would decrease the costs.
- Last but not least, a revised technical system design with the same inputs and outputs might result in lower production cost. This is due to the fact that the current system cost breakdown shows that about ¾ of production cost is related to the PtG-GtL section and only 25% is related to the cost of electricity. As an example, eliminating the SNG production step in this energy system and focusing on direct production of RE-diesel from water and CO₂ will increase the efficiency, which might decrease the production cost further. But so far, PtL technology has been operating on a laboratory and pre-commercial scale only and the capex for this process is still high. Thus, it depends on the advances in the technology and the balance between increase in the efficiency and capex and their effects on the production cost. A cost comparison among these different routes is needed for a better understanding of the most promising options.

In conclusion, the external factors can have a strong impact on the competitiveness of the RE-PtG-GtL system and in a beneficial combination they can reduce the cost of RE-diesel from the aforementioned 191 USD per oil equivalent barrel to about 121 USD, which had been a crude oil price level for already some years in the recent past (BP, 2015). These results have a significant impact on the discussions of the energy transformation towards sustainability ahead. If not concurring with the market, the hybrid PV-Wind-RE-PtG-GtL system could set an upper limit for fossil fuel prices, globally. It would also further increase the demand for solar PV systems, wind turbines, water electrolyzers, methanation plants and CO₂ capture plants. The additional market for solar PV and wind energy can be estimated to be in the terawatt scale. This potentially huge market itself would further reduce production costs and increase research and development investments in the field for more efficient technologies.

Acknowledgements

The authors gratefully acknowledge the public financing of Tekes, the Finnish Funding Agency for Innovation, for the 'Neo-Carbon Energy' project under the number 40101/14. The first author thanks the Gas Fund for the valuable scholarship. We also thank Michael Child for proofreading.

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