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Techno-economic evaluation of retrofitting power-to-methanol: grid-connected energy arbitrage vs standalone renewable energy

Siphesihle Mbatha^{a,b,*}, Payam G. Panah^c, Xiaoti Cui^c, Paulo Debiagi^d, Benoit Louis^e,
 Nicholas M. Musyoka^{d,*}, Raymond C. Everson^{b,1}, Ksenia Parkhomenko^e,
 Henrietta W. Langmi^f

^a HySA Infrastructure Centre of Competence, Centre for Nanostructures and Advanced Materials (CeNAM), Chemicals Cluster, Council for Scientific and Industrial Research (CSIR), Pretoria 0001, South Africa

^b Centre of Excellence in Carbon-Based Fuels, School of Chemical and Minerals Engineering, Faculty of Engineering, North-West University, Private Bag X6001, Potchefstroom 2531, South Africa

^c Department of Energy, Aalborg University, Pontoppidanstr. 111, 9220 Aalborg, Denmark

^d Nottingham Ningbo China Beacons of Excellence Research and Innovation Institute, University of Nottingham Ningbo China, Ningbo 315100, PR China

^e Institute of Chemistry and Processes for Energy, Environment and Health (ICPEES), UMR 7515 CNRS-University of Strasbourg, 25 rue Becquerel, Strasbourg 67087 Cedex 02, France

^f Department of Chemistry, University of Pretoria, Private Bag X20, Hatfield 0028, South Africa

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ABSTRACT

The power-to-methanol (PtMeOH) will play a crucial role as a form of renewable chemical energy storage. In this paper, PtMeOH techno-economics are assessed using the promising configuration from the previous work (Mbatha et al. [1]). This study evaluated the effect of parameters such as the CO₂ emission tax, electricity price, and CAPEX reduction on the product methanol economic parity with respect to a reference case. Superior to previous economic studies, a scenario where an existing methanol synthesis infrastructure is 100 % retrofitted with the promising electrolyser is assessed in terms of its economics and the associated economic parity. The volatile South African electricity market is considered as a case study. The sensitivity of the PtMeOH and green H₂ profitability are checked. Grid-connected and standalone renewable energy PtMeOH scenarios are assessed. Foremost, generalisable effect trends of these parameters on the net present value (NPV) and the levelized cost of methanol (LCOMeOH) and H₂ (LCOH₂) are discussed. The results show that economic parity of H₂ (LCOH₂ = current selling price = 4.06 €/kg) can be reached with an electricity price of 30 €/MWh and 70 % of the CAPEX. While the LCOMeOH will still be above 2 €/kg at 80 % of the CAPEX and electricity price of 20 €/MWh. This indicates that even if the CAPEX reduces to 20 % of its original in this study, and the electricity price reduces to about 20 €/MWh, the LCOMeOH will still not reach economic parity (LCOMeOH > current selling price = 0.44 €/kg). The results show that to make the retrofitted plant, with a minimum of 20 years of life span, profitable, a feasible reduction in the electricity price to below 10 €/MWh along with favourable incentives such as CO₂ credit and reduction in CAPEX, particularly that of the electrolyser, and treatment of the PtMeOH as a multiproduct plant will be required.

1. Introduction

The ongoing wars and the recent global pandemic have posed significant uncertainty in the future of energy supply and increased the need for its diversification [1]. Most countries are looking at localising a large share of their energy supply by reducing their energy and fuel

imports [1]. To serve their energy markets, electrification and fuels are two options. Renewable energy offers an opportunity for diversification of the energy supply. Despite the growing interest in electrification using renewable energy sources, fuels still contribute a large share of the global energy demand. For example, in 2021, fuel contributed 76 % of the total global energy consumption [2].

Although renewable and nuclear resources are targeted to reduce

* Corresponding authors.

E-mail addresses: siphe.mbatha94@gmail.com (S. Mbatha), Nicholas.Musyoka@nottingham.edu.cn (N. M. Musyoka).

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Nomenclature

Symbol Meaning

AWE	Alkaline-water based electrolyser
BOP	Balance of plant
CAPEX	Capital Expenditure
CEPCI	Chemical engineering plant cost index
CO ₂ -eq	CO ₂ - equivalent
CCS	Carbon capture and storage
CRF	Capital cost recovery factor
DAM	Day ahead market
ΔHr	Heat of reaction
ITOU	Industrial time of use
LHV	Lower heating value
MeOH	Methanol
MPSP	Minimum product selling price
MW	Megawatt
NPV	Net present value

NPVH2	Net present value of hydrogen
NPVMeOH	Net present value of methanol
PPA	Power purchase agreement
PtMeOH	Power to methanol
PEM	Polymer-exchange membrane
PV	Photovoltaic
LCO	Levelized cost
LCOH2	Levelized cost of hydrogen
LCOMeOH	Levelized cost of methanol
OPEX	Operating Expenditure
RTM	Real time market
RPLUG	Plug flow reactor
SOEC	Solid oxide electrolyser
TAC	Total annual cost
TEA	Techno-Economic Analysis
TRL	Technology readiness level
WACC	Weighted average cost of capital

fuels in the electricity production sector, the hydrocarbons will still contribute a large share, between 74 % and 57 % of mid-century energy supply as per the Stated Policies and Announced Pledges scenarios, respectively, as predicted in the IEA World Energy Outlook [2]. Medium-term market outlooks also indicated the mild growth in oil [3], gas [4], and coal [5] demand, pointing to the Stated Policies pathway as the highly probable scenario in the future [2]. Renewable energy-derived fuels in the form of chemical energy storage will improve the effectiveness of the energy transition to intermittent renewable energy resources and help to diversify the energy supply, hence taking advantage of the existing infrastructure in areas where new transmission facilities may be challenging to implement. New transmission facilities and grid expansions to accommodate intermittent renewable energy may be dampened by the implementation of chemical energy storage. As a form of renewable chemical energy storage, power to methanol (PtMeOH) promises more than its alternatives. Indeed, methanol has a well-established market and infrastructure with a variety of uses that offers potential for further processing as a bulk chemical to other hydrocarbons.

Willing to turn PtMeOH into an effective solution, it remains imperative that the product methanol selling price is comparable to that of the existing fossil fuel derived methanol as a benchmark or at least a reasonable premium is applied and accepted by markets. Several studies have investigated the techno-economics of this process either based on the current market conditions or future market prices. However, most studies are focused on deterministic economic analysis, and some consider sensitivity analysis as part of their investigation. These studies either do not quantify the uncertainty involved in the economic parameters or treat it rather briefly by only performing the single-parameter sensitivity study [2]. The investment decisions for the power to methanol are difficult to make with a lack of general understanding of the influence of the key parameters on the process's economic viability. This paper contributes with offering these generalisable effect trend and perform sensitivity on a combination of parameters to assess the feasible regions.

1.1. Deterministic focused techno-economic analysis with sensitivity considerations

PtMeOH via CO₂ utilisation and with green-H₂ generated from using renewable energy resources such as wind and solar via electrolysis route is of interest [6]. Recent studies have looked into the techno-economics of PtMeOH integrated with alkaline water-based electrolyser (AWE), solid oxide electrolysers (SOEC), and polymer exchange membrane

(PEM), as promising electrolysis technologies [6–14]. Many studies have assessed the techno-economic viability of the PtMeOH [8 – 15]. These studies pointed out the high electricity price and demand, high H₂ production and the electrolyser CAPEX costs as the major factors limiting the techno-economic viability [8]. Perez-Forbes et al. [11] investigated the economics of the conventional MeOH production process using the itemized cost estimation and profitability analysis and deduced that the MeOH production break-even at 854 \$ ton⁻¹. Recently, Nizami & Purwanto [13] performed a techno-economics and environmental analysis with heat integration for year 2020 and 2050 scenarios. In their study, they assessed the projection of the levelized cost of methanol production in the PV-grid and PV-battery scenario between 2020 and 2050 using the learning rate method. From their study, they deduced that methanol production cost with the PV-battery scenario is higher than that of the PV-grid. The methanol production cost was estimated for the PV-grid and PV-battery scenarios to be 1040 and 1670 \$/tonne-MeOH, respectively. However, the lower CO₂-eq emission comes from the PV-battery scenario. On the other hand, the overall energy efficiency of the integrated process before and after the heat integration were 48.39 % and 55.16 %, respectively. Since the combination of PV – battery proved to have the highest learning rate compared to the PV – grid, this study gave hope that the CAPEX and OPEX reduction may be realised in the future.

In the work of Porter et al. [14], a techno-economic analysis of the methanol synthesis fed with Blast Furnace Gas (BFG) was discussed. The findings from this study indicated that the methanol production process fed with BFG can be made economically attractive under certain scenarios and assumptions, reaching a levelized cost of methanol production (LCOMeOH) of 344.61 £/ton-methanol. The said authors [14] performed a sensitivity analysis with consideration of the impact of parameters such as reactor size and/or recycle ratio on the LCOMeOH. Parameters such as cost of feed stock and carbon price (estimated to be between 10.59 and 24.61£/ton-steel for CCU and CCUS, respectively) emerged as having strong a bearing on the economic feasibility. The authors propose the co-selling of the N₂ rich by-product produced to enhance the overall profitability of the process. Consideration of co-selling the oxygen produced from electrolysis has also been recommended by several studies in the literature [10–12].

Vo et al. [15] showed that the PtMeOH based on AWE and SOEC technologies represents promising candidate designs. The authors deduced that, from an economic point of view, the PtMeOH integrated with SOEC and heat, steam, and power is superior under the scenario of reduced electrolyser CAPEX and increased electrolyser lifetime.

1.2. Techno-economics under uncertainty and assessment of economic parity studies

Lee et al. [16] considered solar PV, on-shore wind, hydropower as electricity sources, and AWE, PEM, and SOEC integrated with methanol synthesis to assess the best candidate electrolysis technology with respect to the unit MeOH production cost and the MeOH economic parity (defined as a point when green MeOH production cost is comparable with that of grey MeOH production) for year 2050. In their study, in addition to the base scenario, the scenarios were binary portioned per experience rate of the water electrolysis system; the minimum scenario was characterised by the lowest experience rate and the maximum scenario with the highest experience rate for each water electrolysis technology. They deduced that the SOEC integrated with methanol synthesis has the lowest unit MeOH production cost in the future (in year 2050). This was attributed to the SOEC having the highest energy efficiency compared to AWE and PEM, yielding the lowest energy consumption at similar and constant H₂ production rate. Hence, Lee et al. [16] deduced that SOEC and AWE are more promising than PEM when considering the fast realisation of the MeOH economic parity, for both the base and maximum scenarios. However, PEM emerged as a promising candidate under the minimum scenario. Their study pointed out that the developments in the electrolysis technology will strongly influence its adoption for future application. Kim et al. [17] assessed four cases for methanol production classified according to the technologies for hydrogen production. The study set to investigate the best pathway from an economic and environmental point of view with sensitivity, uncertainty and carbon footprint analyses for the four cases. Their result showed that reactants, CO₂ cost, reactor, compressor and electrolyser electricity cost, distillation operating cost had the strong effect on the MeOH unit production cost. These results depicted that as one changes the technology type and the scale, the critical factors having strong impacts on the economics changes. Thus, the authors deduced that uncertainty analysis using a Monte-Carlo simulation method gave reliable MeOH unit production costs, with better consideration of the price variation of the economic bearing parameters [18].

Abbas et al. [19] performed a techno-economic investigation of the three cases (i.e., base, integrated, and 100 % renewable) to evaluate the economic viability and risk associated with the renewable methanol production process (at a 100 MW plant size). The authors highlighted the hydrogen price and plant scale as the critical parameters with a strong bearing on the economic feasibility of the plant. For all cases, the methanol selling price became better with the increase in the plant scale, but got limited by the resultant increase in the investment cost. The 100 % renewable design became the worst scenario due to its projected renewable hydrogen price being difficult to achieve in the near term. The authors proposed as a potential solution to run the process at 50 % renewable and 50 % petroleum-based utilities. A combination of the hydrogen price < 1.2 \$/kg and plant scale ≥ 100 MW was proposed as being able to make the renewable methanol production price achieve economic parity or even be below the current methanol selling price for the base and integrated designs. Overall, the process economics will also depend on the plant availability (usually defined by load factor), which is also a function of renewable energy availability, dependent on factors such as climatic conditions, geopolitics, and policies.

1.3. Coupling flexibility to increase plant availability and techno-economics

Recently, Svitnič & Sundmacher [20], Ma et al. [21], and Inkeri et al. [22] investigated the impact of operating flexibly the methanol synthesis process on the LCO_{MeOH}. The common finding from these studies is that operating the PtMeOH flexibly while taking advantage of the electricity price variation does reduce (>10 %) the LCO_{MeOH}. From Svitnič & Sundmacher [20], it was discussed that the impact of flexibility is more pronounced for the designs with a single source of variable

renewable energy (either solar or wind). The economic benefit imposed by flexible operation is minimised for the design that simultaneously use both solar and wind resources. This is so because the combined availability of these resources improve the stable hours of operation of the chemical processes. This then minimised the influence of flexibility to 5.1 %. Moreover, the authors deduced that the design with a single renewable resource resulted into roughly 4 times larger reduction of LCO_{MeOH} than the multi-energy-resource and relatively stable option.

Ma et al. [21], investigated the flexible operation of the PtMeOH retrofitted into a steam methane reforming process (50 % PtMeOH and 50 % SMR-based process) based on exploiting the day-ahead (DAM) and real-time market (RTM) electricity price dynamics to bring down the overall production cost of the PtMeOH operation. In their study, only the upstream electrolysis section responds flexibly to market price dynamics. They compared the flexible and non-flexible operations. Their main findings were that when the PtMeOH is operated non-flexibly, the electricity price contributes to 60 % of the overall operating cost. Whereas flexible operation of the PtMeOH by exploiting the market price dynamics collapses the electricity cost contribution to almost zero especially when the electrolyser takes advantage of the low or negative electricity prices (associated with excess power supply, and common in the grid with high wind power penetration) to produce hydrogen to be used during peak hours. Although flexible operation resulted in increased investment costs, it was found to yield an economically viable process with a corresponding payback period of 8–10 years. The non-flexible operation of this retrofitted process was not economically feasible. Participating in RTM with the load switch every 15 min consistently outperformed participation in DAM. In addition, under certain scenarios (with high frequency of negative electricity prices and sufficiently low average prices), the flexible electrification unit can produce synthetic gas at a lower cost than the steam methane reforming. These authors [21], being the first to consider the economics of a retrofitted PtMeOH process in this manner, did not discuss the economics of a 100 % retrofitted process as considered in this study.

Other studies have considered the impact of selecting different types of intermediate storage in the power-to-methanol system. Recently, Bai et al. [23]'s study assessed and presented a comprehensive multi-period proactive flexible load management strategy for optimizing the flexible load management in the off-grid green methanol production systems. With load flexibility achieved through active control of the hydrogen flowrate, their findings indicated that hydrogen storage offers more economic benefits than battery storage due to higher battery cost. The study showed that battery storage is preferred as a supplementary power source to meet the demand for rapid response and at load below 10 %. Furthermore, these authors deduced that flexible operation offers up to 90 % reduction in the hydrogen storage needs and consequently a 69.1 % decrease in the hydrogen storage size requirements.

Vo et al [24] proposed a novel approach, integrating forecasting and surrogate models with mixed-integer linear programming to optimise the long-term integrated design and planning optimization of the PtMeOH process, with the aim of reducing the production cost and enhancing flexibility. With consideration of the transformer model capable of accurately forecasting the wind and solar energy over an exemplary period of four years, the authors identified that a lithium battery integrated with a grid connection is the optimal option. They deduced that with the efficient design, the methanol production cost can be reduced by up to 68.2 %. With grid-connection, the system can purchase the electricity at a low price, thus reducing the need for a large-scale battery. The grid-connected lithium battery integrated with PtMeOH takes advantage of operational flexibility to achieve cost savings.

Overall, these findings indicate that diverse markets may offer unique advantages, and that there is a need to consider flexibility, grid-connection to take advantage of price flexibilities via energy arbitrage, and the comparison thereof with off-grid connections.

1.4. Identified gap and statement of originality

Although several studies have investigated the techno-economics of this process, most studies are not only focused on deterministic economic analysis but also treat rather briefly the economic sensitivity by only performing the single-parameter sensitivity study [2]. There is a lack of generalisable understanding of the influence of the combination of economic parameters on the NPV, LCOMeOH and LCOH. This makes the decisions to invest on PtMeOH difficult to make. This paper contributes with offering these generalisable effect trend and perform sensitivity on a combination of parameters to assess the feasible regions. There is also a lack of studies that investigate the economics of a 100 % retrofitted PtMeOH process. Limited studies also consider grid-connected energy arbitrage and renewable standalone performance comparison for an integrated PtMeOH process. In this paper, PtMeOH techno-economics is assessed using the promising configuration described in our previous work [25]. This study considers the evaluation of the economic parity and the CO₂ emission tax, electricity price, and the electrolyser cost variations which are anticipated to change the realization of the methanol parity as will be investigated in this study. In essence, the question of how much the electricity and the CAPEX cost reduction should be to reach the cost parity on green methanol is investigated. On the other hand, a scenario where existing methanol synthesis infrastructure is 100 % retrofitted with the promising electrolyser is investigated in terms of its economics and the associated economic parity. This study considers South Africa's market volatility in the electricity price and its impact on the process's economic viability. South Africa has attractive renewable energy endowments and presents a relevant case study to the practitioners. The sensitivity of the PtMeOH vs hydrogen profitability is checked considering parameters such as the carbon tax, the load factor, and the electricity price. Generalisable effect trends of these parameters on the NPV and the levelized cost of methanol and hydrogen are discussed. To the authors' best knowledge, no prior work in the literature has investigated these aspects. In this paper, Section 2 presents the base process configuration, approach to its modelling, and scenarios; Section 3 gives the techno-economic methodology used in this study; Section 4 presents the results and discussion; Section 5 gives the conclusions and recommendations from this study.

2. Process configuration, scenarios and model consideration

The modelling of the PtMeOH process encompasses the electrolysis technology, methanol synthesis and separation sections with the balance of plant (BOP) equipment (see block-flow diagram in Fig. 1). Section 2.1 describes the considered modelling scenarios and the market electricity

price arrangements with reference to South Africa (SA) as a case study.

Section 2.2 describes the considerations for the SOEC-based electrolysis section modelling. Section 2.3 discusses the approach taken in the methanol synthesis and separation section modelling of the work.

2.1. Modelling scenarios and the market electricity arrangements: South Africa case

In South Africa (SA), a mix with coal energy will continue to dominate but a fraction of solar PV & wind will be coming into the grid [26]. SA is endowed with high intensity solar and wind energy resources, minerals for electrolyzers, fuel cells, and batteries, and as a result, it is positioned as a front-runner for green hydrogen technology and green fuels production. Eskom is the main public enterprise energy supplier. Eskom's electricity price increases have been very volatile, and it is expected that the electricity price will increase by a factor from 5.5 % to 12.1 % per year on average, following from the historic price increases, see Table 3 and Table 4 [27,28]. The grid connection is considered for buying electricity, and the electricity price is based on the hourly industrial time of use tariffs (ITOU) historical data corresponding to eThekweni (Durban) Municipality. The standalone electricity supply is based on the South Africa Hydrogen valley report published by the Department of Science and Innovation [29], in which the projected price of electricity from hybrid wind and solar in Durban Richards Bay by 2030 will be slightly cheaper than today (see Table 1).

For grid connected electricity: A flat rate according to reference [30] which is the average of high demand season and low demand season standard off-peak industrial time of use (Table 2) is calculated as: (incl. VAT) = (113.24 (high demand season price off peak) + 100.27 (low demand season price off peak))/2 = 106.8c/kWh = R1.068/kWh = R 1068/MWh = 59.3 US\$/MWh = 52.5 €/MWh as the electricity price currently. From discussing with experts, the electricity may increase to R2.12/kWh = 212c/kWh during off peak in the next 6 years assuming a flat average 12.1 %/per year increase (see Table 3) or up to 82 US \$/MWh = 72.5 €/MWh when assuming a 5.5 % per year increase (see

Table 1

Electricity price considering a case of Durban (eThekweni), South Africa with grid-connected and off-shore Solar and wind.

Durban	LCOE durban	Reference
Grid-connected with PV + Wind	Current 52.5 €/MWh 2030: 72.6–118 €/MWh	[29,30]
Standalone Solar + Wind	Current: 40.7 €/MWh 2030: 38.1 €/MWh	[29–32]

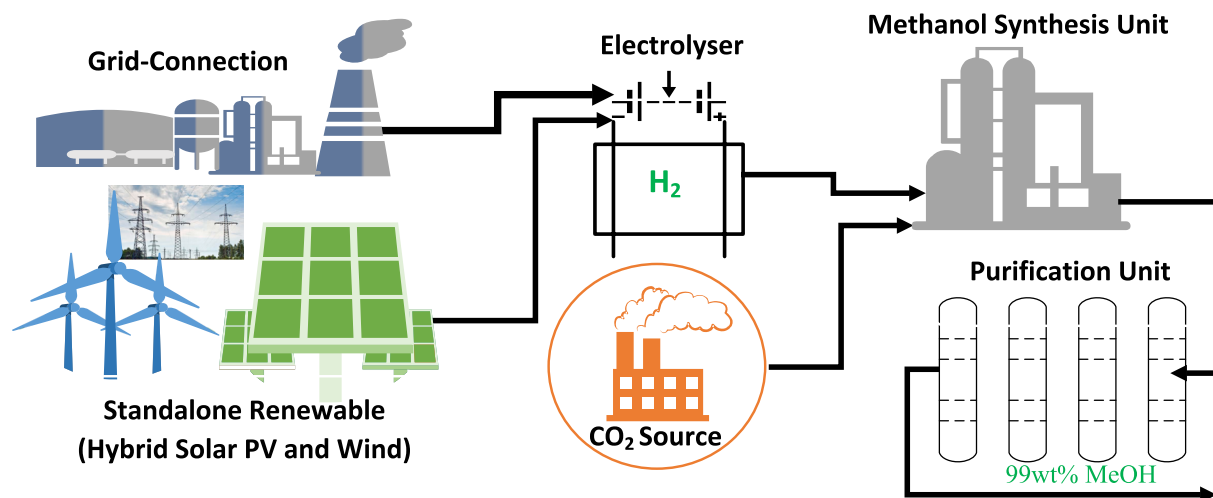


Fig. 1. Block-flow diagram of the Power to methanol process configuration.

Table 2

Electricity price considering a case of Durban (eThekweni), South Africa with the grid-connected industrial time of use tariff structure [30].

Industrial Time of Use (ITOU) Electricity Pricing						Low demand season					
High demand season						Low demand season					
Peak	VAT incl	Standard	VAT incl	Off-Peak	VAT incl	Peak	VAT incl	Standard	VAT incl	Off-Peak	VAT incl
c/kWh		c/kWh		c/kWh		c/kWh		c/kWh		c/kWh	
524.86	603.59	169.16	194.53	98.47	113.24	180.97	208.12	129.12	148.49	87.19	100.27

Table 3

Electricity price considering a case of Durban (eThekweni), South Africa with grid-connected electricity price increase with average of 12.11% [27,28].

Grid-connected scenario				
Average price increase = 12.11 %				
	1€=1.13US\$	1US\$ = R18.01		
	€/MWh	US\$/MWh	R/MWh	R/kWh
2024	52.5	59.30	1067.99	1.07
2025	58.83	66.48	1197.34	1.20
2026	65.96	74.53	1342.36	1.34
2027	73.95	83.56	1504.93	1.50
2028	82.90	93.68	1687.20	1.69
2029	92.95	105.03	1891.54	1.89
2030	104.2	117.75	2120.64	2.12

Table 4

Electricity price considering a case of Durban (eThekweni), South Africa with grid-connected electricity price increase with average of 5.5% [27]-[28].

Grid connected scenario				
Average price increase = 5.5 %				
	1€=1.13US\$	1US\$ = R18.01		
	€/MWh	US\$/MWh	R/MWh	R/kWh
2024	52.5	59.30	1067.99	1.07
2025	55.4	62.56	1126.73	1.13
2026	58.4	66.00	1188.70	1.19
2027	61.62	69.63	1254.08	1.25
2028	65.01	73.46	1323.06	1.32
2029	68.58	77.50	1395.82	1.40
2030	72.36	81.77	1472.59	1.47

Table 4).

Four scenarios are studied to illustrate the main differences regarding the availability of electricity. Renewable electricity is available from wind power and solar photovoltaics in the form of a power purchase agreement (PPA). The PPA is defined so that the PtX plant owner buys all the electricity produced by specific wind and solar farms.

It is assumed that no profit is obtained from the surplus electricity which the PtMeOH plant cannot utilize. In addition to wind and solar power, regular grid electricity is also an option. Table 5 summarises the key considerations in the calculation of the techno-economics. The following scenarios are investigated:

- Scenario 1: Only grid-connected electricity is available with battery storage installed for energy arbitrage. This scenario assumes that the battery is charged during off-peak, and is discharged during the peak

Table 5

Summarises the key considerations in the calculation of the techno-economics.

Parameter	Value	Units
Electricity demand	125.472	MWh
Battery Cost	25,094,400	€
Peak electricity price	130	€/MW
Standard electricity price	41	€/MW
Off-peak price	24	€/MW
Array Size	12	

hours when electricity is expensive according to the industrial time of use tariff structure. In this way, energy price arbitrage is performed using the battery storage.

- Scenario 2: Only grid-connected electricity with no battery storage. The plant is only operated with off-peak electricity. The plant is assumed to shut down during the peak time. Sensitivity analyses on lifespan and selling prices are performed. On the other hand, the lifespan is gradually changed from 1 to 20 years along with the selling price of hydrogen and methanol to evaluate the profitability trends of the investments. In addition, for this scenario, it is predicted that the electricity price will be steadily increasing and thus sensitivity analysis is performed on the effect of annual electricity price rise.
- Scenario 3: This features a standalone hybrid renewable solar PV and wind energy used to supply electricity to the power-to-methanol process. In this scenario, the investment in the battery is not considered as the electricity provider guarantees a fixed price 24/7 and the plant can run continuously. In other words, the load factor is first set to 100 % and the electricity bill is fixed in a 5-year contract. Then the sensitivity on the load factor is performed by varying it gradually from 50 % to 100 %.
- Scenario 4: Everything is similar to scenario 3 with an adjustment such that the plant is operated at a high load factor. Sensitivity on the electrolyser price is performed. The economic parity is assessed in terms of when will the green methanol equal the current selling price and what combination of the most critical factors will yield that scenario. Furthermore, a retrofitting scenario where the investment is made on the electrolyser infrastructure only is evaluated. This means an existing downstream methanol system is retrofitted with the electrolysis section to make it green and thus no investment is made in purchasing the downstream methanol synthesis and separation section.

The electricity generation might not be located at the same site and can thus need to be transported to the PtMeOH plant [33]. These transmission costs might also be dictated and regulated by other companies/stakeholders, making it difficult to define the actual cost for a single plant. Therefore, due to the aforementioned complexity, the transmission costs are neglected in this study, similar to reference [33]. In this paper, the Tesla Megapack Li-ion battery with a round-trip efficiency of 90 % and a power/energy ratio of 741.2 kW / 2964.8 kWh, was utilised. Thus, one battery can supply 2984.8 kWh as the energy stored and 741.2 kW as the power produced, and a total of 43 batteries are required to make one modular pack. This takes into consideration the discharge efficiency and the minimum state of charge, taken as equal to 10 % of the stored electricity. Following the findings from Bai et al. [23] pertaining the advantages of hydrogen storage, the hydrogen storage tank sized for 2 h and consequently, with an overall capacity of 4888 kg is considered. The assumptions associated with hydrogen storage tank size and costing are in Table S6 of the supplementary material, under the section S4.

2.2. Process description: Hydrogen production via electrolysis

Three electrolysis technologies are available commercially, albeit at different scales. Both AWE and PEM are well-established and commercialized, with most medium-term PtMeOH investment projects focusing

on them [18,31,34]. The SOEC is largely being developed and commercialised by Sunfire GmbH, Dresden, Germany which has deployed commercial (even industrial) scale size on various projects [30]. As deduced by Inkeri et al. [22], there are several reasons for the variation in electrolysis investment cost. The first is related to the different assumptions and years regarding learning rate by technology development and scale-up, and the second is about the difference between the cost of the actual stack and other components, and indirect costs such as building and planning. SOEC has been deduced to have a likelihood of improved profitability with promoted hydrogen price and low electricity price, but the NPV gap is notable, more so for private investors [18]. Table 6 deduces the performance and economic parameters for the AWE technology. Although AWE is the cheapest of all the technologies, it is still marred by poor efficiency, fast degradation under dynamic conditions, and poor dynamic start-up time. Innovation on the material front is being pursued to address these challenges [34,35].

Table 7 gives the performance and economic parameters for the PEM technology. Although PEM is promising for integration with renewables on the front of fast dynamic start-up than all other electrolysis technologies, it is still marred by high cost due to special materials (platinum and iridium) used as electrocatalysts, relatively marginal improved efficiency, and scalability issues in as far as large-scale production firms are concerned [35,41,42].

Table 8 summarises the performance and economic parameters for the SOEC technology. The SOEC is characterised by high efficiency due to its ability to use a hybrid of heat and electricity.

However, SOEC operation at a higher temperature has its downside in that it limits the dynamic start-up time to several minutes or even hours and makes the technology less flexible with respect to ramp down/up rates. However, its abilities to be switched to bidirectional operation in a form of electrolysis to fuel cell and vice versa and to produce either hydrogen or syngas appeals attractively to a wide market. This has garnered efforts to improve the existing and derive new materials to address the start-stop rate, material degradation, and high-cost challenges [35,41]. Thus, there are reasons to retain confidence that these challenges will be addressed in the medium to long term. As deduced by Lee et al. [16], the SOEC is one of the promising future technologies to be integrated with methanol synthesis with the lowest unit methanol production cost and potential to reach methanol economic parity due to its high learning rate. In this paper, this technology is selected and modelled to produce hydrogen at a rate described in Table 9. Water is supplied from the desalination plant at a rate and price described in Tables 9 and 10, respectively. The calculated hydrogen purchase price falls within the range of the literature derived values presented in Table 10 [49].

Table 6
Alkaline Electrolyser (AWE) data.

Parameters	Current Value	Future projected value	Reference
CAPEX (\$/kW)	500–1400	248–506, 200	[36,37]
Stack unit size (MW)	1	10	
Stack lifetime (kh)	90–100	>150	[38,39]
Stack consumption (kWh/kgH ₂)	52–61	<45	[38]
Efficiency LHV/%	55–63.9	69–74	[36–40]
Percentage of BOP price in total water electrolysis system/%	50	–	[36–40]
Percentage of supplement in total equipment cost/%	20	–	[36–40]
Percentage of maintenance price in total initial capital cost/%	2.5	–	[36–40]
Percentage of other costs in total initial capital cost/%	1	–	[36–40]
Stack replacement cost in total initial capital cost	50	48, 44	[40]

Table 7
PEM Electrolyser data.

Parameters	Current Value	Future projected value	References
CAPEX (\$/kW)	1100–1800	200	[36,43]
Stack unit size (MW)	1	10	[36,43–45]
Stack lifetime (kh)	40–80	100–125	[44]
Stack consumption (kWh/kgH ₂)	55.8–64.4	<45	[44]
Efficiency LHV/%	52–63.9	–	[45]
Percentage of BOP price in total water electrolysis system/%	40	–	[36,43–45]
Percentage of supplement in total equipment cost/%	–	–	[36,43–45]
Percentage of maintenance price in total initial capital cost /%	4	–	[36,43–45]
Percentage of other costs in total initial capital cost/%	–	–	
Stack replacement cost in total initial capital cost	50	48, 44	[36,43–45]

Table 8
SOEC Electrolyser data.

Parameters	Current Value	Future projected value	References
CAPEX (\$/kW)	2800–5600	880–1408, 300	[43,46,47]
Stack unit size (MW)	0.005	0.2	[43,44]
Stack lifetime (kh)	10–40	80	[43,44]
Stack consumption (kWh/kgH ₂)	42.6–55	<40	[43,44]
Efficiency LHV/%	84 [3]		[48]
Percentage of BOP price in total water electrolysis system/%	40	–	[40,43,44]
Percentage of supplement in total equipment cost/%	–	–	
Percentage of maintenance price in total initial capital cost /%	5	–	[40,43]
Percentage of other costs in total initial capital cost/%	–	–	
Stack replacement cost in total initial capital cost	23.5	13.5, 9.5	[40]

Table 9
Main input and output mass balance of the process (final product methanol).

Process streams (Main input and product)	Value	Unit
Methanol Production rate	12712.0	kg/h
Hydrogen required for methanol production	2444.0	kg/h
CO ₂ required for methanol production	17,650	kg/h
Oxygen produced	20399.3	kg/h
Fresh Water required	22,101	kg/h

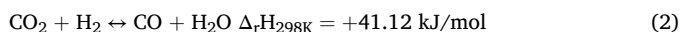
Table 10
Product/Feed current market selling price.

Product/feed	Current value	Units	Ref
Methanol	310–500	€/t	[50–52]
Oxygen	0.336	€/kg	[53]
Renewable Hydrogen	3.6–5.13	€/kg	[29,49]
CO ₂ purchase price from industrial point source (iron and steel).	35.4–106.2	€/t	[54]
Deionized water cost	0.009	€/kg	[36]
Cost of methanol catalyst	115.9	€/kg	[55]

2.3. Process description: CO₂ source, methanol synthesis and separation section

As discussed by Inkeri et al. [22], the cost of CO₂ can be considered as per utilized mass of CO₂, instead of investment and operational cost.

This represents a situation where a third party is selling the CO₂ for the PtMeOH plant. Herein, no investment in the carbon capture and storage unit is considered but rather the CO₂ is purchased purified from an industrial point source (iron and steel), see Table 10 for the purchase price. Compared to carbon capture and storage (CCS), only the capture cost (40–120 \$/ton) is considered, as there is only limited demand for transportation and storage [22,29]. The feed stream of CO₂ and H₂ are compressed to 78 bar. This is achieved by making use of multi-stage compressors each having an isentropic efficiency of 75 %. Methanol is produced via direct CO₂ hydrogenation reaction from the reactions in Eq. (1) in the presence of a competing reverse water gas shift reaction (Eq. (2)) in a multi-stage reactor configuration with inter-stage cooling and separation.



With consideration of the paramount safety aspects, the compression ratio is kept at 3 while inter-stage cooling was implemented to avoid excessive and detrimental compressor temperature increase. For all the reactors, the feed temperature was set to 210 °C [25,56]. This inlet temperature falls within the optimal region of an industrial methanol reactor [57]. From previous studies it was deduced that a further increase in the inlet temperature can result in increased hot spot and reduced methanol yield, with the potential of exceeding the

recommended temperature limit of 285 °C for the adiabatic reactor(s). Table 9 summarises the overall mass balance; detailed mass balance can be found in section S3 of the supplementary material. On the other hand, the allowable lower inlet temperature limit is set by the adopted catalyst, and for the commercial Cu-based catalyst it is around 190 °C [57].

This study adopts the commercialised Cu/ZnO/Al₂O₃ catalyst fitted in an adiabatic reactor(s) tube. Table S1 in the supplementary material gives the properties of the catalyst and the adiabatic reactor(s) modelled as a plug-flow (RPLUG). The choice of adiabatic reactors is based on its low associated cost, derived from its simple structure, in comparison to the water-cooled and gas-cooled reactors [57]. However, for flexible operation, a different reactor may be more favourable than the adiabatic reactor, but flexible market response is proposed for future work in this paper and is not considered explicitly.

3. Techno-economic evaluation methodology

The techno-economic analysis considers both the capital cost (CAPEX) and operation expenditure (OPEX) of the process. OPEX cost includes variable costs i.e., the labour cost, electricity, catalysts, oxygen, carbon dioxide, etc., and the depreciation cost.

Fig. 2 summarises the techno-economic methodology followed in this work, with a highlight of the important considerations. Techno-economic modelling was performed using the data generated from steady state modelling of the PtMeOH flowsheet. CEPCI was utilised in

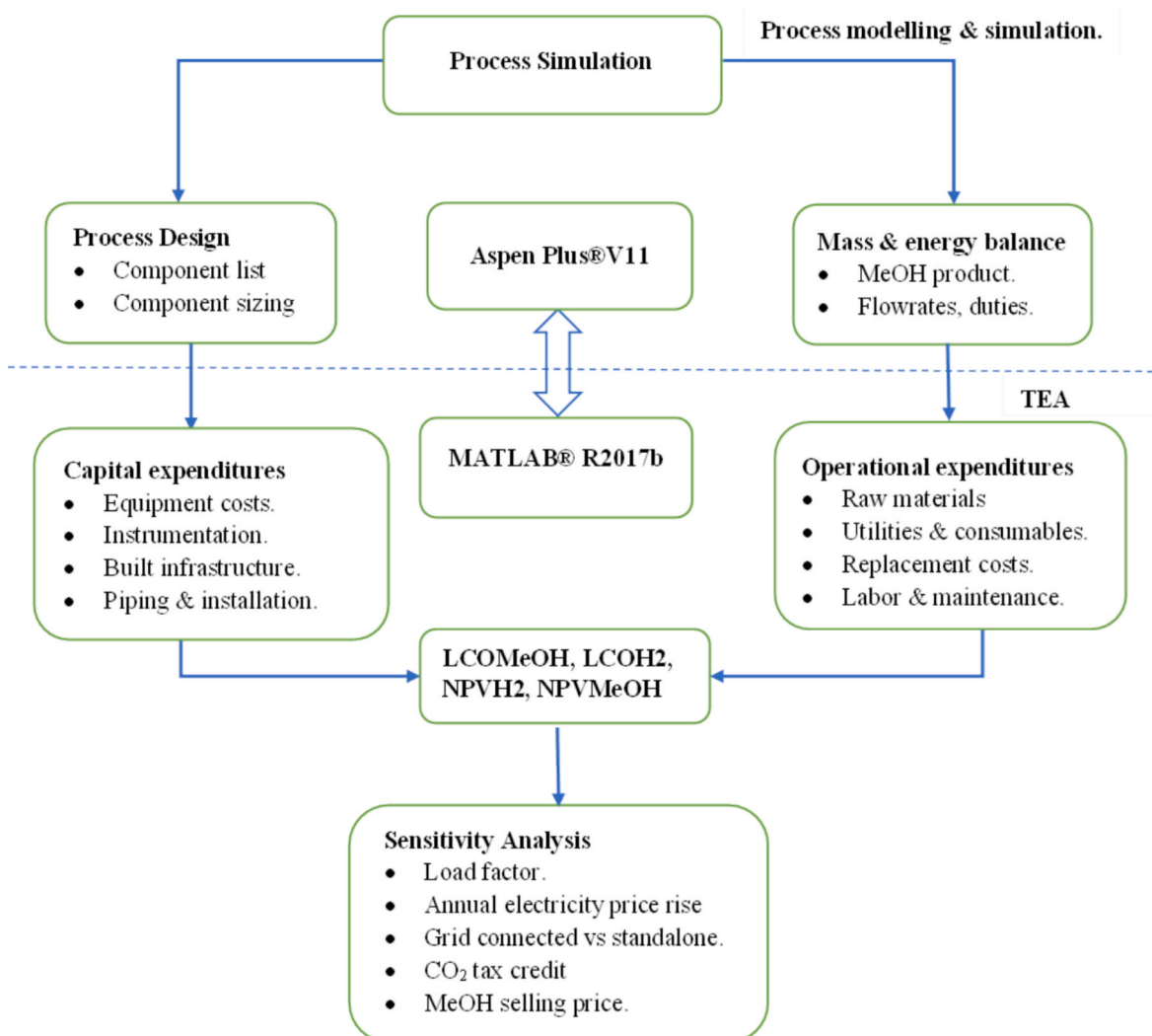


Fig. 2. Summary of the method followed in this study [58].

order to take into account the impact of change in CAPEX over time (i.e., inflation and/or deflation). Furthermore, techno-economics and sensitivity analysis were performed using the code with linear algebraic equations implemented in the software, MATLAB (version: R2017b).

3.1. Capital investment and operation expenditure

The purchase equipment fixed capital investment is calculated for some standard equipment such as heat exchangers, compressors, pumps, reactors, and distillation columns by using the Lang factors and can be found in section 3 of the supplementary material along with detailed mass balance. According to Bellotti et al. [50], the projected future product methanol selling price is between 565 and 904 US\$/ton from an optimistic viewpoint.

The total annual cost (TAC) of methanol production is calculated using Eq. (3).

$$\begin{aligned} TAC &= \text{total annual cost} \\ &= \text{operating cost} + \text{utilities} + \text{annualised capital cost} \end{aligned} \quad (3)$$

CRF which refers to the cost recovery factor was calculated using Eq. (4) below. Considering Eq. (4), the lifetime of the electrolyser can be accounted for as the parameter “n”. To calculate the annual capital cost, Eq. (5) below is used.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (4)$$

$$C_{\text{annual capital cost}} (\$/\text{yr}) = C_{\text{cap}} (\$) \times CRF \quad (5)$$

The economic assumptions used in this study are up to 20 years of plant life, 8 % discount rate, up to 7920 h of operation per year, electricity price as in Table 1, and CO₂ purchase price as presented in Table 10. The typical price of methanol from fossil fuels (fMeOH) is between 310–500 €/ton whereas the price of renewable methanol (eMeOH) ranges between 584–1146 €/ton [59]. Since historic market data does not represent the future potential of the technology [18], uncertainties in these parameters should be considered in future studies and their influence must be assessed via Monte-Carlo simulation applying the triangular distribution for the aforementioned parameters.

3.2. Net present value

The investment attractiveness/business feasibility of the process is quantified and compared via the net present value (NPV). NPV is calculated by using Eq. (6) for capital budgeting and investment planning, and help in assessing the risks and profitability of the process [18]. The NPV and levelized cost were assessed based on cash flow analysis, which was estimated from considering the anticipated revenue and expenditure items.

$$NPV = \sum_{i=0}^N \frac{\text{Netcashflowinyeari}}{(1 + \text{discount rate})^i} = \sum_{i=1}^N \frac{CF_n}{(1 + r)^i} - I_0 \quad (6)$$

where N is the number of years. CF_n represents the net cash flow at the operating year i , I_0 is the CAPEX, and r is the discount rate to calculate a change in the value of cash (this is in a range of 4–9 % for the energy industry facilities). The discount rate or Weighted Average Cost of Capital (WACC) is assumed as a uniform value of 8 % [18]. The discount rate factors the opportunity cost of the invested capital, the inflation, earning rate and the risk level of the project. Table 11 shows the critical economic parameters and their variation bounds considered in this work. The global sensitivity analysis is conducted by using values in the range from low to high values for the most important parameters, as presented in Table 11. Table 11 also shows the fixed parameters.

In this study, for the investment cost no loans and interest on debts are considered. With the considered discount rate, a positive NPV means

Table 11
Economic sensitivity variable bounds.

Economic parameters	Value	Unit	Ref.
Project lifetime	10 to 20	years	–
Discount rate	8	%	–
SOEC lifetime ^a	10 to 20 ^a	years	[44]
CO ₂ credit	0.008 to 0.8	€/kg	[60,61]
Load Factor	50 to 100	%	
Electricity price	Refer to Section 2, Table 1 to 4		

^a using estimated future lifetime of the technology.

that the generated revenue exceeds expenditures and that investment in the project is worthwhile. Following the South Africa National Budget Speech in February 2022, the carbon tax was set at R144 per 1MT CO₂e (8US\$/ton CO₂e) with an aim to reach 20US\$ and 30US\$/ton in 2025 and 2030 respectively [60,61]. Using an exchange rate of 1€ = 1.13 US\$, the current carbon tax is 7.1 €/ton while the 2025 and 2030 are 17.7 and 26.5 €/ton CO₂e, respectively. The carbon tax is an example of a Pigouvian tax, which forces market participants to internalise the climate externalities and also affects the electricity producers [60,61].

3.3. Levelized cost of hydrogen (LCOH2) and methanol (LCOmeOH)

The economic analysis is also conducted using the Levelized Cost (LCO) method. The levelized cost of hydrogen and methanol are the average value over the lifetime calculated using Eq. (7) and Eq. (8), respectively. LCO is a multivariable function with uncertainties of electrolysis method, hydrogen/methanol market, transportation, energy source, and storage [18]. This LCO also represents the breakeven selling price that repays the total cost (C_{tot}) by producing a certain amount of fuel (M_{tot}) at the end of the plant lifetime. It takes into effect the total CAPEX, utility costs, cost of feedstock, and fixed O&M costs. The LCOH2 and LCOmeOH were assessed based on cash flow analysis, which was estimated from considering the anticipated revenue and expenditure items.

$$\begin{aligned} LCOH2 &= \frac{C_{tot}}{M_{tot}} \\ &= \left(\sum_{i=1}^N \frac{\text{totalcostsinyeari}}{(1 + \text{discount rate})^i} \right) / \left(\sum_{i=1}^N \frac{\text{producedhydrogeninyeari}}{(1 + \text{discount rate})^i} \right) \end{aligned} \quad (7)$$

$$\begin{aligned} LCOmeOH &= \frac{C_{tot}}{M_{tot}} \\ &= \left(\sum_{i=1}^N \frac{\text{totalcostsinyeari}}{(1 + \text{discount rate})^i} \right) / \left(\sum_{i=1}^N \frac{\text{producedmethanolinyeari}}{(1 + \text{discount rate})^i} \right) \end{aligned} \quad (8)$$

4. Results and discussion

4.1. Grid-connected scenarios

For all the grid-connected scenarios, sufficient renewable energy is assumed, and the selling price is equivalent to that of the current grid and future grid electricity selling price in Durban (Table 1). An exchange rate of 1€ = 1.13 US\$ is used to convert all the values in US\$ to Euro (€).

4.1.1. Scenario 1

In this scenario, the battery storage is sized big enough to sustain continuous operation during peak hours when the electricity is expensive. The battery should only provide 5 h per week (corresponding to peak hours according to reference [30]) to avoid peak-priced electricity. The 5 h per week is calculated from the industrial time of use tariff structure from the considered Durban (eThekweni) Municipality. The total energy demand of the system is around 126 MWh. The battery is

modelled with 90 % round-trip efficiency. This scenario assumes that the battery is charged during off-peak and discharged during the peak hours to the electrolysis and the methanol synthesis system. This allows the energy price arbitrage.

The load factor is maximised to 100 % with continuous operation ensured through the use of battery storage. Thus, the cost of 1 MW electricity per day during the weekdays, Saturday, and Sunday are 763 €, 695 €, and 576 €. This depicts that maximising charging of the battery over weekends (Saturday and Sunday) is attractive. However, under the current battery and electricity price conditions, the investment in this scenario is unprofitable (negative NPV). The battery cost of 25 M€ was too expensive to result in a meaningful investment. The finding that the use of a battery for energy storage is unprofitable in line with other literature findings such as in the recent work of Qi et al. [62].

4.1.2. Scenario 2

In this scenario, the grid-connected electricity is considered but no investment in the battery storage is made. The plant is only operated with off-peak electricity. The plant is shut down during peak hours when electricity is expensive. The corresponding weekdays load factor is 79 % and that of the weekends (Saturday and Sunday load factors) is 100 %. The corresponding calculated total load factor is 85 % based on the time-of-use tariff structure. The load factors are maximum for the weekends due to the flat tariff structure, where most hours correspond to off peak

hours, more especially for Sunday where there is only off-peak price charge throughout. Thus, the cost of 1 MW of electricity per day during the weekdays, Saturday, and Sunday are 643 €, 695 €, and 576 €, respectively. The corresponding average cost of 1 M electricity per day is 641€ which is equivalent to 26.7 €/MWh. The calculated NPV of hydrogen production (NPVH₂) and NPV of methanol production (NPVMeOH) were 828.7 M€ and -3626.1 M€, respectively. The corresponding levelized cost of hydrogen (LCOH₂) and the levelized cost of methanol (LCO_{MeOH}) were 5.458 €/kg and 7.685 €/kg, respectively.

A positive NPV for Power-to-hydrogen indicates that the project is profitable, but the obtained negative NPV for Power-to-methanol means that it is an unprofitable investment. In this scenario, the calculations have assumed H₂ selling price of 4.06 €/kg and MeOH selling price of 0.44 €/kg. Spending money and energy to turn a more valuable product (H₂) into a cheaper one (MeOH) deteriorates the profit. From this scenario, a potential option to improve profitability is to sell both hydrogen and methanol as the final product. Alternatively, electricity can be sold along with methanol by operating the SOEC under fuel cell mode when the electricity price is high. These operation modes could be dictated by the selling price of hydrogen, electricity, and methanol, and will demand optimizing the operating hours on one mode in alignment with the price forecast. However, this may need bigger storage of hydrogen, which is more expensive and will further deteriorate the profitability [62]. Although hydrogen storage is considered and sized for 2 h, the main

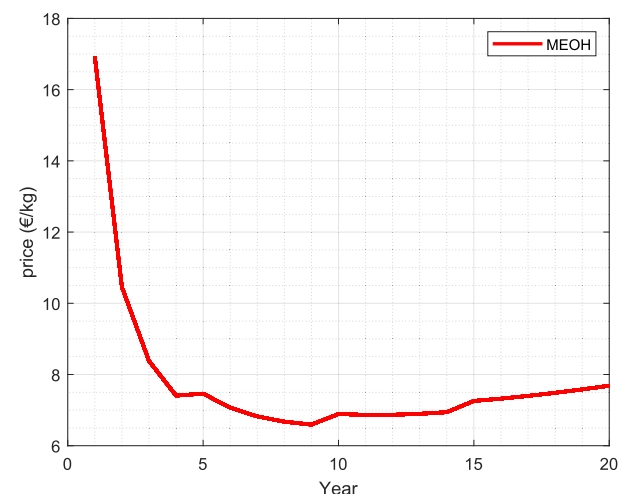
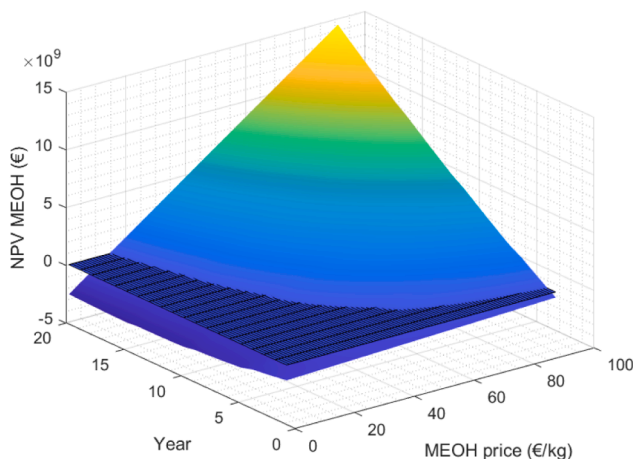
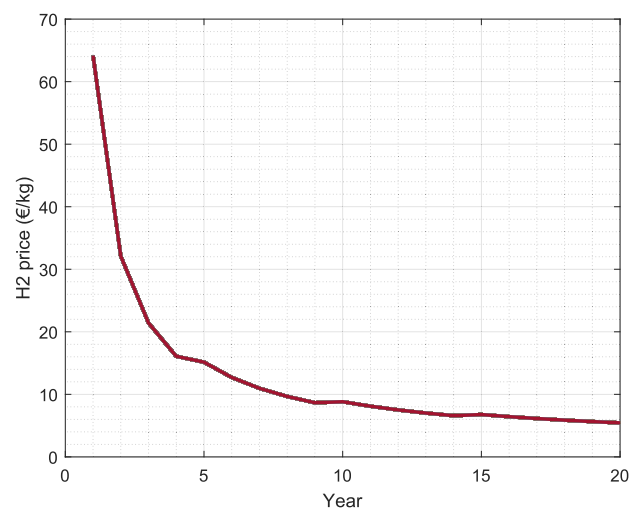
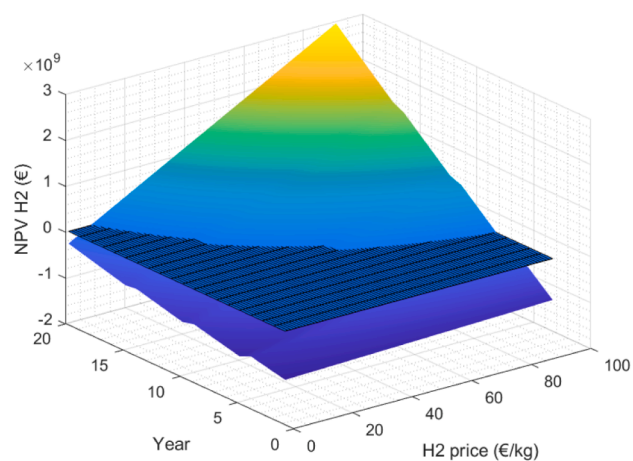


Fig. 3. Scenario 2 sensitivity analysis on lifespan and H₂ and MEOH selling price on the NPVH₂, NPVMeOH.

premise of the work was on using methanol synthesis as a cheaper form of green-hydrogen storage. For this reason, it was decided not to use a bigger storage size because it is expensive. In addition, the production cost of methanol would be even higher since the capacity factor of the methanol plant gets lower if some of the produced H_2 is not converted to methanol, unless the electrolysis unit is oversized. Optimisation of the H_2 storage for multi-product treatment of methanol is recommended for further investigation in future work. On the other hand, there are still prevailing safety concerns around the hydrogen storage, which, by using methanol synthesis and operating its system flexibly, can at least be reduced by minimizing the size of H_2 storage.

The plant lifetime is gradually changed from 1 to 20 years, together with the selling price of hydrogen and methanol to evaluate the profitability trends of the investments. Fig. 3 plots the results of the sensitivity analysis against the NPV H_2 , NPVMeOH, H_2 , and MEOH selling price. The results show that NPV H_2 cannot be positive if the lifespan is below 7 years; however, the hydrogen price needs to be extremely high to make it profitable. Hence, this project can only be feasible if treated as a long-term investment (20 years or more). The result implies that plants that still have 20 years and beyond of lifetime left are recommended for retrofitting, below the 20 years, the investment will be difficult to justify.

The price of hydrogen will drop to below 10 €/kg. The results of MeOH are similar to the hydrogen case. However, if the price of

methanol is abnormally high, the project falls into the profitability area sooner than hydrogen production. This corresponds to a price of more than 10 €/kg. This is a riskier selling price to expect the markets to accept and it is excessively higher (>50 times) than the current market selling price of fossil-fuel based methanol.

The methanol selling price as depicted in Fig. 3 drops to below 8 €/kg in the next 10 years. However, the methanol selling price does not drop down steadily as the hydrogen selling price; and this is due to the additional maintenance cost of the methanol synthesis unit.

It is predicted that the grid-connected electricity price will be steadily increasing, in reference to Tables 1, 3, and 4. In this scenario, an optimistic pattern by which the price rises by 5.5 % (average yearly) versus a pessimistic one where the price increases by 12.1 % were considered. The definitions of peak, standard, and off-peak stay the same, and similar time frames are used in the calculations. Simulations are developed assuming that the annual rise of electricity price is gradually changing from 0 to 15 % for a plant life span of 20 years. The effect of the electricity price rise is plotted against the NPV H_2 , NPVMeOH, H_2 and MEOH selling price in Fig. 4.

For both pessimistic and optimistic scenarios, the annual rise in the electricity price exponentially decreases both the NPV H_2 and NPVMeOH. On the other hand, for both pessimistic and optimistic scenarios, the annual rise in the electricity price exponentially increases both the H_2 and MEOH selling prices.

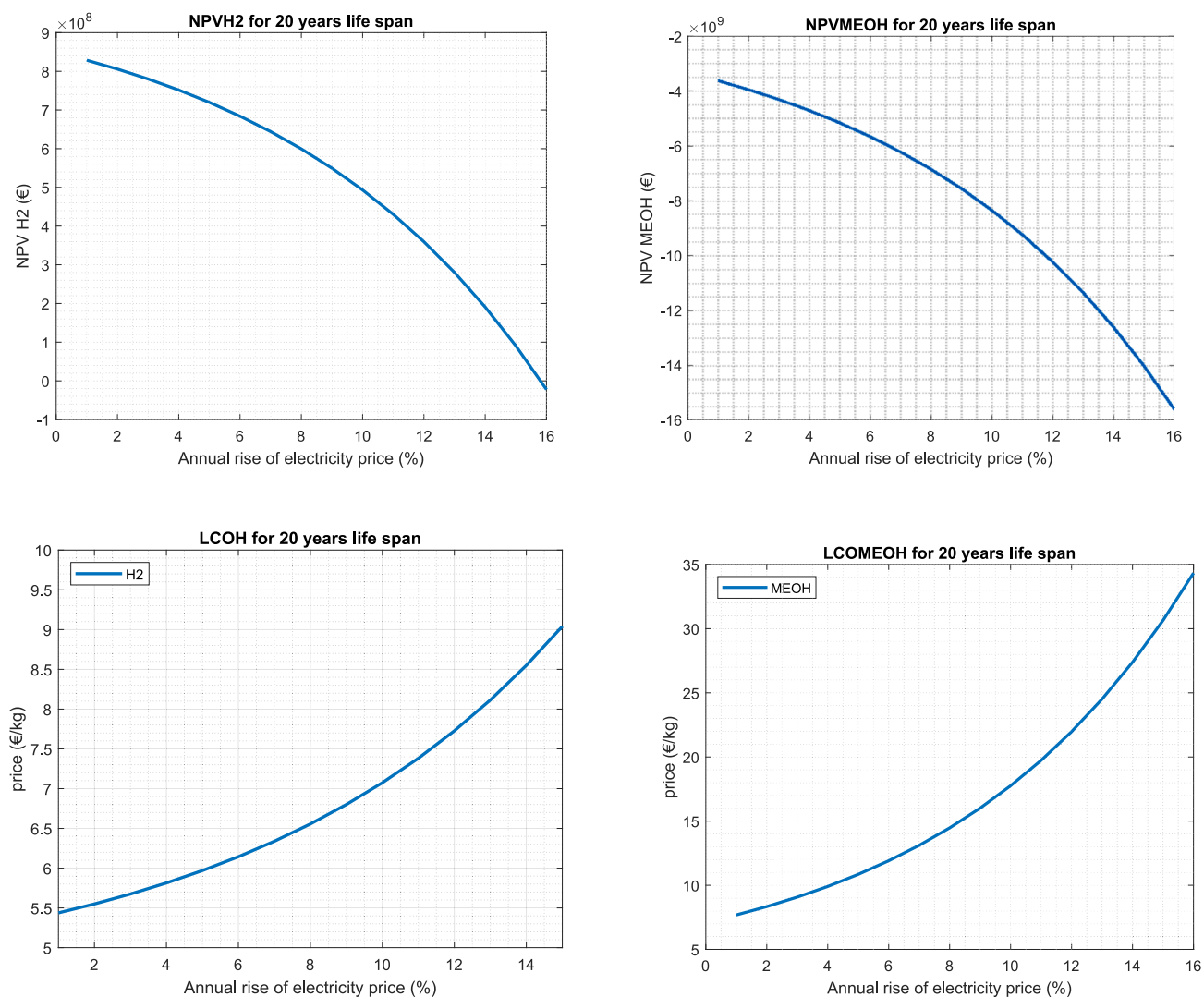


Fig. 4. Scenario 2- annual electricity price rise variation effect.

The profitability of the grid-connected scenario project will be hampered if the electricity price continues to increase.

4.2. Standalone solar PV and wind scenario

Two scenarios were considered i.e., scenario 3 and 4. In scenario 3, the price of electricity from hybrid wind and solar in Durban Richards Bay by 2030 is going to be slightly cheaper than today, see Table 1.

4.2.1. Scenario 3

In this case, the price of battery is not considered, and the electricity provider guarantees a fixed price 24/7 to run the plant continuously. In other words, the load factor is 100 % and the electricity bill is fixed in a 5-year contract. If the electricity price is assumed constant at 46 €/MWh (see Table 1), the load factor ideally 100 %, hydrogen price 4.06 €/kg, methanol price 0.44 €/kg; but CO₂ tax credit is gradually varied and increases up to 100x (from 0.008 to 0.8 €/kg), therefore the NPVH₂ is 1111.1 M€ and LCOH₂ is 4.873 (€/kg). Fig. 5 shows the trend of the NPVMeOH and LCOMeOH variation with the CO₂ tax credit.

The carbon tax credit will improve the profitability of the PtMeOH. Fig. 5 shows that the NPV of the PtMeOH process increases linearly with increase in the carbon tax credit. On the other hand, the levelized cost of methanol decreases with the increase in the carbon tax credit. Although

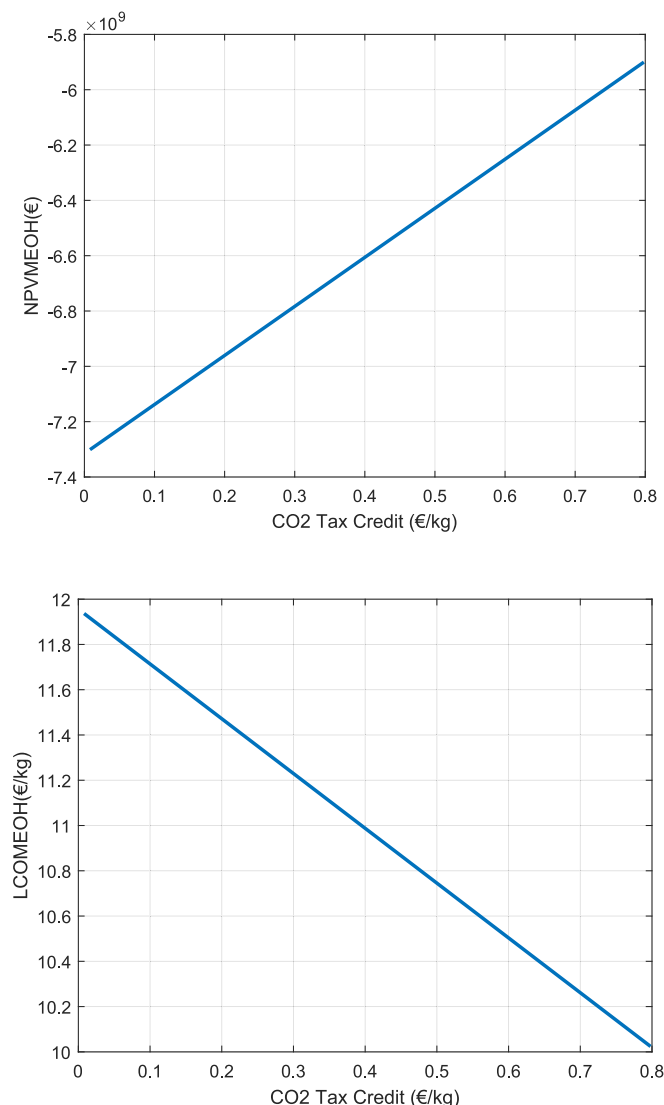


Fig. 5. Scenario 3-effect of carbon tax credit on the standalone solar PV plant.

the carbon tax will help to improve the profitability of the process, it must be coupled with other factors such as a significant decrease in the electricity price to make the project feasible.

The load factor gradually changes from 50 % to 100 %. High load factors are required to improve the competitiveness of the hydrogen and methanol production cost in the PtMeOH plant, otherwise extended periods under negative electricity price operation will have to be realised (which is unrealistic to expect). Similar conclusions were deduced by Zhang et al. [12], who indicated that the cost of the product increases when the electrolysis capacity factor reduces. This talks to why all the reported economic analyses are carried out assuming high-load factors, in the range of 82 % to 94 %.

As expected, higher load factors and high carbon tax credit result in product prices along the favourable cost reductions. The LCOMeOH planes are also plotted in Fig. 6. It is noteworthy that when the system is operated at load factors of more than 80 % (higher load factors), the LCOMeOH gaps are reduced. This indicates that, although the CO₂ tax credit does positively impact the profitability of the plant, the electricity price and load factors play a more dominant role in the project profitability.

4.2.2. Scenario 4

Everything is similar to scenario 3 with an adjustment such that the plant is operated at high load factor. Sensitivity on the CAPEX of the plant together with the electricity price is performed. The economic parity is assessed in terms of when will the green methanol equal the current selling price and what combination of factors will yield that scenario. Fig. 7 shows the effect of CAPEX and electricity price variation on the LCOMeOH, LCOH₂C, NPVH₂, and NPVMeOH. The figure shows that the decrease in CAPEX and electricity price will make the NPVMeOH more positive even with the current selling price. In this scenario, without the consideration of the CO₂ tax credit and incentive, an electricity price of 20 €/MWh and the plant CAPEX reduces to 20 %, then the NPVMeOH falls into break even region. However, the 20 % of the CAPEX seems unrealistic. This indicates that the power-to-methanol process as investigated in this study will require incentives such as CO₂ credit along with substantial electricity price and CAPEX reduction, particularly the electrolyser cost, to make it profitable. Similar to the previous scenarios, the NPVH₂ falls into a more profitable region earlier than the NPVMeOH. At 80 % of the CAPEX reduction and electricity price of 20 €/MWh, the NPVH₂ falls into a break-even region already. This is due to the current favourable higher price of hydrogen compared to that of methanol.

When looking at the levelized cost in Fig. 7, a LCOH₂ below 2 €/kg can already be achieved with 80 % of the CAPEX and 20 €/MWh. This indicates that the economic parity of H₂ (LCOH₂ = current selling price = 4.06 €/kg) can be reached with an electricity price of 30€/MWh and 70 % of the CAPEX. While the LCOMeOH will still be above 2 €/kg at 80 % of the CAPEX and the electricity price of 20 €/MWh. This indicates that even if the CAPEX reduces to 20 % of its original in this study, and the electricity price reduces to about 20 €/MWh, the LCOMeOH will still not reach economic parity (LCOMeOH > current selling price = 0.44 €/kg). This indicate that due to the low selling price of methanol, the electricity price holds more strength to make the PtMeOH profitable than the CAPEX reduction. Thus, if the investment is made on the electrolyser infrastructure only, which means an existing downstream methanol system is retrofitted with the electrolysis section to make it green and thus no investment is made on purchasing the downstream methanol synthesis and separation section, including its BOPs but only their OPEX considered, with the current price of electricity and electrolyser cost, the plant will still not be profitable. To make the retrofitted plant profitable, a feasible reduction in the electricity price to below 10 €/MWh, along with favourable incentives such as CO₂ credit and reduction in CAPEX, particularly the electrolyser, will be required. Alternatively, the co-selling of H₂/green electricity and product methanol could also be a better strategy.

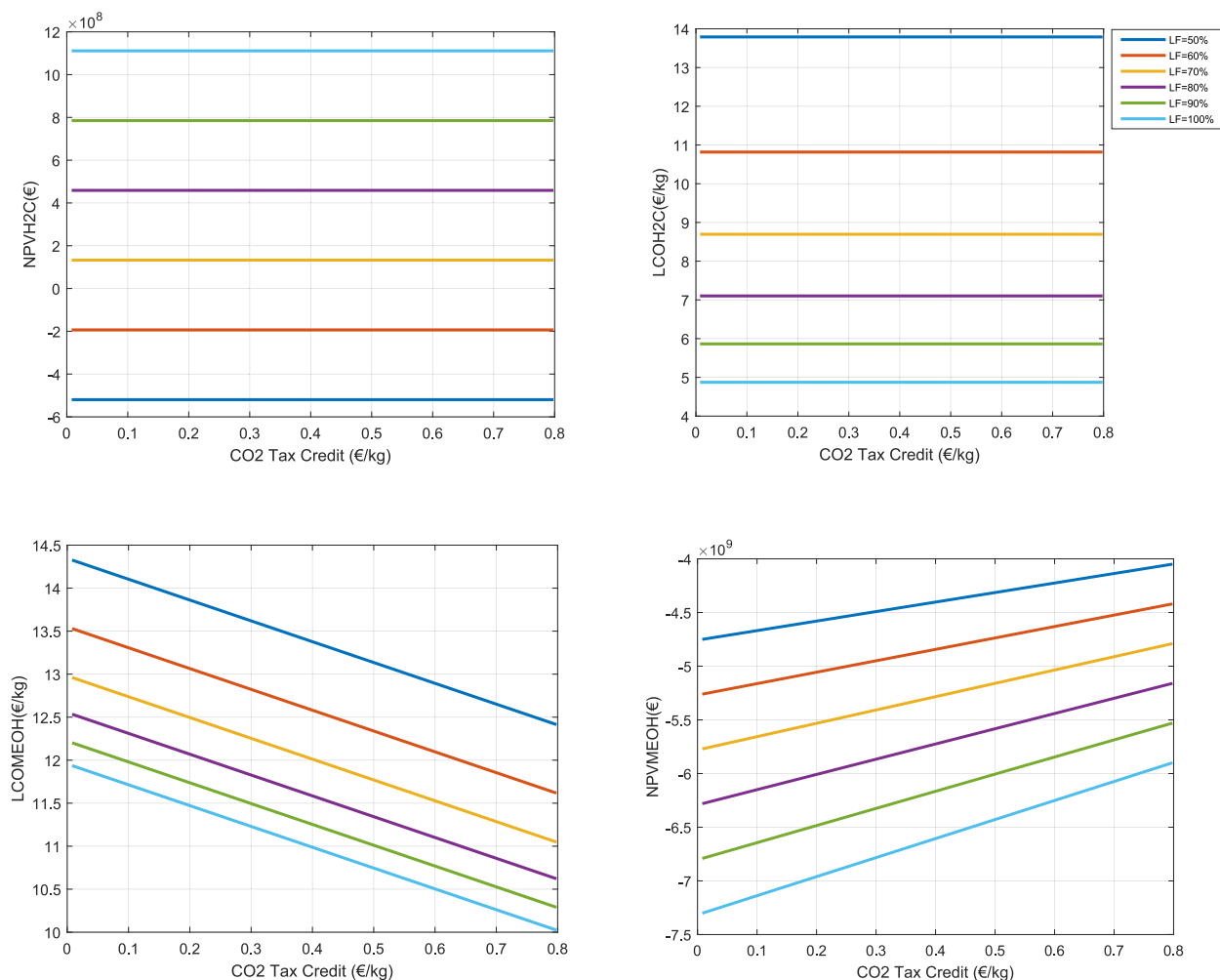


Fig. 6. Scenario 3-Effect of variation of the CO₂ tax credit and load factors on the LCOMeOH, LCOH₂, NPVH₂, and NPVMeOH.

4.3. Comparison of the findings with literature and other markets

It is critical to highlight that the economics are difficult to compare on the same basis since there are regional differences (e.g., electricity prices & incentives), different assumptions, and capacity considerations in the vast literature studies. This section attempts to compare the LCOH₂ and LCOMeOH from this paper with those from other regions, as presented by several cited authors. Table 12, adapted from Table 6 of the work of Panah et al. [18], presents these different studies. It is evident from Table 12 that different regions and the associated different findings are due to different CAPEX considerations in the green hydrogen and methanol synthesis, as well as different electricity prices and incentives, thus making the LCOH₂ and LCOMeOH differ and region-specific [63]. For example, the regions such as the USA and some areas in Europe can have the LCOH₂ reaching as high as 8.5 to 11 €/kg. A recent (year 2024) study by TNO [64] has shown that the LCOH₂ is in the order of 12 €/kg to 14 €/kg at a higher electricity price in the Netherlands. These studies are in the range of the findings obtained in this paper at higher electricity prices. As noted in the findings, different electricity and CAPEX assumptions are the two elements that make the prices differ by significant margins [64].

For areas like China with cheaper electricity prices, the LCOH₂ tends to be smaller. Somewhat, for a cheaper Chinese electricity supply market, the literature work of Bai et al. [23] found that their non-flexible process has a LCOMeOH of 2.36 €/kg (i.e., conversion after considering 1€ = 1.13 \$ as a standard in this paper, in their paper it is \$2.67/kg). This result is almost similar to the findings at 80 % of CAPEX

reduction and electricity prices 20 €/MWh in this paper, indicating that LCOMeOH can be abnormally higher than 2 €/kg. As also deduced by Bai et al. [23], although these findings indicate an unusually high LCOMeOH, they are still valuable for practitioners looking to invest in the commercialization of these technologies, highlighting the advantages and disadvantages of each region. Compared to the work of Bai et al. [23], the higher LCOMeOH is due to high LCOH₂, high electricity prices, and other factors like the cost of the large battery storage and load factors. Sollai et al. [79] also determined, considering an Italy's grid-connected scenario, that depending on the load factor and the electricity price, the LCOMeOH can range from 1.0 to 8 €/kg. In line with the findings from Vo et al. [15], the results in this paper show that the electrolyzer CAPEX and the use of a large battery storage make the LCOMeOH abnormally high. The electrolyzer CAPEX, electricity price, and therefore the LCOH₂ still dominate the LCOMeOH, even for a retrofitted scenario. However, retrofitting existing plants will be superior under reduced electrolyzer CAPEX and electricity prices, and high load factor.

5. Conclusions and future work

This work has investigated the grid-connected scenario where energy arbitrage is taken advantage of, such that the electricity used in the PtMeOH is purchased when the electricity price is low (off-peak) and used in the PtMeOH process for hydrogen and subsequently methanol synthesis, and the standalone renewable energy (solar and wind) scenario. Neither scenario is profitable with the current selling price of

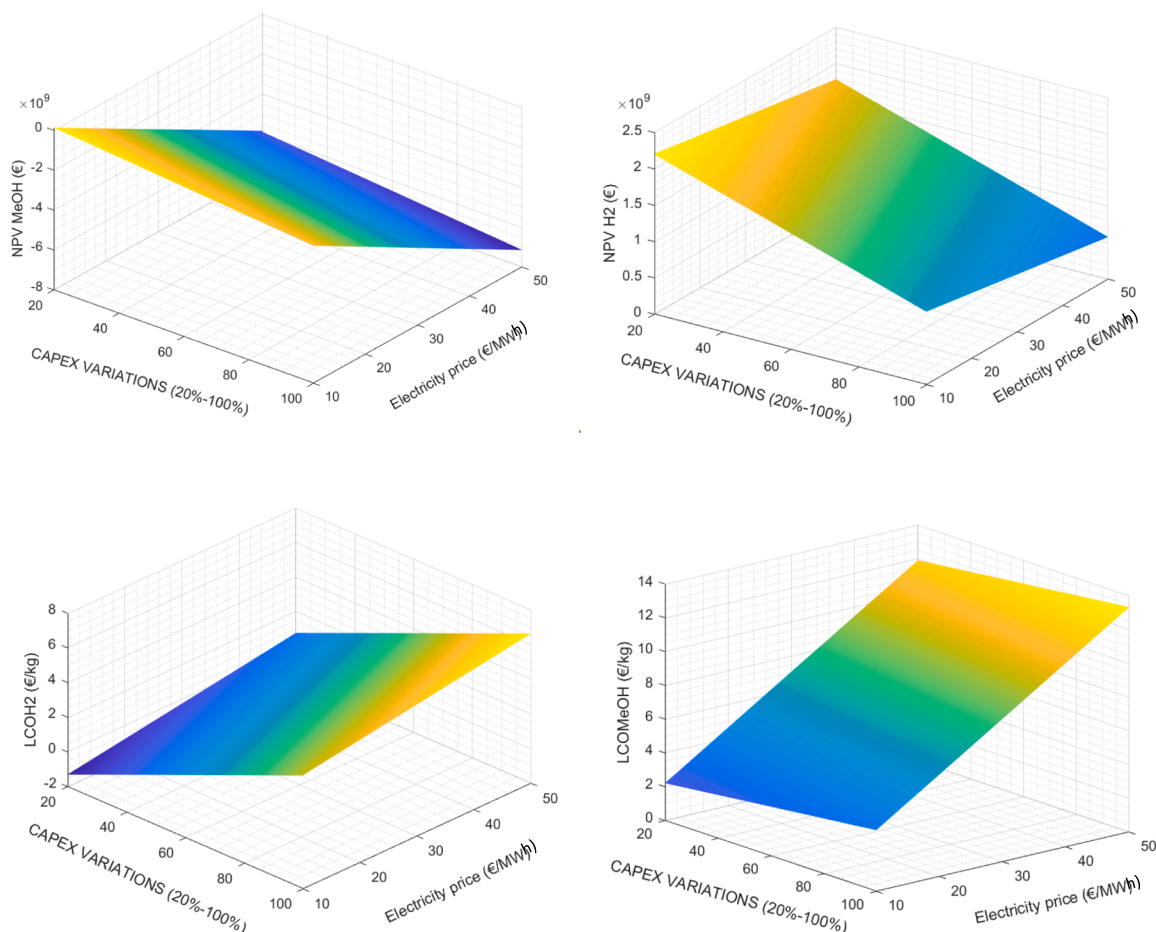


Fig. 7. Scenario 4-Effect of variation of the plant CAPEX and electricity price on the LCOMeOH, LCOH₂, NPVH₂, and NPVMeOH.

methanol and hydrogen. The energy arbitrage scenario is largely prohibited by the high cost of the battery. While the standalone scenario is mostly prohibited in achieving its feasibility by the cost of electricity and the adopted selling price of the final commodity. However, with the introduction of incentives such as the CO₂ tax credit and the feasible reduction in the electricity price, the NPVMeOH will break even earlier than the NPVH₂. On the other hand, the high load factors and reasonable plant lifetime (20 years or more) are required to make the plant feasible, which justifies most economic studies in selecting these conditions in their evaluations. Although the CO₂ credit and reduction in the overall plant CAPEX play a pivotal role in the profitability of the plant, even with a feasible increase and decrease, respectively, they cannot solely make the plant profitable, and thus, the reduction in electricity price still holds the strength to make the PtMeOH profitable. Retrofitting the existing methanol synthesis plant with the electrolysis section in the upstream cannot achieve profitability and economic parity on PtMeOH with the current methanol selling price and electricity price considered herein. However, a significant electricity price reduction to below 10 €/MWh can bring the retrofitted PtMeOH plant to economic parity. Thus, the profitability of the PtMeOH plant is heavily dependent on the electricity and the product selling prices.

Co-selling of the electricity/hydrogen and methanol could be a better strategy to bring the PtMeOH plant closer to feasibility. The plant operation can be scheduled to target enhanced methanol production at low electricity prices with i.e., solid oxide cells operating in electrolysis mode, and to switch to electricity co-production at high electricity prices, by operating the solid oxide cells in reverse fuel cell mode, preferably the H₂ fuel cells. The volatility of the grid-connected electricity

price in the South African electricity market makes it challenging to achieve the feasibility of the PtMeOH. However, this could play into the advantage for plants designed to co-sell the electricity by exploiting the market price dynamics with an aim to optimise profit via process flexibility. The load level can also be varied according to the electricity price. This requires advanced control, scheduling and planning in the process with accurate predictive demand, supply and price forecast model. Future work should consider a more detailed investigation of the effect of co-selling the said commodities and the requirements in terms of electricity price, CO₂ credits, load factors, and CAPEX reduction to make the multi-product plant feasible. Comparison of the effect of using the H₂ and methanol fuel cells must be performed as part of the future studies on these multi-product plants to give more direction to policymakers. For example, it is anticipated that the co-selling of the electricity will be prohibited by the cost of the battery and /or fuel cells – with associated product storage requirements. In addition, uncertainties via Monte-Carlo simulation must be considered on the critical economic feasibility bearing parameters. Moreover, dynamic techno-economic response to electricity price variation based on real time/day ahead and product demand response scenarios deserve further investigation with consideration of uncertainties. This investigation offered a nuanced understanding and generalisable effect trends of various PtMeOH economic feasibility bearing parameters for policymakers and professionals working on addressing the intermittent energy storage using the Power to hydrogen and PtMeOH.

Table 12
LCOH₂ and LCOMeOH from different regions as reported in literature [18].

LCOH Data				LCOMeOH Data			
Configuration/operation	Region	LCOH ₂ (€/kg)	Source	Configuration/operation	Region	LCOMeOH (€/kg)	Source
Grid-connected	USA	7.4	[65]	Grid-connected	Finland	0.6–2.0	[66]
	USA	5.2	[67]		Singapore	1.1–1.2	[24]
	Europe	11	[65]		Nordics	1.8	[68]
	Germany	5	[69]		Sweden	1.1	[70]
	Germany	5.9	[71]		Europe	1.0 – 1.2	[72]
	Belgium	8.1	[71]		Italy	1.0–8	[67]
	The Netherlands	5	[69]		Germany	2.3–2.5	[73]
	Spain	5	[69]		Germany	1.3–1.7	[74]
	Iceland	8.5	[71]		USA	1.6–2.5	[74]
	Denmark	2.5	[75]		Denmark	1.1–1.5	[76]
	Denmark	4.8	[77]				
	China	4.6	[67]				
	Japan	8.4	[75]				
	New Zealand	4	[78]				
	Grid-connected/off-peak	USA	3.4		[67]	Grid-connected/off-peak	Europe
China		2.3	[67]	Singapore	1.0–1.2		[24]
Curtailed Electricity	USA	9.3	[65]	Curtailed electricity	Germany	2.0–6.2	[74]
	USA	4.6	[79]				
	Europe	9.1	[65]				
	China	1	[67]				
Offshore WT	Global	4–8	[80]	Off-shore WT	Sweden	1.5–2.2	[81]
	Denmark	5	[82]		Europe	1.0–2.7	[72]
	Norway	5.2	[83]		Britain	1.95–7.2	[84]
	Ireland	5	[85]				
	USA	3.6	[86]				
WT	USA	3.1	[87]	WT	Finland	1.3–1.5	[66]
	Spain	3.4	[87]		Sweden	1.2	[70]
	Saudi Arabia	3.3	[75]		China	1.2–2.4	[23]
	Australia	3.1–3.6	[75]		Netherlands	4.0–4.5	[88]
	Australia	3.3	[87]		Finland	1.2–1.5	[66]
	Japan	4	[87]		Scotland	>1.1	[88,89]
	Chile	3	[87]				
	Netherlands	12–14	[64]				
	PV						

CRedit authorship contribution statement

Siphesihle Mbatha: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Payam G. Panah:** Writing – review & editing, Validation, Software, Methodology. **Xiaoti Cui:** Writing – review & editing, Visualization, Validation, Supervision, Methodology, Conceptualization. **Paulo Debiagi:** Writing – review & editing. **Benoit Louis:** Writing – review & editing. **Nicholas M. Musyoka:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Raymond C. Everson:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Ksenia Parkhomenko:** Writing – review & editing. **Henrietta W. Langmi:** Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

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Data availability

Data will be made available on request.

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