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Techno-economic Analysis of a Decentralized Polygeneration System

DOMINIC RIVEST
Département de génie mécanique

Mémoire présenté en vue de l'obtention du diplôme de *Maîtrise ès sciences appliquées*
Génie mécanique

Avril 2023

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Ce mémoire intitulé :

Techno-economic Analysis of a Decentralized Polygeneration System

présenté par **Dominic RIVEST**
en vue de l'obtention du diplôme de *Maîtrise ès sciences appliquées*
a été dûment accepté par le jury d'examen constitué de :

Massimo CIMMINO, président
Étienne ROBERT, membre et directeur de recherche
Guillaume MAJEAU-BETTEZ, membre

DEDICATION

The following section is written in French.

Une pousse de plus dans la canopée des savoirs

C'est la fin de ma maîtrise, mais surtout la fin de deux formidables années. Je suis reconnaissant d'avoir eu cette occasion de contribuer au savoir collectif. Cela ne s'est pas fait seul. Je tiens à remercier les personnes que j'ai côtoyées pendant cette aventure. Particulièrement mon directeur de recherche, Étienne Robert, qui m'a initié à la recherche scientifique par un projet UPIR sur la manipulation acoustique des particules il y a plus de 5 ans. Merci Étienne pour ton support, ta flexibilité envers mes projets d'expédition et les opportunités de recherche extrêmement variées que tu m'as confiées (il y a deux ans, je photographiais des médecins éternuant devant une feuille laser pour quantifier les aérosols produits).

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Je tiens à remercier mes parents pour leur support inconditionnel dans mes entreprises. Merci également à mes frères et à ma sœur; Jean-François, Simon et Florence, qui m'ont offert des exemples de réussite dans leurs domaines respectifs et bien des encouragements. Merci à Marie-Léa pour ton soutien tout au long de la rédaction. Je tiens à remercier mes amis et colocataires, Florence, Philippe et Vincent pour ces belles années à l'appartement. Enfin, merci également à tous ceux avec qui j'ai partagé des moments en plein air et toutes sortes d'autres activités. Vous m'avez changé les idées et donné de l'énergie dans les derniers miles.

ACKNOWLEDGEMENTS

The following section is written in French.

J'aimerais tout d'abord remercier mon directeur de recherche, Étienne Robert, pour m'avoir permis de travailler sur un projet aussi intéressant. Ce travail n'aurait pas été possible sans Elie Antar, qui a développé le système de polygénération. Merci Elie pour les réponses à mes nombreuses questions et pour l'aide que tu m'as apportée. Je tiens également à remercier Clémence Lavigueur pour le modèle TRNSYS de la serre, qui fut un élément important de l'analyse techno-économique. Un merci spécial à Marianne Perron pour son support mutuel devant les incertitudes de nos projets parallèles. Je tiens à remercier les équipes de médecins et chercheurs au CHUM et à l'hôpital Ste-Justine avec qui j'ai publié deux articles avant de réaliser le présent projet sur la biomasse. Enfin, merci à Hydro-Québec pour les bourses d'excellence qui m'ont libéré l'esprit des contraintes financières.

RÉSUMÉ

En plein cœur de la crise climatique, des solutions efficaces sont nécessaires pour décarboner la société. Les systèmes énergétiques décentralisés de petite taille permettent l'usage de ressources locales pour répondre aux besoins de la communauté et de l'industrie. Antar et Robert ont publié une étude thermochimique sur un petit système de polygénération fonctionnant à base de biomasse résiduelle lignocellulosique (copeaux de bois) et produisant de l'électricité, du méthanol, de l'hydrogène et un flux de dioxyde de carbone quasi-pur. L'aspect techno-économique d'un tel système doit être exploré pour qu'il passe un jour de la théorie à la réalité.

Cet aspect est évalué ici par une étude techno-économique de l'implantation du système dans une serre du sud du Québec. L'investissement en capital fixe, les dépenses opérationnelles, la valeur actualisée nette (VAN), entre-autres, sont calculées. Une comparaison est faite avec une solution de référence basée sur la combustion simple de biomasse résiduelle pour une durée de vie de 15 ans ; chaque système ayant à répondre aux besoins en chaleur de la serre.

Le prix des copeaux de bois est considéré à 100 CAD/TMA (tonne métrique anhydre), équivalent à 66,67 CAD par tonne de biomasse contenant 45% d'humidité. Trois scénarios de marché sont considérés pour les prix de vente de l'électricité, du méthanol et de l'hydrogène : un scénario pessimiste, de base et optimiste ; menant à l'évaluation de 27 scénarios. Le flux de CO2 produit par le système de polygénération est considéré suffisamment pur pour l'injection directe aux fins d'enrichissement de l'atmosphère de la serre. Cinq puissances de chauffage équivalentes sont testées pour les deux types de système dans le scénario de marché de base avec, au besoin, un système de chauffage auxiliaire pour couvrir les pointes de demande. Pour tous les autres scénarios, seule la configuration la plus prometteuse dans le marché de base du système de polygénération est évaluée.

Le calcul de l'investissement nécessaire en capital est réalisé en se basant sur les données de coût obtenues dans la littérature et sur l'information provenant du modèle thermochimique du système, réalisé à l'aide de l'outil Aspen Plus. Le système de polygénération peut fonctionner dans quatre modes différents, qui visent chacun la maximisation de la production de l'électricité, du méthanol, de l'hydrogène ou de la chaleur, respectivement. L'optimisation de la performance annuelle des deux types de système est faite en implémentant un programme d'optimisation linéaire mixte à l'aide du langage de modélisation Pyomo et du solveur SCIP. La demande en chaleur est obtenue d'une simulation TRNSYS d'une serre de taille moyenne (20 000 m2) située à proximité de Montréal, Québec. L'optimisation est accomplie pour une

durée d'un an en utilisant des pas de temps de 15 minutes.

Des cinq configurations du système de polygénération, c'est la plus puissante (8000 kW) qui offre les meilleurs résultats économiques en termes de revenus annuels et de valeur nette actualisée cumulative. En ce qui concerne le système basé sur la combustion, c'est le quatrième plus puissant (5200 kW) qui offre les meilleurs résultats. La performance économique du système de polygénération est majoritairement dictée par le prix de l'hydrogène. Dans le scénario pessimiste du prix de l'hydrogène, seul un sous-scénario (prix optimiste de l'électricité et du méthanol) génère une VAN cumulative positive. Cependant 7 des 9 sous-scénarios présentent une VAN cumulative semblable ou supérieure au système basé sur la combustion. En tout, 19 des 27 scénarios de marché génèrent une VAN cumulative positive. Dans les scénarios de base et optimiste du prix de l'hydrogène, les valeurs de VAN cumulative vont d'environ 15 MCAD à 40 MCAD.

La profitabilité du système dépend considérablement de l'évolution future des marchés de l'hydrogène et du méthanol verts. L'adoption généralisée de ces biocarburants en tant que vecteurs énergétiques favoriserait l'implémentation de systèmes similaire à celui développé par Antar et Robert. Si la taxe sur le carbone augmente, le reste du flux de CO_2 pourrait être capturé, ce qui a le potentiel de rendre les émissions de carbone du système négatives et d'accroître du même coup les revenus générés.

Les serres et autres industries utilisant plusieurs types d'énergie pourraient profiter d'une valorisation locale des ressources en biomasse. Une autonomie accrue, une résilience augmentée face aux prix du marché et le contournement des difficultés reliées aux chaînes d'approvisionnement sont tous des avantages apportés par un système de polygénération. Les communautés isolées pourraient également réduire leur dépendance aux ressources importées en adoptant ce genre de système. Enfin, des applications de chauffage et de production d'énergie communautaire sont à considérer pour de futures études.

ABSTRACT

In the context of addressing man-made climate change, effective solutions are needed to decarbonize society. Small-scale decentralized energy systems enable the use of local resources to answer the energetic needs of people, communities, and businesses. Antar and Robert have published a thermo-chemical study on a small-scale polygeneration system running on wood chips producing heat, electricity, methanol, hydrogen, and a high-purity stream of carbon dioxide, but the techno-economic aspect of the system remained unexplored.

The evaluation of this aspect is carried out in the context of implementation in a southern Quebec greenhouse, by the means of a techno-economic assessment (TEA). The fixed capital investment (FCI), operational expenditure (OPEX), cumulative net present value (NPV), among other metrics, are evaluated. Comparison is done with a biomass combustion-based reference system for a lifetime of 15 years. Both systems have to cover the greenhouse heat demand, with the eventual use of a costly auxiliary burner to cover demand peaks.

Wood chips feedstock is considered at 100 CAD per oven-dry metric ton (ODMT), corresponding to 66.67 CAD per ton of 45% moisture content biomass. Three price scenarios are investigated respectively for electricity, methanol, and hydrogen: pessimistic, baseline, and optimistic; leading to the evaluation of 27 market scenarios. The polygeneration system CO_2 output stream is considered pure enough for direct injection in the greenhouse for atmosphere enrichment. Five power scenarios are investigated for both polygeneration and combustion-based systems in the baseline market scenario. In the 26 other market scenarios, the optimization is run only for the most promising polygeneration configuration.

The FCI evaluation is accomplished using data from the literature and the information from the thermo-chemical model of the polygeneration system, implemented in the Aspen Plus software. The polygeneration system can run in four different modes, each one aiming to maximize the production of either electricity, methanol, hydrogen, or heat. To optimize the annual operational performance of both system types, a mixed-integer linear program is implemented using the Pyomo modeling language and the SCIP solver. The input heat demand is obtained from a TRNSYS simulation of a medium-sized greenhouse tomato producer (20 000 m^2) operating close to Montreal, Quebec. The optimization is run for a year using 15 minutes timesteps.

Of the five polygeneration power configurations, the most powerful system (8000 kW) yields the best economic results in terms of annual revenues and cumulative NPV. On the combustion side, the fourth most powerful combustion-based system (5200 kW) gives the highest

(but negative) cumulative NPV. The hydrogen price is the most determining factor regarding the cumulative NPV. In the pessimistic hydrogen market price scenario, only one sub-scenario (varying methanol and electricity prices) has a positive cumulative NPV, but seven of the 9 low hydrogen price sub-scenarios give similar or better results than the combustion-based system. Overall, 19 of the 27 market scenarios present a positive cumulative NPV. In baseline and high hydrogen market price scenarios, the cumulative NPV ranges approximately from 15 MCAD to 40 MCAD.

The profitability of the system depends considerably on the future market evolution of green hydrogen and green methanol. The widespread adoption of those biofuels as energy carriers would promote the implementation of systems similar to the one developed by Antar and Robert. If carbon pricing increases, the remainder of the CO_2 rich stream could be captured to make the system carbon negative and more profitable.

Greenhouses and other industries requiring many utilities could benefit from producing them on their premises. Increased autonomy, resilience to market prices, and to difficulties in the supply chain are examples of those benefits. By adopting polygeneration systems, isolated communities could reduce their dependence on foreign resources. District heating and energy production applications should also be considered in future studies.

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LIST OF SYMBOLS AND ACRONYMS

CAPEX	Capital expenditure
CAD	Canadian dollar
CEPCI	Chemical engineering plant cost index
CGC	Cold gas cleaning
CHP	Combined heat and power
GHG	Greenhouse gas
DER	Distributed energy resources
DFB	Dual fluidized bed
DPP	Discounted payback period
ER	Equivalence ratio
EUR	Euro
FCI	Fixed capital investment
FTS	Fischer–Tropsch
HGC	Hot gas cleaning
HHV	Higher heating value
IRENA	International Renewable Energy Agency
IRR	Internal rate of return
LCOE	Leverized cost of energy
LHV	Lower heating value
MILP	Mixed-integer linear programming
NPV	Net present value
ODMT	Oven-Dry Metric Tonne
OECD	Organization for Economic Co-operation and Development
OPEX	Operational expenditure
SEK	Swedish krona
SNG	Synthetic natural gas
SOFC	Solid oxide fuel cell
SOEC	Solid oxide electrolyzer cell
TCI	Total capital investment
TEA	Techno-economic assessment
USD	United States dollar

CHAPTER 1 INTRODUCTION

Humanity is already facing the impacts of climate change caused by fossil fuel combustion and the pollution of ecosystems. The multiplication of catastrophic events such as wildland fires, floods, and droughts has raised awareness and emphasized the need for a bold and quick shift toward renewable energy. Keeping current greenhouse gas (GHG) emission levels constant during the next decades could lead to a disastrous change in global mean surface temperature of + 2.1 °C up to + 3.5 °C [6].

There is a plethora of interrelated macro and micro-scale solutions to alleviate this complex issue. On a large scale, it generally means replacing the fossil fuel part of the energy mix with renewables, especially in power production, transportation, and industrial sectors. On a smaller scale, it means decentralizing and diversifying energy production to make it closer to the end users. The adoption of renewable distributed energy resources (DER) increases the resilience of energy systems, lowers consumers' energy bills and, if managed properly, can help to stabilize national energy grids [7].

1.1 Context

Except for hydroelectricity production, most renewable energy sources are intermittent (i.e. solar and wind). They also need suitable geographical conditions: hydraulic potential for hydroelectricity; windy conditions for wind farms; low enough latitudes for interesting solar energy. The mismatch between renewable power production and consumer demand induces the need for complementary baseload power sources. While having traditionally been provided by coal, natural gas and nuclear power plants, biomass can cover a part of that baseload.

Because of their convenience and energy density, fossil fuel products are transported over long distances before their conversion into large facilities and end-use. The crude oil consumed in Quebec in 2020 mostly came from Western Canada and the United States [8]. In opposition, biomass has a smaller density and is attractive when used locally. As the feedstock for combined heat and power (CHP) and polygeneration installations, biomass can also enable the on-site use of byproducts (heat, biofuels, CO_2, etc.) thus leading to better overall energetic efficiencies than equivalent separated systems [9].

Furthermore, locally-sourced biomass is available in many areas. If harnessed, it can become a powerful local development lever. For example, the German cities of Emden and Soltau showcase the benefits of a renewable energy ecosystem based on wind turbines and biogas

production. Cooperation between institutions and different actors of the renewable value chain were the keys that helped to increase local income and employment while diversifying the regional economy [10].

1.1.1 Decentralization as a tool to fight climate change

The increasing complexity of power loads challenges traditional grid designs and the way energy is priced. Centralized grid models with unidirectional current from power stations to consumers through long transmission lines don't have the flexibility to cover those varying loads. DER, such as wind turbines, rooftop photovoltaic panels, and their coupling with battery storage systems, are to play a key role in the energy transition, bringing the flexibility needed in the grid [11, 12]. The adoption of DER, pushed by the increasing affordability of renewable production means, enables consumers to become prosumers, increasing their autonomy, reducing the transport of energy and creating grid optimization opportunities [13].

Furthermore, producing energy near its consumption site reduces the need for large and controversial transport facilities such as pipelines and high-voltage transmission lines. The multiplication of small energy producers may also impede the need for new large power stations such as hydroelectric complexes, nuclear and thermal power facilities. However, even if DER face less opposition than large energetic projects, social acceptance is capital for their widespread adoption in neighbourhoods [14–16].

1.1.2 Exploring the potential of polygeneration

While CHP installations produce two product types (heat and power), polygeneration facilities produce three or more. The polygeneration system of interest in this study aims to produce storable biofuel from perishable biomass, among other energy vectors. Concerning the feedstock type, one can distinguish three generations of biofuel. The first generation is made from edible food crops such as corn, sugar cane, and sugar beets. In some countries, the trade-offs between human food, animal feed and biofuel production are a matter of debate, as well as the sustainability of the monoculture related to first-generation biofuels [17, 18]. The global bioethanol market is led by the U.S.A. and Brazil, which use corn and sugar cane, respectively [19]. In opposition, second-generation biofuels are obtained from non-edible crops, edible crop residues, municipal waste, forest residues, etc. Most of this feedstock is composed of lignocellulose. Lignocellulose is composed of hemicellulose, cellulose and lignin, and is widely available on Earth [20]. It has the advantage of being non-digestible by humans and most animals, preventing the food competition associated with first-generation biofuels. The potential of the third generation, derived from algae, is still under evaluation [21]. The

present study considers the use of lignocellulosic feedstock (wood chips).

There are many possible paths for biomass conversion to biofuels. Of those, there are three main thermochemical conversion routes for lignocellulosic feedstock: combustion, pyrolysis, and gasification. Combustion is only good at producing heat, fast pyrolysis is suitable for conversion into bio-oil and gasification converts the feedstock into producer gas [22]. This syngas has the advantage of being a highly flexible product, making gasification a promising process for a polygeneration system.

Canada and more specifically Quebec possess abundant residual lignocellulosic resources from the agricultural and forestry sectors [23]. However, there were no commercial gasification plants in activity in the province as of 2021 [24]. Biomass-powered polygeneration systems could provide the energetic needs of isolated communities having access to ample lignocellulosic resources. Northern villages in Quebec could, for instance, replace the outdated and heavily polluting diesel power generation units with biomass-powered polygeneration systems.

Polygeneration systems could also serve other sectors currently relying on fossil fuels. Agriculture is one of those. The propane crisis of 2019 clearly shows the drawbacks of relying on distant energetic resources. The CN strike caused a propane shortage for Quebec corn farmers at the moment of grain drying [25]. The crisis resulted in grain losses. Having the possibility of producing renewable fuels locally could have changed the outcome.

Greenhouses could also see benefits in more efficient energy systems, as heating is their second most important cost after labour in cold climates [26]. It was determined that cucumber, tomato, and pepper production could be profitable in Canadian prairies, but was highly dependent on the product prices. In northern Saskatchewan communities, local greenhouse production would take advantage of the high prices of imported food during winter months [27]. Similar conclusions can be expected for the province of Quebec. Since heat, power, and CO_2 are needed for greenhouse vegetable production, it becomes a promising location for the implementation of biomass-based polygeneration systems.

Antar and Robert worked on the design of decentralized polygeneration systems capable of producing heat, electricity, methanol and a CO_2-rich stream [1]. The systems were modelled using the Aspen Plus process simulator. The authors studied two gasifier configurations: downdraft and dual fluidized bed (DFB) gasifiers. Both were associated with a syngas cleaning system, a methanol synthesis subsystem, a solid oxide fuel cell (SOFC) for power production, and a solid oxide electrolyzer cell (SOEC) for oxygen generation and syngas H_2 enrichment prior to biofuel conversion. Theoretical efficiencies and parametric studies on key design parameters were conducted and enabled the definition of four operational modes.

Each mode aims to maximize the production of either electricity, methanol, hydrogen or heat. For both technologies, the total efficiency was close to 85% in the four modes. The DFB system was found to convert a higher proportion of biomass into valuable products that were not heat. It was chosen as the system of interest for the present study. While those results are promising, a lack of information on the system's techno-economic performance remains.

In the DFB gasifier-based system, the biomass is first dried before the gasification in the DFB. The combustion chamber, with pure oxygen as the oxidizer, provides the necessary heat for the steam-based gasification process through the bed material and is also the source of the exiting high-purity CO_2 stream. The syngas from the gasifier is cleaned and sent to the methanol reactor, which operates at 30 bar. The remaining syngas is sent to the SOFC to generate either surplus electricity or the amount needed for compressor and SOEC operation. Leftover syngas is burned to generate steam. Steam is used as a gasification agent and as an input for SOEC oxygen and hydrogen production. A simplified schematic of the system is shown in figure 1.1.

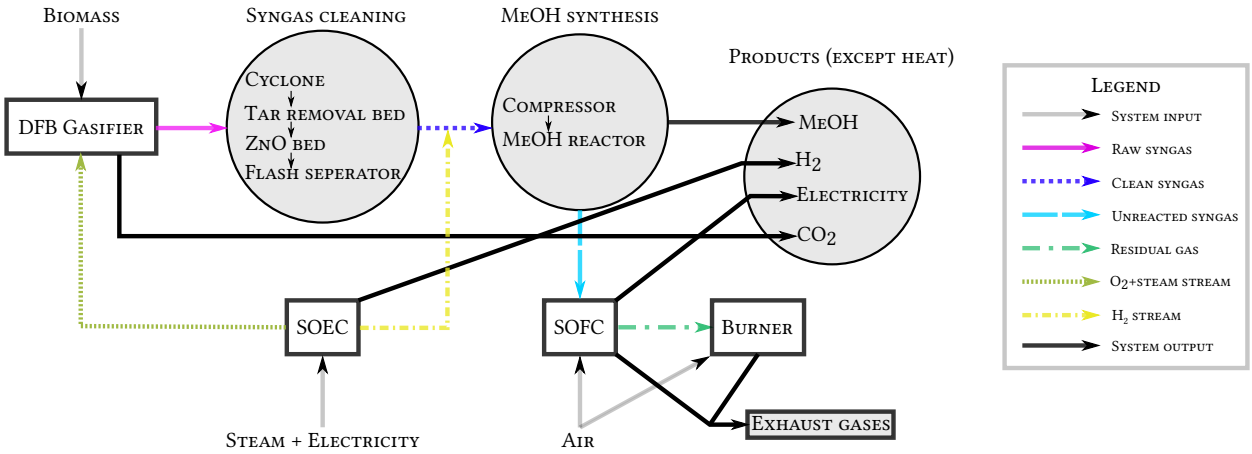


Figure 1.1 Simplified schematic of the DFB polygeneration system

1.2 Research objective

A techno-economic assessment enables the evaluation and comparison of technologies on the technological and economic side. Other factors, such as environmental impacts and social acceptance can be considered. While many techno-economic studies have been conducted on gasification installations, few have been realized on small-scale polygeneration systems. To the author's knowledge, no research has been conducted on such a system implementation in the context of greenhouse heating.

This study means to assess the techno-economic potential of the aforementioned DFB system, paired with a medium-sized greenhouse (20 000 m^2), in comparison with a combustion-based system.

1.3 Thesis outline

Apart from the current introduction, this thesis is divided into 5 main chapters. The first one is the literature review. The second one contains precisions on the methodology used for fixed capital investment and optimization implementation. The third one is the article that was submitted to *Sustainable Energy Technologies and Assessments*. The fourth one presents the discussion of this study, and the last one is the conclusion.

CHAPTER 2 LITERATURE REVIEW

The following literature review exposes the key subjects for the techno-economic analysis of the polygeneration system proposed by Antar and Robert.

As the techno-economic assessment requires the preliminary design of subsystems, the literature review presents the technologies related to or competing with the ones used in the polygeneration system (figure 1.1). Available techno-economic assessment approaches are also discussed and examples of energetic system analysis are presented, with an emphasis on biomass-powered and small-scale implementations. Electricity, green methanol, and green hydrogen markets are discussed because of their importance on the financial results of the polygeneration system's TEA.

2.1 Thermochemical biomass conversion

There are three main traditional technological biomass conversion pathways: biochemical, hydrothermal, and thermochemical [2, 3]. They are shown in figure 2.1. The polygeneration system mentioned above is based on thermochemical syngas production from gasification. The main difference with conventional paths resides in the way that produced syngas can be used. The following section focuses on gasification and syngas conversion technologies. The topic order generally follows the biomass feedstock path into the polygeneration system presented in figure 1.1. For major subsystems, technologies having similar purposes to the ones selected are discussed.

2.1.1 Gasifier technologies

Gasification process and technologies

With biomass gaining interest as a source of decentralized renewable energy, many gasification technologies have emerged in the past years. Gasification refers to converting a solid carbonaceous feedstock into a gas called syngas, or producer gas [28]. The feedstock can be either fossil-based, such as coal, or biomass-based, such as wood chips. The gasifier is the core of the polygeneration system considered in this study, as the syngas it produces is the input of all subsequent processes, converting it into other valuable products. It also constitutes a significant source of heat for the system.

Molino *et al.* describe the gasification process in five main steps: Oxidation (exothermic);

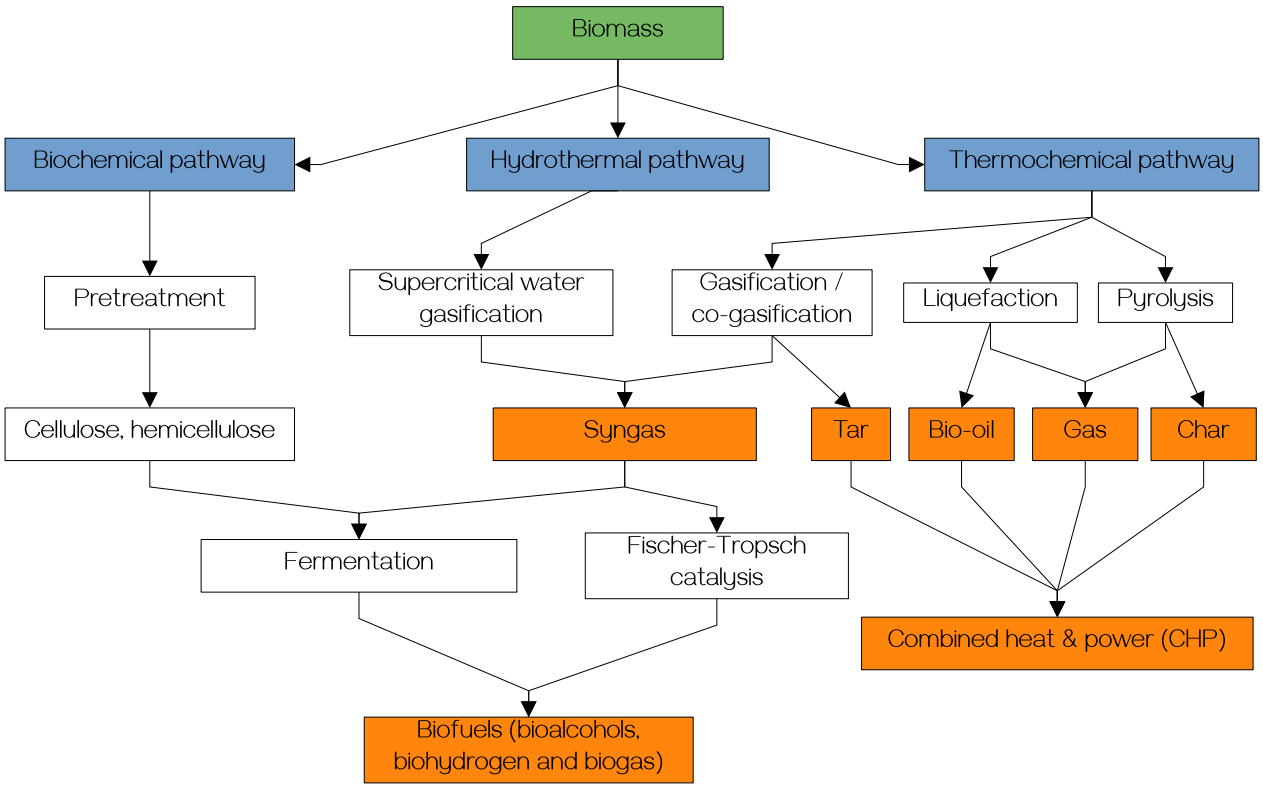


Figure 2.1 Major biomass conversion routes (redrawn from [2, 3])

Drying (endothermic); Pyrolysis (endothermic); Reduction (endothermic); Tar decomposition (endothermic) [29].

The necessary heat for the endothermic reactions comes from the oxidation step, where the feedstock is partially burned. The resulting heat dries the fuel, which goes through pyrolysis and reduction. The tars produced during the pyrolysis process are partially decomposed before going through reduction. The resulting product gas is called syngas and is primarily composed of carbon monoxide (CO) and hydrogen (H_2) [30]. Generally, all these reactions occur in a gasifier. Five main reactor technologies are used in biomass gasification: entrained flow, fixed bed, fluidized bed, rotary kiln, and plasma.

In the first one, the pulverized biomass fuel and the gasifying agent are injected co-currently. Two entrained flow reactor types are distinguished: slagging and non-slagging. In the first type, slag covers the reactor walls while flowing down towards the bottom, where it is collected [31]. Slag is a residue matter mainly created by two mechanisms during biomass combustion: crystal precipitation of alkali metal components of the feedstock and ash fusion [32]. Fuel pulverization requires feedstock pre-treatment to reduce particle diameter to approximately 100 µm, a very energy-intensive process. High sensible heat in producer gas, necessitating

heat recovery to increase the efficiency, and high-maintenance cost hinder the attractivity of entrained flow gasifiers [33].

The second one, fixed bed reactors, is declined in two types: updraft and downdraft reactors. In updraft reactors, the gasifying agent is injected at the bottom, the fuel at the top, and the resulting syngas is extracted at the top of the reactor. In downdraft reactors, the gasifying agent is injected at the center, while the fuel is injected on top, and the syngas is extracted at the bottom of the reactor. Both are simple designs, with the downdraft considered more reliable. Still, both reactor types face scale-up issues, and disadvantages (difficult temperature control, limited flexibility, high content of tar for updraft reactors, etc.) [29, 34].

The third one, fluidized bed reactors, is also declined in two types: bubbling and circulating fluidized bed reactors. Here, the bed refers to a mixture of solid fuel with another mostly inert solid material such as sand. In bubbling reactors, the gasification agent is injected into the bed, creating gas bubbles. In the circulating reactors, the bed is dragged in a circulating loop by the gasification agent. Compared to fixed bed reactors, fluidized bed reactors mechanically break fuel particles, offering better mixing capabilities leading to higher heat transfer rates and more constant temperatures in the gasifier. According to Molino *et al.*, it is the most promising technology but is also more expensive than fixed bed reactors [29].

The fourth type, the rotary kiln gasifier, involves a slowly rotating horizontal cylinder in which the feedstock is fed on top as opposed to the gasifying agent provided at the bottom on one side of the kiln. The collection of the syngas and the slag is done on the opposite side of the kiln. With good efficiency and reduced investment costs, it also features high maintenance costs (partly related to rotating parts) along with a problematic temperature control [35–37].

The last type of reactor is the plasma gasifier. The plasma is either produced with torches or microwave-induced. The first technology uses electrodes to create the plasma that heats the fuel directly or the gas obtained by upstream gasification. While yielding the best syngas among the other reactors, it presents very high plant and maintenance costs, moving parts, safety challenges, and lack of standards while being a non-continuous process [38]. Another technology involving plasma gasification has emerged in the past years: microwave-induced plasma gasification. Addressing many of the problems in plasma gasification, such as the short lifespan of electrodes, it also yields syngas with a low tar content [39]. Vecten *et al.* have made a 6 kW microwave power setup yielding hydrogen-rich syngas [40]. The authors obtained satisfying results yet there is a need for optimization and investigation of the contaminants produced.

While a broad range of gasification technologies is available, only some are adapted to decen-

tralized operation. Out of the lot, fixed and fluidized bed gasifiers offer a good compromise between cost and efficiency for decentralized wood chip gasification. The limited feedstock pre-treatment associated with those reactor types is also attractive for decentralized operation. A fluidized bed reactor configuration was selected for the present techno-economic analysis because it yields the best syngas among the two types. The use of pure oxygen as the oxidizing agent, often overlooked in the literature because of the related costs, is also considered in this study. It increases the chemical power density of the resulting syngas while reducing the gasifier's footprint.

2.1.2 Gasification facility design

With the gasification technology democratization, some focus has been given to the design process of small-scale facilities, including CHP and polygeneration ones. Design methods such as Cross's [41] conceptual approach, Peters's plant design methodology [42] or Woods's rules of thumb [43] give guidelines for the process. Those methodologies are relevant to the component selection for the subsystems of the polygeneration system discussed in this study. As an example, Zoungrana *et al.* followed Cross's method in the development of a 44 kW (syngas power) small-scale combined heat and electricity biomass gasification installation in West Africa [44]. Through their design process, local manufacturing and simplicity of maintenance were put on emphasis. Using rice husk as the feedstock, a downdraft gasifier, a cleaning and cooling unit (cyclone, heat exchanger, rice husk filter with oil bubbler for tar removal), and an internal combustion engine, they were able to build a working prototype. While yielding lower efficiency than other available technologies, the design responded adequately to the decentralized energy problem the authors faced.

Once a concept is established, variations of interesting designs are compared to each other in terms of energy, exergy, environment, and sometimes economics. Available resources, economic parameters, and simplifications from the literature are stated as the systems' comparison basis. The cold gas efficiency, the potential for power generation, CO_2 emissions, global heat balance, and return on investment are all popular metrics, among others. With the help of a sensitivity analysis, the most important process parameters are pointed out [45–47]. Identifying simple and efficient approaches in facility design is a key step for the preliminary work required in the techno-economic analysis of the polygeneration system of interest.

2.1.3 Syngas cleaning

The raw syngas exiting a gasifier contains contaminants such as particle matter (PM), tar, acid gases (H_2S, HCl), and alkali compounds that must be removed/reduced before any

downstream processes to ensure their proper operation. In the present study, the SOFC used in the system requires a gas with low contaminant content to operate properly, making syngas cleaning technologies important. Woolcock *et al.* have done an extensive review of hot gas cleaning (HGC) and cold gas cleaning (CGC) solutions [48]. CGC solutions are more mature techniques compared to HGC. However, they offer a worse energy efficiency than their hot counterpart and often imply a wastewater stream that must be treated. HGC techniques, reducing the need for cooling, are more efficient, but some are still under development.

Particle matter and tar removal

Particle matter removal in HGC can be done with inertial separation (cyclones), electrostatic precipitation, and barrier filtration (with different types of filters). In CGC, PM can be removed by wet scrubbing. Wet scrubbing is done by spraying a liquid (often water) onto the syngas to collect particulate matter and tar in a waste stream. This waste stream is next treated in proper facilities before its disposal. In a small-scale and decentralized system, these facilities would require a substantial additional investment, making wet scrubbing unattractive [49]. The most cost-effective solution for PM removal in the system considered here allowing continuous operation in a high-temperature environment with minimal maintenance is a cyclone.

Depending on the gasifier type, the tar content in the syngas can be relatively high, up to 10-20 % by mass for updraft gasifiers [50]. Using a dual-fluidized bed (DFB) gasifier with proper bed material can significantly reduce syngas tar content [51]. High tar content can clog engines and cause heat exchanger fouling [52, 53]. In HCG, removing tars can be done in four ways: thermal cracking, catalytic cracking, non-thermal plasma, and physical separation. In CGC, tar removal can be carried on by wet scrubbing and with the use of biofilms [48]. A lot of work has been done to implement syngas cleaning solutions. For example, Wiyono *et al.* tested a multi-integrated gas cleaner system (IGCS) composed of a cyclone, a venturi scrubber, and a rotary separator after a downdraft gasifier. They were able to reduce significantly syngas tar content [54]. In the present study, a nickel steam-fluidized bed reactor is considered for tar cracking. The DFB gasifier also partially cracks tar before the nickel bed reactor.

Acid gases and alkali compounds treatment

Reduction of the syngas ammonia (NH_3) content is necessary for many downstream syngas applications (e.g., gas turbines, fuel cells). In HGC, it is mainly achieved using catalysts such as Ni-based compounds. In CGC, since ammonia is highly soluble in water, wet scrubbing

or similar techniques involving water are used. Depending on the feedstock, there may also be a need for hydrogen chloride (HCl) removal. It is usually removed in CGC along with tars and ammonia. For removal in HGC, several sorbents can be used. Sorbents are compounds that attract specific molecules either by absorption (attractivity inside the absorbent) or adsorption (attractivity on the surface of the adsorbent) [55]. Some examples include calcium-based sorbents, activated carbon, and sodium-rich minerals. Sorbents are used in case of an oil spill to recover oil and prevent its dispersion in the environment. Alkali compounds can be removed similarly (using water in CGC and sorbents in HGC) [48]. The acid gas removal is carried out by a zinc oxide bed in this study.

2.1.4 Conversion of syngas into biofuels

After cleaning, the syngas produced by the polygeneration system can be converted into different value-added energy carriers. This includes methanol, the main storable biofuel considered here. Below is a review of the many syngas conversion possibilities.

One of the main advantages of biomass gasification lies in the versatility of its primary product, syngas. Synthesis gas is composed mainly of carbon monoxide (CO), hydrogen (H_2) and methane (CH_4) [56]. It can also contain carbon dioxide (CO_2), water (H_2O), and be diluted in nitrogen (N_2) if produced by air gasification. Syngas made with air has a lower heating value, around 4-7 MJ/NM^3, than syngas produced with pure oxygen (O_2) or steam (H_2O), which has a heating value of around 10-12 MJ/NM^3. Optimized DFB gasifiers can produce syngas heating values of up to 12-20 MJ/NM^3 [57]. For reference, natural gas has a heating value of around 37 MJ/NM^3 [58]. After cleaning with the means discussed earlier, syngas can be converted to biofuels and other added-value chemicals and used for electricity production.

Numerous routes can be followed to produce high-value chemicals from synthesis gas. Ammonia (NH_3) can be produced by using the water-gas shift reaction to enhance H_2 content before reacting the H_2 with nitrogen (N_2) using a catalyst in the Haber-Bosch process [59]. The catalyst is often iron and is needed to break the stable triple covalent bond between the two nitrogen molecules. The water-gas shift reaction is widely used in the industry to increase the hydrogen content in syngas by the catalyzed reaction of steam and carbon monoxide. The overall reaction mechanism is shown in equation 2.1 [60].

$$\mathrm{CO} + \mathrm{H_2O} \xleftrightarrow{cat} \mathrm{CO_2} + \mathrm{H_2} \tag{2.1}$$

From syngas, replacements for petroleum-based chemical products can be obtained following

the well-known Fischer–Tropsch synthesis (FTS). FTS is a catalyzed hydrogenation reaction of carbon monoxide [61]. The two main reactions occurring during the synthesis are shown in equation 2.2 (alkane formation) & 2.3 (alkene production). Waxes, olefins, diesel and gasoline, can be obtained by the FTS polymerization process.

$$\mathrm{nCO} + (2\mathrm{n}+1)\,\mathrm{H_2} \xleftrightarrow{cat} \mathrm{C_nH_{2n+2}} + \mathrm{nH_2O} \tag{2.2}$$

$$\mathrm{nCO} + 2\mathrm{nH_2} \xleftrightarrow{cat} \mathrm{C_nH_{2n}} + \mathrm{nH_2O} \tag{2.3}$$

Many chemicals can be derived from methanol, and methanol can be produced from syngas through the hydrogenation of carbon monoxide (eq. 2.4) [4]. The reaction is commonly catalyzed by Cu/ZnO or $Cu/ZnO/Al_2O_3$, with the latter increasing the hydrogenation reaction efficiency [62–64].

$$\mathrm{CO} + 2\,\mathrm{H_2} \xleftrightarrow{Cu/ZnO/Al_2O_3} \mathrm{CH_3OH} \tag{2.4}$$

Methanol-derived chemicals include the following: Methyl tert-butyl ether (MTBE), primarily an anti-knocking agent for gasoline; Acetic acid, a well-known solvent; Olefins, raw materials for polymer production; ethanol; Dimethyl ether, a diesel alternative and laboratory reagent; formaldehyde, a food preservative and input in paper, fertilizer and production of some resin. Methanol can also be used directly as a fuel in M85 and M100 fuels, as well as for electricity production in Direct Methanol Fuel Cells (DMFC).

Ethanol, while it can be derived from methanol and DME, can also be produced directly from syngas. The use of single-step tandem catalyst reactor designs now enables an ethanol selectivity of over 90%. Using two reaction-specific catalysts in the same reactor bed decouples complex reactions and leads to a higher syngas conversion than using a more generic catalyst [65].

Isobutane is a refrigerant and a fuel. Isobutene is a fuel additive and the base of butyl rubber. Both are useful molecules in the petrochemical industry and can be produced directly from syngas by catalyzed reactions. Traditionally, thorium oxide was used to catalyze their production but was discarded for being radioactive. Zirconia oxide (ZrO_2) now plays this role, but research is ongoing to improve catalyst activity. As an example, Zn-doping was shown to enhance isobutene selectivity over basic zirconia oxide [66].

Methanation from syngas is a historically known path for synthetic natural gas (SNG) production. To produce methane, carbon monoxide and dioxide are hydrogenated with the help of a catalyst (eq. 2.5 & 2.6). Nickel is the most common catalyst because of its high

selectivity and low cost [67].

$$CO + 3\,H_2 \longleftrightarrow CH_4 + H_2O \tag{2.5}$$

$$CO_2 + 4\,H_2 \overset{ni}{\longleftrightarrow} CH_4 + 2\,H_2O \tag{2.6}$$

The different syngas conversion routes discussed earlier are summarized in figure 2.2.

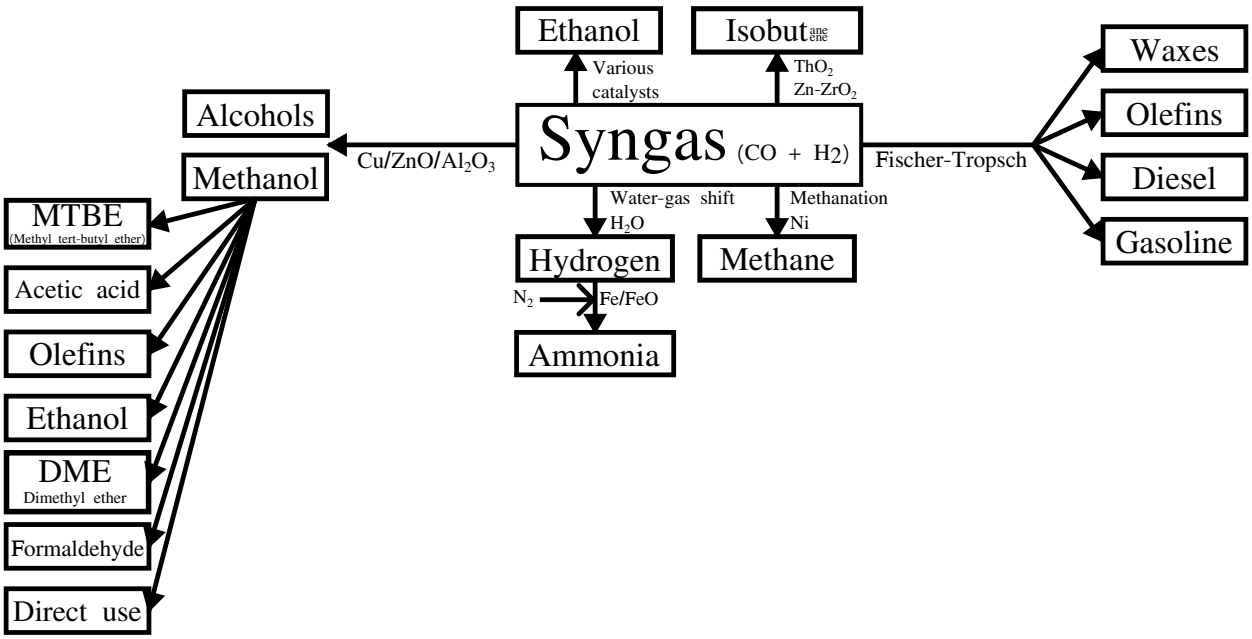


Figure 2.2 Syngas conversion pathways (adapted from [4])

Syngas is a highly versatile product. Its conversion offers a great number of possibilities, constrained mainly by equilibrium reactions, catalyst development, and cost. In the present study, syngas is partly converted to methanol. The leftover is fed to a SOFC (discussed in the next section), and the residual gas is burned to produce steam for the gasification process. Other routes are to be explored in the future, including the production of methane instead of methanol. One could also imagine a modular approach where syngas would be fed to different production modules, following the need and prices for the chemicals produced by the polygeneration system.

2.1.5 Electricity production

Power production from syngas is achieved either by internal combustion engines (ICE), gas turbines, or fuel cells. While the two first approaches are already implemented at the com-

mercial scale, fuel cells are a novel promising technology that has not yet been deployed at large scale, according to Molino *et al.* [29]. Fuel cells are the technology considered in this study for electricity production.

Internal combustion engines (ICE)

It is common for currently operating CHP small-scale gasification installations to use internal combustion engines (ICE) coupled with a generator to produce electricity [68]. While a flexible and proven technology, ICEs have a remarkably low thermal efficiency estimated between 10-15 % when operated with syngas [69]. Two types of ICE exist, spark ignition and compression ignition. Well explored with diesel and natural gas, dual-fuel compression engines running on a mixture of syngas and diesel or diesel surrogate are being investigated. They achieve better thermal efficiency than spark ignition engines but also require another fuel, usually fossil-sourced to operate. Efficiencies up to 38% were reported, with syngas composing 90% of the fuel energetic value [70]. Tar and other impurities deposition in engines, and syngas composition change during storage have been identified as the major fuel contaminant-related problems [71]. ICE syngas contaminant content requirements are the following: tar <100 mg/NM^3; particulate < 50 mg/NM^3; metals < 0.025-0.1 ppmw; H_2S < 20 ppmw [29]. Low efficiency, the high number of moving parts, and the low heating recovery potential of the exhaust gas are the reasons why ICEs have been discarded for use in the polygeneration system.

Gas turbines (GT)

Usually seen in large CHP installations, gas turbines can be used with syngas to power generators. However, the development of optimized GT is necessary to ensure proper operation with lower heat value fuels such as syngas. Higher exhaust mass flow, adaptation needs for auxiliary equipment, and the hydrogen-rich syngas combustion characteristics (high flame speed, high flame temperature, and wide flammability range) are challenges when burning syngas in GT [72, 73]. Syngas must be cleaned before its use in GT. The syngas contaminant content requirements for GT are the following: tar <10 mg/NM^3; particulate < 2.4 mg/NM^3; metals < 0.025-0.1 ppmw; H_2S < 20 ppmw [29].

Micro gas turbines (MGT) are small-scale power generation systems offering 15-300 kWe of power have been developed in recent years. Compared to ICE, they offer similar cogeneration efficiency, reduced emissions, smaller footprints, quieter operation, reduced maintenance, greater fuel flexibility, and higher reliability, but require higher investment costs [74]. Successful experiments have been accomplished to fuel MGT with syngas, but they face similar adaptation challenges than their larger counterparts. It has also been shown that MGT can

offer flexibility in shifting between electricity and thermal power production [74–76]. Their low electrical conversion efficiency ≈ 30% is the reason why MGT were not selected to be part of the polygeneration system.

Solid oxide fuel cell (SOFC)

Fuel cells represent a promising mean of energy conversion because of their higher efficiency, reliability, and relative cleanliness compared to other means, such as ICEs [77]. Solid oxide fuel cells (SOFC) are highly efficient power generators suitable for integration with gasification systems, yielding efficiencies around 60% for power generation only and up to 90% in CHP facilities [78]. The working Principle of the SOFC is shown in figure 2.3.

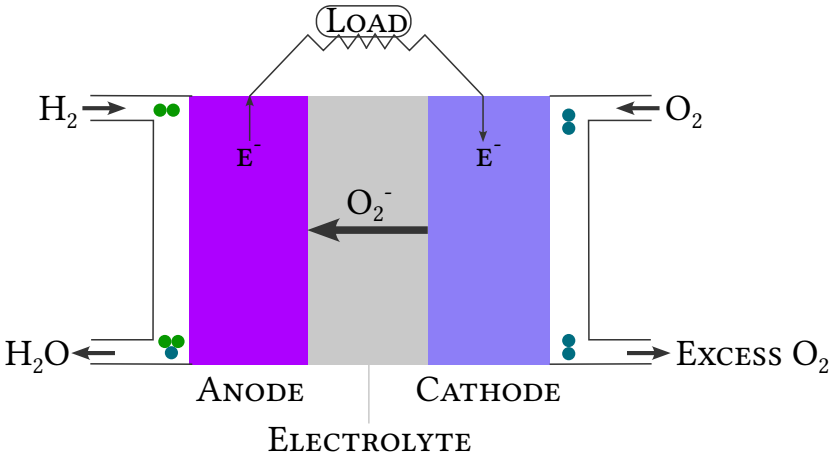


Figure 2.3 Working Principle of the SOFC

SOFC applications require low contaminant levels to ensure their proper operation and reliability. Marcantonio *et al.* have done a review of the syngas cleaning techniques suitable for feeding a SOFC system [79]. Most of the methods presented are discussed in section 2.1.3. The difficulty in predicting the actual cell voltage also remains a challenge in adopting SOFCs for syngas fueled systems [80]. The SOFC technology was selected for electricity production in the polygeneration system because of its high efficiency and suitability for combined syngas electrical conversion and heat production.

Oxygen and H_2 production with solid oxide electrolyzer cell (SOEC)

A SOFC operated in a regenerative mode is called a solid oxide electrolyzer cell (SOEC). It consumes electricity to separate molecules. When used with steam, SOECs can produce pure steams of H_2 and O_2 [81]. In a gasification system, H_2 can be used to enrich the syngas hydrogen content while O_2 can serve as the gasifier oxidizer agent instead of air, as

in the present polygeneration study. Hydrogen enrichment enables a higher syngas calorific value [82]. The use of pure O_2 as gasification agent also means lower flow rates for the same amount of energy produced, reducing the gasification system's physical footprint.

2.1.6 Combined heat and power and polygeneration systems

Existing small-scale biomass combined heat and power facilities

Combined heat and power facilities can be considered polygeneration systems precursors. They pursue the same purpose: using feedstock more efficiently by converting it into more than one form. The following section is devoted to existing CHP installations and to polygeneration system designs.

With interest in harnessing the potential of local biomass resources, many gasification projects have been implemented in the last decades. Situmorang *et al.* have done a worldwide review of small-scale gasification systems with an emphasis on sub-200 kW facilities. While research and development of biomass gasification were mainly conducted in Europe, especially in Germany, Denmark and Sweden, most small-scale systems are implemented in Asia (mainly in China, Japan, India, Bangladesh, and Thailand) [83]. The most widely spread technology for those gasifiers was the fixed bed downdraft gasifier.

Government incentives play a significant role in the regional development of the biomass sector. Patuzzi *et al.* found 47 CHP installations in the South Tyrolean region of Italy. Financial incentives have promoted the development of such facilities between 2010 and 2015 [68]. The gasifier technologies used included the following: rising co-current with a stationary fluidized bed; downdraft with a fixed bed; double stage with a fluidized bed; double stage with a floating fixed bed.

The electricity production mainly came from internal combustion engines (ICE) since the technology is less expensive at a small scale than others and widely available. One of the technology used a dual-fuel compression engine (secondary fuel unspecified but probably diesel), whereas all the others used spark ignition engines without any second fuel injection. Significant variation in efficiency, including thermal and electric production, was observed depending on the technology: from 53.5 % (conventional downdraft gasifier) to 78.5% (dual stage gasifier).

Polygeneration design studies

Polygeneration systems are expected to produce more than one product (e.g. heat, power, and fuel) in opposition to traditional systems having only one product type. While CHP systems could be considered polygeneration systems, the distinction is made here by using the polygeneration appellation for systems producing three products or more. If there are many studies on polygeneration systems, few actual implementations seem to be in operation. By their nature, polygeneration systems are diverse. The possible combinations of solar panels, wind turbines, fuel cells, gasifiers, and other equipment are countless.

Due to their complexity, the polygeneration systems' flexibility comes with a hefty price tag. The successful integration of such systems in society and the economy must be thoroughly studied in every case. Many promising integration scenarios have been investigated: from grid-balancing using the profit of electricity price variations and power-to-biofuel reversibility [47] to the provisioning of the energy demand for a livestock farm [84] and beyond.

However, polygeneration systems can be less profitable than more conventional installations. For example, Lythcke-Jørgensen and Haglind explored the possibility of retrofitting a Danish CHP plant into a polygeneration system producing ethanol. They found a diseconomy-of-scale, i.e. an economic disadvantage to scale up, for the ethanol production and thus no clear advantage of doing the retrofitting. These results highlighted the importance of considering operating conditions when designing a flexible polygeneration system [85]. To address this issue, operating conditions can be simulated from software such as TRNSYS (for heat demand) [84]. Such results are also influenced directly by environmental economics and the way society values different outputs. For example, taxing carbon could foster renewable systems or those where carbon capture is possible [86].

The present study is based on the thermochemical assessment of the aforementioned polygeneration system developed by Antar and Robert [1]. The authors compared two systems, one based on a dual fluidized bed gasifier, and the other based on a downdraft gasifier. Represented in figure 1.1, the DFB gasifier-based system showed high total efficiency ranging from 83.9% to 85.0% depending on four different operating conditions. These operating conditions are each related to the maximization of either electricity, methanol, hydrogen or heat production, as shown in table 2.1. The parameters differentiating the operating modes are the SOFC split and the ratio between the actual recycled and baseline hydrogen. The SOFC split is the proportion of unreacted syngas sent to the SOFC. The rest is sent directly to the residual gas burner to increase heat production. The baseline hydrogen means the quantity produced by the SOEC while producing the exact amount of oxygen required by the gasifier. More hydrogen can be produced, requiring more electricity and increasing methanol yield.

The downdraft gasifier-based system showed similar total efficiencies, but converted a lower proportion of syngas into other-than-heat products (electricity, methanol and hydrogen), as shown in table 2.2. The control parameters enabling different operating modes are the equivalence ratio (ER) in the gasifier and the proportion of recycled hydrogen from the SOEC into the syngas before the methanol reactor. The ER is the ratio between the actual oxidizer quantity and the quantity needed for stoichiometric combustion of the fuel (wood chips in this case).

Table 2.1 Operating modes efficiencies of the DFB gasifier-based polygeneration system [1]

Mode #	***Objective***	***SOFC split***	$\boldsymbol{H_{2,\ actual}}$ / $\boldsymbol{H_{2,\ baseline}}$	$\boldsymbol{\eta_{electricity}}$	$\boldsymbol{\eta_{MeOH}}$	$\boldsymbol{\eta_{H_2}}$	$\boldsymbol{\eta_{thermal}}$	$\boldsymbol{\eta_{total}}$
1	Maximising electricity	100%	1	16.1%	12.2%	0%	56.6%	84.9%
2	Maximising MeOH	100%	2.8	0%	14.1%	0%	70.8%	84.9%
3	Maximising H_2	100%	0	0%	11.1%	31.9%	42.0%	85.0%
4	Maximising heat	43%	1	0%	12.2%	0%	71.7%	83.9%

Table 2.2 Operating modes efficiencies of the downdraft gasifier-based polygeneration system [1]

Mode #	***Objective***	***ER***	$\boldsymbol{H_{2,\ recycled}}$	$\boldsymbol{\eta_{electricity}}$	$\boldsymbol{\eta_{MeOH}}$	$\boldsymbol{\eta_{H_2}}$	$\boldsymbol{\eta_{thermal}}$	$\boldsymbol{\eta_{total}}$
1	Maximising electricity	0.2	100%	9.2%	10.3%	0%	65.1%	84.6%
2	Maximising MeOH	0.26	100%	0%	11.0%	0%	73.6%	84.6%
3	Maximising H_2	0.26	0%	0%	8.2%	26.3%	50.9%	85.4%
4	Maximising heat	0.32	100%	0%	10.3%	0%	74.2%	84.5%

Because of the greater modularity offered by the operating modes of the DFB gasifier-based system compared to the downdraft gasifier-based one, it was decided to make the current techno-economic evaluation on this technology.

2.2 Techno-economic analysis (TEA) process

The core of this work is a techno-economic assessment of a polygeneration system. The National Research Council of Canada (NRC) defines the Techno-economic analysis (TEA) as a decision-making tool used to assess and benchmark different technology options using technical, environmental, economic, social, and regulatory criteria [87]. This tool and its related metrics are widely used in the power generation and biofuel production fields to evaluate different technological options [88,89]. A TEA clusters various economic metrics concerning the technological use-case under review; from the installation price to the efficiency, operating parameters and more. Common evaluation metrics include the total capital investment (TCI) or capital expenditure (CAPEX), OPEX, levelized cost of energy (LCOE), discount rate,

NPV, discounted payback period (DPP), internal rate of return (IRR), and minimum selling price (MSP). As carbon pricing spreads, the cost of avoided CO_2 is also a metric that will become more important over time.

CAPEX is the capital necessary to implement a process and includes everything from equipment purchase to installation, plant building construction, piping, and all the other expenses that are not directly related to the operation. OPEX is the working capital needed for the process to operate, including workers' salary, raw materials, maintenance costs, catalysts, etc. [42].

The LCOE is a metric for the cost evaluation of a project producing energy, distributed onto its lifetime, and calculated in $/kWh (eq. 2.7) [90]. It is often used for electricity.

$$LCOE = \frac{CAPEX * FCR + O\&M + F}{E} \tag{2.7}$$

Where FCR is the fixed charge rate, E is the annual electricity plant output (kWh), O&M is the fixed and variable operating and maintenance costs, and F is the feedstock costs (i.e. biomass in this study). The 6.4 ¢/kWh announced for the energy of Hydro-Québec's controversial La Romaine complex is an example of this metric [91]. The LCOE becomes less interesting when benchmarking polygeneration systems because it does not account for the nature of energy.

The discount rate and the NPV concepts are interlinked. The discount rate accounts for the time-wise value of money and is used in the evaluation of the NPV of future cash flows. The discount rate is chosen by the evaluator of the NPV. It can represent the return that could be earned through an alternative investment, the company's cost of capital or any other rate internally defined. The NPV is useful to compare the current future worth of different projects to know which ones are more costly/profitable. Equation 2.8 shows how it is calculated [92].

$$NPV = \sum_{t=0}^{n} \frac{R_t}{(1+i)^t} \tag{2.8}$$

Where R_t is the net cash flow during period t, i the discount rate, and t the number of periods. The DPP is the time that it takes for the project to break even (NPV=0). The IRR is the discount rate that makes the NPV equals to 0 at the end-of-life of the project (ex: after 15 years).

The MSP is the product price that makes a project break even at its end of life. It is less suitable for polygeneration installations because many products are to be made in such

facilities.

In summary, global project metrics like NPV, IRR and DPP can be useful to assess the economic side of a polygeneration project. However, metrics used traditionally used in the power production field, like the LCOE, are less adapted to this purpose.

2.2.1 TEA on biomass-powered energy systems

Several TEAs have been conducted over the years on energy systems (CHP, biomass to fuel, storage, etc.). The following literature overview gives insights into current trends in the field and related examples.

Gassner and Maréchal have developed a methodology to optimize thermochemical fuel production routes by coupling energy flow, energy integration, and economic models with multi-objective optimization. Applied to synthetic natural gas (SNG) production from lignocellulosic material, their methodology allowed the elimination of sub-optimal concepts and guides toward the most promising flowsheets [93]. The comparisons based on process flowsheets are also applied in other TEAs. Biomass-to-fuel processes using circulating fluidized bed (CFB) or entrained flow gasification coupled with FTS, Methanol to Gasoline (MTG) or Topsoe Integrated Gasoline synthesis (TIGAS) fuel production routes are evaluated in a similar fashion [94, 95]. Syngas cleaning technologies (sulphur removal, for example) are compared using TEAs as well [96]. Hence, pragmatic techno-economic approaches are efficient in evaluating complex systems. These methodologies can be applied to the assessment of polygeneration systems implementation in specific contexts.

The diversity of worldwide available feedstock is reflected in biomass-related TEAs. The impacts of using local feedstock such as sugarcane bagasse in Brazil or a prominent wood species in the Azores can be evaluated with this tool [46, 97]. The International Renewable Energy Agency report on Biomass for Power Generation gives a good overview of biomass power generation technologies advancement worldwide. Market trends, costs of biomass, feedstock moisture content, and LCOE (as it is for electrical power generation) are also discussed. Moisture in feedstock reduces its energetic value (i.e. \$/GJ) because a portion of the feedstock energy is used to evaporate water [98]. This explains the drying stage in the present polygeneration system to reduce the feedstock moisture content prior to the gasification stage.

TEAs also enable the comparison between novel technologies/processes using traditional fossil fuel-based systems with carbon capture and storage (CCS) or chemical looping combustion [99]. In every case, a techno-economic study is made to solve a location-specific problem, but

links can be made to universalize some results and transpose methods to other locations.

As an example, grid balancing is becoming a challenge with intermittent renewable energy production means. Lee et al. studied the power-to-synthetic-natural-gas (SNG) option for doing so in South Korea with stochastic means. Their approach involved Monte-Carlo simulations in assessing the possible variations in production. They found that such grid-balancing was still economically unfavourable in South Korea [100]. That could or could not be the case elsewhere; but this demonstrates the capability of the methodology used to reach this result.

Methods were also developed to assess biofuels' economic, environmental, and energetic performance in different market scenarios. Heyne and Harvey used the Energy Price and Carbon Balance Scenarios (ENPAC) tool developed at Charmers University in Sweden. The tool allowed them to determine SNG synthesis performance compared with conventional natural gas for power production [101]. Such works help to select installation locations or favourable economic factors for the realization of a project. Some additional work is needed to adapt those tools and optimize them for biofuel production in a polygeneration context.

While projects techno-economics are essential, their impact on local economic development also matters. Klagge and Brocke studied the effect of decentralized renewable electricity generation in two pioneering regions in Germany. They found out that implementing such decentralized facilities helped the regions diversify their economy and enhanced the creation of new renewable energy specialized firms [10]. Based on local needs for yam storage, Lamidi *et al.* have made a TEA in the north-central part of Nigeria on a small-scale cogeneration unit (electricity and refrigeration). Biodigestion provided the biogas used in the ICE that powers the generator and the chiller. They used Aspen plus to model the system and the net present value (NPV), discounted payback period (DPP), and LCOE to assess the system economics [102]. This kind of work can have considerable positive impacts on local communities around the world.

2.2.2 TEA on small-scale renewable energy systems

Small-scale renewable gasification and energetic systems, in general, allow decentralized energy generation and add the possibility to valorize local resources, especially in remote locations. Cardoso *et al.* conducted a TEA on bubbling fluidized gasification for power production in the Azores archipelago (Portugal). By doing simulations confirmed by experimental results, they found that a 1000 kW plant would be profitable based on NPV and a Monte Carlo sensitivity analysis. A similar 100 kW plant was revealed as unprofitable. Unsurprisingly, the most impactful factors on profitability were electricity sales price and electricity

production [46]. It shows that even in small-scale systems, size does matter, and economies of scale still play a role. That is why, in the current study, five different systems size are considered for the polygeneration and reference systems.

Conventional turbine cycles are advantageous in large-scale systems for electricity production, but less prone for implementation in small-scale systems. SOFC are more adapted to this purpose. Palazzi *et al.* developed a thermo-economic optimization method to maximize SOFC efficiency and minimize its specific cost based on the pinch method. They successfully applied their approach to design a 50 kW SOFC installation [103]. This size is roughly 15-fold less powerful than the biggest SOFC systems considered in the current study, but recent techno-economical literature is available for MW-class SOFC stacks [104].

The downstream gasifier, the most common gasification technology for small-scale installations, is often discussed in TEAs. Integrating ecological aspects with a techno-economic study, Boloy *et al.* compared syngas combustion in an ICE with biodiesel, gasoline, natural gas, and diesel combustion. The syngas was produced by gasifying a Eucalyptus feedstock [69].

In summary, TEAs realized on small-scale systems do not differ considerably from those made on larger systems, although the technologies considered do. Importance must also be given to the proper sizing of the system to ensure the profitability of installations.

In Canada

Ahmadi *et al.* studied four conventional small-scale biomass conversion paths (e.g. gasification with ICE, fast pyrolysis with ICE) for Canadian rural and remote communities using a TEA and life-cycle analysis (LCA). Based on the California-Quebec emission trading system and carbon taxation, they found that all four paths gave a good carbon offsetting potential compared to the diesel-based reference system. Gasification-based solutions yielded better performance than combustion-based and fast pyrolysis-based solutions, regarding carbon offsetting [105]. Cheayb *et al.* published a TEA on trigenerative (heat, cold, and electricity) compressed air energy storage for remote Canadian communities. The authors built an economic model based on literature values to assess the variation of several parameters (pressure, capacity, etc.) on the system costs and compare results to battery electrical storage [106].

2.2.3 Renewable electricity, green methanol, and green hydrogen: a market overview

An essential part of a TEA is based on assessing the market in which the system evaluated will play. In this case, the polygeneration system of interest aims to produce electricity,

methanol, and hydrogen. While the electricity market is well established, green methanol and hydrogen are emerging as transition fuels, and their demand is expected to grow in the following decades [107, 108]. Socio-political conflicts, climate change impacts, and the affordability of renewable energy sources are pushing forward the changes in the energy production field.

More than 99% of Quebec's electricity comes from renewable sources.The figure is approximately 66% for Canada [109]. Those numbers are considerably higher than in other parts of the world. In times of socio-political conflict such as the invasion of Ukraine by Russia, this high share of renewable acts as an anti-inflation protection against high fossil fuel prices [110]. With European countries most of them being natural gas dependent and struggling with their aging fleet of nuclear reactors, they are accelerating their transition towards renewable energy [111]. When looking at the electricity prices in the Organisation for Economic Co-operation and Development (OECD) countries, the variation is striking. With the purchasing power parity (PPP) adjusted, the household prices range was between 0.11 USD (≈0.14 CAD) for Canada and 0.41 USD (≈0.52 CAD) at the beginning of 2022. The prices are shown by country in figure 2.4. The prices for business, usually lower because of incentives, ranged from 0.05 USD (≈0.06 CAD) in Iceland to 0.26 USD (≈0.32 CAD) in Germany [5]. Such differences must be taken into account when doing a market analysis.

Methanol is an essential molecule in today's chemical industry. Currently mainly produced from natural gas steam reforming and coal, it could also play a vital role in the energy transition if produced by renewable means. The existing worldwide infrastructure gives methanol an advantage over other promising green fuels, such as hydrogen. In the European Union, methanol as an eFuel has the potential to bring continuity in the energy transition using this advantage [112]. Some major industries envision methanol as a decarbonization tool. The largest container shipping line, Maersk, has established several partnerships to power future vessels with green methanol [113]. However, only 0.2% of the 2020 methanol production came from renewable sources, showing the need for a scale-up [107]. Green methanol production is possible from biomass, municipal solid waste (MSW), biogas, and green hydrogen. The production costs of methanol from biomass (priced under 6 USD/GJ) were estimated between 327 and 764 USD per ton [107].

Green hydrogen has become a buzzword in the past years. If the hydrogen market develops, it could play an essential role in decarbonizing society, especially in highly polluting sectors such as steel and cement production [108]. The growing interest in hydrogen has also been seen by the increased number of publications in scientific literature [114]. To implement hydrogen, challenges such as the supportive infrastructure development (production and

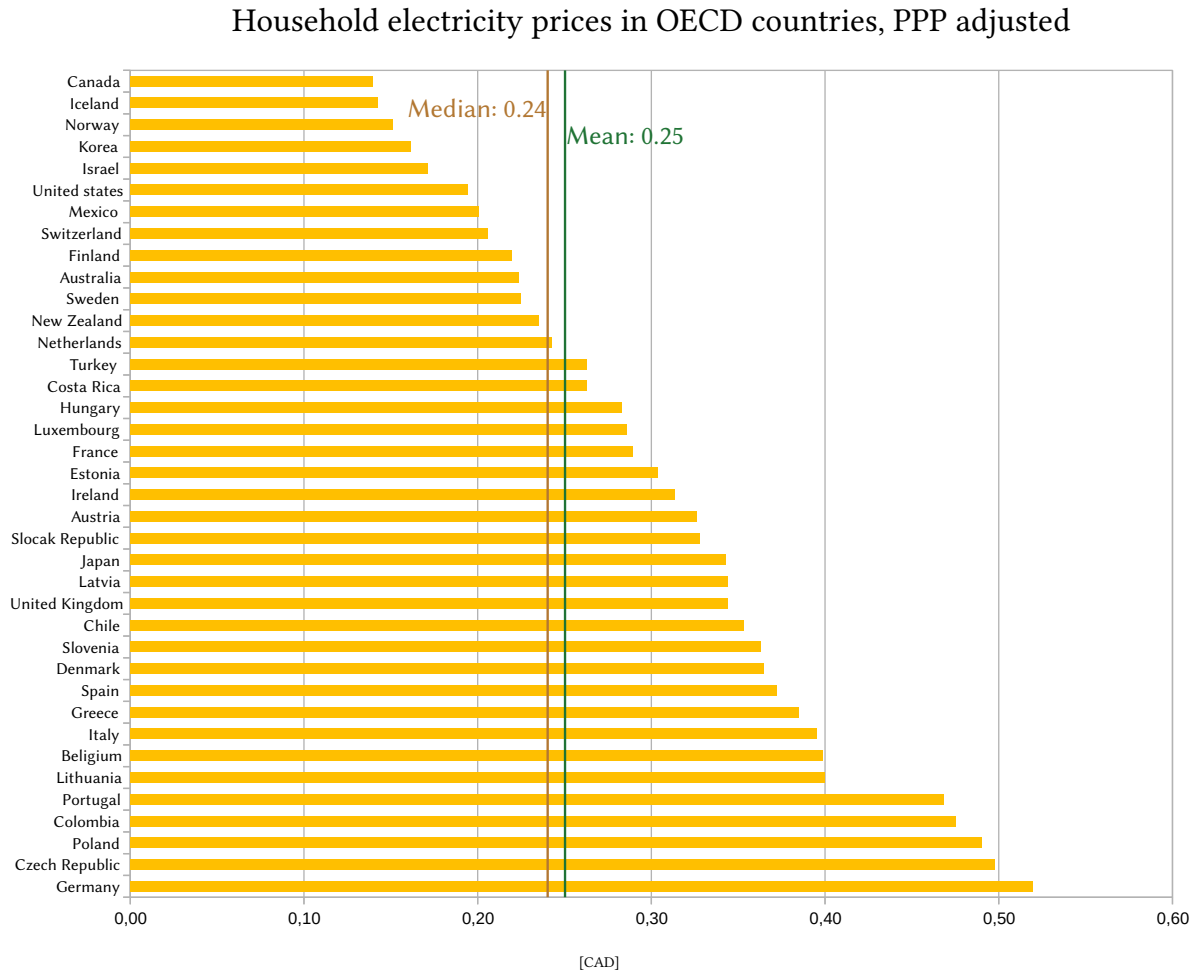


Figure 2.4 Household electricity prices in OECD countries, PPP adjusted (reproduced from [5])

storage facilities, pipelines, etc.) and water sourcing for electrolysis must be solved, among others [115, 116]. To accelerate the development of the industry, the concept of integrated ecosystems, called "hydrogen valleys", has emerged. The hydrogen valley platform, supported by Mission Innovation, a European Commission body, lists flagship projects to promote them in the value chain. The platform also gives information on the cost and selling price distribution of green hydrogen among the participating projects, a key but difficult-to-find information due to the early development stage of the green hydrogen market. The sales price distribution range from 1 EUR/kg up to more than 10 EUR/kg [117].

2.3 Biomass in greenhouses

Greenhouse production extends the harvest season through winter [118]. It has been gaining interest in Canada, and more studies on the techno-economic side have been published in recent years. Ontario, British Columbia, and Quebec are the leading provinces in greenhouse cultivation areas. Canadian northern communities could also be home to profitable greenhouses [27]. Tomatoes, peppers, and cucumbers are the most greenhouse-cultivated vegetables in the Country [119].

If greenhouse production is seen marketed as "green", it is not necessarily better than transporting vegetables from other regions, from an environmental point of view. Greenhouse heating with fossil fuels (i.e. natural gas) generates twice the GHG amount compared to transporting the same vegetables from the Southern USA to Canada [120]. Using wood pellets and other non-fossil energy sources are efficient solutions to reduce GHG emissions while also being economical [121–123]. Apart from heating, biomass gasifiers could also provide the necessary CO_2 for greenhouse enrichment [124, 125].

Quebec possesses an annual residual lignocellulosic energetic potential from the forestry sector of 3,4 million of Oven-Dry Metric Tonne (ODMT), or 63,4 PJ [23]. Excluding all other forms of biomass feedstock, it is equivalent to approximately 8% of the annual electrical energy produced in the province (212.9 Twh or 766,44 PJ) [109]. However, no commercial gasification plants were running in 2021 [24]. Most of the available biomass is located in the four regions of Saguenay-Lac-Saint-Jean, Mauricie, Outaouais, and Abitibi-Témiscamingue. Hence, with the low density of biomass and associated high transport costs, there is plenty of potential for biomass usage in those regions of Quebec. Answering greenhouses' energetic needs is a possible avenue to valorize this resource and would help decarbonize the production of vegetables.

2.4 Critical analysis of the literature and research objectives

2.4.1 Critical analysis of the literature

This literature review shows that many studies were published on biomass gasification-based systems. Of those, most small-scale configurations produced heat and power using conventional technologies such as downdraft gasifiers and internal combustion engines [68, 126–128]. Biomass is seen as an interesting tool to decentralize energy production and balance energy grids while providing the stability that other renewable technologies do not offer. Biomass gasification can lower Canada's and Quebec's energy supply carbon intensity. However, chal-

lenges remain in syngas cleaning technologies, explicitly in catalyst deactivation. Advances are seen in electricity generation from syngas, from dual-fuel compression engines to microturbines and MW-class fuel cells. Some research works were found on polygeneration systems [47, 80, 85, 86, 129]. They illustrate that polygeneration is still expensive and needs proper market conditions to be profitable. Few articles were found on small-scale polygeneration systems [84, 130, 131]. To the author's knowledge, none was found on a similar design to the one developed by Antar and Robert, producing heat, biofuel, a CO_2-rich stream, and power.

The techno-economic aspect of such a system still needs to be explored. The raw cost of implementation or the potential revenues and operating expenses are to be determined. However, many techno-economic assessments were conducted on biomass-powered systems [40, 46, 94, 95, 97, 102, 129, 132–138]. Most of those TEAs do not consider a defined varying heating load. This consideration is essential for implementation in locations with seasonal weather changes, such as Canada. It is also necessary to account for the daily variation of real-life use cases. This need is further emphasized in a greenhouse production context, where non-adequate temperatures can affect the growing of vegetables and cause harvest loss in case of freezing. In this case, meeting the load is capital for the business's survival.

The literature review shows high variability between current electricity prices and projected green methanol and hydrogen prices. To quantify revenues and benefits relative to the possible price variations, a market scenario approach is adopted in this study. It is effective to investigate the impacts of market volatility, especially for a system producing many energetic products. To further assess the effect of smaller price variations ($\pm 15\%$) on the system's economic results, a sensitivity analysis is conducted on the baseline economic scenario.

In summary, some TEAs were published on biomass boilers implementation in greenhouses [125], even in Canada [121, 122]. Lignocellulosic biomass feedstock was shown to be widely available in the country and in the province of Quebec [23, 139]. To the author's knowledge, no study has been done on the techno-economic integration of a polygeneration system with the varying heating load of a greenhouse environment.

2.4.2 Research objectives

Based on the literature review, a project scope divided into three objectives was established:

1. The first objective of this study is to evaluate the fixed investment and operating cost of a polygeneration system designed for a greenhouse reference scenario.

2. The second objective is to optimize the annual economic performance of the poly-

generation system in different electricity, green methanol, and green hydrogen market scenarios.

3. The third objective is to compare the performance and economics of a typical biomass-powered combustion-based system to the polygeneration system.

CHAPTER 3 Precisions on methodology

The following section offers precisions on the methodology used to obtain the results of the paper. The basic subsystem design parameters are presented along with a description of the optimization model implementation.

3.0.1 Preliminary conception

The polygeneration system preliminary dimensioning is based on the five scenarios of biomass raw input power: 1600 kW, 3200 kW, 4800 kW, 6400 kW, and 8000 kW. For comparison, the five biomass boiler power scenarios are sized accordingly, based on the conversion efficiency of biomass to heat in the maximum heat mode: 71,7%. Considering a boiler efficiency of 90%, the boiler scenarios have a maximum heat output of 1300 kW, 2600 kW, 3900 kW, 5200 kW, and 6500 kW. For both types of systems, components' size and cost were scaled to the power output of their respective scenario.

Polygeneration system components

The following section discusses the role and main dimensioning parameters for every major component of the polygeneration system in addition to their fixed capital investment (FCI) estimation.

Free-on-bord (FOB) costs for common plant equipment come from *Rules of Thumb in Engineering Practice* [43]. The costs for those pieces of equipment are multiplied by several factors (Labor and material, taxes, freight, insurance, etc.). The *Chemical Engineering Plant Cost Index* (CEPCI) accounts for the evolution of chemical plant equipment costs in time. The reference CEPCI value used in the book is 1000 while the value considered in this study is 797.6 (based on the January 2022 index value). Exchange rates of 1.27 CAD/USD, 1.35 CAD/EUR, and 0.13 SEK/CAD are considered. The multiplication of the FOB costs by the factors aforementioned, adjustment for cost time evolution with the CEPCI and the conversion in Canadian dollars result in the bare module (BM) cost. The BM represents a fully installed and working unit. The methodology for FCI estimation of common plant equipment is shown in figure 3.1. The prices for the other components, such as the dual fluidized bed gasifier and the solid oxide fuel cell are obtained from the literature, as described below.

Subsystems' operating parameters (volumetric flow, mass flow, operating temperature, etc.) were obtained from the Aspen Plus model developed by Antar and Robert, the basis of the

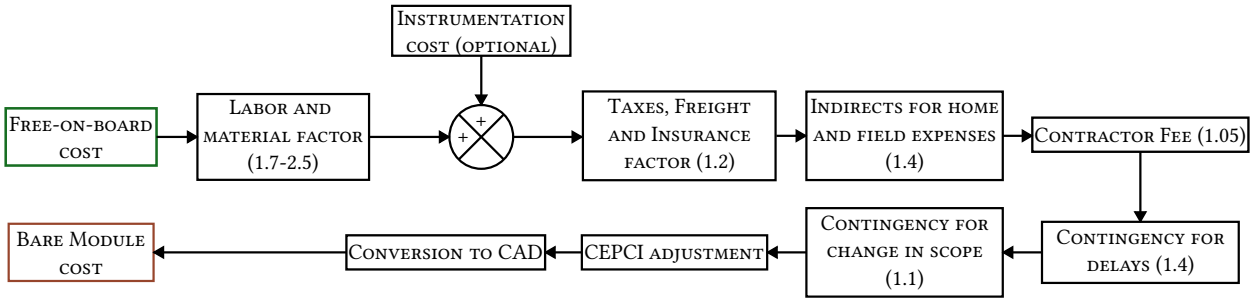


Figure 3.1 Methodology for fixed capital investment estimation of subsystems

previously published thermodynamic analysis of the system [1]. The values were obtained based on 1 kg/s of input moist biomass (45% moisture content, equivalent to a polygeneration system power of around 3890 kW) and scaled to the power scenarios.

Gasifier The dual fluidized bed gasifier (DFB) is the core of the polygeneration system, converting biomass into raw syngas. Information on the price of DFBs was hard to find because of two factors: few commercial DFBs are in operation worldwide, and most date from the beginning of the 2000s [140]. To the author's knowledge, the only recently commissioned plant (and also decommissioned) is the GoBiGas pilot plant in Gothenburg, Sweden. The plant was in operation from 2013 to 2018. It was decided to base the installed cost of such a gasifier on the detailed economic assessment of possible improvements to the GoBiGas plants published by Thumnan *et al.* [141]. In addition to the CEPCI adjustment of the value, the scaling factor of 0.7 provided in the article was used along with an exchange rate of 0.13 SEK/CAD. The GobiGas plant had a capacity of 6 oven-dry metric tons (ODMT) per hour [142]. For comparison, the 8000 kW polygeneration system configuration would use around 1.4 odmt/h.

Cyclone The cyclone is the first step in syngas cleaning and aims to remove most particulate matter. Per kg/s of moist biomass, it has a mass flow rate of 1.92 kg/s and a volumetric flow rate of 7.32 m^3/s. Since this is common plant equipment, the price is given in the *Rules of Thumb in Engineering Practice* [43]. A high-efficiency cyclone is selected along with a centrifugal radial-bladed fan. An example calculation of the free-on-board cost is shown in

equation 3.1 for the cyclone of a system consuming 1 kg of moist biomass per second.

$$\text{BM cost}_{\text{Cyclone}} = \left(\underbrace{\$\ 35\ 000 * (\frac{7.3}{10})^{0.56}}_{\text{cyclone}} + \underbrace{\$\ 27\ 750 * (\frac{7.3}{10})^{0.93}}_{\text{cyclone fan}} \right) * \underbrace{\frac{797.6}{1000}}_{\text{CEPCI adjustment}} * \underbrace{\frac{1.27\ \text{CAD}}{1\ \text{USD}}}_{\text{Currency conversion}} * \underbrace{1.2 * 1.4 * 1.05 * 1.4 * 1.1}_{\text{Other factors}} = 137\ 730\ \text{CAD} \tag{3.1}$$

Nickel fluidized bed The nickel steam fluidized bed is used for tar decomposition and to increase the syngas H_2 and CO content. Steam is injected into the reactor at a rate of 0.056 kg/s per kg of moist biomass per second for a total mass flow rate of 1.976 kg/s. A gas hourly space velocity of 10 000 h^{-1} was selected to determine the fluidized bed volume, as seen in other studies involving reforming with Ni-based catalyst and in accordance to the <1s residence time prescribed for gas with solid catalytic operations in fluidized beds [43,143,144].

ZnO guard beds The zinc oxide guard bed aims to remove the acid gas content in the syngas by adsorption, before further processing. Downstream components, such as the SOFC are sensitive to contaminants such as acid gases (H_2S, HCl) [79]. The information on the guard bed free-on-board cost comes from a study on biomass to liquid processes by *Albrecht et al.* [134]. The guard bed has the same mass flow rate as the nickel steam fluidized bed. To convert the FOB cost into a bare module cost, instrumentation costs, labour and material factor, and the other aforementioned factors for fixed capital investment were taken into account.

Knockout pot The knockout pot is used for water removal using condensation. Following the advice in *Rules of Thumb in Engineering Practice*, it was designed as a vertical cylinder with a height 1.5 times greater than the diameter and for a liquid residence time of 450 s [43]. The knockout pot removes 0.94 kg/s of water in a system consuming 1 kg of moist biomass per second.

Compressor The compressor increases the pressure to 30 bar before the methanol reactor, leading to a higher yield in methanol production. The compressor work from the Aspen Plus model, 8.7% of raw biomass input power, was used as a design value. For a polygeneration system consuming 1 kg of moist biomass per second, the compressor power required is 340 kW. The compressor and instrumentation costs are taken from *Rules of Thumb in Engineering*

Practice [43].

Methanol reactor The methanol reactor converts a part of the syngas into methanol (MeOH) at an operating pressure of 30 bar and a temperature of 225°C. The choice of a lower-than-ideal pressure (30 bar instead of 60-80 bar) is explained by the small-scale decentralized nature of the system [1]. The overall exothermic reaction is catalyzed with a Cu/ZnO catalyst and needs to be cooled. Multi-tubular fixed catalyst bed reactors are suitable for such applications because of their heat-exchanging capabilities. Commercial operation of those reactors for methanol production is conducted close to gas hourly space velocities of 10 000 h^{-1} [145]. Again, the costs are taken from *Rules of Thumb in Engineering Practice* [43].

SOFC and SOEC The solid oxide fuel cell (SOFC) aims to produce electricity from the syngas leaving the methanol reactor. The solid electrolyzer fuel cell uses steam and electricity to make pure streams of hydrogen, used to enrich the syngas H_2 content and methanol yield, and oxygen, used as the oxidizing agent in the gasifier. The prices per kWe for both fuel cells are taken from the United States Department of Energy evaluation of future SOFC costs [146]. The prices include the SOFC stack, enclosure, inverter, cathode air blower, and heat exchanger. The SOFC converts 33,9% of the system's biomass raw input power into electricity, while the SOEC consumes 8.9% of that power.

Residual syngas burner The residual syngas burner serves as a steam boiler. The steam is the DFB gasifier's gasification agent and is also used in the nickel steam fluidized bed. The nominal power of the residual syngas steam boiler is at 34% of the biomass raw input power. The cost estimation for the boiler is taken from the Danish Energy Agency's catalogue on energy plants for electricity production and heating generation [147]. The case considered was a heating-only plant running on natural gas. The price was linearly interpolated for the year 2022.

Peaking methanol boiler The peaking methanol boiler produces enough heat to cover the remainder of the greenhouse heat demand under the maximum load of the year, which corresponds to 5900 kW. The sizing is done by subtracting the heat contribution of the polygeneration system in the maximum heat mode (71.7% of the biomass input power is converted into heat) to the maximum demand and rounding up the number to the closest upper 0.5 MW multiple. The cost information is based on the same case as the residual

syngas burner. The peaking burners are more powerful for small polygeneration system configurations than for big ones, as shown in table 3.1.

Table 3.1 Peaking boiler power in function of polygeneration system power

Polygeneration system power	***Peaking boiler power***
kW (raw input biomass)	**kW (heat)**
1600	5000
3200	4000
4800	2500
6400	1500
8000	1000

Heat exchanger The heat exchangers bring process streams to adequate temperature while providing heat to the water heating system of the greenhouse. The heat exchangers considered here are implemented before adsorption in the zinc oxide guard bed, before water removal in the knockout pot, after the methanol reactor, and for the isothermal SOFC cooling. A heat transfer coefficient between cooling water and syngas of 0.160 $kW/(m^2 \cdot K)$ was assumed, based on the mean value for general hot gases - water shell & tube coolers [148]. The costs of recuperative fuel cells heat exchangers and methanol reactor heat exchangers are already included in the fixed capital investment estimation of their subsystems. The FCI estimation is done with cost values for shell and tube cooler from *Rules of Thumb in Engineering Practice* [43].

Combustion-based system sub-systems

Biomass boiler The biomass boiler is the most important equipment of the combustion-based solution, providing heat to the greenhouse by burning wood chips. The fixed capital estimation for the biomass boiler is taken from the Danish energy agency's catalogue on energy plants for electricity production and heating generation [147]. The case considered is a small-scale heating-only plant running on biomass.

Peaking propane boiler Peaking propane boilers help the biomass boiler to cover the greenhouse heat demand by providing additional heating power when needed. Similarly to the methanol peaking boilers used for the polygeneration system, the power requirement of the peaking boilers is inversely proportional to the biomass boiler power. The FCI estimation is also conducted with values of the Danish energy agency, by considering a heating-only plant running on natural gas [147].

3.0.2 Optimization model implementation

The optimization model described in the paper was implemented in python using the open-source optimization language Pyomo and the non-commercial solver SCIP. The problem was divided into 36 parts, time-wise, to make it computable with the available hardware. Multiprocessing was implemented to solve it for the different power configurations and economic scenarios. The source code and instructions to compile it are available on GitHub, in the repository *LEMUR-Polygen-Market-Optimization*, at `https://github.com/domrivest/LEMUR-Polygen-Market-Optimization`.

CHAPTER 4 ARTICLE I: TECHNO-ECONOMIC ASSESSMENT OF A BIOMASS GASIFICATION-BASED POLYGENERATION SYSTEM FOR GREENHOUSES

This section presents the article *Techno-economic assessment of a biomass gasification-based polygeneration system for greenhouses*, submitted to *Sustainable Energy Technologies and Assessments* on 20 March 2023. The paper presents the techno-economic study realized on the polygeneration system developed by Antar and Robert in the implementation context of a medium-sized greenhouse in southern Quebec. Elie Antar and Étienne Robert are the other authors of the paper.

Those are the highlights of the paper:

- A techno-economic analysis is done on a novel lignocellulosic biomass-powered polygeneration system producing electricity, methanol, hydrogen and a CO_2-rich stream.
- The system performance is analyzed for five system powers and in 27 market scenarios for the prices of electricity, methanol and hydrogen.
- A comparison between the polygeneration system and a reference solution based on biomass combustion shows that the polygeneration system generates a superior NPV in 22 of the 27 market scenarios investigated.

4.1 Abstract

Decentralized biorefineries are an attractive solution to reduce the carbon footprint of agricultural greenhouses, by converting the abundant local residual biomass into value-added products such as biofuels. While the thermodynamic performance of many biomass system configurations has been investigated in the literature, techno-economic assessments are needed to validate the potential of such facilities. In this study, this approach is applied to a small-scale polygeneration system that has been developed for a use-case in a southern Quebec greenhouse. The polygeneration system can produce heat, electricity, methanol, hydrogen, and a CO_2-rich stream. A TRNSYS model is used to simulate the heat demand of a 20 000 m^2 greenhouse. The work presented here compares the polygeneration system with a conventional solution based on biomass combustion. Five configurations between 1120 and 5600 kW of thermal output power are investigated for both systems. Three market scenarios are considered for the prices of electricity, methanol, and hydrogen: pessimistic, baseline, and optimistic. Fixed capital investment (FCI), operation expenses (OPEX), and NPV are presented. In the most pessimistic market scenario, the best polygeneration system would have an NPV of -8.2 M CAD. In the baseline and optimistic scenarios, the same polygeneration system would have an NPV of 17.6 M CAD and 40.2 M CAD, respectively. By comparison, the best combustion-based solution would have the highest NPV at -5.0 M CAD. Those results highlight that small decentralized polygeneration systems are promising. However, their profitability is heavily dependent on future energy market developments.

4.2 Introduction

Climate change alleviation requires a quick shift from a fossil fuel-dependent world to an economy based on renewable energy. Decentralized renewable energy systems offer flexibility and the advantage of efficiently meeting local needs with local resources such as wind, hydro, solar and biomass [149]. The latter, biomass, has the inherent advantage of being a relatively energy-dense material that can readily be burned for heat or stored, although only for a limited time. Furthermore, biomass conversion processes can yield value-added products such as biofuels and other chemicals that are storable. The agricultural sector accounted for 7.4% of Canada's GDP in 2020, but was the fifth biggest polluter in terms of greenhouse gas emissions (GHG), with 10% of the national share [150, 151]. The bulk of which comes from animal food production. In most agricultural sectors, energy needs are provided using fossil fuels. Energy-intensive tasks in agriculture include machinery operation, grain drying, fertilizer production, and greenhouse heating [152].

To increase sustainability and reduce food loss, a change towards a more plant-based diet is needed [153]. At high latitudes, populations rely on imported vegetables during winter. In addition to the global trend towards local-based diets, this creates remarkable opportunities for greenhouse agriculture [154, 155]. Currently, many greenhouses are heated by burning fossil fuels and the shift to heat pumps and other renewable solutions is slow [27, 156, 157]. Biomass-powered systems are a potential solution to reduce GHG emissions, already implemented at a relatively large scale depending on countries. In Sweden, 73% of greenhouses are heated by wood chips, but biomass accounted only for 10% of greenhouse heating in Ontario, the most active province of Canada in greenhouse growing [158, 159].

In Canada and especially in Quebec, residual lignocellulosic biomass is a high-potential resource. In its 2020 Quebec biomass inventory, WSP evaluated the annual technical potential of wood industry residues to 255 PJ [23]. This potential is almost equivalent to the total energy consumed by the 3,6 million Quebec households [160, 161]. However, wood chips present high transportation costs due to their low bulk density [162]. It is considered the main hurdle for woody biomass use [163]. Most of the valorized sawmill residues currently go to the paper industry [23]. Decentralized biomass-powered installations could leverage this enormous resource by using local feedstock while significantly reducing transportation costs.

Antar and Robert have developed a biomass polygeneration system (heat, electricity, methanol, hydrogen, and a CO_2-rich stream) that could turn traditional energy consumers, such as greenhouses, into decentralized energy producers [1]. Moreover, the CO_2-rich stream, when not used for atmosphere enrichment in the greenhouse itself, could be easily sequestrated to make the process carbon-negative. However, the system has not been compared yet to traditional heating solutions for greenhouses. The system gasifies biomass into syngas and processes it to obtain the desired products with significant waste heat available as a by-product. The present study aims to compare this novel polygeneration system with a conventional biomass boiler through a techno-economic assessment (TEA) in a southern Quebec greenhouse production context. A TEA is a well-known decision-making tool used to benchmark multiple technological solutions from the economic, environmental, and social points of view [87].

TEAs have been used to assess the potential of novel small-scale energy conversion technologies. For instance, Cardoso *et al.* [164] used it for a forest biomass gasification system producing electricity in the Azores archipelago, while Ulleberg and Hancke [165] assessed the economic potential of small-scale hydrogen supply systems in Norway, showing the flexibility of this tool. This flexibility makes the comparison of results obtained through different studies a challenge because the methodologies used can be considerably different [134]. However,

by offering clear metrics to evaluate projects in defined settings, the increasing use of TEAs supports stakeholders in the biofuel sector through the decision-making process associated with project planning [166].

The goal of this study is to optimize the operation of the polygeneration system for the use-case of a southern Quebe greenhouse. A dynamic numerical thermal model of a medium-sized greenhouse (20 000 m^2) serves as the starting point of the TEA presented here. Five constant power scenarios are considered for the polygeneration system and a conventional biomass boiler is used as a reference. The scenarios are coupled with peaking boilers sized to meet the heating load peaks. Mixed-integer linear optimization is conducted to minimize the systems' operating costs. Additionally, three market scenarios are considered for electricity, methanol, and hydrogen prices: pessimistic, baseline, and optimistic. Net present value (NPV) and internal rate of return (IRR) are obtained for each configuration.

4.3 Material and methods

4.3.1 Polygeneration system

The polygeneration system developed by Antar & Robert can produce heat, hydrogen, methanol electricity, and a high-purity stream of carbon dioxide, making it promising for greenhouse applications [1]. The H_2 stream can be extracted for external use or recycled internally to enhance methanol production. The polygeneration system's main components are a dual fluidized bed gasifier (DFB) [140], a syngas cleaning system (cyclone, nickel catalyst steam-fluidized beds, catalytic zinc oxide bed, and knockout pot), a methanol synthesis reactor, a residual gas burner, and reversible solid oxide cells (RSOCs). The latter can be operated either as a fuel cell (SOFC) or as an electrolyzer cell (SOEC) when desired. The DFB gasifier works with steam as the gasification agent and O_2, for partial oxidation, to obtain heat from exothermic combustion reactions. The gasifier uses steam in an allothermal bubbling fluidized bed, in which the endothermic biomass gasification reactions are sustained by circulating the hot bed material from a separate combustion chamber that feeds on the residual char. Oxyfuel combustion is adopted in the latter, which yields a high-purity nitrogen-free exhaust, which can be used for greenhouse atmosphere enrichment. Figure 4.1 shows a simplified schematic representation of the system.

The operating mode of the system can be readily changed, by for instance changing the fraction of syngas that is sent to the SOFC or the hydrogen recycling rate. Consequently, the system has four operating modes corresponding to the maximization of its main products (electricity, methanol, hydrogen, and heat). The conversion efficiency into each product for

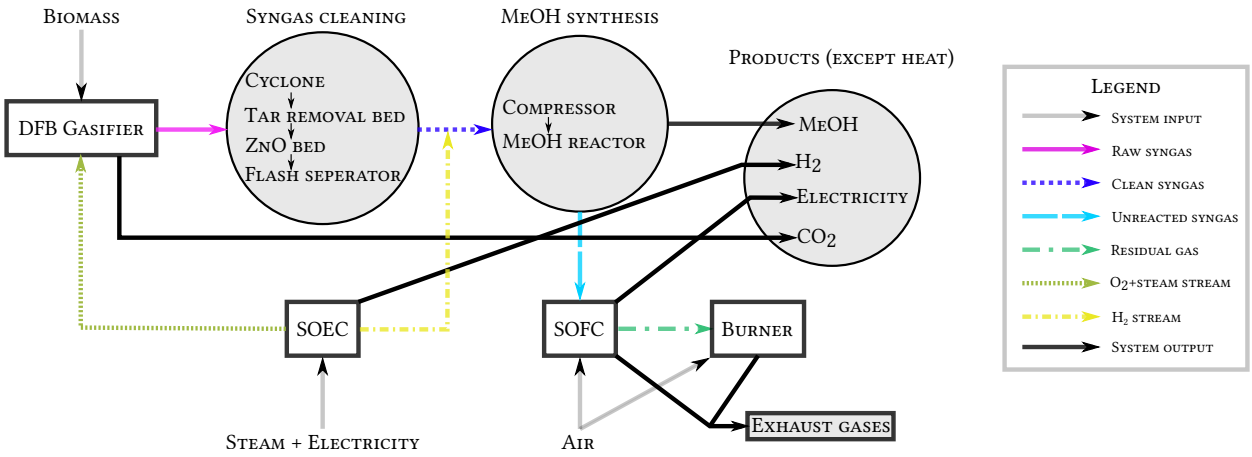


Figure 4.1 Simplified schematic of the polygeneration system

all operating modes is shown in table 4.1 along with the total efficiency, the ratio between the actual quantity of H_2 produced to the baseline amount associated with the required O_2 for the gasifier, and the SOFC split, representing the proportion of the syngas sent to the SOFC, the rest being sent directly to the syngas burner. The maximum MeOH mode is associated with high waste heat production (70.8% of input biomass), close to the maximum heat mode (71.7 %). In this mode, all the hydrogen is used to enhance methanol production. The maximum H_2 mode generates the least amount of heat among the four modes (only 42% available as heat). The only mode producing a net electricity output can convert up to 16.1% of the input biomass energy into electricity. In all the other modes, the electricity output of the SOFC powers the compressor and the SOEC. A Sankey diagram showing energy flows in the maximum electricity mode is presented in figure 4.2.

Table 4.1 Operating modes efficiencies of the DFB gasifier-based polygeneration system [1]

Mode #	***Objective***	***SOFC split***	$\boldsymbol{H_{2,\ actual}}$ / $\boldsymbol{H_{2,\ baseline}}$	$\boldsymbol{\eta_{electricity}}$	$\boldsymbol{\eta_{MeOH}}$	$\boldsymbol{\eta_{H_2}}$	$\boldsymbol{\eta_{thermal}}$	$\boldsymbol{\eta_{total}}$
1	Maximising electricity	100%	1	16.1%	12.2%	0%	56.6%	84.9%
2	Maximising MeOH	100%	2.8	0%	14.1%	0%	70.8%	84.9%
3	Maximising H_2	100%	0	0%	11.1%	31.9%	42.0%	85.0%
4	Maximising heat	43%	1	0%	12.2%	0%	71.7%	83.9%

The feedstock for this study is wood chips, as it presents a high gasification potential in Canada [167]. Moreover, the country's sawmills generate vast quantities of wood residues with limited commercial value because of the reduced production of printed newspapers [23]. The wood chips' properties considered in this study are presented in table 4.2 and are the same as those used in the thermodynamic analysis of Antar and Robert [1].

A greenhouse reference scenario was defined to assess the techno-economic performance of

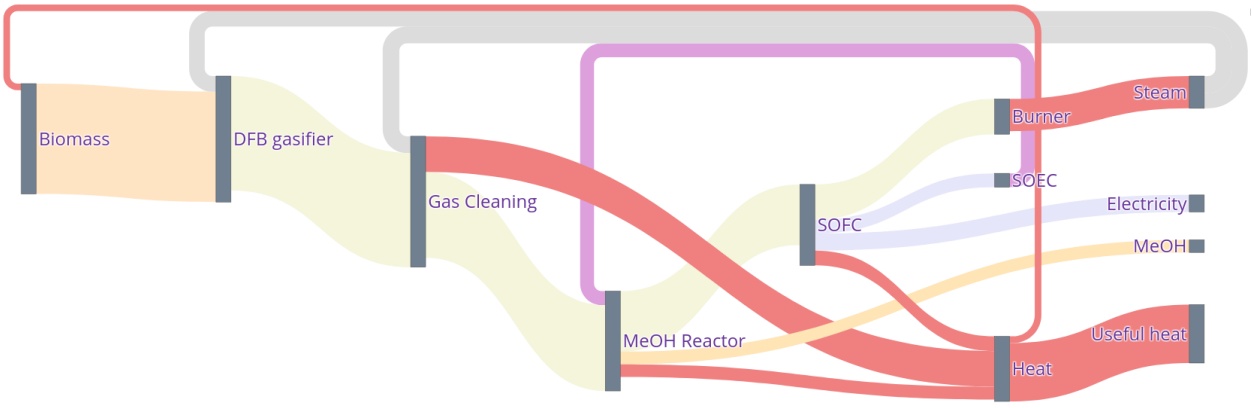


Figure 4.2 Sankey diagram of the system in the maximum electricity mode

Table 4.2 Wood chips properties [1]

Ultimate analysis (wt% dry basis)	
C	50.6
H	6.5
N	0.2
O	42
Proximate analysis (wt% dry basis)	
Moisture	45
Fixed carbon	19.2
Volatile matter	80.1
Ash	0.7
LHV (MJ/kg wet basis)	12.1
HHV (MJ/kg wet basis)	14

the polygeneration system in the agricultural sector. It is based on the installations of a medium-sized Quebec tomato producer. The greenhouse currently uses two biomass boilers (2.2 MW each) and peaking propane boilers (2.3 MW total) during winter months. Yearlong production of tomatoes and a greenhouse reference area of 20 000 m² are considered. 380 tons of CO_2 per year are injected in the greenhouse for optimal crop growth. It is currently purchased in liquid form, at 200 CAD/ton, in the reference scenario. Using the sum of the total biomass and propane consumption for one year, the annual heat demand of the greenhouse was estimated to 14 GWh.

A TRNSYS dynamic model of the greenhouse installation was developed by Lavigueur and Kummert. It assesses the greenhouse's thermal needs considering its geometry and location [168]. Simulations were carried out with 15-minute timesteps for the reference year 2019-2020, with the weather data obtained from a station located 30 km west. The heating demand evaluated from the TRNSYS model is shown in figure 4.3. Diurnal fluctuations can be observed along with the seasonal demand highs and lows associated with winter and summer. The simulated heat demand sum is 11.7 GWh, 16.4% under the estimated actual greenhouse heat demand. Neglecting ventilation openings for humidity control purposes in the model could explain this difference, among other factors. Table 4.3 presents the sum, mean and max of the heat demand with the annual CO_2 consumption for greenhouse injection.

4.3.2 Combustion-based system

The combustion-based system serves here as the reference scenario for heating the greenhouse. It is composed of a biomass boiler with a 90% LHV efficiency and an operating range of 20-100% of its nominal power. Peaking propane burners with a 95% LHV efficiency are used to cover the remainder of the heat demand [169].

Table 4.3 Parameters of the simulated greenhouse

Parameter	**Value**	**Unit**	**Source**
Greenhouse total area	20000	m²	-
Actual greenhouse estimated heating demand sum	13 990	MWh	Tomato producer
Simulated greenhouse heating demand sum	11 730	MWh	TRNSYS model
Simulated greenhouse mean heating demand	1350	kW	TRNSYS model
Simulated greenhouse max heating demand	5900	kW	TRNSYS model
CO^2 consumption	380	tons/year	Tomato producer

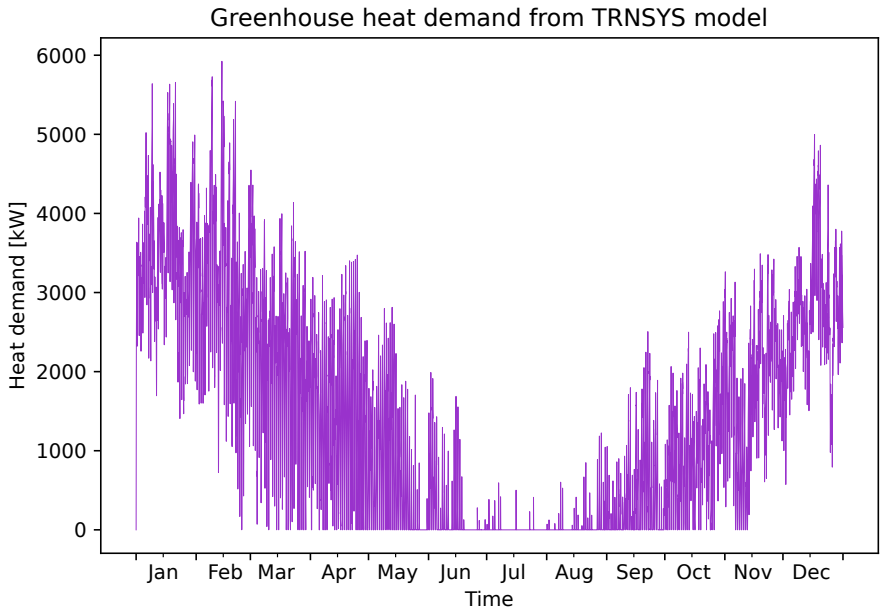


Figure 4.3 Annual heat demand obtained from the TRNSYS model of the greenhouse

4.3.3 Techno-economic assessment

Five polygeneration system power configurations are considered based on the biomass input higher heating value (HHV): 1600 kW, 3200 kW, 4800 kW, 6400 kW, and 8000 kW. Here, the thermal power output of the polygeneration systems is assumed constant for each operating mode, as the load following capabilities of such complex systems is very limited. Those configurations are compared to five biomass boilers sized to provide a similar thermal output: 1300 kW, 2600 kW, 3900 kW, 5200 kW, and 6500 kW, but this time with load-following capabilities over 20-100% of their nominal power.

To provide sufficient heat during winter coldest days, peaking boilers are dimensioned to cover the highest annual power peak, minus the baseline system thermal input. Peaking boilers allow the baseline systems to cover the base load without being overdesigned. Propane boilers are considered for the combustion-based system since they are commonly used in the agricultural sector and methanol boilers are considered for the polygeneration system since it produces methanol itself. As for propane boilers, a thermal efficiency of 95% LHV is considered for methanol peaking boilers.

Cost of the resources The prices of the resources considered in this study (biomass, propane, and CO_2) apply to vegetable production in Quebec. If no value is found, the

Canadian price is used when it is available. All prices are displayed in Canadian dollars (CAD).

An oven-dry metric ton of biomass (odmt) is considered to have an HHV of 5830 kWh (21 MJ/kg) [170]. The price of wood chips (including transport) is considered at 100 CAD/odmt, corresponding to 66.67 CAD per ton of 45% moisture content biomass. [24]. It represents 0.01714 CAD/kWh of HHV. The price of propane is the average Canadian auto propane price for the first half of 2022 (1.1928 CAD/L). Considering an HHV of 6.97 kWh/L, it represents 0.1711 CAD/kWh of HHV [171]. The price of CO_2 for greenhouse injection is assumed 0.2 CAD/kg.

General economic parameters The plant is assumed to be in operation for 8000 hrs/year (91.3 % plant operating factor). While heating is required for most of the year, the heat demand is much less important during the summer months. Thus a maintenance break of 760 hours is considered from the beginning of July. A discount rate of 10 % is considered. Table 4.4 summarizes the general economic parameters.

Use of the polygeneration system products The polygeneration system's heat is used directly to meet the greenhouse's needs. The scope of this study is to optimize the polygeneration system's operational behaviour without other additions to the greenhouse. In future works, an additional thermal energy storage medium could be coupled with the current model to dampen the heat demand peaks from the greenhouse, thus reducing the need for auxiliary burners and shrinking the required system's size. This would require optimization coupling in regard to the size and cost of the heat storage. The electricity is considered to be sold, but in reality a part of it would reduce the power bought from utilities for greenhouse operations (e.g. lighting). An existing connection to the power grid is assumed. The produced methanol is stored partially for peak heating during winter's coldest days. The other part is sold. Hydrogen is assumed to be entirely sold. The infrastructure for hydrogen handling is assumed to be available in this study. A fraction of the produced CO_2 is needed for greenhouse atmo-

Table 4.4 General economic parameters

Parameter	***Value***	***Additional information***
First-year inflation rate [%]	6.84	2022 Jan-Sep average Canadian inflation rate [172]
Inflation rate [%]	3.04	2018-2022 average Canadian inflation rate [172]
Plant annual operating hours [-]	8000	Operating factor of 91.3 %
Discount rate [%]	10	

sphere enrichment, the rest is released in the environment but could also be considered for valorization or sequestration in future work.

Three market scenarios enable the consideration of different electricity, methanol, and hydrogen prices: pessimistic (low price), baseline (median price), and optimistic (high price). Electricity prices in these three scenarios are the 10^{th} percentile, median and 90^{th} percentile of the power prices for businesses in the Organization for Economic Co-operation and Development (OECD) countries [5]. This represents 0.11 CAD/kWh, 0.17 CAD/kWh, 0.26 CAD/kWh, respectively.

Since bio-methanol and green hydrogen usage as energy carriers remain marginal, the data on their current prices is sparse. Methanol prices considered are based on the range of production costs for bio-methanol according to the innovation outlook on renewable methanol by the International Renewable Energy Agency (IRENA) [107]. The lower limit (415 CAD/t), median (693 CAD/t), and upper limit (970 CAD/t) of the price range were selected as described above. Since those prices are based on production costs, they represent a conservative estimate of a potential green methanol sales price. As a reference, the Methanex price for non-renewable methanol was 745 CAD/t (585 USD) in North America and 500 CAD/t (395 USD) in China in November 2022. Hydrogen prices are based on the Hydrogen Valley platform, a joint initiative of the Clean Hydrogen Joint Undertaking and Mission Innovation, two bodies of the European Union [173]. The platform reports the green hydrogen sales price distribution among the participating projects [174]. Again, the scenarios are based on the 10^{th} percentile (4.73 CAD/kg), the median (9.45 CAD/kg), and the 90^{th} percentile (13.50 CAD/kg) of the distribution. For example, the price for filling a hydrogen car was reported to be approximately 13 CAD/kg during the summer of 2022 in Canada [175]. Table 4.5 shows the electricity, methanol, and hydrogen prices for the three market scenarios.

Table 4.5 Market price scenarios for electricity, methanol, and hydrogen

Market scenarios	***Electricity***	***Methanol***		***Hydrogen***	
	CAD/kWh	**CAD/t**	**CAD/kWh**	**CAD/kg**	**CAD/kWh**
Pessimistic	0.11	415	0.07	4.73	0.12
Baseline	0.17	693	0.11	9.45	0.24
Optimistic	0.26	970	0.15	13.5	0.34

Estimation of the fixed capital investment The fixed capital investment (FCI) evaluation for the polygeneration system and the combustion-based system is done following the capital cost estimation method presented by Woods [43]. The FCI is calculated by multiplying free-on-board costs by factors for equipment-specific labour and material (1.7-2.8), taxes,

freight and insurances (1.2), indirect costs for office and field expenses (1.4), contractor fee (1.05), contingency for delays (1.15) and contingency for change in scope (1.1), to obtain the "bare module" (BM) cost. The BM price represents a fully installed and functioning unit.

The purchased equipment cost of the different systems are obtained from literature and are adjusted for this study using an equipment-specific scaling factor, as presented by Peters *et al.* [42]. This factor is applied to adjust the FCI to the capacity of the systems considered and accounts for the economies of scale for specific equipment, as presented in eq. 4.1.

$$EC_{scaled} = EC_{reference} * \Big(\frac{capacity_{scaled}}{capacity_{reference}}\Big)^{n} \tag{4.1}$$

Where EC_{scaled} is the cost of the scaled equipment, $EC_{reference}$ is the cost of the reference, and n is the equipment-specific scaling factor applied. For the five-fold power difference between the lowest and highest polygeneration system configurations, it means that the increase in FCI should be lower than fivefold (according to the results, it is actually $5^{0.72}$ or 3.18). The equipment cost is also actualized to 2022 dollars using the *Chemical engineering plant cost index* (CEPCI) as in eq 4.2.

$$EC_{present} = EC_{scaled} * \frac{Index_{early2022}}{Index_{reference}} \tag{4.2}$$

Estimation of the operational expenses (OPEX) Fixed OPEX for labour, maintenance, and insurance are respectively considered at 0.5% FCI, 2% FCI, and 3% FCI. Those values are similar to other studies on small-scale renewable-based energy conversion systems [164,165,176]. Variable OPEX depends on the system's resource (biomass and methanol or propane) consumption evaluated by optimization.

Optimization of the polygeneration system's operation Operational optimization of the system's four modes is conducted with mixed-integer linear programming (MILP). This type of problem considers the discrete nature of certain variables (i.e. the operating mode) as well as continuous variables (i.e. the biomass consumption). The optimization is done following the greenhouse heating demand on a 15-minute basis for one year. Peaking MeOH burners cover the heating demand exceeding the capacity of the polygeneration system. Optimization was done for the five power scenarios (1600 kW, 3200 kW, 4800 kW, 6400 kW, and 8000 kW). The sets, variables, parameters, constraints, and objective function of the optimization problem are presented in table 4.6. For every timestep of the year, the problem minimizes the operational costs of the system (cost of inputs minus the cost of outputs)

while satisfying the greenhouse heat demand and respecting the maximum power output of the system.

Table 4.6 Definition of the optimization problem

Sets	
Inputs i	Biomass, MeOH
Products j	Electricity, MeOH, H_2 and Heat
Time t	Time steps of 15 minutes during 1 year (35041 steps)
Operating mode o	1: Maximize electricity, 2: Maximize MeOH, 3: Maximize H_2 and 4: Maximize Heat
Variables	
x_{iot}	Consumption of input i at time period t (kWh)
y_{jot}	Production of product j in operational mode o at time period t (kWh)
z_{ot}	State of operational mode o at period t (-): $z_o(t)$ (1 if mode o is activated, 0 otherwise)
Parameters	
$q(t)$	Greenhouse heating demand (kWh) from TRNSYS
p_i, p_j	Market prices of inputs and products [$ CAD/kWh]
P_{nom}	System nominal power [KW]
η_{jo}	Energy conversion efficiencies for operation regimes [-] (where o is the operating mode and j the product type)
$t = 0.25$	Time step between data points [h]
$\eta_{MeOH_{Burner}} = 0.9$	Efficiency of the MeOH burner (LHV) [-]
Constraints	
Satisfaction of heat demand	$\sum_{o=1}^{4} y_{Heat,o}(t) + x_{MeOH}(t) * \eta_{MeOH_{Burner}} \geq q(t) \quad \forall\, t \,\epsilon\, T$
System's maximum power	$x_{Biomass}(t) \leq P_{nom} \quad \forall\, t \,\epsilon\, T$
Link between biomass consumption and products	$y_{jo}(t) \leq x_{Biomass,o}(t) * \eta_{jo} \quad \forall\, t \,\epsilon\, T,\ j \,\epsilon\, J,\ o \,\epsilon\, O$
Operating mode activation	$\sum_{j=Elec,MeOH,H_2,Heat} y_{jo}(t) \leq z_o(t) * 2 * P_{nom} \quad \forall\, t \,\epsilon\, T,\ o \,\epsilon\, O$
Single operating mode	$z_1(t) + z_2(t) + z_3(t) + z_4(t) \leq 1 \quad \forall\, t \,\epsilon\, T$
Maintenance break	$x_{Biomass}(t) \leq 0\ \forall\, t \,\epsilon\, [T_{maintenanceStart}, T_{maintenanceEnd}]$
Objective function	
Minimize the operational costs of the greenhouse by subtracting the revenues obtained with the products to the biomass and MeOH costs	$min \sum_{t\,\epsilon\,T} \left[\sum_{i\epsilon I} x_i(t) * p_i - \left(\sum_{j\epsilon J} \sum_{o=1}^{4} y_{jo}(t) * p_j \right) \right]$

Optimization of the combustion-based system operation Similarly, a simple optimization MILP was designed to calculate the biomass and propane consumption for the five evaluated configurations of the combustion-based system (1300 kW, 2600 kW, 3900 kW, 5200 kW and 6500 kW). This implementation enables the consideration of the operating range of the biomass boiler (20-100%).

4.4 Results

4.4.1 Fixed investment capital (FCI) and operational expenses (OPEX)

Table 4.7 shows the equipment cost references used for FCI estimation for both polygeneration and combustion-based systems. In the case of the combustion-based system, only the biomass boiler and the peaking boiler are considered. If not specified, the costs presented are the free-on-board costs, which are multiplied by, among others, the equipment-specific labour and material factor (1.7-2.5), mentioned in section 4.3.3.

Table 4.7 Major equipment cost references (CAD 2022)

Equipement	$EC_{reference[CAD]}$	$Capacity_{reference}$	***Unit***	***n***	***Ref***
Biomass boiler [a, b]	1 322 700	6800	kW	1	[147]
Compressor	4 406 300	300	kW	0.85	[43]
Cyclone	35 500	10	m^3/s	0.56	[43]
Cyclone fan	27 800	10	m^3/s	0.93	[43]
Gasifier	5 307 700	6	odmt/h	0.7	[141]
Heat exchanger	70 900	100	m^2	0.71	[43]
Knockout pot	101 300	20	m^3	0.52	[43]
Residual gas boiler[a]	112 200	1000	kW	1	[147]
MeOH reactor	350 000	3	m^3	0.52	[43]
Nickel fluidized bed[a]	4 254 400	12	m^3	0.67	[43]
Peaking boiler [a, c]	112 200	1000	kW	1	[147]
SOEC [a,d]	1 700 000	1	MW	-	[146]
SOFC [a,d]	1 700 000	1	MW	-	[146]
ZnO guard bed	37 400	8	m^3/s	1	[134]

[a] Bare module cost shown

[b] The biomass boiler cost is only considered in the combustion-based reference system

[c] This value is used for both polygeneration and combustion-based systems

[d] Total SOFC module cost per kW (including SOFC stack, enclosure, inverter, cathode heat exchanger, etc.)

The FCI and the fixed OPEX costs are shown for each power configuration for both polygeneration and combustion-based systems in table 4.8. The inherent complexity of the polygeneration system (and the associated equipment) increases the FCI an order of magnitude over similar heating power combustion-based systems.

Table 4.8 Fixed capital investment and fixed annual OPEX for the range of system power considered

Polygeneration system		
Power [kW]	**FCI [$CAD]**	**Annual fixed OPEX [$CAD]**
1600	5 180 800	284 900
3200	8 240 600	453 200
4800	11 039 200	607 200
6400	13 769 300	757 300
8000	16 462 800	905 500
Combustion-based system		
Power [kW]	**FCI [$CAD]**	**Annual fixed OPEX [$CAD]**
1300	780 000	42 900
2600	887 100	48 790
3900	994 200	54 700
5200	1 101 200	60 600
6500	1 264 400	69 500

4.4.2 Comparison of the combustion-based and polygeneration systems in the baseline market scenario

Figure 4.4a presents the annual variable cashflows of the optimized polygeneration systems (resource-wise) for the different power configurations in the baseline market scenario. In lower power settings, the cash flow sum is remarkably impacted by the methanol consumption by peaking burners, with biomass and fixed OPEX becoming the main cost driver in upper power settings. The 3200 kW system power configuration is the smallest to provide a positive annual cash flow but requires more methanol for the peaking burner than the quantity produced by the system. This scenario is unattractive if a self-sustaining profitable system is desired. At 4800 kW and above, the optimized system becomes profitable and produces a net output of MeOH. Figure 4.4b shows the cash flows for the combustion-based system power configurations. A pattern similar to that of the polygeneration system methanol consumption can be observed for low-power biomass boilers and their propane consumption, where a large amount of propane must be bought to cover demand. While the two lowest-power biomass boiler configurations show a clear disadvantage in annual performance, the 3900 kW, 5200 kW, and 6500 kW boiler configurations are similar, having approximately a 0.4 MCAD variable cost for their annual operation.

Figure 4.5a shows the evolution of the greenhouse heat demand and the polygeneration system energy flows throughout the year for the highest power configuration in the baseline market scenario. The decrease in biomass input power observed in the middle of the year

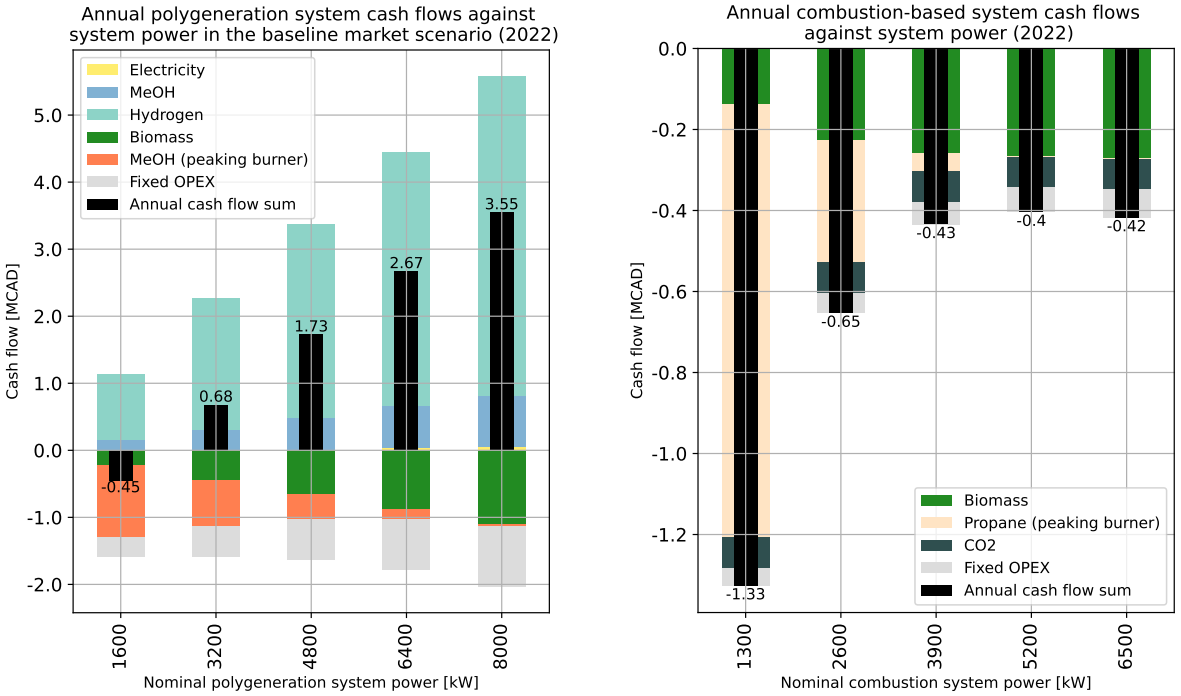
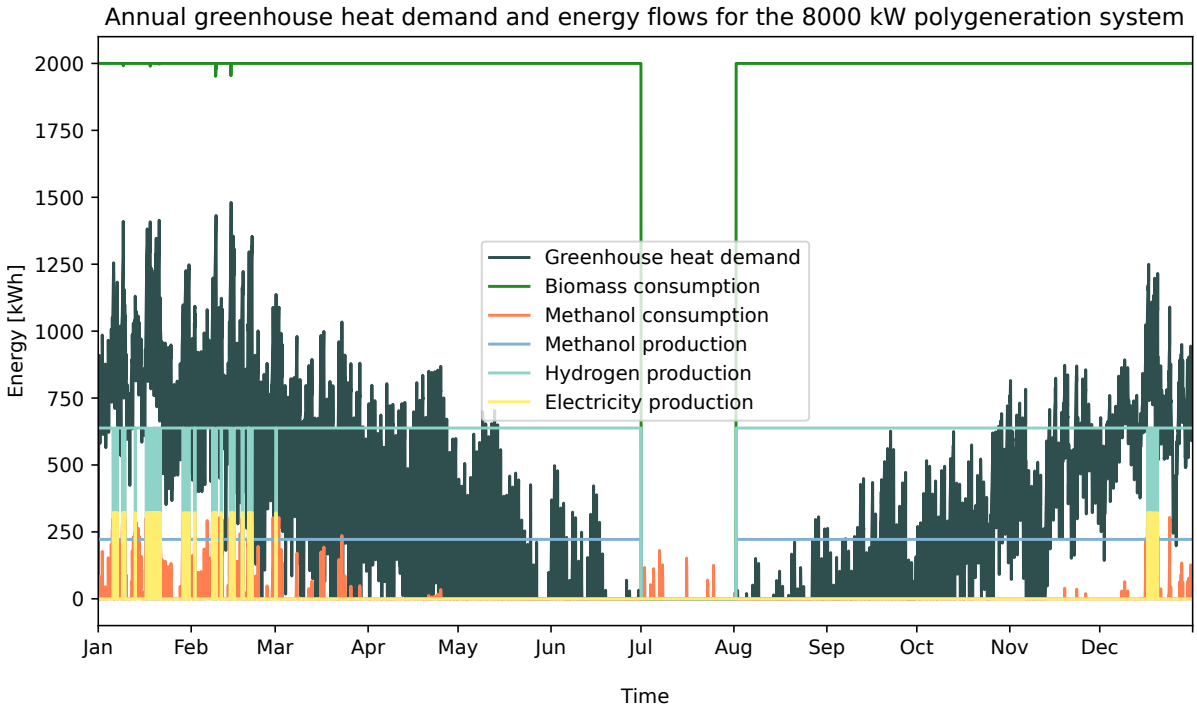
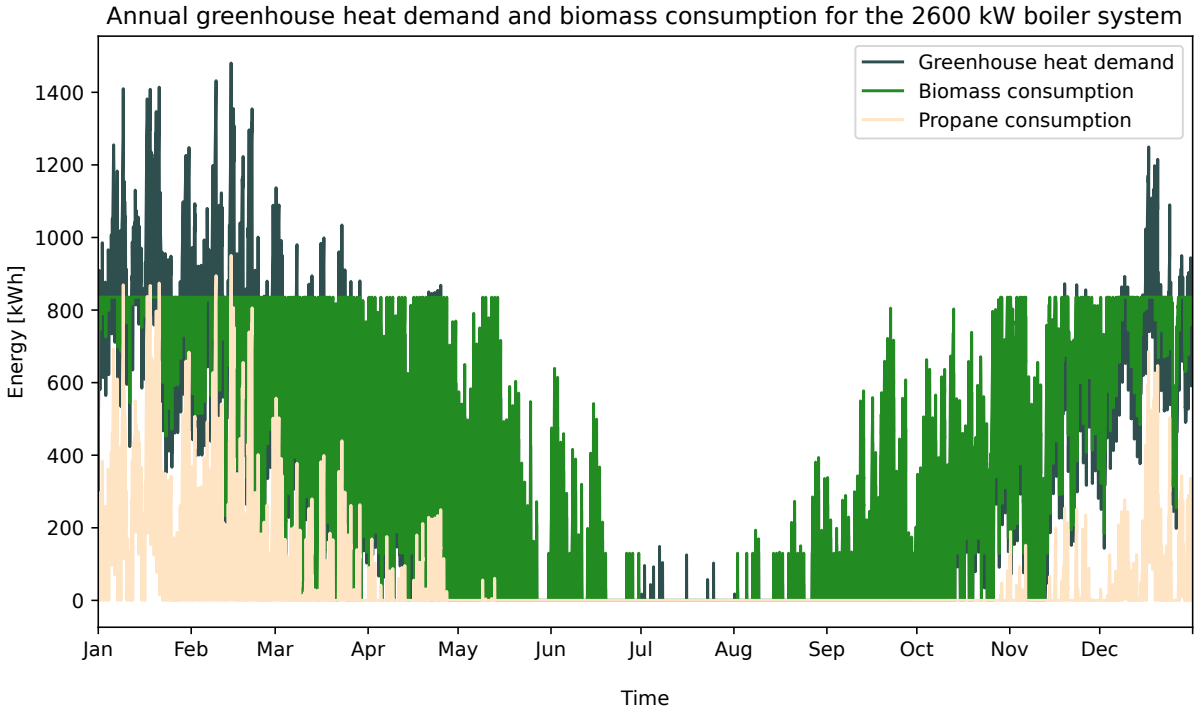


Figure 4.4 Annual cash flow (2022, first year) as a function of system power for (a) polygeneration system in the baseline market scenario and (b) combustion-based system

is the maintenance break of July. The most profitable and highest power polygeneration system (8000 kW) would produce 1 409 000 litres (1115 tons) of methanol, 504 800 kg of hydrogen, and 267 MWh of electricity while providing 11 420 000 kWh of heat to the greenhouse from 16 500 tons of moist biomass. 75 000 litres of methanol would be used to cover the heating demand peaks. To obtain those results, the system operates almost continuously in the maximum hydrogen mode. During heat demand peaks, it switches to maximum electricity and maximum methanol modes to provide more heat to the greenhouse. Different optimization objectives could be chosen in real-life usage. Electricity autonomy and minimization of the auxiliary burners are two examples. Figure 4.5b shows the equivalent information for the 2600 kW combustion-based system. Compared to the polygeneration system results, the most powerful combustion-based layout (6500 kW) would use 3.5 times less biomass (4700 moist tons) and no propane to cover the greenhouse heating needs. 3900 kW and 5200 kW biomass boilers would need 42 000 and 1 000 litres of propane, respectively.



(a)



(b)

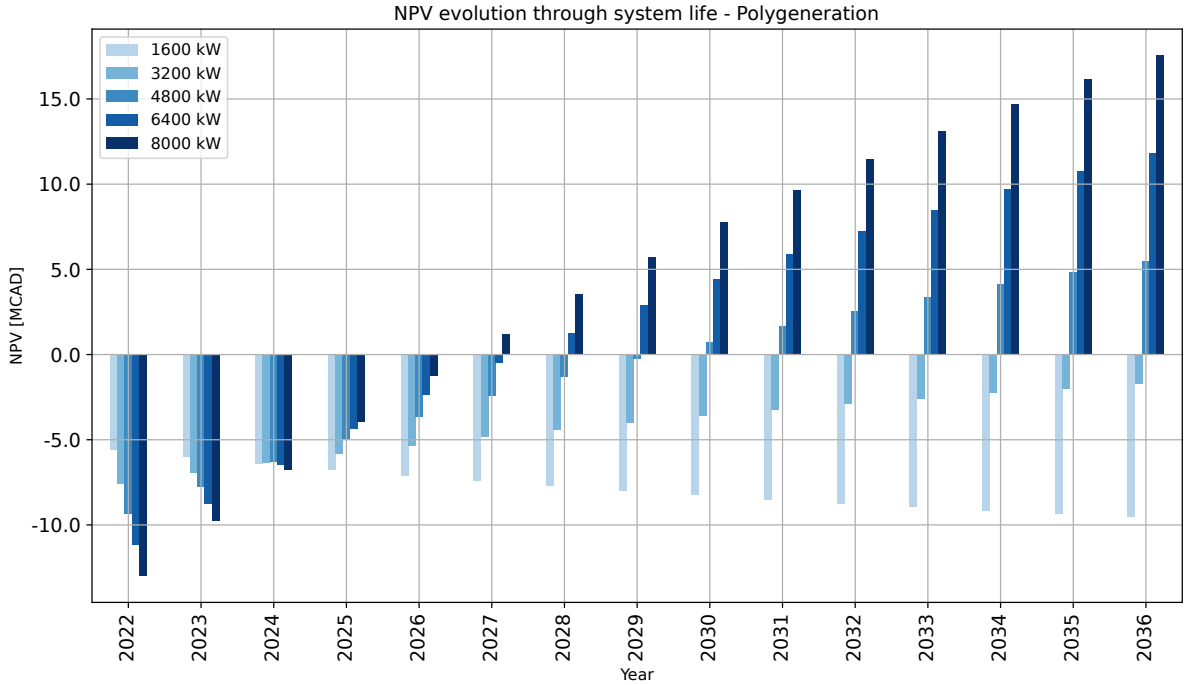
Figure 4.5 Annual energy flows of a) 8000 kW polygeneration system and b) 2600 kW biomass boiler

Net present value (NPV) comparison Figure 4.6a shows the NPV evolution of the different polygeneration system power configurations through their life. The FCI is considered to be paid at the beginning of the system's life. Figure 4.6b does the same for combustion-based systems. In the baseline market scenario, the NPV analysis shows that the most powerful polygeneration system configuration (8000 kW) is unsurprisingly the most profitable over its life, with an NPV of 17.6 M CAD after 15 years at a 10% discount rate. The 4800 kW and 6400 kW power configurations also show a positive NPV. On the combustion side, the 5200 kW configuration is the least expensive, having an NPV of −5.0 M CAD after 15 years, but the 3900 kW and 6500 kW configurations are close at −5.2 and −5.3 M CAD respectively. For both combustion-based and polygeneration systems, the most powerful layouts take advantage of the low biomass prices compared to the relatively high peaking fuel prices impacting the smaller configurations. It is worth noting that the 1600 kW polygeneration system is the only one to have a lower NPV than the three best combustion-based systems. In this market scenario, coupling a properly-sized polygeneration system could be profitable for greenhouse owners, either decreasing their energy-related expenditures or turning them into a source of income, as discussed further below.

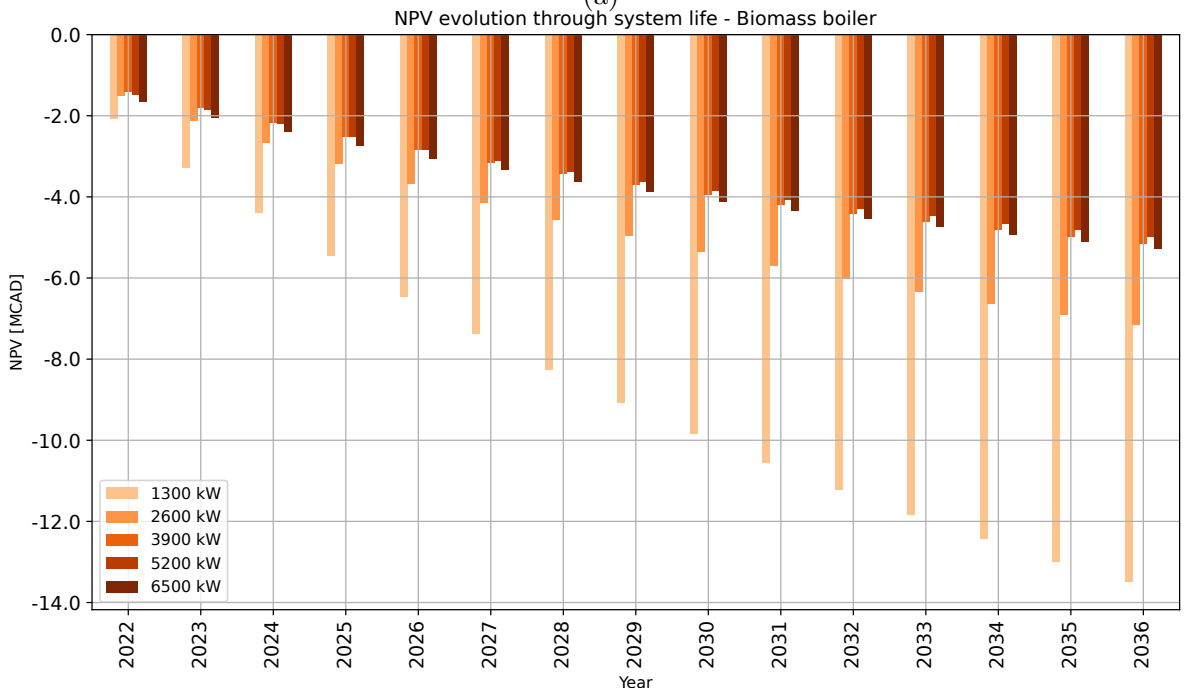
Figure 4.7 shows the impact of the discount rate on the cumulative NPV of the most advantageous polygeneration and combustion-based systems. Lower discount rates favour the 8000 kW polygeneration system, and higher discount rates, the 5200 kW combustion system. The high initial capital costs of the polygeneration systems compared to the biomass boilers explain those results. Even if high discount rates reduce the gap between both systems, the polygeneration option stays better than the combustion-based alternative NPV, for the range considered here.

Sensitivity analysis in the baseline market scenario A sensitivity analysis was conducted to assess the impact of price variation of resources and products on the cumulative NPV for the highest system power configuration. A ±15% variation (30% range) of the input prices presented in section 4.3.3 was applied, independently, in the optimization problem. The results are shown in figure 4.8. The variation of hydrogen (-39.0% and +39.0% change in NPV), biomass (-8.9% and +8.9%), and methanol (-5.9% and +5.9%) prices had the most impact. The variation in electricity (-0.4% and +0.4%) prices had the least. Since the variation is symmetrical, the applied changes have not modified the system's operating mode behaviour. In all cases, the system mostly relies on hydrogen sales to ensure its profitability.

Assessment of the different market scenarios In addition to the baseline presented above, 26 other scenarios were investigated to assess the impact of the combination of pes-



(a)



(b)

Figure 4.6 NPV evolution through the system life for every power configuration of a) polygeneration systems and b) combustion-based systems

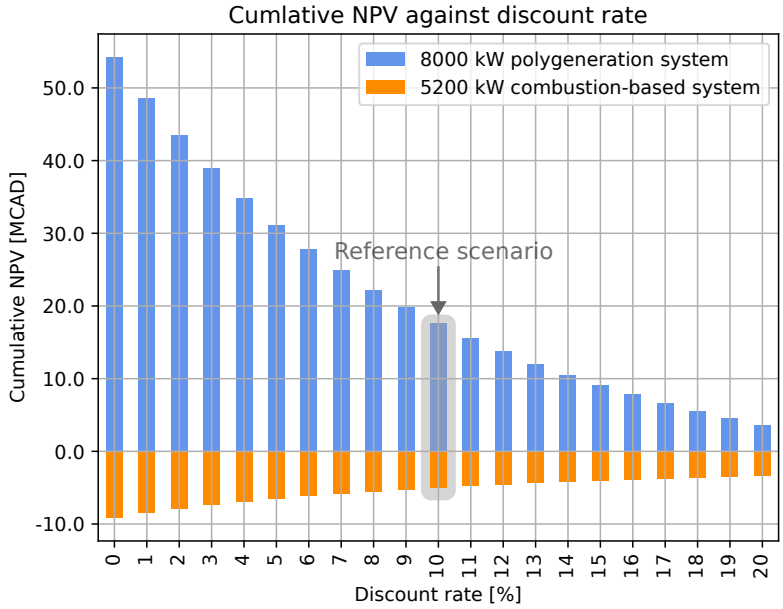


Figure 4.7 Cumulative NPV of the 8000 kW polygeneration and 5200 kW combustion-based systems as a function of discount rate

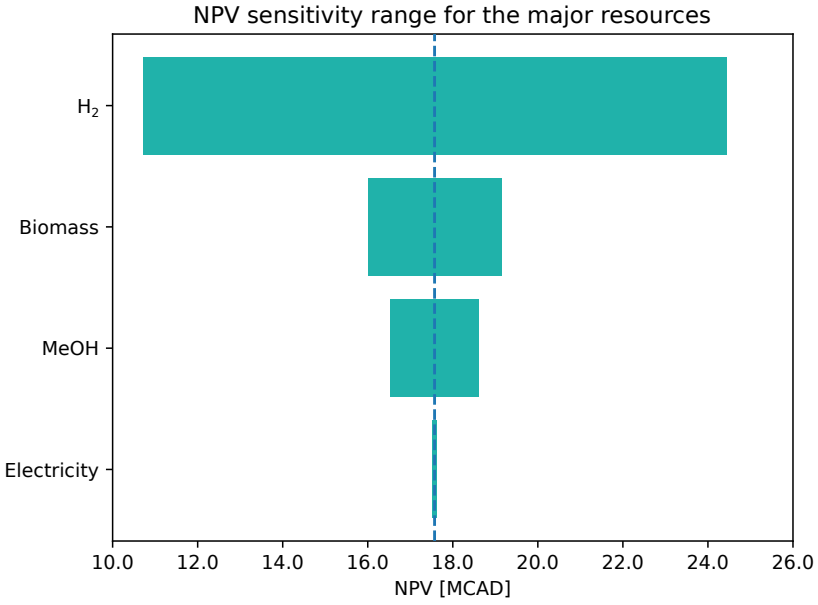


Figure 4.8 Cumulative NPV sensitivity range (±15% variation) for major resources

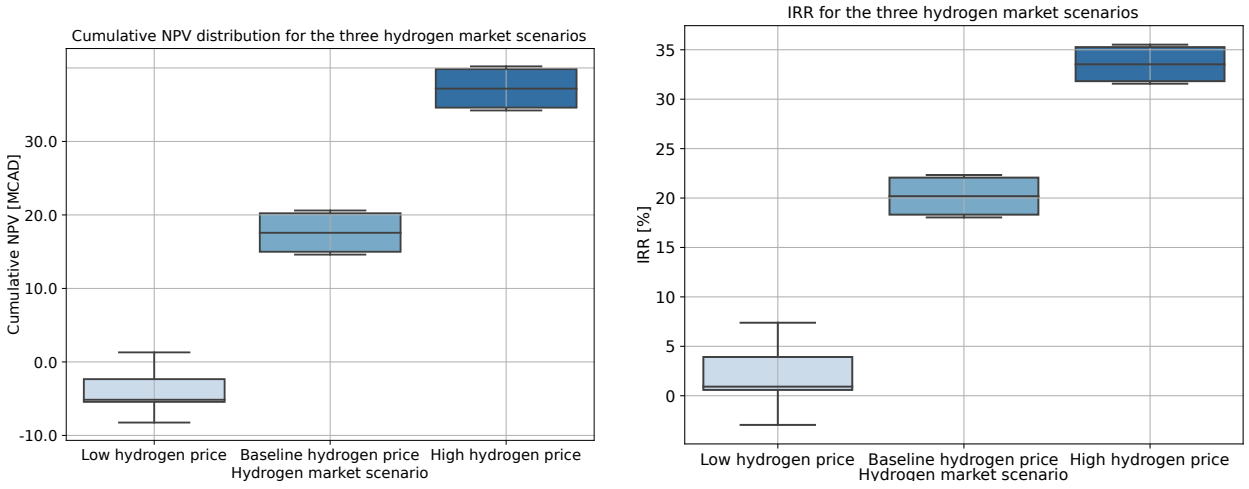
simistic, baseline, and optimistic prices for electricity, methanol, and hydrogen. The impacts on cumulative NPV are shown in figure 4.9a, classified by hydrogen price, the main driver of

change. The internal rate of return (IRR) was also computed for all scenarios. The results are shown in figure 4.9b. Negative IRR can be observed for some low hydrogen price scenarios. None of these scenarios has an IRR over 10%. The investment is quite attractive in the baseline (≈20.2% IRR) and high hydrogen price (≈33.5% IRR) scenarios. In baseline and high hydrogen market price scenarios, the distribution is symmetrical around the median. It is not the case in the low hydrogen market price scenario, which means that a system change of behaviour is observed. When low hydrogen prices are coupled with high electricity prices, the maximum electricity mode is selected 91% of the time, replacing the maximum hydrogen mode favoured in other scenarios. This is further investigated in figure 4.10. The only low hydrogen price scenario to have a positive NPV is the one with high methanol and high electricity prices. However, seven of the nine low hydrogen price scenarios still give similar or better results than the best combustion-based biomass system.

4.5 Discussion

While the optimization problem was implemented here to minimize the system's expenses, other objectives could be chosen for further studies. A minimum threshold could be set for products other than heat to reflect the potential owner's needs. For example, studying the case of operation in an isolated community would probably imply a multi-objective optimization. Profitability could also be increased by selling the remaining heat to surrounding installations or including a storage tank to reduce heat demand peaks and related methanol consumption. In further studies, the operational flexibility of the system could be used at its highest potential by considering dynamic resource prices (i.e. high electricity rates during demand peaks).

The system's results have shown that the cumulative NPV was heavily dependent on the price of green hydrogen, a market in its early development. In July 2022, green hydrogen prices are reported to have reached 21 CAD/kg (16.80 USD/kg) in Texas, and over 12.70 CAD/kg for conventional hydrogen in other parts of the World [177]. In this study, the hydrogen prices considered were 4.13, 9.45, and 13.5 CAD/kg, depending on the scenario. At the same time, the infrastructure to handle the distribution and consumption of hydrogen has yet to be implemented worldwide. Implementing a polygeneration system today would require specific industrial ecosystems grouping producers and consumers, as seen in the EU-sponsored Hydrogen Valley initiative. Hydrogen could also be injected directly into a natural gas grid, but research is still being conducted on this practice [178]. Overall, the great sensitivity of the system's profitability to the hydrogen price is a vulnerability, although obvious opportunities exist in the short term. Drastic innovation in the green hydrogen production field could lower



(a) (b)

Figure 4.9 a) Cumulative NPV as a function of electricity and methanol market scenario for the three hydrogen market scenarios considered. b) Internal rate of return (IRR) for the three hydrogen market scenarios

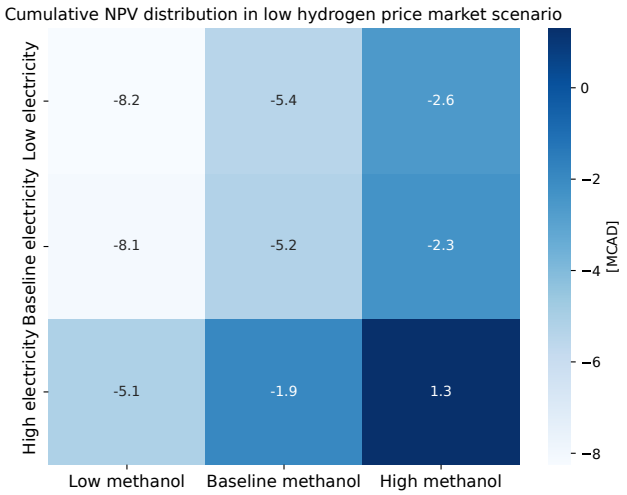


Figure 4.10 Cumulative NPV as a function of electricity and methanol prices in pessimistic hydrogen market scenario

market prices and make the system less profitable or unprofitable.

Traditionally, greenhouses and farms have been energy consumers. With this kind of polygeneration system, they could become energy producers. Better autonomy, augmented resilience to market volatility and increased diversification of activities are the potential benefits of using those systems. With the onsite production of biofuels, adopters would reduce their agricultural operations' GHG footprint, currently relying on fossil fuels, and possibly reduce nearby industries' carbon emissions. Furthermore, the possibility of sequestrating the CO_2-rich stream paves the way to carbon-negative agriculture.

If this TEA reveals the attractive possibility of implementing bio-refinery technologies in agricultural settings, potential limitations must however be considered thoroughly before a real-life implementation scenario. For instance, a startup phase was not considered and the uncertainty regarding the price of fuel cells remains high. Moreover, the small number of DFB gasifiers currently in operation is also a factor that could influence the economic viability of this kind of polygeneration system.

4.6 Conclusion

A techno-economic study is conducted on a novel polygeneration system producing electricity, methanol, hydrogen, and heat based on wood chips gasification. A TRNSYS thermal model is used to simulate the heating demand of a 20 000 m^2 greenhouse located in southern Quebec. A MILP problem is solved to optimize the system operating regimes throughout the year while answering the heating demand. Five power configurations (1600 kW, 3200 kW, 4800 kW, 6400 kW, and 8000 kW) are evaluated and compared to their biomass boiler equivalent (in terms of heating power). Peaking boilers are dimensioned to cover the residual demand for every configuration. Three market scenarios are investigated for electricity, methanol, and hydrogen prices. The NPV analysis shows that the 8000 kW polygeneration configuration and the 5200 kW combustion-based layout are the most advantageous among their groups. In the baseline market scenario, an 8000 kW polygeneration system would have an NPV of 17.6 M CAD at a 10% discount rate and an IRR of 20.2%, while the 5200 kW combustion-based system would have an NPV of -5.0 M CAD. Those results show the potential benefits of replacing simple boilers with flexible polygeneration systems. Of the 27 market scenarios investigated, the most powerful polygeneration system had a superior NPV over the 5200 kW combustion-based system in 22 cases, a similar one ($\pm$0.4 M CAD) in three scenarios, and an inferior one in only two. The NPV results heavily depend on hydrogen prices. The polygeneration system considered has the potential to turn traditional energy consumers into producers. Aside from greenhouses, off-grid communities should be considered to assess

its full implementation potential. This type of system can contribute to the required GHG emissions drop when replacing fossil-fuel-based systems.

CHAPTER 5 GENERAL DISCUSSION

The general purpose of this work was to quantify the techno-economic potential of the coupling between the polygeneration system developed by Antar and Robert and the heat demand of a greenhouse operated in southern Quebec. The objectives were to evaluate the fixed capital investment and operating costs of a polygeneration system designed for a greenhouse reference scenario; to optimize the annual economic performance of such a system in different electricity, green methanol, and green hydrogen market scenarios; to compare the performance and economics of a typical biomass-powered combustion-based system to the polygeneration system.

In light of the techno-economic assessment presented in chapter 4, those objectives were attained. The FCI and fixed OPEX have been estimated for the five power configurations of both system types using the methodology precisions presented in chapter 3. The FCI estimation for the polygeneration systems is roughly 10-times greater in cost than for similarly sized combustion-based systems.

A mixed-integer linear program has been implemented and solved to optimize the annual operation of the polygeneration system in 27 market scenarios by varying the sales price of hydrogen, methanol, and electricity. With the inclusion of peaking burners, the system can cover the greenhouse heating demand while generating positive annual revenues for all polygeneration configurations except the one with the lowest power (1600 kW) in the baseline market scenario.

The assessment of the discount rate variation impact on net present value, with the cumulative NPV evaluation, has enabled the comparison between polygeneration and combustion-based heating solutions. The polygeneration system yields similar or higher cumulative NPV in 25 of the 27 market scenarios investigated. Low discount rates increase the gap between the cumulative NPVs of the best polygeneration system and the best combustion-based configuration. Higher discount rates reduce it. The internal rate of return of the polygeneration system is attractive at 20.2% for the most powerful design (8000 kW) in the baseline market scenario.

This study has shown the techno-economic potential of the polygeneration system developed by Antar and Robert. Those results are based on the commercialization of emerging technologies such as dual fluidized bed gasifiers and solid oxide fuel cells and are dependent on their future development. However, in proper market conditions, this system could enable the economic diversification of small-scale energy consumers, such as greenhouses, by promoting

them to energy producers. The local production of diverse energy products would increase the autonomy and resilience of adopters by reducing their dependence on external resources and their exposition to market volatility. Furthermore, the operating mode flexibility gives the system the leverage to take advantage of the seasonal weather changes observed at high latitudes. With this kind of decentralized system, many communities could replace fossil fuels with local resources to power their daily activities.

CHAPTER 6 CONCLUSION AND RECOMMENDATIONS

This analysis aimed to assess the techno-economics of a polygeneration system running on wood chips producing electricity, methanol, hydrogen, and a high-purity CO_2 stream, in the implementation context of a greenhouse.

6.1 Summary of Works

To understand the different fields related to a complex system like the one developed by Antar and Robert, a broad literature review was conducted on biomass gasification, syngas cleaning and conversion, techno-economic analysis of similar systems, electricity, green methanol, and green hydrogen markets. Cumulative NPV and annual cash-flow comparisons were made between this system and a biomass combustion-based reference option with a TEA. Five equivalent heating powers were considered. Pessimistic, baseline and optimistic market scenarios were investigated based on the worldwide distribution of current electricity, green methanol, and green hydrogen prices. A mixed-integer linear program was implemented to optimize the system's annual revenues while providing enough heat to the greenhouse. The five power configurations were optimized in the baseline market scenario for both system types. The results demonstrated that the most promising configurations are the 8000 kW polygeneration system and the 5200 kW combustion-based system. Optimization in the 26 other market scenarios with the 8000 kW configuration has shown that the hydrogen market scenarios had the most impact on the system's economic performance. Variations in methanol and electricity prices did not influence the results significantly.

6.2 Study limitations

If the study results are promising for the polygeneration system, potential limitations should be considered in future studies. The price estimation for two of the major technologies used in the system is uncertain. There are few dual fluidized bed gasifiers in operation worldwide, and the solid oxide fuel cell industry is nascent. The price estimations depend on the future developments of those technologies. Similarly, the main revenue of the system comes from hydrogen, but green hydrogen prices are uncertain. The resource production, the hunger from industrials to decarbonize their activities, and the widespread adoption of hydrogen as a fuel are not guaranteed. Proper hydrogen infrastructure development is also needed. Refinements could be applied to the TEA as well. Consideration of a startup phase, the

inclusion of the cost of catalysts, and consideration of catalyst deactivation are all possible improvements. Finally, including the implications of a dynamic operation, considering for instance the transition phase between operational modes, would refine the analysis.

6.3 Future Research

For future works, the possibilities are numerous. Considering heat storage to reduce the heat demand peaks of the greenhouse could lessen or even eliminate the use of peaking burners. Addressing the elements presented in the study limitations, such as the assessment of the dynamic nature of the system and evaluation of the catalyst costs and behaviour, are capital steps towards a more refined analysis of the polygeneration system implementation. Dynamic pricing could also be considered in future studies. Aside from the coupling with a greenhouse, other use cases of the system could be envisioned: district heating and local energy production in cities or isolated communities and association with other industries in need of hydrogen, fuel, electricity, and even CO_2. A life-cycle analysis of the system would be interesting to quantify its GHG reduction potential. Using the remainder of the CO_2-rich stream for carbon capture and storage could make the system carbon negative. Evaluating this possibility and the impact of carbon pricing on its attractiveness would be of interest. This future research will eventually pave the way, if returns are positive, towards implementing a polygeneration system pilot plant.

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