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Flex fuel polygeneration: Integrating renewable natural gas

by

Matthew Kieffer

A thesis submitted to the graduate faculty

in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Major: Mechanical Engineering; Biorenewable Resources and Technology

Program of Study Committee:

Robert C. Brown, Major Professor

Mark Mba-Wright

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Iowa State University

Ames, Iowa

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LIST OF ACRONYMS

AD: anaerobic digestion

BTL: biomass-to-liquids

Btu: British thermal unit

CTL: coal-to-liquids

DCFROR: discounted cash flow rate of return

EIA: Energy Information Administration

EPA: Environmental Protection Agency

FCI: fixed capital investment

FFPG: flex fuel polygeneration

FTS: Fischer-Tropsch synthesis

GTL: gas-to-liquids

IRR: internal rate of return

kPa: kilopascal

kWh: kilowatt hour

LFG: landfill gas

LO: livestock operations

MJ: megajoule

MM: million

MSW: municipal solid waste

MW: megawatt

NETL: National Energy Technology Laboratory

NG: natural gas

O&M: operating and maintenance

RIN: renewable identification number

RNG: renewable natural gas

WGS: water gas shift

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ABSTRACT

Flex Fuel Polygeneration (FFPG) is the use of multiple primary energy sources for the production of multiple energy carriers to achieve increased market opportunities. FFPG allows for adjustments in energy supply to meet market fluctuations and increase resiliency to contingencies such as weather disruptions, technological changes, and variations in supply of energy resources. In this study a FFPG plant is examined that uses a combination of the primary energy sources natural gas and renewable natural gas (RNG) derived from MSW and livestock manure and converts them into energy carriers of electricity and fuels through anaerobic digestion (AD), Fischer-Tropsch synthesis (FTS), and gas turbine cycles. Previous techno-economic analyses of conventional energy production plants are combined to obtain equipment and operating costs, and then the 20-year NPVs of the FFPG plant designs are evaluated by static and stochastic simulations. The effects of changing operating parameters are investigated, as well as the number of anaerobic digestion plants on the 20-year NPV of the FTS and FFPG systems.

CHAPTER 1. INTRODUCTION

Energy Markets Overview

The consumption of energy globally has continually increased over the past decades and shows no sign of slowing. This indicates the advancement of technology and electrical devices as well as mankind's increasing extension of resources to remote areas where electricity was not provided earlier. Increases in energy usage leads to higher demand of energy supply. Currently, the global supply of energy is provided by fossil fuels: coal, petroleum, natural gas, and other resources that have undergone high pressures and temperatures over centuries, resulting in energy dense carbonaceous fuels. Historically, the availability and price of fuels were the main factors that drove the market. However, current forms of technology to extract and utilize fossil fuels result in potentially harmful gases being released to the environment. Legislation is implementing stricter regulations on emissions including nitrogen, mercury, sulfur, and carbon dioxide from power plants, fuel refineries, factories, homes, and vehicles [1]. Along with harmful emissions, the global supply of fossil fuel will one day be used up with the global production (different than extraction) rate much slower than the global consumption rate. Studies have shown the diminishing reserves of fossil fuels [2], which leads to the question of where the next fuel supply will come from. Current fuel markets are no longer driven only by what is available and the cost. Now fuel production is also affected by political incentives, social perception, environmental protection, and energy independence [1]. To help stabilize harmful emissions related to energy production in the

U.S., the focus has shifted towards increases in energy efficiency and away from more carbon intensive fuels, such as coal for electricity production [3].

Research Motivation

Factors that determine the success or failure of energy production plants include capital and operating costs, government policies, available technology and resources, sustainability, industrial and consumer acceptance and demand, weather, and location [4-6]. Fuel availability and prices in the United States are always changing, mainly due to supply and demand. Severe weather events can temporarily disrupt oil, natural gas, and biomass supply chains as well as product markets, potentially resulting in increased feedstock or product prices [7-9]. Weather can also affect crop production and harvesting, supply chain infrastructure, processing, refining, and distribution [10]. While energy security, climate change, and fossil fuel depletion are likely to provide new investment opportunities for alternative energy routes, venturing into new energy sectors also includes increased risk due to the uncertainty in technology implementation and exploring new markets [11]. If energy production plants are designed so that they are able to adapt to market supply and demand fluctuations, the risk involved with investing in these plants decreases. Aligned with traditional economic practices, a diversified portfolio leads to lower risk, often lower than the weighted average of its constituents [12]. If an energy plant is flexible enough to shift towards lower consumption of expensive feedstocks while adjusting its products portfolio to maximize profits, it is more likely to obtain greater economic returns. Polygeneration, which focuses on turning one feedstock into multiple types of energy, has been previously explored in energy production as a way to meet swings in market demand for various energy products [13, 14]. One of the most familiar examples is the co-generation of electric power and the production of process heat from steam. Additional scenarios of polygeneration have also been studied that utilize multiple feedstock to produce multiple products. An example of polygeneration that utilizes multiple feedstocks is an electric utility company that is able to fire combinations of coal, natural gas, and biomass pellets in boilers or provide peaking power from gas turbines fired with natural gas or fuel oil that can rapidly come on line [15]. In this study we refer to polygeneration that utilizes multiple feedstock as flex fuel polygeneration (FFPG). Flex fuel polygeneration can employ both multiple primary energy sources (including fossil and renewable energy) and technologies to produce multiple energy carriers (fuel, electricity, chemicals, and heat). Cai et al. and Floudas [16, 17] state that combining subsystems into a larger system has the ability to decrease the overall equipment, installation, and labor costs relative to multiple individual energy plants. There are many technologies to be considered when creating FFPG plants, the choice of which depends on plant location, feedstock availability, product demand, technology readiness, and other factors that influence the functionality of the plant. The types of technologies and feedstock utilized can be tailored to specific locations when designing FFPG plants. Technologies chosen in this study are used to illustrate the possible advantages associated with FFPG.

The most profitable way to produce fuel is to utilize a low cost feedstock and transform it into a high value product with an efficient technology. However, there are technical limitations that restrict the flexibility of these transformations. High priced feedstocks coupled with low cost products can lead to diminishing returns on investment and should be avoided. Taking a look at Figure 1, the reason coal is has been used so often in the past to produce electricity is the high availability of coal, the readiness of the technology to process it, and the high selling price of the product. The prices of energy sources and energy carriers are continually fluctuating as a result of the market supply, transportation costs, social considerations, weather, and other factors. For example, in 1979 the price of crude oil nearly doubled when petroleum production was greatly reduced [18]. In 2012 the price of corn used for fuel greatly increased due to weather events. In 2013 hurricane Sandy hit the East coast and disrupted transportation infrastructure. The cost of a feedstock and the selling price of a produce play an enormous role in the overall financial performance of energy production scenarios.

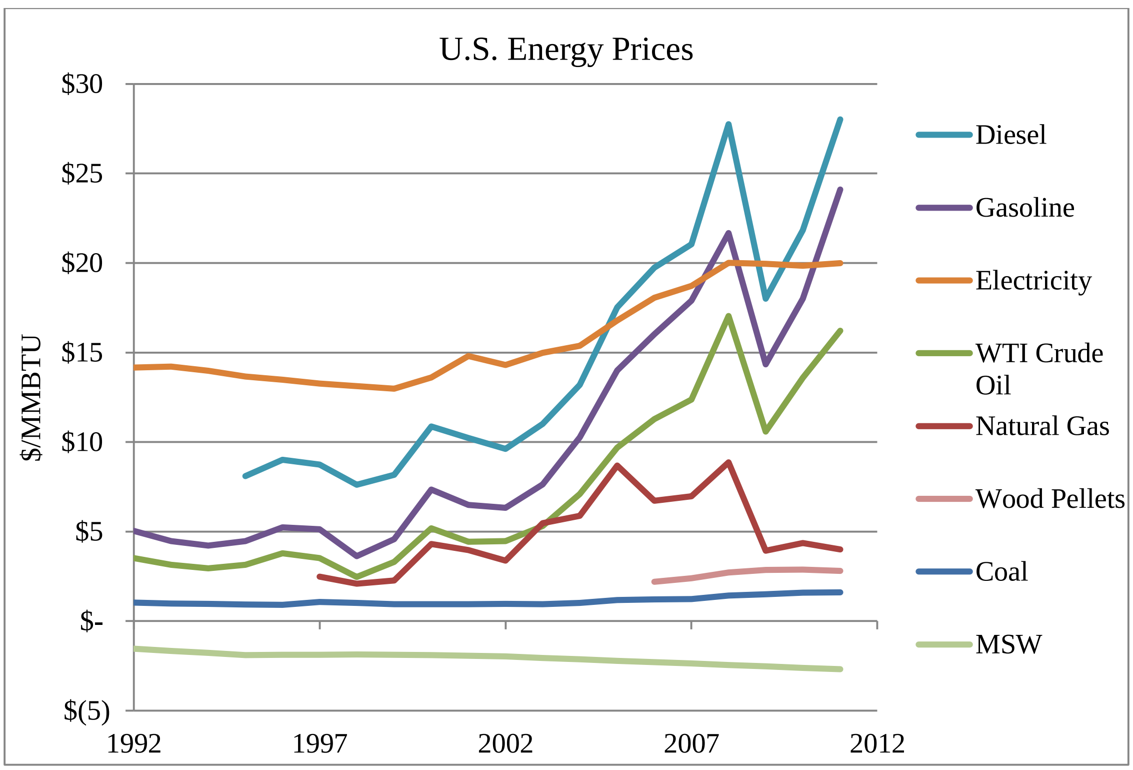

Figure 1. U.S. Energy Prices [19]

Approach to the Problem

The current study investigates a method to alleviate some of the financial stresses on energy production facilities by integrating multiple feedstock sources into the supply chain and producing multiple products. To analyze this, a Fischer-Tropsch synthesis (FTS) plant is investigated that utilizes natural gas (NG) as a feedstock. The FTS plant is retrofitted to substitute a portion of the NG with renewable natural gas (RNG) that is produced from the anaerobic digestion of organic matter to alleviate the dependence on a single feedstock. Three different scenarios to produce RNG are analyzed to understand the impact of varying parameters on the overall 20-year net present value (NPV) of each scenario. The first scenario (FFPG MSW AD) collects mixed municipal solid waste and anaerobically digests it in tanks to produce biogas. The biogas is then upgraded to pipeline quality natural gas (RNG) and fed to the FTS system for reforming. The second scenario (FFPG LO AD) produces biogas from the anaerobic digestion of manure from livestock operations, which is subsequently upgraded to RNG and fed to the FTS system. The third scenario (FFPG LFG) collects biogas from an existing landfill, upgrades it to RNG, and integrates it into the FTS system. The 20-year NPVs of the retrofitted systems are compared to the economic performance of the FTS systems that only utilize natural gas. The 20-year NPV of the systems are analyzed by looking at capital and operating costs associated with the energy production scenarios. Information on capital and operating expenses are taken from literature and are scaled using a power law. Sensitivity analyses as well as stochastic Monte Carlo analyses are utilized to gain insight into the overall profitability of the systems.

CHAPTER 2. LITERATURE REVIEW

Introduction

The interest in and demand for renewable sources of fuel have increased within the last few decades due to a number of factors including pollution, national security, waste management, as well as the availability (and lack thereof) of fossil fuel supplies. Efforts are being made to make fossil fuel energy providers more efficient, generate lower carbon emissions, and produce renewable energy locally that can support the economy and lower dependence on foreign sources or petroleum. To do this, some have suggested the integration of multiple technologies to increase efficiency and profitability while lowering emissions and the risk involved with the production of energy carriers. With new technologies, the EIA estimates that from 2012 to 2040 there will be 56% increase in natural gas production [19]. Increased production has already led to an increased adoption of natural gas production technologies [19]. While natural gas burns cleaner compared to petroleum and coal, there are still adverse effects to the environment resulting from the extraction process. Biogas on the other hand is a fuel source produced by a natural process that decomposes organic matter and has similar characteristics to that of natural gas. Biogas, consisting mainly of methane and carbon dioxide, results from the breakdown of organic material by bacteria in anaerobic conditions [20]. Biogas can be directly substituted for natural gas subsequent to the removal of carbon dioxide, water, and other undesirable compounds that may harm equipment in which it is being used. This review of literature will cover polygeneration systems, Fischer-Tropsch synthesis, and the production and utilization of biogas produced from organic waste.

Energy Production

There are many technologies that are utilized to process primary sources of energy into more usable forms of energy carriers. Primary energy can be harvested or extracted from the environment and processed into more usable forms of energy, such as electricity and fuels. Primary energy sources include fossil fuels: coal, crude oil, and natural gas, nuclear fuels, as well as renewable energy: hydropower, biomass, solar energy, wind, bio-thermal, and ocean energy [21]. Since the 19th century, stationary combustion systems have been at the heart of producing energy that can be introduced and utilized by the electrical grid. Traditional electrical power plants consist of three main technologies [22]. The first component is harvesting or converting fuels into usable sources of energy. The second component is utilizing the available energy to generate mechanical movement and turn a turbine. The third component converts the mechanical energy from the turbine into electrical energy by means of a generator and oscillating magnetic fields. Direct combustion of fuels for electric power generation is a well-developed commercial technology that has been developed for many years.

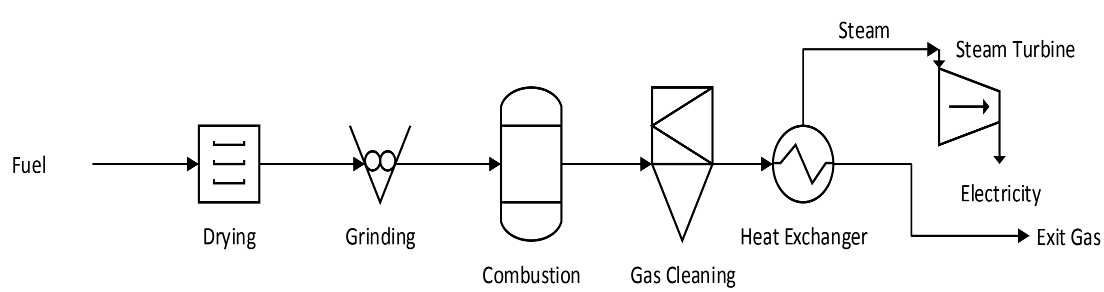

Figure 2. Process diagram for direct combustion to power (adapted from [23])

Along with electricity, other product avenues from processing primary energy sources are fuels and chemicals. In 2012, fuel from petroleum made up around 99% of the energy used in the U.S. transportation sector [21]. This has changed in the previous few years, however since the 1940's petroleum has dominated the transportation market. Petroleum is extracted from the ground and upgraded to different fuel and chemical types. Along with petroleum, natural gas and coal are mined and used as gaseous or liquid fuel sources for transportation, electricity, or heating/cooling applications. Gas-to-liquid (GTL) is focused around Fisher-Tropsch synthesis, which converts natural gas into longer chain hydrocarbons or alcohols depending on the catalyst and operating conditions. Coal-to-liquid (CTL) technologies include pyrolysis, direct liquefaction, and indirect liquefaction. Pyrolysis volatilizes compounds that are condensed as liquids in an oxygen free environment [24], whereas direct and indirect liquefaction use high pressures and temperatures to liquefy and increase the hydrogen content [25]. Nuclear energy has the potential of generating large amounts of energy with small volumes of primary energy and operates by the fission of nuclear fuel such as uranium. Historically, emphasis has been placed on using it for electricity generation through steam turbines. More recently, however, alternative applications such as hydrogen production have become more popular [26]. Although there are potential benefits, high initial capital costs and additional risks that are associated with nuclear energy have limited the market viability [21]. Renewable energy generation has gained large interest and investment in the previous decade due to motivations to reduce foreign energy dependency and address climate issues [24]. Renewable energy is generated from resources that are naturally replenished [21]. Biomass-to-liquid technologies convert organic materials into synthesis gases, which can then be processed into liquid fuels. Often times, the same technologies in GTL and CTL are used to transform biomass. Other liquid fuels, such as biodiesel and ethanol that are produced from vegetable oils and sugars, have increased volume in the U.S. since the introduction of the Energy Policy Act of 2005. Along with biofuels, renewable energy encompasses a broad range of primary energy sources, including hydro, solar, biomass, wind, geothermal, and ocean energy. Interest in renewable energy soared in the 1970's following the oil embargos. However with increased global petroleum production in the 1980's, the price of petroleum fuels diminished along with the focus on renewable energy. More recently there has been a shift towards renewable energy production again as changes in the atmosphere are thought to be linked to energy consumption and the related emissions and environmental compliance acts have been instated [27].

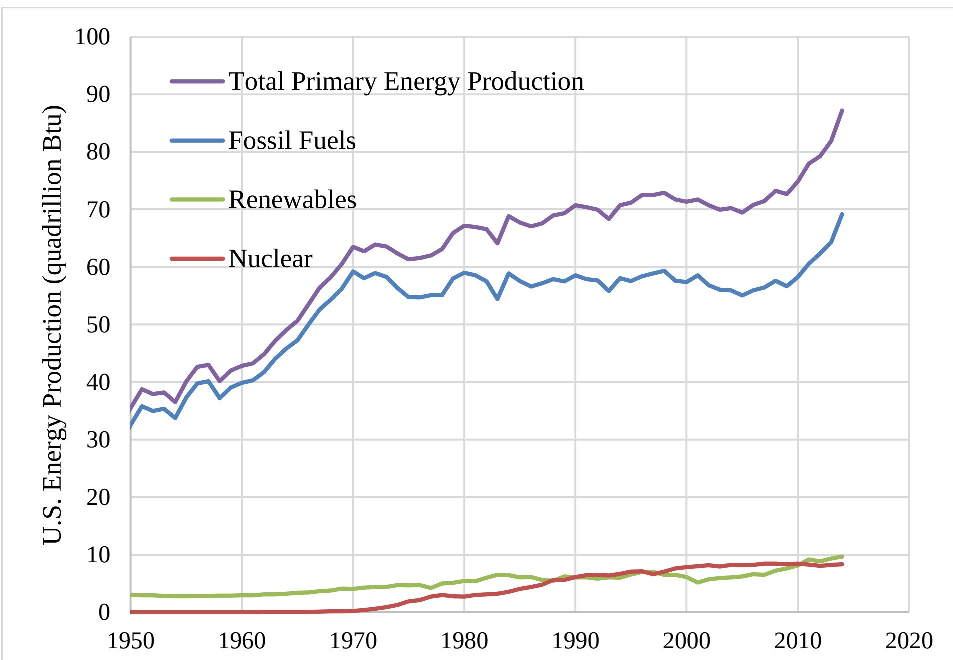

Figure 3. U.S. Primary energy production by source [28]

The primary energy processing technologies previously mentioned often integrate one feedstock into production and produce one main product. Technologies that are dependent on a single feedstock or product can be more susceptible to market fluctuations. As an example, in 2012 a drought occurred in the U.S. that impacted corn producers and associated industries. As a result, the price per bushel of corn rose to over $8, which impacted ethanol producers greatly. As a result of increased corn prices, producers were forced to slow production and reduce profitability [8]. Another example shows the impact on natural gas prices. In 2005, hurricane Katrina hit South East United States, and resulted in 37% of the plants in the Gulf of Mexico to shut down [29]. As a result, the average NG price prior the hurricane, $9.81/MMBtu rose to an average $14.10/MMBtu, impacting many refiners and producers [30].

Polygeneration plants come in a variety of forms, integrating multiple products or feedstock, renewable and fossil energy sources, and alternative processing technologies. A study done by Jana [31] delivers multiple outputs from a single input of agricultural waste. Performance estimates from the investigation show that turning agricultural wastes into a range of products such as electricity, refrigeration, utility heat, and ethanol can improve sustainability and efficiencies. Polygeneration for a rural community provides an economically feasible, decentralized energy production scenario by maximizing feedstock utilization and conversion efficiency [31].

Another study done by Swanson et al. [32] integrated biomass gasification into two FTS plants and analyzed the fuel product value. The analysis simulated processing 389 MW of biomass in a low temperature, fluidized gasifier and a high temperature, entrained flow gasifier. The fluidized gasifier turned the biomass into 150 MW of liquid fuels and 31 MW of electricity, while the entrained flow gasifier converted it into 193 MW of liquid fuels and 36 MW of electricity. These systems required between $500 and

$650 million in investment and resulted in a product value of $4-5 per gallon of gasoline equivalent. Of the factors considered in the study, those that had the largest impact on the product value were feedstock cost and return on capital investment.

Another biomass processing plant analyzed by Zhang et al. [33] focused on pyrolysis as the core technology. The study simulated the polygeneration of monosaccharides, hydrogen, and transportation fuels from turns 2,000 tons/day of lignocellulosic material. The pathway of biomass to products included pretreatment and processing of the feedstock via pyrolysis, following by liquid/solid separation and recovery. During recovery, the light end fraction of the bio-oil is sent to upgrading while the heavy ends are water washed to remove sugars for hydrolysis to monosaccharides. The components of the system that influenced the internal rate of return (IRR) were feedstock costs, product yields, and product credits.

A study done by Kou [34] analyzes the economic performance of dry and wet milling corn ethanol plants. The authors decided to undergo the study due to events in 2008 that caused many dry milling plants to go bankrupt, while wet milling plants were able to survive. They claim that ethanol producing wet milling plants operate at much higher performance than dry milling plants due to their diverse product portfolio which included starch, high fructose corn syrup, gluten meal, gluten feed, and corn oil as opposed to the dry milling plant that had many fewer products. However, the most financially profitable production scenario was wet milling that produced high fructose corn syrup instead of ethanol. In the years of which the plant profitability was analyzed, the price of oil dropped, and the ethanol market was affected by lower selling prices as well. As a result, the HFCS production scenario proved to be the most profitable. This study is a clear example of the benefits associated with operational flexibility and the ability to adapt to disruptions from feedstock supply changes and continuously fluctuating market conditions. The profitability of an energy production plant depends heavily on the market value of the product.

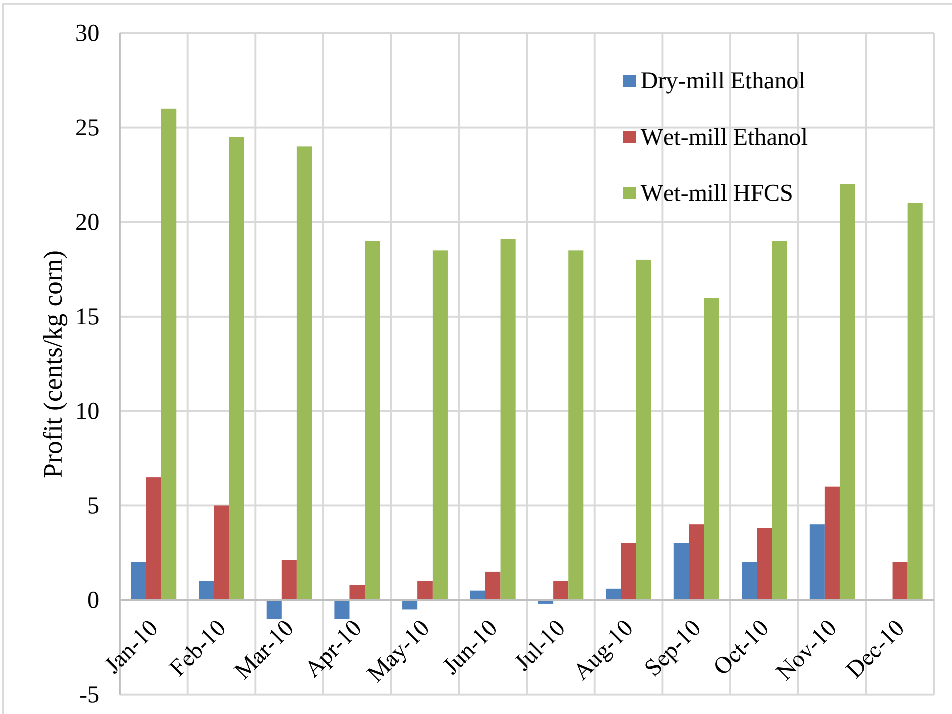

Figure 4. Dry-milling and Wet-milling Profit Margin (adapted from [34])

Cai et al. [16] highlight the opportunities to achieve higher efficiencies, lower capital investment, and generate less environmental impact as compared to traditional production methods by combining single product systems into polygeneration systems. One example Cai et al. used to highlight the need for alternative sources of inputs and technologies is the gasification of coal or other feedstock to produce syngas that can be upgraded to liquid fuels. While gasification is effective, it requires high capital investment and may not be the most efficient method to produce syngas from certain feedstock due to high exergy destruction. It may be profitable to investigate alternative methods to aid gasification in synthesis gas production. By combining a methanol production facility with an integrated gasification combined cycle, the study showed a total capital cost reduction compared to the single production facilities not integrated was approximately 9%. The profitability improvement, along with the primary energy savings show the efficacy of implementing polygeneration.

While single feedstock single product systems can capitalize on the simplicity of handling one incoming primary energy source and one outgoing energy carrier they can be plagued by interruptions in the supply chain and product portfolio risk. On the other hand, polygeneration systems that convert a feedstock into more than one product can avoid some of these challenges.

Polygeneration systems are often known for being able to more effectively utilize the available resources, for being more cost effective, and having the ability to avoid risk associated with single feedstock or product producing plants. Cai et al. [16] declare the major concerns for energy production processes are the highest possible conversion of the initial feedstock to the resulting product along with the thermal energy utilization. A FFPG system can address both of the challenges at once, increasing the overall efficiency of the plant. When multiple energy systems can be paired and cascaded, there are greater opportunities for energy or chemical transformation to products [16].

Along with higher processing efficiencies, the financial performances are impacted. Liu et al. [35] state that the economic parameters to think about when considering polygeneration vs. stand-alone production are the price of products, and the capital and operating costs associated with the technologies. The value of the products relative to each other, and the reliance of the product portfolio on one another is key when determining plant profitability and flexibility of product production. When integrating multiple technologies, capital costs and operating costs need to be considered. In one of the scenarios studied by Liu et al., capital and fixed operating costs were decreased by 50%, while the conversion rate was increased by 50%. As a result, the profitability of the system hardly changed, pointing to the fact that the profit earned by improving process efficiency offsets increased investments in additional technologies [35].

Studies have shown that including multiple feedstock into polygeneration systems can provide flexibility, allowing alternative inputs to be considered for energy production facilities. As Floudas [17] states in their study on hybrid and single feedstock energy processes, hybrid (or FFPG) systems have the opportunity to increase their energy resource portfolio and the flexibility to generate additional products from multiple sources. Along with this, hybrid systems can substitute renewable resources for fossil fuels, thereby reducing GHGs. Most studies that have previously been carried out on polygeneration with multiple feedstock focus on combining coal and natural gas or coal and biomass in co-firing gasification units [36-40]. However only a few have considered biomass and natural gas-to-liquids [41-44].

The studies done on biomass integration with natural gas-to-liquids scenarios focus on methanol production as well as the reduction of harmful emissions from the conversion processes. In a study done by Liu et al. [41], it was found that supplementing natural gas conversion to transportation fuels with biomass gasification can reduce GHG emission prices needed to cost effectively employ carbon capture and sequestration. By including biomass, emissions from the production process are significantly reduced, which therefore creates an attractive system for low-carbon natural gas power. Another study by Borgwardt [42] considers integrating biomass gasification with natural gas into methanol production. From the study, it was found that the use of natural gas and biomass, as opposed to coal, reduces net carbon dioxide emissions and can also eliminate one of the production steps. Borgwardt mentions the potential use of gas and sludge derived from waste water treatment facilities as potential future feedstock to convert to transportation fuels. Another methanol production scenario from biomass and natural gas was studied by Dong and Steinberg [44]. By analyzing the hydro-gasification of biomass via the Hynol process they were able to show benefits of emission reduction, cost reduction, and higher yields. Emissions were reduced because of operation under reducing conditions. The study states that under the conditions studied, CO_2 is reduced and SO_2 and NO_x are not found. Along with this benefit, the system can lower capital costs and improve process yields. This is done by recycling H_2 rich and other unconverted process gases, therefore eliminating the need for an oxygen plant and improving overall conversion efficiency.

Fischer Tropsch Synthesis

Fischer Tropsch synthesis (FTS) is used to transform synthesis gas, composed of carbon monoxide and hydrogen, into a diverse range of hydrocarbons including LPG, gasoline, and diesel. Due to these characteristics, it is a viable candidate technology to integrate into FFPG as it has the capability of utilizing multiple feedstocks and producing multiple products. As Tijmensen et al. state [45], due to the versatility of FTS and the number of steps taken to produce FT liquids, there are many paths to get to the final products. However, FTS can be broken down into several key processes, including feedstock preprocessing, synthesis gas generation, synthesis gas cleaning, fuel synthesis, and hydroprocessing [46].

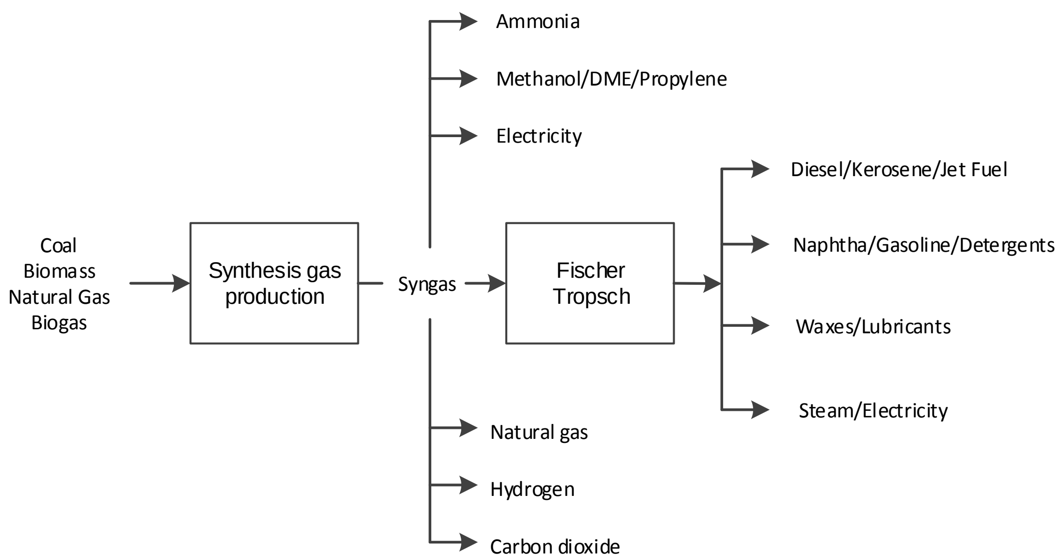

Figure 5. Potential products from syngas and FTS (adapted from [47])

Preprocessing of the feedstock varies depending on the material that is being used as the energy source. Coal, which is a common feedstock in FTS, requires little preprocessing prior to being gasified and turned into a synthesis gas mixture. Biomass on the other hand requires drying and potentially acid treating to remove ash and other contaminants that could be detrimental to the operation of the gasifier. Other feedstocks, such as natural gas or biogas, need to have water, carbon dioxide, any alkali compounds, nitrogen compounds, and heavy hydrocarbons removed from the gas stream, leaving a methane rich feed that is ready to be converted into synthesis gas [46]. Failure to clean the incoming gas can lead to problems downstream, including catalyst deactivation or unwanted material buildup. After the incoming gas (either from gasification or natural gas) is cleaned, it is passed through a reforming step that converts methane into the desired ratio of hydrogen to carbon monoxide by means of partial oxidation (POX), steam methane reforming (SMR), heat exchange reforming, or autothermal reforming (ATR) [48]. Following the syngas generation step, the H_2/CO mixture enters the FT reactor where it is often passed over a cobalt catalyst and transformed into hydrocarbons following the general equation [48]:

$$(2n+1)H_2 + nCO \rightarrow C_nH_{(2n+2)} + nH_2O - \Delta H_{298} \qquad (1)$$

Catalysts, as well as the operating temperatures and pressures, have the greatest effect on the distribution of products [49]. These parameters affect the probability of chain growth, α. The higher α is, the greater the portion of long chained hydrocarbons will be present in the final products. Cobalt catalysts, commonly used in lower temperature slurry reactors, encourage reaction (1) but they do not encourage the water gas shift (WGS) reaction that turns carbon monoxide and water into hydrogen and carbon dioxide. Alternatively, Iron-based catalysts that are often used in fixed bed reactors at higher temperatures do encourage the WGS reaction [50]. Product distributions for Fe and Co catalysts at specific temperatures are shown in Table 1. FT reactors come in a variety of configurations, including fixed bed reactors, circulating fluidized bed reactors, and fixed slurry bed reactors and they are often operated at high temperature (300 to 350°C) or low temperature (200 to 240°C) [48]. Higher temperatures result in lower chain growth probability, which attributes to greater fractions of light gases and small carbon chains in the products. While pressure has a smaller effect on the chain length growth relative to catalyst type and temperature, higher pressures ensure the conversion of gases into fuels [49]. Following initial production of fuels in the FT reactor, additional hydroprocessing can be integrated to crack heavier waxes to medium chain length compounds [32]. As Swanson [32] states, hydrogen for the process can be derived in the fuel synthesis step.

Table 1. FTS product distributions (adapted from [50])

Selectivity %	Fe: magnetite with promoters at 340^0C	Fe: precipitation at 235^0C	Co: Al or Si support at 220^0C
CH_4	8	3	4
$C_2 - C_4$	30	8.5	8
$C_5 - C_6$	16	7	8
C_7-160°C Boiling Point	20	9	11
160-350°C	16	17.5	22
350°C+	5	51	46
Water soluble oxygenates	5	4	1

Along with fuel and chemical production, excess heat and steam produced in the system can be integrated into combined cycles to provide electricity for unit operations. Apart from the major fuel fractions of diesel and naphtha (which account for approximately 70-80%), the remaining low molecular weight gaseous hydrocarbons can be used as a fuel for a gas turbine to produce electricity and process heat [32].

Biogas Production and Upgrading

Organic materials are used by humans daily and disposed of regularly. The remnants are often rich sources or carbon, nitrogen, and oxygen that can be processed by waste management facilities and transformed into useful energy sources via thermal gasification or anaerobic digestion [51]. The products can be utilized for a variety of applications. The residual bio-solids can be used as a source of nutrients in agriculture, while the biogas can be integrated into heat and electricity production along with transportation fuels. Additional benefits of processing organic materials include increased solids reduction, odor removal, neutralization of potentially hazardous compounds, and energy recovery [52, 53]. Because biogas is often produced from waste streams, the feedstock are usually available at low cost, or even for a tipping fee [54]. Depending on the composition of the organic material, there are varying amounts of cellulose, hemi-cellulose, and lignin. The composition of the waste stream determines the methods used to handle the material. The biogas produced from the decomposition of organic materials can be an excellent substitute for traditional energy sources such as natural gas and propane. Not only is it a byproduct of naturally occurring processes, it has the potential to turn a gas that is hazardous when emitted into the atmosphere into a valuable product.

Biogas is generated following the anaerobic digestion of organic matter in three common steps as outlined by Yadvika et al. [55]. The first step, hydrolysis, includes breaking down biomass from larger complex molecules into compounds that can be used as energy, such as monosaccharides and other simple organic compounds. Following hydrolysis, a group of microorganisms ferments the simple organic compounds into lower weight compounds such as acetic acid, carbon dioxide, hydrogen, and organic acids which are eventually turned into acetic acid. This step is called acidogenesis. Lastly, methanogenesis bacteria convert the lower molecular weight compounds into methane.

The production of biogas from the decomposition of organic matter comes from sources such as municipal wastes, sewage, animal waste, agricultural and industrial wastes, and waste water steams. The Alternative Fuels Data Center [56] outlines the most common sources of biogas as biogas from landfills, livestock operations, wastewater treatment, and industrial wastes. Biogas produced from anaerobic digestion of municipal wastes that are buried in landfills or processed in anaerobic digestion facilities can be harmful to the environment if not handled correctly. Emissions from landfill gas are a major source of methane emissions in the U.S. [57]. Utilizing emission controls to capture the gas produced from MSW can be an effective method to reduce the amount of harmful gases released to the environment. In 2012, MSW landfills accounted for near 18% of human related methane emissions, ranking 3rd on the list, according to the EPA Landfill Methane Outreach Program [57]. The emission from landfills represents a lost opportunity to utilize excess energy and avoid harmful gas being released to the environment. Natural gas that is released to the atmosphere is 21 times as harmful as carbon dioxide in regards to global warming [58]. However, if these gases are handled properly, they can be used as a source of energy. In the United States, many landfills are reaching their capacity and alternatives are being sought to divert waste streams such as gasification plants and dedicated anaerobic digestion facilities. In 2009, the U.S.

generated 243 million tons of municipal solid waste (MSW) that was comprised mainly of food scraps, yard waste, plastic packaging, furniture, tires, appliances, paper, and cardboard [59]. Due to this, MSW and landfill gas often contain a complex mixture of compounds that need to be separated and cleaned so that they do not cause downstream problems with corrosion and contamination [60]. According to the EPA [61], there were over 621 landfill gas to energy projects in the U.S. in 2013.

Along with landfills, livestock operations, wastewater treatment plants, as well as industrial, institutional, and other commercial entities have a large potential to contribute to biogas production in the U.S. [56]. According to the EPA [53], in 2010 there were over 8,000 animal farming operations that could produce over 1,600 MW of energy, which could replace traditional fossil fuel energy production facilities. Similar to animal farming operations, there are many landfill operations that have the potential to integrate biogas collection and upgrading equipment. According to the EPA Landfill Methane Outreach Program (LMOP), there are over 650 current landfill to energy projects that are installed in U.S. that are heating greenhouses, producing electricity, supply vehicles with fuel, and injecting RNG into the NG pipeline [62]. Along with those projects that are currently installed, the LMOP claims there are an additional 440 candidate sites that could capitalize on biogas collection and utilization systems that are not currently doing so. Wastewater treatment facilities also pose a large opportunity to produce biogas. These facilities remove large quantities of organic materials through sediment tanks which can later be digested to biogas. Following biogas production, many operations collect the waste and dispose of it to agricultural land because of its high nutrient value, generating an additional potential source of income. The EPA [63] estimates that every 100 gallons of wastewater could produce around 1 ft^3 of digester gas. The Des Moines, Iowa Wastewater Reclamation Facility (WRF) produces 2.1 ft^3 of digester gas for every 100 gallons of water treated, and use it to generate about half of their annual energy demand at the treatment plant [64].

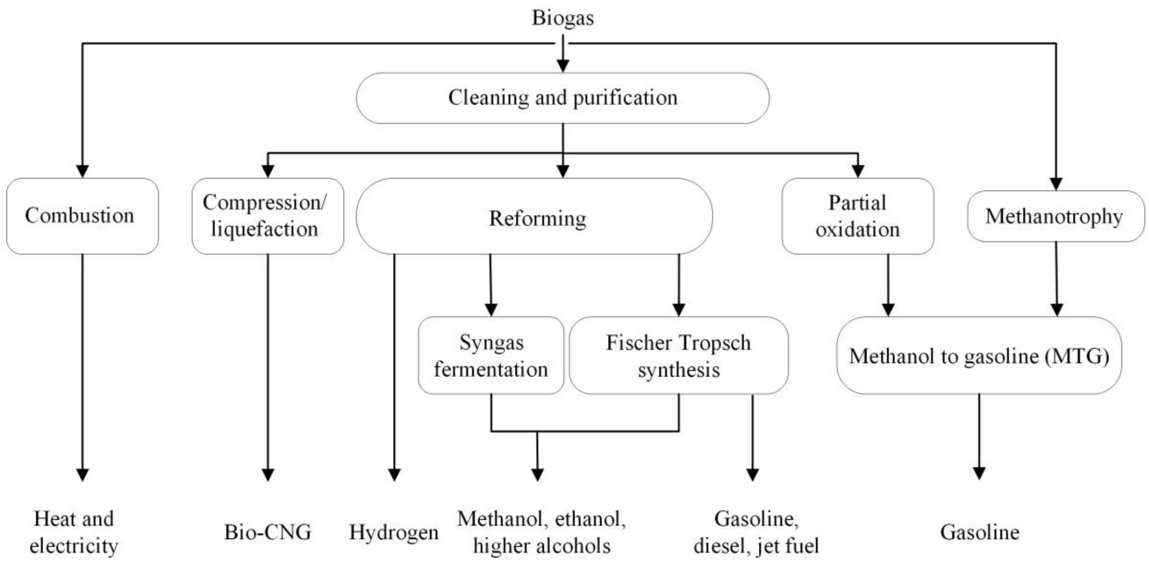

Figure 6. Biogas cleaning and upgrading pathways (adapted from [54])

Biogas can be integrated into many applications that use traditional fossil fuel natural gas, including production of heat and steam, electricity production with combined heat and power (CHP), industrial heating or cooling, upgrading for use as a vehicle fuel, production of chemicals, fuel for fuel cells, and injection into natural gas grids [65, 66]. At the moment, biogas is mostly used for electricity generation, but usage as a vehicle fuel is increasing due to its ability to reduce emissions relative to traditional fossil fuels [54, 66]. For each application, varying levels of preprocessing are required due to the composition of biogas. Biogas is composed of approximately 45-65% CH_4, 20-50% CO_2, 5-40% N_2, 0-5% O_2, and traces of many other compounds including H_2, H_2S, NH_3, chlorine, and other organics [51, 52, 54, 59, 64, 66]. Compared to traditional natural gas that has an energy content of around 40 MJ/kg, biogas ranges from 10-30 MJ/kg [66].

Table 2. Typical composition of biogas and natural gas (adapted from [66, 67])

Character	Unit	Natural gas	Landfill biogas	AD biogas
CH_4	vol%	81-89	30-65	53-70
CO_2	vol%	0.67-1	25-47	30-50
N_2	vol%	0.28-14	< 1-17	< 1
O_2	vol%	0	< 1-3	0-5
H_2	vol%	NA	0-3	NA
Higher hydrocarbons	vol%	3.5-9.4	NA	NA
H_2S	ppm	0-2.9	30-500	0-2000
NH_3	ppm	NA	0-5	< 100
Total chlorines	mg/Nm3	NA	0.3-225	< 0.25
Siloxane	ug/g-dry	NA	< 0.3-36	< 0.08-0.5

Due to the varying composition of biogas, cleaning steps need to be undertaken to remove the undesirable impurities that accompany methane. These impurities, such as N_2, O_2, H_2, H_2S , and NH_3, need to be removed or they may cause problems with corrosion, toxicity, and reduced heating values [54]. The process of removing these contaminants can be costly, as it is energy demanding. The only preprocessing step required for the Des Moines WRF to utilize their biogas in reciprocating engines for electricity generation is the removal of the moisture from the biogas that contains 63% CH_4 [64]. However, if additional compounds besides water need to be removed, the process becomes more expensive.

A comprehensive overview of biogas cleaning and upgrading to RNG is given by Yang et al. [54]. The most common methods for biogas cleaning are pressurized water scrubbing, pressure swing adsorption (PSA), membrane permeation, and amine absorption. Pressurized water scrubbing utilizes the higher solubility of CO_2 and H_2S

compared to CH_4 and separates the compounds at high pressures in the range of 900-1200 kPa [68]. The methane content of biogas following pressurized water scrubbing is often >96% [69]. Among the top biogas cleaning processes, water scrubbing is currently the largest used option. Following water scrubbing, the next most used cleaning strategy is PSA which uses differences in gas adsorption rates to remove specific gases (most often used for CO_2, O_2, and N_2). The process operates at higher pressures and uses adsorptive materials such as zeolites and activated carbon to separate specific compounds. The adsorbed compounds are then released at lower pressures to regenerate the filter media [54]. Amine adsorption, which uses alkylamines such as monoetanolamine or diethanolamine to adsorb compounds at different affinities, is employed specifically to remove CO_2 and H_2S. Most of the CO_2 and some H_2S are adsorbed in the solvent in the reaction vessel which operates around 650 kPa, allowing the methane to escape at a higher purity. The solvent is then regenerated through a gas stripping column. As Yang states, although this method is effective, it is energy intensive and the cost of amines is not low. Membrane permeation, another cleaning method, allows smaller molecules to permeate through membranes while larger molecules are retained. Most often, compounds such as CO_2, O_2, and H_2O can penetrate the membrane while CH_4 is retained and collected [70, 71]. Along with these main cleaning methods, alternatives include temperature swing adsorption (TSA), cryogenic separation, and biofilters [54]. The most effective method based on cost and efficiency is dependent on a case to case scenario influenced by the technology availability, feedstock being utilized, gas composition, and the desired final application.

Considering RNG integration into traditional energy systems, there are barriers that need to be overcome. While there is an abundance of resources to utilize and upgrade, the challenges associated with upgrading biogas to a natural gas quality can be challenging and costly. In a report published by the American Biogas Council [72], the major barriers to overcome are an absence of state level low carbon fuel standards, instability in vehicle fuel credit markets, a lacking national quality standard for injecting RNG into the natural gas pipeline system, as well as cheap and abundant natural gas. The low price of natural gas makes it challenging for RNG to enter the market on a cost competitive basis. However, as increasing technologies adapt their technologies to utilize natural gas, there is the potential to directly substitute RNG in the future following improvements in the technology and cost.

Previous studies have proven the benefits of integrating multiple technologies into one system to improve process efficiency, while allowing flexibility to adapt to market fluctuations in prices and availability. Currently natural gas and other fossil fuel primary energy sources dominate the market. However, as the need for renewable technologies increases and fuels derived from renewable resources are incentivized there will continue to be growing opportunities. Biogas presents an opportunity to utilize organic waste and integrate the resulting product into facilities where natural gas is traditionally used. The EPA has proven the vast amount of waste resources that are available to be turned into high valued products.

CHAPTER 3. MATERIALS AND METHODS

Scenario Selection

In this study, one example of FFPG was developed to quantify its impact on an adopting plant's 20-year NPV compared to that of its more conventional single feedstock counterpart. The analysis was based on previous literature where capital and operating cost parameters are made available. While the methodology is relatively high level, more detailed analyses can be achieved through the development of customized process models of FFPG systems. Equipment sizes and costs were adjusted based on literature references. Following the scaling of the equipment parameters, a cash flow analysis was developed, followed by sensitivity analyses and Monte Carlo simulations.

This study selected a FFPG plant that uses natural gas and biogas as the primary energy sources and turns them into electricity and transportation fuels (Fig. 1). The primary feedstocks were chosen due to their ability to be processed into syngas streams and their relatively large availability. Natural gas production in the United States from 2005-2013 increased from 18.1 Tcf to 24.4 Tcf, a growth of 35% [73]. Future U.S. natural gas production is estimated to increase 45% from 2013 to 2040 [73]. Along with utilizing natural gas, three different technologies were considered to produce biogas than can accompany natural gas in the FFPG system. In these technologies, MSW and animal waste are processed via anaerobic digestion (AD) to provide an alternative renewable feedstock and address a growing waste disposal problem. Fischer-Tropsch Synthesis (FTS) converts the resulting synthesis gas to liquid fuels [74] while combined cycle power converts them into electricity [24].

Anaerobic digestion is attractive as it can produce an alternative source of methane from a wide variety of biomass feedstocks. Anaerobic digestion can also process waste biomass, converting 79 to 85% of biodegradable feedstocks to biogas while the residual stable organic matter can be composted and used as an environmentally safe and nutrient rich soil amendment agent [75]. In this study, three different scenarios of biogas production are considered, including AD of MSW in digestion tanks, animal waste from livestock production facilities, and MWS from landfills. When feeding MSW to AD tanks, a pre-treatment step consisting of mechanical and manual sorting is employed to remove oversized and non-digestible materials. Following removal of inorganic materials, the remaining waste is sent to non-sterile reaction vessels where gas production occurs in a relatively simple process [74]. Biogas production that takes place at livestock production facilities is typically carried out in covered lagoons and plug flow digesters [76]. The biogas produced in these systems is often utilized on-site for energy and heat production; however, the gas can also be cleaned and compressed, resulting in a product that is analogous to traditional natural gas. Similar to animal waste biogas, biogas from landfills, termed landfill gas (LFG), can be collected with relatively low capital costs, upgraded, and used for electricity and heat or as a substitute for natural gas. Once the biogas is produced through AD, it is combined with purchased natural gas. The gas steam is then cleaned in a water scrubber to remove any traces of sulfur that can poison FT catalysts [77].

The cleaned biogas and natural gas are reacted with steam and oxygen in an autothermal reactor (ATR) to produce hydrogen, carbon monoxide, and carbon dioxide. The carbon dioxide and water are removed while the hydrogen and carbon monoxide are sent to a Fischer-Tropsch reactor where reactions over a cobalt catalyst produces a range of straight-chain alkanes [78]. The FT liquids are distilled to separate olefins and alkanes, the latter of which are refined to naphtha and diesel range hydrocarbons [78]. While one FFPG was developed, five scenarios are studied to compare the financial advantages and disadvantages. The first scenario, termed FTS No Co-gen, is a FTS plant that utilizes NG and converts it to FT liquids but is required to purchase electricity, as it is not produced on site. The second scenario analyzed is termed FTS with Co-gen, and is similar to the first plant but includes a steam generator that produces electricity for the plant and sells the excess amount to the grid. The third, fourth, and fifth scenarios substitute natural gas in the FTS process with RNG from the digestion of MSW in digestion tanks, animal waste, and MSW from landfills, respectively. Each scenario is outlined in Table 3. Figure 14 in the Appendix shows a diagram of the production pathways.

Table 3. Details of the scenarios considered in this study

Scenario	1	2	3	4	5
Name	FTS No Co-gen	FTS with Co-gen	FFPG MSW AD	FFPG LO AD	FFPG LFG
Feedstock	NG	NG	NG and RNG	NG and RNG	NG and RNG
Biogas Production Method	-	-	MSW AD in Tanks	Livestock Waste AD	Landfill Waste AD
Fuel Synthesis	FTS	FTS	FTS	FTS	FTS
Co-generation of Electricity	No	Yes	Yes	Yes	Yes

(FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity with steam turbines, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas)

FFPG System

The FFPG system analyzed in this study is the integration of NG and RNG into a FTS process to produce liquid fuels and electricity. Three different RNG production scenarios are analyzed to determine their impact on the 20-year NPV of the overall system. The MSW AD system employed in this study processes 250,000 tons/year of mixed solid waste in digestion tanks. Although facilities in the U.S. have struggled to receive investment to produce facilities of this size due to a lack of subsidies, there are several plants of this scale in operation around the world and others that are being constructed to come online in the near future [79]. AD of MSW has been implemented at scales ranging from 1,000 to 300,000 tons/year [79]. Improved technologies, advantages associated with larger scale, and the rising need to manage waste resources will continue to drive forward increased capacities of plants to anaerobically digest municipal wastes to gaseous products. The second method, AD of animal waste, is a technology that has been successfully employed at large livestock operations to generate on-farm electricity and heat. Challenges in the past of manure AD systems include poor design and improper installation, however the technology has improved and can be a profitable operation for most livestock operations [76]. The animal waste AD system assumed in this study digests waste from the equivalent of approximately 40,000 heads of dairy cattle, or 282,000 heads of swine. The AD of livestock waste provides a waste management solution and can generate a valuable product. The third method to produce RNG for the FFPG system is from landfills. Landfills inherently produce large amounts of biogas during the decomposition process that is often flared in order to combust the harmful release of methane gas to the environment. However, over 600 landfill to gas energy projects are how in place in the U.S. to capture the energy source and use it onsite for electricity generation, or upgrade it to vehicle grade compressed natural gas (CNG) and pipeline quality RNG [61]. The biogas, containing approximately 55% methane, is cleaned, upgraded to high-Btu gas via pressure swing adsorption (PSA) and combined with pipeline natural gas which is then fed to an autothermal reformer to produce CO and H_2 [80]. The biogas produced by AD replaces 10% of the NG used in the baseline FTS system.

Along with having the flexibility of multiple feedstocks, FTS plants have flexibility in their liquid product distributions. The FTS products in this study are upgraded to diesel and naphtha range hydrocarbons, however other compounds such as LPG and waxes are possible depending on operating parameters and upgrading processes [48]. When the reaction temperature in the FT reactor is increased, the conversion of CO and H_2 to CH_4 increases while the probability of chain growth decreases. This is due to the rate of hydrogenation of the produced CH_4 units [81]. Along with liquid fuels, electricity is generated through gas and steam turbines. The value of the electricity compared to the value of naphtha and diesel range fuels is low and does not play a significant role in the NPV when the price fluctuates. In order to increase the profitability by shifting towards higher electricity generation the selling price of electricity must increase greatly and the selling price of liquid fuels drop substantially compared to their historical price range, which would seem an unlikely scenario. As a result, this study does not incorporate the capability to shift a majority of the syngas away from fuel production towards increased electricity generation.

Capital and Operating Expenses

The FTS employed in this study utilizes equipment and process information by the National Energy Technology Laboratory (NETL) [82]. The equipment, direct, and indirect costs determined by NETL were developed and scaled from previous NETL reports, with code blocks in AspenPlus® that were used to provide details on the process simulation. NETL states that the accuracy of the cost estimations fall within the range of -15% to +30% of actual costs due to the complexity and uniqueness of each individual project analyzed.

The equipment costs were adjusted using a power law rule to account for differences in capacity. The equipment costs for the MSW anaerobic digestion system, which processes mixed waste to produce syngas, were scaled to a case study done by Allen Kani Associates et al. [83]. Utilizing mixed waste, which contains both organics and inorganics, requires separating equipment to remove the majority of the metal contaminants from the waste stream, as well as equipment to minimize the particle size of the material fed into the reactors [83]. The costs of upgrading the gas produced by the MSW AD system to pipeline quality were taken from a range of studies [84-86]. The capital costs for the livestock operation AD were modified from those provided by a range of studies done by the USDA [76] and the Iowa Biogas Assessment Model (IBAM) developed by EcoEngineers [87]. The IBAM is an economic analysis tool that provides general biogas facility cost evaluations based on data gathered in literature. Costs were scaled from the base model in the IBAM to match the biogas output of the MSW AD facility. Capital costs for the landfill gas method were based off of a costing model generated by the EPA [88]. The costing model provides initial economic feasibility analysis to determine the profitability of landfill gas projects. The processing equipment was scaled to produce an equal amount of energy as the MSW-AD facility and includes the required equipment for compressing, separating, and drying the biogas to pipeline quality. The distance from each biogas production scenario to a pipeline is considered negligible, assuming that the plant is constructed or the landfill is located near a pipeline. In literature, natural gas pipeline is often estimated at $330,000/mi [88], which can impact the feasibility depending on the distance required to be traveled. However, in the present study pipeline costs are not included. The capital costs for each FFPG system are generated by combining costs from both FTS and the biogas AD and associated upgrading equipment. There is a likely reduction in costs from shared equipment when estimating capital costs for joint systems[16]; however, this reduction is not taken into consideration in this study. The basic costs for each AD method and FTS are outlined in Table 6. The costs are in 2013 dollars.

When scaling equipment size, the costs were calculated using the power law relationship with suggested exponents between 0.6 and 0.73 [24, 89]:

$$C_{p,s} = C_{p,b}(S_s/S_b)^n \quad \text{(Eq. 1)}$$

where:

$C_{p,s}$ = predicted cost of specified equipment

$C_{p,b}$ = known cost of the baseline equipment

S_s = size of specified equipment

S_b = original capacity

n = economy of scale sizing exponent (less than unity)

Inflation was normalized among the various analyses employed using the relation:

$$C_{p,c} = C_{p,p}(I_c/I_p) \quad \text{(Eq. 2)}$$

where:

$C_{p,c}$ = inflation-adjusted costs of equipment in current year

$C_{p,p}$ = known cost of equipment in a previous year

I_c = inflation index factor for current year

I_p = inflation index factor for the previous year in which equipment cost is known

20-year net present value (NPV) was used to evaluate the economic performance of the FTS and FFPG systems. Sensitivity analyses were performed by adjusting the prices of feedstock, products, and capital costs to determine the influence on the resulting NPVs. An uncertainty analysis was performed via Monte Carlo simulation to assess the influence of price fluctuation on NPV over time. Further details on this analysis are subsequently described. The O&M costs for the GTL and anaerobic digestion systems are comprised of fixed and variable costs. The main O&M costs for the systems are calculated, as differences in minor costs play a small roll in this study and vary with each specific project. O&M costs for the FTS system were scaled from the NETL model and include labor, overhead and maintenance, insurance and taxes, feedstock, water and chemical costs [82]. The O&M costs for the AD facilities include labor, pretreatment, collection and disposal costs, as well as compost curing [83]. Costing assumptions are detailed in Table 4.

Table 4. Costing Parameters and Assumptions

Assumptions	Value
Type of depreciation	DDB
Depreciation period (yr)	7
Construction period (yr)	2.5
Start-up time (yr)	0.5
Income tax rate (%)	39%
Annual operation (hrs)	7,900
Cost year for analysis	2013
Diesel production rate (MMgal/yr)	15.9
Gasoline production rate (MMgal/yr)	7.1
Avg. diesel selling price ($/gal)	$3.79
Avg. gasoline selling price ($/gal)	$3.25
Avg. electricity selling price ($/kWh)	$0.065
Avg. cost of natural gas ($/MMBtu)	$5.12

(FCI: fixed capital investment, DDB: Double declining balance)

Feedstock and Product Prices

Monte Carlo simulations using Crystal Ball® were performed to evaluate the effect of fluctuations in the market prices of feedstock and products on NPV. As described by Smith [90], often times a statistical method to estimate uncertainty involves formulating the data around a common distribution, thus simplifying the analysis. Monte Carlo simulation methods, on the other hand, generate data from a known or historical distribution and therefore can potentially estimate uncertainty to a higher degree than single distribution estimation methods. To generate distributions of data by the Monte Carlo method for integration into estimation models, previous data can be used to generate possible values for each parameter. Once the distributions for each parameter are determined, data is generated from the distributions and used as inputs into a model [90]. In this study, historical price trends are used to provide a framework for feedstock and product price determination. Following a method utilized by Brown [91], uncertainty prices for commodity prices were represented by fitting distributions to each input parameter. The distributions were developed from historical price data of each commodity and then applied to the annual average price for the given year. The best-fit commodity distributions were chosen using the Anderson Darling goodness-of-fit test [91, 92]. For each Monte Carlo analysis 2,000 trials were run using the probability distributions where feedstock and product values were randomly varied according to the defined distribution for each value. The resulting Monte Carlo distributions and values are laid out in Table 5, and more detailed distributions are shown in the Appendix.

Table 5. Feedstock and Product Values and Distributions

Value	Diesel $/gallon	Electricity $/kWh	Gasoline $/gallon	MSW $/ton	NG $/MMBtu	RIN $/RIN
Distribution	Lognormal	Logistic	Lognormal	Logistic	Logistic	Logistic
Mean	$3.79	$0.065	$3.27	$65.44	$5.06	$0.71
Median	$3.78	$0.065	$3.26	$65.38	$5.06	$0.71
Standard Deviation	$0.10	$0.001	$0.09	$4.32	$0.17	$0.03
Minimum	$3.44	$0.063	$2.96	$51.18	$4.25	$0.59
Maximum	$4.09	$0.068	$3.57	$81.89	$5.63	$0.84

(MSW: municipal solid waste, NG: natural gas, RINS: Renewable Identification Number)

The historical price distribution of NG was calculated using 1992-2011 market Henry Hub Natural Gas Spot Prices supplied by the 2011 EIA Annual Energy Outlook [93]. The MSW tipping fee, a price paid by waste generators to dispose of their waste, counts as a revenue source for waste-to-energy producers [94-96]. The price of tipping fees varies greatly across the U.S. due to population density, amount of waste, and available space to dispose of the waste. Currently, tipping fees in the U.S. range from $35-$240 per ton with the average falling around $50-$60 per ton [79]. However if a carbon tax was imposed the fee could range even higher, similar to the approximate average $100/ton implemented in the EU [97]. U.S. average tipping fees from a report by the National Solid Waste Management Association (NSWMA) were used [98]. Naphtha products are often represented by light and heavy naphtha streams including hydrocarbons up to boiling points of 75°C and 165°C, respectively [99]. For the purpose of this study the naphtha stream is assumed to contribute to gasoline range products. The selling price distribution of naphtha and diesel were determined using historical 20 year prices supplied by the 2012 EIA Annual Energy Outlook [100]. Historically, there was a correlation of 0.77 between diesel and naphtha prices. The selling price distribution of industrial electricity was determined using reported national industrial retail prices for the past 20 years supplied by the EIA Electric Power Annual 2011 [101]. Lastly, D5 renewable identification number (RIN) values were developed from information published by EcoEngineers for 2013-2014 [102]. While the presence of RIN values cannot be counted on as certain when analyzing the future NPV of a system due to regulatory uncertainty, there is currently an infrastructure in place providing an incentive for biogas production and utilization. As determined by the EPA [103], biogas from landfills, agricultural digesters, and MSW digesters are also eligible to generate cellulosic RINs (D-3 and D-7). However, due to the low volume of D-3 RINS currently generated there are no broker price spreads available yet. The basis of D-3 RINS is the value of D-5 RINs plus cellulosic waiver credits. With the uncertainty in the length of availability of the cellulosic waiver credit, D-5 RINS are considered in this study.

Profitability Analysis

A discounted cash flow rate of return (DCFROR) spreadsheet was used to calculate a 20-year NPV for each scenario developed by the National Renewable Energy Laboratory (NREL) and modified by Wright et al. [104]. The assumptions for the DCFROR model are outlined in Table 4.The O&M costs for the GTL and anaerobic digestion systems are comprised of fixed and variable costs. The main O&M costs for the systems are calculated, as differences in minor costs play a small roll in this study and vary with each specific project. O&M costs for the FTS system were scaled from the NETL model and include labor, overhead and maintenance, insurance and taxes, feedstock, water and chemical costs [82]. The O&M costs for the AD facilities include labor, pretreatment, collection and disposal costs, as well as compost curing [83]. Costing assumptions are detailed in Table 4.

Different methods have been used in the literature to analyze the performance of energy production plants. Often sensitivity analyses are performed on the plants to determine which parameters play the largest roles in plant profitability. These sensitivity analyses, along with Monte Carlo simulations, can provide a comprehensive understanding of economic performance. For the sensitivity analyses, the discount rate is held constant while adjusting single feedstock and product prices by one standard deviation of historical annual data to determine the influences on the NPVs. This method was used to calculate the mean NPV, standard deviations, and cumulative distribution functions for the baseline FTS and FFPG scenarios. In the following analysis, the baseline FTS system is compared to the FFPG system to determine FFPG's ability to alleviate disruptions caused by fluctuations in feedstock and product prices and improve the NPV.

CHAPTER 4. RESULTS AND DISCUSSION

The costs associated with each individual process prior to being integrated into FFPG are outlined in Table 6. The fixed capital investment (FCI) of the FTS plants represents a significant amount of the overall capital costs for all of the scenarios investigated. As mentioned in the scenario descriptions, the FTS portion of the process includes the synthesis gas conversion and upgrading equipment. For the MSW AD process, a large portion of the capital costs are attributed to the feedstock pretreatment and reactor. Differing from the MSW AD process, the LO AD and LFG AD scenarios have some of the required infrastructure for collecting waste and producing biogas in place, resulting in lower contributions to the overall capital costs. The main costs in the final two stages compose of the biogas upgrading equipment. Of the three FFPG systems, LFG AD has the lowest capital and operating costs.

Table 6. Capital and Operating Costs for Single Plants

Parameter	FTS No Co-gen	FTS with Co-gen	MSW AD to RNG	LO AD to RNG	LFG AD to RNG
FCI ($MM)	$246.0	$260.2	$66.4	$13.0	$8.7
Operating Costs ($MM/yr)	$22.6	$22.6	$32.5	$24.6	$22.8

(FCI: fixed capital investment, FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity with steam turbines, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, RNG: renewable natural gas)

The FFPG systems integrate each AD method with the FTS Co-gen facility to produce liquid fuels and electricity. The capital costs and NPV for each scenario, given the base case operating values for each parameter (fuel price, electricity price, etc.), are shown in

Table 7 Table 7. The FTS No Co-gen has the lowest overall capital cost of $246MM, as it does not include a steam generator to produce electricity or additional equipment to produce RNG. By including an electricity generation station, the capital cost increases to $260MM for the FTS with Co-gen scenario. The FFPG scenarios have larger capital costs than the FTS with Co-gen scenario as a result of the additional equipment needed to produce biogas and upgrade it to RNG. The capital cost of the MSW AD to RNG system accounts for 20% of the FFPG MSW AD scenario capital costs, while the LO AD and LFG AD to RNG account for 5% and 3% of their respective FFPG systems. As research and development focuses on improving and increasing the scale of these technologies the costs will continue to decrease as efficiencies increase.

The capital costs for traditional FTS plants are often very high, due to the large scale of the plants needed to take advantage of economies of scale. The FTS plant in this study was scaled to accommodate the smaller scale of the anaerobic digestion plants. Anaerobic digestion plants in the U.S. are growing in number and size, however the current small scale of operating plants limits the amount of biogas that can be generated. As a result of the FTS size and developing technology of AD to high-Btu biogas, a large portion of the resulting NPVs in this study are negative. The negative NPVs signal the challenge associated with scaling down a FTS plant to a scale where biogas utilization has the opportunity to displace a fraction of the traditional natural gas used. The results can provide insight into the efficacy of FFPG and the benefits integrating RNG as a substitute for NG. Traditional FTS plants operate in the range of 40-500 MGY of liquid fuel produced, but in this study it was scaled down to 23 MGY of liquid fuel produced. Instead of capitalizing on economy of scale benefits that are traditionally associated with increasing the capacity of a plant, the inverse occurred and resulted in high costs. With a fixed discount rate of 10% the NPV for the FTS No Co-gen amounted to -$49.4MM while the FTS with Co-gen amounted to an NPV of -$35.3MM. The FFPG scenarios resulted in similar or improved NPVs, with MSW AD resulting in an NPV of -$34.5MM, and LO AD and LFG AD resulting in NPVs of -$27.3MM and -$15.8MM, respectively. These are the base NPV*s* that each scenario is compared to when a single parameter is altered in the sensitivity analysis.

Table 7. Capital costs, operating costs, and mean NPV for each scenario

Parameter	FTS No Co-gen	FTS with Co-gen	FFPG MSW AD	FFPG LO AD	FFPG LFG
Capital Costs ($MM)	$246.0	$260.2	$326.6	$273.7	$268.9
Operating Costs ($MM)	$22.6	$22.6	$32.5	$24.6	$22.8
Mean NPV ($MM)	$(49.4)	$(35.3)	$(34.5)	$(27.3)	$(15.8)

(NPV: net present value, FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity with steam turbines, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, RNG: renewable natural gas)

The FTS capital costs are a large fraction of the overall required capital expenditures. Looking into further detail, the amortized capital costs range between 23% and 34% of the total annual expenses (Figure 8). When the FTS operating costs (without fuel) are included, these two values make up approximately 56% of total annual costs.This is high compared to the costs for anaerobic digestion. The AD capital costs for MSW AD make up 6% of the total system costs, while LO AD and LFG make up 1.5% and 1% respectively. When operating costs are combined with the capital costs, MSW AD accounts for almost 17% of the overal cost, while LO AD and LFG AD only account for 4% and 1%. The capital cost of the MSW AD system is thirteen times greater than the LFG AD system, and contributes to the difference in resulting NPVs of -$34.5MM and -$15.8MM respectively. Although the capital and operating costs associated with the RNG production only account for a small fraction of the overall annual costs, they can play a significant role in the profitability of the system.

The main sources of income result from the sales of liquid transportation fuels. Diesel fuel makes up 76% of the total income for the FTS No Co-gen and FTS with Co-gen scenarios. Diesel sales represent a lower percentage of income in the FFPG scenarios as a result of other sources of income, and range from 58% to 69%. Along with diesel sales, gasoline sales account for one third of the revenue or less in all scenarios. Electrcity from co-generation contributes to less than 1% of sales. In an FTS system the main value of electricity production is supplying the plant and avoiding additional costs for inputs (as are encountered in the FTS No Co-gen scenario).

Although the annual costs of the FFPG systems are higher than the traditional FTS systems, they also generate higher income that is a result of waste collection and biogas production. The national values for tipping fees can vary greatly depending on the location of disposal, availability of waste disposal facilities, and regulations.The MSW AD system receives an average $61/ton of waste collected and digested, which accounts for 16% of the income for this scenario. In the FFPG LO AD and LFG AD scenarios, no tipping fee is assumed. The tipping fees collected by the landfill where the respective LFG AD is installed are not accounted for. Another source of income for the FFPG systems comes from RIN generation. Depending on the market value, RINs can generate an income of $8-$12/MMBtu. D-5 RINs are generated in all FFPG scenarios and represent 4% of the income. Without RINs, RNG production costs range between 4-35$/MMBtu [105]. However RINs make RNG production cost competitive at the current stage of technology development. Increasing the amount of RNG that substitutes NG from 10% would increase the RINs generated and decrease the dependence on diesel and gasoline as sources of income.

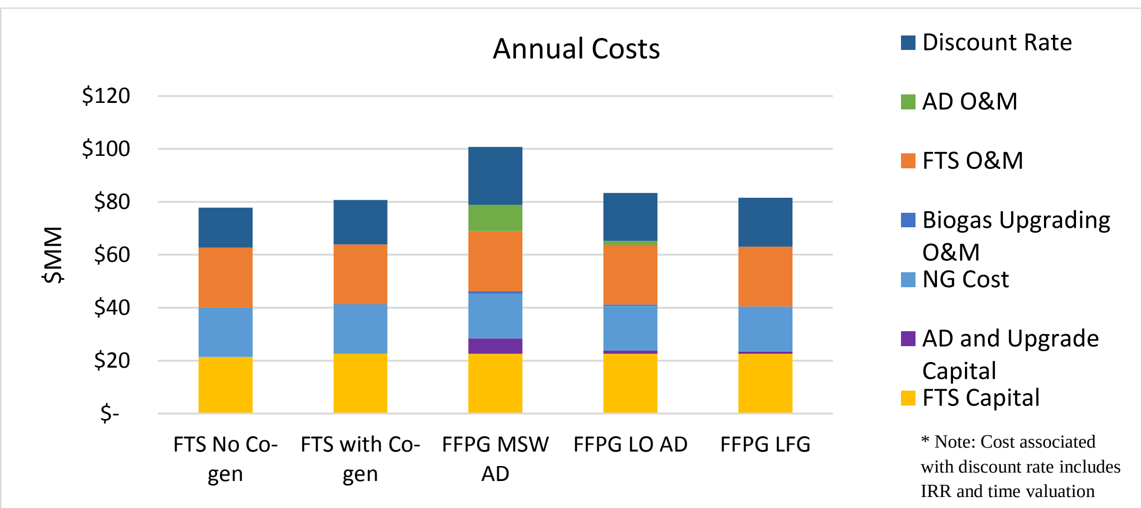

Figure 7. Annual expenditures for each scenario

(FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas, RINS: renewable identification number, O&M: operating and maintenance)

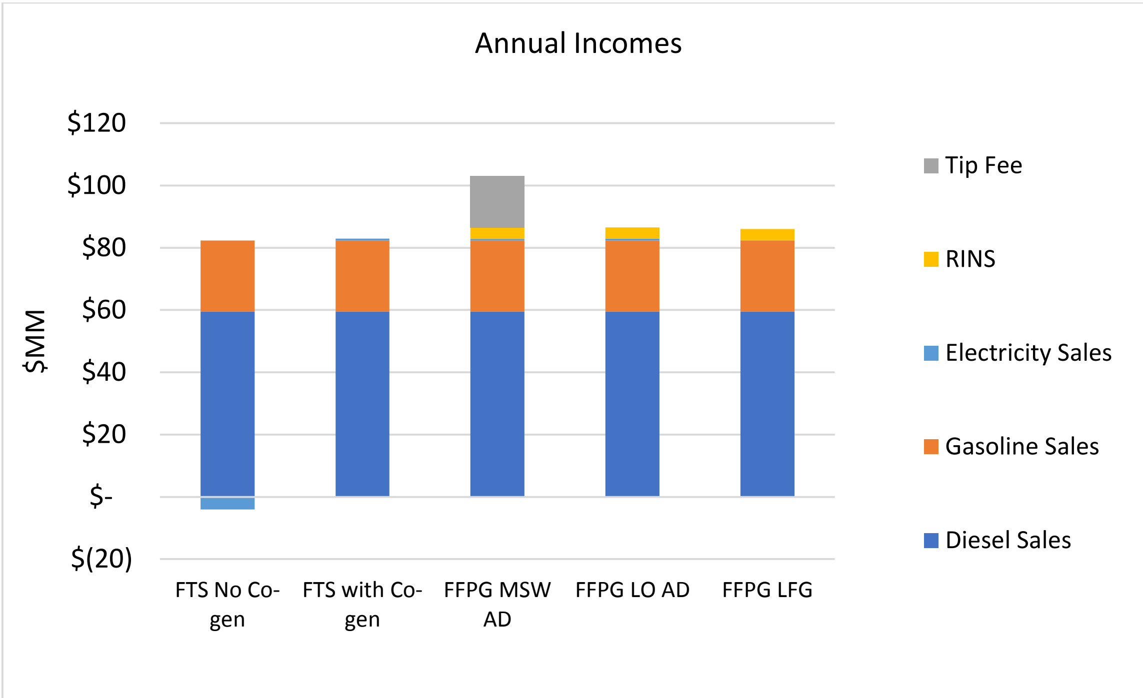

Figure 8. Annual expenditures and incomes for each scenario

(FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas, RINS: Renewable Identification Number, O&M: operating and maintenance)

Following the preliminary results of the costs and NPVs, sensitivity analyses were performed to determine the impact of modifying a single variable at a time. Figure 9 shows the results of two of the sensitivity analysis while changing the range of each variable +/- 30% of its 20 year average price. All of the sensitivity analysis figures are found in the Appendix. Additional information outlining the impact of each individual parameter by showing the resulting NPV's distance away from the mean NPV is found in Table 8 and Figure 9.

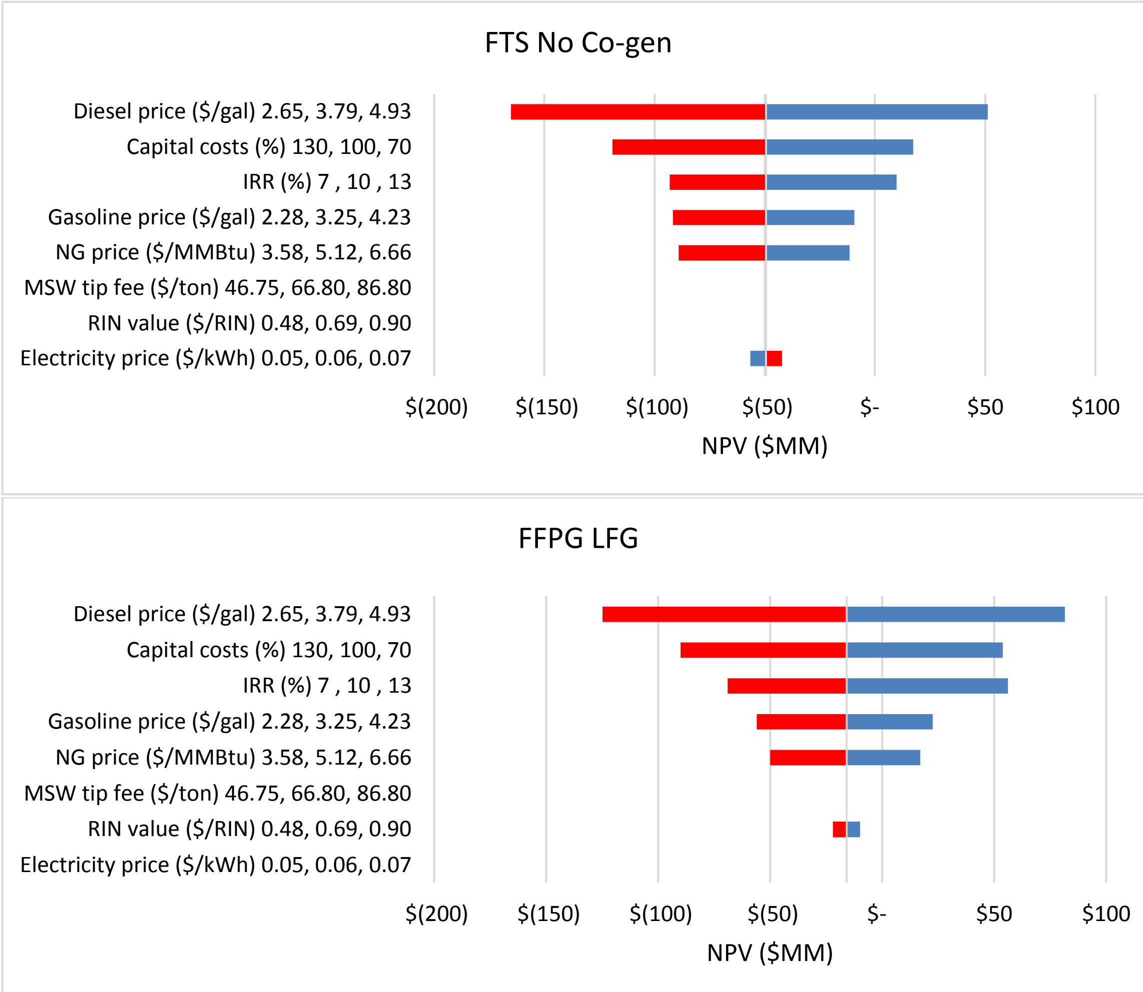

Figure 9. Sensitivity analyses of an FTS and FFPG system

(Other scenarios in Appendix. FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LFG: landfill gas, NG: natural gas, RINS: renewable identification number)

All of the systems produce negative NPVs when the base values for each system are used. The factors that have the largest potential negative impact on the 20 year NPV are variations in the selling price of fuel products, capital costs, and the cost of natural gas. Looking at the impact of each parameter that was adjusted in the sensitivity analysis provides more insight into each scenario (Table 8). The NPV of every scenario was altered the most when changing the price of diesel. Diesel accounts for nearly 70% of the annual income, thus making the impact of a price change prominent. Changing the diesel price impacted the resulting NPV by over $115MM for the FTS No Co-gen scenario. However, altering the price of diesel had less impact on the FFPG scenarios, causing a NPV change of $109MM for the LFG system. Following the price of diesel, the parameter with the second highest impact by adjusting the values by 30% was the capital cost. As noted in Figure 8, the capital costs accounted for approximately 35% of the annualized costs, greater than any other single cost. As opposed to an alteration in the price of diesel, a changing capital cost had a larger impact on the FFPG scenarios than the FTS scenarios. With higher capital investment requirements, a deviation away from the expected capital costs leads to potentially larger losses or gains compared to the FTS, which has lower capital requirements.

The next two parameters with the largest impact on NPV were the price of gasoline and the price of NG. Both of these values impacted the NPV of the scenarios that did not use RNG greater than those that did utilize RNG. Decreasing the price of natural gas by 30% changed the NPV of the FTS No Co-gen scenario by -$39.7MM, while changing the FFPG LFG scenario by -$34.1MM. If higher amounts of RNG were integrated into the system, the FFPG would be affected less (Figure 11). The price of electricity had the lowest impact on all of the scenarios. Changing the price of electricity affected the FTS No Co-gen scenario by $7.2MM because of the need to purchase lower priced electricity. However for the scenarios that sell excess electricity, it altered the NPV by approximately $1M.

Table 8. Average difference from the mean NPV as a result of changing specific parameters by +/- 30% ($MM)

	FTS No Co-gen	FTS with Co-gen	FFPG MSW AD	FFPG LO AD	FFPG LFG
RIN value ($/RIN) 0.48, 0.69, 0.90	$ -	$ -	$6.2	$6.2	$6.1
MSW tip fee ($/ton) 46.75, 66.80, 86.80	$ -	$ -	$29.6	$ -	$ -
Electricity price ($/kWh) 0.05, 0.06, 0.07	$7.2	$1.1	$0.9	$1.1	$0.1
IRR (%) 7 , 10 , 13	$43.7	$48.5	$63.2	$52.4	$53.1
NG price ($/MMBtu) 3.58, 5.12, 6.66	$39.7	$38.7	$34.4	$34.4	$34.1
Gasoline price ($/gal) 2.28, 3.25, 4.23	$42.2	$41.1	$40.5	$40.6	$40.2
Capital costs (%) 130, 100, 70	$69.7	$72.8	$90.8	$76.0	$74.1
Diesel price ($/gal) 2.65, 3.79, 4.93	$115.7	$112.4	$109.2	$110.4	$109.0

(FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas, RINS: Renewable Identification Number, O&M: operating and maintenance, IRR: internal rate of return)

Sensitivity analyses give a snapshot of plant economic performance based on a limited set of information. To support the sensitivity analyses, probability distribution functions (PDF) from Monte Carlo analyses run in Crystal Ball® were generated for each scenario. The PDFs provide the percentage over the course of the Monte Carlo simulations that the NPV is above 0, as well as averaged mean NPVs, and standard deviations. Similar to the results seen in the sensitivity analyses, the FFPG systems that integrate RNG produced overall higher mean NPVs. The FTS No Co-gen and with Co-gen systems produced mean NPVs of -$44.1 and -$30.1M respectively. The FFPG MWS AD, LO AD, and LFG scenarios generated mean NPVs of -$22.0M, -$21.4M, and -

$10.2M, all of which are higher than the FTS systems. Not only were the mean NPV values higher, the FFPG systems also generated on average a higher percentage of positive results over the 2,000 Monte Carlo simulations that were run.

Over the course of the Monte Carlo simulations, 1.8% of the FTS No Co-gen system NPVs were positive, while the FTS with Co-gen system generated 7.5% positive NPVs. When RNG systems are included, the NPVs were positive more than 15% of the trials. The FFPG MSW AD system generated positive NPVs 20.9% of the time. The FFPG LO AD system generated positive results 15.1% of the time, followed by the FFPG LFG system which generated positive NPVs 30.4% of the time. These results accentuate the ability to generate higher value by diversifying feedstock use and product distribution, especially when there is an incentive for renewable biogas included. The FTS scenarios depend on natural gas as the single feedstock. The exposure to multiple inputs and outputs decreases the sensitivity of NPV to sharp changes in prices. There are additional factors that may impact the effectiveness and feasibility of adding additional plants, however these are outside the scope of this study. These factors include location, the distance from pipelines, available waste, the ability to obtain capital to invest, and working with private and public entities.

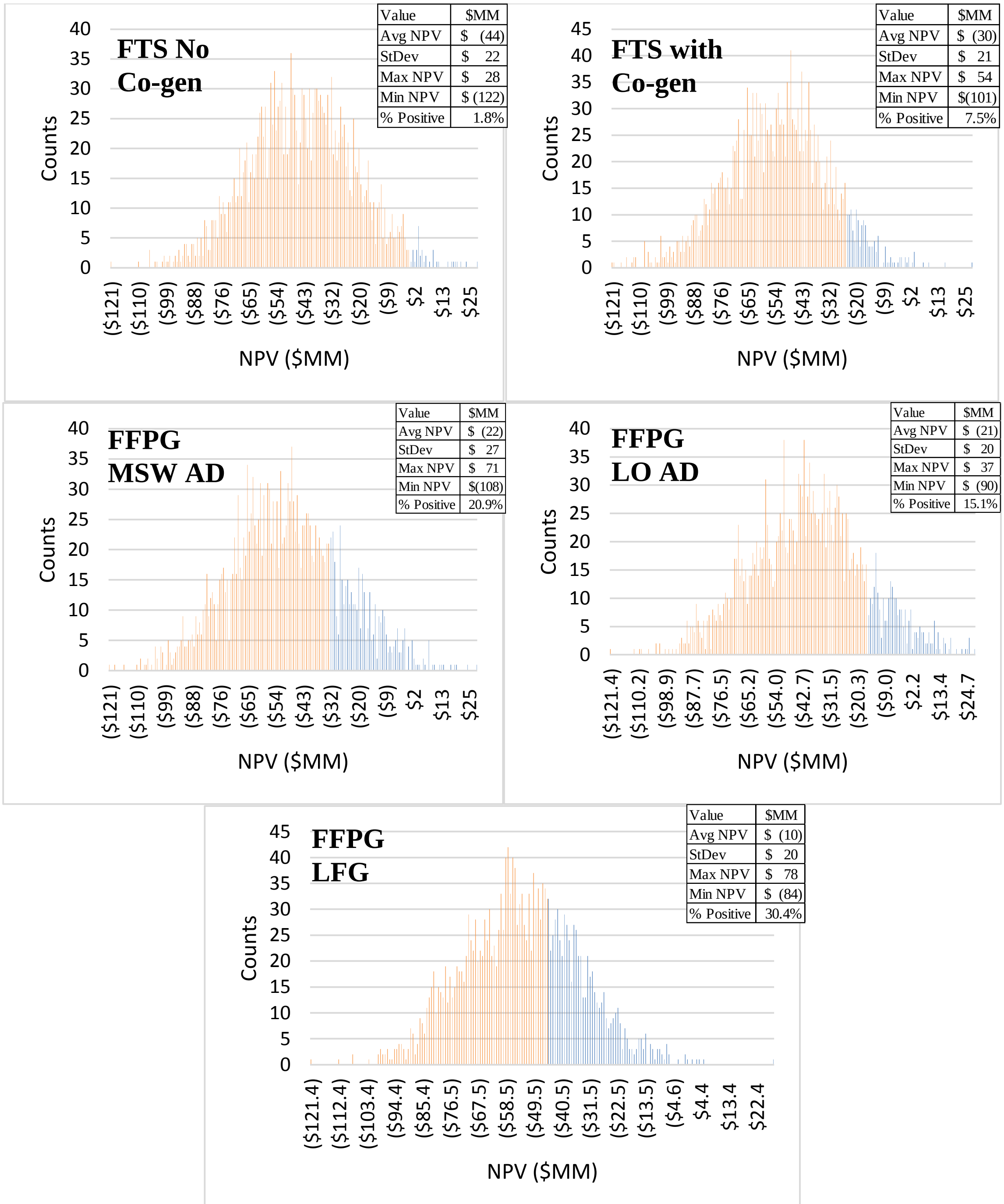

Figure 10. 20-year NPV probability distribution functions

(Positive NPV counts in blue. NPV: net present value, FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas, RINS: Renewable Identification Number, O&M: operating and maintenance)

The initial scale of the FTS plant was scaled to the size where 10% of the NG was substituted by a single RNG facility. However there are opportunities to increase the NPV by increasing the amount of RNG that is used in combination with NG. In order to supply additional supply of RNG, more AD facilities are assumed. To stay in line with the scale of current projects, additional plants are added to provide the additional capacity to produce and upgrade biogas instead of increasing capacity. For each AD plant that supplies the FTS scenario with biogas, an additional 10% of RNG is substituted for purchased NG from the pipeline. Shown in Figure 11, by increasing the amount of RNG that substitutes NG (requiring an additional plant for each 10%), the resulting NPV significantly increases for both the LO AD and LFG scenarios. Added RNG from subsequent MSW AD facilities results in a lower increase in NPV. The high capital costs associated with MSW AD facilities results in the production of RNG at a price similar to what NG can be purchased for. One approach to improve the NPV for the MSW AD scenario is to increase the scale of the individual MSW AD facility rather than increase the number of facilities in order to capitalize on economy of scale. To ensure the benefit of economy of scale, further analysis of scaling factors for anaerobic digesters should be carried out. Along with scaling factors, feedstock availability as well as the impact of increased transportation and logistics costs should be considered. Increased costs associated with larger scale feedstock collection and storage could negate the benefits associated with economy of scale.

For the MSW AD system, the NPV increased by approximately $7.4MM for every additional 10% of RNG that substituted NG. The cost to produce RNG from the MSW AD scenario is $35/MMBtu, however when tipping fees and RINs are accounted for the cost can be reduced to between $7 and -$9/MMBtu depending on the tipping fee. With NG prices in the $3/MMBtu range it can be profitable to substitute RNG from MSW AD. For the LO AD and LFG scenarios, every additional 10% of RNG increased the NPV by $19MM and $21MM. The resulting cost to produce RNG from these scenarios amounts to $7/MMBtu and $2/MMBtu, respectively. When RINs are included, these scenarios generate revenue for the production of RNG, approximately -$3/MMBtu and -$8/MMBtu, and contribute to an increasing NPV.

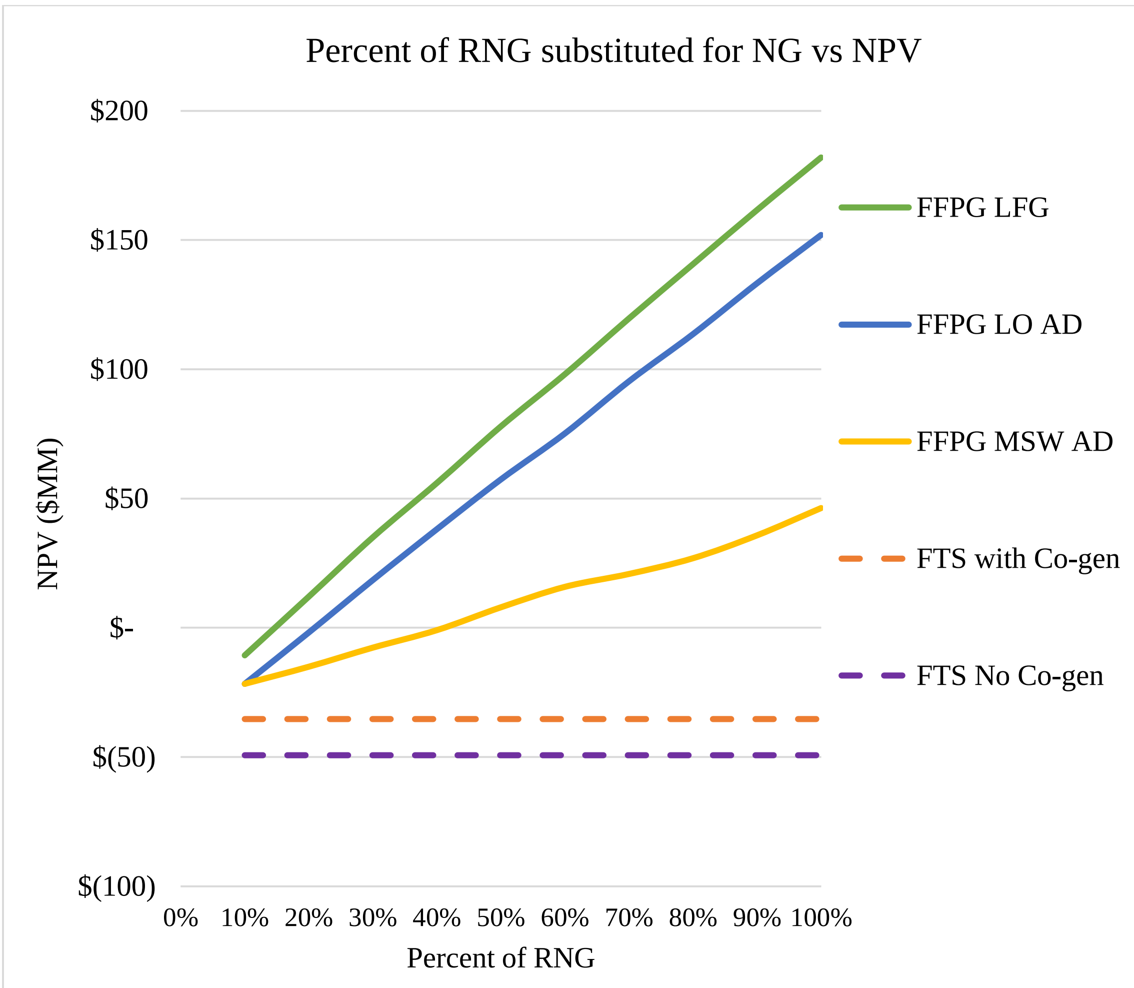

Figure 11. NPVs with increased RNG Plants

(NPV: net present value, FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas)

The addition of multiple AD plants to provide the FTS scenarios with more RNG can improve the NPV. To further explore the benefit of integrating higher volumes of RNG into the FFPG scenarios, the effect of an increasing NG price was evaluated to compare the FTS systems vs the FPPG systems that utilize 50% RNG. While the increased NG price had an impact on the FTS and FFPG scenarios when 10% of the NG was substituted by RNG, a greater difference in plant profitability was observed with systems that integrated even larger amounts of RNG. The FTS No Co-gen and FTS with Co-gen scenarios were the most sensitive to the increase in feedstock prices due to the dependence on the single input. The FTS scenarios resulted in the largest negative slopes in Figure 12, denoting the largest decreases in NPV given the unit increase in NG prices of approximately -$26MM per $1 increase in NG prices. The scenarios that included five RNG facilities, and hence depended 50% less on NG, were impacted less for each unit increase in NG price. On average the FFPG scenarios NPVs decreased $12MM per 1$ increase in NG prices. The largest differences between the FTS scenarios and the FFPG scenarios were realized when NG reached its highest prices. At a NG price of $3/MMBtu, the difference between FFPG LFG and FTS No Co-gen was $86MM, while at $11/MMBtu the difference was $218MM.

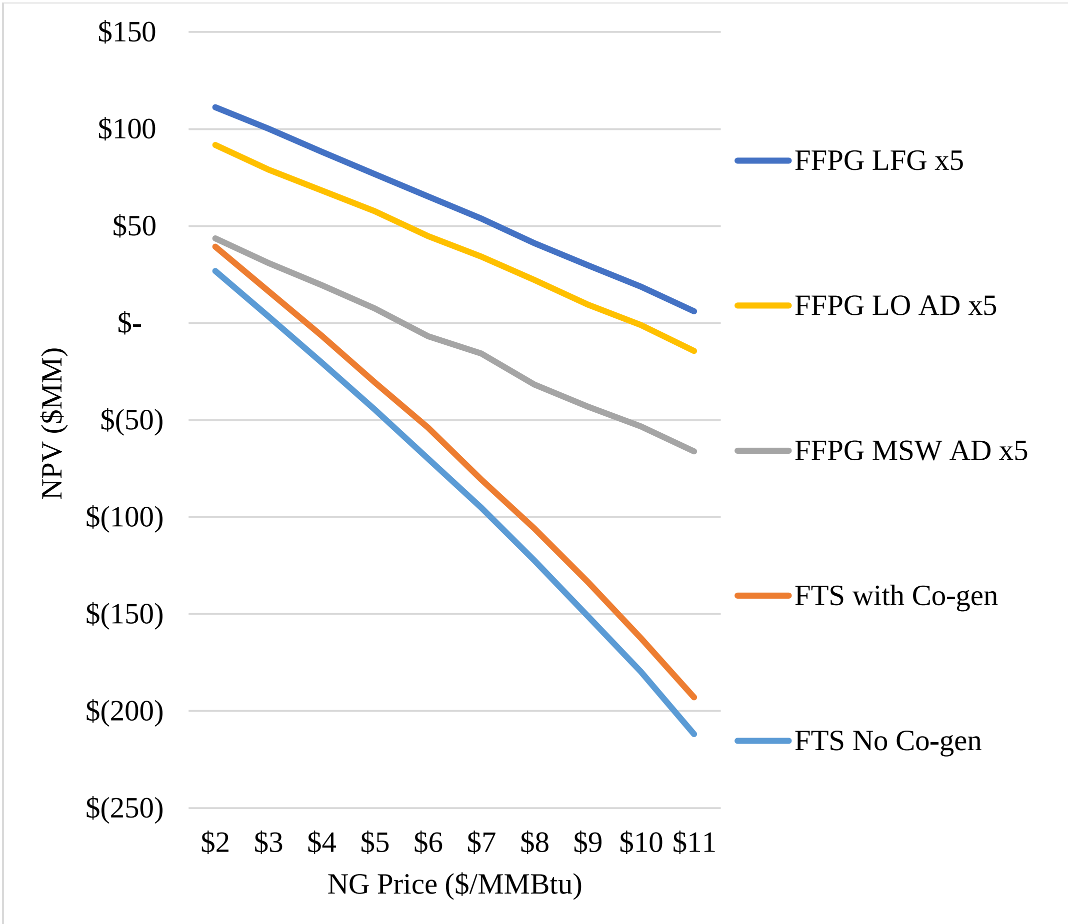

Figure 12. NPVs with increasing NG prices

(NPV: net present value, FTS: Fischer-Tropsch synthesis, Co-gen: co-generation of electricity, FFPG: flex fuel polygeneration, AD: anaerobic digestion, MSW: municipal solid waste, LO: livestock operation, LFG: landfill gas, NG: natural gas, RNG: renewable natural gas)

Out of the three FFPG scenarios that integrate RNG as a substitute for traditional NG, LFG scenario produces the most profitable 20-year NPV with the given conditions. The scenarios that integrated more RNG as a substitute for NG yielded the highest NPVs, especially when the price of NG increased. Additional costs and challenges may be encountered when scaling up the size and number of AD plants, however improved profitability can be realized.

CHAPTER 5. CONCLUSIONS

This study proposes an additional approach to multiple feedstock polygeneration, termed flex fuel polygeneration (FFPG), that addresses energy plant flexibility and utilization of market opportunities. Models were developed by employing public domain literature to design hypothetical (FFPG) energy plants. The FFPG energy plants consisted of a traditional Fischer Tropsch synthesis (FTS) facility integrated with three different types of plants that produce renewable natural gas (RNG). Sensitivity analyses were performed and showed the impact of individual parameters on plant 20-year NPV. From the sensitivity analyses it was determined that to increase the resiliency of a plant, more than one highly valued product should be produced to allow adjustment of production towards the most profitable scenario. Following the sensitivity analyses, Monte Carlo simulations were performed to give a more comprehensive understanding of plant performance when more than one variable was changed simultaneously. They represent a more realistic view of plant performance by integrating historical trends of parameter values used to produce estimated NPVs. When adding additional technologies to a FFPG plant the overall capital and O&M costs increase, however this can also increase the longevity and profitability of a plant.

Overall, the FFPG LFG and LO AD scenarios produced the highest 20-year NPVs out of all the scenarios analyzed. The largest difference in NPVs between the two FFPG plants and the other scenarios considered occurred when the price of traditional NG was increased. The lower capital costs associated with the FFPG LF and LO AD plants, the value generated by RINS, and the displacement of traditional NG use also led to higher NPVs. Considering the number of RNG plants, the benefits of the FFPG increased as the number of RNG plants increase for the LFG and LO AD scenarios. For the MSW AD scenario, as the number of plants increased, the NPV increased at a lower rate than the alternative AD scenarios. The NPV of the FFPG MSW AD was comparable to the FTS with Co-gen scenario. While the FFPS AD system received a tipping fee for the waste collected as well as RINs for the RNG generated, the high capital costs balanced the generated income.

Additional feedstock and a diverse product portfolio can alleviate unprofitable periods due to price fluctuations. If a facility becomes negatively impacted by the shift in feedstock or product prices, a flexible system allows for a longer time span to re-evaluate and adjust its energy production approach to operate more profitably due to the lower impact on the NPV of the system. The FFPG facilities are affected less (Table 8, Figure 12), therefore allowing alternative decisions to be made at a potentially lower loss than the single feedstock FTS systems. With low feedstock costs and high product prices, the FTS with Co-gen system has potential to achieve similar NPVs as the FFPG MSW AD system. However, introducing flexibility can lead to a greater potential to mitigate risk and increase revenue in the future. RNG derived from waste products can be utilized in many different applications to offset costs and risks associated with the utilization of a single feedstock, specifically natural gas. By integrating biogas into FFPG, more opportunities can be explored to improve utilization of waste materials, offset the use of energy derived from fossil fuel, and the mitigation of risk by diversifying feedstock and product portfolios.

This study provides insight into the benefits of integrating RNG into traditional NG conversion processes to fuels. However, additional research can be performed to enhance the results and understand added benefits that are outside the scope of the current study. To realize the value of including multiple feedstocks and products in energy conversion, a scenario should be analyzed to determine how changing prices of fuel and feedstock over time affect a plant that has the ability to autonomously switch its fuel mix and product portfolio. The amount of flexibility as well as additional required capacities and costs for the associated pathways would provide more information on FFPG's ability to mitigate risk. Along with this, further investigation into the costs of smaller Fischer-Tropsch plants and larger anaerobic digestion plants could lead to more profitable NPVs. Technical research should be focused on improving the feasibility of smaller scale FT plants that can be utilized in an array of locations. If cost effective, these small plants can capitalize on available feedstock in different locations that may not be feasible for integrating with large scale FT plants. Having the ability to operate in more places could also reduce costs associated with transportation as well as provide more valuable avenues for waste streams, such as biogas. Along with smaller FT plants, larger AD plants that process readily available waste streams can be investigated to solve waste accumulation challenges and turn them to profitable endeavors. Integrating FT and AD is an attractive approach to improve waste utilization, decrease dependency on single feedstocks and products, and increase returns on investment compared to FTS systems that utilize a single feedstock.

APPENDIX. ADDITIONAL MATERIAL

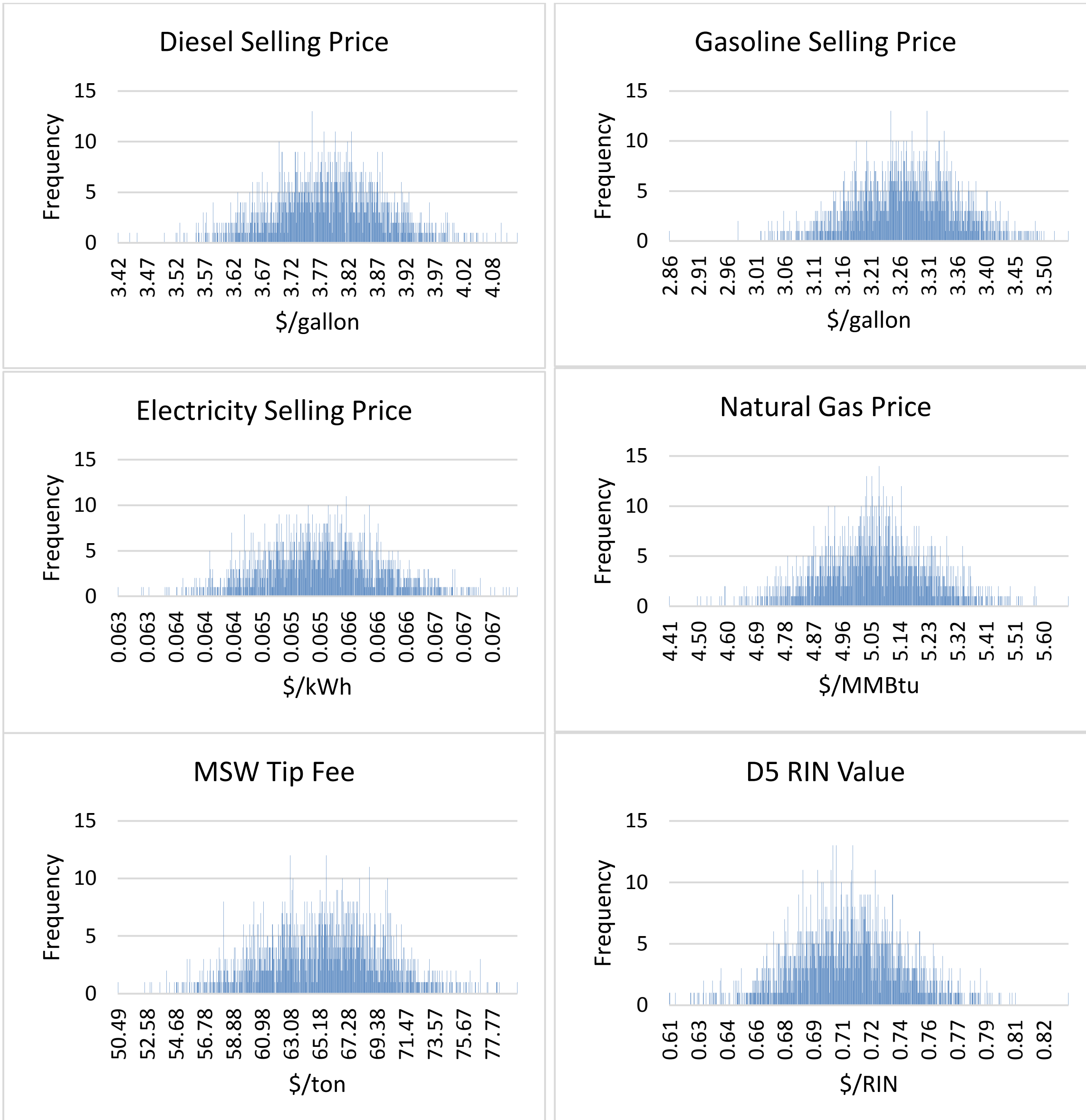

Figure 13. Parameter distributions for Monte Carlo simulations

(MSW: municipal solid waste, RIN: Renewable Identification Number)

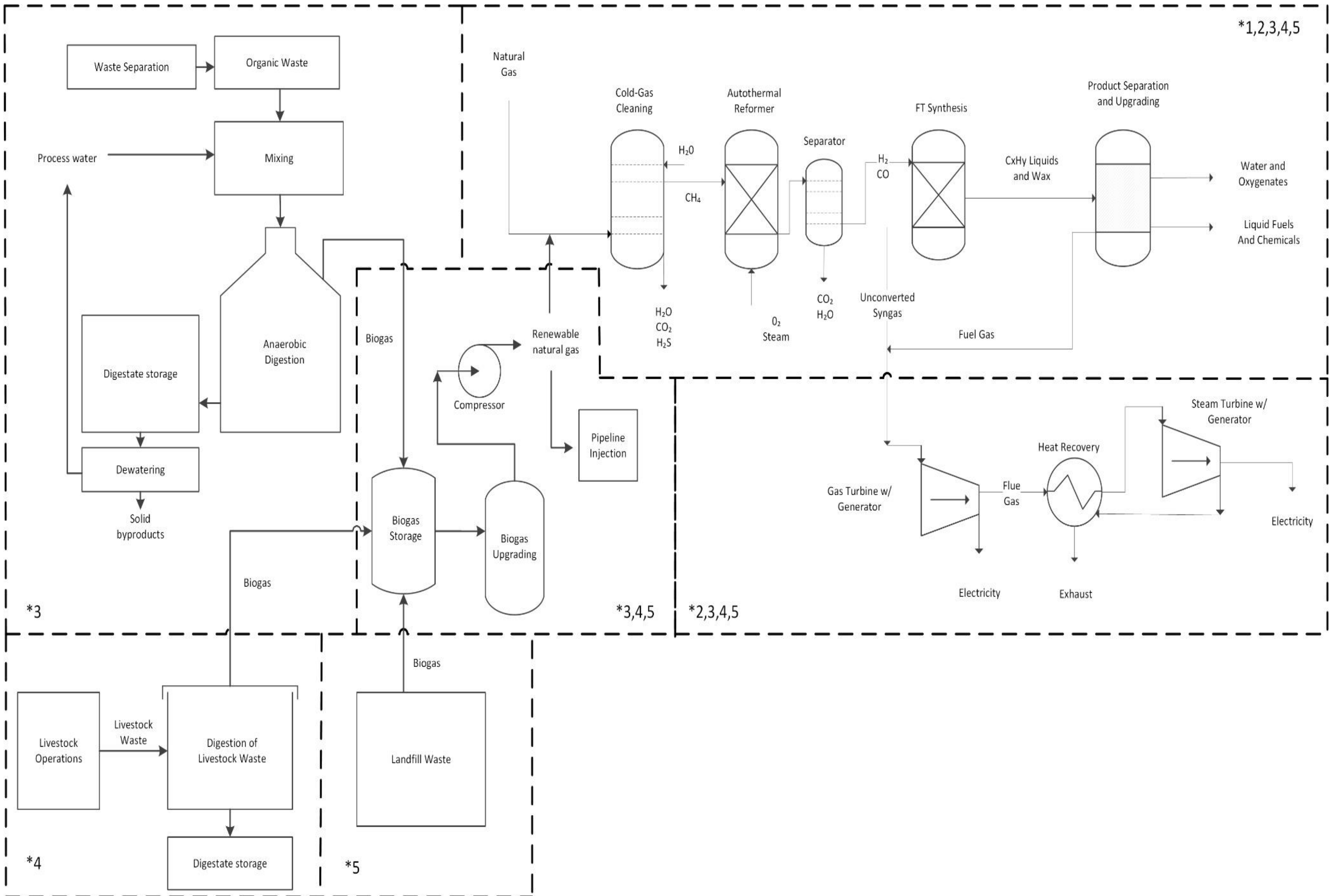

Figure 14. Energy production process diagrams (Each section denoted by scenario inclusion)

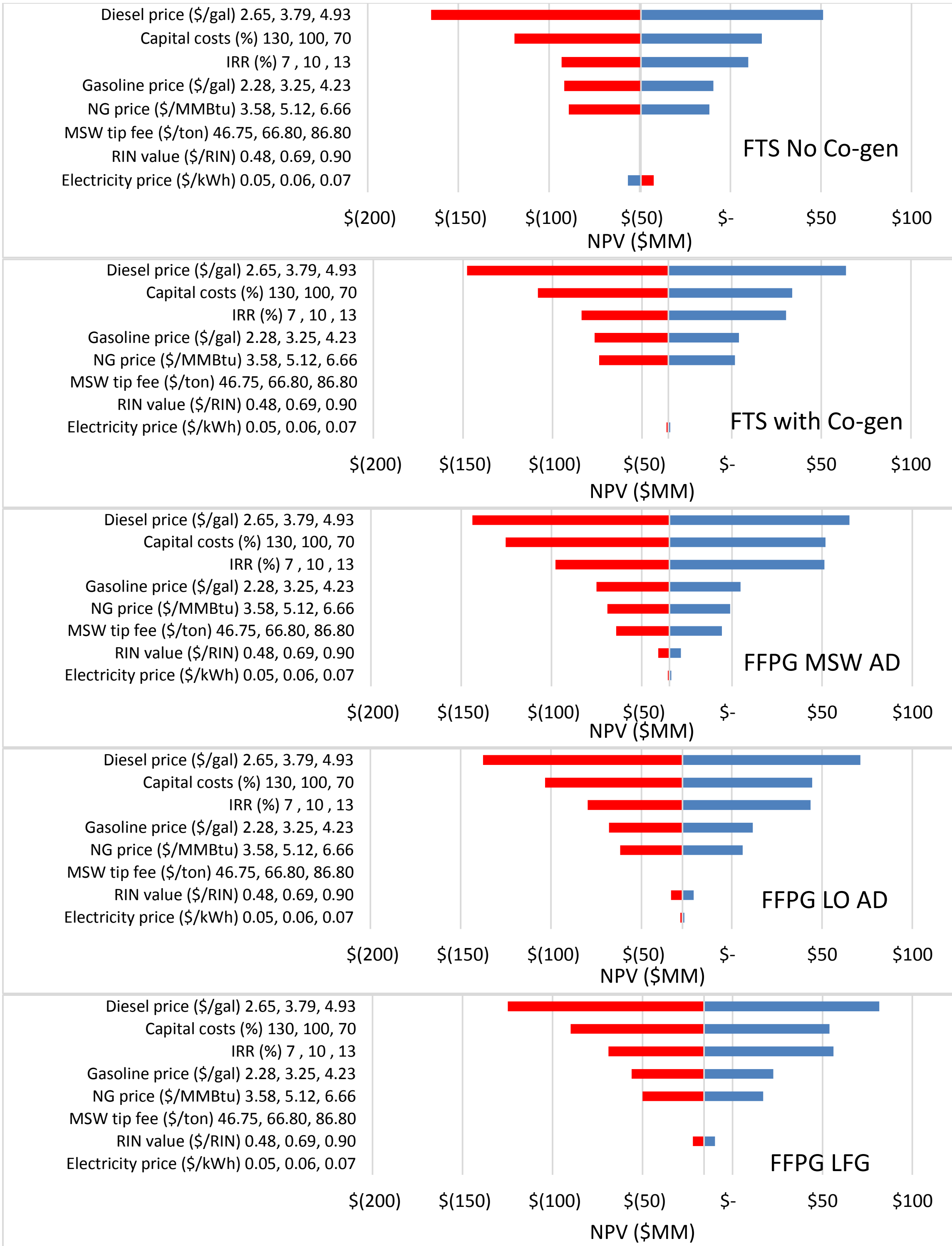

Figure 15. Sensitivity analyses of energy production scenarios (single RNG facilities)

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