General Equilibrium Impacts of New Energy Technologies on Sectoral Energy Usage

by

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Abstract

The dissertation examines conditions under which gas-to-liquids (GTL) technology penetration shifts the crude oil-natural gas price ratio. Empirical research finds long-run relationships between crude oil and natural gas prices. Some studies include time trends that steadily evolve the pricing relationship, while others show a long-run relationship that occasionally shifts significantly. A common hypothesis is that technologies that increase substitutability or complementarity between fuels are the source of the price linkage. However, empirically measuring the effects of a gradually-penetrating technology across narrow time frames is not possible due to intervening economic shocks. This thesis examines the effects of an energy conversion technology penetration on the crude oil-natural gas price ratio through its influence on sectoral energy use in the U.S. GTL must be less expensive and more efficient, and natural gas prices must be lower, than currently forecast for an effect to be measured. In the absence of a technology that explicitly allows for substitution between natural gas and petroleum-based fuels, different rates of demand growth result in a steadily-rising oil-gas price ratio. If a viable GTL technology successfully competes against petroleum-derived refined fuels, it dampens crude oil price increases and brings the oil-gas price ratio below the levels found in cases without a viable GTL technology.

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Chapter 1

Introduction

The purpose of this dissertation is to determine whether, and under what conditions, gas-to-liquids (GTL) technology penetration can shift the crude oil-natural gas price relationship.[1] GTL uses a natural gas input to create diesel and petrochemical feedstocks. It allows natural gas to directly compete with crude oil in the production of transportation fuels.

Crude oil has been an unchallenged source of transportation fuels for nearly a century. Historically, an increase transportation fuel demand has been met by an increase in crude oil refining. Non-petroleum-fueled vehicles, such as hydrogen or plug-in hybrids, require substantial infrastructure investments and remain inferior to petroleum-fueled vehicles in range and performance. Their penetration into the transport sector has been slow or perpetually on the horizon. GTL has the potential to displace petroleum products in the transportation sector. It utilizes natural gas feedstocks to make high-quality diesel fuels that seamlessly integrate into existing infrastructure and vehicles. Its only barriers to penetration are the cost and efficiency of the GTL technology and the cost of its natural gas feedstock. If natural gas were sufficiently inexpensive, the output of a low-cost/high efficiency GTL configuration could partially displace crude-based fuels in transportation. An increase in natural gas usage to serve transportation demand would weaken demand for crude oil.

[1]The oil-gas price relationship is measured by the ratio of the crude oil price to the natural gas price. A relative increase in the crude oil price increases the ratio, and a relative increase in the natural gas price decreases the ratio.

Industry, traders, and market analysts have long identified a price linkage between crude oil and natural gas. A common hypothesis among them (and academics) is that the oil-gas price ratio is stable because there are opportunities to substitute between natural gas and petroleum products in some sectors. This hypothesis has not been explicitly tested. Most technologies penetrate slowly, and their incremental effects on the crude oil-natural gas price ratio are not measurable in the face of major disruptions to energy prices such as wars, recessions, and natural disasters. In 2009-2010, hydraulic fracturing[2] of shale gas deposits coincided with a halving of the natural gas price, but also with a global recession. Either or both could have been responsible for the shift in natural gas prices that changed the crude oil-natural gas price ratio.

GTL creates both diesel and naphthas.[3] The combustion of GTL diesel emits no sulfur and less GHG pollutants than petroleum-based diesel. The fuel is suitable in high-performance vehicles yet maintains diesel's fuel efficiency. GTL proponents claim that these characteristics could entice drivers to shift to diesel-fueled vehicles and thus burn less fuel overall, reducing emissions of carbon and other pollutants in the process. However, GTL is not a new technology. The dominant GTL process technology was invented in the 1920s. In the United States, GTL production has generally cost 30-70% more than an oil refinery, though if natural gas prices and GTL costs were low enough, GTL could potentially be economic.

This dissertation tests whether the penetration of an energy conversion technology (GTL) can influence the crude oil-natural gas pricing relationship, and under what conditions. It turns out that the conditions that must be in place for any substantial penetration of GTL are rather extreme in terms of low GTL and natural gas costs and high GTL efficiency. Because GTL cannot deploy without a low-cost natural gas feedstock, I also model a low-cost natural gas production technology. I simulate the global economy over the course of the 21st century in a computable general equilibrium (CGE) model. In the simulation, no unanticipated shocks occur, and the gradual

[2]"fracking"

[3]Naphtha is one of the feedstocks blended to make gasoline. It is a principal petrochemical feedstock.

effects of GTL penetration on the crude oil-natural gas price ratio are measured as the difference between a case in which an economically viable version of GTL exists and an initial case using current costs and efficiencies (in which GTL fails to deploy). In order to trace out the full range of possible outcomes, I simulate a wide range of GTL cost/efficiency estimates and a range of natural gas prices.

1.1 Gas-to-liquids (GTL) technology

GTL creates transportation fuels (diesels and jet fuels) and naphtha (a petrochemical feedstock) from natural gas. Its penetration would increase substitutability between crude oil and natural gas through direct competition. Of the energy technologies on the horizon, it creates the most explicit competitive linkage between crude oil and natural gas. Though GTL is not new, low-cost natural gas extraction has recently made GTL economically attractive and thus potentially deployable.

GTL proponents cite numerous benefits: diesel fuels that match the performance of gasolines [157, 49], increases in energy security for gas-endowed nations [44, 95], and even reductions in tailpipe emissions for numerous pollutants [49, 160, 148, 80, 83]. The assumption is that since per-unit fuel emissions are lower, GTL displacement of petroleum refineries will only yield benefits. But the systemic effects of GTL adoption are potentially consequential. If transportation fuels were created from an additional fossil fuel source, how would that affect transportation fuel prices? How would consumers respond to the new fuel prices? What would happen to natural gas usage in other sectors once they must compete against GTL for natural gas feedstocks?

GTL was first developed after World War I [161]. It is not a novel technology, but its costs have been declining for the last two decades and plants have only just started to be deployed. This means that the global economy has not yet been affected by its production. From the market perspective GTL would be a technology with no prior influence on the economy. Crucially, it is the recent decline in the relative price of natural gas versus crude oil that makes GTL attractive. Could GTL become such a significant source of natural gas demand that the relative gas price rises, closing

GTL's window of profitability?

1.2 The crude oil-natural gas price relationship

For decades, the oil and gas industries recognized a price relationship between crude oil and natural gas. A long-standing rule of thumb is that the crude oil price in dollars per barrel ($/bbl) is ten times higher than the natural gas price in dollars per million British thermal units ($/mmBtu): the 10-to-1 rule. Another rule of thumb assumes that since both crude oil and natural gas are energy sources, their relative prices should be a reflection of their energy content. A barrel of crude oil contains about 5.8 mmbtu, so under this rule of thumb the ratio should be 6-to-1.

From the industry perspective, the notion of a price linkage makes sense: crude oil and natural gas are often discovered together, so an oil discovery increases supplies of both crude oil and natural gas. An increase in the supply of a good weakens its price if demand is held constant, so the prices of both goods should weaken together. Further downstream, oil refineries use natural gas as an input, so an increase in crude oil demand translates into an increase in natural gas demand. An upstream linkage of a distinct nature is that oil wells and gas wells employ the same drilling equipment and labor. Drilling for crude oil excludes drilling for natural gas. This would increase the crude oil supply (weakening its price), while decreasing natural gas supply in relative terms (strengthening its price). Under these circumstances, the prices would move back toward each other. Eventually, the profit margin on drilling for natural gas would be higher than for crude oil, and the rigs would be shifted back to natural gas production.

Joint discoveries of the commodity and the use of natural gas in petroleum refining reflect complementarity between the commodities. Complementarity means that demand pressures on both commodities move in the same direction, and their prices move together. The bidding war for drilling rigs reflects competition for common inputs. In competition, a drift apart in prices is eventually reversed as supply and demand shifts move the prices back into a long-run relationship. Competition is marked by a convergence of prices after an initial event that drives them apart.

The rules of thumb were benchmarks. In the short run, prices could diverge, but the rule of thumb represented a long-run relationship. However, over longer timeframes, neither the 10-to-1 nor the 6-to-1 rules of thumb proved very accurate. When natural gas prices became too high to fit the 10-to-1 rule, it was postulated that the linkage between crude oil and natural gas was really due to competition between natural gas and refined products downstream from the oil and gas industries. Thus emerged the burner-tip parity rules: natural gas would be related to the cost of either residual or distillate fuel oils, where the fuels competed in heating or power generation [16]. The problem with the rules of thumb was that there was a cyclical component and a random component to their errors. This was due to the annual variation in natural gas prices and stochastic volatility in the prices of both fuels. None of the rules held past time windows spanning a few years. This led a few researchers to conclude that the link between crude oil and natural gas had been broken [153] or that the linkage was coincidental [12].

Researchers were able to filter out much of the volatility in characterizations of the oil and gas price relationship through cointegration modeling. Cointegration is the condition in which two non-stationary data series are related to one another through a single stable equation. This equation is the cointegrating relationship. Cointegration models control for variables that contribute to volatility in either or both time series and filter out the short-run volatility, enabling a clearer picture of the underlying relationship between the prices. The models include a measurement of the rate at which deviations from this "long-run" relationship are corrected. Under cointegration modeling, empirical researchers fairly consistently identified a long-run relationship between crude oil and natural gas prices. Even so, there were discrepancies. Villar and Joutz included a time trend in their model that exogenously increased natural gas prices over time [172]. Hartley, Medlock and Rosthal used the average heat rate as a technology proxy, with identical effects [73]. Brown and Yücel found a stable relationship without a time trend after explicitly controlling for certain drivers of natural gas volatility [21]. In 2010 it was discovered that the long-run price relationship between crude oil and natural gas was not constant over longer time windows. The relationship had shifted to a new equilibrium from 2006 through 2009 as both oil and natural gas prices rose steeply [133, 134]. An oil price collapse in 2009, combined with a halving of the US natural gas price in 2009-2010, led many to hypothesize that the two commodity prices had become de-linked. Later research concluded that the link in the USA had been re-established at another level [98, 20].

One recurring hypothesis was that crude oil and natural gas prices were linked because the fuels either competed with or complemented each other in key sectors. The changing relationship could have been caused by changes in the technologies being used. Competition could be due to direct substitutability (e.g., a dual-fuel boiler or generator) or portfolio substitution (e.g., a power generator has both diesel-fired and natural gas-fired plants, but only dispatches the one with the least expensive fuel). The fracking of shale gas deposits was one hypothesized cause for the dramatic fall in natural gas prices at the end of 2009. This fall in natural gas prices would have established a new oil-gas price ratio. Another hypothesis for the natural gas price collapse was that the global recession reduced demand for natural gas. In reality, it could have been a combination of both events. That a recession could depress natural gas prices is obvious. The hypothesis that could not be independently tested was that the deployment of a new technology (fracking) had affected the long-run crude oil-natural gas price ratio.

1.3 Research question and experimental design

My research question is "Can the penetration of an energy conversion technology (GTL) affect the crude oil-natural gas price relationship?" A decline in the oil-gas price ratio over time after GTL penetration would suggest that GTL increased substitutability between the fuels. A related question is whether the apparent linkage between the two commodities is merely coincidental due to the fact that crude oil and natural gas are both pervasive inputs to economic activity, and so a growing (or shrinking) economy increases (or decreases) demand for both commodities in the same direction. In this case, a sharp decrease in natural gas prices would cause the price ratio to increase, and no adjustment in sectoral fuel usage over time would bring the ratio back down again.

Most of the cointegration papers assumed that there was substitutability or complementarity between oil and gas, and that technology was the driver [172, 73, 21, 133, 134]. However, economic expansion increases demand for energy, putting upward pressure on all energy prices, and recessions do the opposite. Under these circumstances, the strength of the cointegrating relationship between crude oil and natural gas prices could be simply because they are the most heavily traded energy commodities whose prices react quickest to changes in economic conditions. Bachmeier and Griffin were the most explicit in this view [12], but the models with the time trend/technology parameter could imply a similar paradigm [172, 73].

The problem is that the occasionally-shifting/steadily trending "long-run" relationship in the cointegration models is a relationship that has only been demonstrated to hold for at most a decade. In the shorter run, prices "correct" toward this long-run relationship, but then the relationship weakens before prices settle into a new relationship. Over the longer run, the models that allowed for a drift in the price relationship implied that demand for each commodity grows at different rates, but that the difference is subtle. In the shorter run this would look just like a stable "long-run" relationship that shifts over time. If true, this implies that the crude oil-natural gas price relationship is a spurious correlation, and that the apparent "shifts" in the relationship would actually be dependent on the choice of time window in the data upon which to focus. In order to resolve which of these paradigms carries more weight, the time window of observation must be widened significantly.

What is the influence of technology and what is the influence of longer-term economic trends? This dissertation seeks to determine if technology has any influence on the crude oil-natural gas price relationship by making a cost-effective conversion technology available in a long-term, forward-looking simulation of the economy and tracking the effects of its deployment.

1.3.1 Hypothesis: an energy conversion technology will influence the crude oil-natural gas price relationship

My hypothesis is that the crude oil-natural gas price relationship will be significantly affected by the deployment of a cost-effective version of an energy conversion technology such as GTL. The convention for the rules of thumb as well as the cointegration analyses was to measure the relationship as the ratio of crude oil prices to natural gas prices. The hypothesis rests on the following logic:

- Demand for goods and services increases with income. Demand growth is not uniform across all goods and services or across all regions. Globally, transportation demand increases with wealth. Cooling demand grows rapidly with wealth in the developing world because most developing countries are in warmer climates. The demand for air conditioning translates into increased demand for electricity. For the same reason, heating demand is not forecasted to grow as quickly as the demand for transportation or electricity. This is because the countries with the greatest heating demand are already wealthy, and are already meeting most of their need for heat.

- The main driver of the crude oil price is demand for transportation fuels: diesels, gasolines, and jet fuels. Increasing demand for transportation over time increases the demand for transportation fuels. Crude oil is largely unchallenged in the production of transportation fuels, so increases in transportation demand translate into increases in crude oil demand. This means that crude oil prices increase as transportation demand increases.

  Refineries also produce other products: refinery gases, petrochemical feedstocks, residual oils, and petroleum coke. These are by-products of creating the more profitable transportation fuels. Due to crude oil chemistry and petroleum refinery configuration, refined fuels are made in largely fixed proportions.

- The main drivers of demand for natural gas are for heating and electricity generation. The petroleum by-products compete with natural gas to meet heating demand. In electricity generation, natural gas is a major input, but it faces significant competition from other fuels, especially coal. As transportation demand grows, the supply of petroleum by-products grows. This increases the relative supply of the by-products and makes them relatively less expensive than natural gas over time. This effectively lowers the cost of heating. Natural gas will not be used for heating if its price rises too high.

Increases in electricity demand thus only partly translate into increases in natural gas demand because natural gas faces significant competition in electricity generation. Increases in heating demand likewise only partly translate into increases in natural gas demand because natural gas competes with petroleum by-products in heating.

- These trends suggest that crude oil prices will increase more rapidly than natural gas prices, implying that the crude oil-natural gas price ratio should continually increase over time.[4]

On the other hand, *if GTL were economically viable*, there are conditions under which growth in GTL fuel production could alter the long-run trend in the crude oil-natural gas price ratio.

- If GTL were inexpensive enough, crude oil would no longer be the lone competitor in the transportation fuel market. In order to be deployed it would have to produce diesel at a lower cost than an oil refinery. Eventually GTL fuel production could displace a portion of petroleum-based fuel production because it would have capped the cost of diesel production at the cost of GTL. The increased supply of transport fuels due to GTL penetration should weaken their price. Increases in transportation fuel demand would only partially translate into increased crude oil demand. Crude oil price increases would be dampened over time. Some of the increase in transportation fuel demand would translate into an increase in natural gas demand. The increased usage of natural

[4]The drifting oil-gas price ratio would appear to give credence to the researchers who included a trend in their cointegration models. However, both of those models utilized a trend of *increasing* natural gas prices, which would make the oil-gas price ratio *decrease* over time.

gas as a GTL feedstock should increase its price. Thus if GTL were inexpensive enough, its fuel production could shift the crude oil-natural gas price ratio downward. This would dampen the trend described in the absence of a viable GTL technology.

Empirically testing the historical influence that a technology in deployment had on the crude oil-natural gas price relationship is difficult. This is because technologies generally deploy incrementally, and the prices of both crude oil and natural gas move erratically in response to seasons, weather, catastrophes and geopolitical events. These unexpected events exert much greater temporary influence on prices than the instantaneous impact of a gradual deployment of the technology. The fall in the natural gas price in 2009 is a prime example of temporary events drowning out the gradual impact of a technological deployment. I thus employ a computable general equilibrium (CGE) model to measure the influence that the deployment of an energy conversion technology would have on crude oil and natural gas price ratios in the absence of the stochastic shocks that occur in real life.

1.3.2 Experimental design

I simulate the global economy over the course of this century using a CGE model that captures the breadth of global energy usage across the major energy-consuming sectors. I examine the changes in the crude oil-natural gas price ratio that occur when GTL technology is modeled at a range of costs and efficiencies and available in the U.S. The aim is to be able to capture second- and third-order effects of technology penetration, including rebound effects, fuel substitution, and shifts in energy usage across sectors. These will be reflected by changing prices of crude oil and/or natural gas, thus affecting the oil-gas price ratio.

Initial explorations revealed that GTL technology is currently much too expensive and inefficient, and estimated natural gas prices are too high, for GTL to be deployed at a large scale in the United States. There are three factors that influence whether GTL will be economic: the natural gas price, the GTL plant cost, and GTL efficiency.

Thus another energy technology that allows for a reduction in the production cost of natural gas must be added. The experimental design tests the interactions of these two distinct technological deployments: the supply-side technology that lowers the cost of producing natural gas to a fraction of its baseline production cost and GTL. The gas cost reduction technology should shift the crude oil-natural gas price ratio upward. If there is sufficient opportunity to substitute crude oil products for natural gas, then over time the oil-gas price ratio should fall again. If GTL is inexpensive and efficient enough to penetrate widely, it should eventually decrease the crude oil-natural gas price ratio.

Three distinct versions of the gas production technology and three distinct cost and efficiency specifications for GTL are modeled. Two trading paradigms paradigms are imposed. The experiment is three-dimensional. In the first dimension there are three states. The first state deploys no natural gas production cost reduction technology. In the other two, a version of the low-cost gas technology is deployed. Within each of these states I model three GTL cost/efficiency scenarios along the second dimension. The scenario with the highest GTL cost and lowest efficiency reflects the current best estimate of GTL technology. The other two scenarios decrease GTL costs and increase its efficiency. Thus the highest-cost combination of natural gas prices and GTL technologies is actually the reference baseline. The third dimension features two trading regimes: in one, international distillate fuel trade is disabled, so GTL diesel cannot be exported. In the other, trade is unfettered and U.S.-produced GTL diesel has access to external markets. All together, there are 18 distinct scenarios to examine.

In addition to the above experimental design, further modifications were necessary in order to make GTL a feasible alternative to crude oil refining. This was because under low-cost natural gas production and low-cost/high-efficiency GTL configurations, GTL made an initial penetration, and the demand for natural gas that resulted caused natural gas prices to rise, which made GTL unprofitable and halted its deployment. To remove the resource scarcity constraint, the natural gas resource was increased 100-fold globally, and other modifications that made natural gas less costly to produce, even under the baseline scanario, were made. This enabled an analysis of a wider range of outcomes.

1.3.3 Relevance of this research

This dissertation addresses a latent issue in the study of commodity pricing relationships: are the demonstrated statistical relationships due to true competition and/or complementarity of fuels, or because of common trends in demand growth that are coincidental? Only by widening the time frame of observation can this question be addressed. Under a wider time frame, the penetration of a technology from initial deployment to market saturation can be modeled. Its influence on the crude oil/natural gas pricing relationship can be measured. If the influence turns out to be significant, it lends credence to the hypothesis that technologies can affect competition between crude oil and natural gas to the extent that it shifts their long-run pricing relationship. If not, it gives weight to the counter-argument that common trends independently influence commodity prices in similar ways, and that this effect is much stronger than the introduction of inter-fuel competition through technology. This dissertation will show, perhaps surprisingly, that there exists little opportunity for substitution between petroleum products and natural gas in the economy under current trends in sectoral energy usage and estimates of technological availability in the future.

The dissertation also employs an alternative method to estimate future pricing relationships between key energy commodities. Most price forecasting – even far into the future – relies on statistical decomposition of historical prices. This assumes that past is prologue. Simulating the global economy into the future allows for known time trends to be considered in price formation. It also allows for adjustment to future price paths based on the effects of various experimental scenarios. Since the cointegration literature has shown that a stable relationship between the two volatile price series can persist for over a decade, the approach used here could be useful in determining future price relationships under various user-defined scenarios of resource and technology availability.

This alternative method for pricing far into the future is also useful for firms that are contemplating the deployment of a new technology whose integration in the economy is uncertain. In traditional project valuation, firms assume prices that are chosen by the investigator to model potential profitability. Generally, in a sensitivity analysis, modelers simply individually calculate the prices of inputs and outputs that would reduce profits to zero. There is no mechanism by which prices can be affected by the industrial-scale growth of the new technology, nor any connection between the value of the input and the output. The method explored in this thesis allows for the growth of industry to influence the prices of the inputs and outputs of the project. It provides a price relationship that would be expected to prevail given current estimates of sectoral energy usage and technological availability. It would inform decision-making by adjusting costs and revenues based on the amount of industry-wide capacity likely to deploy over the project's economic lifetime. It also provides insight as to whether a project's profitability window is narrowing or widening over the project's lifetime.

This research is also relevant to policymakers. It enables analysis of the systemic effects of GTL deployment on emissions, fuel usage, and economic performance. It will provide evidence to suggest that GTL, at scale, would not be a useful technology for reducing pollutant emissions. This informs the argument on whether to trust in technological deployments alone to reduce overall emissions, or whether an emissions reduction policy is necessary to limit the emissions of heat-trapping gases and other pollutants. The results of this research provide strength to the latter option.

1.4 Structure of this dissertation

The remainder of this dissertation is organized as follows. Chapter 2 frames the problem in detail and discusses the approaches that have been applied across a handful of threads in the literature. Chapter 3 is a primer on GTL technology and its history, as well as an analysis of GTL economics. Chapter 4 discusses the methodology behind the model structure and the experimental design. Chapter 5 presents the experimental results. Chapter 6 concludes with a discussion of the results, along with potential policy prescriptions for various stakeholders.

Chapter 2

Theoretical Background and model selection

This chapter reviews the literature on commodity pricing relationships and technology modeling. It discusses the efforts to identify and characterize a relationship between crude oil and natural gas prices and how commodity prices are forecast. Then the focus shifts to approaches to the integration of new technologies into the economy so that systemic effects can be traced to shifts in the relative prices of crude oil and natural gas. The chapter ends with a discussion of specific modeling paradigms.

2.1 Energy pricing relationships and price formation literature

Academic research into the price relationship between crude oil and natural gas grew from efforts to improve industry rules of thumb that characterized stable relationships between the commodities. The rules of thumb were simple ratios to describe long-run pricing relationships between crude oil and natural gas – the 10-to-1 rule was a ratio of the crude oil price (in \$/bbl) to the natural gas price (in \$/mmBtu). It was a benchmark through the 1990s. The 6-to-1 rule gained traction in the 2000s, and it was based on the relative energy content of the fuels. Early research focused on downstream competition between the fuels, giving rise to the distillate and residual burner-tip parity rules. Each of these rules were accurate for certain periods of time. None of them were able to characterize the crude oil-natural gas price ratio consistently, so they were not reliable benchmarks.

2.1.1 Using cointegration to identify long-run crude oil-natural gas price relationships

There were two problems with the rules of thumb – even when they were accurate. One was that both crude oil and natural gas prices are volatile, and do not tend to return to a stable price. The drivers of volatility for each commodity are not identical, so most of the time the relationship did not exactly hold. The other problem was that the price of each commodity drifts over time. This makes identifying and characterizing a long-run relationship difficult. However, a statistical method has been developed to characterize a stable relationship between two non-stationary data series by accounting for the different sources of volatility between them. This development largely solved the first problem.

Cointegration is a statistical term to describe a stable relationship between two non-stationary data series. Energy prices over time are an example of non-stationary data series. Since prices drift according to supply and demand shifts, the averages of their time series are not stable. A mean of the series in one time window is not likely to be the same as one taken in another time window. This could be true even of overlapping time windows. However, if two (or more) data series are governed by a shared underlying causality, they can be related to one another through a stable relationship. Even though the data series are constantly moving, it is sometimes possible to identify a statistical *relationship between them* that is stable. A set of researchers have identified cointegrating relationships between crude oil (or petroleum products) and natural gas prices [172, 21, 73, 133].[1]

[1]Petroleum product prices are also cointegrated with crude oil prices, but this relationship is trivial: crude oil is the input to the production of all petroleum products. Price changes in crude oil are passed on to the products for which crude serves as a feedstock.

There are many reasons why crude oil and natural gas would exhibit similar price movements. Since both are fuel inputs to economic activity, both would react to an economic boom (in which demand for fuel inputs increases) by a rise in prices. Similarly, a recession would decrease demand for the fuels, and prices would be expected to follow. This should be true of all energy sources. The relationship between crude oil and natural gas is more clearly defined than a general directional movement. Short-term fluctuations in crude oil prices are followed closely by similar movements in natural gas prices (e.g., [172, 21]).

One possible explanation for this phenomenon is contractual arrangements. In Asia and Europe, natural gas is mostly imported. Gas prices are more volatile than crude oil prices on the spot markets [134], and natural gas importers are reluctant to take on the risk of a long-term delivery contract. As a result, in both Asia and Europe contract pricing provisions explicitly tie the price of natural gas to the price of crude oil. The importers receive the benefit of greater price stability.[2] Regions in which natural gas supply contracts are structured this way should have strong pricing correlations. Whether this is a cause or an effect of the contractual arrangements is difficult to determine.

In North America, crude oil and natural gas prices are strongly correlated even on the day-ahead ("spot") markets [172, 21]. Spot markets are where the marginal barrels of oil or Btus[3] of natural gas are bought and sold. There are no contractual pricing arrangements tying the fuels together, so there is no confusion as to the source of any measured relationship. Simple supply and demand pressures govern the settlement prices in spot markets. Because the transactions are short-term, the volatility in spot

[2] Crude oil prices are roughly half as volatile as natural gas prices [133]. There are many reasons why natural gas prices are more volatile than crude oil prices. Unlike crude oil, natural gas is traded regionally rather than globally, so natural gas prices are higher in the winter wherever natural gas is used for heating or power generation (in the latter case, to provide heat from electric heaters). Where natural gas is used for power generation there is also a smaller price increase in the summers in response to cooling demand to power air conditioners. Second, the fragmented nature of natural gas markets leads to more gluts or shortages than crude oil markets. These supply shocks translate to price swings. Crude oil does not face these pressures because the oil can be delivered wherever it is needed year-round.

[3] British thermal unit. It is the amount of energy needed to heat one pound of water by one degree Fahrenheit. It is approximately equivalent to 1,055 joules.

markets is higher than in the futures markets. Despite these features, natural gas and crude oil prices tend to move together in North American spot markets. There are a number of overlaps between the crude oil and natural gas industries, both in production and in consumption. For example:

1. Crude oil and natural gas are often discovered together. The natural gas is marketed it has market access. Thus an increase in crude oil production results in an increase in both crude oil and natural gas supplies. Increasing supplies (all else held equal) weakens prices. In this case, the pressures on crude oil and natural gas prices move in the same direction.

2. Crude oil and natural gas exploration use the same drilling rigs and labor. If the price of crude oil were to increase relative to the price of natural gas, crude oil explorers would be willing to pay more for drilling rigs, bidding them away from the natural gas explorers. As the rigs begin to produce crude oil, the increase in supply moderates crude oil prices. Eventually this makes natural gas relatively more expensive than before, pulling the prices closer together again. With time, the return on natural gas will be high enough that gas explorers will bid drilling rigs away from the crude oil explorers again.

3. Natural gas is a feedstock for petroleum refineries. It is also a feedstock to oil sands production and upgrading. Therefore, an increase in demand for petroleum products will increase demand for both crude oil and natural gas. The price pressures again move in the same direction for both commodities.

4. Some industrial machinery can switch between petroleum-based fuels – such as diesel or residual fuel oils – and natural gas. If the relative price of one commodity rises far enough above the others, these machines can switch to the relatively cheaper fuel. In the United States this flexibility has been decreasing since the 1970s. In other regions fuel substitutability may still be a significant factor. Since a drift in the relative prices from a prior relationship triggers the fuel switching, fuel substitutability tends to keep prices from drifting too far from one another.

5. In the power generation sector in many countries there are utilities with a portfolio of generators burning natural gas, diesel, residual fuel oil, or petroleum coke. Utilities dispatch the generator consuming the cheaper fuel. This decrease in demand for the more expensive fuel puts downward pressure on its price, pulling the commodity prices closer together again.

The cointegration models specifically control for the volatility in pricing. This is the key improvement that these types of models have made over the rules of thumb. The result is a much clearer picture of the true underlying relationship between the fuels. However, the problem of a potentially shifting price relationship is not yet settled.

Estimating cointegration

Cointegration models use a nested set of equations to evaluate multiple time series. One is an estimated long-run relationship between the fuels. The other is a vector autoregression (VAR) with an error correction mechanism (ECM) [172, 21, 133]. The ECM measures the rate at which one commodity "corrects" toward the long-run relationship. The rationale is that if a long-run relationship between the two time series exists, then there must be some rate of "correction" toward this relationship whenever the series diverge from it. The entire set of equations is called a vector error correction model (VECM). The first-step equations for a VECM comparison of crude oil and natural gas prices follow:

$$P_{gas,t} = \gamma + \beta P_{oil,t} + \mu_t \tag{2.1}$$

$$\Delta P_{gas,t} = a + \alpha(\mu_{t-1}) + \sum_{i=1}^{n} b_i \Delta P_{oil,t-i} + \sum_{i=1}^{n} c_i \Delta P_{gas,t-i} + \sum_{j=1}^{k} d_j X_{j,t} + \epsilon_t \tag{2.2}$$

$$\Delta P_{oil,t} = a + \alpha(\mu_{t-1}) + \sum_{i=1}^{n} b_i \Delta P_{oil,t-i} + \sum_{i=1}^{n} c_i \Delta P_{gas,t-i} + \sum_{j=1}^{k} d_j X_{j,t} + \epsilon_t \tag{2.3}$$

Equation 2.1 characterizes the long-run relationship between natural gas and crude oil. The natural gas price at time t, $P_{gas,t}$, is determined by an estimated constant γ and a multiplicative coefficient β (also estimated) on the crude oil price at time t, $P_{oil,t}$.

μ is the estimation error in time t, which is the residual after the estimated natural gas price is subtracted from the actual price. The β coefficient is the VECM equivalent of the ratio in the simplest rules of thumb. Equations 2.2 and 2.3 measure the *change* in price of natural gas and crude oil between each time period. a is an estimated constant. n is the number of lagged price changes to include for estimation. Each lagged price change included in the price change estimation ($\Delta P_{oil,t-i}$ or $\Delta P_{gas,t-i}$) is multiplied by an estimated coefficient (b_i for the crude oil price and c_i for the natural gas price). In order to account for some of the factors that drive the volatility in the natural gas price, k exogenous variables ($X_{j,t}$) are included in the regression. In the literature, these variables have included heating degree days (HDD), cooling degree days (CDD), deviations from normal HDD and CDD, and shut-in production statistics due to hurricanes or other natural disasters [21, 73, 133, 134].[4]

All of the variables in the price change equations account for the short-term volatility in the markets except one: α is an estimated coefficient multiplying the errors from the previous time period μ_{t-1}. The α coefficient is the error correction term. It measures the rate at which the commodity's price moves toward the long-run relationship whenever it deviates. Because α is a percentage of the deviation from the long-run price relationship, larger deviations result in larger corrections. When α is negative and statistically significant, the data series are considered cointegrated.

If cointegration is identified, the model can be refined. In the case of crude oil and natural gas cointegration, crude oil prices tend to move before natural gas prices. The error correction term in Equation 2.2 is negative and statistically significant, but the one in Equation 2.3 is positive and statistically insignificant. Because of this, cointegration models treat the crude oil price as the marker to which the natural gas price adjusts. Once this distinction is made, the model is simplified into a conditional error correction model (CECM) [172, 133, 134]. The CECM takes the long-run coin-

[4]HDD and CDD are measurements of the need for heating (HDD) or cooling (CDD) in a given day. Each is measured as the difference between 65°F and the average day's temperature. Heating degree days are the number of degrees that the average temperature is below 65°F. Cooling degree days are the number of degrees that the average temperature is above 65°F. The deviations from normal HDD and CDD capture unexpected cold snaps and heat waves, which are shocks to the market. Hurricanes or earthquakes that result in shut-in natural gas or crude oil production are also shocks that can be controlled for if included in the model as exogenous variables.

tegrating equation (Equation 2.1) as given, and applies the error correction term to the "dependent" variable.[5] The CECM is a simple VAR model:

$$\Delta P_{gas,t} \quad = \quad a + \alpha(\mu_{t-1}) + b\Delta P_{oil,t} + \sum_{i=1}^{n} c_i \Delta P_{gas,t-i} + \sum_{j=1}^{k} d_j X_{j,t} + \epsilon_t \qquad (2.4)$$

The error correction mechanism does not change in the CECM. The b coefficient is now only on the simultaneous price change in the crude oil price, but there are still n lags included for price changes in the natural gas price, and there are still k exogenous variables representing sources of natural gas price volatility included in the model.

Interpreting cointegrating relationships

VECM models feature three components. The central component is the estimation of a long-run relationship between the data series. The secondary component is a characterization of the volatility in the movements of each data series around the long-run relationship. The third is the ECM. Much of the last section focused on the latter two components. Filtering out the volatility is essential to discerning the longer-run movements. It was the main improvement over the rules of thumb, which in their most complex form resembled Equation 2.1 without any conditions or ECM. The VECM / CECM framework improved the accuracy of the estimated long-run relationship.

Filtering out the volatility left a more precise estimate of the long-run relationship. The stability of that relationship became another open question. The long-run relationship was initially considered constant. Ramberg and Parsons noted that some researchers included either a time trend for the natural gas price or a technology proxy in the form of the average heat rate of an electric generator over time [134, 172, 73]. This, in contrast to other models, suggested a continuously evolving long-run relationship. Ramberg and Parsons demonstrated that the long-run relationship appears

[5] In this case, the natural gas price is the "dependent" variable and the crude oil price is the "independent" variable. This is a mathematical term; the movement in the crude oil price does not actually *cause* the movement in the natural gas price. Crude oil prices happen to respond more rapidly to market signals that affect both commodities. From a statistical perspective, the crude oil price movements "cause" the natural gas price movements.

stable, but can shift over time to new equilibria [134, p. 33]. This new paradigm did not feature a gradually evolving relationship, but a stable relationship that occasionally jumps to a new level after a transition period. They identified a distinct high-gas price relationship beginning in 2006 that appeared to hold through 2009. Then the natural gas price collapsed. Ramberg and Parsons concluded that any relationship post-2009 had not lasted long enough for cointegration analysis to identify whether a third relationship had developed, or whether the commodity prices had de-linked [134]. They left open the possibility that what appeared to be shifts in stable equilibria could actually be a slowly-evolving relationship. Later researchers [98, 20] confirmed that a new long-run relationship had developed between crude oil and natural gas after 2010 – at least in the USA. The realignment was premised on the availability of natural gas from shale deposits using the hydraulic fracturing process. This brought the price of natural gas down relative to crude oil, and the commodities settled into a new stable price relationship.

Most researchers concluded that crude oil and natural gas prices were cointegrated. However, there were unresolved discrepancies that implied different paradigms. Villar and Joutz included a time trend in their model that made natural gas prices more expensive relative to crude oil over time [172]. Hartley, Medlock and Rosthal used a similar proxy tied to technology in the form of an average heat rate [73]. Even these papers assumed that technology was a major driver behind the competition between fuels that ultimately manifested as a cointegrating relationship. However, the models that included time trends implied that the relationship might be due to similar reactions in commodity supply and demand in response to universal economic conditions. For example, economic expansion increases demand for energy, putting upward pressure on all energy prices, and recessions do the opposite. Under these circumstances, the strength of the cointegrating relationship between crude oil and natural gas prices could be simply because they are the two most heavily traded commodities whose prices react quickest to changes in economic conditions. Bachmeier and Griffin were the most explicit in this view [12], but the models with the time trend/technology parameter also leave open this possibility [172, 73].

The problem is that the "long-run" relationship in the cointegration models (regardless of whether it is shifting or not) has only been demonstrated to hold for at most a decade. In the short run, prices correct toward this long-run relationship. Then the relationship weakens before prices settle into a new relationship. Over the longer run, the models that allowed for a drift in the price relationship implied that demand for each commodity grows at different rates, but that the difference is subtle. In the shorter run this would look much like a stable "long-run" relationship that shifts over time. If true, the crude oil-natural gas price relationship could be a spurious correlation, and the apparent "shifts" in the relationship could actually be dependent on the time window of the research focus. Only a study spanning a much-wider time frame would be able to resolve whether shifts in the long-run price relationship were continuously evolving or jumping between states (or both). In addition, the VECM is not an ideal model for testing whether the impacts of the integration of a technology in deployment affect the production or usage of natural gas, crude oil, or refined products.

Econometric analyses look backward to find relationships between variables. They are ill-suited to project forward any further than the number of lags included in the model. To do otherwise is to assume that past is prologue and that the drivers of the value of each variable are constant. Trying to determine whether the long-run price relationship will change going forward, and to which level, is not possible using this method.[6] Brigida [20] developed a model in which the price relationship reflects different "states". He constructed a Markov chain to switch between the states based on the historical probability that the crude oil-natural gas price relationship would be in that state. The problems with this approach are that (1) just because historically there have been two pricing relationships, it does not mean that there can/will only be two; (2) the probability of switching between the relationships was based on the historical probability that the states in fact switched. Again, the analysis is tied to

[6]Impending changes in the price relationship *can* be signaled in the data. The warning appears when the statistical significance of the cointegrating relationship weakens as the regression time window is extended. However, where the new relationship will settle, and whether the commodities will de-link completely, is not possible to determine before the new relationship has been established and has remained stable for a sufficient number of data points for it to appear statistically significant.

past data. The conditions are not guaranteed to hold into the future.

Most cointegration modelers mentioned key fundamental factors that drive the crude oil-natural gas price relationship. Among these factors are policies, infrastructure, and the equipment used by industries and end-users. Installed infrastructure and equipment are technologies. Technologies require energy inputs. The collective energy requirements of the technologies used in the economy determine the input mix of petroleum products and natural gas. This fuel mix in turn influences commodity prices. Wherever technologies can substitute between petroleum products and natural gas, or whenever users have a portfolio of technologies that can use either set of fuels to meet their needs, there is support for a stable pricing relationship between the fuel commodities. No econometric paper has yet examined how the adoption of a technology or set of technologies affects the pricing relationships between crude oil and natural gas.

The problem is that the effects of a gradually deploying technology are drowned out by stronger effects in empirical data. For example, combined-cycle natural gas (NGCC) power generators began to deploy in the US in the 1990s. By 2002, CCNG generators were routinely dispatched to meet peak demand. However, during the decade of NGCC generator penetration, a host of other events affected the price series that dwarfed the effects of NGCC's gradual penetration. The oil markets were roiled by the Asian Financial Crisis in 1997-1998. The oil exploration and refining industries were restructured by a wave of late-1990s-early-2000s mergers of international oil majors.[7] In 2000, the dot-com bust caused a recession that depressed oil and natural gas prices. Hurricanes in the Gulf of Mexico (e.g., Hurricane Andrew) shut in offshore natural gas production and caused massive but short-lived spikes in the natural gas price. Price spikes in natural gas in 2000-2001 were exacerbated by two dry but frigid winters (increasing heating demand, curtailing hydropower output and forcing NGCC units into the base load). The same year, natural gas pipeline owners colluded with energy trading floors to restrict the supply of natural gas to

[7]For example, Chevron and Texaco merged into ChevronTexaco, Conoco and Phillips 66 merged to form ConocoPhillips, Exxon and Mobil Oil merged into ExxonMobil, and BP and ARCO merged into BP.

the West through a few major southern pipelines. Natural gas prices reached their highest levels in history. As a result, the effect of the gradual integration of NGCC generators was drowned out by the “noise” – the volatility – in the crude oil and natural gas markets caused by less subtle factors.

Random[8] shocks affect commodity pricing more than the incremental penetration of a technology. To measure the effects of a technology deployment requires a model capable of replicating the underlying supply and demand structures of the crude oil and natural gas markets without shocks. Then the shifting fuel consumption patterns of consumers and producers in response to changes in supply and demand can be modeled. This model could characterize shifts in the long-run crude oil-natural gas pricing relationship. Modeling a long-run commodity pricing relationship into the future may be more valuable than a simple price forecast. The cointegration literature has demonstrated that although prices themselves are volatile and unpredictable, the long-run price relationship can be very stable, lasting over a decade.

Section 3.3 describes the Discounted Cash Flow (DCF) model, which is a fundamental tool for technology feasibility analysis. It is inadequate to this task. DCF models used by entrepreneurs to evaluate technologies estimate project costs. However, markets are characterized through exogenously-imposed scenarios. These scenarios are generated based on intuition and history. The effects of technology deployment on the market prices of its inputs and outputs is beyond the scope of a DCF model. A model setting a wider system boundary is required.

2.1.2 Perspectives on fossil fuel price analyses

Section 2.1.1 discussed pricing relationships between energy commodities. Researchers postulated that the price relationships and the strength of those relationships arose from the capacity of energy consumers to substitute among energy input options. However, research on commodity price determinants has tended to focus on macroeconomic factors such as interest rates, inflation, export or import policies, exchange rates, etc. [90, 143, 17]. Some models include commodity stock levels. A focus

[8] “Stochastic”

on interest and exchange rates is an implicit acceptance of Hotelling's principles for exhaustible resources [75]. These studies use a variant of Hotelling's construct to measure the evolution of a price, p, over time according to the interest rate, γ: $p = p_0 e^{\gamma t}$. In each case, the initial price, p_0, is given. Some models also incorporate Hubbert's logistic curve [76]. The economic activities that generate the initial price are unexplored. Some acknowledge that structural factors are important, but are difficult to forecast. They rely on the statistical decomposition of price evolution in a time series [127]. Pindyck's paper models energy prices as volatility around a stochastic time trend using a Kalman filter to predict prices far into the future. He uses no data simulating the physical bases for energy commodity price formulation (e.g., sectoral demand, income, production and inventories).

Supply-demand models are another broad approach to evaluate price formation. They focus on a structural representation of the economic system in a closed model. Where physical determinants are estimated, aggregated data are used. Chevillon and Rifflart examined oil prices as a function of inventories and the exercise of OPEC market power [29]. They used a "real" oil price in each country,[9] crude oil demand by region, OPEC production quotas, and crude stocks in their model. They did not examine sectoral usage of oil-derived products. Dees *et al.* modeled oil prices as an interaction between price- and GDP-driven demand and a supply curve that integrates OPEC's non-competitive behavior [42]. They account for supply shocks such as the First Persian Gulf war [42, p. 9], but do not account for substitutability between oil and other fuels, nor do they focus on sector-specific demand for refined fuels [42, p. 4]. Their model was an error-correction model, but they examined cointegration between crude oil prices and GDP instead of other commodity prices. Dees *et al.* did not simulate oil prices into the future. They lacked a method of generating a forward series of GDP values.

A shortcoming of the supply-demand models is that the demand curves are based on the price and income elasticities of demand. Estimates of these are inconsistent. Fattouh documents a range for short- and long-run price elasticity of crude oil demand

[9]The real oil price was calculated by dividing the nominal crude price by a GDP deflator.

of 0 to -0.64 across multiple papers [50, p. 10]. The range of income elasticity of oil demand is from 0.4 to 1.4 [50, p. 12]. Gately and Huntington claimed to discover asymmetry in both price and income elasticity of demand for oil: the response to an increase in price was more dramatic than a response to a decrease in price, and in some countries, demand responded more dramatically to increases in income than to decreases [55]. The implication was that failure to account for this asymmetry depressed forecast estimates of oil (and energy) demand. Their demand model was based on income and the price of crude oil in each country, along with prior demand. Griffin and Schulman posited that this perceived asymmetry in demand response to price was in reality the result of a shift in capital stock to more energy-efficient technologies [63]. The problem was that "...absence of detailed capital stock data for energy-using equipment preclude estimating..." a structural econometric model that controls for shifts in technological energy efficiency – say, increases in vehicle MPG [63, p. 5]. The problem with the Gately/Huntington model is that the asymmetry in demand is equivalent to an inward shift in the demand curve. The latter is due to the adoption of more energy-efficient technologies when energy prices rise. Using price or income elasticities of demand for model structure depends on prior assumptions about the structure of the market. Using a forward-looking model driven by demand elasticity of income and price assumes this market structure will be constant.

Some supply-demand models explicitly account for substitution among inputs and an economy's adaptation to changing prices. Energy commodity prices are determined by relative energy usage, but relative energy usage is influenced by price. These papers examine the latter phenomenon. Ma *et al.* econometrically measured Chinese flexibility to changes in energy prices by backing out elasticities of inter-factor and inter-fuel substitution [100]. Wachsmann *et al.*'s study on the Brazilian economy from the 1970's through 1995 addressed how changes in energy consumption translated to prices [173]. An input-output table decomposed the determinants of energy demand by sector. Wachsmann *et al.* aggregated all energy sources, and focused on shifts in overall energy usage and the energy intensity of industries. Neither model focused on the formation of the prices themselves.

To resolve the Gately/Huntington-Griffin/Schulman controversy requires a model that (1) accounts for GDP by its sectoral components, and (2) explicitly tracks the deployment of technologies. Furthermore, as Fattouh noted, these models treat GDP and oil prices separately, despite evidence that there is mutual influence between both variables [50, p. 14]. High GDP growth can provoke higher oil prices, and an oil price spike can retard growth. This interaction has not been disentangled using econometric methods. Nor are the econometric techniques dependable for simulating these interactions into the future, for they are calibrated to historical data.

2.2 Purposes of various economic models

This section seeks a method to model how a conversion technology's deployment affects energy usage, and, through that mechanism, pricing relationships. Such a model must track the sectoral energy usage that drives price changes. The price changes cause shifts in energy price relationships. First a framework is developed to identify the important model components and interactions. Later, specific models that examine technological change and its effects are explored.

2.2.1 The Fossil Fuels Complex from a systems perspective

The industries that extract, refine, deliver, and use fossil fuels are more than a collection of technologies. World culture has adapted to the use of these fuels, and most technologies at every level are at least indirectly powered through fossil fuel combustion. The processes, from fossil fuel extraction to the end uses of their derivative products, are each individually complex systems that I will collectively label the Fossil Fuels Complex. Some argue for policies restricting the operation of the Fossil Fuels Complex to reduce environmental damage. However, changing how the Fossil Fuels Complex operates involves more than replacing technologies – to curtail emissions, consumer behaviors must shift so that less fossil fuels are consumed. Lastly, the Fossil Fuels Complex delivers the energy that enables nearly all activity on the planet: without fossil fuels, travel and trade on the scale currently enjoyed would be impossible. There would be shortages of electricity even for vital services such as hospitals and communication. The world would no longer function in a recognizable way. It is because the Fossil Fuels Complex is so intertwined with all other activities that a systems approach is necessary to identify an appropriate method for analyzing the questions raised in this research.

This dissertation seeks to analyze the economic effects of an energy conversion technology's deployment so that shifts in pricing relationships between fossil fuels can be measured. That these changes must be traced back to shifts in fuel usage among energy-consuming sectors. To identify an appropriate method for analyzing these impacts, the relevant system boundaries and important interactions must be defined.

Paradigms for complex sociotechnical system analysis: CLIOS and systems-of-systems

Modern methods of system characterization recognize that complex systems are multidimensional. Systems have both boundaries and hierarchies. The system boundary can be compared to the two-dimensional area on a map. The system hierarchy is akin to altitude [41]. From a high altitude, only the most prominent features of a landscape are visible. For example, one cannot easily track individual automobiles from a high altitude, but identifying traffic jams is easy. The movement of the individual automobile is an element of the larger system of traffic. The observer at high altitude can perceive systemic events (like traffic jams) much more easily than the individual decisions of elements in the system (choice of route given the roads available). In other words, at different levels of the hierarchy, there are different input and output variables available. The higher the level of the hierarchy, the more aggregated the data. For example, in the cointegration literature, the system boundary is an entire national commodity market. The prices are the outcomes of millions of individual decisions about consumption made by all who use natural gas, crude oil, or petroleum products. The cointegration model sits at the highest level of the Fossil Fuels Complex hierarchy. The individual decisions that determine prices cannot be analyzed by the cointegration researchers – despite the fact that predicting long-run pricing relationships requires information about how the prices of commodities are generated.

Two common paradigms for complex system analysis are the CLIOS process and systems-of-systems [101, 163]. Both consider system boundaries and hierarchies, and there is considerable overlap in their characterization of complex sociotechnical systems. CLIOS is an acronym for Complex Large-scale Interconnected Open Sociotechnical [163, p. 4]. The method was devised to characterize a complex sociotechnical system (a CLIOS system) and identify a methodology to examine the elements that are relevant to research questions. While the CLIOS process is a system analysis and management tool, it characterizes the system under study. This makes decisions regarding *how* to analyze or evaluate such systems much easier.[10] This dissertation utilizes the Representation phase of the CLIOS process in order to sketch out the system that produces the pricing relationships discussed in Section 2.1.1. The first step in using CLIOS is to draw and then describe a diagram of the system of interest. Figure 2-1 depicts a static view of the Fossil Fuels Complex, including nodes of activity, hierarchy, physical/value flows of product, and flows of information. To simplify, a time dimension is omitted.

Figure 2-1 organizes the Fossil Fuels Complex hierarchically. At the top level are the markets. Below the markets is the Exploration/Refining level. Transportation is below Exploration/Refining, but in reality it is a go-between. It links elements in Exploration/Refining with each other as well as between the Exploration/Refining level and the Intermediate level of the hierarchy. Transportation also links elements in the Intermediate level with each other. At the bottom of the hierarchy is the End Use level, which is exclusively served by the Retail sector of the Intermediate level. I discuss each level of the hierarchy and its elements in greater detail below.

The commodity markets in the Fossil Fuels Complex are for coal, crude oil, petroleum ("refined") products and natural gas. Each has its own node. The dotted lines linking each of the market nodes represent information flows. The column

[10] The CLIOS process was originally designed to change or re-design the system of interest. This dissertation uses the CLIOS process for system identification and boundary-setting so that the problem can be analyzed appropriately.

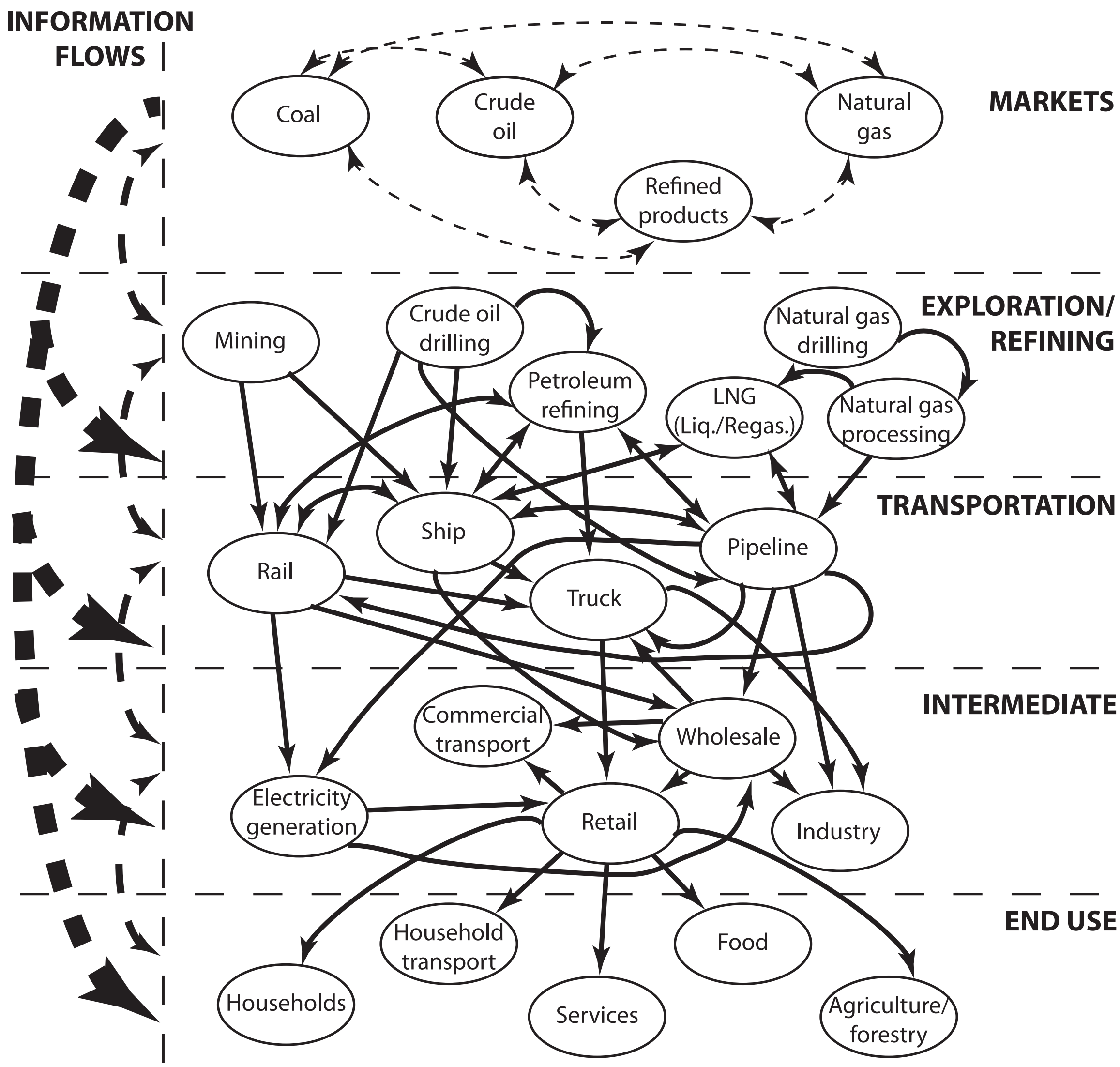

Figure 2-1: The Fossil Fuels Complex

labeled "INFORMATION FLOWS" to the left depicts the flow of information from the Markets level to each of the other levels of the Fossil Fuels Complex hierarchy. Information is passed between each level in both directions: down to the End Use level and up to Markets. Each information linkage upward is cumulative; information reaching the Markets level is the accumulated information from End Use, Intermediate, Transportation, and Exploration/Refining. The totality of available information on supply, demand, logistics, sales, prices and shocks is the foundation of the commodity market prices.

In reality, there are multiple commodity markets, even for the same commodity. There are physical markets and financial markets for each, as well as markets for short-term and long-term delivery of each commodity, both in the physical and financial senses. Furthermore, there are multiple sub-markets within the Refined products node. There are hundreds of outputs from oil refineries. The most common grades of the most common fuels have their own markets: gasolines, diesels and distillate fuel oils, residual fuel oils, and petrochemical feedstocks all trade in both spot and futures markets. To simplify the Fossil Fuels Complex, they have been aggregated into the "Refined products" node in the Markets level of the hierarchy. Similarly, they have been aggregated into "Petroleum refining" in the Exploration/Refining level.

Production of fossil fuels occurs in the Exploration/Refining level. Taking pricing cues from the Markets and demand information from the Intermediate and End Use levels, the sectors in Exploration/Refining extract fossil fuels and transform them (if necessary) into usable products. Mining covers the exploration and production of coal, which is then shipped by Rail or Ship (or Truck) to the Electricity Generation and Industry sectors in the Intermediate level. In some regions, Coal is consumed in the End Use level. Crude oil drilling extracts petroleum, where it is then transferred to Petroleum refining either directly, or by Pipeline, Ship or Rail. Crude oil may also be exported by Pipeline, Ship or Rail. The Petroleum refining sector sends its output of refined petroleum products[11] by Pipeline, Rail, Ship or Truck to Electricity Generation, Wholesalers, or Industry in the Intermediate level of the hierarchy. The natural gas value chain begins with Natural gas drilling. Raw natural gas is processed before being sent to either a Pipeline (where it will eventually find its way into Electricity generation, Industry, an LNG plant or a Wholesaler[12]) or directly to an on-site LNG terminal, where it will be exported by Ship.

The Transportation level contains the modes of transporting fossil fuels from producers to end users. These are Rail, Ship, Truck, and Pipeline. The transport

[11]These include products like gasoline, diesel, refinery gases (such as propane or butane), petrochemical feedstocks (like naphtha, waxes, or lubricants), heavy distillate and residual fuel oils, and petroleum coke.

[12]In the case of natural gas, a wholesaler is the regional gas utility.

sectors link elements of Exploration/Refining with each other, and also link Exploration/Refining with sectors in the Intermediate level. The transport modes also link sectors within the Intermediate level. Transportation does not modify the product. It adds costs as the product is moved from one node of the Fossil Fuels Complex to another, and leaves product characteristics unchanged.

Fossil fuel products reach the Intermediate level sectors in their final, usable form. The Intermediate sectors use fossil fuels to produce goods, services, or electricity. Energy products flow from Wholesalers to Retailers, where they are distributed to End Use sectors. However, heavy industry and other large-scale users can be supplied directly from Wholesalers. In Industry, Wholesalers are sometimes bypassed where factories are adjacent to major natural gas or petroleum product pipelines.

The bottom of the hierarchy is the End Use level. End Use sectors consume energy at retail prices and quantities. The End Use level includes Households, Services, Food, and Agriculture/forestry. This classification is solely from the perspective of the Fossil Fuels Complex, because these sectors neither transform nor re-distribute fossil fuels onward to other sectors.[13] Sectors in the End Use category influence upstream activities through changes in fuel consumption – either through efficiency measures or fuel substitution. Fuel substitution either changes the fuel used or allows for fuels to be substituted in plant or equipment. The decision to substitute fuels is based on the relative prices of the fuels that new equipment would use in operation. If capital costs are equal, the equipment with the cheapest fuel will be selected. The investment in and depreciation of capital is a part of a time dimension that is not depicted in Figure 2-1. The Industry and Commercial transport sectors in the Intermediate level have the same influence, but they are also large enough to directly negotiate changes in the production and distribution-related sectors.

To address the questions posed in Section 2.1.1, most of the elements in Figure 2-1 need to be retained. Transportation can be simplified. As long as the costs of transport are represented, the mode is not important. The Transportation level

[13] In standard economic modeling the only end-use sectors are households: Households and Household transport in Figure 2-1. This distinction will be important as modeling options are explored later.

elements can be merged into a single "Transport" sector.

This dissertation compares the economy under the Fossil Fuels Complex in Figure 2-1 to the economy when GTL is deployed at the Exploration/Refining level of the hierarchy. GTL is chosen for two reasons: first, it creates an explicit upstream linkage between the crude oil/petroleum refining sectors and the natural gas drilling/processing sectors; second, the upstream shifts in supply and demand balances of fuels should affect prices, which provokes adjustments in energy consumption by downstream sectors. The downstream adjustments likewise affect prices. The change in the price relationship between crude oil and natural gas could then be measured, as well as the degree to which each sector altered its energy usage. There are thus two components to the final price shift: an upstream component that affects the supply and demand of natural gas, crude oil, and petroleum products directly, and a downstream component that reflects the cost-minimizing adaptation by sectors to the changing price relationship. Both components affect the price relationships between the fuels.

Figure 2-2 depicts the Fossil Fuels Complex as modified to address my research questions. The changes are in boldface and highlighted in gray. GTL technology is added to the Exploration/Refining level. Its feedstock is sourced either directly from the wellhead, after processing, or from an LNG plant (both of the latter of which may be through pipeline deliveries). The transport sectors (including Commercial transport from the Intermediate level) are merged to a single sector in the Transportation level. This simplification omits tracking of the logistics of trade, and still allows for changes in energy usage and emissions within the Transportation sector to be measured.

The CLIOS process allows for the elements depicted in Figure 2-2 to be conceptualized as systems and sub-systems of the larger, overall economy. Each sector itself could be broken down into its own system, with arrows showing one- and two-way interactions with other systems. This type of conceptualization is the system-of-systems approach, which shares features with the CLIOS process.

The Fossil Fuels Complex fits Maier's two criteria for a system-of-systems. The

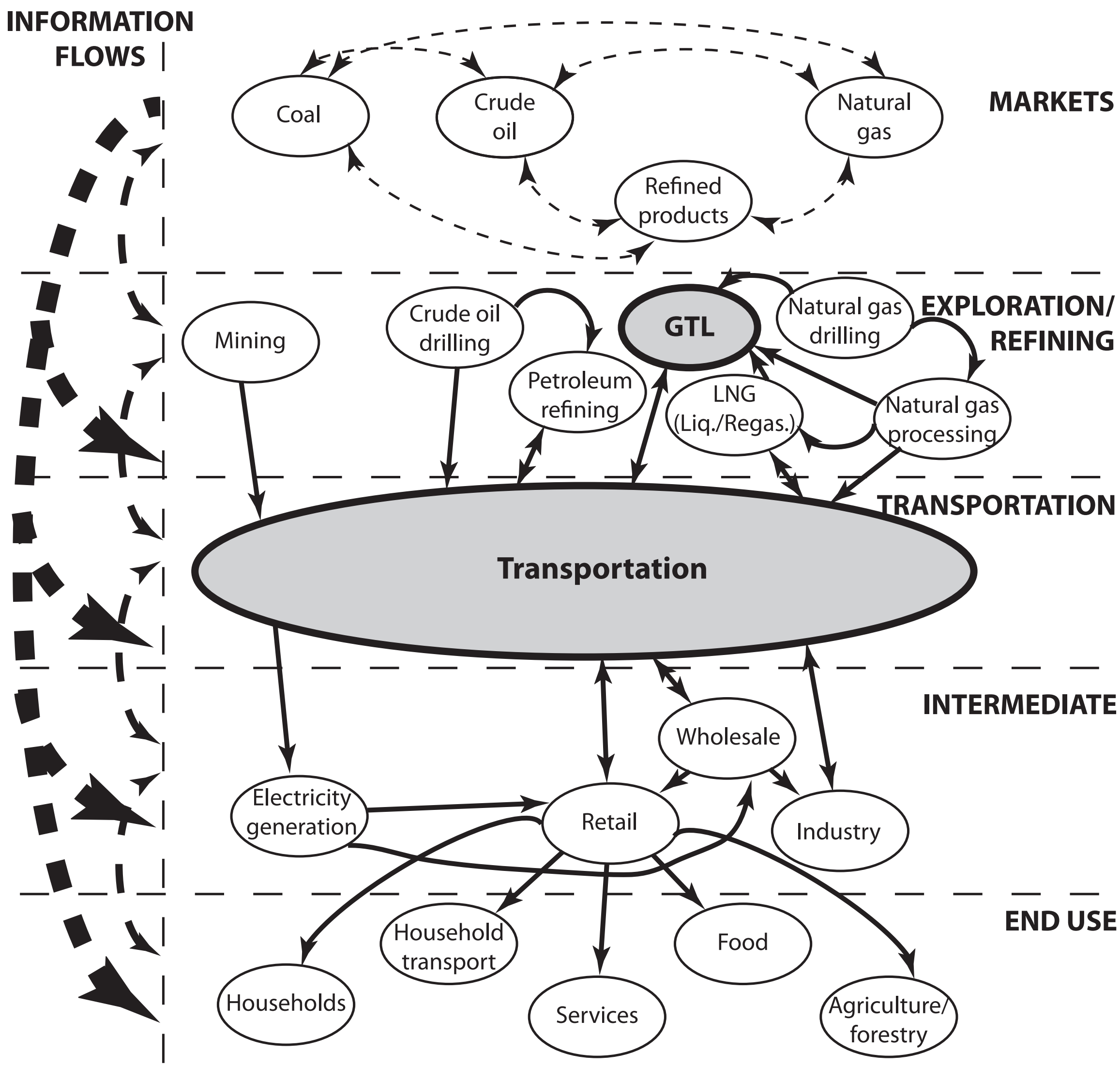

Figure 2-2: The Fossil Fuels Complex - Simplified

first is the "operational independence of the components" [101, p. 271]: each node in Figures 2-1 and 2-2 are complex systems that operate independently of one another and the larger economic system into which they are integrated. The second criterion is "managerial independence of the components" [101, p. 271]. Each node is independently operated, and competition exists within each sector in the Fossil Fuels Complex diagrams. The Fossil Fuels Complex features other aspects of the system-of-systems architecture: companies operating within each sector enter and exit the marketplace without damaging the larger system, there is "leverage" at the interfaces (e.g., the Transportation linkage from producers to consumers is both vulnerable and powerful), and the incentives for collaboration (i.e., profit motive) are built into the system to ensure that the it continues to operate [101, p. 273]. This dissertation treats sectors as their own sub-systems within the larger system in order to track how they shift their energy usage and emissions patterns.

The hypothesis in Chapter 1 relates to the *changes* in the Fossil Fuels Complex after GTL technology is introduced into the system. GTL outputs of diesel and petrochemical feedstocks change the supply balances of fuels and their relative availability. Sectors that use fossil fuels may change their consumption patterns, affecting the demand balance. The interplay of shifting supply and demand changes the relative prices of the fuels. Sectoral fuel consumption patterns are governed by price signals, and energy consumption is a driver of prices. The idea is to utilize a method that will be able to account for these changes as they are traced through the system in Figure 2-2.

2.2.2 Modeling technologies in the economy

A variety of approaches examine the causes of technological penetration and the influence that technologies have on the economy. This section reviews the literature.

The effect of technological change on economic growth

Robert Solow represented the technological contribution to economic growth in 1956 [158]. Solow posited an extension to the Harrod-Dumar model of economic output[14] – an exogenous multiplier representing technological growth across all sectors of the

[14] Solow's contention with the Harrod-Dumar model was its assumption of fixed proportions of capital and labor. Solow argued that there should be substitutability between the two factors of production so an equilibrium could be found even if the growth rates of each deviated from the fixed proportions posited by Harrod-Dumar. In 1958 Robert Eisner [46] claimed that the Harrod-Dumar model *could* adapt to shifting proportions of capital and labor and still find equilibrium. However, Solow's critique that the model did not explicitly account for substitutability was valid.

economy:[15]

$$Y = A(t)F(K, L)$$

Economic output (Y) is a function ($F(\cdot)$) of capital (K) and labor (L) multiplied by Solow's coefficient of technological improvement at time t ($A(t)$). Solow had observed that output increased over time even when inputs of capital and labor remained fixed. This "residual" was an improvement in productivity due to technological changes in capital. Kaldor characterized technological progress as a function of the change in output from one year to the next[16] less the contribution of the growth of the labor pool [89]. Kaldor only identified the *effect* of the "technological progress" variable. Like Solow's $A(t)$, it was parameterized exogenously by the modeler. For Kaldor the decision to employ capital depended on the costs of the options available to the entrepreneur (including increasing labor input) [89, p. 602]. It followed that although the rate of progress was exogenous, the improvement could only be realized if the investment was made.

The idea that technological change accrued to the economy in the aggregate became the standard. The assumption was that productivity increases were due to improvements in technology. In 1962, Kenneth Arrow postulated that Solow's technological improvement term $A(t)$ was due to the accumulation of experience in the workforce [7]. This was the "learning-by-doing" (LBD) model for economic growth. Arrow used cumulative historical investment to endogenize the rate of technological improvement. New capital would be an improvement over previous capital because of the ever-growing ability of the national workforce. Previous investment in new capital in turn resulted in workers with superior abilities, which in turn resulted in greater overall productivity. Shell hypothesized that active investment programs in research and development (R&D) would increase the rate of technological change [155]. Since

[15] Solow assumed that every sector and every actor benefits equally from the technological growth.

[16] The change in output from one year to the next was defined as a function of the investment/capital ratio.

technological improvement is available to everyone once implemented, there is no incentive (beyond the patent system in limited cases) to invest in the R&D necessary to produce the new technology. The benefits would be diffuse, but the costs would be concentrated. Shell's solution was for a government tax that was re-invested directly into R&D to correct the market imperfection.

Cass tied the source of additional *investment* in capital to the savings model developed by Ramsey [25, 135]. This was an effort to endogenize improvements in capital performance through additional investment by treating savings as a factor that could be incentivized by policymakers to achieve an "optimal" growth path [25]. In 1967, Jorgenson and Griliches hypothesized that the "growth" in total factor productivity[17] is negligible "...if real product and factor input are accurately accounted for...." [88, p. 250]. Their assumption was that measurement errors in inputs and/or outputs were generating the majority of Solow's "residual".[18] The authors utilized social accounting and production theory methods to narrow the gap to up to about 95% of the original residual, depending on the time period they studied. Their central argument was that the "technological improvement" that appeared as an inexplicable increase in factor productivity could actually be accounted for if careful measurement of inputs and outputs under constant prices were made.

In contrast, Abramovitz found that output expanded more rapidly than inputs of either labor or capital during the "long swings"[19] and implied that some other factor increased productivity [2]. He did not attribute this residual to technology, however.[20] Parvin addressed this issue in 1975 by examining the "residual" in countries that were clearly not the original developers of the technology they adopted [124]. He identified the cost of technological progress by finding a greater productivity increase in the countries that adopted technologies than in the countries that invented them. The

[17] Solow's "residual".

[18] Solow's residual was interpreted as learning-by-doing or technological improvement in the literature up to that point.

[19] The long swings were decadal growth periods in the business cycle.

[20] The Abramovitz "long swing" problem was documented in the Jorgenson and Griliches paper. They noted that for certain periods their accounting method could only account for about 73% of the growth in output, and also pointed out that depending on which section of the business cycle the data set fell into, productivity could appear to be either increasing or decreasing [88].

former did not have to incur the costs of development.

In 1992, Mankiw, Romer and Weil augmented Solow's original capital-labor production function with a "human capital" factor that could also receive investment [102]. They econometrically tested the central conclusions of Solow's theoretical model: that savings is positively correlated, and population growth is negatively correlated, with the income growth rate. Their conclusion supported the Solow paradigm in a cross-country comparison. Their model accounted for about 80% of the cross-country income variations [102, p. 408]. Mankiw *et al.* frame their paper as a defense of the Solow "exogenous growth" model against those who endogenized economic growth: the reasons growth models fit better with exogenous parameterization is that the data no not include country-specific tax and education policies, political stability, and family size [102, p. 433]. Islam followed up by expanding the cross-country analysis into a full panel regression. He found that the $A(t)$ of Solow ($A(0)$ in Mankiw *et al.*) corresponded to actual country-level differences in institutions or culture that moderated their growth rates [85].

By the 1990s, a consensus had formed. First, technologies are instructions for manipulating raw materials in order to produce a good. It is based on three premises, expressed by Romer:

1. "[T]echnological change... lies at the heart of economic growth... [It] provides the incentive for continued capital accumulation, and together, capital accumulation and technological change account for much of the increase in output per hour worked." [140, p. S72]

2. "[T]echnological change arises in large part because of intentional actions taken by people who respond to market incentives." [140, p. S72]

3. Technologies "... are inherently different from other economic goods. Once the cost of creating a new set of instructions has been incurred, the instructions can be used over and over again at no additional cost. Developing new and better instructions is equivalent to incurring a fixed cost." [140, p. S72]

Under these premises, only a model including monopolistic behavior (i.e., market power) could explain the investment in growth: if the benefit of technology is non-rival and non-excludable, then there is no return on the R&D investment. Without the return on the investment, no entrepreneur invests.[21] Romer modeled a multi-sector economy, each sector with a single monopolistic firm that received economic rents due to infinitely lived patents. Producers purchased intermediate goods from the monopolists to make consumer goods. Capital grew by output less consumption. The knowledge stock (Arrow's LBD parameter $\dot{A}$) grew as a function of the number of researchers (H_A), the existing knowledge stock (A), and a productivity parameter (δ): $\dot{A} = \delta H_A A$. Romer's focus had moved from the *effect* of technological change on the economy to its *causes*.

De Long counter-argued that simple investment in machinery was at least as important as investment in human capital, if not more so [40]. However, De Long admitted that in order to utilize new technologies – particularly imported ones – at least a portion of the labor force who were familiar with how to operate the new machinery also had to be imported [40, p. 30-31]. Both human capital and investment in new machinery were necessary, but human capital investment alone could not increase the growth rate.

In the discussion to Jorgenson's 1995 paper on technology in growth theory, Gene Grossman summarized growth theory research: first, there are decreasing returns to scale on investment in capital and labor, so if the growth rate is increasing, technological progress must have some influence [87, p. 83]. Second, the "growth accounting" approach to growth theory is just that – accounting. Just because growth accounting can point to an increase inputs to production does not explain *why* that input increased, or whether it would under alternative circumstances [87, p. 84]. He makes the same claim about investments: it is more useful to understand what prompted the investment than to note that after it occurs, productivity increases. For Grossman, endogenous growth is not growth that can be accounted for from social accounts but

[21] Griliches addressed this problem by dividing technological "knowledge" into excludable and non-excludable portions [64].

"... growth that can be traced to its fundamental economic determinants." [87, p. 85].

Takeaways from the technological change literature

Solow and Kaldor measured the effects of technological change on the economy to explain why economies grew faster than the rates of their inputs of capital and labor. These models also determined the demographic factors (population growth, wealth) that were relevant to growth rates, and their influence. Later researchers endogenized the technological change parameters affecting performance. Each modification to the original model better accounted for aspects of the accumulation of technical knowledge in the economy. The focus of each was to explain previously unaccounted-for changes in economic performance. The potential impacts of different *kinds* of technologies on different sectors of the economy or different regions was unexplored, even though it is a question that could have arisen from the Solow and Kaldor modifications to the Harrod-Dumar models.

The "accountant" branch of the technological change literature still aggregates technological change across all technologies, with investments occurring in response to market incentives. These incentives are the cost of new technologies, the costs of the inputs to the novel production processes, and the value of outputs. It lacks a set of insights about how technological development influences the pricing relationship between inputs and outputs over the lifetime of large-scale capital-intensive projects. It does not examine how individual technologies get deployed and their individual effects on economic growth, nor does it focus on how a new technology changes the economic *structure* of the economy into which it is introduced. The data used by the accountants are too aggregated to provide these insights.

The system boundary of the problem the "accountants" study encompasses the entire economy, but their research is conducted at a high altitude within that system boundary. More detail is necessary to measure the impacts of a single technology on economic development and productivity. The models used by the accounting technologists do not capture the activity in lower levels of the hierarchy they study, nor do they account for the interactions of sub-systems within their system of interest.

Technological innovation

Other researchers focused on *how* technologies get adopted. Some examine the mechanism by which innovations are diffused. Others examine whether the complexity of the technology impacts its adoption rate. None explicitly examine how the markets or overall economy change as the innovations are adopted. This is a brief overview.

Cowan employed an either-or model of technology adoption (similar to a game theory setup) to examine why some technologies become the standard while others fail. The "superior" technology did not always become the standard [38]. He recommended policy intervention at the point that a technological breakthrough occurs, so that the most beneficial technology could be adopted as the standard rather than the first-mover or the one with the most financial support.

The diffusion of innovations literature examines human interactions as a route to technological penetration. These studies focus on how to speed diffusion of potentially life-saving technologies (e.g., water purification systems) in societies that are not culturally predisposed to accept change. Rogers hinges the diffusion of innovation on four characteristics of the technology or the society into which the technology is adopted: the innovation itself, communication channels, time, and the social system [139]. Of these, only the innovation element corresponds to the technology's characteristics. The rest is dependent on the social structure of the culture. This dissertation examines an upstream technology for which little of the consumer-goods focus of Rogers' research applies.

Another branch of innovation literature focuses on the characteristics of the technology itself. McNerney *et al.* examined how the design complexity of a technology affects future cost reductions [107]. Design complexity is defined as the interdependency of components. Through random technology characteristics, the researchers produced a downward-sloping power curve for technology cost reduction. The implication is that the simpler, cheaper options are more likely to become economic sooner, and thus be adopted. It confirms a central tenet of economics: that in the aggregate, consumers will gravitate toward the lowest-cost option that provides the desired results. As a framework to analyze the larger questions of this dissertation, the abilities of this methodology do not align well with the hypothesis testing needed. Their findings also contradict Cowan.

The following section will examine complex approaches to answering questions surrounding technological adoption and its effects on economic performance. These are almost always economic simulations of full economies at varying degrees of disaggregation, or of a subset of economic sectors that act within a larger, exogenously imposed economy.

Modeling technologies within entire sectors or economies

Mensch, Haag and Widlich explored the investment side of the accountants' technological modeling by breaking investors into classes based upon their behaviors and preferences in a "post-Schumpeterian" model. They developed a model linking the macro- to the micro-focused models in which investors employed distinct strategies. The interplay of these strategies influenced the direction and magnitude of investments in the economy. A mix of investments of varying levels of success and impact constitute aggregate investment, depending on the risk and reward preferences and perceptions of the investors [108]. Coricelli *et al.* discussed how to tie in microeconomic processes to the macroeconomic data used by the technological change "accountants". He generated macroeconomic data by modeling microeconomic processes [36]. These early explorations in microeconomic modeling were short steps from thought experiments. They were driven by heuristics and logic, and yielded useful insights. These papers were attempting to settle a problem with the econometric analyses of macroeconomic data: the inability to provide predictive power or insights as to the actual mechanisms that generate their source data in the first place. They were laying the groundwork for more ambitious efforts.

Bottom-up vs. top-down modeling

There are two principal classes of model that include specific technologies and examine their performance in the economy: bottom-up and top-down. A bottom-up model uses detailed technical data about each technology to be modeled. Component costs are accounted for, and a palette of technological options is produced. Because of their wealth of detail, bottom-up models tend to focus on specific economic sectors. Activities outside of the sector of focus are either held constant (meaning that they cannot affect the sector of focus) or their effects are imposed exogenously (as were prices in discounted cash flow (DCF) models). The objective function in a bottom-up model tends to minimize costs. The lowest-cost technologically feasible technologies tend to be deployed. Top-down models, on the other hand, tend to model interactions between economic sectors within and between global economies. They use detailed models of sectoral activity and interactions between markets and sectors in terms of value and/or volume flows. Markets and consumer preferences, rather than cost, drive the results of top-down models. Any activity undertaken in a given sector impacts the activities of other sectors due to a competition for factors of production.[22] Activities in other sectors collectively form the economic environment in the sector of interest. Sectoral interactions are endogenous in top-down models. The trade-off is a sacrifice in the richness of technological detail. Often this is a small sacrifice. The impacts of the market tend to outweigh the small difference increased technological cost accuracy would have on overall economic performance.

The MARKet ALlocation (MARKAL) model was created by Brookhaven National Lab in the 1970s. It is one of the earliest bottom-up models for technological analysis. The International Energy Agency (IEA) further developed the MARKAL model in its Energy Technology and Systems Analysis Program (ETSAP) [170]. MARKAL employs linear and mixed integer programming to determine the lowest-cost technology mix that meets energy demand given a set of user-defined constraints. These constraints can include the supplies of natural resources, the level of energy demand in the region(s) of analysis, and carbon emission caps. Each technology includes fixed and variable costs, an emissions profile, an efficiency, and its regional availability [1, 137, 52]. Income and energy demand are exogenous, and technological devel-

[22]Factors of production are inputs to the activities in a given sector of the economy. The most commonly modeled factors of production are capital and labor, but energy, land, materials, and/or a host of other factors could also be modeled.

opment and deployment cannot affect economic performance or energy demand in MARKAL [137]. The U.S. Department of Energy's Energy Information Administration (EIA) also uses MARKAL for its System for Analysis of Global Energy Markets (SAGE) model. SAGE is used to produce the EIA's International Energy Outlook.

The MESSAGE model is another early version of a detailed bottom-up model for technology analysis. Developed in the early 1980s, MESSAGE is a dynamic linear programming model that calculates the least-cost technology mix for supplying energy demand in various sectors [150]. The information about each technology's costs are built from detailed engineering data. MESSAGE includes a number of constraints that represent how technologies interact with one another and limit the rate of technological penetration. These constraints are exogenous to the model, as are the sectoral demands for energy. MESSAGE identifies the mix of technologies that will meet energy demand in each sector at the lowest cost – all else is held equal. The results are deterministic. In order to generate a probability distribution of outcomes, multiple iterations utilizing a range of cost possibilities are run. Later versions of MESSAGE added a stochastic component to allow for a probability distribution for given outcomes [109].[23] Using a stochastic version enables policy planners to identify risk-weighted lowest-cost technology portfolios for energy production. MESSAGE can also incorporate environmental damages into its objective function, and has been used to determine the lowest-cost pathway to meet CO_2 emissions targets [70]. However, even in the stochastic version, technology cost risk is the only risk factor measured, and the risks are exogenously imposed – just like energy demand. There is no change in energy demand as a result of technology deployment. For example, the model is capable of limiting a new electricity generator's penetration by imposing a resource consumption constraint on the feedstock. It also allows resources to deplete over time. But there is no complementary reaction on the part of the demand sectors to the resource scarcity caused by the new technology's use of that resource, nor does the additional demand for the technology's input resource translate into a shift in

[23] A stochastic version of a model means that certain model input variables are treated as random variables with known distributions. The model randomly draws from that distribution and uses it as a parameter in the model run.

resource prices.

MARKAL and MESSAGE are emblematic of bottom-up models. The technologies included are based on detailed engineering data and they cover their sector of interest exhaustively. For industry-level technologies, individual components are often modeled. Model solutions identify the least-cost portfolio of technologies needed to meet the research goals, subject to modeler-imposed constraints. However, interactions with the wider economy are simply assumed, much as in the DCF model case described in Chapter 3. As Löschel claimed: "Absolute shifts in bottom-up models neglect transaction costs, inertia in the energy system and market failures on the demand side (e.g., information costs, high discount rates) and thus yield too optimistic cost estimates" [99, p. 5]. Since the focus of this dissertation is on how one sector's adaptation to a newly-penetrating technology impacts the activities of other sectors, a bottom-up model is not an ideal tool. The inter-sectoral interactions will be lost.

In contrast to the bottom-up models are top-down models. Some are actually a combination of models that interact with one another. These are called integrated assessment models (IAMs). Among he IAMs are MiniCAM (of the University of Maryland and the Pacific Northwest National Laboratory) [45, 19], the Integrated Global Systems Model (IGSM) of MIT [11, 122], and various incarnations of Nordhaus' DICE model (DICE, RICE, ETC-RICE, R&DICE) [117, 119, 118, 23].

There are many ways to configure a top-down model, but they are all closed-loop systems. Once parameterized, all expenses (including savings) must match exactly with all revenues – every value is generated by activity, and every good produced is purchased. In IAMs with economic models linked to climate models, the earth's atmosphere is also a closed system. As computing power becomes less expensive and more capable, bottom-up models may begin to close their loops, and top-down models may reach into greater and greater detail. Just as bottom-up models have a wide range of possible configurations, the same is true of top-down models.

For this research, a full IAM is not necessary. I focus on the economic impacts of GTL technology penetration. The impact on emissions is of interest, but the impact on global and regional climate is not. I require a model that focuses on the regional and global economy. The two main options are partial equilibrium and general equilibrium. Partial equilibrium is the standard model by which economics students are taught about the interactions between supply and demand [104]. In its most simple form, a single sector is analyzed in two dimensions. Price is plotted along the y-axis and quantity is plotted along the x-axis. The supply curve is plotted by matching the quantity that firms could collectively produce at a given price. As the price rises, more firms are able to produce the good and cover costs. The supply curve is thus an increasing function of price. The demand curve is plotted on the same axes. Since fewer consumers are willing or able to purchase a good when it is expensive than when it is inexpensive, the demand curve is modeled as a decreasing function of price. The intersection of the supply and demand curves is the equilibrium price and quantity. Using this model one can explore how equilibrium price and quantity shifts when events transpire to shift either the supply or demand curve, as well as producer and consumer surplus.[24] The partial equilibrium paradigm is very useful at gaining insights, and the method can be expanded beyond a single product in order to compare policy costs. However, its weakness is always that sectors and products outside of the sectors in the partial equilibrium model must be held constant – changes occurring in the sector(s) being analyzed are not allowed to impact external sectors, and vice versa. As Section 2.2.1 shows, the Fossil Fuels Complex is wide-ranging, and the point of this dissertation is to trace the impacts of the deployment of GTL on the wider economy and measure the interactions that occur. Expanding the boundaries of the model to encompass all of the relevant interactions means including all sectors that depend, even indirectly, on fossil fuels. That leaves the general equilibrium model as an appropriate option.

General equilibrium was introduced by Leon Walras at the end of the 19$^{\text{th}}$ century [175]. Walras postulated that every market should be able to "clear" – that is, identify an equilibrium price and quantity – simultaneously. The computational complexity of his model meant that it could only be proven with very rudimentary economies,

[24] Consumer surplus represents the amount of value that consumers would collectively have been willing to pay above the equilibrium price. The producer surplus is the amount of value that firms collect when prices are above their costs.

but the theory became a foundation of modern equilibrium economics. In 1984, Mathiesen developed an algorithm for computing a general equilibrium problem by solving the economic model as a series of linear complementarity problems [105]. Rutherford developed a programming language (MPSGE) that solves computable general equilibrium (CGE) problems that are formatted as complementarity problems [141]. CGE makes general equilibrium economic problems tractable. Among the CGE models that use MPSGE is MIT's Economic Projection and Policy Analysis (EPPA) model.[25] Aside from the overall format of economic models, many parameters must be chosen by the modeler. These choices and the limitations of CGE models will be explored in the rest of this section, though many of these elements can be a part of any forward-looking top-down or bottom-up model.

Model characteristics for characterizing technological performance and improvement

There are many nuances in simulating an economy. The number of regions to model, the number of iterations in the time horizon, how the solution is calculated, how to treat capital and GDP, and a host of other parameters differentiate models. These differences can produce divergent outcomes. Some models solve in "recursive-dynamic" fashion: each time step is solved in isolation to maximize profit (or minimize cost) subject to constraints. The alternative is "inter-temporal optimization", in which actors have perfect foresight of future events, and make sacrifices in the present in order to reduce costs (or damages) over the entire time horizon. These choices can result in different decisions and outcomes [33]. Mathematically the two approaches solve completely different problems even if the parameters that they model are identical. In the real world nobody has perfect foresight. However, the value in modeling a problem from the perspective of perfect foresight is to see how the optimally-identified decision differs from the recursive-dynamic perspective. Since the short-term profit-hungry world operates on a paradigm closer to the recursive dynamic formulation, a recursive dynamic model is an appropriate choice for this thesis.

[25] Formerly the Emissions Prediction and Policy Analysis (EPPA) model.

Another issue is the treatment of technological change. Some approaches to technology deployment and diffusion are exogenous and others are endogenous. Among the exogenous approaches are an autonomous energy efficiency improvement (AEEI) parameter [122, 56, 131]. The AEEI is a modeler-defined multiplier that improves energy efficiency in each time step. In contrast, are endogenous methods for technological penetration modeling. One identifies the optimal level of R&D expenditure needed for technological diffusion, while another ties the growth rate to historical data and estimates it econometrically [129]. Modeling R&D expenditures to foment technological advancement explores what the optimal level of R&D should be for productivity growth. It is a means of accounting for differences in economic growth rates [99]. Induced technological change is the idea that scientific advances can be "pushed" out into the economy, as opposed to change resulting from the "pull" of market demands. The former is a focus of many growth models [24, 118, 61, 60, 22, 94]. The latter tends to be covered through the use of backstop technologies, which will be discussed below.

Another endogenous method of modeling technological change is a learning-by-doing (LBD) parameter. LBD postulates that as workers gain experience using a technology, their productivity increases and the cost of deploying that technology decreases [99, 129]. Ideally, all parameters would be endogenous, but it is not always possible to construct a realistic growth rate endogenously. It has been demonstrated that the AEEI nonetheless produces results that are very similar to more complex, endogenous methods of energy improvement such as learning-by-doing (LBD) parameters [179].

A "backstop" technology is an exogenous technological advancement [116]. It replaces an existing economic activity with an improvement in a socially valuable dimension – for example, by emitting less pollution – at a given price. The technology is not viable at the beginning of the modeling window, so the true cost is unknown and is imposed by the modeler. Not all backstop technologies are complex, conform to engineering data or perform according to actual demonstrated efficiencies [99]. However, McFarland *et al.* demonstrated how engineering data could be translated into the value-flow format used in CGE modeling and preserve the engineering characteristics (such as efficiency, fuel inputs/flexibility in fuel inputs, and outputs) [106]. With this modification, many of the benefits of cost-based bottom-up modeling can used in a top-down CGE model. Chen explored the performance of a coal-to-liquids (CTL) technology within a CGE framework [28]. Chen's research questions did not explore how CTL penetration shifted energy inputs across sectors or price relationships, but rather whether the technology could penetrate and what its overall impact on emissions would be.

2.3 Model selection: Computable General Equilibrium

Only a CGE model is designed to account for the interactions between sectors that result as GTL technology penetrates. My hypothesis is that the penetration of GTL into the economy will disrupt the crude oil-natural gas price ratio. In order for a price relationship to hold, there must be portions of the economy in which natural gas competes with petroleum products. GTL deployment creates direct competition between refined fuels and natural gas in the transportation sectors. This could change the demand for both natural gas and crude oil. Shifts in sectoral energy usage as a result of the changing availability and pricing of fuels drives changes in the crude oil-natural gas price relationship. Not only are prices affected by energy usage, but energy usage in turn affects prices. Of the models examined in this chapter, only general equilibrium models capture these interactions.

Chapter 3

Key Aspects of GTL Technologies

This section covers three aspects of GTL technology: its history, its technical characteristics, and its economics. It concludes with a brief section discussing the implications that GTL penetration has on the competition between crude oil and natural gas.

3.1 History of gas-to-liquids technologies

In 1902, Sabatier and Senterens created methane (CH_4) (and water (H_2O)) by reacting hydrogen (H_2) and carbon dioxide (CO_2) over a nickel (Ni) catalyst under high pressure and temperature [145]. The reaction is exothermic, though heat is required to start the reaction. This was the first successful gas-to-liquids reaction.

In World War I, Germany lacked oil reserves. They researched a method to convert coal to transportation fuels. By the end of the war, they had successfully created tar at very low yields. In 1923, Franz Fischer and Hans Tropsch developed the Fischer-Tropsch ("FT") process. They converted a 2:1 mixture of hydrogen (H_2) and CO_2 into a mix of organic compounds containing oxygen, but which were not hydrocarbons. They dubbed the mixture "synthetic gas" (also known as "syngas").[1] By 1928, Fischer and Tropsch had converted syngas to liquid and gaseous hydrocarbons that were

[1] Syngas is produced from hydrocarbons in the presence of heat, pressure and/or steam. The technology is older than the Fischer-Tropsch process, dating back to the mid-19$^{\text{th}}$ century.

free of oxygenated compounds. They used an iron-copper catalyst, a pressure of 1 atmosphere (atm), and a temperature of 190°C [161].

In 1936, the first industrial-scale plants were built: four units producing 800,000 barrels annually of gasoline, diesel, lubricants and chemicals [145, 161]. By 1944, there were nine plants operating, all of which used an expensive cobalt (Co) catalyst [145] instead of the iron-based ones used by Fischer and Tropsch. The plants produced an output of over 70% motor vehicle fuels [161]. They applied the FT process on syngas produced from Germany's coal supplies.

After World War II, interest in FT processes waned. Only a few plants were commissioned, each with incremental improvements: a Brownsville, Texas plant in the U.S. tested a fixed fluidized bed in 1950 [151, 145]. This enabled greater contact between the feedstock and the catalyst. Köelbel developed a slurry-phase reactor in Rheinpreussen that operated from 1950 to 1955 [151, 145]. The slurry phase reactor was an alternative method of increasing feedstock/catalyst contact. The U.S. Bureau of Mines built and operated a Louisiana, Missouri plant based on the original iron catalyst [145], which was cheaper than the cobalt-type catalysts. Plants based on the ARGE (Ruhrchemie-Lurgi) process, which used a multi-tubular, fixed-bed reactor [151], were built and operated in Germany. The ARGE plants were better at removing heat from the highly exothermic FT reaction.

From the mid-1950s, large oil discoveries in the Middle East, Alaska, and the North Sea eroded the appeal of FT-based reactors. Coal-to-liquid technology was too expensive to compete with the abundant, low-cost crude oil reserves. All of the plants listed above ceased operations.

South Africa continued to pursue FT technologies. It has ample coal reserves and is far from the traditional supply routes for crude oil. Its apartheid government triggered international condemnation and trade embargoes, which made coal-to-liquids plants appealing despite the unattractive economics elsewhere [37]. To encourage the investment, the South African government established Sasol in 1950 to produce liquid fuels from coal [146]. With public funds backing the venture, Sasol had a greater tolerance for risk than a privately-held company.

Sasol I first produced synthetic fuels from coal-derived syngas in Sasolburg, South Africa in 1955 [146]. Sasol I was a coal-to-liquids (CTL) plant using a combination of the ARGE process, tubular fixed-bed reactors, and circulating fluidized bed synthol reactors [145]. Sasol II was commissioned in 1980 and Sasol III was built in 1982. Their synthol circulating fluidized bed reactors were eventually replaced with fixed fluidized bed reactors based on Sasol's SAS reactor designs [145].

The Arabian oil embargoes and the Iranian Revolution of the 1970s renewed interest in Fischer-Tropsch processes. By the 1990s the discovery of numerous stranded gas fields[2] sparked interest in the use of Fischer-Tropsch processes to convert this natural gas to liquid transportation fuels – the first push to commercialize GTL plants.

The first commercial-scale GTL plant was built by Petro SA, the national oil company of South Africa. Petro SA's Mossgas plant in Mossel Bay was completed in 1992 and was based on Sasol's FT technologies. It produced 23,000 barrels per day (b/d) of gasoline for the South African markets using natural gas as a feedstock [44]. The plant was built to research the viability of FT processes using natural gas feedstocks instead of coal. The same year, Rentech built a 10 b/d pilot plant in Pueblo, Colorado, but it only operated for about a year [156]. In 1993, Shell completed its plant in Bintulu, Malaysia based on Sasol technology. The Bintulu plant used the Sasol Slurry Phase Distillate process to produce middle distillates. The 14,700 b/d capacity reflected its purpose as a research facility [44, slide 25]. Sasol opened a 3,000 b/d pilot plant in Sasolburg, South Africa in 1993 to prepare for a commercial-scale GTL project in Qatar, and ExxonMobil opened a 200 b/d pilot plant using its own technology in Baton Rouge, Louisiana the same year [156]. From 2002 to 2004, four other pilot plants were inaugurated: ConocoPhillips built a 400 b/d plant based on their technology in Ponca, Oklahoma in 2002, and BP built a 300 b/d plant in Nikiski, Alaska the same year [156]. In 2003, Syntroleum began operations at a 70 b/d plant in Tulsa, Oklahoma (which was itself shipped in pieces from ARCO's Cherry Point, Washington refinery) [156]. In 2004, Statoil, in a joint

[2]Fields whose natural gas reserves have no economic route to market are called stranded gas fields.

venture with Petro SA, commissioned a 1,000 b/d pilot plant in Mossel Bay, South Africa [156].

In 2006 the Oryx GTL plant in Ras Laffan, Qatar was built. It was a joint project between Sasol and Qatar Petroleum. Based on the Sasol Slurry Phase Distillation (SPD) process and designed to produce diesel, naphtha, and liquefied petroleum gases (LPGs) for export, the plant did not reach its design capacity of 34,000 b/d until after 2009 [125, 44]. The Pearl GTL plant, also in Ras Laffan, is a joint venture between Shell and Qatar Petroleum. It began operations in March 2011, made its first shipment in June 2011, and achieved full capacity in the fourth quarter of 2012 [58]. Based on the Shell Middle Distillate Synthesis (SMDS) process, it produces 140,000 b/d of GTL fuels – diesel and naphthas – and 120,000 b/d of natural gas liquids[3] [57, 130]. Pearl's estimated cost was $18–$19 billion [130]. Both of the Qatar projects are profitable *only* because Qatar's massive North field contains stranded gas. Some suspect that the gas feedstocks for both Oryx and Pearl are being provided by Qatar Petroleum nearly free of charge.

Many GTL projects were either shelved or delayed. Chevron repeatedly delayed its Escravos project in Nigeria. A joint venture between Chevron and the Nigerian National Petroleum Company, Escravos was designed to produce 34,000 b/d of diesel and naphtha and was based on Sasol's FT and Chevron's Isocracking technologies. It was to cost $8.4 billion [15], but the latest news cited costs of $10 billion [10, 39]. Originally the plant was to come online in 2005 [39], but Escravos did not finally begin producing its first liquid fuels until the end of August 2014 [9].

ExxonMobil was once a leader in the development of GTL technologies, with documentation for its AGC-21 technology extending back to 1997 [128, 62]. Its proposed plant in Qatar was shelved due to cost overruns in 2008 [81]. Other plants that were being considered in Qatar were a 120,000 b/d GTL plant by Marathon Oil, an 80,000 b/d ConocoPhillips plant, and an additional Sasol Chevron plant with an 80,000 b/d capacity [156]. None of these have advanced.

[3] NGLs, which serve as petrochemical feedstocks and are directly derived from the natural gas without passing through the FT process.

Sasol has proposed its first GTL plant in North America to take advantage of low-cost shale gas [181, 86]. However, its cost would dwarf that of the Oryx plant in Qatar, so the project's prospects are uncertain. Table 3.1 lists the commercial-scale plants in operation as of August 2014. All of them produce transportation fuels and/or petrochemical feedstocks. In the case of Pearl GTL, in addition to the listed capacity of transport fuel production, the plant produces 120,000 b/d of non-FT natural gas liquids (NGLs).

Table 3.1: Existing commercial-scale GTL plants

Company	**Plant Name**	**Location**	**Capacity (b/d)**	**Year**
Petro SA	Mossgas	Mossel Bay, South Africa	23,000	1992
Shell	SPDP	Bintulu, Malaysia	14,700	1993
Sasol/QP	Oryx GTL	Ras Laffan, Qatar	34,000	2006 (2009)
Shell/QP	Pearl GTL	Ras Laffan, Qatar	140,000	2011
Chevron/NNPC	Escravos	Escravos, Nigeria	34,000	2014

Sources: Diemer [44], Simbeck and Wilhelm [156], and Atuanya [9]. Abbrebiations: SA: South Africa, SPDP: Slurry Phase Distillate Plant, QP: Qatar Petroleum, NNPC: Nigerian National Petroleum Company

Smaller companies have also proposed GTL projects. Some claim to have developed small, well-top GTL plant designs to take advantage of resources in smaller stranded gas fields. According to SRI Consulting,[4] if GTL plants could be economically scaled down to 2,000 b/d, 40% of the world's gas fields would become viable for GTL [176]. In 2011, Oxford Catalysts announced plans to open a plant in Karns, Pennsylvania through its Velocys subsidiary by 2014 [91, 181]. Sundrop Fuels, Primus Green Energy, Coskata, and Calysta Energy all claim to have designed small-scale GTL plants [74]. Some of these use a non-FT approach to GTL synthesis. A lack of documentation of the non-FT technologies precludes their discussion here.

Many small-scale GTL producers have either failed or have been absorbed by larger companies. Syntroleum was acquired by Renewable Energy in 2013 [8], more than three years after their 11,500 b/d GTL plant was to open in Australia [156]. The

[4]Owned by IHS.

plans never materialized. World GTL's Trinidad plant was seized by state-owned Petrotrin just as it was to be commissioned. Petrotrin was subsequently sued by World GTL for $2 billion [115]. While the details are sordid,[5] World GTL ultimately had to deliver over 95% of its shares to Petrotrin for failure to meet a contractual deadline for operations [114].

The projects of the smaller players are numerous, and their progress is difficult to track. After over 50 years of relative obscurity, interest in GTL technologies grew rapidly from the 1990s and has exploded since 2008. The fact that so many small players have failed and so many large players have declined to commercialize their technologies illustrates the risk of operating in the GTL industry.

3.2 Technical overview of GTL fuels and technologies

There are two types of GTL: one uses Fischer-Tropsch synthesis to create middle distillates, base oils, or waxes [125], and the other creates oxygenate-liquid compounds, such as methanol and dimethylether (DME). Only the Fischer-Tropsch version has been deployed at scale. This section covers variants of the Fischer-Tropsch GTL technology.[6] Figure 3-1 illustrates the GTL process in general terms.

This is not an in-depth engineering study of GTL technologies, but a primer for an economist seeking to identify the balance of costs and product value in each process. Only a few papers detailed the costs of individual components of a GTL plant. Where possible, I provide a cost estimate for each unit in 2013 dollars by inflating all capital costs from the base year value cited in the paper using the *Chemical Engineering Plant Cost Index* (CEPCI) [48]. Non-capital costs are inflated using the GDP deflators of the U.S. Bureau of Economic Analysis (BEA) [120].

[5] World GTL claims that their plant construction was sabotaged. An ammonia plant upwind, owned by Petrotrin, had a number of massive ammonia emissions requiring evacuation of the construction site during the project's construction phase. According to World GTL, this forced the plant to miss its project milestones.

[6] There is an active research into the oxygenate-liquid version of GTL as well (e.g., [35]), but non-FT GTL processes are not well documented.

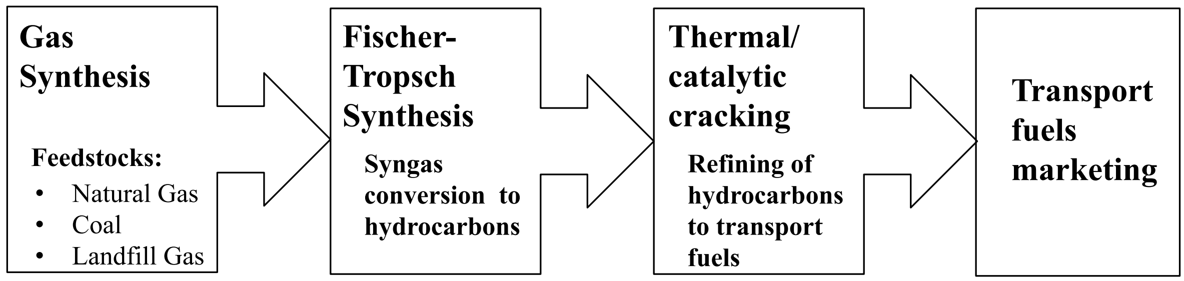

Figure 3-1: Basic GTL Process Chain

3.2.1 Gas synthesis

Syngas[7] can be produced from coal, heavy oil products (like residual fuel oils or petroleum coke), methane (the principal component of natural gas), or landfill gas. Biomass (such as wood) can also produce syngas [14]. Gas synthesis from solid or liquid sources is twice as expensive as syngas production from gases. This is one reason why GTL plants have been built at commercial scale, while CTL plants have only been pursued in apartheid-era South Africa and at a coal minemouth in Australia [47].

Air separation unit (ASU)

An air separation unit (ASU) separates nitrogen (N_2) from oxygen (O_2). The oxygen is added to methane (CH_4 – the primary component in natural gas) and heat (and sometimes steam) to create syngas. Air separation units cool the air until the nitrogen and oxygen liquefy. When the liquid mixture is gradually heated, the nitrogen vents off, leaving pure oxygen for gas synthesis [138, 30].

The ASU accounts for approximately 15-27% of the total production cost in a GTL plant [138, 30, 156]. Choi et al.'s 1998 ASU cost estimate, including water and sulfur removal and pre-treatment, is over $15,000 per barrel per day (b/d) capacity in 2013 dollars [30, 48]. In 2007 Simbeck and Wilhelm calculated an ASU cost between $5,400 and $5,800 per b/d capacity for a stand-alone ASU. Including gas pre-treatment raises the costs to $6,600 per b/d capacity [156, 48].[8] In general, the cost of the ASU ranges

[7]Synthesis gas

[8]Pipeline gas has already been pre-treated, covering both water removal and de-sulfurization. For

from 22% to 27% of total plant capital expenditures (CAPEX).

An ASU can be omitted in a GTL plant, but gas de-sulfurization and treatment would still be necessary if the plant were not located on a pipeline. Steam reforming (SMR) uses air rather than oxygen as an input, and needs no ASU. Certain configurations of auto thermal reformers (ATR) also omit the ASU, and instead use a nickel (Ni) catalyst to purify the air. BP has patents for an SMR design, and Syntroleum developed an ATR process without the ASU [138, 62].

Partial oxidation (POX)

Partial oxidation (POX) gas synthesis provides the nearly ideal ratio of hydrogen (H_2) to carbon dioxide (CO_2) for FT synthesis [145]. POX requires an ASU for a pure oxygen feed. Natural gas is reacted with oxygen under temperatures of 1200-1500°C and pressures greater than 140 *bar* [145]. The reaction follows:

$$2\mathrm{CH_4} + \mathrm{O_2} \quad \rightarrow \quad 2\mathrm{CO} + 4\mathrm{H_2}$$

The syngas is a nearly 2:1 ratio of hydrogen to carbon dioxide, but varies by design [156, 30]. The theoretically ideal mix of hydrogen to carbon monoxide in syngas for FT synthesis is 1.87:1 [30], though there are arguments for 1.9:1 [177]. POX requires no catalyst [145], so it costs about half as much as steam reforming (SMR), though there are versions of SMR that are only about 30% more expensive [138]. Including the cost of the essential ASU, POX ranges from about 8% cheaper than SMR to about 50% more expensive [138].

Choi *et al.* reported costs for a POX unit of about \$27,000 per b/d GTL capacity[9] in 2013 dollars. Given the time passed since their 1998 paper, this cost is likely the upper bound [30, 48].

Royal Dutch Shell and Texaco hold patents for POX technologies [145]. Shell's

a GTL plant using pipeline gas, the capital costs would be in the range of Simbeck and Wilhelm's lower figures, though the cost of the natural gas would be higher than they assume.

[9]This figure includes pre-sulfur removal, post heat recovery (for use in other processes) and syngas cooling.

Middle Distillate Synthesis (SMDS) and Exxon's AGC-21[10] technologies both incorporate POX for gas synthesis [138, 177]. Sasol once included POX as one stage of its two-stage syngas production [138], though the technology in the Oryx plant uses auto-thermal reforming (ATR) [59]. POX can also produce syngas from coal or heavy oil products.

Steam reforming (SMR)

Steam reforming is older than POX, and there are more patents for it. Major SMR patent holders include Foster Wheeler, Haldor Topsoe, International BV, Kinetics Technology, Lurgi AG, and Uhde GmbH. SMR reacts natural gas with steam over a nickel- (Ni) based catalyst at lower temperatures and pressures than POX. The SMR temperature range is 800-900°C and the pressure is about 20-30 *bar* [145]. The reactions are principally:

$$\begin{aligned} \mathrm{CH_4 + H_2O} &\rightarrow \mathrm{3H_2 + CO} \\ \mathrm{CO + H_2O} &\rightarrow \mathrm{CO_2 + H_2} \end{aligned}$$

SMR produces more hydrogen than necessary for the FT reaction. It is 30-100% more expensive than POX to build and operate because of the nickel catalyst and the need to generate steam.[11] About 1/4 of the natural gas input is used to generate steam, leaving 3/4 of the natural gas input for syngas feedstock [177]. The steam must be from purified water to avoid fouling the catalyst. These factors increase costs. The maximum pressure for SMR is about 30 *bar*, while the ideal pressures for FT synthesis are much higher [168], so syngas must be compressed. However, since SMR does not require a pure oxygen input, avoiding the ASU cost means that SMR is usually cheaper than POX.

Some GTL designs incorporate a small SMR unit with a POX unit that is 30 times larger to fine-tune the H_2:CO mix. The excess hydrogen in the SMR syngas

[10] "AGC" stands for "Advanced Gas Conversion".

[11] It is possible to use excess heat from the exothermic FT reaction to generate steam and/or electricity. This accounts for the wide range of cost estimates when compared to POX.

is blended with the lower H:C ratio POX syngas to reach the (approximately) 1.9:1 ideal [30, 177]. Shell does this in the SMDS process [177, 168]. Sasol's FT technology also employs a POX-SMR chain [138].

Choi et al. modeled an SMR unit with a POX unit in their GTL design. Their SMR unit was $1/24^{\text{th}}$ the size of their POX battery, at a cost about 15% higher per b/d capacity than a POX unit – $31,000 [30].

In the late 1990s BP revealed a compact SMR process that removed heat from the reactor through steel tubing [62]. This innovation would halve the cost of an SMR unit [138]. However, aside from its 300 b/d pilot plant in Alaska, BP has never broken ground on a GTL project.

Auto-thermal reforming (ATR)

Auto-thermal reforming is a combination of POX and SMR, but it uses a single reactor. ExxonMobil's AGC-21 technology uses ATR in a fluid bed reactor [138]. Other ATR patent holders are Haldor Topsoe and Lurgi AG [145]. ATR requires an ASU like the standard versions of POX and SMR. In ATR, the basic reaction is:

$$2CH_4 + H_2O + \frac{1}{2}O_2 \quad \rightarrow \quad 5H_2 + 2CO$$

The 5:2 ratio of H_2 to CO is more saturated in hydrogen than necessary, but closer to ideal than the SMR reaction. POX and ATR are considered superior methods of syngas production for FT synthesis [177, 174]. Even though the syngas is over-hydrogenated, the process is only slightly more expensive than POX. This is because the SMR phase is of lower volume than the POX phase, meaning that less steam and catalyst are required.

Syntroleum's GTL design includes an ATR, but uses ambient air instead of oxygen [177].[12] This saves on the ASU cost, but still requires the nickel catalyst and steam, resulting in a syngas-phase savings of just under 50% compared to the POX-only

[12]Syntroleum is now owned by Renewable Energy.

designs [138]. The resulting output from Syntroleum's ATR design is:

$$\mathrm{CO + 2H_2 + N_2}$$

All of the natural gas is used as feedstock. However, Syntroleum's ATR design emits carbon monoxide (CO), nitrous oxides (NOx) and volatile organic compounds (VOCs) [177].

Simbeck and Wilhelm examined the cost of syngas generation using exclusively ATR units. Their cost ranged from \$3,200 to \$3,500 per b/d of installed capacity[13] – about half of the cost of the ASU [156].

3.2.2 Fischer-Tropsch (FT) synthesis

Syngas is fed to the Fischer-Tropsch (FT) reactor, where it mixes with a catalyst under pressure and temperature to produce hydrocarbons of various chain lengths. There are a variety of catalyst and reactor designs, and each produces different outputs. This section describes the basic combinations of catalysts and reactor designs in use or development. However, FT technologies are trade secrets and details are scarce. There are two main types of FT synthesis: low-temperature Fischer-Tropsch (LTFT) and high-temperature Fischer-Tropsch (HTFT). Each produces a distinct mix of hydrocarbon outputs, and each uses different catalysts and reactor designs.

The general equation in the Fischer-Tropsch process is:

$$\mathrm{n(CO + 2H_2) \;\; \rightarrow \;\; -(CH_2)_n- + nH_2O, \quad \Delta H = -167kJ/mol}$$

$-(\mathrm{CH}_2)_n-$ signifies variable-chain-length hydrocarbons, and the negative value for ΔH means that the reaction is exothermic [125]. The excess heat can be used to generate steam for other processes in the plant. The general equation is simplified; there are a number of simultaneous reactions, each of which is affected by the choice

[13] 2013 dollars

of catalyst, heat and pressure. For example [125]:

$$\begin{aligned}
\mathrm{nCO + (2n+1)H_2} &\rightarrow \mathrm{C_nH_{2n+2} + nH_2O} \quad \text{(paraffin synthesis)} \\
\mathrm{nCO + 2nH_2} &\rightarrow \mathrm{C_nH_{2n} + nH_2O} \quad \text{(olefin synthesis)} \\
\mathrm{nCO + 2nH_2} &\rightarrow \mathrm{C_nH_{2n+1}OH + (n-1)H_2O} \quad \text{(oxygenate synthesis)} \\
\mathrm{CO + 3H_2} &\rightarrow \mathrm{CH_4 + H_2O}, \quad \Delta\mathrm{H} = -206\mathrm{kJ/mol} \quad \text{(methanation)} \\
\mathrm{CO + H_2O} &\rightarrow \mathrm{CO_2 + H_2}, \quad \Delta\mathrm{H} = -41\mathrm{kJ/mol} \quad \text{(water gas shift)} \\
\mathrm{2CO} &\rightarrow \mathrm{C + CO_2}, \quad \Delta\mathrm{H} = -172\mathrm{kJ/mol} \quad \text{(Boudouard reaction)} \\
\mathrm{H_2{+}CO} &\rightarrow \mathrm{C + H_2O}, \quad \Delta\mathrm{H} = -133\mathrm{kJ/mol} \quad \text{(coke formation)}
\end{aligned}$$

Tijm described the reactions in FT synthesis as probabilistic. There is a probability α of long-chain hydrocarbon formation, and the alternative probability $(1-\alpha)$ of chain termination [168, 125]. α is largely determined by temperature. It is easier to keep α near zero or 1 than it is to maintain it in between. This is because temperatures rise rapidly during synthesis, with a narrow temperature window for selectivity [168]. In practice, only the methanation reaction has 100% selectivity [168], but that re-creates methane from a methane-derived syngas. Higher temperatures push FT synthesis toward methanation and lighter, gaseous products in general [82], so LTFT synthesis is the preferred method for GTL projects.

Low-temperature Fischer-Tropsch (LTFT) synthesis is dominant

LTFT reactors operating at 200-250°C produce a higher volume of middle distillates in their output mix, with implications for the product upgrading stage [82].[14] Over 35% of a mid-α LTFT output is gasoline, while 30% of the output is olefins and paraffins with 2-4 carbon molecules. Just over 10% of the output is middle distillates like diesels and jet fuels, and just under 10% is heavy oils and waxes [180]. LTFT can thus market nearly 50% of its output without further refining or upgrading. The

[14]HTFT occurs in the 300-350°C temperature range

lightest products are mostly used as blendstocks, which are less valuable than gasoline and middle distillates, and the 15% of output that are heavy waxes and parrafins need to be either catalytically or thermally cracked.[15] Cracking units are the most complex and expensive in a modern refinery. However, depending on the catalyst used, the long-chain paraffins can be selected consistently [168]. The Shell Middle Distillate Synthesis (SMDS) process produces highly paraffinic waxes, which are then broken down through hydrocracking or hydroisomerization [145, p. 87–88]. The cracking units enable precise selectivity in outputs, so pushing LTFT yields toward waxes allows for a consistent product slate.

The two dominant reactor designs for LTFT are the multi-tubular fixed-bed reactor (MTFB or FBR) and the slurry column bubble reactor (SCBR) [125, 30, 156]. Both use cobalt (Co) as a catalyst because iron provokes more of the useless water-gas shift reaction than cobalt [125]. The MTFB pushes syngas through a catalyst bed, with perimeter tubes stabilizing temperatures. Shell uses a proprietary metallocene catalyst [92, p. 17] to consistently yield long-chain paraffins. The SCBR puts the catalyst into a slurry, and syngas is bubbled up from below to pass through the slurry. Sasol uses an SCBR, but it relied on an iron catalyst until recently.[16]

The SCBR is a newer technology and is cheaper to build and operate than the MTFB reactor, but the Oryx GTL plant in Qatar (with the SCBR) did not reach design capacity until 2009 – three years after construction was completed – due to problems of carbon deposition on their catalyst [80]. In contrast, the Shell Pearl GTL plant (based on an MTFB reactor) went from startup to full operation between March 2011 and September 2012 [58].

Simbeck and Wilhelm estimated the cost of the Oryx GTL reactor from publicly-available data. Their costs per b/d of installed capacity for the SCBR ranged from $5,200 for a two-train plant to $5,800 for a one-train plant [156, 48]. Thus the SCBR accounts for about 22% of CAPEX. Including other units in the battery, such as the FT gas treater, add another $1,600 to $2,000 per b/d of installed capacity. Together

[15] Thermal cracking is also known as “coking”.

[16] Iron is a superior catalyst for coal-based syngas [125], and Sasol’s initial experience with FT synthesis was in CTL plants.

with the SCBR reactor, this pushes the FT synthesis share of the project cost to about 30%.

Choi's study described a plant similar to Pearl GTL, which is much larger than Oryx. Choi's FT synthesis reactor cost about $9,800 per b/d capacity [30, 48]. This is about 15% of CAPEX. Choi's FT battery has more components than the SCBR: CO_2 removal units, a recycle gas compression and dehydration unit, a hydrocarbon recovery unit and a hydrogen recovery unit. Together, these add another $4,000 per b/d capacity to the FT battery cost, for a total share of about 21% of CAPEX [30].

3.2.3 Product upgrading

After FT synthesis, long-chain hydrocarbons are broken down into lighter components that become diesels, kerosenes, and petrochemical feedstocks. Upgrading technologies are neither novel nor exotic.

Simbeck and Wilhelm provide few details about the post-FT process. They list an FT hydrotreater, a steam superheater, a steam-turbine power generator, and "utilities". Only the hydrotreater is explicitly designed to upgrade FT output. The power generator is the most expensive piece. The total cost of all components is between $5,500 and $6,400 per b/d of GTL plant capacity [156, 48]. This is about 25% of CAPEX. Choi was more explicit in upgrading needs, including a wax hydrocracker, distillate and naphtha hydrotreaters, a catalytic reformer, a C_4 isomerizer, a C_5/C_6 isomerizer, an alkylation unit, and a saturated gas plant for product blending. The cost of these components is about $8,100 per b/d of installed capacity, or 12% of CAPEX.

Gary and Handwerk's textbook [54] lists refinery components that break down long-chain paraffins (Table 3.2). A GTL plant could use a variety of combinations of the units in Table 3.2 to achieve its desired mix of transportation fuels. It would not need all of them.

Table 3.2: Capital costs of refinery upgrading units per b/d capacity

Unit	**Cost (2013$)**
Coker	$8,500
Middle Distillate Hydrotreater	$2,600
Fluid Catalytic Cracking Hydrotreater	$2,500
Fluid Catalytic Cracker	$4,400
Hydrocracker	$13,600
Naphtha Hydrotreater	$1,800
Reformer	$4,600
Isomerizer	$5,800
Alkylation Unit	$6,600

Sources: Gary, Handwerk, and Kaizer [54]

3.2.4 Comparing emissions of GTL plants and petroleum refineries

A GTL plant consumes 9–12 mmBtu of natural gas to create a barrel of product containing about 6 mmBtu [154, 157, 136, 57, 166, 167, 82, 138, 62, 144, 128, 156, 97, 72, 177, 174, 30]. Along with the loss of energy, there are significant emissions of CO_2. Even accounting for slightly lower CO_2 emissions from diesel combustion, a GTL plant would emit about 15% more CO_2 than a petroleum diesel value chain [62, p. 5].[17] The FT process itself is not the culprit. Syngas generation emits about 0.38 moles of CO_2 for each mole of methane converted to liquid fuels [62, p. 25]. Thus about 20.6kg of CO_2 is emitted for each mmBtu of natural gas fed into a GTL plant [132, 34]. Natural gas contains 53.0kg of CO_2 per mmBtu [6], so a GTL plant emits 38.9% of the carbon contained in natural gas inputs as CO_2.

Aside from CO_2 emissions, GTL plants are fairly environmentally friendly. One estimate suggests that a GTL plant produces 30–70% less smog and 21–41% less acidification in the atmosphere than a petroleum refinery of comparable size [147].[18]

[17] If a GTL plant were sited at a field where the gas had been previously vented or flared, a GTL plant may decrease CO_2 emissions [62, 147, 78, 177, 84, 26].

[18] Sasol – an industry player with a vested interest in the success of GTL – makes this claim.

3.2.5 GTL fuel characteristics

In theory GTL plants can make a range of products. However, middle distillates are the most flexible, and potentially most profitable, cut of the crude barrel. Among published yields, most GTL plants produce a 70/30 mix of diesel and naphtha. Table 3.3 provides an overview of reported outputs.

Table 3.3: Fuel output mix of selected GTL technologies

Company	**Diesel %**	**Naphtha %**	**LPG %**	**Source(s)**
Shell	65–75%	25–35%	0%	[57, 62]
Sasol	70–75%	15–25%	1–5%	[156, 167, 51]
BP	65%	20%	15% (lube)	[93]
ExxonMobil	70%	30%	0%	[138]

GTL diesel has a higher cetane number than petroleum diesel. Cetane measures the time between injection and ignition for diesels. Like octane in gasoline, a higher number means a faster-igniting fuel. The cetane number of ultra-low sulfur diesel (ULSD) is 40-56 [147, 49]. GTL diesel's cetane number is 70-80 [147, 49, 62]. GTL diesel has no sulfur, and could be blended with existing ULSD to improve performance and emissions [157, 62]. Higher cetane implies that GTL diesel-fueled sports cars could be viable [62, 177]. If drivers shifted from gasoline to GTL diesel, it could result in about 4% fewer lifecycle emissions of CO_2 if driving behaviors were otherwise unchanged [62].

GTL diesel has lower non-GHG emissions than ULSD. Table 3.4 reports reductions in emissions of particulate matter (PM), hydrocarbons (HC), carbon monoxide (CO), nitrous oxides (NOx), volatile organic compounds (VOCs), and carbon dioxide (CO_2) from the ULSD baseline when burning GTL diesel. The reduction in CO_2 is for combustion only, not the lifecycle.

Table 3.4: Emissions reductions in key pollutants from burning GTL diesel vs. ULSD

Pollutant	**Low est.**	**High est.**	**Source(s)**
PM	21%	89%	[125, 43, 62, 149, 103, 177, 148]
HC	20%	90%	[125, 62, 149, 103, 148]
CO	33%	90%	[125, 62, 149, 103, 148]
NOx	8%	37%	[43, 62, 149, 148]
VOCs	5%	82%	[177, 78]
CO_2	0%	4%	[125, 43, 62, 149, 103, 177, 148]

3.3 Economics of GTL projects

A standard method of determining whether a project is worth the investment is to use a discounted cash flow (DCF) model. A DCF model itemizes costs and revenues in each period of the project lifespan, from pre-construction until the capital fully depreciates. Incremental cash flows are typically calculated on an annual basis. However, future money is worth less than current money. Future cash flows are discounted to present value by calculating the value in today's money that, when invested, will grow to the value of the future cash flow. The interest rate applied to today's money for the hypothetical investment is the discount rate. To find the value of a future cash flow in present-day money, the following formula is applied: $\frac{c_n}{(1+r)^n}$, where c is the future cash flow, r is the discount rate, and n is the period in which the cash flow occurs.[19] Once each cash flow is discounted to its current value, the discounted cash flows are summed. The sum of the discounted cash flows is today's value for the series of future cash flows. This is the net present value (NPV). If the NPV of a project is positive, it will be profitable. This section analyzes the NPV of various GTL projects based on public information.

[19] This is the simplest approach. More detail can be found in any standard finance textbook, e.g., Brealey, Myers and Allen [18].

3.3.1 Data on GTL projects

There are two common rules of thumb regarding costs and efficiency of GTL projects: first, 10 mmBtu of natural gas produces one barrel of FT transportation fuels. Second, the variable operations and maintenance (O&M) cost is about $5.00 per barrel produced. Most of the information about GTL projects come from press releases or news articles. These tend to lack useful statistics. There are some engineering studies on GTL technologies that detail the economics of projects. I put the data into the following categories, in order of their reliability:

1. Engineering studies of existing *plants* in peer-reviewed journals: no citations
2. Engineering studies of existing technologies in peer-reviewed journals: [97, 125, 145]
3. Reports on GTL engineering from government-funded laboratories or contractors: [174, 62, 138, 177, 30]
4. Economic studies/statistical databases from international agencies: [82, 5]
5. Economic studies from non-profit research centers: [156, 128]
6. Reports from industry-funded umbrella groups: [157]
7. Articles from the trade press (including online): [144, 167, 166, 165, 72]
8. Articles from the mainstream press (including online): [15, 96, 136]
9. Articles and presentations about existing plants from project owners: [154, 57]

This list contains only sources with credible figures. Only analyses of FT synthesis-based plants were included. Most of the sources only contained partial data, and none contained a complete set of all of the data necessary to construct a DCF model of a GTL project. In some cases I could estimate missing data based on the information given.[20] Some sources compared multiple plant configurations or technologies accord-

[20]For example, I could calculate mmBtu of natural gas input per barrel of output by dividing the amount of natural gas consumed per day by the daily barrels of production capacity for the plant.

ing to patented designs. Others analyzed only hypothetical plants. The following data were of interest:

1. Capital costs per barrel per day (b/d) of installed capacity
2. Fixed operations and maintenance (O&M) costs in dollars per year ($/yr)
3. Variable O&M costs in dollars per barrel ($/bbl) produced
4. Natural gas input (in mmBtu) per barrel of GTL output

Since these data were published between 1995 and 2013, I inflated cost estimates to 2013 dollars using the CEPCI [48] and the BEA GDP deflators [120]. Table 3.5 produces the data points by source and the base year for the cost calculation.

Table 3.5: Key cost components of GTL plants by source and year

Plant/Scenario	**Base Year**	**Capacity b/d**	**Capital Cost $/b/d**	**Fixed O&M $/yr**	**Var. O&M $/bbl**	**Gas Input mmBtu /bbl**	**Source**
Bintulu-orig.	1993	12,500	$108,000			14.13	[62]
Syntroleum syn-crude	1993	8,815	$48,000		$4.94	11.69	[30]
Syntroleum-base	1997	5,000	$40,000			10.30	[128]
Synroleum-next	1997	30,000	$18,000			10.30	[128]
Bintulu-exp.	1997	14,700	$100,000			12.27	[136]
Generic	1998	44,602	$65,000		$6.00	9.58	[30]
Basic-POX	1998	300,000	$42,000		$10.93		[138]
Basic-SMR	1998	300,000	$45,000		$15.73		[138]
Sasol	1998	300,000	$38,000		$12.24		[138]
Exxon ACG-21	1998	300,000	$35,000		$10.02	10.30	[138]
BP SMR	1998	300,000	$27,000		$12.67		[138]
Syntroleum	1998	300,000	$25,000		$8.74		[138]
DOE ceramic	1998	300,000	$29,000		$10.34		[138]
Generic-low	1998	300,000	$22,000		$6.56		[138]

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Table 3.5 – *Continued from previous page*

Plant/Scenario	**Base Year**	**Capacity b/d**	**Capital Cost $/b/d**	**Fixed O&M $/yr**	**Var. O&M $/bbl**	**Gas Input mmBtu /bbl**	**Source**
Generic-high	1998	300,000	$44,000		$10.20		[138]
Sasol	1999	10,000	$44,000		$7.26	10.30	[62]
Sasol/Chevron-low	1999	20,000	$36,000			10.30	[62]
Sasol/Chevron-high	1999	20,000	$44,000			10.30	[62]
Shell	1999	50,000	$44,000			10.30	[62]
BP	1999		$29,000			10.30	[62]
Syntroleum-low	1999	2,500	$32,000			10.30	[62]
Syntroleum-high	1999	2,000	$40,000			10.30	[62]
CERA	1999		$36,000			10.30	[62]
Shell SMDS-low	1999		$48,000			10.30	[62]
Shell SMDS-high	1999		$55,000			10.30	[62]
Corke	1999		$87,000			10.30	[62]
Exxon-small	1999	50,000	$37,000			10.30	[62, 138]
Exxon-large	1999	100,000	$37,000			10.30	[62, 138]
Inefficient	1999					12.62	[177]
Efficient	1999					8.80	[177]
Majors'	1999					9.36	[177]
Incremental	1999					10.56	[177]
Leap forward	1999					10.18	[177]
No steam avg.	2001					9.21	[174]
Steam avg.	2001					10.56	[174]
Sasol/Chevron	2004	130,000	$59,000				[156]
Chevron Escravos	2004	34,000	$64,000				[156]
Shell Pearl	2004	140,000	$46,000				[156]
Exxon	2004	154,000	$58,000				[156]

Continued on next page

Table 3.5 – *Continued from previous page*

Plant/Scenario	Base Year	Capacity b/d	Capital Cost $/b/d	Fixed O&M $/yr	Var. O&M $/bbl	Gas Input mmBtu /bbl	Source
BP	2004		$26,000				[156]
ETSAP small	2006	10,000	$13,000	4% CAPEX	$4.52	11.37	[82]
ETSAP medium	2006	30,000	$13,000	4% CAPEX	$3.83	11.37	[82]
ETSAP large	2006	60,000	$13,000	4% CAPEX	$3.13	11.37	[82]
Sasol Oryx GTL	2006	32,400	$32,000		$6.56	10.45	[72]
Sasol-large	2007	34,000	$38,000		$8.36	9.87	[156]
Sasol-small	2007	17,000	$42,000		$9.39	9.87	[156]
Liu recycled	2007	8,760	$65,000			10.41	[97]
Liu recycled CCS	2007	8,760	$68,000			10.41	[97]
Generic	2007					10.30	[157]
Sasol Oryx-exp.	2007	130,000	$48,000			10.76	[167]
Sasol/Chevron Escravos-exp.	2010	120,000	$70,000			10.15	[166, 15]
Shell Pearl-low	2011	140,000	$71,000			9.06	[57]
Shell Pearl-high	2011	140,000	$75,000			9.06	[57]
Sasol Westlake	2011	96,000	$104,000				[96]
Sasol/Chevron Escravos-initial	2011	33,000	$247,000			10.15	[166, 15]
Petro SA demo	2012	1,000	$51,000		$12.62	9.40	[165, 154]
Generic-med	2013	34,000	$100,000		$20.50	10.00	[144]
Generic-low	2013	34,000	$80,000		$18.00	10.00	[144]
Generic-high	2013	34,000	$200,000		$23.00	10.00	[144]
Chevron Escravos	2014	33,000	$303,000				[10]

Energy efficiency has gradually improved over time. Figure 3-2 depicts the trend: a 0.06 mmBtu/bbl decrease per year in the amount of natural gas required to produce a barrel of transportation fuels. The only commercial-scale plants that were operational are Shell's Pearl GTL plant and Sasol/Chevron's Oryx GTL plant, both in Qatar. The

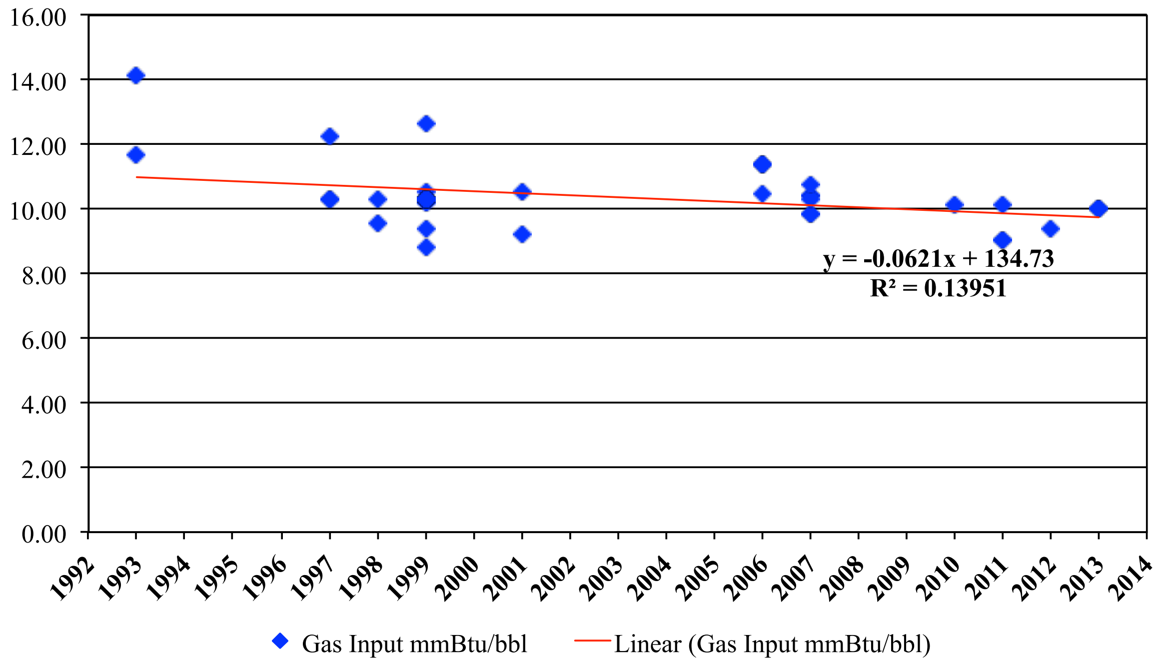

Figure 3-2: GTL gas input requirement, mmBtu per barrel produced

only research/demonstration-scale plants that had been built are Shell's Bintulu and Bintulu expansions, and the Petro SA demonstration plant. The rest of the estimates are either hypothetical or pre-construction engineering estimates by potential vendors.

Shell's Pearl GTL plant is the largest ever built. The capital cost estimate of $71,000-$75,000 is Shell's reported $18-$19 billion CAPEX divided by the 260,000 b/d capacity in total products (140,000 b/d of GTL products from FT synthesis and 120,000 b/d of NGLs[21] extracted from the gas in Qatar's North Field). The CAPEX includes 37 miles of 30-inch diameter natural gas pipelines, a gas treatment unit and desulfurizer, and a massive NGL unit processing 1.6 billion cubic feet of natural gas per day (bcf/d) [57]. These costs are all outside of the GTL process shown in Figure

[21]Natural Gas Liquids.

3-1. The CAPEX for the GTL portion is uncertain. The gas input per barrel suffers the same uncertainty: 9.06 mmBtu/bbl is an average of dividing the 1.6 bcf/d figure by either 260,000 b/d (including both the NGLs and the GTL products) or by 140,000 b/d (including only the GTL products). The former yields an unreasonably efficient input of 6.34 mmBtu/bbl, while the latter yields an inefficient 11.78 mmBtu/bbl. The Pearl plant includes a combined-cycle natural gas (CCNG) power plant to cover both the GTL and NGL processes, as well as compression for the pipeline and a unit to remove gas impurities. Not all of the gas input is for the GTL process. But the simple average probably produces a more favorable estimate of GTL process energy efficiency, since GTL production is more gas-intensive than pipeline compression, NGL stripping, and gas purification.

The Sasol Oryx GTL plant data are more explicit. Gas input values range from 9.87 mmBtu/bbl [156] to 10.45 mmBtu/bbl [72], which on average is a slight improvement from the hypothetical studies of the late 1990s, which cited an input rate of 10.30 mmBtu/bbl for Sasol technology. Capital costs across ranged from $32,000 [72] to $42,000 [156] for the Sasol Oryx plant. The variable O&M cost estimate for Sasol Oryx ranged from $6.56/bbl [72] to $9.39/bbl [156].

The Petro SA demonstration plant was a joint venture with Statoil [165]. The capital cost of $51,000 is low for completed projects,[22] and the estimated gas input rate of 9.4 mmBtu/bbl is the industry leader for projects in production. The variable O&M on the plant is reportedly about $12.60/bbl.

The original Shell Bintulu "Sasol Slurry Phase Distillate Plant" had a capacity of 12,500 b/d at a cost of about $108,000/b/d capacity [62]. It was damaged in a fire and rebuilt at a cost of $100,000/b/d capacity for 14,700 b/d of capacity. In both cases, the Shell process consumed about 10.30 mmBtu of natural gas for each barrel of GTL fuel produced [136].

The cost range for the hypothetical and unbuilt plants is wide – $13,000 to $247,000 per b/d capacity – and the gas input ranges from 8.8 to 11.4 mmBtu/bbl. Plants already in existence have input rates at or just under 10 mmBtu/bbl. The

[22] The Chevron Escravos plant ended up costing over $300,000 per b/d of installed capacity [10].

cost range for variable O&M is from \$3.13/bbl to \$23.00/bbl, though the data for existing plants are sparse and the range is likewise wide. The fixed O&M cost of 4% of CAPEX per year was reported by the Energy Technology Systems Analysis Programme (ETSAP) at the International Energy Agency (IEA) [82]. This estimate is similar to the refinery cost estimates from the Gary, Handwerk, and Kaiser textbook [54].

3.3.2 DCF model parameters for a GTL project

I use the following figures for modeling a GTL plant, drawn from the data in Section 3.3.1:

1. Capital cost per b/d capacity: \$68,000
2. Fixed O&M cost per year: 4% of capital expense
3. Variable O&M cost per barrel produced: \$5.00
4. Gas input rate, mmBtu per barrel produced: 9.85

\$68,000 per b/d capacity is on the high side of the literature, but it represents a self-contained plant – including a CCNG generator scaled to exactly meet electricity needs. Some of the lower capital cost figures were for plants that had to purchase electricity. \$68,000 per b/d is lower than the estimate for Pearl or Escravos, since the modeled project will use pipeline gas. The fixed O&M represented the only concrete estimate in the literature. The variable O&M is slightly lower than most estimates, but the goal is to model a technology that is to be deployed over the next decades, so the \$5.00/bbl figure reflects gradual improvements. For example, Shell estimates it could reduce costs by up to 15% in the next plant it builds [126]. \$5.00/bbl fits the "rule of thumb" for variable O&M costs. The gas input rate of 9.85 mmBtu/bbl is a central figure in the range of the Shell Pearl and Sasol Oryx input rates.

The remaining parameters for a DCF analysis are (1) plant capacity in b/d, (2) the product output mix between distillates, petrochemical feedstocks, and liquefied petroleum gases (LPGs), (3) the capacity utilization percentage, (4) the project lifespan in years, (5) the construction lead time, (6) the tax rate, (7) the discount rate, (8) the market prices of the outputs and the natural gas input, and (potentially) (9) the level of debt financing. The straightforward parameters are:

- Plant capacity, b/d: 120,000[23]
- Capacity utilization: 93%[24]
- Project lifespan: 25 years[25]
- Construction lead time: 3 years[26]
- Tax rate: 35%[27]
- Debt financing: 0% (in the baseline assessment)
- Discount rate: 10%[28]

The following sections discuss the possibilities for setting the product output mix and market prices.

Product output mix

Table 3.3 reported GTL fuel outputs from four energy majors. Of the four, only two have built plants. This leaves a mix of about 70% distillates and 30% petrochemical feedstocks (naphtha) for Shell's SMDS technology, or about 71% distillates, 26% naphthas, and 3% LPGs for Sasol. Shell's Pearl and Bintulu plant capacities together comprise well over 50% of global GTL production capacity, so I model a 70/30 mix of distillates-to-naphtha in the base case scenario. Other scenarios will test the Sasol output mix.

[23] This is a large commercial-scale project size.

[24] Petroleum refineries assume a 92–96% utilization rate [54, p. 366]. Salehi et al. used a 93% availability rate [144].

[25] Typical capital-intensive projects assume a 20–30 year lifespan before full depreciation.

[26] Based on a range from one to four years in the literature.

[27] Reflective of the U.S. corporate tax rate as a general assumption.

[28] 10% is a standard starting point for project evaluation. The number is almost never below 10% and can frequently be raised above 10% if the risk is considered to be great. For the purposes of an initial analysis, I will use 10%.

Market prices of GTL output and input fuels

GTL profitability will be most sensitive to the cost of natural gas and the price of the output products. The volatility in energy prices is a major source of risk to GTL project viability. Both commercial-scale plants were built in Qatar, where local markets for natural gas are scarce and LNG export capacity is far below what Qatar's massive gas reserves could support. The cost for natural gas for both projects is probably heavily subsidized by the state of Qatar, thus reducing project risk for both Shell and Sasol.

I model a GTL plant operating for 25 years in competitive markets using pipeline gas. Guidance on future costs and potential revenues is essential. The New York Mercantile Exchange (NYMEX) trades natural gas, gasoline, diesel, propane and butane. An examination of each product provides a snapshot of risk-weighted market expectations for prices far into the future.

NYMEX trades the Henry Hub Natural Gas Futures Contract [66]. It is based on the price at Henry Hub, where numerous pipelines intersect near the Texas-Louisiana border in the United States. On September 10, 2014 there was active trading in every near-month delivery contract from October 2014 through May 2019.[29] "Prior settle" prices were listed monthly through the September 2024 contract. Natural gas prices fluctuate over the year. In North America, they peak in the winter and fall to an annual low in the spring, with prices slowly rising over the rest of the year in anticipation of winter heating demand. This seasonality masks the overall price trend. The seasonality can be filtered out by calculating 12-month moving averages. By this measure, the natural gas price rises from \$3.97/mmBtu in September 2015 to \$4.90/mmBtu in September 2024. The contract price increases by only 23% in 10 years. The unfiltered monthly maximum price was in January 2024 at \$5.27/mmBtu. The average spot price of Henry Hub natural gas from 2010 to 2013 was \$3.82/mmBtu in 2013 dollars.[30] The maximum monthly price in the futures curve is only 40% higher

[29] See the CME Group website for the Henry Hub natural gas futures contract, `http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html`, for more information. Accessed September 10, 2014.

[30] A spot price is the price in the physical markets of a commodity for delivery the next business

than recent natural gas prices. The maximum 12-month moving average futures price for natural gas was \$4.98/mmBtu, reached in August 2024. This is only 30% higher than the 2010-2013 average spot natural gas price. The cost of natural gas is the biggest risk to GTL plant profitability. The gradual price increases predicted by the NYMEX futures contracts hint that the markets do not predict any major upheaval that would adversely impact GTL economics.

Ultra-low sulfur diesel (ULSD) also trades in a futures contract on NYMEX [69]. The contract for delivery at New York Harbor is the most liquid. On September 10, 2014, contracts were actively traded monthly from October 2014 through March 2016, with monthly "prior settle" price indicators extending to January 2018.[31] Petroleum products trade globally year round, so prices exhibit no seasonality to filter out. The October 2014 price for the New York Harbor ULSD futures contract was \$115.76/bbl. The January 2018 price was \$112.18/bbl – a decrease of just 3% over 40 months. Though the NYMEX ULSD price is stable, a falling diesel price is another major risk for a GTL plant, since it decreases revenues going forward. The maximum futures contract price was \$117.66/bbl, for the January 2016 contract. The minimum price was \$112.18/bbl for January 2018. The falling price through the end of the trading window hints that price decreases for diesel could continue well into the 2020s. The ULSD spot price in the U.S. – an average of the New York Harbor and Gulf Coast spot prices – was \$122.11/bbl from 2010-2013, in 2013 dollars. This implies a price decrease of around 8% through the contract trading window.

Sasol GTL produces a small quantity of LPGs, so the prices of butane and propane are relevant. NYMEX trades both the Mont Belvieu Normal Butane (OPIS) Futures Contract [68] and the Mont Belvieu (LDH) Propane (OPIS) Futures Contract [67]. Both the butane and propane contracts are lightly traded, so pricing information

day. Each annual average price was inflated to 2013 dollars before averaging using the GDP deflators from the Bureau of Economic Analysis' Table 1.1.4 Price Indexes for Gross Domestic Product (A) (`http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1`, accessed July 31, 2013) [120].

[31] See the CME Group website for the NY Harbor ULSD Futures Contract, `http://www.cmegroup.com/trading/energy/refined-products/heating-oil.html`, for more information. Accessed September 10, 2014. Prices cited here converted from dollars per gallon (\$/gal) to dollars per barrel (\$/bbl) by multiplying the \$/gal price by 42.

was limited to the "prior settle".[32] Each reports monthly notional futures contract prices from September 2014 through December 2018. The highest price in the butane contract is \$53.94/bbl, on January 2015, while the minimum occurs on January 2018 at \$47.02/bbl. The propane contract's maximum and minimum fall on the same dates as the butane contract, with a maximum price of \$45.27/bbl and a minimum price of \$42.11/bbl. These compare to the 2010-2013 average butane price of \$62.90/bbl and the average propane price of \$49.92/bbl. Over the next 51 months, prices are expected to fall by about 11% for butane and by about 5% for propane. Again the prices of the output product are expected to slowly but steadily decrease over time. For the DCF model, I use an average of the butane and propane prices to estimate LPG value.

Petrochemical feedstocks like naphtha do not trade on NYMEX. But a rough price relationship between petrochemical feedstocks and diesel can be calculated from the IEA's Energy Prices and Taxes database [79] and the State Energy Data System database [169]. Used in conjunction with the IEA's Energy Statistics [5] and the Global Trade Analysis Project (GTAP) 8 database [71], a volume-weighted average price ratio between diesel prices and petrochemical feedstocks can be calculated. On average, petrochemical feedstocks cost 18% more than diesel.[33] Using a multiplier on the diesel price for the petrochemical feedstock price makes the price trends (and risk profiles) identical for both fuels.

Figure 3-3 plots the NYMEX futures curves of ULSD, propane, butane and crude oil in dollars per barrel, and the 12-month moving average (MA) futures price of the NYMEX natural gas contract in dollars per million Btu. The four petroleum product prices are measured on the left-hand vertical axis labeled "\$/bbl", while natural gas prices are measured on the right hand vertical axis labeled "\$/mmBtu".

[32]See the CME Group website for the Mont Belvieu Normal Butane (OPIS) Futures Contract (`http://www.cmegroup.com/trading/energy/petrochemicals/mont-belvieu-normal-butane-5-decimals-swap.html`) and the Mont Belvieu LDH Propane (OPIS) Futures Contract Specs (`http://www.cmegroup.com/trading/energy/petrochemicals/mont-belvieu-propane-5-decimals-swap.html`), both accessed September 10, 2014 for more information. Prices cited here converted from dollars per gallon (\$/gal) to dollars per barrel (\$/bbl) by multiplying the \$/gal price by 42.

[33]More information on how this figure was calculated can be found in Appendix A.

The propane, butane, and ULSD curves slope downwards until the end of the contract

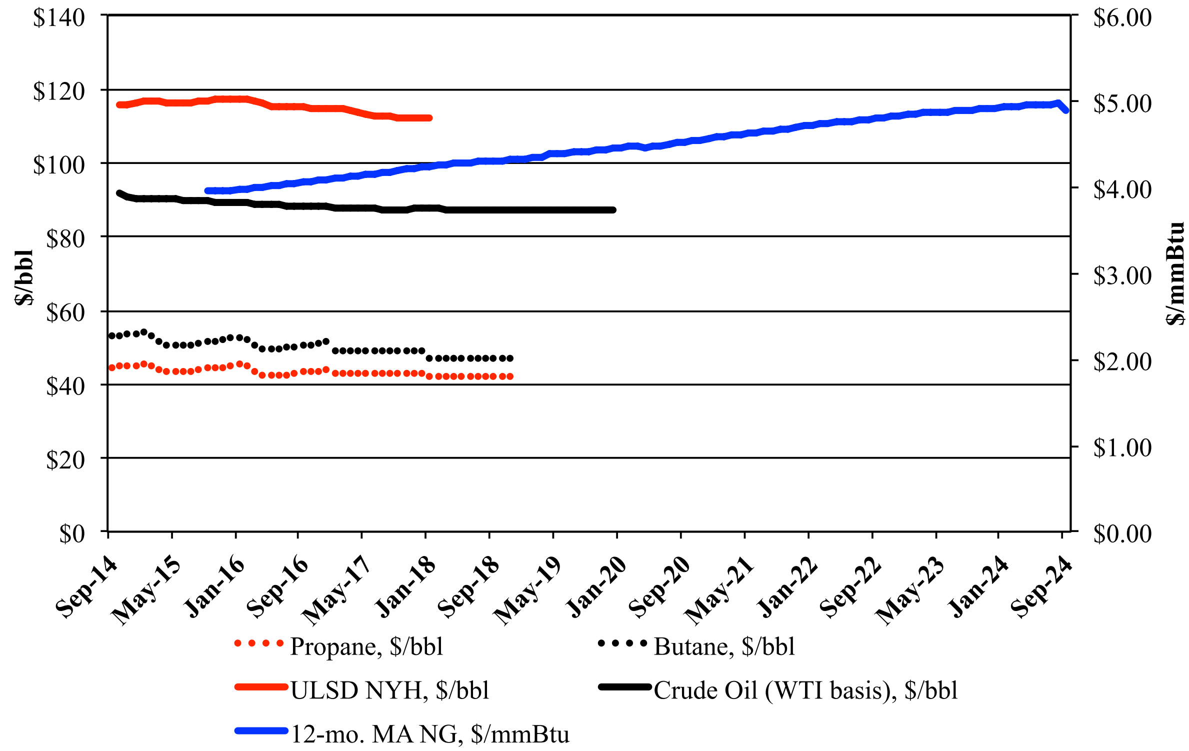

Figure 3-3: NYMEX futures curves for crude oil, natural gas, and select products

window in 2018, while the natural gas price rises through 2024. The natural gas price levels off below \$5.00/mmBtu between 2022 and 2023. The direction of the price movements suggests increasing risks to GTL profitability. The NYMEX Crude Oil Futures Contract [65] price is \$91.72/bbl for the October 2014 contract. The price declines through the 2018 trading window of the other petroleum products, but then levels off at \$87/bbl in mid-2019.[34] Crude oil's historical average price from 2010 to 2013 was \$93.71/bbl in 2013 dollars. Since petroleum product prices move with the value of crude oil, this suggests that the prices of other products will also stabilize. If diesel prices stabilize at, say, \$110/bbl and natural gas price increases stabilize near \$5/mmBtu, there is still a window of profitability for a GTL plant well into the next decade.

[34]See the CME Group website for the Crude Oil Futures Contract, `http://www.cmegroup.com/trading/energy/crude-oil/light-sweet-crude.html`, for more information. Accessed September 10, 2014.

The range and mean of the historical and futures price data are reported in Table 3.6 below. The difference between the 2010-2013 historical mean and the mean of the

Table 3.6: Historical and futures price ranges for select energy products

Product	**Unit**	**Mean (2010-2013)**	**Mean (futures)**	**Min. (futures)**	**Max. (futures)**
Nat. Gas (Henry Hub)	\$/mmBtu	\$3.82	\$4.18	\$3.83	\$5.27
Nat. Gas 12-mo. MA	\$/mmBtu	NA	\$4.49	\$3.96	\$4.98
Crude oil	\$/bbl	\$93.71	\$88.12	\$86.93	\$91.72
ULSD	\$/bbl	\$122.11	\$115.15	\$112.18	\$117.66
Propane	\$/bbl	\$49.92	\$43.27	\$42.11	\$45.47
Butane	\$/bbl	\$62.90	\$49.90	\$47.02	\$53.94

futures curves is minor. For natural gas, the mean of the futures curve is only 9% greater than the 2010-2013 average. For crude oil and ULSD, it is only 6% lower. For propane, the futures mean is 13% lower than the 2010-2013 historical average, and for butane, the futures mean is nearly 21% lower. For the base case DCF analysis of a GTL plant, the 70/30 diesel/petrochemical feedstock mix is less risky, since the LPG prices fall much further from historical averages than others.

For the base case DCF analysis, I use the following prices:

- Natural gas price: \$5.00/mmBtu
- Diesel price: \$115.00/bbl
- Petrochemical feedstock price: \$135.70/bbl[35]
- LPG price: \$46.59/bbl[36]

3.3.3 Discounted cash flow models of GTL plants

For the DCF model, all capital costs are paid up front, in year zero. The capital expenditure (CAPEX) is the capital cost per b/d capacity multiplied by the b/d

[35]This represents 118% of the diesel price.

[36]This is a straight average of the means of the propane and butane futures curve prices.

capacity of the plant. CAPEX is then multiplied by one minus the percentage of the project that is debt financed (in this case, zero debt financing means no adjustment). For the base case, the total capital expenditure in year zero is \$8.2 billion for a plant of 120,000 b/d capacity at a cost of \$68,000 per b/d capacity.

The plant is then under construction for three years and the capital value remains fixed at \$8.2 billion. In year 4, full-capacity operations begin. Annual fuel input is the number of mmBtus input per barrel of output multiplied by the plant capacity in b/d multiplied by the capacity utilization factor (a percentage) multiplied by 365 days/year. This is 9.85 mmBtu/bbl times 120,000 b/d times 93% times 365 d/y to get 401.2 million mmBtu/year of feedstock. Feedstock cost is the feedstock input multiplied by the natural gas price (\$5.00/mmBtu). This is \$2 billion per year. The variable O&M expenditure is the variable O&M per barrel (\$5.00) multiplied by the plant capacity, then by the capacity utilization factor, then by 365 days. The variable O&M expenditure is \$200 million per year. The fixed O&M cost is 4% of the \$8.2 billion CAPEX: \$326 million. The total annual costs are the sum of the fuel cost, the variable O&M and the fixed O&M: \$2.54 billion in year 4.[37]

Revenues are the daily output in barrels of each product (84,000 bbl ULSD and 36,000 bbl petrochemical feedstocks) multiplied by each product's price (\$115/bbl for ULSD and \$135.70/bbl for petrochemical feedstocks), then by the capacity utilization factor (93%), then by 365. Revenues are \$4.94 billion in year four.[38] Revenues less costs are the earnings before interest, taxes, depreciation, and amortization (EBITDA). For the base case GTL project, EBITDA is \$2.4 billion per year (as long as feedstock and output prices hold constant). For depreciation, I impose a straight-line depreciation over 25 years. Each year the plant loses $1/25^{\text{th}}$ of its original \$8.2 billion CAPEX. This works out to \$326 million per year. There is no interest payment when there is no debt financing.

Taxable income is EBITDA minus the depreciation and interest expenses: \$2.1 billion per year. Taxes of 35% are \$726 million each year. After subtracting the loan

[37] As long as the natural gas price remains constant and there is no debt financing, this will be the nominal cost every year.

[38] This will be true every year as long as the product prices remain constant, as in the base case.

payment (zero in the base case), the net cash flow is about \$1.7 billion per year. The total cash flow is the net cash flow less any additional CAPEX in the year.[39] In the base case, net cash flow is \$1.7 billion. The cash flow is discounted at a 10% discount rate under the formula $\frac{c_n}{(1+r)^n}$, where c is the future cash flow, r is the discount rate, and n is the period in which the cash flow occurs. For year 4, this is:

$$\approx \frac{\$1,700,000,000}{1.1^4} = \frac{\$1,700,000,000}{1.4641} \approx \$1.14 \text{ billion}$$

While the nominal cash flows are identical each year under the base case, the discounted cash flows get smaller and smaller over the 25 year lifespan of the plant. The 25^{th} year is discounted to the 28^{th} power, leaving a present (year-zero) value of just \$116 million.[40] Plant profitability is the sum the net present values (NPVs) of each year (the NPV in year zero was $-\$7.8$ billion). The NPV of the base case GTL plant is \$3.3 billion. A positive NPV means that the project is profitable, but there are other metrics. The most common alternative is the internal rate of return (IRR). The IRR is a measure of the percentage return on the investment.[41] The IRR is calculated by determining the discount rate that would prevail if the project were to make zero profits. In the base case GTL project, the IRR is nearly 13.5%. By either measure, the base case GTL project is profitable.

The levelized cost of energy (LCOE) is the flat cost in current dollars to produce a barrel of output every year. The output in barrels is discounted using the same discount rate used in the NPV. Then the discounted costs are divided by the discounted output to return the LCOE. Including taxes, the LCOE of the base case GTL plant is \$109.46/bbl. Excluding taxes, the LCOE is \$91.64/bbl. Table 3.7 summarizes the key metrics in the GTL DCF model. Table 3.7 also reports the operating expenditure (OPEX). For this research, OPEX is the sum of the capital recovery, the fixed costs, and the variable O&M costs. It is the LCOE less the cost of the fuel input. I will use OPEX to examine a number of the specific technologies described in Table 3.5.

[39] CAPEX is assumed to be zero after the initial expenditure in year zero.

[40] This is the "net present value" (NPV) of the cash flow in year 28.

[41] There are many strong arguments in favor of the NPV versus the IRR. I will not argue for one or the other here, but will present both metrics.

Table 3.7: Profitability of a base case GTL project

Parameters	**Base Case Values**
Capital Cost, \$/b/d capacity:	\$68,000
Gas Input, mmBtu/bbl output:	9.85
Variable O&M, \$/bbl:	\$5.00
Fixed O&M, \$/yr (as annual % of Capital Cost):	4%
Capacity, b/d:	120,000
Capacity, b/d ULS Diesel:	84,000
Capacity, b/d Petrochemical feedstocks:	36,000
Percent Financed:	0%
Capacity utilization:	93%
Number of years for project:	25
Tax Rate:	35%
Interest Rate:	10%
Discount Rate:	10%
Diesel Price, \$/bbl:	\$115.00
Natural Gas Price, \$/mmBtu:	\$5.00
NPV:	\$3,262,930,536
OPEX (fixed + variable cost), \$/bbl (ex fuel), ex tax:	\$42.39
OPEX (fixed + variable cost), \$/bbl (ex fuel), tax:	\$60.21
LCOE, \$/bbl, ex tax:	\$91.64
LCOE, \$/bbl, tax:	\$109.46
Internal Rate of Return (IRR):	13.46%

Abbreviations: b/d: barrel-per-day. NPV: net present value. OPEX: operating expenditure. LCOE: levelized cost of energy.

The base case is profitable, but it is sensitive to the prices of natural gas and petroleum products. At a natural gas price above \$6.85/mmBtu, the NPV shifts to negative. The futures curve for Henry Hub natural gas never exceeded \$5.27/mmBtu, but historically the average price[42] of natural gas in the US was at or above \$6.85/mmBtu from 2004 through 2008. Figure 3-4 traces the net income of a GTL plant had it existed as far back as 1997.

The two plots reflect the weighted output value[43] less the LCOE, both with (black line) and without taxes (blue line). The y-axis measures profits (when the plot lies above zero) or losses (when the plot lies below zero) per barrel of output, in 2013 dollars per barrel. The x-axis marks the date. In 2005, the average natural gas price

[42]in 2013 dollars

[43]The weighted output value is the value of a barrel of output weighted by the prices and production volumes of diesel and petrochemical feedstocks.

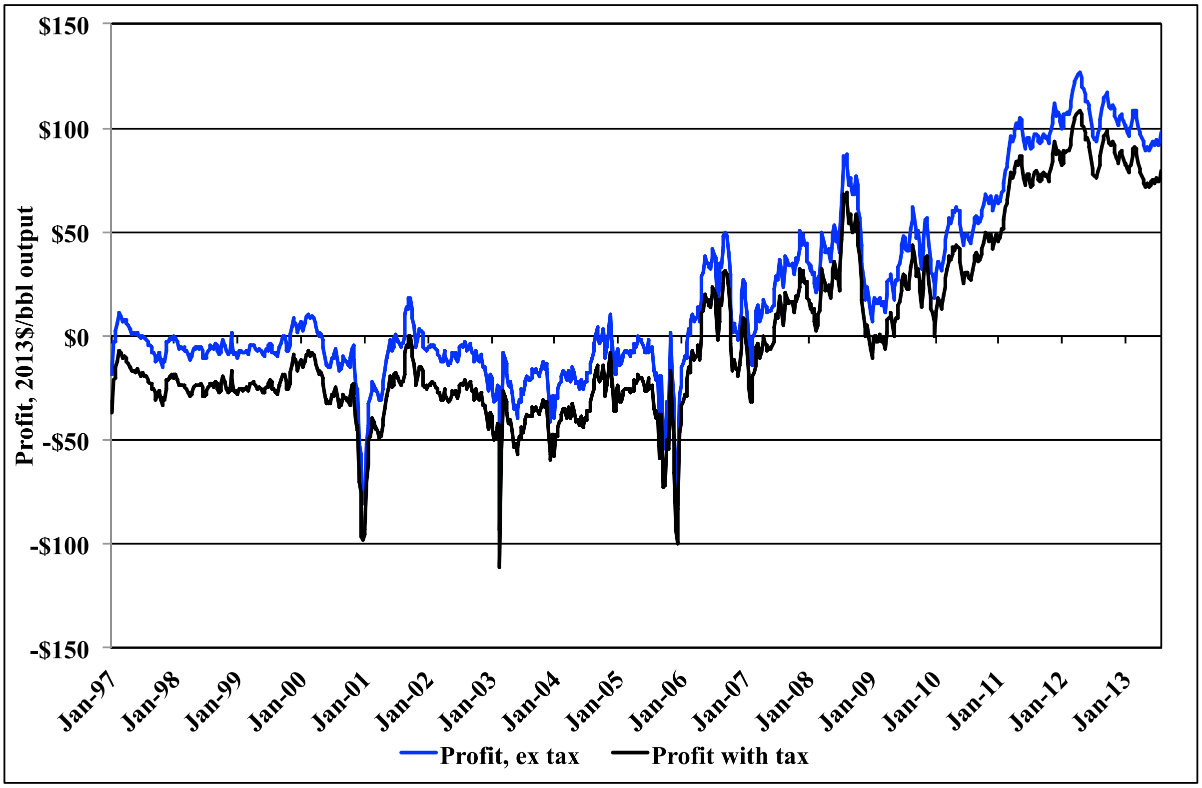

Figure 3-4: U.S. profit for base case GTL plant (wtd. output price – LCOE), 2013$/bbl

Price source: Weekly low-sulfur diesel and natural gas prices from the U.S. Energy Information Administration (U.S. EIA).

exceeded $10/mmBtu, and losses per barrel would have ranged from $30 to over $97. At $10/mmBtu gas, the NPV is −$5.6 billion. A diesel price below $97.86/bbl also pushes the NPV into negative territory. The average ULSD price in both 2006 and 2009 were below the profitability threshold. In these years after-tax profits would have ranged from −$33/bbl to $37/bbl given weekly natural gas and diesel prices. Historically, high natural gas and low diesel prices have coincided: in 2006 diesel prices averaged $92.50/bbl, while natural gas prices averaged $7.55/mmBtu. 2006 losses would have averaged $20/bbl. In 2009, with diesel prices in the $75-$76/bbl range and a natural gas price of $4.20/mmBtu, the NPV would have been −$2.8 billion. The fairly consistent profits depicted in Figure 3-4 since 2007 coincide with the deployment of the Sasol Oryx and Shell Pearl GTL plants, which came online in

2007 and 2011, respectively.

Next I examine a range of capital costs, O&M costs, output mixes, and product prices found in the literature and commodity markets in the DCF model.

High capital cost case(s)

A common risk to capital-intensive projects is an escalation of capital costs once construction begins. In 1999 Shell's SMDS technology was estimated to cost between $48,000 and $55,000 per b/d capacity[44] [62]. Just before breaking ground, the Shell Pearl GTL plant was estimated to cost about $46,000 per b/d capacity [156]. By the end, it cost between $71,000 and $75,000 per b/d capacity [57].[45] In 1999, it was assumed that a Chevron plant using Sasol's FT technology and Chevron's isocracking units [44] would cost between $36,000 and $44,000 per b/d capacity [62]. By 2004, the cost estimate for the Chevron Escravos plant was $64,000 per b/d capacity [156]. By 2010, with the project languishing, the cost estimate was $70,000 per b/d capacity [166, 15]. In 2011, the estimate increased to $247,000 per b/d capacity [166, 15], and at the plant completion in 2014, Chevron Escravos cost $303,000 per b/d capacity.

Modeling the Escravos plant at its final capital cost using the Sasol output ratio (diesel/petrochemical feedstocks/LPGs), the NPV is −$7.6 billion. Even if the Nigerian government were to offer the natural gas for free, the project would still have an NPV of −$5.2 billion. With free natural gas feedstock and zero taxes, the plant NPV would be −$4.1 billion. The Escravos plant could almost break even if there were no taxes, the natural gas was provided free of charge, variable O&M was $1/bbl, the fixed costs were 1% of total CAPEX, the diesel price rose to $136.50/bbl, and the LPG price rose to $67.35/bbl. None of these assumptions is credible. There are few rational reasons why Chevron finished construction. One is that excluding capital costs, there are positive discounted cash flows over the project lifetime. Completion and operation would allow a partial recovery of sunk costs. Chevron may have used

[44] The original figure was inflated from 1999 to 2013 dollars [48].

[45] However, the final figure includes a massive NGL plant and gas purification section that was not part of original estimates. The likely cost escalation was probably less than the 29–63% increase the Shell figures suggest.

the plant as a large-scale pilot to further refine their abilities. Maybe Nigeria hinged the approval of some other more lucrative project on the completion of the Escravos plant.

Under the base case conditions, a capital cost per b/d capacity that escalates beyond $93,000 would render the project infeasible.

High gas/low product price case

Here a high natural gas price and a low diesel price are examined.[46] Other variables will match the base case. Historically a high natural gas price can coincide with a low diesel price. This would make GTL projects infeasible. However, the cointegration literature showed that price relationships can shift over time, and authors have suggested that the post-2009 paradigm is one in which, in equilibrium, natural gas is relatively cheaper than petroleum products [134, 144, 20]. Figure 3-5 traces the shifting crude oil-natural gas price relationship over time, beginning with historical data and extending through the end of the crude oil trading window on the NYMEX futures market. The monthly spot price data are from the U.S. Energy Information Administration (EIA) for WTI crude oil[47] [4] and Henry Hub natural gas[48] [3]. After August 2014, monthly prices are for the NYMEX futures contracts cited in Section 3.3.2 [65, 66]. The relationship was less than 10-to-1 prior to 2009 but shifted to nearly to 20-to-1 after 2013. Natural gas in 2014 is half as expensive in relation to crude oil as it was before the 2009 price turmoil in the petroleum markets. A high natural gas cost (in $/mmBtu) is likely to be accompanied by a crude oil ($/bbl) price that is 20 times greater. Since ULSD is about 15-30% more expensive per barrel than crude oil, the diesel price would be even higher in such a scenario. Table 3.8 depicts a case in which the natural gas rises by 50%, to $7.50/mmBtu. If diesel prices remained

[46] Changing the diesel price automatically changes the petrochemical feedstock price, since the petrochemical feedstock price is a multiplier of the diesel price.

[47] See the page "Spot Prices for Crude Oil and Petroleum Products" for monthly data (`http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm`), accessed September 12, 2014.

[48] See the page "Natural Gas Spot and Futures Contracts (NYMEX), Monthly Henry Hub Natural Gas Spot Price (dollars per million Btu)" for monthly data (`http://www.eia.gov/dnav/ng/ng_pri_fut_s1_w.htm`, accessed September 12, 2014. Use `http://tonto.eia.gov/dnav/ng/hist/rngwhhdm.htm` for direct download of .xls file.

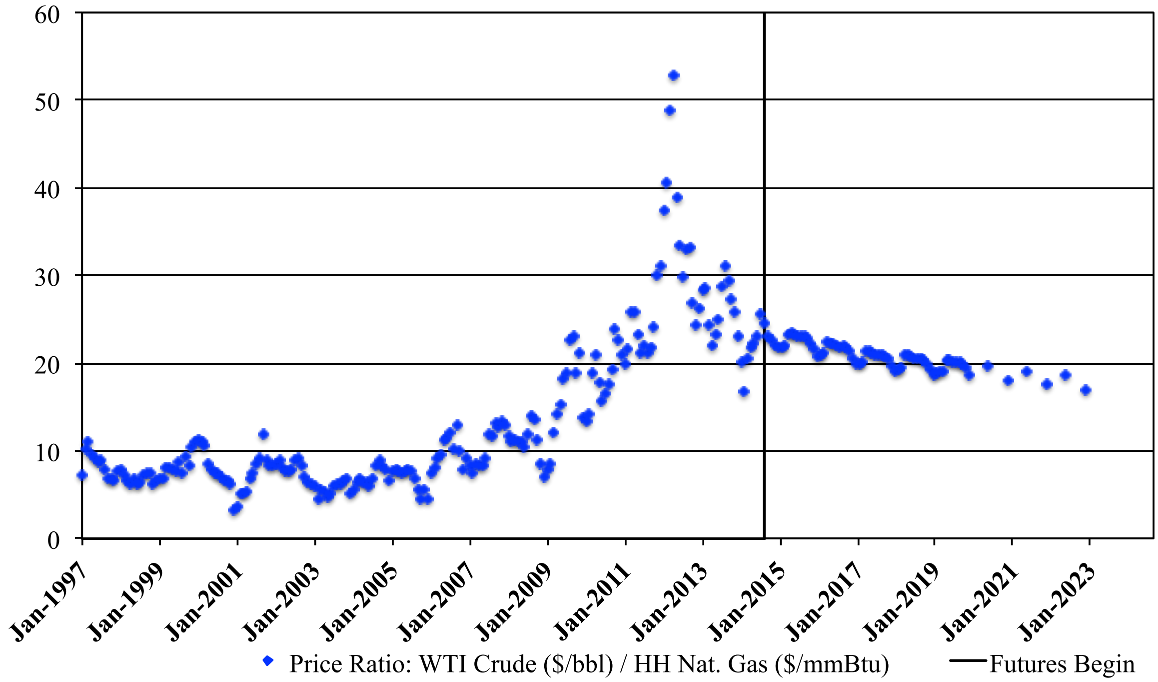

Figure 3-5: Ratio of WTI crude oil to Henry Hub natural gas spot and futures prices ($/bbl:$/mmBtu)

at $115/bbl, the plant would be uneconomic. But this case sets the diesel price at the lowest multiplier of the natural gas price exhibited by the *crude oil*–natural gas pricing relationship in the NYMEX futures curve. The diesel price (in $/bbl) is 17 times greater than the natural gas price in $/mmBtu: $127.50/bbl.[49] Even though the natural gas price rises by 50% over the base case, the diesel price increases by just under 11%. The GTL plant using base-case technology is still profitable in tis scenario. The natural gas price can rise faster than the diesel price without jeopardizing plant profitability. This result hinges on the assumption that current crude oil-natural gas price ratios will hold.

Low-cost gas case

Assuming a stable oil-gas price ratio, inexpensive natural gas would be accompanied by inexpensive diesel and naphtha. In this case, natural gas prices are fixed at their

[49]If diesel were to be priced according to its relationship with crude oil prices, the multiplier on the natural gas price would be between 19.5 and 22.

Table 3.8: Profitability of a GTL project: high-cost gas/low value diesel

Parameters	**Values**
Capital Cost, $/bpd capacity:	$68,000
Gas Input, mmBtu/bbl output:	9.85
Variable O&M, $/bbl:	$5.00
Fixed O&M, $/yr (as annual % of Capital Cost):	4%
Capacity, bbl/d:	120,000
Capacity, bbl/d ULS Diesel:	84,000
Capacity, bbl/d Petrochemical feedstocks:	36,000
Percent Financed:	0%
Capacity utilization:	93%
Number of years for project:	25
Tax Rate:	35%
Interest Rate:	10%
Discount Rate:	10%
Diesel Price, $/bbl:	$127.50
Natural Gas Price, $/mmBtu:	$7.50
NPV:	$1,195,446,823
OPEX (fixed + variable cost), $/bbl (ex fuel), ex tax:	$42.39
OPEX (fixed + variable cost), $/bbl (ex fuel), tax:	$56.21
LCOE, $/bbl, ex tax:	$116.26
LCOE, $/bbl, tax:	$130.08
Internal Rate of Return (IRR):	11.35%

lowest historical level and the lowest historical crude oil-natural gas price ratio is used to set the price of diesel. The minimum weekly natural gas price since 1997[50] was $1.81/mmBtu on December 4, 1998. On that date the crude oil/natural gas price ratio was 8.4, and the crude oil price was $15.20. Setting diesel at the crude price is more conservative than the $56.87 diesel price on that date. The project NPV is −$10 billion. If the $56.87/bbl diesel price is used, the NPV is −$2.1 billion. However, operating revenues are positive, and the project would break even at a discount rate of about 7.3%. For a base case GTL plant to break even at a natural gas price of $1.81/mmBtu and a 10% discount rate, the diesel price would need to be nearly $69/bbl – more than 38 times the cost of natural gas. As the natural gas price increases, the diesel/natural gas price ratio necessary for profitability decreases. For

[50] Prices were inflated to 2013 dollars by using the relative difference between the BEA's GDP price indexes for the nominal price year and 2013. The equation is $\frac{d_{nom}}{d_{2013}}$, where d_{nom} is the GDP deflator in the nominal year and d_{2013} is the GDP deflator in 2013. The resulting figure is multiplied by the nominal price to return the 2013-equivalent price. The data are from the BEA's Table 1.1.4.

example, at a \$5/mmBtu natural gas price, the break-even diesel price is \$97.86/bbl – 19.6 times the natural gas price. At a \$10/mmBtu natural gas price, the break-even diesel price is \$144.58/bbl – 14.45 times the natural gas price, and at a \$15/mmBtu natural gas price, the break-even diesel price is \$191.31/bbl – 12.75 times the natural gas price.

The insight is that a low-cost natural gas feedstock alone will not ensure project viability. Given the historical relationship between natural gas and crude oil prices, and the fact that fixed costs become an ever-larger portion of the plant cost structure as the natural gas price decreases, diesel prices have to be less volatile than natural gas prices in order for the plant to be profitable. When gas prices increase, the diesel price does not need to increase as dramatically in order for the GTL plant to profit. But natural gas price collapses require that diesel prices decline more gradually or the plant will become uneconomic. These price sensitivity analyses point to the utility of a modeling structure capable of treating price shifts endogenously. The DCF model lacks this capability.

Technology breakthrough case

Prices are the biggest source of risk to project profitability. This section explores whether an improvement in GTL technology – a 30% reduction in capital costs per b/d capacity and a 35% reduction in gas feedstock requirements from the base case – mitigates the fuel price risks. Under the base case prices of \$5/mmBtu for natural gas and \$115/bbl for ULSD, the NPV is \$9 billion, with an IRR of 21.1%. Table 3.9 illustrates the potential profitability of a GTL plant under the efficient technology conditions. The capital cost of \$47,600 per b/d of capacity is within the cost range of technologies listed in Table 3.5. The feedstock requirement is lower. The LCOE for this project is \$63 per barrel before taxes, compared to the base case LCOE of over \$91/bbl ex tax. The \$9+ billion NPV suggests room for significant adverse price movements.

However, using the \$1.81/mmBtu natural gas price and the \$15.20/bbl diesel price from the initial run of the low-cost gas scenario, the plant is still uneconomic: NPV

Table 3.9: Profitability of a GTL project: technological breakthrough case

Parameters	**Values**
Capital Cost, \$/bpd capacity:	\$47,600.00
Gas Input, mmBtu/bbl output:	6.40
Variable O&M, \$/bbl:	\$5.00
Fixed O&M, \$/yr (as annual % of Capital Cost):	4%
Capacity, bbl/d:	120,000
Capacity, bbl/d ULS Diesel:	84,000
Capacity, bbl/d Petrochemical feedstocks:	36,000
Percent Financed:	0%
Capacity utilization:	93%
Number of years for project:	25
Tax Rate:	35%
Interest Rate:	10%
Discount Rate:	10%
Diesel Price, \$/bbl:	\$115.00
Natural Gas Price, \$/mmBtu:	\$5.00
NPV:	\$9,023,777,431
OPEX (fixed + variable cost), \$/bbl (ex fuel), ex tax:	\$31.17
OPEX (fixed + variable cost), \$/bbl (ex fuel), tax:,	\$56.71
LCOE, \$/bbl, ex tax:	\$63.18
LCOE, \$/bbl, tax:	\$88.73
Internal Rate of Return (IRR):	21.12%

is -\$6.3 billion. Cash flows are negative in every year of the project. In order for the improved GTL plant to be economic at a \$1.81/mmBtu gas price, the diesel price must be at least \$48.21/bbl – over 26.6 times the gas price. At \$2/mmBtu natural gas, the multiplier falls to 24.6. At \$5/mmBtu natural gas, the multiplier is 13.5. At \$10/mmBtu natural gas, the break-even multiplier for the diesel price in \$/bbl is 9.8. At \$15/mmBtu natural gas, the break-even multiplier is 8.6.

The technological breakthrough case made dramatic improvements to the LCOE and profitability of the plant, but the project's vulnerability to price risk remained high. Price movements pose considerable risks to GTL profitability, and one shortcoming of the DCF model is that those price inputs are exogenously determined by the modeler.

3.3.4 Profitability range of 18 GTL technologies

This section concludes with a summary of the potential profitability of the key technologies described in Table 3.5. Figure 3-6 depicts the profitability band of 18 technologies that exist and have been either deployed as a pilot or commercial plant or have been analyzed by researchers. These include the base case explored in this sec-

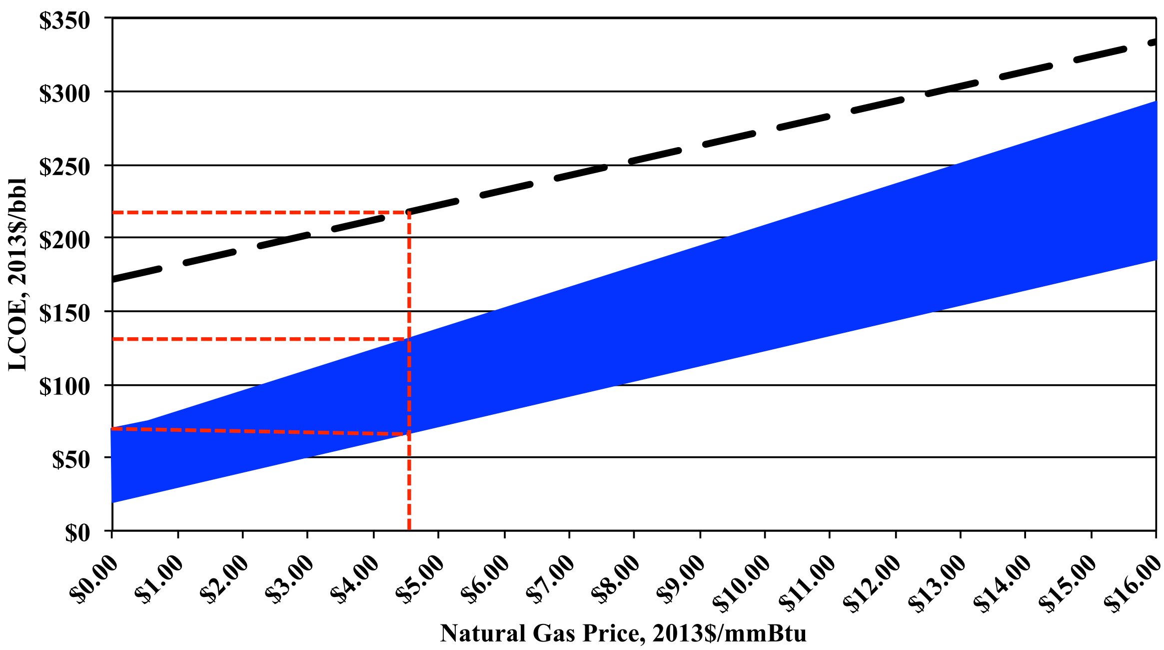

Figure 3-6: LCOE range per barrel of GTL output, 2013$

tion; the Sasol Oryx GTL plant [72, 167]; the Shell Pearl GTL plant [57]; the Chevron Escravos plant [10, 166, 15]; Sasol's proposed Westlake GTL plant [96]; Petro SA's demonstration plant [165, 154]; Shell's Bintulu plant (both before [62] and after the rebuild [136]); the six plant types explored by Robertson in the INEEL study: basic POX, basic SMR, Sasol FT, Exxon AGC-21, BP compact SMR, Syntroleum, and the DOE ceramic membrane [138]; Oak Ridge National Laboratory's (ORNL's) general GTL plant [62]; Salehi et al.'s general plant (base case) [144]; and Bechtel's general GTL plant [30].

The thick blue band represents the range of 17 of the 18 technologies' LCOE values (not including taxes[51]) at any given natural gas price. The black dashed line

[51]Taxes were excluded to reflect the fact that different countries have different tax rates. This

represents the Chevron Escravos unit, which is a significant outlier. The LCOE was determined by summing the OPEX[52] with the product of the natural gas price and the feedstock requirements of each technology. This produced a cost curve for each technology as a function of the natural gas price in \$/mmBtu. One can refer to the LCOE of a barrel of output of the 18 technologies by tracing upwards from any given natural gas price until an intersection with one of the cost curves (either the blue band or the black dashed line). The value on the y-axis at that intersection is the LCOE of the technology at the given natural gas price. The dotted red lines are an example of the LCOE for the technology band and the Escravos plant at a natural gas price of \$4.55/mmBtu. This is the NYMEX price of natural gas for delivery in January 2018. The vertical red line rises from \$4.55/mmBtu. The first horizontal red line is the LCOE of the least-cost GTL technology of the 17 technologies in the blue band: \$69.36/bbl, the cost of the Syntroleum technology as modeled by Robertson [138]. The next red dotted line marks the high-cost end of the 17-technology band: \$128.69/bbl, the cost of the original Bintulu plant's technology circa 1993 [62]. The last red dotted line is the intersection of the \$4.55/mmBtu natural gas price and the cost curve for Chevron's Escravos plant: \$217.79/bbl. Both the Sasol Oryx GTL plant and the Shell Pearl GTL plant cost curves fall at the low end of the technology boundary, with LCOEs of \$71.71/bbl and \$86.37/bbl, respectively. The base case GTL plant is close to these levels, at \$87.20/bbl. For the same delivery date of January 2013, the NYMEX ULSD contract traded at \$112.18/bbl. The weighted barrel value for the 70/30 diesel/petrochemical feedstock mix would be \$118.24. At that price, every technology except the Shell Bintulu plant and the Chevron Escravos plant would at least break even. Even at \$112.18/bbl, only the Sasol Westlake plant (at a loss of 17 cents/bbl) and the Shell Bintulu plant after the 1997 rebuild would be added to the unprofitable list.

The NYMEX futures price spread between diesel and natural gas for January 2018 deliveries is significant: a GTL plant owner could lock in prices on the September 10,

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convention removes any bias toward U.S.-specific scenarios.

[52]OPEX is all fixed and variable costs, including capital recovery, on a per-barrel basis. Fuel costs are not included.

2014 trade date for natural gas by purchasing as many contracts as necessary to cover their feedstock requirements. Then the same plant owner could sell as many diesel contracts as necessary to cover their output. A GTL plant owner could lock in profits over 4 years in advance of operations (as long as that price spread is sufficient to generate profits in the first place). These are the reasons that GTL plant owners are sanguine about project feasibility, even though those that have not yet built plants are leery of taking the risk.

3.4 GTL as a potentially disruptive technology

GTL creates an explicit upstream linkage between the crude oil and natural gas markets by allowing natural gas to compete with crude oil in the production of transportation fuels. Such a technology has a fair chance of shifting long-run price relationships between crude oil and natural gas. GTL plants are already being built at commercial scale, so the technology is not merely fantasy. In some regions, creating transportation fuels from natural gas is cheaper than importing them or producing them from hard-to-access petroleum deposits. In others, the gas resource is easy to access but has no pipeline or LNG[53] route to market. In such cases a GTL plant would generate greater returns than an LNG plant: the GTL plant cost is similar, but the value of the transportation fuels exceed the value of natural gas. GTL lies at the head of a long value chain for energy products. Transportation fuels and other petroleum products are utilized in every industry. Changes to the structure of how those fuels are delivered or their demand and supply balance could affect how every industry uses fuels. The final outcomes through such a web are hard to predict. This is the challenge that modeling the integration of GTL into the economy poses. There is, however, another potential aspect of GTL technology: it has the potential to disrupt the petroleum industry and change the way fossil fuels are extracted and used.

[53]Liquefied Natural Gas.

3.4.1 Is GTL Innovative?

GTL diesel is a higher-performance fuel with less non-GHG pollutants than either petroleum-based ULSD or gasoline. It is a novel method for producing transportation fuels. In this sense, it could fit imperfectly into either or both of James Utterback's main categories for innovative technologies: product or process [171]. GTL producers are a small and growing group of companies, with a fair amount of turnover as the weak competitors are weeded out and the stronger ones grow. This matches the initial flat segment in Utterback's S-curve [171]. Furthermore, the technological improvement in traditional refining has been on a plateau for decades. This sets up the petroleum refining as a potential "prey" industry [171]. However, when the potential impacts of GTL industry growth on the growth of petroleum refining are examined and vice versa, each industry has a negative impact on the growth of the other. This is more a "pure competition" than a "predator-prey" situation [171]. On yet another dimension, the performance of GTL significantly lags petroleum refining. A refinery is an efficient, complex and interconnected set of process technologies. GTL plants are only able to convert about 60% of the feedstock energy into products, but their efficiency has been improving. This efficiency improvement could fit the innovation paradigm defined by Utterback. Furthermore, the GTL process itself is simpler than the petroleum refinery in some respects: there are less units required for processing the FT product, and the paraffinic output is more uniform than the crude oil feedstock that refineries must process. This, too, fits Utterback's innovation paradigm. GTL technologies have another advantage: GTL products integrate seamlessly into existing infrastructure. There are no barriers to adoption. GTL fuels use the same pipelines, tankers, and fuel delivery systems as petroleum-based fuels, and can be mixed with them (improving fuel quality in the process). They can be consumed in the same vehicles or generators that use the traditional petroleum products. This is another aspect of an innovative technology [171].

Despite the similarities between GTL technologies and the "innovative technology" that Utterback describes, Professor Utterback would not consider GTL technologies to be “innovative”.[54] GTL is very old, yet has not been adopted until very recently. It is an example of an old technology that suddenly becomes economic under limited circumstances. Furthermore, GTL does not fit into the predator-prey paradigm that Utterback describes [171]. The interactions between petroleum refining technologies and GTL resembles the pure competition paradigm.

3.4.2 Is GTL disruptive?

GTL technologies are not likely “innovative”. But could they still be disruptive to existing industry? Clayton Christensen describes characteristics of well-established industries that make them vulnerable to disruption. One is that the industry has settled into a clear development path – constant improvement to existing product lines [32]. Novel methods of production or novel products are not pursued, since they siphon resources that could be spent improving current products. They also cater to existing customers. In the U.S., refineries are geared toward providing gasoline to drivers. GTL promises a diesel that performs on par with high-octane gasoline, but with diesel’s fuel efficiency. It would be expensive for existing refiners to re-configure their refineries to produce diesel instead of gasoline. GTL appeals to those who have yet to purchase a car, and who may choose diesel. These are all characteristics of a disruptive technology in a dominant industry that is vulnerable to disruption [32].

Disruptive technologies are usually born within the dominant industry, through its own R&D. DCF modeling shows a lower return than the established activities, and so are not pursued. The new technologies often get spun out to smaller companies, who take the technology and commercialize it – sometimes to the dismay of the original inventors [32]. GTL matches this description. The majority of patents in GTL are held by established energy majors like Shell, ExxonMobil, ChevronTexaco, BP, ConocoPhillips, Sasol, Statoil, etc. With three exceptions now, they have neglected to deploy. Meanwhile, smaller plants based on these technologies are gaining traction, or are at least being talked about (e.g., [53, 95, 91, 176, 51]).

[54] Professor Utterback told me as much himself when I took his class “Disruptive Technologies: Predator or Prey?” in 2010.

Disruptive technologies are *not* necessarily innovative or revolutionary. They are usually simple [32]. GTL has been around for over 80 years. It has simply become economic under certain circumstances (e.g., to provide Qatar with revenues for gas reserves in its North Field that would otherwise have been stranded). A disruptive technology does not enable new activities – it provides an alternative (potentially less expensive) way to provide established products to customers. GTL does not perfectly fit into this category. According to Table 3.10, the cost of the base case GTL plant before taxes is slightly greater than the cost of a refinery of comparable size. If a \$4.18/mmBtu natural gas price were used,[55] the markup for GTL would be just 93% before taxes. At \$3.82/mmBtu,[56] the markup is 89% ex tax, and just 110.3% including U.S. tax rates.

Table 3.10: Cost comparison: base case GTL plant vs. petroleum refinery

	LCOE, \$/bbl, ex tax	**LCOE \$/bbl with US Tax**	**OPEX (LCOE ex fuel), \$/bbl, ex tax**	**OPEX (LCOE ex fuel), \$/bbl, with US tax**
GTL Plant:	\$91.64	\$109.46	\$42.39	\$60.21
Refinery:	\$89.87	\$92.37	\$15.62	\$18.11
GTL Markup:	102.0%	118.5%	271.4%	332.5%

Refinery cost data source: Gary, Handwerk and Kaiser [54].

What makes GTL a potentially disruptive technology is that it does not look as profitable as existing business lines to refineries. A niche market for stranded gas exploitation will not noticeablely increase an energy major's balance sheet. Majors prefer large, stable, capital-intensive and long-lived projects with multi-billion dollar NPVs. GTL lies in a blind spot for established industries [32]. Since small companies would find the risk worthwhile, GTL is an unimaginative but potentially disruptive technology.

[55] This is the mean traded NYMEX futures price as of September 10, 2014.
[56] This is the average price prevailing from 2010-2013.

Chapter 4

Methodology

4.1 The CGE model

A computable general equilibrium (CGE) model simulates microeconomic processes over long time scales. CGE models capture the sectoral activities that link crude oil and natural gas markets. They also model production as a choice between inputs of varying levels of substitutability. Consumption is treated in a similar fashion. In these models, shifts in the price ratio between crude oil and natural gas can be traced back to industry activities. These features make a CGE model appropriate for examining the influence of GTL technology on energy commodity pricing relationships.

To review, my hypothesis is that the crude oil-natural gas price relationship will be affected by the deployment of an energy conversion technology such as GTL. GTL penetration should decrease the oil-gas price ratio.

MIT's Emissions Projection and Policy Analysis (EPPA) model at the Joint Program on the Science and Policy of Global Change includes the features described above. The current version, EPPA6, is described in Chen *et al.* [27]. Details of an earlier version are in Paltsev *et al.* [122]. The global economy is broken into 18 regions and 14 sectors of production, with 2 sectors for consumption: final demand and household transportation. Sectors that use both petroleum products and natural gas are represented, and it includes exploration and production of fossil fuels, oil refining, and power generation. Sectors with heating, transportation, and electricity demand are all included. There is a single producer in each sector that operates under the principle of perfect competition (price equals cost). Each sector produces a single commodity. That commodity is traded under an Armington specification[1] in every case except crude oil. Crude oil is traded under the Heckscher-Ohlin assumption of perfect substitutability across regions. Production functions are nested constant elasticity of substitution (CES) functions. This is useful for examining how one fuel input can be substituted for another. The data in the model are from the Global Trade Analysis Project (GTAP) [112]. The model is calibrated to a 2007 base year. It solves for 2010, then solves through 2100 in five-year intervals thereafter. The model uses a fixed-factor to moderate technological penetration. This is an input to technologies that is initially in short supply, making its initial cost high. The supply increases with output from the new technology, lowering costs and allowing for more rapid penetration over time [111]. The method replicates the "S-curve" penetration profile widely cited in innovation and diffusion literature [171, 32].

I make two modifications to test my hypothesis. First, EPPA uses a single sector and commodity for refined oil, called ROIL. Treating all refined fuels as a single aggregated commodity assumes that demand growth, usage, and tradeability of each refined fuel is uniform, and that each is perfectly interchangeable. I examine the impact of GTL technology penetration on competition between crude oil and natural gas. GTL fuels are only perfectly substitutable with diesel and petrochemical feedstocks, and no other fuels. Furthermore, GTL diesel will compete with more dominant refined fuels (i.e., gasoline) in the transport sector. Natural gas competition with the by-products of petroleum refining need to be examined as well. These all require the ability to model competition *between* distinct refined fuels. A single commodity is too aggregated for this purpose. In 2006, Choumert *et al.* developed a version of EPPA that disaggregated the ROIL commodity into six products: refinery gases, distillate fuels, gasolines, heavy fuel oils, petroleum coke, and other products [31]. He also

[1]The Armington model of trade assumes that internationally-traded products are not uniform in quality or other characteristics, so are not perfectly substitutable. Each commodity has an elasticity of substitution that measures the degree to which imported goods are substitutable with domestically-produced ones.

added technologies that were relevant only if the ROIL product were separated into distinct fuels. The modified model was EPPA-ROIL. I follow Choumert's methodology to break out the individual fuels from the aggregated refined oil (ROIL) product, and add GTL technology.

Second, the aggregated ROIL commodity is traded as an Armington good. This makes sense under an aggregated petroleum product, since many refined fuels are of limited international substitutability. However, for transportation fuels, the Heckscher-Ohlin paradigm of perfect international substitutability is more appropriate for modeling inter-regional trade. The next section briefly describes the disaggregation of the refined oil sector and the modification of trading specifications for transport fuels.

4.2 Adapting the model to this research

The only criterion that the EPPA model did not meet was the ability to track differences in the market interactions of distinct refined fuels – demand and supply growth, usage, trade, inter-fuel competition, and pricing. Therefore most of the modifications to the model involved separating the individual refined fuel volumes and value flows from the aggregated refined oil commodity (ROIL), and then modifying sectoral production functions to utilize or produce these specific fuels. Drawing from Choumert's earlier work [31], I separated refined oil into six products. These were refinery gases (RGAS), distillate fuels including diesel and jet fuel (DISL), gasoline-type fuels (GSLN), heavy (residual) fuel oil (HFOL), petroleum coke (COKE), and other products including petrochemical feedstocks, lubricants, and waxes (OTHP). I adapted the production functions of each sector that used/created refined fuels to the specific fuels being used/created. This section is a brief summary of the work. Appendix A provides greater detail.

The GTAP8 database provides the initial data [113]. It has volume and value flow data for domestic production, consumption, and international trade of an aggregated refined oil commodity across multiple regions and sectors. I broke these data into volume and value flows for specific fuels by using alternative data sources providing product-specific detail. These sources used distinct methods of aggregation and accounting, so totals did not match. To compensate, I calculated each petroleum product's *share* of the total refined product volume or value, in each activity, in each sector, within each region. The share was multiplied by the original GTAP aggregated refined product value. The result was an estimate for each refined fuel that summed to the original GTAP value. This preserved the balanced nature of the GTAP database and enabled its use as a social accounting matrix for the CGE model.

I used the IEA Energy Statistics and Balances Database[2] [5] to break out the volumes produced, consumed, imported and exported of the individual refined fuels. I estimated product prices (with and without taxes) using a combination of the IEA Energy Prices and Taxes database [79], the EIA State Energy Data System (SEDS) database [169], and GTAP. Value flows were estimated by multiplying volumes by prices. Each fuel's share of total refined commodity values was calculated to break out the value flows from the GTAP8 data. Data from the International Council on Clean Transportation (ICCT) Global Transportation Roadmap model [77] were used to disaggregate the household transportation fuel usage in each region.

I estimated the international trade flows of the six refined fuels. I used a function minimizing the difference between the initially-estimated import and export volumes and values of each fuel and the optimized figures, subject to a number of constraints: price must equal cost for every product in every sector (the "zero-profit condition"), domestic and imported markets must clear,[3] and the inter-regional trade of all products must sum to the GTAP8 value for the single refined oil commodity.

The production function of each sector in the model was then adapted to the specific fuel it used or created. Nine technologies from the earlier version of EPPA-ROIL were updated to the new 2007 base year values and included in the model. I also added a CGE representation of the GTL technology, described below.

[2] `http://www.oecd-ilibrary.org/energy/data/iea-world-energy-statistics-and-balances_enestats-data-en`

[3] Domestic market clearing means that the total amount spent on a good in a region must equal the sum of expenditures on that good in each sector of that region. Imported market clearing means that the total value imported (after accounting for transport costs, export subsidies, and import tariffs) must equal the market value of imported goods in each sector of each region.

4.2.1 Representing GTL in a CGE context

GTL was described in Chapter 3. I adapted the base case GTL cost from Section 3.3.3 to the 2007 prices of fuels derived from the disaggregated GTAP database. The natural gas input cost is the Armington price.[4] Distillate and petrochemical feedstock output is based on the domestic production cost of each fuel. Table 4.1 reports the base case GTL cost in 2007 U.S. prices. This was repeated for each

Table 4.1: Base case input variables to GTL for DCF analysis: USA

Parameter and units	Value
Capital Cost, $/bpd capacity:	68,000
Gas Input, mmBtu/bbl output:	9.85
Variable O&M, $/bbl:	5.00
Fixed O&M, % of Capital Cost/yr:	4.00
Capacity, bbl/d:	120,000
Capacity, bbl/d ULS Diesel (DISL):	84,000
Capacity, bbl/d Petrochemical feedstocks (OTHP):	36,000
Percent Financed, %:	0.00
Capacity utilization, %:	93.00
Number of years for project (after 3 year construction):	25
Tax Rate, %:	35.00
Interest Rate, %:	10.00
Discount Rate, %:	10.00
Diesel (DISL) Price, $/bbl:	49.83
Petrochemical Feedstock (OTHP) Price, $/bbl:	102.60
Natural Gas Price, $/mmBtu:	6.79

region so GTL could be modeled anywhere. This dissertation focuses on the USA, so regional details are omitted. The only differences across regions were the values of diesel, petrochemical feedstocks, and natural gas. The DCF model was run and the LCOE per barrel was calculated. This was compared to the weighted output value (70% diesel and 30% petrochemical feedstocks by volume). The LCOE divided by the weighted output value is the markup. The markup is the cost of GTL relative to an oil refinery in the base year.

I adapted the cost data to a nested constant elasticity of substitution (CES) production block. Each input bundle is related through an elasticity of substitution

[4] The Armington price is the weighted average price of a product accounting for both imports and domestic supplies.

σ. Whenever substitutability is identical across multiple inputs, more than two inputs were included in a single nest. The elasticity of substitution measures the ease with which one input can be substituted for another. It is the slope of the relative amounts of two inputs in the graph of a production function at the calibration point. It must be positive. When σ is equal to zero, there is no substitutability. This is called a Leontief input structure. Outputs are related by an elasticity of transformation, τ, and function in the same manner. Figure 4-1 depicts the GTL CES nesting structure. The Labor (L) inputs are the Fixed and Variable O&M cost *share* of the total LCOE

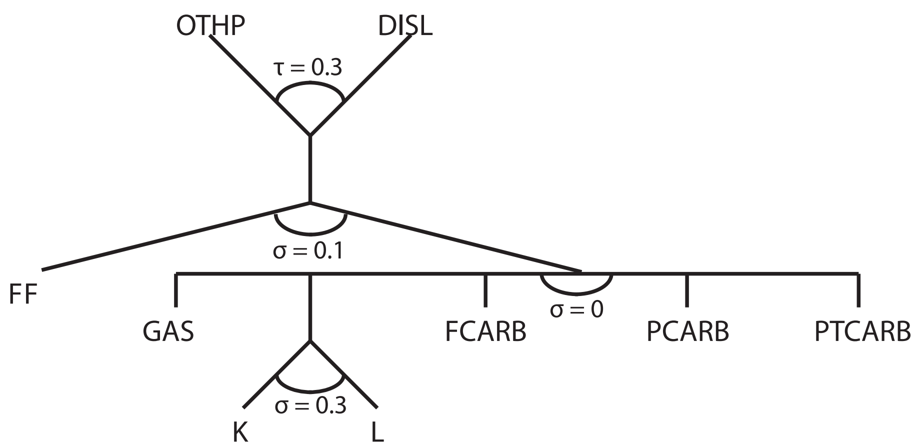

Figure 4-1: CES nesting structure for GTL

per barrel over the project's 25-year lifetime. Capital (K) inputs are the capital expenditure share of total LCOE per barrel. The GAS input is the natural gas cost share of total LCOE costs per barrel. FF is the fixed factor input cost share.[5] Normally the fixed factor would range from 1-5% of total input costs. This dissertation sets the fixed factor share to zero to examine the effects of GTL penetration *at equilibrium*. There are three additional inputs: FCARB, PCARB, and PTCARB. FCARB is the non-tradable CO_2 permit price on final demand emissions. PCARB is the non-tradable CO_2 permit price on all emissions, and PTCARB is the tradable CO_2 permit price on all emissions. This research enacts no climate policies, so the

[5]The fixed factor was described above. It serves to limit the rate of penetration of a new technology in its early phases of deployment.

inputs for these are zero.

GTL technology inputs are inflexible. Capital and labor are of limited substitutability, with a σ of 0.3. The K-L bundle, the GAS inputs, and the carbon permits are all in a Leontief nest, so are not substitutable. I negate the fixed factor input, so the value of σ in the nest with the FF input is re-set to 1.0, which avoids distorting the input shares as they face a 0% fixed factor input. The τ elasticity of transformation between DISL and OTHP outputs is 0.3. The 70/30 DISL/OTHP ratio is difficult to alter.

4.3 Designing the experiment

I design a set of experiments for hypothesis testing: the crude oil-natural gas price ratio will fall with the penetration of an energy conversion technology such as GTL. The ratio is the crude oil price, in dollars per barrel ($/bbl) is divided by the natural gas price, in dollars per million Btu ($/mmBtu). An oil-gas price ratio shift means that either the crude oil price changes, the natural gas price changes, or both change at different rates or in opposite directions. This informs my experimental design.

4.3.1 Factors that affect the crude oil-natural gas price ratio and GTL penetration

There are three categories of drivers that could change the oil-gas price ratio as GTL penetrates. One set of drivers influences the crude oil price. Another set of drivers affects the natural gas price. The third set of drivers affects the rate and extent of GTL penetration.

A number of factors drive crude oil supply and demand, which together influence its price. One is the resource base, another is its production cost, and another is the cost of refining. My hypothesis focuses on one major driver of crude oil demand: the demand for transportation fuels. As transportation demand grows, so does the demand for transportation fuels. Transportation fuels are produced almost solely by refining crude oil. If GTL plants successfully compete with oil refineries, then not all of the increased demand for transportation fuels will translate into increased demand for crude oil; some of it will translate into increased demand for natural gas. This relative weakening of crude oil demand should moderate its price increases over time. In order to keep price movements of crude oil endogenous to its level of competition with GTL, I do not directly influence the crude oil price. This leaves two other categories of drivers that can provide variability: drivers of the natural gas price, and drivers of the rate and extent of GTL penetration.

Natural gas is the only energy input to the GTL plant.[6] Therefore, a change in the natural gas price will also affect the economics of GTL. Unlike crude oil, natural gas is not easily traded internationally. Natural gas tends to be traded by pipeline,[7] and export markets are thus limited. It is priced as a good under the Armington trade model. The natural gas price in the USA was very high in 2007, especially compared to prices after 2009. Since I want GTL to penetrate in at least some cases, I consider drivers that reduce the natural gas price.

Two supply-side drivers of the natural gas price are the amount of natural gas resources and the existence of extraction technologies that can lower the cost of production. Shale gas drilling techniques are an example of the latter. The existence of improved extraction technologies can also expand the amount of reserves considered technically feasible for extraction.

A third set of factors that can affect the crude oil-natural gas price ratio are those that influence the economics of GTL technology. The cost of a GTL project is a key factor in its potential level of market penetration. As Figure 4-1 depicts, GTL costs are expressed through three inputs: capital costs, labor costs, and natural gas input costs. Since the natural gas price is endogenous, either capital and labor costs can be manipulated, or the energy efficiency of GTL technology can be modified.

Whether or not international trade in diesel fuels is possible is a factor that po-

[6]GTL plants also consume electricity. The way GTL has been priced in this study includes a gas-fired generator that provides all of the plant's electricity needs with no surplus. Thus natural gas is the only external energy input.

[7]So far LNG shipments make up a small fraction of natural gas trade and consumption. It is also very expensive.

tentially affects the crude oil price, the natural gas price, and GTL penetration all together. This dissertation already restricts GTL technology to the USA. I could prohibit distillate exports from the USA. If the only market for the additional supplies of diesel were the US region itself, this could limit GTL penetration. It could exacerbate the impacts of excess diesel supplies in the region, with uncertain effects on the global diesel and crude oil prices. Enabling or disabling the export of GTL diesels from the USA is a potentially insightful lever.

4.3.2 Experimental design

I design a three-dimensional experiment, drawing from the crude oil-natural gas price drivers. The first dimension alters natural gas production costs. Three technology proxies in this dimension make global natural gas production progressively less expensive. The second dimension is a set of three GTL technology cost/efficiency scenarios, each progressively less expensive and more efficient. The third dimension regards the international trade of distillate fuels. There are two states: in the first, the USA (which is not currently a net exporter of diesel) cannot export distillate fuels from the country. In the second, exports are permitted. Figure 4-2 illustrates. The natural gas production cost dimension is labeled "Gas Cost Multiplier". In the "H" scenario, the current best estimate of gas extraction costs are used, so the multiplier is 1. This is the baseline. In the "M" scenario, gas production costs are cut to 2/3 of the baseline, and in the "L" scenario, gas production costs are cut to 1/3 of the baseline. The cost reduction is universal across all regions. This enables me to model the impact of an additional technology on the crude oil-natural gas price ratio. The gas production cost reductions correspond to the deployment of a supply-side technology such as fracking. The technology comes online over a single 5-year interval and instantly reduces natural gas production costs. This will cause a corresponding upward shift in the crude oil-natural gas price ratio. Varying the natural gas production costs should create three distinct crude oil-natural gas price ratio paths in which GTL technologies can compete. The difference in GTL penetration rates, and their effects, can be measured as they are deployed across these distinct cost scenarios.

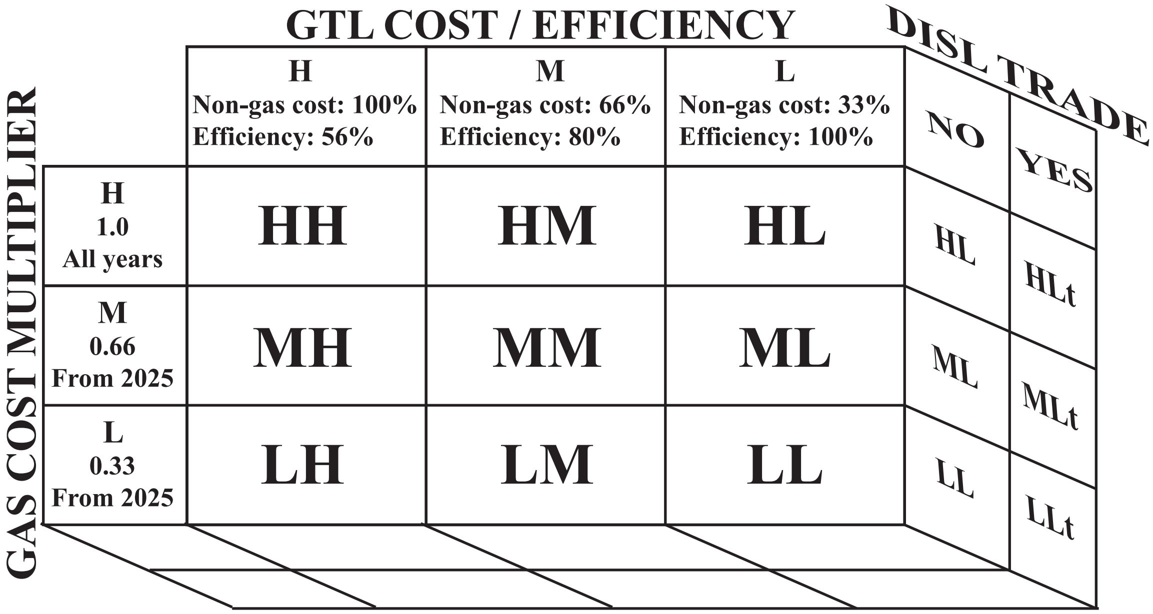

Figure 4-2: 3-dimensional experimental design matrix

The second dimension models distinct cost/efficiency combinations for GTL technology. Table 4.2 details the how the input shares of natural gas (GAS), capital (K), and labor (L) vary under different assumptions about cost and efficiency, and how these changes translate into changes in the markup. The fixed factor input is zero in each case, which allows the analysis to focus on the economic conditions once GTL reaches its equilibrium level of penetration. Including various cost/efficiency scenarios

Table 4.2: USA input shares to GTL for three cost scenarios

Case name	Cost adjustment	Efficiency	GAS	K	L	Markup
H	100%	60%	61.2%	26.9%	11.9%	1.665
M	66%	80%	64.3%	26.4%	9.3%	1.117
L	33%	100%	75.9%	19.2%	4.9%	0.771

allows for a range of potential GTL penetration levels. GTL can never be made less expensive than an oil refinery in the USA under any capital or labor cost reductions alone. Since prices are endogenous to the model, the gas input price cannot be manipulated for the base year. Only increasing the fuel efficiency can make a GTL plant less expensive than oil refineries for producing distillates and petrochemical feedstocks. While 100% efficiency is not thermodynamically possible, it spans the solution space for a range of GTL penetration levels from zero to saturation. The extent of GTL penetration should correlate with GTL's impact on the crude oil-natural gas price ratio.

The third dimension controls whether the USA can export its distillates or not. The initial scenario will prohibit distillate (DISL) exports (No-DISL-Trade). This baseline will not use any additional labeling for the cases (HH, HM, HL, MH, MM, ML, LH, LM, and LL). In another scenario, distillate exports will be allowed from the USA (DISL-Trade). To distinguish these cases from the No-DISL-Trade cases, I append a "t" to the case label for "trade". This makes the case labels under the DISL-Trade scenario HHt, HMt, HLt, MHt, MMt, MLt, LHt, LMt, and LLt.

Uniform conditions across all cases

Under the base assumptions for cost and efficiency, GTL is too expensive to be viable in the U.S. The technology does not deploy under normal circumstances. Even under the low-cost, high efficiency cases, an initial GTL penetration increases demand on natural gas, and its price rises high enough to halt GTL penetration. Early tests showed deployment in other regions. However, U.S. economic data are among the most complete and reliable across all of the regions in the model, so the confidence in the outcomes there is higher than for a smaller or less developed region. Furthermore, the U.S. is the world's largest economy, so events there affect the rest of the world. In order to produce cases in which GTL is sufficiently viable that it actually penetrates in the U.S., some universal conditions had to be set that apply to all of the scenarios.

Natural gas resource constraints were an issue, since the U.S. is already a major consumer of natural gas. The growth of the GTL industry was inhibited because resource scarcity in natural gas made the technology uneconomic after low levels of penetration. To remove the resource constraint on natural gas, initial natural gas resource estimates were multiplied by 100. In order to further weaken the potential that resource scarcity would preclude GTL expansion, the elasticity of supply for natural gas (the ability of the natural gas resource to substitute for other inputs like capital and labor) was increased sixfold, from 0.5 to 3.0. This enabled additional gas resources to substitute for labor or capital should they become expensive. In order to avoid causing market distortions, the resource expansion and elasticity of supply modification was applied to every region. The requirement of a fixed factor input to GTL was also suppressed. This allows GTL to penetrate to the extent that the market will allow in each period. Otherwise, GTL might still be in the early stages of penetration at the end of the model horizon, and its eventual price impact could not be measured. Additionally, technologies are deployed at different points in time so that their impacts can be isolated: GTL is available only in the USA starting in 2020. The natural gas production cost reduction technology deploys globally in 2025. The model is run through 2100 in every case.

All together there are 18 distinct cases across the three dimensions. The next chapter will discuss the most illuminating results across the 18 cases and whether (and under which circumstances) GTL competition with oil refineries had an impact on the crude oil-natural gas price relationship.

Chapter 5

Results

Empirical research identifies a long-run relationship between crude oil and natural gas prices after filtering out short-term volatility [172, 21, 73]. In 2010 it was discovered that the long-run price relationship between crude oil and natural gas had shifted to a new equilibrium from 2006 through 2009 as both oil and natural gas prices rose steeply [133, 134]. An oil price collapse in 2009, combined with a halving of the US natural gas price in 2009-2010, led many to hypothesize that the two commodity prices had become de-linked. Later research concluded that the link in the USA had been re-established at another level [98, 20]. Data availability has limited the time horizon that could be examined, precluding a clear identification of a longer-term trend in price evolution. A recurring hypothesis for the crude oil and natural gas price linkage was that there were opportunities for substitution between the fuels in sectoral activity. The substitutability would have been due to the combination of technologies in use. Shale gas fracking was one hypothesized cause for the collapse of natural gas prices at the end of 2009, which established a new oil-gas price relationship. However, the natural gas price collapse could have been due to the global recession that reduced demand for natural gas. Disentangling the effects of each potential cause is difficult.

The focus of this dissertation is to determine whether GTL can shift the crude oil-natural gas price relationship, and under what conditions. My hypothesis is that the crude oil-natural gas price relationship will decrease with the deployment of GTL technology.

Empirically testing the historical influence of a new technology on the crude oil-natural gas price relationship is difficult. This is because most technologies deploy incrementally, and the prices of both oil and gas move erratically in response to seasons, weather, catastrophes and geopolitical events. Unexpected events exert greater temporary influence on prices than the impact of a gradual deployment of the technology. The fall in the natural gas price in 2009 is an example of temporary events drowning out the gradual impact of a technological deployment. I employ a CGE model to examine the influence that the deployment of an energy conversion technology would have on crude oil and natural gas price ratios in the absence of the stochastic shocks that occur in real life.

My experimental design is to test the interactions of two distinct technological deployments. One is a supply-side technology that lowers the cost of producing natural gas to a fraction of its baseline production cost. The gas cost reduction technology should shift the crude oil-natural gas price ratio upward. The other technology is GTL. If it is inexpensive enough to penetrate sufficiently, it should eventually decrease the crude oil-natural gas price ratio. The experimental design is detailed in Section 4.3, and the series of cases is depicted in Figure 4-2.

5.1 The effects of energy technology penetration on the crude oil-natural gas price relationship when distillate exports are restricted

All nine cases were examined under the No-DISL-Trade scenario in which the USA cannot export distillate fuels.[1] The medium and low-cost natural gas technology deployments provoked immediate changes in the crude oil-natural gas price ratio. In the ML, LM, and LL cases, overall GTL costs were low enough that GTL penetration resulted in a second, gradual shift in the oil-gas price ratio. The three cases that

[1]The No-DISL-Trade cases have no additional labeling. The DISL-Trade cases, in which exports of distillate fuels are enabled, have a "t" appended to their labels.

mark the extremes of the cost ranges studied provide the most illustrative results. These are the HH, LH, and LL cases. The impact of GTL penetration on the crude oil-natural gas price ratio in these three cases is depicted in Figure 5-1. Reported

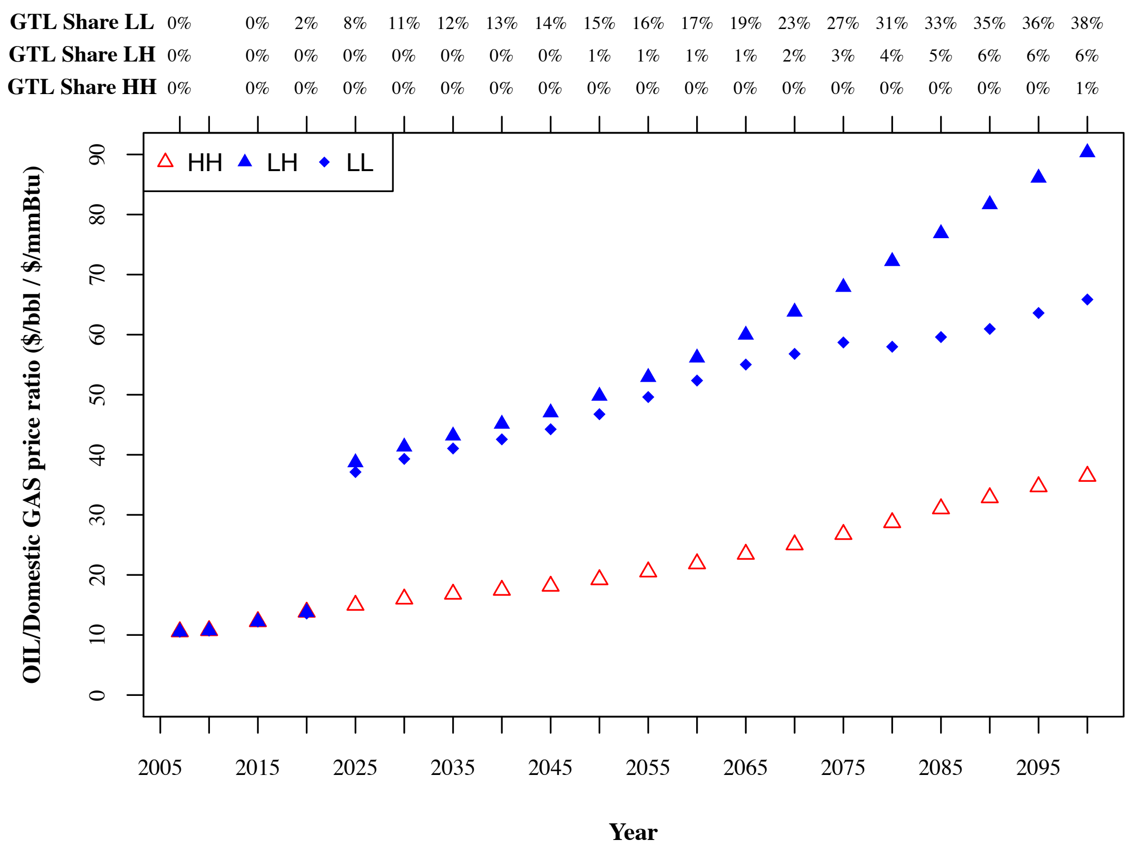

Figure 5-1: World crude oil / domestic natural gas price ratios ($/bbl / $/mmBtu) for three GTL and natural gas production cost cases: No-DISL-Trade

along the x-axis above the graph is GTL production as a share of global refined fuel production in each case for each year.

I measure all impacts in reference to the HH case, which serves as a baseline. The HH case used current cost estimates of natural gas production and GTL for its scenario modeling. It was named HH because these estimates represented the highest costs for natural gas production and GTL in the set of experiments. Like all cases, the HH case assumed a massive expansion of natural gas reserves. Although gas production costs remain the same, scarcity due to natural gas resource depletion is negated as a factor that could affect the crude oil-natural gas price ratio.

Under the HH case, the oil-gas price ratio rose from 10-to-1 to 36-to-1 over the course of the simulation. This is because of the difference in relative growth in sectors driving demand for crude oil versus natural gas. As developing countries became more wealthy, their demand for transportation increased rapidly. Many of these countries are located in warmer regions, where heating demand is weak. Electricity demand for cooling grew in these developing regions, but in electricity generation natural gas primarily competes with coal. Nothing competes with crude oil for transportation fuel demand. Thus while all of the increase in transportation fuel demand translated to an increase in crude oil demand, only a portion of the increase in electricity demand translated to an increase in natural gas demand. The result is that crude oil demand rose more rapidly than natural gas demand, so the crude oil price rose more rapidly than the natural gas price. This made the oil-gas price ratio slope upward. The other eight cases are experiments that change one or more of the conditions in the HH case.

The other two cases in Figure 5-1 produced the most extreme shifts in the oil-gas price ratio. Each shift was a response to the penetration of one of the two experimental technologies. The first shift in the ratio was a result of the deployment of the low-cost gas production technology, which is akin to the worldwide deployment of an advanced version of natural gas fracking technology. It caused an immediate reduction in the cost of producing natural gas. The LH case (blue triangles) traced the impact of the deployment of the low-cost gas production technology on the oil-gas price ratio when GTL costs were too high for GTL to become an effective competitor to oil refineries. The second shift was a gradual transition in response to the penetration of the lowest-cost GTL technology in the USA. This is the LL case (blue diamonds). Once GTL reached a certain threshold of global refined fuel production, the oil-gas price ratio began to fall below the LH trend line. GTL was only able to provoke the second shift in the ratio if one of the lower-cost natural gas production technologies had deployed first. These were the ML, LM, and LL cases.

The first price ratio shift was immediate and it was the most extreme. The global deployment of gas production technology cut natural gas production costs to 1/3 of the baseline. This decreased the cost of natural gas production (and thus its price) worldwide in the LH and LL cases. The lower natural gas price pushed the crude oil-natural gas price ratio from 14-to-1 to 39-to-1. The shift in the oil-gas price ratio was nearly four times greater than the shift when the medium-cost gas production technology was deployed, despite the lowest-cost version being only half as expensive as the medium-cost version. Low production costs, combined with plentiful natural gas reserves, stabilized natural gas prices. Natural gas became more competitive in the sectors where it was active, and natural gas demand increased. However, the nature of the cost multiplier meant that any increase in demand only translated into 1/3 of the cost impact that would have occurred in the high gas cost cases. This dampened increases in natural gas prices going forward. Crude oil prices continued to rise. The result was a steeper curve, terminating in a 90-to-1 oil-gas price ratio by the end of the time horizon in the LH case. The oil-gas price ratio rose more steeply after the implementation of the low-cost gas production technology in the LH case. This was not due to some causal relationship between crude oil and natural gas, but simply because the gas production technology made natural gas comparatively less expensive. This means that the technology did not increase competition between natural gas and crude oil, despite the fact that natural gas became much cheaper. This result is counterintuitive to the assumptions made about substitutability between refined fuels and natural gas in the economy. The implication is that there is not enough opportunity for substitution between the fuels to significantly affect their relative demand. Otherwise, the fall in the natural gas price would have made it an attractive fuel to use in lieu of petroleum products, and their prices should have converged as natural gas demand increased and crude oil demand weakened.

In the LH case, there was no sector where low-cost gas could significantly compete against products that drive crude oil demand. The baseline cost/efficiency GTL technology in the LH case was not sufficiently competitive with oil refineries to displace oil-based transportation fuels, so the crude oil price continued to rise with transportation demand. Other sectors where natural gas usage expanded due to low costs either (1) used so little fuel that even the displacement of petroleum products by natural gas had little overall impact on the global demand for crude oil (e.g., forestry, dwellings), or (2) had little or no petroleum products in use, so natural gas displaced non-petroleum fuels (like coal in the electric generation sector).

The second oil-gas price ratio shift was due to the penetration of extremely low-cost GTL in the LL case. It involved a gradual flattening of the slope of the oil-gas price ratio. The low-cost natural gas feedstock, combined with the low cost and high efficiency of the GTL technology, enabled steady penetration of GTL plants. Unlike the LH case, in which the main shift was due to natural gas cost decreases, the LL case featured a cost-competitive GTL technology. Low-cost GTL enabled low-cost production of transportation fuels. This effectively dampened the price increases in transportation fuels by capping their cost of production. In the US, capacity additions to meet growing transportation demand went to the more cost-effective GTL plants. The result was an increasing market share for GTL fuels as overall transportation demand increased. This made crude oil demand increase more slowly than in the LH case, and depressed its price growth. The result was to pull the oil-gas price ratio below the LH levels. The LL scenario depicts the impact on the oil-gas price ratio when technology penetration *increases* competition between natural gas and crude oil.

The assumptions behind the costs and implementation of both technologies are extreme. The low-cost gas production technology is an immediate and global breakthrough. The decline in natural gas production costs in the US due to fracking technology actually falls between the medium- and low-cost gas production technologies modeled in this experiment. The difference is that in this set of experiments it is deployed globally under the assumption that every region can utilize it. The assumptions surrounding GTL costs are more extreme. GTL is of a dubiously low cost and a thermodynamically impossible efficiency – and only available in a single region. The medium-cost GTL case is probably at the thermodynamic limit of what the most efficient, lowest-cost GTL technology could achieve, and even then it is slightly more expensive than petroleum refining in the US. The lowest-cost scenario is less expensive and more efficient (100%) than even the most optimistic GTL boosters would imagine. However, these experiments clearly expose the nature of the shifts in the oil-gas price ratio and make the usually-subtle changes, market interactions and market responses that moderate this shift much clearer than would be found under more moderate assumptions. The fact that only the lower-cost versions of GTL (operating under lower-cost gas production scenarios) managed to provoke noticeable changes in the ratio attest to the utility of examining the market impacts and interactions with extremely cost-effective versions of the technologies. It appeared that if GTL were inexpensive enough (including the costs of feedstock) for its capacity to reach over 1/5 of global refined fuel production capacity, the demand for crude oil could be dampened and crude oil price increases could be muted.

Brief description of the cases not covered in Figure 5-1

I will briefly describe the outcomes of the six cases that are not depicted in Figure 5-1. The HM case[2] involved GTL deployment as early as 2045, but total penetration never exceeded 6% of global refined fuel production by 2100. The impact on the oil-gas price ratio is indiscernible. The HL case[3] featured GTL deployment in 2020, as soon as it was ready for potential deployment. By 2100, its penetration level had reached nearly 21% of global refined fuel production. However, the price effect was very minor. It was not substantial enough to be considered a significant shift in the oil-gas price ratio that prevailed in the HH case.

All three of the middle-gas cost cases[4] showed an immediate upward shift in the crude oil-natural gas price ratio of about 45%, from 14-to-1 to 22-to-1, in 2025. The new trend was slightly steeper than the HH trend depicted in Figure 5-1. The MH case[5] deployed GTL in 2055 initially. Output grew to about 2.4% of global refined fuel production. GTL penetration did not dampen the steady increase in the oil-gas

[2]The HM case was the high gas/medium GTL cost scenario. The baseline natural gas cost was used, and GTL costs were 66% of the baseline, with an efficiency of 80%.

[3]The HL case was the high gas/low GTL cost scenario. The baseline natural gas cost was used, and the GTL costs were 33% of the baseline, with an efficiency of 100%.

[4]In the "M" gas-cost scenario, the natural gas production cost was cut to 2/3 of the baseline production cost.

[5]The MH case was the medium gas/high GTL cost case. The natural gas production cost was cut to 2/3 of the baseline in 2025, and GTL at the baseline cost was ready for deployment in 2020.

price ratio through 2100. The MM case[6] initially deployed GTL in 2020 in a very small capacity. By 2100, GTL output in the MM case had reached nearly 10% of global refined fuel output, but it still made only an insignificant shift in the oil-gas price ratio. The ML case[7] was one of the three cases that dampened the increases in the crude oil-natural gas price ratio. Initial GTL deployment occurred in 2020. By 2085, when the oil-gas price ratio fell below the MH trend line, GTL output was just over 20% of global refined fuel output, and by 2100 the total GTL share reached nearly 31%.

The only other case not discussed thus far was the LM case.[8] All three cases using the low-cost natural gas production technologies shifted strongly as soon as the technology was deployed in 2025. The oil-gas price ratio increased by over 160%, to 39-to-1 from its 14-to-1 baseline. In the LM case GTL deployed initially in 2020, as soon as it was ready for deployment. The first noticeable deviation from the LH trend line occurred in 2095, when GTL output was about 18% of global refined fuel production. By 2100, the output level had reached 22% of global refined fuel production.

5.1.1 Differences between the shifts in the oil-gas price ratios

The first shift in the price ratio developed more rapidly than the second. This is not solely because the development of the GTL industry depended on the prior deployment of the gas production technology.[9] It is due to the markets in which each technology competes. The low-cost gas production technology operates at the wellhead. This technology complements existing production technologies – it does not compete with them. Decreasing the cost of natural gas production globally directly

[6]The MM case was the medium gas/medium GTL cost case. The natural gas production cost was cut to 2/3 of the baseline in 2025, and the GTL cost was 66% of the baseline, with an efficiency of 80% and deployable in 2020.

[7]The ML case was the medium gas/low GTL cost case. The natural gas production cost was cut to 2/3 of the baseline in 2025, and the GTL cost was 33% of the baseline, with an efficiency of 100%.

[8]The LM case was the low gas/medium GTL cost case. The natural gas production cost was cut to 1/3 of the baseline in 2025, and the GTL cost was 66% of the baseline, with an efficiency of 80% and deployable in 2020.

[9]After all, without the growth restriction (the fixed-factor input) GTL instantly expands to the size the market can bear.

translates into a fall in the natural gas price. A falling natural gas price directly results in a rising oil-gas price ratio. The technology operates in a single sector (natural gas production). It does not create any additional linkages between sectors, but it does make natural gas more attractive in the sectors that already use natural gas.

The market integration of GTL, on the other hand, is more complex. GTL deploys into the transportation fuels market, in which oil refining is a single dominant player. GTL competes only if it can make transportation fuels at or below the cost of oil refineries. At the date of availability, oil refineries already have all of the capacity needed to cover all of the demand for transportation fuels. GTL enters the market by deploying to meet the incremental increases in transportation fuel demand. The investor must prefer to build a new GTL plant rather than a new oil refinery to meet increases in transportation fuel demand. Second, GTL makes diesel, which is only one of the major transportation fuels. Diesel is the dominant fuel in commercial transportation, but gasoline is the dominant fuel in private transportation. GTL must make diesel at a low enough cost that private consumers switch from diesel to gasoline when they make their next vehicle purchase. This process also takes time. Eventually, enough consumption has shifted away from gasoline and toward diesel that oil refiners have lost their two most profitable outputs, and must cut production. This dampens global crude oil demand, and flattens its price. Once crude oil prices stop rising, the oil-gas price ratio stabilizes at the second shift. Another factor is the restrictions imposed on trade in the No-DISL-Trade scenario. The market for GTL diesel is limited to the USA in this set of cases, so regardless of what happens globally to the demand for diesel fuels, GTL can only serve the US markets.

The two technologies have distinct implications regarding inter-fuel competition. The first shift in the oil-gas price ratio was the result of a technology that did not increase competition between crude oil and natural gas. It muted natural gas price increases, but did nothing to affect the unabated growth in crude oil demand. This resulted in a widening rift between crude oil and natural gas prices, and an increasing oil-gas price ratio. The second shift was the result of GTL technology penetration, which increased competition between crude oil and natural gas through transportation fuel production. This meant that eventually, GTL could reach enough market share to depress the increase in crude oil demand, which dampened its price increases. This decreased the oil-gas price ratio and stabilized it over time.

5.1.2 Changing dynamics in response to technology deployments

Low-cost natural gas production technology deployment cut gas production costs to 1/3 of their baseline level immediately. This resulted in an almost four-fold increase in the crude oil-natural gas price ratio in both the LH and LL cases. In the LL case, a second shift in the oil-gas price ratio developed gradually as low-cost GTL managed to displace oil-sourced refined fuels in the transportation sector. This section will examine the changes in market structure that were the consequence of the first ratio shift and which laid the groundwork for the second shift.

The most apparent consequence of the first shift in the oil-gas price ratio was a drop in US domestic natural gas prices to about 40% of their prior value. This made natural gas attractive in the sectors in which natural gas competed. There was a sharp increase in the use of natural gas worldwide. After the technology deployment, global natural gas consumption was 80-90% higher than the HH case. Over time consumption further increased as sectors where natural gas competed shifted more sharply toward natural gas usage.

The final demand sector is illustrative. The HH case featured the baseline natural gas costs. In the LH and LL cases, the low-cost gas production technology deployed. The difference in natural gas consumption between the HH case and the LH and LL cases in the USA right after the deployment of the low-cost production technology is evident in Figure 5-2. In the HH case, final demand consumption shares are almost equally divided between natural gas and electricity. In both the LL and LH cases, over 3/4 of final energy consumption is natural gas. This shift occurs immediately in the same year that the natural gas production technology deployed. Over time, the sector became ever-more dependent on natural gas. The rapid shift reflects the high

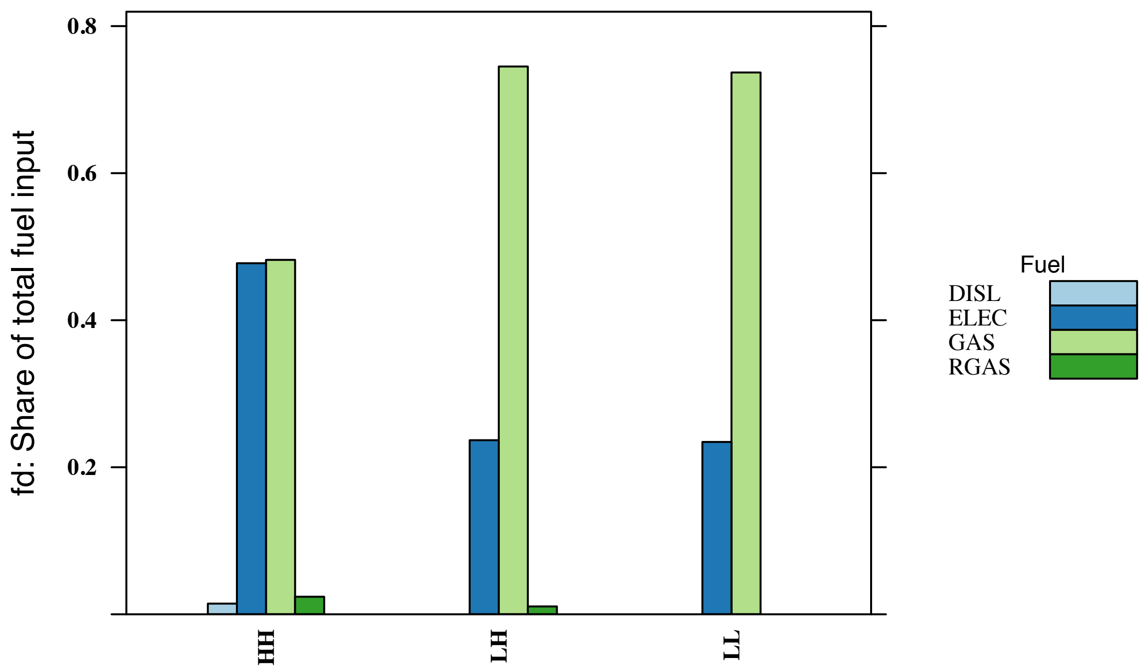

Figure 5-2: USA energy usage shares for final consumption in three cases at deployment of low-cost gas production technology

level of substitutability in final consumption between natural gas and electricity. The shift over time reflects the drive to replace energy-consuming technologies from electricity to the lower-cost natural gas, where possible (such as for heating and cooking). Similarly dramatic shifts were evident in dwellings, energy-intensive industry, other industry, and services. The electric generation sector also shifted toward natural gas and away from coal, but it did so more gradually since a large number of coal-fired power plants had not yet depreciated, coal plants are less expensive than gas plants to operate, and coal remained an inexpensive feedstock. Even the refined oil sector increased natural gas inputs at the expense of crude oil inputs as a result of the low cost of natural gas.

Low-cost gas created an environment conducive to the penetration of low-cost/high efficiency GTL technology. GTL could only provoke a second oil-gas price ratio shift in three of the nine cases. The impact in the LL case is depicted in Figure 5-1. The

ML[10] and LM[11] cases each provoke a more subtle shift in the oil-gas price ratio. This is because both feature a low-enough natural gas cost combined with a low-enough GTL cost to promote sufficient market penetration to dampen crude oil demand and its price increases. However, the ML and LM shifts occur much later than in the LL case, and they are more subtle. In short, it is possible for GTL to penetrate to the extent that it can compete sufficiently with oil refineries to weaken crude oil demand and initiate a shift in the crude oil-natural gas price ratio. However, it can only do so under below-baseline natural gas prices and lower-cost/higher-efficiency GTL configurations.

In the LL case, GTL production increased four-fold between its initial year of availability and the deployment of the low-cost gas production technology five years later. With low-cost gas feedstock available, it grew at double-digit rates for the rest of the simulation. The first effect of the growth of GTL production was to depress the price of diesel fuels. Figure 5-3 tracks the price of distillate fuels in the HH, LH, and LL cases. When GTL was first ready to deploy in the US, diesel prices were only slightly below the values in the cases where GTL had not yet deployed. As soon as natural gas prices fell, two things happened in the LL case. First, GTL capacity reached a level at which its production could impact US diesel prices. Since the US could not export this diesel in the No-DISL-Trade scenario, its price fell by nearly 40% and then continued to trend downward as GTL capacity expansions mounted and diesel supplies grew. The US diesel price ranged from 40-70% below the global diesel price by 2100. In the US, GTL had capped the cost of diesel production below the cost at which an oil refinery could produce it. The diesel price impact was hardly noticeable in the LH case, which used current assumptions of GTL costs and efficiency. In the LL case, US diesel prices dropped to 1/3 of the cost of US gasoline as soon as the low-cost natural gas production technology came online. Oil refinery operations did not change dramatically. Oil refineries make the vast bulk of their profits on

[10]The ML case is the combination of the medium-cost natural gas technology (enabling production at 2/3 of the baseline cost) and the lowest-cost/highest-efficiency GTL technology.

[11]The LM case is the combination of the lowest-cost natural gas technology (enabling production at 1/3 of the baseline cost) and the medium-cost/medium-efficiency GTL technology.

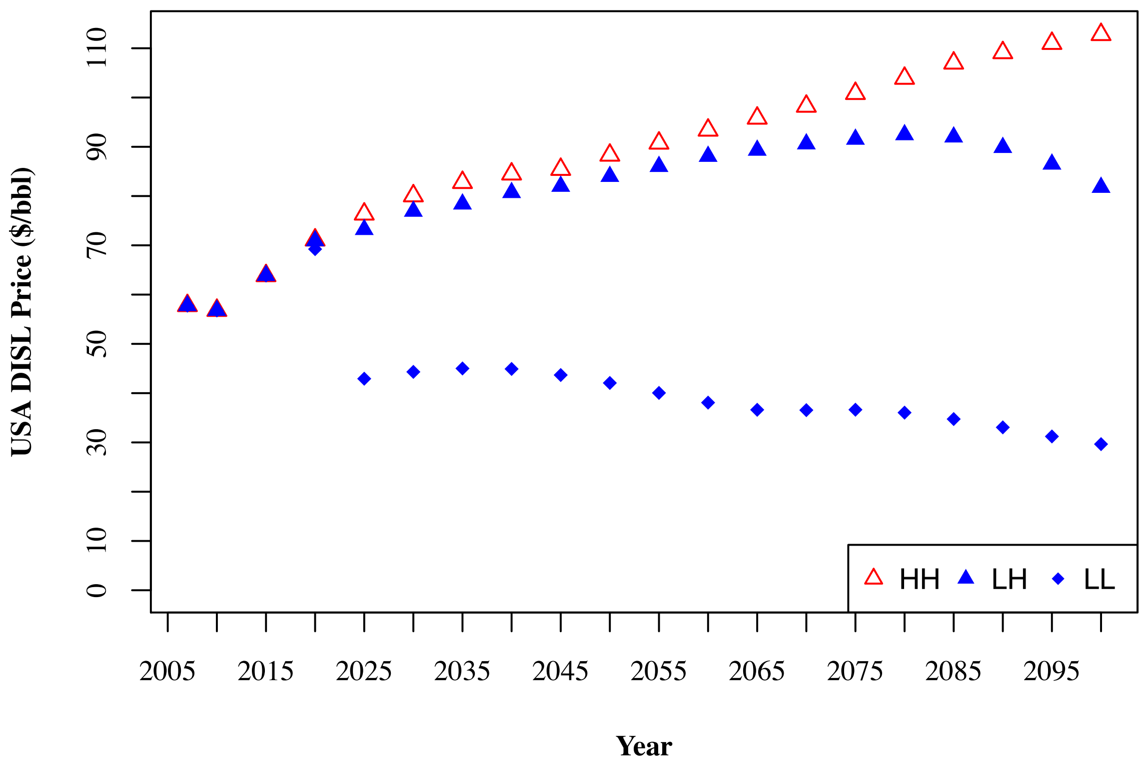

Figure 5-3: USA distillate fuel price ($/bbl) in high- and low-cost cases

distillate fuels and gasolines. Although refineries would no longer find distillate fuel production to be profitable, gasoline demand remained high, so refineries continued processing crude oil into refined fuels.

However, the relatively inexpensive diesel fuel, trapped in the US by the trade restriction, made diesel an attractive alternative to gasoline in the transportation sectors. This was especially true in household transportation, which was initially dominated by gasoline consumption. Figure 5-4 depicts the LL case evolution of energy usage in US household transportation as GTL diesel production increased. Initially, US household transportation was fueled almost entirely by gasoline (see "Initial"). When the low-cost natural gas production technology deployed (Low-cost gas (LCG)), there was only a slight shift toward GTL diesel. However, by the time the first wave of GTL plants had fully depreciated (LCG+25), the gasoline share of energy consumption had already fallen below 40%. By the time of the second major shift in the oil-gas price ratio (Ratio Shift #2), gasoline had been nearly completely

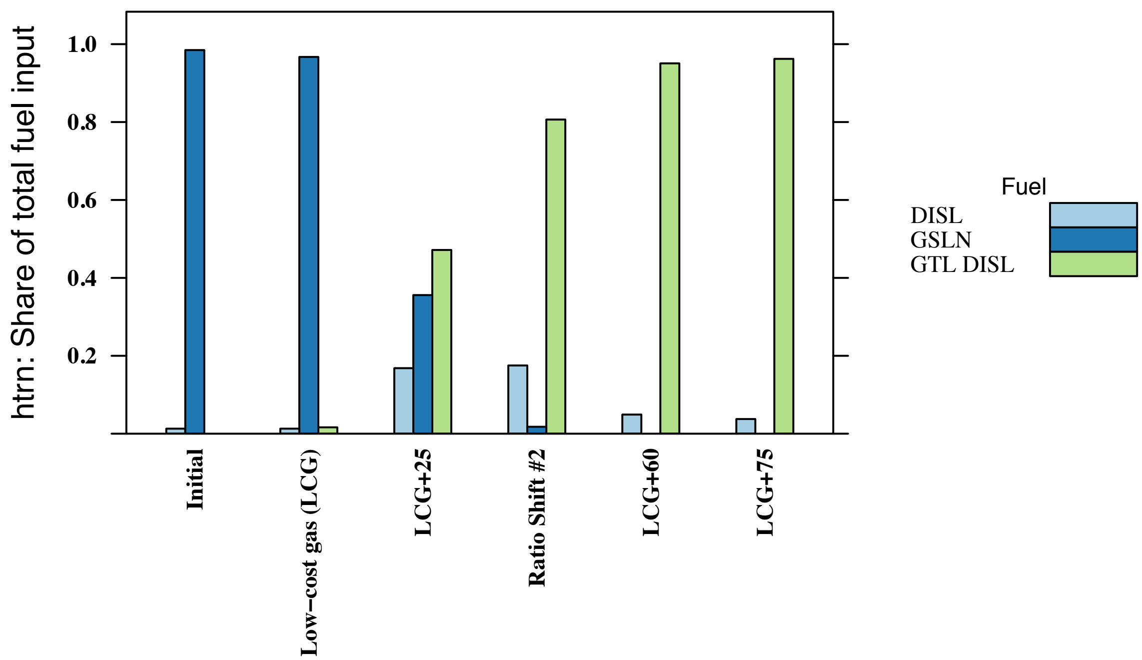

Figure 5-4: USA household transportation energy consumption shares at key times: LL case

displaced by petroleum and GTL diesels. GTL diesel made up over 80% of energy consumption in household transportation.

A similar pattern emerged in the US commercial transportation sector. Commercial transportation fuel consumption was about 3/4 diesel fuel even in the base year, with gasoline making up the bulk of the remainder. Figure 5-5 shows how GTL diesels completely pushed out gasoline, and had nearly displaced petroleum-based diesel, by the time of the second major shift in the price ratio. All cases showed a general shift toward diesel and away from gasoline over time. Even in the HH case diesel accounted for nearly 90% of commercial transportation fuel consumption. But the LL case is a clear outlier in its displacement of petroleum-based fuels. The low-cost/high efficiency GTL technology, combined with the low-cost natural gas feedstock, kept the cost of GTL diesel production steady or falling, while the price of crude oil continued to rise. These diverging trends made GTL diesel increasingly attractive, and made

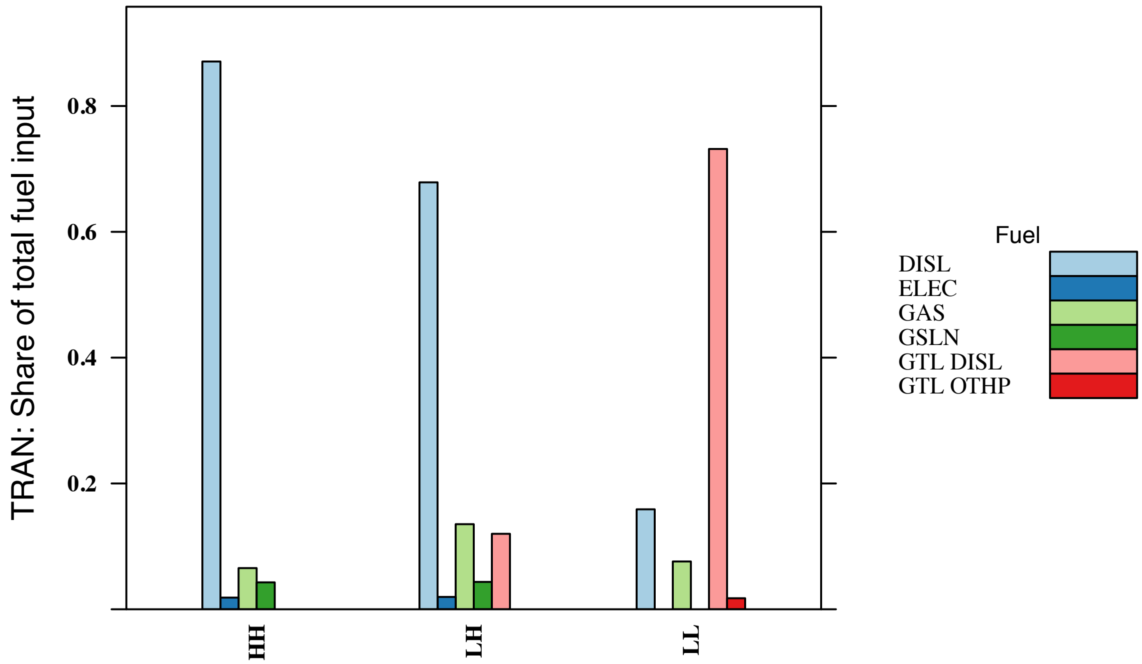

Figure 5-5: USA commercial transportation energy consumption shares at the second major price ratio shift

diesel production from oil refineries uneconomic. However, refineries were not able to eliminate distillate fuel production because of the fact that, depending on the grade of crude oil and the refinery configuration, fuels were produced in largely fixed proportions. Furthermore, with diesel exports restricted, US refineries could not export their surplus diesel fuels. By the time of the second shift in the crude oil-natural gas price ratio, US diesel prices were only about 40% of the global average. US diesel prices were the lowest in the world.

In the USA, the pervasiveness of low-cost diesel fuels provoked a strong rebound effect. A rebound effect is when, in response to a good becoming less expensive, more of it is consumed. There were significant rebound effects for diesel fuels in the LL case in the following US sectors: crops, energy-intensive industry, food, livestock, other industry, oil refining, services, transportation, final demand, and household transportation. By far the largest rebound effect was for household transportation.

By the time of the second oil-gas price ratio shift, the household transportation sector was consuming 41 times more refined fuel in the LL case than in the HH case, and almost all of it was diesel. In contrast, the commercial transportation sector was consuming just twice as much refined fuels, the service sector was consuming 3.5 times as much refined fuel, and the food sector consumed 9 times as much refined fuels as in the HH case.

There were also fairly strong rebound effects for natural gas consumption in the LL case. Dwellings, energy-intensive industry, food, other industry, services, commercial transportation, and final demand all consumed significantly more natural gas in the LL case than in the HH case. By the time of the second major shift in the oil-gas price ratio, each of these sectors was consuming 120-180% more natural gas than in the HH case.

The rebound effect in household transportation for diesel fuels alone was ten times more extreme than all other sectors' rebound effects for natural gas and diesel combined. The US household transportation sector consumed 898 EJ more diesel in the LL case than in the HH case during the second oil-gas price ratio shift. In contrast, the rebound effect in both diesel and natural gas for every other US sector was just over 90 EJ. US household transportation accounted for all of the rebound effect for diesel globally in the sector when the oil-gas price ratio shifted for the second time.

There are environmental repercussions to rebound effects. In Table 3.4, it was shown that GTL diesel emits less of a range of pollutants than petroleum-based diesel. Proponents have argued that if a cleaner diesel from GTL were added to the normal diesel mix, the emissions per unit combusted would be lower. But in the LL case, GTL activities increased the supply of diesel, and its price fell significantly. Lower prices promoted more consumption, and in the aggregate the hoped-for emissions decrease did not materialize due to the rebound effect – specifically in household transportation. NOx and VOC emissions were actually higher, and emissions of carbon monoxide were only slightly lower. The effect was especially pronounced in its effect on methane and CO_2 emissions. LL case methane emissions were 36% above the HH case emissions at the time of the second oil-gas price ratio shift. CO_2 emissions were 766% higher. Given that emissions even in the HH case were well above 2000 levels, and that in order to avert catastrophic consequences of climate change the emissions should be significantly *below* those levels, GTL technologies do not help reduce carbon emissions.

The other consequence of the rebound effect was that the additional demand was met almost entirely by expanding GTL production capacity. Global refinery production in the LL case tracked to within 1% (either above or below) the HH case levels up until the second major oil-gas price ratio shift. US refinery output tracked below HH case levels, but never by more than 15%. This began to change dramatically at the start of the second oil-gas price ratio shift. Figure 5-6 illustrates. Demand for diesels began to explode in the US due to the rebound effect. However,

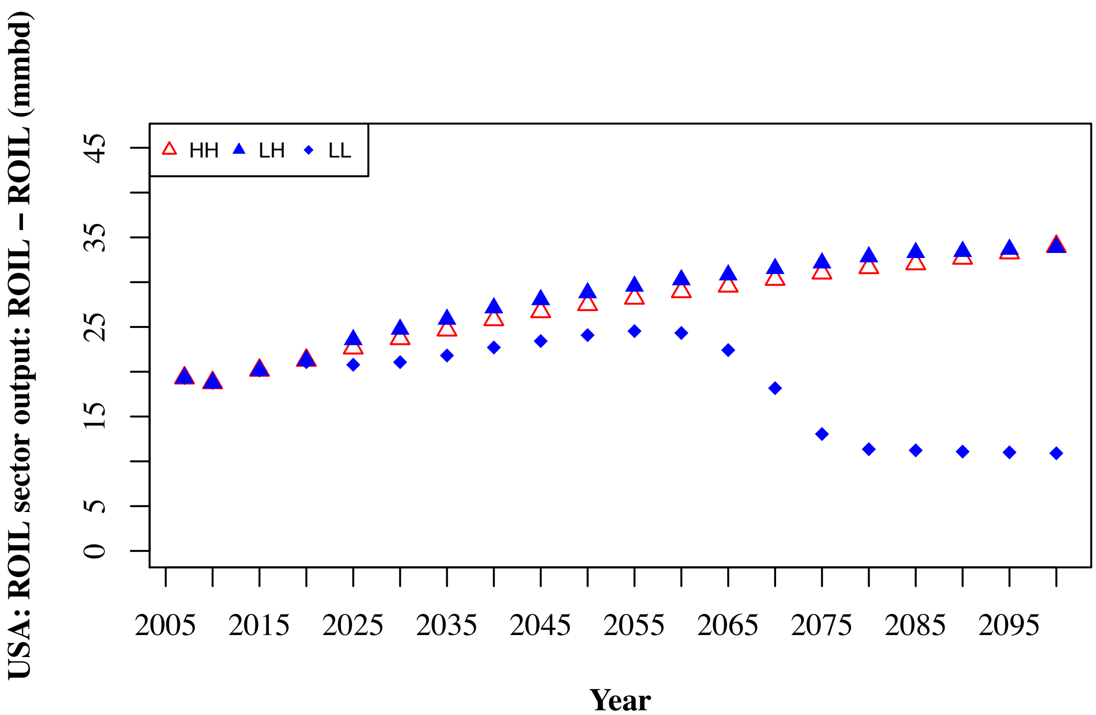

Figure 5-6: USA refined oil sector output in million barrels per day (mmbd) in high- and low-cost cases

the price of diesel continued to fall, while crude oil prices continued to rise. GTL capped the cost of producing diesel fuels, and it continued to cost-effectively produce GTL diesel to meet the new demand. For oil refineries, the rising cost of crude oil and the falling price of diesel made diesel production unprofitable. Furthermore, very little of the other transportation fuels (gasoline and heavy fuel oils) were being used in the USA any more. Most sectors had substantially switched over to diesel fuels or natural gas. As a consequence of this loss of profitability, US refiners made a sharp cutback in production. By the time the oil-gas price ratio settled into a flatter trend, US refinery output in the LL case was 65% below the HH case, and 42% below 2007 output levels. Crude oil inputs to refinery operations fell to half the levels that they were just before the second oil-gas price ratio shift began. The decrease in US crude oil inputs weakened global crude oil demand. Figure 5-7 shows how this weakening of crude oil demand translated into a dampening of increases in the crude oil price. The

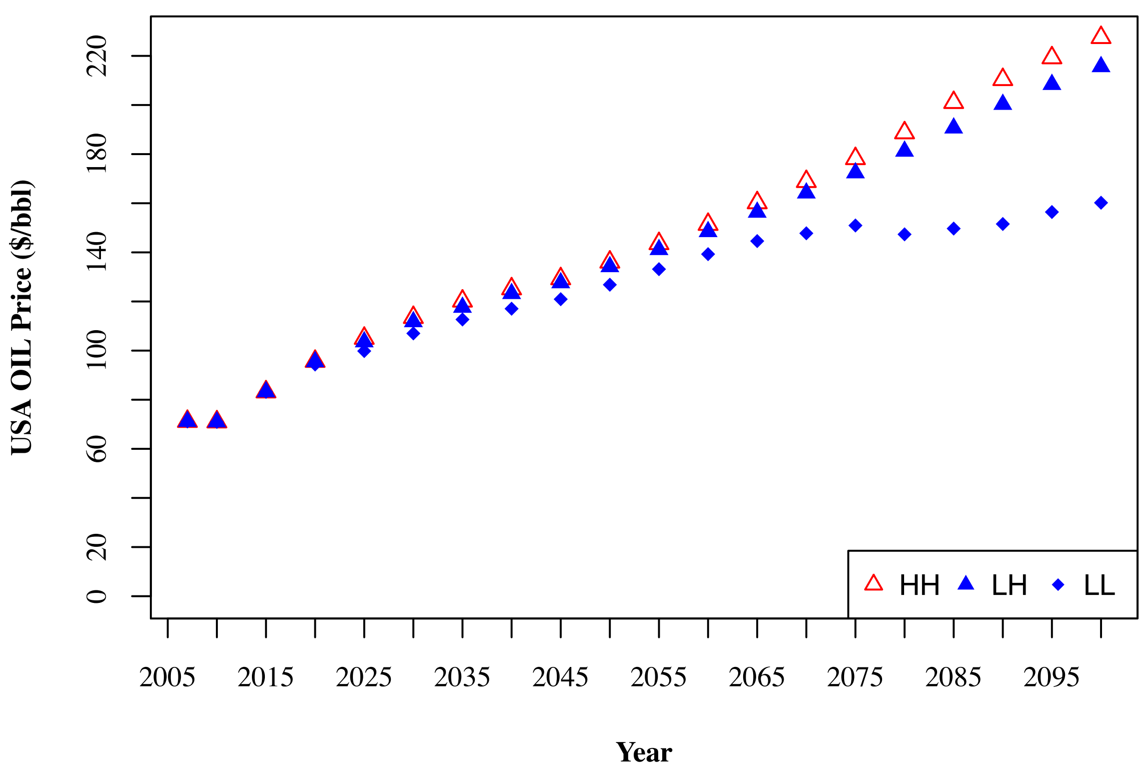

Figure 5-7: World crude oil fuel price ($/bbl) in high- and low-cost cases

arrest of the rise in crude oil prices stabilized the crude oil-natural gas price ratio at the end of the time series in Figure 5-1.

5.2 Comparing the effects of energy technology penetration on the crude oil-natural gas price relationship: No-DISL-Trade vs. DISL-Trade

The same nine cases were also run under the scenario in which international trade in diesel fuels was unrestricted (the DISL-Trade scenario). This section compares the differences in outcomes under the more realistic scenario where international trade is uninhibited. The same three gas cost-GTL cost/efficiency combinations (HHt, LHt, and LLt) capture the full range of outcomes. Figure 5-8 presents the paths of the crude oil-natural gas price ratios across the HHt, LHt, and LLt cases. Two

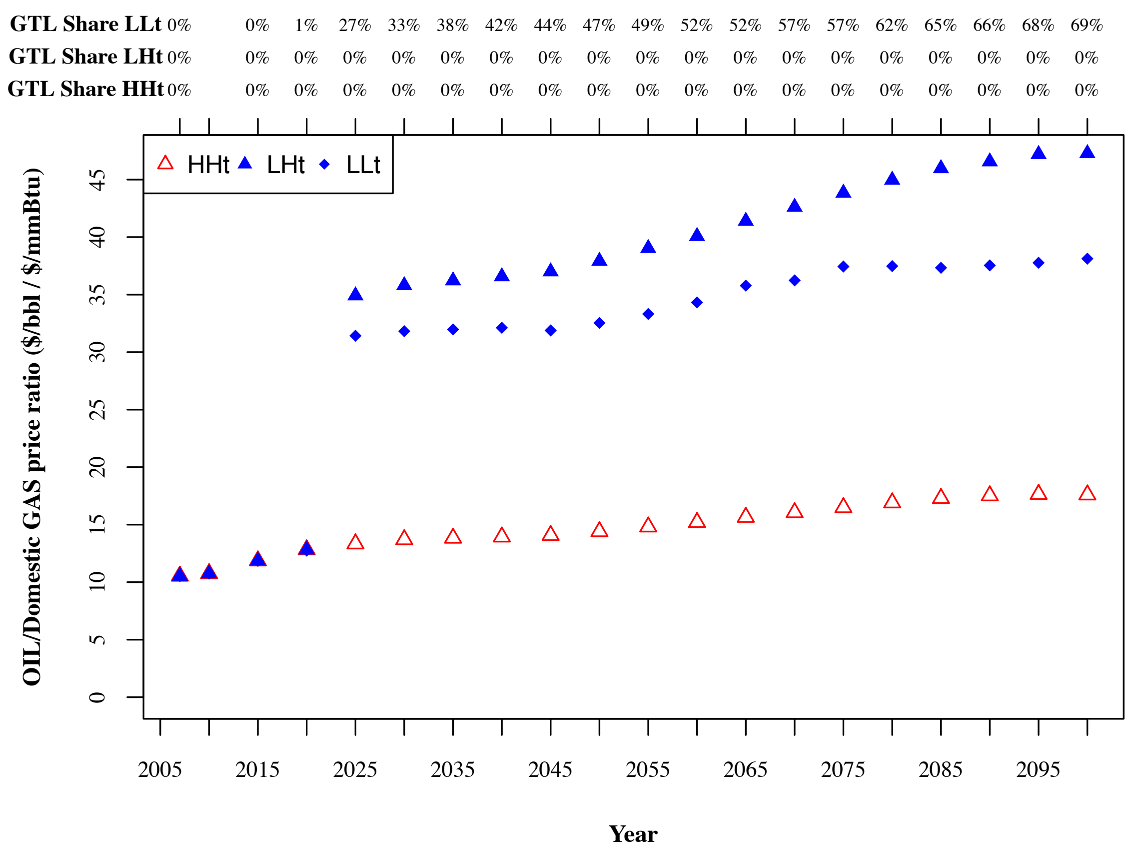

Figure 5-8: World crude oil / domestic natural gas price ratios ($/bbl / $/mmBtu) for three GTL and natural gas production cost cases: DISL-Trade

significant differences are immediately apparent. First, there was no delay in the shift in the crude oil-natural gas price ratio in the LLt case. It occurred immediately in tandem with the deployment of the low-cost natural gas production technology. The second significant difference is that GTL only significantly deployed in the LLt case. There was no GTL activity whatsoever in the HHt case, and GTL capacity never even reached 0.5% of global refined fuels production in the LHt case. None of the other cases managed to deploy GTL in amounts that were sufficient to have any effect whatsoever on the crude oil-natural gas price ratio. This is because GTL diesel had to compete with a global distillate fuel price, and many regions have very low-cost refinery sectors. In the case in which GTL was inexpensive enough, it deployed strongly. GTL fuel production as a share of global refined fuel production in the LLt case was much higher than under the trade-restricted scenario. GTL fuel production reached 27% of global refined fuel output immediately at the deployment of the low-cost natural gas production technology, and reached nearly 70% of global production by the end of the simulation.

Global oil refinery output is initially more adversely affected by GTL penetration in the DISL-Trade scenario. Refined fuel output fell by over 5% as the low-cost natural gas production technology came online and GTL capacity surpassed 1/4 of total refined fuel production. But over time the oil refineries recovered, eventually producing more in the LLt case than in the HH case. US oil refinery output was likewise above HH levels in the LLt case. The only difference between the cases is that refineries had the ability to export their distillate fuels.

There was a rebound effect in this set of cases as well, but it was much more muted. Only a few sectors used more refined fuels in the LLt case than in the HHt case. The rebound effect on US household transport only resulted in twice as much fuel being consumed in the LLt case as in the HHt case. Commercial transportation actually used less refined fuels in a number of time periods. The natural gas rebound effect was also less pronounced. This is because GTL production consumed much more natural gas in order to produce GTL fuels in the DISL-Trade scenario, leaving less low-cost gas for other activities. GTL output in the LLt case was about 2.5 times greater than in the LL case. This level of global penetration capped the cost of producing diesel fuels internationally. Since most of the fuel produced by GTL operations was exported in this scenario, US emissions of CO_2 were lower. However, global CO_2 emissions increased significantly because more fuel was ultimately consumed. What was an implausibly large rebound effect under restricted trade became a plausible rebound effect when the products of GTL plants were able to compete on the global markets. In the aggregate, GTL technology promoted even more fuel consumption than under the trade restricted scenario.

5.3 Key findings

These are the key findings from this set of experiments:

- **Competition (i.e., substitutability) between crude oil products and natural gas is limited.** The main driver of crude oil demand is the demand for transportation fuels. Crude oil products are largely unchallenged in this sector. The main drivers of natural gas demand are for heating and electricity. In both of these activities, natural gas competes with other fuels like fuel oils and electricity (for heating) and coal and renewables (for electricity). There is little overlap between the sources of demand for crude oil and natural gas. As countries get wealthier, their demand for transportation and electricity grows. Since most of the underdeveloped countries are in warmer climates, heating demand grows less than demand for cooling, which is supplied by electricity. When demand for transportation grows, it translates directly into increased demand for crude oil. Only a portion of increases in electricity demand translate into increased demand for natural gas. The result over time is that crude oil prices rise faster than natural gas prices – even under low-cost natural gas scenarios.

  If there were some arena of significant competition between the two fuels, increases in crude oil prices would stimulate demand for natural gas. The increased demand for natural gas would increase its price, and the displacement of crude oil-based fuels by natural gas would moderate the cost of crude oil. The prices of the commodities would move closer together, and the oil-gas price ratio would stabilize. This does not happen in these experiments when the low-cost gas production technology is deployed, even though natural gas should have become more appealing. There were actually few opportunities for substitution built in to the global economic structure according to the GTAP data. Therefore, competition between crude oil products and natural gas is more limited than the assumptions in the cointegration literature implied.

- **Technology improvements in gas production do not increase competition between crude oil and natural gas.** When the low-cost natural gas production technology is deployed, the price of natural gas drops dramatically. This lower cost increases the demand for natural gas in certain sectors – like heating and electricity. But natural gas does not displace petroleum products in any significant sectors where they compete. This is the case under current cost and efficiency assumptions about GTL technology, which does not deploy because it is uneconomic. This confirms the finding that competition (i.e., substitutability) between crude oil products and natural gas is limited, and that a wellhead technology that makes natural gas less expensive does not in itself create a competitive linkage between the fuels.

- **GTL technology increases competition between crude oil products and natural gas.** The penetration of GTL can influence the crude oil-natural gas price relationship, but only under very favorable circumstances. A low-cost, high-efficiency GTL is deployed for incremental increases in transportation fuel production capacity. It will only do so if its diesel production cost is below the cost of oil refining. Under these circumstances, GTL diesel can displace enough petroleum diesel and gasoline in the markets that crude oil demand weakens. This moderates crude oil price increases, and can also put upward price pressure on natural gas.

  The theory of competition is thus met: when one fuel becomes less expensive than the other, consumers choose the cheaper fuel. As demand for the less expensive fuel grows, its price rises. Demand for the replaced fuel weakens, and its price falls. This brings the prices of the two fuels closer together. Of the two technologies modeled, only GTL had this effect. However, the effect only materialized when GTL costs were far below current cost estimates, its energy efficiency was far beyond what is considered feasible, and its feedstock costs were far below current levels. There are few regions in the world where natural gas feedstock costs would be low enough for GTL, and the technology would have to improve considerably to be able to substantially increase competition between crude oil products and natural gas. In addition, this experiment removed any realistic constraints on the rate of GTL penetration. The technology was allowed to penetrate instantly. Under more realistic conditions, GTL might not penetrate sufficiently to impact the oil-gas price ratio at all.

- **GTL is not a viable technology for the USA at current costs or even under the extreme low range of cost and efficiencies.** In the DISL-Trade scenario in which US-based GTL plants must compete with global oil refineries to sell distillate products, GTL capacity only expanded in the lowest-cost natural gas, lowest-cost/highest-efficiency GTL case (LLt). The natural gas cost assumption is unlikely and the GTL technology configuration is impossible. Since international trade in distillate fuels is largely unrestricted in the real world, GTL is not likely to gain a foothold – at least in the United States. Other regions may find GTL to be economic under less extreme assumptions about costs and efficiencies.

- **Rebound effects on private transportation overwhelm any potential emissions benefits of GTL fuels.** GTL only enters the transportation fuel market when its production costs are below those of oil refineries. If natural gas is abundant enough to support rapid growth in GTL production, then the cost of transportation fuels would not grow any faster than the cost of natural gas. This would make GTL diesel increasingly attractive, and its lower cost would promote increased fuel consumption. Fuel consumption increases translate into emissions increases in CO_2 and other pollutants. For the purposes of enabling economic growth without increasing carbon emissions, GTL is not a helpful technology.

Chapter 6

Conclusions

This dissertation examined the long-run effects of the penetration of GTL technology on the crude oil-natural gas pricing relationship. The literature on energy commodity pricing cointegration had hypothesized that the basis for the stability of a long-run price ratio was at least partially due to the use of technologies that linked crude oil (through its products) and natural gas. This linkage enabled either the substitutability or complementarity of the two commodities. A number of technologies already exist that enable this linkage, such as oil and gas drilling rigs, oil refineries, and dual-fuel generators. However, empirical testing of the effects of a gradual penetration of new energy technologies on the oil-gas price relationship was nearly impossible in the presence of much more dramatic shocks to the economy. The effect of these technologies could not be discerned within the larger impacts of recessions, wars, or natural disasters. The single example of a rapid technology deployment – shale gas fracking – coincided with a global recession that rendered differentiating the effects of the technology and the recession impossible. The other problem is that the empirically-derived "long-run" relationships were estimated across time scales that were too narrow to determine their consistency over time. Was the measured relationship due to a truly significant overlap in fuel usage, or was it merely a statistical outcome of coincidental patterns of demand growth that were due to similar reactions to the economic environment? Were the measured shifts in the long-run relationship really just snapshots of a continuously evolving price ratio? The empirical models could not determine this in the 20-year time span for which reliable data were available.

I examined the effect that an energy conversion technology – GTL – had on the crude oil-natural gas price relationship in a controlled simulation. To ensure that GTL would deploy in at least some cases, I also modeled the impact of a technology that dramatically cut the cost of natural gas production – gas-to-liquids technology cannot deploy without access to very low-cost natural gas. No unexpected shocks were imposed on the economy, and the time window was expanded to 80 years. Three GTL technology specifications and three natural gas production technology specifications were examined across two distinct trading paradigms.

6.1 Principal conclusions

- The opportunities for substitution between crude oil and natural gas in the economy are limited under the technologies currently deployed and in the range of resource costs examined. The key sector that drives crude oil demand is the transportation sector, and the key sectors driving natural gas demand are heating and electricity. Transportation demand is growing, which causes the value of transportation fuels to rise. This translates into a demand increase for crude oil, which increases its value. Heating and cooling demand are also growing, but because of competition in those sectors, not all of the demand increase translates into an increase in natural gas demand. This causes an expanding differential between crude oil and natural gas prices (an increasing oil-gas price ratio) under current GTL costs and efficiency estimates.

  Unless GTL is inexpensive (and efficient) enough to deploy, there is very little overlap across the key sectors. The sectors where natural gas and petroleum products do compete are relatively insignificant, or use too little of the fuels for substitution to influence overall demand. Cost decreases in natural gas fail to provoke a reduction in the oil-gas price ratio over time. If there were significant opportunities for substitution between natural gas and petroleum products, the price increases in crude oil should not have continued unabated – natural gas usage would have displaced petroleum product usage and the price ratio would have fallen. In fact, there was very little substitution away from petroleum products toward natural gas in any sector except for transportation, and that was only in the cases in which the economic conditions for GTL penetration were favorable.

- The technology that reduces the natural gas production cost makes natural gas less expensive, but under the range of cost reductions examined, it did not provoke any increase in oil-gas substitutability. The low-cost natural gas only makes natural gas more competitive in sectors where it already competes with other fuels (e.g., by displacing coal in the electricity sector). Without a technology that explicitly creates a competitive linkage between petroleum products and natural gas, low-cost natural gas alone will not displace petroleum products or weaken crude oil demand. The current GTL cost and efficiency is not sufficient to deploy even with very low-cost natural gas.

- GTL deployment increases competition between crude oil products and natural gas. GTL allows natural gas to directly compete against crude oil products in the sector most responsible for crude oil demand: transportation. It increases portfolio substitutability between oil and gas. If its cost is low enough and its efficiency is high enough, GTL penetration will displace a sufficient amount of petroleum-based fuels to provoke a decrease in the oil-gas price ratio by weakening crude oil demand. This is evidence that a significant deployment of GTL increases the opportunities for substitution between crude oil and natural gas. This can only occur in low-cost natural gas scenarios employing GTL technology that is much less expensive and more efficient than today.

- GTL is not a viable technology in the USA at current costs or even under the extreme low range of possible costs and efficiencies. GTL never makes a significant deployment unless certain conditions are met: the cost of GTL must be far below current cost estimates, the efficiency of GTL must be much higher – perhaps beyond what is technically feasible, and natural gas prices relative to crude oil prices must be among the lowest in recorded history. This confluence of factors is unlikely. When unfettered international trade is enabled, only impossible GTL configurations deploy and penetrate in the United States. There is a possibility that other regions could find GTL to be viable under less extreme fuel, cost, and efficiency assumptions, however.

- Rebound effects in the transportation sectors overwhelm potential emissions benefits of GTL fuels. GTL can only deploy and penetrate if its cost is significantly below oil refinery costs. This condition also caps the cost of diesel fuels far below current prices. The low-cost diesel fuel provokes far more fuel consumption than when GTL is too expensive and inefficient to deploy, which overwhelms the modest reductions in non-GHG emissions. CO_2 emission increases are even more dramatic. Any significant penetration of GTL would be counterproductive to reducing greenhouse gas and pollutant emissions.

6.2 Relevance of research

One novel finding relevant to cointegration modelers and industry participants is that the crude oil-natural gas price ratio is expected to *increase* over long time periods given current trends in demand growth across regions, sectors, and income classes. That could inform empirical researchers as to whether their findings are part of a short- or long-run trend within the larger time frame. It also provides evidence that the findings of cointegration between crude oil and natural gas prices are in reality coincidental. The shifting relationship over time is probably not due to specific technology-based substitutability that keeps the prices moving toward the long-run ratio. Rather, it is likely because both fuels are major energy sources, and economic growth increases demand for energy, while economic contractions reduce energy demand. Since crude oil and natural gas are the most heavily traded fuels and operate in the most liquid energy markets, their prices react to these economy-driven shifts faster than other fuels. This creates the illusion of some physical linkage when employing statistical analysis.

Aside from the findings that relate to the commodity pricing literature, this research has implications for other stakeholders as well. It should provide guidance for integrated energy majors: investments in crude oil production or refining are likely to be more profitable than investments in natural gas production in the absence of any carbon mitigation policy.

This dissertation also employs a novel method of price forecasting for financial markets. Current methods of price forecasting involve statistical decomposition of historical time series, which implicitly assumes that past is prologue, and that no trends that are not already apparent will become active in the future. Using a CGE model for direct price forecasting is not advisable; the baseline outcomes are based on known trends. But the model does provide the ability to rigorously model the full set of secondary effects that would result if certain assumptions were to be changed or certain technologies or policies were to be modeled. The method has increased utility when considering price *relationships* and proportional shifts from reference case price paths. This is because stable price relationships have been shown to hold for much longer periods than price levels alone, and because the CGE model endogenously determines pricing based on relative shifts in demand for the fuels.

The method employed in this research augments the traditional DCF model by allowing for scenario-consistent pricing relationships to be tested. For example, it provides relative prices that are tied to how actual commodity usage changes in response to economic forces. It is an improvement to the traditional method of simply testing for sensitivity. The CGE model itself serves as a useful supplemental tool to the DCF model for evaluating project viability. For example, at current cost and efficiency estimates, GTL is not likely to be profitable in the US, but it could be in some other gas-rich region. In addition, the CGE model allows for a path of relative prices between input fuels and output fuels to be traced over the lifetime of the project. Currently DCF analyses rely on user-generated hypothetical scenarios based on intuition rather than explicit modeling.

Finally, this research has shown policymakers that the emissions trends provoked by low-cost GTL penetration far outweigh any incremental benefits in per-unit emissions reductions. This is due to rebound effects that become more severe as GTL penetration increases. It provides another piece of evidence that hoping for a purely technological fix in the absence of an explicit policy to reduce emissions is naïve and potentially dangerous.

6.3 Further research

There are many additional questions raised in this dissertation that could be addressed more deeply through further examination. Some additional research that could be conducted using a detailed refined oil sector include:

- Exploring how the addition of compressed natural gas (CNG), plug-in hybrid electric (PHEV), full electric (EV) and hydrogen-fueled vehicles to the transportation sector influences the viability and penetration of GTL technology, and how they perform under different natural gas cost paradigms.

- Investigating the impact of the International Convention for the Prevention of Pollution from Ships (MARPOL) treaty restrictions on the sulfur content of marine fuels on the future of refinery coking operations when the regulations come into effect in 2025.

- Examining the effects that restricting the combustion of petroleum coke or heavy fuel oil would have on the refining industry.

- Developing a fuel-specific drivetrain vintaging structure so that fuel substitution between diesel and gasoline fuels could be explicitly modeled as separate vehicle types. This could alter the rate at which the rebound effect increases fuel consumption.

6.4 General insights for research into technological penetration and deployment

GTL is a process technology. It takes a primary fuel as an input, and its output is itself an input to many activities. A process technology is further "upstream" in the value chain than a final product. This makes it more likely to have an influence on a wide range of activities as it penetrates. The closer the technology is to a final consumer, the less potential uses it has, and its effects on markets outside of its own sector become more muted. The further a technology is from a final consumer product, the wider its influence will be on overall market activity. Taking this into consideration will help to define the boundaries of the system relevant to the technology's performance. It informs modeling choices: a DCF model will be more useful in assessing the viability of a plant producing consumer electronic devices than it would be for a large process technology whose deployment could affect the development and behaviors of entire economic sectors. For the latter, a model with a wider boundary that allows for endogenous calculation of input and output prices would be more useful.

The structure of the market into which a new technology is to compete will influence the rate and extent of its penetration. Whether the new technology is complementary to existing activities or in competition with them will also affect their deployment. The low-cost natural gas production technology was immediately activated in the model used in this dissertation. However, even if it were modeled as a gradual replacement of existing capital stock it would have deployed more rapidly and seamlessly than GTL. That is because the technology directly complements existing activities. Industry had an immediate incentive to embrace the technology because it made operations less expensive, thus improving profit margins. Technologies that compete with existing technologies have more obstacles to deployment. In the case of GTL, oil refineries were a dominant player in transportation fuel production, and GTL plants had to compete on cost in order to deploy. GTL plants then had to maintain lower costs for decades to win market share from refiners and eventually become the dominant technology.

The longevity of the capital in place in the market of competition is also relevant. Oil refineries last for decades, while computers (for example) usually last five years or less. This will define the rate of technological turnover. A technology that competes against long-lived, currently utilized technologies will take longer to deploy and penetrate. This might be true even if the technology is *less* expensive than the old one, because the older equipment has already been deployed and faces only operating costs. This was the case with GTL plants in competition with oil refineries. In the complementarity case, the longevity of existing technology might be less of an obstacle: a technology that improves the performance of existing activities may be deployed to replace less-efficient ones even before existing technologies are fully depreciated. This latter case reflects the low-cost gas production technology scenario.

These are the general insights that this dissertation revealed. They fit the generalizations described by Utterback and Christensen [171, 32], and would be useful hypotheses for further study of other technologies using distinct methodologies. Particularly, a technology that complements existing activity will deploy more rapidly and penetrate more widely than a technology that competes with other technologies – at least initially. The longevity of existing technologies will also influence the rate and extent of the penetration of a new technology – especially if the new technology is a competitor to existing ones. Finally, the extent to which a technology enables economic activity in other sectors will correlate with the breadth of its influence on the economic performance.

Appendix A

Methodological Details

Almost all of the modifications that were needed in order to explore the research questions of this dissertation revolved around the disaggregation of the aggregated refined oil commodity (ROIL) into sub-products that would allow for inter-fuel competition to be modeled. Five databases were utilized.

The initial data came from the GTAP8 database [113]. This contained the volumes and values consumed in each region and sector for the aggregated refined oil product. Volumes were disaggregated using the International Energy Agency (IEA) Energy Statistics and Balances Database [5].[1] Value flows were re-constructed by referring to the IEA Energy Prices and Taxes database [79] for principal fuels. Then the relative prices between the principal fuels and the products that were not included in Energy Prices and Taxes were estimated using the State Energy Data System (SEDS) database [169]. Data from the International Council on Clean Transportation (ICCT) Global Transportation Roadmap model [77] were used to disaggregate the household transportation fuel usage. The following sections explain the process in greater detail.

[1] http://www.oecd-ilibrary.org/energy/data/iea-world-energy-statistics-and-balances_enestats-data-en

A.1 Data

This section describes the five databases that were used to disaggregate the refined oil commodity into the six sub-commodities: RGAS, DISL, GSLN, HFOL, OTHP, and COKE. Later sections will detail how these databases were used to implement the disaggregation.

A.1.1 The Global Trade Analysis Project (GTAP) 8 database

The aggregated refined oil product data comes from the GTAP database, version 8 ("GTAP8"). It covers 244 countries aggregated into 129 regions and 57 commodities/sectors. Each sector produces a single commodity, and the inputs of all other commodities to support the activities in each sector are recorded. All production, trade flows and consumption are balanced so that the entire data base is an input-output table for the global economy. The commodities are aggregated from Central Product Classification (CPC) codes for food processing and agriculture (21 sectors) and the International Standard Industry Classification (ISIC) codes for the rest of the data (36 sectors) [112]. The GTAP8 sector that corresponds to the ROIL sector in the model is called the p_c sector. It includes ISIC codes 231 (Manufacture of coke oven products), 232 (Manufacture of refined petroleum products), and 233 (Processing of nuclear fuel) [113].

The p_c sector in GTAP8 appears in many data sets that are relevant to the structure of the CGE model. Table A.1 presents a list of the components of GTAP8 utilized that contain the p_c commodity. Agent prices are prices including taxes. Market prices are ex-tax. The indices on each data set are as follows: i is for sectors, j is an alias for sectors to distinguish inter-sectoral transactions, r is for regions, s is an alias for regions to distinguish region-to-region trade flows, f is for factors of production, src denotes the source (domestic or imported), and x is for all goods including final consumption, government consumption, and investment.[2] The goal

[2]Initial data preparation integrates *vdpm* and *vdgm* into *vdfm*, *vipm* and *vigm* into *vifm*, *vdpa* and *vdga* into *vdfa*, and *vipa* and *viga* into *vifa*. Private households are designated as sector "c" and government is designated sector "g" in *vdfm*, *vifm*, *vdfa*, and *vifa*.

Table A.1: GTAP8 data sets containing the p_c product for disaggregation

GTAP8 data set	**Description**
vdga(i,r)	Government - domestic purchases at agents' prices
viga(i,r)	Government - imports at agents' prices
vdgm(i,r)	Government - domestic purchases at market prices
vigm(i,r)	Government - imports at market prices
vdpa(i,r)	Private households - domestic purchases at agents' prices
vipa(i,r)	Private households - imports at agents' prices
vdpm(i,r)	Private households - domestic purchases at market prices
vipm(i,r)	Private households - imports at market prices
evoa(f,r)	Endowments - output at agents' prices
evfa(f,x,r)	Endowments - firms' purchases at agents' prices
vfm(f,x,r)	Endowments - firms' purchases at market prices
vdfa(i,x,r)	Intermediates - firms' domestic purchases at agents' prices
vifa(i,x,r)	Intermediates - firms' imports at agents' prices
vdfm(i,x,r)	Intermediates - firms' domestic purchases at market prices
vifm(i,x,r)	Intermediates - firms' imports at market prices
vxmd(i,r,s)	Trade - bilateral exports at market prices
vxwd(i,r,s)	Trade - bilateral exports at world prices
vst(i,r)	Trade - exports for international transportation
vtwr(i,j,r,s)	Trade - margins for international transportation at world prices
ftrv(f,j,r)	Taxes - factor employment tax revenue
fbep(f,j,r)	Protection - factor-based subsidies
isep(i,j,r,src)	Protection - intermediate input subsidies
osep(i,r)	Protection - ordinary output subsidies
adrv(i,r,s)	Protection - anti-dumping duty
tfrv(i,r,s)	Protection - ordinary import duty
purv(i,r,s)	Protection - price undertaking export tax equivalent
vrrv(i,r,s)	Protection - VER export tax equivalent
mfrv(i,r,s)	Protection - MFA export tax equivalent
xtrv(i,r,s)	Protection - ordinary export tax
edf(i,j,r)	Usage of domestic product by firms (mtoe)
eif(i,j,r)	Usage of imported product by firms (mtoe)
edp(i,j,r)	Private consumption of domestic product by firms (mtoe)
eip(i,j,r)	Private consumption of imported product by firms (mtoe)
edg(i,j,r)	Government consumption of domestic product by firms (mtoe)
eig(i,j,r)	Government consumption of imported product by firms (mtoe)
exidag(i,r,s)	Volume of trade (mtoe)

Source: Narayanan, Dimaranan, and McDougall [113].

is to disaggregate the p_c sector into the six sub-products wherever it appears in the data sets shown in Table A.1. The p_c product only needs to be disaggregated when it is used as an input into other activities and in production. I do not need to disaggregate p_c when it is listed as a consumer of inputs, since the p_c sector maps directly into ROIL as a production sector. Unlike every other sector in the model I use, the ROIL sector is a multi-output sector, producing six commodities. That means that 13 sectors will each produce a single commodity. The ROIL sector will produce six commodities.

A.1.2 The International Energy Agency (IEA) Energy Statistics and Balances Database

The detailed volume data in the IEA Energy Statistics and Balances Database are used to break the GTAP8 p_c commodity volumes into the six ROIL sub-products. The website for the Organization for Economic Cooperation and Development (OECD) contains the Energy Statistics and Balances Database.[3] The Energy Statistics database contains data for 102 "FLOWS" – which are a combination of sectoral consumption, production, imports, and exports – and 143 countries. 57 of the FLOW entries represent consumption by economic sectors. It also traces the volumetric flows of 68 energy products in tons of oil equivalent (TOE) [5]. 24 of these energy products are sourced from petroleum. I mapped the IEA regions, sectors, and fuels directly to the EPPA regions, sectors and fuels. Table A.2 illustrates the IEA-GTAP8-EPPA regional mapping relationships.

Table A.2: IEA-GTAP8-CGE regional mapping with description

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Albania	ALB	roe	Non-EU Europe/FSU
Algeria	XNF	afr	Africa
Angola	XAC	afr	Africa
Argentina	ARG	lam	Latin America
Armenia	ARM	roe	Non-EU Europe/FSU
Australia	AUS	anz	Australia/New Zealand and Pacific Islands
Austria	AUT	eur	European Union
Azerbaijan	AZE	roe	Non-EU Europe/FSU

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[3] http://www.oecd-ilibrary.org/energy/data/iea-world-energy-statistics-and-balances_enestats-data-en

Table A.2 – *Continued from previous page*

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Bahrain	BHR	mes	Middle East
Bangladesh	BGD	rea	Rest of Asia
Belarus	BLR	roe	Non-EU Europe/FSU
Belgium	BEL	eur	European Union
Benin	XWF	afr	Africa
Bolivia	BOL	lam	Latin America
Bosnia and Herzegovina	XER	roe	Non-EU Europe/FSU
Botswana	BWA	afr	Africa
Brazil	BRA	bra	Brazil
Brunei Darussalam	XSE	rea	Rest of Asia
Bulgaria	BGR	eur	European Union
Cambodia	KHM	rea	Rest of Asia
Cameroon	CMR	afr	Africa
Canada	CAN	can	Canada
Chile	CHL	lam	Latin America
Chinese Taipei	TWN	asi	Asia Pacific
Colombia	COL	lam	Latin America
Congo	XCF	afr	Africa
Costa Rica	CRI	lam	Latin America
Cote d'Ivoire	CIV	afr	Africa
Croatia	HRV	roe	Non-EU Europe/FSU
Cuba	XCB	lam	Latin America
Cyprus	CYP	eur	European Union
Czech Republic	CZE	eur	European Union
Dem. People's Rep. of Korea	XEA	rea	Rest of Asia
Democratic Republic of Congo	XAC	afr	Africa
Denmark	DNK	eur	European Union
Dominican Republic	XCB	lam	Latin America
Ecuador	ECU	lam	Latin America
Egypt	EGY	afr	Africa
El Salvador	SLV	lam	Latin America
Eritrea	XEC	afr	Africa

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Table A.2 – *Continued from previous page*

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Estonia	EST	eur	European Union
Ethiopia	ETH	afr	Africa
Finland	FIN	eur	European Union
Former Yugoslav Republic of Macedonia	XER	roe	Non-EU Europe/FSU
France	FRA	eur	European Union
Gabon	XCF	afr	Africa
Georgia	GEO	roe	Non-EU Europe/FSU
Germany	DEU	eur	European Union
Ghana	GHA	afr	Africa
Gibraltar	XER	roe	Non-EU Europe/FSU
Greece	GRC	eur	European Union
Guatemala	GTM	lam	Latin America
Haiti	XCB	lam	Latin America
Honduras	HND	lam	Latin America
Hong Kong, China	HKG	chn	China
Hungary	HUN	eur	European Union
Iceland	XEF	eur	European Union
India	IND	ind	India
Indonesia	IDN	idz	Indonesia
Iraq	XWS	mes	Middle East
Ireland	IRL	eur	European Union
Islamic Republic of Iran	IRN	mes	Middle East
Israel	isr	mes	Middle East
Italy	ITA	eur	European Union
Jamaica	XCB	lam	Latin America
Japan	JPN	jpn	Japan
Jordan	XWS	mes	Middle East
Kazakhstan	KAZ	roe	Non-EU Europe/FSU
Kenya	KEN	afr	Africa
Korea	KOR	kor	South Korea
Kosovo	XEE	roe	Non-EU Europe/FSU
Kuwait	KWT	mes	Middle East

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Table A.2 – *Continued from previous page*

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Kyrgyzstan	KGZ	roe	Non-EU Europe/FSU
Latvia	LVA	eur	European Union
Lebanon	XWS	mes	Middle East
Libya	XNF	afr	Africa
Lithuania	LTU	eur	European Union
Luxembourg	LUX	eur	European Union
Malaysia	MYS	asi	Asia Pacific
Malta	MLT	eur	European Union
Mexico	MEX	mex	Mexico
Mongolia	MNG	rea	Rest of Asia
Montenegro	XER	roe	Non-EU Europe/FSU
Morocco	MAR	afr	Africa
Mozambique	MOZ	afr	Africa
Myanmar	XSE	rea	Rest of Asia
Namibia	NAM	afr	Africa
Nepal	NPL	rea	Rest of Asia
Netherlands	NLD	eur	European Union
Netherlands Antilles	XCB	lam	Latin America
New Zealand	NZL	anz	Australia/New Zealand and Pacific Islands
Nicaragua	NIC	lam	Latin America
Nigeria	NGA	afr	Africa
Norway	NOR	eur	European Union
Oman	omn	mes	Middle East
Other Africa	MDG	afr	Africa
Other Africa	MUS	afr	Africa
Other Africa	MWI	afr	Africa
Other Africa	UGA	afr	Africa
Other Africa	XCF	afr	Africa
Other Africa	XEC	afr	Africa
Other Africa	XSC	afr	Africa
Other Africa	XWF	afr	Africa

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Table A.2 – *Continued from previous page*

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Other Asia	LAO	rea	Rest of Asia
Other Asia	XOC	anz	Australia/New Zealand and Pacific Islands
Other Asia	XSA	rea	Rest of Asia
Other Asia	XTW	anz	Australia/New Zealand and Pacific Islands
Other Non-OECD Americas	XCA	lam	Latin America
Other Non-OECD Americas	XNA	lam	Latin America
Other Non-OECD Americas	XSM	lam	Latin America
Pakistan	PAK	rea	Rest of Asia
Panama	PAN	lam	Latin America
Paraguay	PRY	lam	Latin America
People's Republic of China	CHN	chn	China
Peru	PER	lam	Latin America
Philippines	PHL	asi	Asia Pacific
Poland	POL	eur	European Union
Portugal	PRT	eur	European Union
Qatar	QAT	mes	Middle East
Republic of Moldova	XEE	roe	Non-EU Europe/FSU
Romania	ROU	eur	European Union
Russian Federation	RUS	rus	Russia
Saudi Arabia	SAU	mes	Middle East
Senegal	SEN	afr	Africa
Serbia	XER	roe	Non-EU Europe/FSU
Singapore	SGP	asi	Asia Pacific
Slovak Republic	SVK	eur	European Union
Slovenia	SVN	eur	European Union
South Africa	ZAF	afr	Africa
Spain	ESP	eur	European Union
Sri Lanka	LKA	rea	Rest of Asia
Sudan	XEC	afr	Africa
Sweden	SWE	eur	European Union

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Table A.2 – *Continued from previous page*

IEA "COUNTRY"	GTAP8 Region	CGE Region	Description
Switzerland	CHE	eur	European Union
Syrian Arab Republic	XWS	mes	Middle East
Tajikistan	XSU	roe	Non-EU Europe/FSU
Thailand	THA	asi	Asia Pacific
Togo	XWF	afr	Africa
Trinidad and Tobago	XCB	lam	Latin America
Tunisia	TUN	afr	Africa
Turkey	TUR	roe	Non-EU Europe/FSU
Turkmenistan	XSU	roe	Non-EU Europe/FSU
Ukraine	UKR	roe	Non-EU Europe/FSU
United Arab Emirates	ARE	mes	Middle East
United Kingdom	GBR	eur	European Union
United Republic of Tanzania	TZA	afr	Africa
United States	USA	usa	United States
Uruguay	URY	lam	Latin America
Uzbekistan	XSU	roe	Non-EU Europe/FSU
Venezuela	VEN	lam	Latin America
Vietnam	VNM	rea	Rest of Asia
Yemen	XWS	mes	Middle East
Zambia	ZMB	afr	Africa
Zimbabwe	ZWE	afr	Africa

Table A.3 details the sectoral mapping between data from the IEA, GTAP8, and EPPA.

Table A.3: IEA-GTAP8-CGE sector mapping

IEA FLOW	GTAP8 Sector	CGE Sector
Agriculture/forestry	c_b	crop
Agriculture/forestry	gro	crop

Continued on next page

Table A.3 – *Continued from previous page*

IEA FLOW	GTAP8 Sector	CGE Sector
Agriculture/forestry	ocr	crop
Agriculture/forestry	osd	crop
Agriculture/forestry	pdr	crop
Agriculture/forestry	pfb	crop
Agriculture/forestry	v_f	crop
Agriculture/forestry	wht	crop
Agriculture/forestry	frs	fors
Agriculture/forestry	ctl	live
Agriculture/forestry	oap	live
Autoproducer CHP plants	ely	elec
Autoproducer electricity plants	ely	elec
Autoproducer heat plants	gdt	gas
BKB plants	i_s	eint
Blast furnaces	i_s	eint
Charcoal production plants	lum	othr
Chemical and petrochemical	crp	eint
Chemical heat for electricity production	ely	elec
Coal liquefaction plants	p_c	roil
Coal mines	coa	coal
Coke ovens	p_c	roil
Commercial and public services	g	serv
Commercial and public services	isr	serv
Commercial and public services	obs	serv
Commercial and public services	ofi	serv
Commercial and public services	osg	serv
Commercial and public services	ros	serv
Commercial and public services	trd	serv
Construction	cns	othr
Domestic aviation	atp	tran
Domestic navigation	wtp	tran
Electric boilers	gdt	gas
Fishing	fsh	live

Continued on next page

Table A.3 – *Continued from previous page*

IEA FLOW	GTAP8 Sector	CGE Sector
Food and tobacco	b_t	food
Food and tobacco	cmt	food
Food and tobacco	mil	food
Food and tobacco	ofd	food
Food and tobacco	omt	food
Food and tobacco	pcr	food
Food and tobacco	sgr	food
Food and tobacco	vol	food
Food and tobacco	rmk	live
For blended natural gas	gdt	gas
Gas works	gdt	gas
Gasification plants for biogases	gdt	gas
Heat pumps	gdt	gas
Industry	fmp	eint
International aviation bunkers	atp	vtwr.atp
International marine bunkers	wtp	vtwr.wtp
Iron and steel	i_s	eint
Liquefaction (LNG)/regasification plants	gdt	gas
Machinery	ele	othr
Machinery	ome	othr
Main activity producer CHP plants	ely	elec
Main activity producer electricity plants	ely	elec
Main activity producer heat plants	gdt	gas
Mining and quarrying	omn	othr
Non-energy use in other	lum	othr
Non-energy use in other	cns	othr
Non-energy use in other	ele	othr
Non-energy use in other	ome	othr
Non-energy use in other	omn	othr
Non-energy use in other	omf	othr
Non-energy use in other	wtr	othr
Non-energy use in other	otn	othr

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Table A.3 – *Continued from previous page*

IEA FLOW	**GTAP8 Sector**	**CGE Sector**
Non-energy use in other	lea	othr
Non-energy use in other	tex	othr
Non-energy use in other	wap	othr
Non-energy use in other	mvh	othr
Non-energy use in other	otn	othr
Non-energy use in other	lum	othr
Non-energy use in transport	atp	tran
Non-energy use in transport	wtp	tran
Non-energy use in transport	otp	tran
Non-energy use industry/transformation/energy	i_s	eint
Non-energy use industry/transformation/energy	crp	eint
Non-energy use industry/transformation/energy	fmp	eint
Non-energy use industry/transformation/energy	nfm	eint
Non-energy use industry/transformation/energy	nmm	eint
Non-energy use industry/transformation/energy	ppp	eint
Non-ferrous metals	nfm	eint
Non-metallic minerals	nmm	eint
Non-specified (energy)	lum	othr
Non-specified (energy)	cns	othr
Non-specified (energy)	ele	othr
Non-specified (energy)	ome	othr
Non-specified (energy)	omn	othr
Non-specified (energy)	omf	othr
Non-specified (energy)	wtr	othr
Non-specified (energy)	otn	othr
Non-specified (energy)	lea	othr
Non-specified (energy)	tex	othr
Non-specified (energy)	wap	othr
Non-specified (energy)	mvh	othr
Non-specified (energy)	otn	othr
Non-specified (energy)	lum	othr
Non-specified (industry)	omf	othr

Continued on next page

Table A.3 – *Continued from previous page*

IEA FLOW	GTAP8 Sector	CGE Sector
Non-specified (industry)	wtr	othr
Non-specified (other)	cmn	serv
Non-specified (transformation)	i_s	eint
Non-specified (transformation)	crp	eint
Non-specified (transformation)	fmp	eint
Non-specified (transformation)	nfm	eint
Non-specified (transformation)	nmm	eint
Non-specified (transformation)	ppp	eint
Non-specified (transport)	otn	othr
Nuclear industry	p_c	roil
Oil and gas extraction	gas	gas
Oil and gas extraction	oil	oil
Oil refineries	p_c	roil
Own use in electricity, CHP and heat plants	ely	elec
Paper, pulp and print	ppp	eint
Petrochemical plants	crp	eint
Pipeline transport	otp	tran
Pumped storage plants	ely	elec
Rail	otp	tran
Residential	c	dwe
Residential	dwe	dwe
Road	otp	tran
Textile and leather	wol	live
Textile and leather	lea	othr
Textile and leather	tex	othr
Textile and leather	wap	othr
Transport equipment	mvh	othr
Transport equipment	otn	othr
Wood and wood products	lum	othr

A.1.3 The International Council on Clean Transportation (ICCT) Global Transportation Roadmap model

To separate household transportation from commercial transportation, I needed to disaggregate the ground transport sector *otp* in GTAP8. The non-household portion is then added to GTAP8's air transport (*atp*) and water transport (*wtp*) values to become the TRAN sector in the final model. In order to break the fuel usage in the IEA's single transport sector into the ROIL sub-products, I used the ICCT Global Transportation Roadmap model. It contains detailed data on transportation fuel usage by power train, fuel, and size, and whether the transport mode was road, rail, water, or air. The regional detail almost perfectly matched the regional aggregation in the model I used for this research. The only differences were that EPPA has two regions related to Asia – ASI and REA – while the ICCT data only has one. The other region not explicitly represented in the ICCT model was Indonesia (IDZ). In both cases, the data from ICCT's Asia-Pacific-40 regional category were used.

A.1.4 The IEA Energy Prices and Taxes database

The IEA's Energy Prices and Taxes database was used to get a baseline for prices and taxes of petroleum products in 29 OECD and 17 non-OECD countries in 2007 [79]. Sectors include Industry, Electricity generation, and Households. Prices are reported for the following petroleum products: low-sulfur fuel oil, heavy fuel oil, light fuel oil, diesel (high- and/or low-sulfur), and gasoline (leaded and/or unleaded, premium and/or regular). Natural gas prices are also included. The prices for transportation fuels (diesels and gasolines) are in units of the local currency per litre. Fuel oils are in units of local currency per 1,000 litres, and natural gas is priced in units of local currency per 10^7 kilocalories gross calorific value (GCV). All were converted to US dollars per metric ton of oil equivalent ($/TOE). These were mapped to the IEA Energy Statistics countries and products. Energy Prices and Taxes reports prices on fewer products than Energy Statistics requires, so I augmented the prices of the fuels reported by the IEA using price ratios between fuels from the EIA's State Energy

Data System (SEDS) database.

A.1.5 The State Energy Data System (SEDS) database

The State Energy Data System (SEDS) database is curated by the U.S. Energy Information Administration (EIA) [169]. It tracks the annual consumption, price, expenditure and production of up to 253 energy products nationally and by state for each year. Price data are ex-tax. SEDS was used to generalize price ratios across multiple products that were benchmarked to prices in the IEA Energy Prices and Taxes database. This generated proxy prices for the IEA Energy Statistics volume data. Value flows based on IEA volume and proxy price data were developed for each petroleum product. Table A.4 illustrates the mapping between the IEA Energy Statistics' petroleum "Product", the six sub-product categories, the IEA Prices and Taxes "Fuel", and the SEDS database "Source" products.

Table A.4: IEA-CGE-SEDS product mapping for commodity price tracking

IEA Product	**CGE Commodity**	**IEA Fuel**	**SEDS Source**
Coke.oven.coke..kt.	COKE		CC
Gas.coke..kt.	COKE		CC
Petroleum.coke..kt.	COKE		PC
Gas.diesel.oil..kt.	DISL	Automotive.diesel	DF
Kerosene.type.jet.fuel..kt.	DISL		JF
Other.Kerosene..kt.	DISL	Light.fuel.oil	KS
Natural.gas..TJ.gross.	gas	Natural.gas	
Aviation.gasoline..kt.	GSLN		AV
Gasoline.type.jet.fuel..kt.	GSLN	Regular.unleaded.gasoline	MG
Motor.gasoline..kt.	GSLN	Regular.unleaded.gasoline	MG
Bitumen..kt.	HFOL		AR
Fuel.oil..kt.	HFOL	High.sulphur.fuel.oil	RF
Refinery.feedstocks..kt.	HFOL		UO

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Table A.4 – *Continued from previous page*

IEA Product	CGE Commodity	IEA Fuel	SEDS Source
Additives.blending.components..kt.	OTHP		AB
Lubricants..kt.	OTHP		LU
Naphtha..kt.	OTHP		FN
Non.specified.oil.products..kt.	OTHP		MS
Other.hydrocarbons..kt.	OTHP		FO
Paraffin.waxes..kt.	OTHP		WX
White.spirit...SBP..kt.	OTHP		SN
Coke.oven.gas..TJ.gross.	RGAS		CG
Ethane..kt.	RGAS	Liquefied.petroleum.gas	LG
Gas.works.gas..TJ.gross.	RGAS	Liquefied.petroleum.gas	GW
Liquefied.petroleum.gases..LPG...kt.	RGAS	Liquefied.petroleum.gas	LG
Natural.gas.liquids..kt.	RGAS		LG
Refinery.gas..kt.	RGAS		LG
	RGAS		SF

This mapping allows for detailed prices (and volumes) of individual products to be aggregated into value flows for RGAS, DISL, GSLN, HFOL, OTHP, and COKE. Like the IEA Prices and Taxes, SEDS divides product prices into Households, Electric Generation, and Industry.

A.2 Disaggregating domestic vs. imported volumes: GTAP8 and IEA Energy Statistics

The *edf*, *eif*, *edp*, *eip*, *edg*, and *eig* sets in GTAP8 contain the imported and domestic volumes of refined oil consumed in each sector. Refined oil is a single commodity.

The IEA's Energy Statistics database tracks sectoral usage for 24 petroleum products. However, the IEA data do not distinguish domestic from imported volumes consumed within each sector. In order to identify the imported vs. domestic volumes I extracted the production, exports, and imports volumes from the IEA data, leaving the consumption data for 57 sectors. Table A.5 provides the map between the IEA's FLOW and the associated activities.

Table A.5: IEA "FLOW"-to-CGE "Activity" map

FLOW	**Activity**
Memo: Feedstock use in petrochemical industry	CONS
Agriculture/forestry	CONS
Autoproducer CHP plants	CONS
Autoproducer electricity plants	CONS
Autoproducer heat plants	CONS
BKB plants	CONS
Blast furnaces	CONS
Charcoal production plants	CONS
Chemical and petrochemical	CONS
Chemical heat for electricity production	CONS
Coal liquefaction plants	CONS
Coal mines	CONS
Coke ovens	CONS
Commercial and public services	CONS
Construction	CONS
Domestic aviation	CONS
Domestic navigation	CONS
Domestic supply	SUPPLY
Electric boilers	CONS
Exports	EXP
Fishing	CONS
Food and tobacco	CONS
For blended natural gas	CONS
From other sources - coal	PROD
From other sources - natural gas	PROD
From other sources - non-specified	PROD

Continued on next page

Table A.5 – *Continued from previous page*

FLOW	Activity
From other sources - oil products	PROD
From other sources - renewables	PROD
Gas works	CONS
Gas-to-liquids (GTL) plants	CONS
Gasification plants for biogases	CONS
Heat pumps	CONS
Imports	IMP
Industry	CONS
International aviation bunkers	EXP
International marine bunkers	EXP
Iron and steel	CONS
Liquefaction (LNG)/regasification plants	CONS
Machinery	CONS
Main activity producer CHP plants	CONS
Main activity producer electricity plants	CONS
Main activity producer heat plants	CONS
Mining and quarrying	CONS
Non-energy use in other	CONS
Non-energy use in transport	CONS
Non-energy use industry/transformation/energy	CONS
Non-ferrous metals	CONS
Non-metallic minerals	CONS
Non-specified (energy)	CONS
Non-specified (industry)	CONS
Non-specified (other)	CONS
Non-specified (transformation)	CONS
Non-specified (transport)	CONS
Nuclear industry	CONS
Oil and gas extraction	CONS
Oil refineries	CONS
Own use in electricity, CHP and heat plants	CONS
Paper, pulp and print	CONS
Patent fuel plants	CONS

Continued on next page

Table A.5 – *Continued from previous page*

FLOW	Activity
Petrochemical plants	CONS
Pipeline transport	CONS
Production	PROD
Pumped storage plants	CONS
Rail	CONS
Residential	CONS
Road	CONS
Textile and leather	CONS
Transport equipment	CONS
Wood and wood products	CONS

Using the data on production, exports, and imports, I calculated domestic vs. imported shares for each IEA product. Exports were reported as negative volumes. I excluded the International Marine Bunker entries. Then I summed production and exports. Wherever the result was negative, I assumed that these volumes were re-exported imports and added the difference to imports. Where this made imports negative, I set imports to zero. I divided the modified Imports by total supply for each product.[4] The result was the share of total supply that came from imports. Subtracting this share from 1 returned the share of total supply that was sourced domestically. Under the assumption that each sector drew its fuel from the same pool of petroleum products, I multiplied the domestic and imported shares to the total consumption in each sector. This disaggregated sectoral consumption into imported and domestic volumes for each petroleum product.

[4]"SUPPLY" is the total amount of each product consumed in each country, including stock changes and statistical differences.

A.3 Breaking out household transportation from final consumption

GTAP8 records the final consumption volumes of the aggregated refined fuels in *edp* (domestic) and *eip* (imports). IEA Energy Statistics reports consumption of specific products by type of use. Residences and a portion of Road volumes correspond to the GTAP8 final consumption data. I use the calibration data in the ICCT's Roadmap model to estimate the portion of each product that is consumed for household transport. The ICCT Roadmap model is calibrated using data from 2005 and 2010. The GTAP8 base year is 2007, so I use an average of 2005 and 2010 data to estimate the proportions.

The ICCT data are divided by drivetrain. Three drivetrains – gasolines, diesels, and LPGs – are used by households, and would correspond to the consumption of GSLN, DISL, and RGAS. Drivetrains are divided by vehicle types: light duty vehicles (LDV), Bus, 2-wheelers, 3-wheelers, truck, passenger rail, freight rail, aviation, and marine. I sum the volumes of LDV, 2-wheeler, 3-wheeler, Bus, and truck for each fuel category to get a total fuel usage figure for each fuel in Road transport. The ICCT categories "Conventional and hybrid gasoline" and "Plug-in hybrid gasoline" correspond to GSLN, "Conventional and hybrid diesel" and "Plug-in hybrid diesel" correspond to DISL, and "LPG" corresponds to RGAS. Then I sum up only LDV and 2-wheeler data for each fuel. These two entries represent the household transportation portion of the total.[5] The household transportation totals within each fuel and within each region are divided by the total road transport for each fuel and each region. This provides the share of on-road fuel consumption of diesel, gasoline, and LPGs that is consumed by households.

I multiply household consumption shares by the corresponding volume in the IEA Road data to estimate household transportation consumption of each fuel. I add these volumes to the Residential consumption category, since these fuels are actually

[5] In making this assumption, taxis end up being included in this total, but the aggregation cannot be avoided. Taxi data is not available for enough regions to be able to break them out.

consumed by households. I subtract the same volume from the Road data, leaving commercial Road transport as the remainder. Next I divide each fuel's household Road volume by the augmented Residential volumes to estimate the *share* of household fuel consumption used for transportation. This share is the "*os*" parameter in my model. It is indexed by fuel (GSLN, DISL, or RGAS) and region. *os* is multiplied by the GTAP household fuel consumption in each region to break out the household transportation volumes in the CGE model.

A.4 Determining prices of petroleum products in IEA Energy Statistics

The IEA's Energy Prices and Taxes reports prices for up to six key products in the OECD countries and 17 non-OECD countries. Not every region reports ex-tax and post-tax prices for every product. Both the GTAP8 database and the SEDS database are used to estimate pre- and post-tax prices for all 24 petroleum products in IEA Energy Statistics.

IEA prices are based on end use, including taxes [79, p. 46 of 2$^{\text{nd}}$ quarter 2008]. These correspond to GTAP's agent prices. Taxes were reported separately. I calculated the share of the total price due to taxes. Subtracting the tax share from one returns a multiplier for the market (ex-tax) prices (the "market price multiplier") in each country for each fuel and in each of the three consumption categories (households, electric generation, and industry).

Then I multiplied each agent price by the market price multiplier to estimate market prices for each of the six products in each IEA country. Where multiple prices were listed for a fuel type, I used the minimum value to set a single market price. The IEA Prices and Taxes data thus provided an agent and market price in 29 OECD and 17 non-OECD countries for up to six petroleum products in up to three sectors (households, electricity generation, and industry).

The IEA Prices and Taxes sectors match the EIA SEDS sectors: households, electric generation, and industry. SEDS contains 22 petroleum products that were mapped to the IEA's 24 petroleum products. Six of the SEDS fuels were mapped to the six fuels in the IEA Prices and Taxes data. Table A.6 contains the map.

Table A.6: IEA Prices and Taxes "Fuel"-to-EIA SEDS "Source" mapping for product pricing

IEA Fuel	**EIA SEDS Source**
Automotive.diesel	DF
Light.fuel.oil	KS
Liquefied.petroleum.gas	LG
Premium.unleaded.95.RON	MG
Premium.unleaded.98.RON	MG
Premium.leaded.gasoline	MG
Regular.unleaded.gasoline	MG
Regular.leaded.gasoline	MG
Low.sulphur.fuel.oil	RF
High.sulphur.fuel.oil	RF
Natural.gas	SF

Using SEDS, I divided the price of each petroleum product by the price of each of the six products that matched the IEA to get a set of price ratios. I estimated market prices for the remaining 18 products by multiplying each ratio by its corresponding IEA benchmark price. I weighted each price estimate by its volume to get a volume-weighted market price estimate for each of the 18 additional products.

Next I estimated prices in the countries that were not covered in IEA's Prices and Taxes. From GTAP, I divided the domestic market value flows (*vdfm*) by the domestic volumes consumed (*ed*) to estimate an average market price for petroleum products by region. Then I calculated price ratios between the regions. I mapped the GTAP ratios to the 18 EPPA regions. I counted Brazil (BRA) as LAM (Latin America). I multiplied the market price ratio by the reference country market price, and used a volume-weighted average in cases where there were more than one reference price per EPPA region.This step produced a full set of domestic market price estimates for 24 petroleum products in 142 IEA countries.

That left three price series to fill in: domestic agent prices, imported market prices, and imported agent prices. Some of the domestic agent prices were already reported in IEA Prices and Taxes. For the rest, I aggregated the GTAP8 volumes and value flows to match the IEA country and sector according to the maps in Tables A.2 and A.3. This gives me total *p_c* volumes, market-priced values, and agent-priced values for imported and domestically-sourced products by IEA country and sector. The average tax rate on domestic petroleum products was calculated by dividing the agent value flow (*vdfa*) of the *p_c* commodity by its market value flow (*vdfm*) in each country and sector. This creates a "domestic agent price multiplier" for cases when the IEA price data do not report taxes. I calculate the agent price multiplier for imported products by dividing GTAP8's *vifa* data by the *vifm* data. I divide total values by total volumes to estimate the volume-weighted average price of petroleum products for domestic and imported market and agent prices. Dividing the imported price by the domestic price in each sector gave me an imported/domestic price ratio for both market and agent prices. These were the price ratios that were used to translate domestic market prices into the other three price series.

The country-specific imported market price was estimated by multiplying the domestic market price by the GTAP8 imported/domestic *p_c* price ratio in each country. To estimate the domestic agent prices, I multiplied the estimated market price in each country by a sector-specific GTAP8 agent/market *p_c* price ratio for each country and sector. I used two methods to estimate the imported agent price: one was to divide the GTAP imported agent price by the imported market price for each sector and region. Multiplying this ratio by the imported market price gives one estimate of the imported agent price. Another method is to divide the GTAP8 imported agent price by the domestic agent price. Multiplying this ratio by the domestic agent price produces an alternative estimate of the imported agent price. The estimates are not identical, so I use a simple average of the two methods to estimate the imported agent price.

This procedure created a set of domestic and imported market prices and domestic and imported agent prices for all 142 countries and all 57 sectors for all 24 petroleum products in IEA Energy Statistics. Many assumptions were made that would undermine the utility of this set as a true price reference. However, it is suitable for creating proxy value flows to determine the relative values of the fuels by sector and region.

A.5 Calculating volume- and value-flow shares of oil products

Value flows are created from the price estimates and volume data. There were four price estimates for each sector and country in IEA Energy Statistics: domestic market prices, domestic agent prices, imported market prices, and imported agent prices. Multiplying the two domestic price estimates by the domestic volumes in IEA Energy Statistics creates the market and agent-priced value flows for domestically-produced volumes. The exercise is repeated for the imported volumes. This creates a set of value flows, both ex-tax and including tax, for both domestic and imported products, in each sector in each country in IEA Energy Statistics.

The IEA volume and value data were then aggregated. IEA's 24 petroleum products were summed into RGAS, DISL, GSLN, OTHP, HFOL, and COKE. The mapping for the petroleum products is covered in Table A.4. IEA's 57 sectors were summed into the 14 sectors (plus final consumption) to be used in the CGE model. The sector mapping is detailed in Table A.3. IEA's 142 countries were summed into EPPA's 18 regions. Regional mapping is reported in Table A.2.

Once the data were aggregated, the volume and value flow shares were calculated according to the following equations:

$$S_{vol_{p,sec,di}} = \frac{Vol_{p,sec,di}}{\Sigma_p Vol_{p,sec,di}} \tag{A.1}$$

$$S_{val_{p,sec,di,type}} = \frac{Pr_{p,sec,di,type}Vol_{p,sec,di}}{\Sigma_p Pr_{p,sec,di,type}Vol_{p,sec,di}} \quad (A.2)$$

$S_{vol_{p,sec,di}}$is the share of total petroleum product volume represented by each product p in each sector sec for imports or domestic goods (di). p is the set of ROIL sector commodities – RGAS, DISL, GSLN, OTHP, HFOL, or COKE. sec is the set of sectors – CROP, LIVE, FORS, FOOD, COAL, OIL, ROIL, GAS, ELEC, EINT, OTHR, SERV, TRAN, DWE, or final consumption. di denotes whether the share is for domestic or imported goods. $S_{val_{p,sec,di,type}}$is the share of total expenditures on petroleum products represented by each product p in each sector sec for imports or domestic products (di) by the price $type$. $type$ is either agent or market. Vol refers to volumes, and Pr refers to prices. Within each $sec/di/type$ combination, the sum of S over all p equals 1.

GTAP8 data was aggregated to 15 sectors (including final consumption) and 18 regions. The ROIL entry in each sector/region combination was multiplied by each of the six petroleum product shares to calculate the value (or volume) represented by each petroleum product. The sum of each of these products equals the original value of ROIL, so the original dataset remained balanced for every activity except trade flows.

The volumes calculated for the household Road transportation and Residential fuel consumption were multiplied by market prices to determine values spent on fuel for (1) transport and (2) other household uses. The value share of household transportation fuel use was calculated by dividing the transport value of each fuel by the total household expenditure for each fuel. This is the es parameter that breaks out the expenditure share of final consumption for household transportation.

A.6 Preparing products for international trade

International trade flows of p_c were disaggregated into the six refined products. GTAP8 trade data for volumes and value flows track country-to-country trade of the

p_c product. The pricing data from IEA Energy Prices and Taxes in conjunction with IEA Energy Statistics identifies the shares of each product in total imports, but not the individual exporters. The same problem exists for exports. The goal is to provide the product-specific trade between regions but ensure that volumes and values still sum to the total export and total import proportions already calculated from GTAP.

In each sector zero-profit conditions must be maintained, and the domestic and imported markets must "clear". Zero-profit conditions mean that the total domestic inputs plus imports (net of tariffs) in each sector must exactly equal post-tax expenditures on domestic and imported goods plus factors of production. Domestic market clearing means that the total amount spent on a good in a region must equal the sum of expenditures on that good in each sector of that region. Imported market clearing means that the total value imported (after accounting for transport costs, export subsidies, and import tariffs) must equal the market value of imported goods in each sector of each region.

I optimize trade flows while enforcing zero-profit conditions and domestic and imported market clearing. I utilized an optimization algorithm to ensure that country-to-country imports from each exporter sum across all exporters to the total imported volume or value flow shares calculated in IEA Energy Statistics. I use the same constraint for exports aggregated across all importers, for each region and petroleum sub-product.

The objective function minimizes the sum of squared differences between the calculated variable value and its estimated value after disaggregation. Squared deviations from the initial volumes are given 100 times more weight than other parameters because of the greater confidence in the accuracy of estimated volumes than in estimated prices. There are the following constraints: the sum of all six petroleum products must equal the original value for ROIL for every volume and value flow; tax revenue/subsidy expenditures for each product must equal the ROIL tax revenue/subsidy expenditures; agent-priced value flows for each commodity must equal the market price plus tax revenue or minus subsidy expenditure. The maximum or minimum price (or tax/subsidy) allowed is based on the maximum and minimum values in GTAP8.

The final data set is the basis for the disaggregated model. It is complete and balanced for international trade flows and domestic and imported value flows (both ex-tax and post-tax). Tax revenues/subsidy expenditures for each product sum to the original GTAP8 value. Data preparation scripts in GAMS translate these to individual tax and subsidy rates.

The last modification related to international trade was to set distillates (DISL), gasolines (GSLN), and heavy fuel oils (HFOL) as tradable goods under the Heckscher-Ohlin model. This implies perfect substitutability between domestic and imported products. Transportation fuels are widely traded internationally. In reality there are various grades and quality levels that preclude true perfect substitutability, but the three fuels are much closer to perfect substitutes than to region-specific fuels. Only regions that exported the fuel in the base year are able to export it going forward, and the same rule applies for imports. This prevents massive trade distortions in the model as trading restrictions are lifted. This feature provides an opportunity. In order to ensure that the goods can be traded unhindered across borders, each country that will trade the good as an importer or exporter must be initialized with a nominal value flow. Trade can be prevented by initializing the value as zero. This allows me to permit or restrict international trade in these fuels, and control which regions are trading – a useful tool in examining the impacts of international trade.

A.7 Integrating the disaggregated products into the CGE model

Each sector that originally used the ROIL commodity as an input was modified so that the appropriate refined product was listed as the input. In cases where the ROIL commodity input was broken into multiple refined product inputs within a single sector, they were placed into a "refined products" nest. I added an appropriate elasticity of substitution for the nest so that the sector could adjust its use of inputs based on changes in the relative prices of the products. The nesting structure is described in greater detail in Chen *et al.*, Paltsev *et al.*, Babiker *et al.*, Choumert *et al.*, and others [11, 121, 123, 162, 122, 31, 178, 27]

The household transportation refined product volume shares (*os*, calculated above) were multiplied by the final consumption of each product to break out the volumes pertaining to household transport. The *es* expenditure shares are applied to the market value flow figures to break out the portions of the refined fuel expenditures devoted to household transportation as well. These are included in an additional final demand category called "htrn".

A.8 Technologies adapted to multiple refined products

A number of technologies in addition to GTL were also added to the model. Table A.7 provides a list of these technologies and the years in which they become available. All of these are treated as backstop technologies in CGE modeling parlance: they are not initially economic and are not in use in the initial year, but can be selected for deployment at some future date if the economics become favorable. Though many would be considered technologies that operate within the operations of existing sectors, they are tracked separately. Among these were versions of technologies that existed in the base model that needed to be differentiated to account for specific outputs or inputs that relate to a disaggregated refined fuels commodity. Others were directly related to oilsands production and upgrading. One technology mirrored the heavy fuel oil upgrading sections of modern oil refineries. This upgrading technology provided more flexibility for existing oil refineries to increase their output of high-value products by upgrading the residuum from their production. Details on all of these additional technologies are available in Choumert *et al.* [31]. I updated them to reflect 2007 prices and costs.

Table A.7: Technologies included and dates of availability

Backstop technology	**EPPA Code**	**Yr. available**
Wind	WIND	2010
Bioelectricity	BIOELEC	2015
Biofuels	BIO-OIL	2015
1st gen. biofuels	BIO-FG	2007
Solar	SOLAR	2010
Synthetic oil	SYNF-OIL	2015
Syngas – coal	SYNF-GAS	2015
Syngas – heavy fuel oil	SYNF-GASh	2010
Syngas – pet. coke	SYNF-GASk	2010
Wind/biofuel backup	WINDBIO	2010
Wind/nat. gas backup	WINDGAS	2010
Nat. gas combined cycle	NGCC	2015
NGCC w/ CCS	NGCAP	2020
IGCC w/ CCS – coal	IGCAP	2020
IGCC w/ CCS – heavy fuel oil	IGCAPh	2020
IGCC w/ CCS – pet. coke	IGCAPk	2020
Advanced nuclear	ADV-NUCL	2020
Non-conventional crudes	NC	2010
NC upgrading	NCUP	2010
NC upgrading w/ CCS	CAPNCUP	2020
NC w/ CCS	CAPNC	2020
Heavy fuel oil upgrading	UPGRAD	2010
Gas-to-liquids	GTL	2020

A.9 GTL costs and input shares across regions including the fixed factor (for reference)

Table A.8 details the initial estimates, by region, of the input shares for GTL technology and its markup in the Base case capital cost scenario. These estimates include the fixed factor inputs. The dissertation suppresses fixed factor inputs for GTL technologies. All inputs are calibrated to 2007 prices. These figures reflect a mechanical calculation of markups and cost shares based on the reported prices of natural gas, distillate fuels (DISL), and other petroleum products (OTHP) in each region. It is not realistic to assume that many of these countries will be viable candidates for GTL

Table A.8: Base case input shares to GTL backstop technology by region

Region	GAS	K	L	FF	Markup	Gas Resource?
USA	60.6%	26.6%	11.8%	1.0%	1.675	YES
CAN	54.7%	30.7%	13.6%	1.0%	1.298	YES
MEX	59.9%	27.1%	12.0%	1.0%	2.026	YES
JPN	61.2%	26.2%	11.6%	1.0%	0.870	NO
ANZ	55.5%	30.1%	13.4%	1.0%	1.038	YES
EUR	62.7%	25.1%	11.1%	1.0%	1.115	YES
ROE	59.6%	27.3%	12.1%	1.0%	0.845	YES
RUS	42.7%	39.0%	17.3%	1.0%	0.667	YES
ASI	60.5%	26.7%	11.8%	1.0%	1.115	NO
CHN	53.2%	31.7%	14.1%	1.0%	0.913	YES
IND	60.2%	26.9%	11.9%	1.0%	1.258	NO
BRA	50.8%	33.4%	14.8%	1.0%	1.459	YES
AFR	54.1%	31.1%	13.8%	1.0%	1.136	YES
MES	44.4%	37.8%	16.8%	1.0%	1.625	YES
LAM	32.5%	46.1%	20.4%	1.0%	1.212	YES
REA	60.5%	26.7%	11.8%	1.0%	0.945	YES
KOR	61.8%	25.8%	11.4%	1.0%	0.889	NO
IDZ	51.7%	32.8%	14.5%	1.0%	0.933	NO

production. Only regions with significant resources or that exported natural gas in the base year should be considered candidates unless modeling a scenario in which natural gas hydrates from the ocean or some as-yet untapped shale gas resources are being exploited. The column “Gas Resource?” reports whether GTL is likely to be deployable in each region given its natural gas resources and its natural gas trade patterns in the 2007 base year.

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