Probing the Climate Target and Climate Policy Implications of Abundant Natural Gas in North America

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Abstract

The past decade witnessed breakthroughs in the extraction of shale and other unconventional natural gas sources, substantially increasing the estimated low-cost supply of natural gas in North America, particularly in the United States. This thesis is an empirical investigation of whether, and to what extent, a falling cost of plentiful natural gas is a benefit or a problem for fighting climate change by exploring the implications of abundant gas on various aspects of climate policy. On the one hand, natural gas is less-emissions intensive than coal and conventional crude oil, and so substitution to natural gas from these sources can potentially serve as a mitigation tool. On the other hand, lower cost gas is only a partial de-carbonization measure relative to near-zero Greenhouse Gas (GHG) technologies like nuclear, carbon capture and storage, and renewable energy. I examined these and other considerations regarding natural gas' interplay with climate policy using the CIMS hybrid energy-economy model. Some key focus areas included:

- What are the near-term implications of abundant gas on GHG emissions?
- What are the implications over a longer period of transition, such as to 2050?
- How might abundant gas play a key role in specific sectors?
- What impact might abundant gas have on a staged implementation of policy, with differing levels of policy stringency by sector?

Some key findings concerning the gas revolution's interplay with climate policy are that:

- Abundant natural gas results in only slight reductions in near-term emissions relative to scarce gas scenarios, although near-term reductions for the power sector are significant.
- Abundant natural gas makes it harder to achieve deep de-carbonization by 2050 relative to scenarios with scarce gas.
- Abundant natural gas worsens emissions leakage from the power sector to end use sectors when the former is subject to stringent policy while the latter is not.
- Abundant natural gas may make it easier to achieve emissions reductions in sectors such as heavy trucking, provided it is coupled with certain complementary fuels like renewable natural gas and climate policy. Otherwise it could result in higher emissions; and

- Abundant natural gas, combined with unanticipated policy, can achieve deep de-carbonization by 2050. However, realizing this outcome necessitates higher carbon prices as the unanticipated policy creates additional costs when coupled with abundant natural gas.

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I wish to thank a number of people who have helped me along throughout the process.

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1. Introduction

Early this century, new technologies and procedures, namely the combination of horizontal drilling and hydraulic fracturing, led to breakthroughs in the extraction of shale and other unconventional natural gas sources, such as tight gas. These advances have substantially increased the estimated low-cost supply of natural gas in North America, and particularly in the United States (US). The US Energy Information Administration (EIA) estimated the technically recoverable resource of US natural gas to be 2462 trillion cubic feet (tcf) in 2016. This amount is 90 times the annual US consumption for that year (EIA, 2018a).[1] The response of many energy analysts to this boom has been to label it a "revolution", with economic historian Daniel Yergin going on to claim, *"the rapidity and sheer scale of the shale breakthrough – and its effects on markets – qualified it as the most significant innovation in energy so far since the start of the 21st century."* Similarly, Energy Economist Amy Mayers Jaffe titled her 2010 Wall Street Journal article on the subject *"Shale Gas will Rock the World",* predicting a world changing transformative effect over the coming decades.

Almost a decade has passed since then and the abundance of natural gas has certainly had a profound effect on North America, if not globally. The shale gas revolution has altered North American trade flows, catalyzed a vibrant extractive industry, encouraged growth in certain energy-intensive manufacturing sectors, impacted projections for the natural gas commodity market itself, and has driven emissions reductions.

Regarding the first point, North America has an integrated market for natural gas, with most movement occurring overland by pipelines, and a far smaller amount by ship via Liquefied Natural Gas (LNG). While the export of LNG from the US to the broader globe has been increasing since the beginning of the natural gas revolution, the long lead times, and capital-intensive nature of LNG facilities have resulted in the dramatic production increases occurring in the US being overwhelmingly localized to the North American market. This glut has affected countries like Canada and Mexico, which have historically

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[1]According to the US EIA gross withdrawls of natural gas in the US have risen from 23.5 tcf in 2006 to 32.6 tcf in 2016 (EIA, 2018b)

been producing more gas than they consume domestically to meet US demand. For instance, increased US domestic production has driven a decline in Canadian natural gas production, despite Canadian discoveries of its own abundant shale resource in the Horn River and Montney formations. In 2017, the US actually became a net exporter of natural gas for the first time in almost 60 years (EIA, 2018c).

On the second point, the shale gas revolution has had a significant impact on US macroeconomic performance and employment— both within the natural gas sector, and in energy-intensive sectors that use natural gas for energy or as a feedstock. In the natural gas sector, a recent paper by Agerton, Hartley, Medlock & Temzelides (2017), using a panel-level regression, found that each additional natural gas rig creates 31 immediate jobs, and 315 long-run jobs. The studies cited in their literature review, many of which used similar regression methodologies, overwhelmingly found similar statistically positive effects on employment. US employment in the oil and gas sector has increased from 121 thousand at its lowest point in 2002, to almost 200 thousand in 2014 (US Bureau of Labor and Statistics, 2018). While some employment decline has followed the 2015 drop in oil prices, preliminary data for 2018 suggests that this may be a short-run phenomenon given the partial recovery of prices in the last couple of years. While it is important to bear in mind when comparing these numbers that the job growth in oil and gas may not correspond to *incremental* growth in national employment due to movement between jurisdictions and between jobs, it provides a measurable insight as to how the shale gas revolution has affected US employment patterns.

In addition, the shale gas revolution has had a profound impact on the US manufacturing sector, especially where natural gas serves as a primary energy input, or as a feedstock, such as in ethylene and methanol production. In the case of ethylene, it is actually not the methane that is the feedstock but ethane, a natural gas liquid found in many of the new shale gas plays. By 2014, this abundance of ethane had resulted in a 7-1 price advantage of US ethylene producers over their global competitors who rely on expensive oil-based feedstocks, boosting the US chemicals sector (Wang et al., 2014). DeRosa & Allen (2015) use a network model to show the cost effects on downstream chemicals products due to changes in the raw material costs – illustrating the wide variety of products that are affected by changes in availability of natural gas (32 intermediates and final products) and natural gas liquids (64 intermediates and final products). The EIA found lower gas prices to result in a 1.2% increase in GDP, a 5.1% increase in industrial output, and an 11.5%

increase in sectors like bulk chemicals and paper in 2040 relative to scenarios with higher gas (Sendich, 2014).

Regarding its impact on the natural gas commodity market, the advent of shale gas has had a dramatic impact on prices in the US natural gas spot market, and projections for this market over the coming decades. Figure 1-1 below situates shale's impact within the broader context of the last 70 years of US natural gas consumption and prices.

Figure 1-1: Wellhead/Henry Hub Natural Gas Price vs. US Net Natural Gas Production
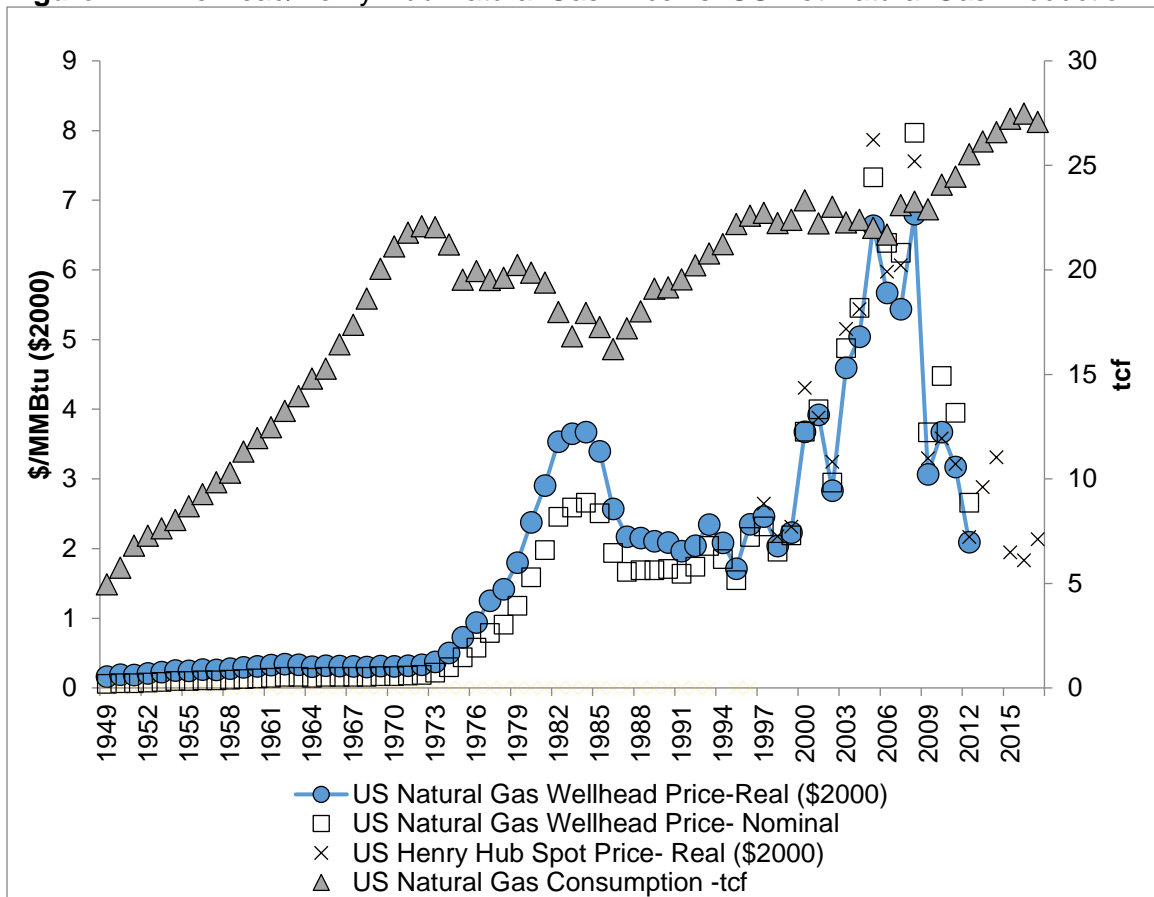
Source: EIA (2018d); EIA (2018e)[2]

The figure shows how, in real terms, the shale gas revolution has resulted in natural gas prices reverting back to levels not seen since the late 1970s, which are far below the mid-2000s peak that many analysts thought to be the new normal. Stemming from the decline in price, natural gas consumption in the United States has increased rapidly, from 22 tcf to 27 tcf between 2005 and 2015. Although not as rapid as the post-war boom in gas

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[2] Wellhead price calculations were discontinued by the EIA in 2012.

consumption, the growth of natural gas over this period is of comparable rate and magnitude to the growth period occurring after the deregulation of the natural gas industry in the 1980s.[3]

Overall, there is a great deal of uncertainty about how long low natural gas prices might persist. Various changes on both the demand side and the supply side will be key driving factors. On the demand side, some of the key uncertainties relate to movements along the demand curve (i.e. to what degree the decrease in gas prices spur an increase in natural gas use?) and by shifts in the curve itself. Some factors that might drive shifts in the curve include the implementation of policies affecting the availability of substitutes (e.g. a total phase-out of coal), improvements in a complement technology (e.g. decreased cost of natural gas trucks), or increased economic growth in sectors in the US economy that are large users of natural gas (e.g. chemicals). On the supply side, there are unknowns surrounding the geological characteristics of natural gas, and especially shale gas. This results in uncertainty about how much gas is recoverable at a given price point and thus, the steepness of the supply curve. Increased technological progress and the discovery of new gas formations, which are also highly uncertain, would shift this curve downward thereby improving supply.

A paper by Schearer, Bistline, Inmam & Davis (2014) illustrates some of this uncertainty pertaining to the supply side. The authors elicited the judgment of 23 experts as to the likely natural gas supply curve for the US by asking for a median, minimum, and maximum view. They found an order of magnitude difference in the range of views, with a maximum estimate of 3960 tcf of gas economically available under $5/MMBtu (nominal) and a minimum of 393 tcf of gas available at the same price. These estimates represent a range of 13.6 years to 137 years of gas at current production levels.

Assumptions concerning technological progress drive much of the divergence in the forecasts discussed above. Evidence from research on shale gas production experience to date indicates that technical progress in shale gas extraction has been profound. Work by Middleton, Gupta, Hyman, & Viswanathan (2017) find dramatic increases in the productivity of more recently drilled wells compared to the early stages of drilling in the Barnett shale formation in Eastern Texas. They find that the average 2007 well took about

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[3] See Peebles (1980) for a history of the gas industry in the US.

7 years to reach 1billion cubic feet of production, while the average 2011 well took only 3 years. While Middleton et al., have noted the leveling off of production improvements since 2012, there have been other advances that directly reduce costs by saving materials or reducing overhead. Multi-pad drilling is an example of such an improvement, as it enables gas producers to spread their fixed capital cost over greater wells that can now share many of the same facilities (Mistré, Crénes, & Hafner, 2018).[4] Overall, cost-saving improvements for the Marcellus shale play have resulted in drilling and completion costs per foot declining by 33% and 38% respectively since the beginning of its development early this decade (EIA, 2016a).

The first year productivity rate, and the shape of the production decline curve, also drive uncertainty of the natural gas supply curve. Shale wells tend to have a much more rapid production decline function than conventional wells, such that their *rate* of production declines dramatically even as early as one year after the hydraulic fracture of the well (Lake, Martin, Ramsey, & Titman, 2013). The rapid decline function for shale wells, combined with the low exploration costs, and high probability of success of adjacent profitable wells in the same play, creates the conditions for lower recovery of the gas-in-place than with conventional gas wells (see Lake et al., 2013; Kaiser, 2011). This implies that resource estimation methods for conventional plays may overstate the ultimate resource in shale wells (Lake et al., 2013). On the other hand, there is potential for increased productivity of 20-30% in the remaining years of production due to technological progress. Moreover, the history of the Barnett Shale play demonstrates that the re-fracturing of once fractured wells yielded significant performance improvement, with those wells behaving almost like new wells. Therefore, these mechanisms could expand the available resource and limit the possible overstatement of the estimated shale gas resource.[5]

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[4] Other factors decreasing costs as identified by the EIA include: i) drilling technology improvements, such as longer laterals, improved geo-steering, minimal casing and liner, and improved efficiency in surface operations, as well as ii) completion technology improvements such as increased proppant volumes, number and position of fracturing stages, shift to hybrid fluid systems, faster fracturing operations, less premium proppant, and optimization of spacing and stacking.
[5] The above paragraph draws on Middleton et al., 2017

These parameter uncertainties have led to prior estimates by modelling agencies, like the EIA through their Annual Energy Outlook (AEO), to be considerable underestimations of future gas production. I have illustrated this in Figure 1-2 below by plotting various AEO forecasts of US natural gas production against the actual historic data. This figure demonstrates how AEO forecasts from 2008 onwards consistently trail below the actual historic data, with each subsequent forecast seeing a ratcheting up of the forecasted production. This underestimation is even evident after accounting for the AEO's more optimistic high gas production case, represented by the error bar, as actual production data yielded values even above these points.

Figure 1-2: AEO US Natural Gas Production Forecasts vs. Actual Historic Data
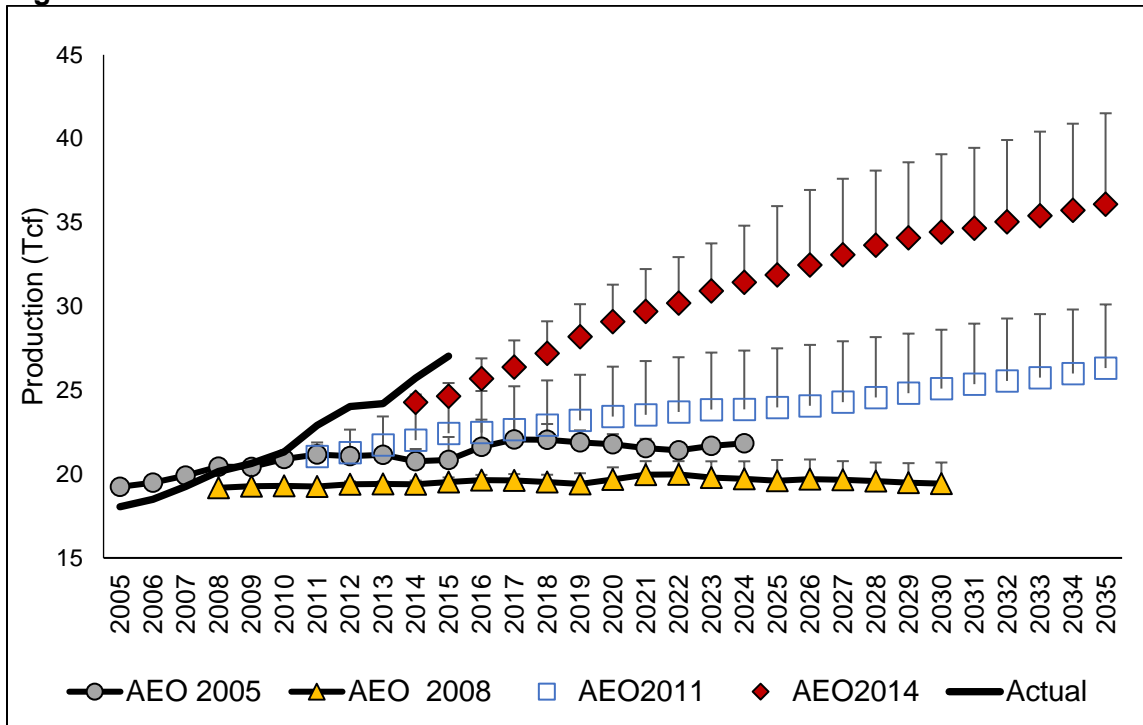
Source: EIA Annual Energy Outlook (2005, 2008, 2011, 2014), EIA (2016b).

Figure 1-3 demonstrates natural gas price forecasts from a number of sources. From this figure, most agencies predict a relatively low gas price by the standard of the early 2000s until 2030, with the upper and lower bounds represented by EIA sensitivity cases around gas resources and technological progress. After 2030, there starts to be more divergence, with some organizations like McKinsey predicting flat prices, and others like the IEA calling for a more bearish outlook. However, even the higher natural gas price forecasts for 2040 are similar to the natural gas prices observed in the US at the beginning of the 21st century.

Figure 1-3: Henry Hub ($2016) Projections by Source
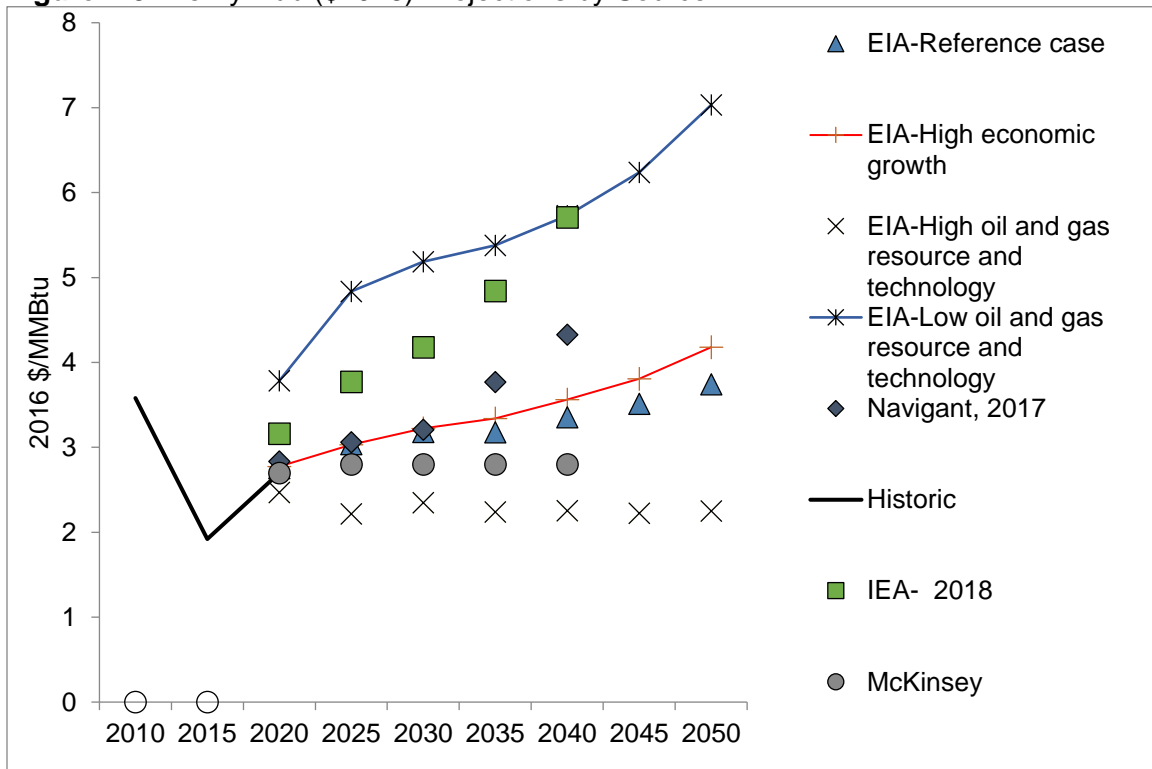
Sources: IEA World Energy Outlook (2018); EIA (2018f); Historic from EIA, McKinsey North American Gas Outlook, Navigant Energy Market Outlook

This abundance of gas has consequences on the type of energy used by the economy and, by extension, on CO_2 emissions and climate policy. Since natural gas is less-emissions intensive than coal and the refined petroleum products produced from conventional crude oil, substitution from these sources to natural gas can potentially serve as a climate-change mitigation tool. In the US context, the combination of low natural gas prices, the relative ease to retrofit coal-fired plants to use natural gas as fuel, and the increasingly stringent environmental regulations on coal-powered facilities has dramatically increased the use of natural gas in US electricity generation. In fact, the share of natural gas in total generation has increased from 18.8% in 2005 to 32.6% today (EIA, 2018g). This has driven a substantial decline in GHG emissions from the US power sector, from 2500Mt in 2005 to little over 2000Mt in 2015 (EIA, 2018h). A second mechanism by which the switch to natural gas has led to lower US power sector emissions is that natural gas combined cycle plants are also much more efficient than the older coal-fired plants they are replacing - 60% vs. 30% efficiency (Cathles, Brown, Taam, & Hunter, 2012).

On the other hand, increased use of gas can only partially de-carbonize the energy system relative to the adoption of near-zero Greenhouse Gas (GHG) technologies like nuclear,

carbon capture and storage (CCS) with coal or natural gas, and renewables. Cheaper natural gas may slow down, or even prevent, investments in these GHG-reducing options, as well as in energy efficiency. Low-cost natural gas might further increase emissions by incentivizing greater energy use, either by promoting more energy intensive modes of production as relative production factor prices change, or by driving more economic activity as input prices fall and US goods become more competitive in global markets.

This thesis is fundamentally about testing the above interplay to discern the climate target and climate policy implications of abundant natural gas in North America. I am interested in situating natural gas within the suite of climate change mitigation options to provide insight to the question: Is abundant natural gas beneficial or detrimental in North America's contribution to fighting climate change? The following formulates some of these dynamics using a simple microeconomic framework of competition used by the CIMS energy-economy model to calculate market share. CIMS, which I discuss in more detail later, is the energy-economy model that I use throughout this thesis.

Suppose a hypothetical energy system with a specific technology j, and a set of all other technologies k. The formula used in the CIMS model to determine market share for technology j (MS_j) is the following, which is the ratio of lifecycle cost of technology j to the sum of the lifecycle costs of all other competing technologies in the system.

$$MS_j = [(CC_j(r/(1-(1+r)^{-N_j})) + MC_j + EC_j + i_j)/n_j]^{-v}/\sum_{k=1}^{K}\{[(CC_k(\frac{r}{(1-(1+r)^{-N_k})}) + MC_k + EC_k + i_k)/n_k]^{-v}\}$$

(Equation 1.1)

Where:

MS_j = the market share of technology $_j$
CC_j = capital cost of technology $_j$
N_j = Life of technology $_j$
MC_j = annual maintenance and operating costs
EC_j = annual energy cost- depends on both energy prices and energy use inputs consumed per unit output of energy service provided by the technology
r = discount rate
i_j = any intangible costs and benefits perceived by consumers
v_j = Market heterogeneity parameter representing different costs for the same technology due to site specific factors, or to represent the distribution of consumer preferences
n_j = annual output

Equation 1.1 is a logistic equation bounded by the v parameter, where v is a value between 1 and 100. The lower the life cycle cost per unit for technology j, the greater is MS_j for a

given cost of other technologies in the market. In the above equation, a lower cost for technology *j* would mean a small number to the power of a negative exponent in the numerator, making the numerator a larger number. This means that a technology with lower lifecycle cost will capture more market share, all else being equal.

Suppose that there are four technologies in the market such that MS_j = the market share for a conventional natural gas utilizing technology (MS_{GAS}). The three other technologies in the market are for a coal burning option, a higher efficiency natural gas burning option, and a renewable option (MS_{COAL}, MS_{GasE}, and MS_{RENEW} respectively). Equation 1.2 becomes:

$$MS_{GAS} = [CC_{GAS}(r/(1-(1+r)^{-n_{GAS}})) + MC_{GAS} + EC_{GAS} + i_{GAS})/n_{GAS}]^{-v} / \{[(CC_{COAL}(r/(1-(1+r)^{-N_{COAL}})) + MC_{COAL} + EC_{COAL} + i_{COAL})/n_{COAL}]^{-v} + [(CC_{GAS}(r/(1-(1+r)^{-N_{GAS}})) + MC_{GAS} + EC_{GAS} + i_{GAS})/n_{GAS}]^{-v} + \{[CC_{RENEW}(r/(1-(1+r)^{-N_{RENEW}})) + MC_{RENEW} + EC_{RENEW} + i_{RENEW)}/n_{RENEW}]^{-v} + [(CC_{GasE}(r/(1-(1+r)^{-N_{GasE}})) + MC_{GasE} + EC_{GasE} + i_{GasE})/n_{GasE}]^{-v}\}$$

<div align="right">(Equation 1.2)</div>

To simplify equation 1.2, I assume

- $EC_{RENEW} = 0$; reflecting a costless source of renewable fuel; like wind or solar
- $O\&M_{RENEW} = O\&M_{GAS} = O\&M_{COAL} = O\&M_{GasE} = 0$; assuming zero O&M for each technology to simplify the equation; and
- $i_{RENEW} = i_{GAS} = i_{COAL} = i_{GasE} = 0$; assuming zero intangible for each technology to simplify the equation
- n is the same for each technology

Thus, under a business-as-usual state without climate policy, the resulting equation 3 becomes:

$$MS_{GAS} = [CC_{GAS}(r/(1-(1+r)^{-n_{GAS}})) + EC_{GAS})]^{-v} / \{[(CC_{COAL}(r/(1-(1+r)^{-N_{COAL}})) + EC_{COAL}]^{-v} + [(CC_{GAS}(r/(1-(1+r)^{-N_{GAS}})) + EC_{GAS}]^{-v} + \{[CC_{RENEW}(r/(1-(1+r)^{-N_{RENEW}}))]^{-v} + [(CC_{GasE}(r/(1-(1+r)^{-N_{GasE}})) + EC_{GasE}]^{-v}\}$$

<div align="right">(Equation 1.3)</div>

From equation 1.3, decreasing the price of natural gas (P_{GAS}) would cause the term EC_{GAS} to fall, (since $EC_{GAS} = P_{GAS} * GasInput/Output * Output$), thereby increasing the market share of the conventional natural gas utilizing technology relative to both coal and renewables, all else being equal. It would also improve the economics of the conventional gas utilizing technology relative to the more efficient gas utilizing technology since

$$EC_{GAS} = P_{GAS} * Input_{GAS}/Output * Output$$

and so $\frac{dEC_{GAS}}{dP_{GAS}} = Input_{GAS}$;

and since $Input_{GAS} > Input_{Gas_E}$

Then $\frac{dEC_{GAS}}{dP_{GAS}} > \frac{dEC_{GasE}}{dP_{GasE}}$

Now, suppose policymakers want to introduce a policy that taxes carbon. The resulting equation 4 becomes

$$MS_{GAS} = [CC_{GAS}(r/(1-(1+r)^{-n_{GAS}})) + EC_{GAS} + Tax_{GAS})]^{-v} / \{[(CC_{COAL}(r/(1+r)^{-N_{COAL}})) + EC_{COAL} + Tax_{COAL}]^{-v} + [(CC_{GAS}(r/(1-(1+r)^{-N_{GAS}})) + EC_{GAS} + Tax_{GAS}]^{-v} + \{[CC_{RENEW}(r/(1-(1+r)^{-N_{RENEW}}))]^{-v} + [(CC_{GasE}(r/(1-(1+r)^{-N_{GasE}})) + EC_{GasE} + Tax_{Gas_E}]^{-v}\}$$

(*Equation 1.4*)

Where Tax_{COAL} is the total annual carbon tax payment by coal defined by $Tax_{COAL} = t * \frac{TonneCO_2}{Output_{COAL}} * Output_{COAL}$ with t being the tax rate and Tax_{GAS} is the natural gas carbon tax burden defined by $Tax_{GAS} = t * \frac{TonneCO_2}{Output_{GAS}} * Output_{GAS}$. Since $TonneCO_2/GJ_{COAL}$ is roughly $2*TonneCO_2/GJ_{GAS}$, then $Tax_{COAL} = 2Tax_{GAS}$

$Tax_{RENEW} = 0$; reflecting the non-emitting nature of this technology, and so was not shown in the equation above

Given that Tax_{GAS} is positive, all else being equal, its introduction will:

- reduce the market share of conventional gas relative to renewable
- increase the market share of gas relative to coal since $Tax_{COAL} = 2Tax_{GAS}$ and so the numerator of this part of the equation increases by more than the denominator; and
- decrease the market share of the conventional gas utilizing technology relative to the more efficient technology.

Overall increases in the market share of gas relative to the other technologies will depend on the relative magnitude of the tax rate vs. the relative magnitude of the other cost elements. Making some assertions about the relative magnitude of these cost elements can then yield some additional insights.

As a simple simulation, I assume the following parameters in Table 1-1 as a stylized example, and then calculate the market share of conventional natural gas technology, as

per equation 1.4 above, with differing gas energy costs and carbon tax costs in Table 1-2. For simplicity, I exclude the efficient gas technology from the simulation.

Table 1-1: Simulation Parameters

Parameter	Value
Life	30 years
EC Coal	$100
R	10%
Capital Cost- Renewable[6]	$4000
Capital Cost- Natural Gas	$2500
Capital Cost- Coal	$2000
V	15

Table 1-2: Simulation Outputs (Market Share for Gas)

		Carbon tax cost ($)							
		0	**25**	**50**	**75**	**100**	**125**	**150**	**175**
	75	0.21	0.45	0.58	0.52	0.35	0.20	0.10	0.05
Gas energy cost ($)	100	0.09	0.23	0.35	0.31	0.19	0.10	0.05	0.03
	125	0.03	0.11	0.18	0.16	0.10	0.05	0.03	0.01
	150	0.01	0.05	0.09	0.08	0.05	0.03	0.01	0.01
	175	0.01	0.02	0.04	0.04	0.02	0.01	0.01	0.00
	200	0.00	0.01	0.02	0.02	0.01	0.01	0.00	0.00

This simulation shows how natural gas' market share is increasing when the carbon tax cost increases in increments of $25 from zero to $50 (orange highlighted section). At these lower carbon tax payments, the economics of gas improves relative to coal. However, for carbon tax payments above $50, the table shows the market share of the natural gas technology decreasing, as gas becomes penalized for its relatively high carbon emissions compared to renewables.

By reading the table from bottom to top, we can see how lowering the gas price, and thus the energy costs from using natural gas, for any given carbon tax cost, increases the market share of the natural gas technology. Depending on what natural gas is displacing, this result would either reduce or increase emissions. The expectation is that at lower

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[6] Assumes no incremental flexibility costs due to intermittency. Could also be thought of as "firm" renewable such as geothermal or intermittent renewable plus storage.

carbon prices, the increased market share captured by the gas technology would be at the expense of coal. Thus, for lower carbon prices, natural gas displacing coal would make carbon pricing more effective.

The above formulation focused on a stylized simulation of the issue by exploring the interrelating effects of only a few key parameters. However, I expect the impact of these parameters to have different effects depending on the sector investigated, depending on assumptions about what happens in other sectors, and depending on assumptions about interrelations with other policies. Thus, there is value in expanding beyond the simple simulation presented here, towards a more technologically and behaviorally rich energy-economy model. This model would serve as a tool that can help investigate the new natural gas supply situation from a variety of angles to discern its impact on markets and policy across timescales and sectors.

A number of studies on various aspects of this topic have emerged in recent years. This thesis adds to this work by focusing on the implications of abundant gas for one key policy dimension, climate policy, for various levels of granularity, and across various timescales. Some broad questions of interest that arise from the abundant gas phenomenon include:

- What are the near-term implications of abundant gas on GHG emissions and near-term less stringent climate policies?
- What are the implications over a longer period of energy transition, such as to 2050?
- How might abundant gas play a key role in specific sectors?
- What impact might abundant gas have on a staged implementation of policy?

The academic literature has addressed a number of these questions sporadically. Thus, there may be value to more investigation of multi-sector interactions, different timeframes for de-carbonization, and other overlooked sectors like freight transport. In particular, many of the papers dealing with this subject tend to focus on electricity generation rather than the end-uses of natural gas. This thesis seeks to address these gaps by investigating the following research questions of relevance to the US and Canadian energy-economy systems:

i-   Do lower natural gas prices affect the cost of achieving an 80% reduction in annual emissions for the US economy relative to 2005 levels by 2050?

ii-   Are cost differences due to the gas price exacerbated when there is a delay in the communication of the necessary stringent policy to achieve this reduction to firms and households?

iii-   Does policy targeting only the electricity sector affect GHG emissions in sectors not covered by policy (the uncovered sectors) and in what direction?

iv-   How can policymakers design electricity sector policy to minimize the increase of GHG emissions?

v-   Is there a role for heavy trucks powered by natural gas, either without blending or blended with renewable natural gas (RNG), in reducing freight sector GHG emissions?

vi-   Can natural gas heavy trucks to act as a bridge-fuel to a full de-carbonization of trucking, via progressively increasing blend rates with RNG?

To answer questions i) and ii), I modelled the US energy-economy system with forecasts of varying gas prices, climate policy, and expectations of climate policy. My hypothesis is that while abundant gas may make it easier to achieve shallow and near-term reductions, it will make it substantially more difficult to achieve more stringent long-term climate targets. I hypothesize that this is especially the case when there is a delay in the necessary policy to achieve the target and its intensity comes as a surprise to firms and households.

To answer questions iii) and iv), I modelled several electricity sector policies to determine the impact of these policies on GHGs for both the power sector itself, and the remaining sectors in the economy that I modelled without policy. My hypothesis is that these electricity sector policies will alter prices facing the sectors not covered by the policy, thereby altering their emissions relative to scenarios without the electricity sector policy. The directional impact will depend on the policy specification, and so there is room for policymakers to design policy to limit this increase in emissions in the uncovered sectors.

Finally, to answer question v) and vi), I modelled the long-haul freight transport sector for the Canadian province of Ontario to determine whether low-gas prices would promote the uptake of natural gas trucks. My hypothesis is that natural gas heavy trucks would be competitive in the freight sector, helping this sector achieve emissions reductions due to the lower GHG emissions of natural gas trucks relative to diesel trucks. The mechanism they could do this is twofold. First, natural gas trucks can reduce emissions in the near-term under weak policy. Second, they can continue to reduce emissions as the stringency of the policy increases via the blending of natural gas with Renewable Natural Gas (RNG).

I structured this thesis as a thesis by manuscript consisting of three chapters exploring the implications of abundant natural gas on climate policy for a variety of jurisdictions, sectors, and time-scales. While my main-focus is techno-economic, I am also interested in the design, stringency, and timing and forewarning of climate policies, because these policy features will influence the possible role that greater use natural gas might play. Thus, this thesis will conclude with possible lessons for policy garnered from the techno-economic analysis performed in the three chapters.

The following paragraphs lay out the objectives behind this research, summarizes each of the chapters, and explicitly states my contribution to each, particularly given that some of these chapters correspond to published papers where there is more than one author.

The papers making up the thesis are as follows:

i. *"Abundant Low-cost Natural Gas and Deep GHG Emissions Reductions for the United States"*, joint with Mark Jaccard, published in Energy Policy 2016, 98(241-253).

This paper investigates how the recent natural gas revolution affects the US' ability to achieve deep emissions reductions of 80% below 2005 levels by 2050. Since combustion of natural gas is less-emissions intensive per unit energy than coal and conventional crude oil, substitution from these sources to natural gas can potentially serve as a climate-change mitigation tool. However, lower cost gas may make it more difficult to achieve the stringent climate target described above by stalling investments in near-zero GHG technologies like nuclear and renewables, and later by requiring expensive retrofits of gas-utilizing technologies into lower-emitting alternatives. I evaluate these claims using a hybrid energy-economy model. The paper finds that while abundant gas makes it slightly harder to achieve the target, this adverse effect can be limited if the policy chosen to achieve the target, such as a rising carbon charge, is credibly announced well in advance. A delay in credible and well-announced policy, however, affects agents' investment decision criteria, and makes this stringent climate target harder to achieve irrespective of the gas price.

In this paper, I conducted the literature review, analysis, and draft of the paper. I also conceived of the study design. The CIMS US model used in the study is a variant of the energy-economy simulation model developed and applied since 1990 by researchers associated with the Energy Materials Research Group (EMRG), led by Professor Mark

Jaccard, in the School of Resource and Environmental Management at Simon Fraser University in Vancouver. I updated the model to ensure it reflected the latest forecasts of energy prices, energy production, and end use sector demand and that it was calibrated to reflect actual historic data **(Appendix A)**. I also worked to soft-link natural gas price changes to natural gas demand changes by the model, thereby endogenizing the natural gas price. I did this with Jotham Peters of Navius Research Inc., a consulting firm that collaborates with EMRG in model development and application. Jotham Peters conceived of the supply curve idea and provided the code to operationalize it. I contributed by calibrating the supply curve to natural gas resource estimates from the literature **(Appendix B)**. Mark Jaccard and Nic Rivers reviewed several drafts of the paper, resulting in substantial changes to the original manuscript. Jotham Peters also reviewed a draft and provided helpful comments.

ii. *"Implications of a US Electricity Sector Emissions Policy for Emissions in the Uncovered Sectors",* published as "Implications of a US electricity standard for final energy demand" joint with Mark Jaccard, published in Energy Economics, 2016 (60)469–475.

This paper analyzes the impact of various specifications of GHG reduction policy for the US power sector on emissions in the manufacturing, residential, commercial, and transportation sectors. An electricity sector policy will have implications for these other "uncovered" sectors of the economy through its effect on economy-wide energy prices, among other mechanisms. Again using the CIMS hybrid energy-economy simulation model, I ran several power-sector policies with varying designs. Overall, I found the emissions response to a power sector policy in the uncovered sectors to vary, with some designs causing a substantial emissions increase relative to BAU. However, I also found policymakers have design levers at their disposal to mitigate some of this effect.

In this paper, I conducted the literature review, analysis, and draft of the paper. As noted, I used the CIMS US model developed at EMRG under the direction of Professor Mark Jaccard. I updated the model to ensure it reflected the latest forecasts of energy prices, energy production, and uncovered (exogenous variables) and that it was backcasting accurately to reflect the current market realities. A conversation with Jotham Peters of Navius Research Inc. encouraged me to focus the paper on final energy demand. With feedback from Nic Rivers on the original concept, I conceived of the idea of expanding the

analysis to investigate how various electricity sector policies affect these end use emissions. Mark Jaccard reviewed several drafts of the paper.

iii) *"Exploring ways to Reduce Greenhouse Gas Emissions from Heavy Trucking: Is there a role for natural gas?"* unpublished.

This paper investigates pathways of GHG emissions reductions for the heavy (long-haul) trucking sub-segment of the freight sector. In particular, the paper looks at the role of natural gas trucks, whether burning pure natural gas, or with natural gas blended with RNG, as a mitigation tool under a variety of carbon policies. Emission reductions for the heavy freight sector were forecast under current policy and under carbon constraints. Many of these reductions occur as the sector switches from truck to rail to move heavy freight, from biofuels (either RNG or renewable diesel), and as more efficient diesel trucks enter the market. While I found a role for RNG blending with natural gas to de-carbonize some of the heavy truck stock under scenarios with carbon constraints, and under favourable assumptions regarding the RNG price, RNG was not found to serve as a bridge-fuel when there is a delay in policy. I also performed sensitivity analysis on some key parameters pertaining to natural gas vehicles, which see them make significant inroads in heavy trucking. However, absent climate policy, this widespread adoption of natural gas trucks worsens the energy use and emissions profile of the sector as more freight is moved by energy intensive heavy trucks than by rail.

In this paper, I conducted the literature review, analysis, and draft of the paper. I also conceived of the study design. The CIMS Canada model used in the study was a variant of the energy-economy model developed by researchers associated with EMRG, as noted. I updated the Ontario version of the model to ensure it reflected the latest forecasts of energy prices, energy production, and exogenous variables and that it calibrates to reflect current market realities. I also added a new fuel, RNG, and worked to softlink price changes of RNG to changes in RNG demand, thereby endogenizing the RNG price via a supply curve as in the previous natural gas study. Mark Jaccard, Nicholas Rivers, and John Nyboer reviewed several drafts of the paper, resulting in substantial changes to the original manuscript.

All three papers discussed above have an applied focus, being primarily interested in the policy implications of various aspects of the natural gas phenomenon. Chapter 3, however,

does use a relatively novel approach to estimate the cost of delay and how this cost is affected by assumptions about differing natural gas availability, which I then use again in chapter 5. I explain the relative novelty of the approach during the introduction and methods section in chapter 3.

The organization of the remainder of the thesis is as follows. Chapter 2 describes the modelling method utilized throughout, while chapter 3 investigates the implications of abundant natural gas for the energy sector in achieving a deep de-carbonization. Chapter 4 examines how policies specifically targeting the power sector of the economy may influence emissions in all other sectors, and how differing the gas price affects these outcomes. Chapter 5 then quantifies the implications of abundant gas on a specific sub-sector of the transportation sector- heavy trucking. Finally, chapter 6 concludes with overarching policy implications of the research.

2. The Modelling Framework

In all three papers in this thesis, I utilized the CIMS energy-economy model. This section describes some of the mechanics of CIMS as well as its strengths and weaknesses in relation to the research questions posed in this thesis.[7] This section takes the description of CIMS that is common to the three chapters and acts as a stand-alone chapter to avoid repetition and to improve the flow of this thesis. I included specific modelling additions and assumptions unique to each chapter in their respective methodology sections.

CIMS is an energy-economy model that is best described by three key characteristics: a) technology-explicit; b) simulation; and c) hybrid.

By technologically explicit, I mean that CIMS tracks vintages of technologies that make up the capital stock for each sector over time. Technologies compete for part of the new market share in each period as per CIMS's market share algorithm. The winning technologies from this competition either expand the capital stock to meet increases in the demand for energy services, or replace some fraction of the existing capital stock that is retired after reaching the end of its useful life. By tracking these technologies, CIMS can approximate energy use and emissions via technology fuel-use characteristics and the emissions profiles of the fuels used. In addition, CIMS allows the potential to retrofit and/or replace certain technologies before the end of their useful life.

CIMS is a simulation model in that it tries to imitate the actual decisions made by firms and households. As such, inputs to the model rely on financial technology costs, but also on intangible costs applied to both direct capital costs and the cost of capital (i.e. a higher "implicit" discount rate). These intangible costs arise from risk (e.g. newer technologies may face higher risk of premature failure than prevailing technologies) and qualitative differences associated with certain technologies (e.g. the shorter distance before requiring refueling for electric vehicles). These parameters add a degree of behavioral realism to CIMS, as some of them are estimated from actual consumer decision-making data obtained via revealed preference and stated preference surveys (Rivers and Jaccard, 2006; Jaccard, 2009). Furthermore, CIMS simulates competition probabilistically, as

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[7] For a more detailed exposition of CIMS, see Murphy and Jaccard (2011). Much of the description of CIMS provided here is a summary of the model description in that paper.

different decision makers may apply different weights to a given feature of a technology, and the technology's associated financial or intangible costs. Thus, CIMS distributes new purchases amongst the competing technologies.

In chapter 1, I used a standard probabilistic discounted cash flow formulation in equation 1.1 for the simple theoretical model. This also happens to be the equation that drives the market share algorithm used in CIMS. In equation 1.1, CIMS compares the usual life-cycle financial costs, but also intangible costs denoted by the variable (i). In addition, the v parameter between 1 and 100 governs the slope of the logistic function that determines market share, enabling the probabilistic simulation characteristic of a CIMS run. Higher values of v mean that the technology competition becomes more sensitive to the life-cycle cost of a technology due to consumers as being more homogenous in their needs. In such cases, cost plays a larger role.

Finally, while predominantly driven by a bottom up/technology explicit methodology, the literature situates CIMS within the typology of models as a hybrid model. As a hybrid model, CIMS combines aspects of conventional top-down models, such as behavioral realism (discussed earlier) and some macroeconomic feedbacks, with the technological explicitness of conventional bottom-up models. CIMS is an integrated model, rather than a partial equilibrium model. As such, feedback mechanisms in CIMS allow it to solve for energy prices. For example, CIMS can show how changes in the demand for a technology using natural gas influences the price of natural gas, which would then feedback and affect demand for natural gas more broadly. In addition, CIMS has a mechanism for linking energy price changes into changes in goods and services demand, and changes in output by sector. It also models some indirect macroeconomic effects, such as how changes in disposable income might influence overall energy use.

CIMS determines the energy equilibrium through interactions between the energy demand and supply sectors. The energy supply sectors of electricity generation, petroleum refining, petroleum crude extraction, natural gas extraction, coal mining, ethanol production, and biodiesel production, supply energy to the system. Energy demand arises from the final demand sectors of residential buildings, commercial buildings, personal transportation, freight transportation, and industrial production (further broken down into chemicals, industrial minerals, iron and steel, metal smelting, pulp and paper, other manufacturing, and mineral mining). The interaction of these sectors creates feedback effects on energy

supply and demand. Increases in demand for a certain source of energy will increase its price, which can then somewhat dampen its demand.

Taking in the above, figure 2-1 below provides a conceptual diagram of the CIMS model:

Figure 2-1: Conceptual Diagram of CIMS Model
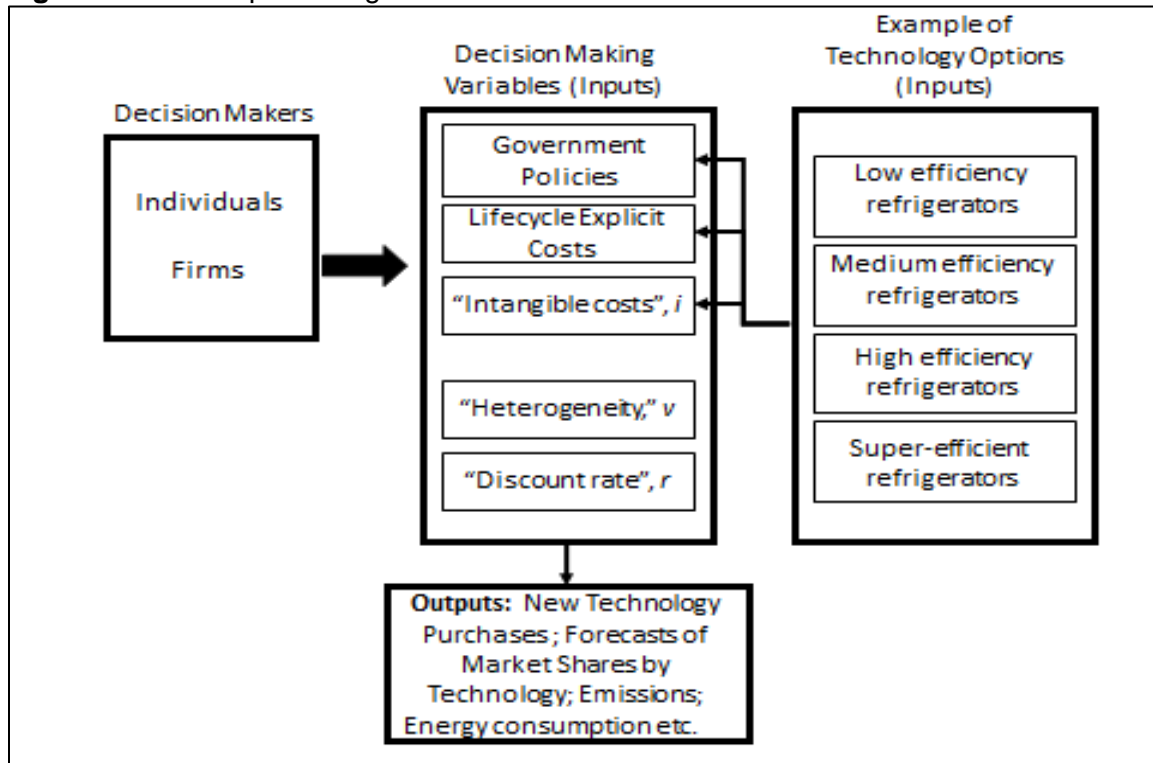
CIMS provides a high degree of technological explicitness and detail, making it well suited to analyze policies applied at sectoral and technological levels. Total output produced for a sector is exogenously determined, before being subdivided into the various final products that are made from a given sector. To make a unit of final product, CIMS breaks out each of the production and process stages into separate modules. These too are, generally, exogenous, and have splits based on the actual process requirements for each product. A prescribed set of technologies competes in each of these production stages to provide the capital stocks that produce the output at any given time. These technologies require energy inputs for services such as steam production, material conveyance, compression, ventilation, machine drive, space heating, lighting, and pumping. All of these energy services have their own subset of technologies, which compete to meet each service demand. Finally, a number of process technologies and intermediate products are required in production.

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This extensive technological detail provides a degree of realism to the CIMS model that is lacking in top-down representations. When top-down models extrapolate historic relationships between energy prices and energy use, they implicitly assume some degree of structural and technological continuity in the examined sectors. However, energy-substitution possibilities could vary substantially over time as they depend on the existing capital stock and available technological alternatives. In addition, CIMS use of intangible costs incorporates the effect of various cognitive factors, such as real and perceived differences in risk, which affects the adoption of certain technologies depending on their attractiveness as viable substitutes for current, mainstream technologies. These non-financial factors may be increasing in importance in cases where technologies pose a significant difference to conventional, fossil fuel using technologies. CIMS' technological representation of these sectors provides a mechanism to approximate some of these shifting factors affecting technology and fuel choices as they occur.

CIMS is also flexible in how it enables the modeller to introduce policies. In addition to being able to model carbon taxes and technology subsidies directly, CIMS also enables the modelling of regulations and standards. For example, CIMS can do this by mandating certain rates of technology penetration, or by phasing out certain technologies by adjusting when they are allowed to compete. One feature of CIMS of particular relevance to the following chapters is the ability for the modeller to set "expectations functions" to provide businesses and consumers with foresight into their future emissions costs (carbon price). CIMS has three options for generating expectations: 1) myopic, where people do not have foresight into their future emissions prices; 2) perfect foresight based on the average emissions prices; and 3) perfect foresight based on the discounted value of emissions prices. These expectations can be set to take effect later in the model run, so that the simulation can start with myopic expectations, before agents receive more information regarding future carbon prices.

For a more technical discussion, table 2-1 below illustrates the key variables within CIMS, whether they are treated endogenously or exogenously and, where endogenous, an explanation of the mechanism by which they are endogenized.

Table 2-1: CIMS- List of Key Variables

Variable	Treatment	Mechanism for Endogenizing (If endogenous)
Market share of technologies	Endogenous	Solved via CIMS market share algorithm
Process and Mode Choice	Endogenous/Exogenous	For some sectors, mode or process choices are solved via CIMS market share algorithm. For other sectors, may be considered fixed and exogenous.
Choice of available technologies that compete	Exogenous	NA
Economic Structure	Exogenous	NA
Technological progress i) **More efficient/new technologies** ii) **Cost declines for existing technologies**	i) Endogenous ii) Endogenous in Chapters 3 and 4, Exogenous in Chapter 5	i) Turnover of technologies in CIMS. New, more efficient, vintages are able to compete over time. ii) Capital cost decline function based on cumulative production and learning rate
Neighbour Effect	Endogenous	Intangible cost decline function based on cumulative production and decline rate
Natural Gas Prices	Endogenous in Chapters 3 and 4, Exogenous in Chapter 5	Soft-linked supply curve in excel that I iterate to generate model prices
Coal Prices	Exogenous	NA
Oil Prices	Exogenous	NA
RPP Prices	Endogenous in Chapters 3 and 4, Exogenous in Chapter 5	Built in supply curve for RPP based on petroleum refining sector module in CIMS- Considers refining production costs
Biofuel Prices	Endogenous in Chapters 3 and 4, Exogenous in Chapter 5	Built in supply curve for biofuels and biofuels supply module in CIMS

Variable	Treatment	Mechanism for Endogenizing (If endogenous)
RNG Prices	Endogenous for Canada	Soft-linked supply curve in excel that I iterate to generate model prices
Electricity Price	Endogenous	Built in electricity supply module in CIMS- considers impact of new generation sources on average cost of production and costs to consumers
Hydrogen Price	Endogenous	Built in hydrogen supply module in CIMS- considers impact of hydrogen production technologies and processes on cost to consumers
Sector Output	Endogenous/Exogenous	Some endogeneity as output can change from the base (exogenous) output projection
Sector Unit Prices	Endogenous	Determined based on average unit cost of production in CIMS from technology cost, fuel costs, carbon prices, service and operating costs.
Emissions	Endogenous. Exogenous treatment in Chapter 5 for upstream emissions only.	Solved based on emissions intensities of technologies and fuels that meet energy service demand and sector output
Energy Use	Endogenous	Solved based on energy intensity of technologies that meet energy service demand and sector output
Technology performance characteristics, v parameter	Exogenous	NA

A number of the above variables are treated as exogenous in the model for various reasons. In the case of technology performance characteristics such as the capital costs or the discount rate, these are exogenous, as is standard in many models, due to being model inputs. Certain fuels, like coal and oil, are treated exogenously due to being traded heavily in global markets. Furthermore, a number of variables were treated as exogenous within the context of chapter 5 only. Since chapter 5 focused on modelling the Ontario

energy system, the rationale for making these variables exogenous was that the activities within that relatively small jurisdiction would not have the same impact, as Ontario is a price taker for these variables in the context of global or regional markets. Finally, aspects like the economic structure, the v parameter, and choice of technologies that could compete would be ideal to endogenize and really strengthen CIMS. However, to do so would require a fundamental change to the very nature of CIMS, and it is unclear if these can be accommodated within the existing CIMS framework without losing beneficial features of CIMS, such as detailed technology choice. In addition, features like understanding how the v parameter might change over time would require a level of resolution that CIMS does not currently possess.

CIMS also has its shortcomings with respect to what it does not include. Here I summarize some of the key limitations facing CIMS, outlined in more detail in Jaccard et al., 2003 and Jaccard, 2009. These pertain to: i) limitations about its representation of information available to consumers and investors, ii) limitations surrounding the representation of macroeconomic feedbacks in the model; and iii) limitations pertaining to data. In addition, I highlight a key difference between CIMS and more traditional micro-economic models which, while not strictly a limitation, may be viewed as such by some.

The first limitation reflects CIMS' equilibrium solution solving sequentially for each time period, without prior decisions influencing future periods. This differs fundamentally from optimization models, which simultaneously solve an objective function for all time periods, subject to the specified constraints. CIMS' mechanism reflects aspects of the concept of bounded rationality, where available information, time, and cognitive abilities limits individual decision-making (Simon, 1982). In many cases, CIMS' assumption of some bounded rationality may be more realistic, and thus a strength. However, CIMS' sequential solutions do not represent decisions are may be linked across time and space.

The second limitation is that CIMS possesses an incomplete inclusion of macroeconomic feedbacks. For instance, CIMS does not presently model the link between energy supply and demand, on the one hand, and key macro-economic outputs such as investment rates, interest rates, employment, trade etc., on the other. In addition, CIMS cannot reflect how adoption of a new technology or process with different material inputs by one sector affects the demand of those materials. For instance, the shift to a mode of production in

one sector, which uses less steel as an input, does not result in a decrease in the aggregate demand of steel in CIMS.

A third limitation pertains to data availability and veracity. CIMS is a technically explicit model consisting of technology performance, financial, and behavioral parameters, for all relevant technologies in the energy system. While I, and other researchers, work to ensure that the key financial, performance, and behavioral parameters facing current technologies are up to date and are sensible, there are some key uncertainties regarding these parameters for future technologies, which may not yet be commercial. In addition, building the empirical foundation for behavioral and intangible parameters is challenging. While surveys completed by the EMRG research team over the past two decades have estimated approximations for these parameters, the resource requirements of these discrete-choice surveys have limited these efforts to several critical nodes at various points of time (Axsen, Mountain, & Jaccard, 2009; Mau, Eyzaguirre, Jaccard, Collins-Dodd, & Tiedemann, 2008). A related limitation specific to the version of the CIMS US model used in two of the chapters of my thesis is that it lacks regional disaggregation and so may not adequately reflect some key cost differences between technologies in different US regions. While the market heterogeneity, "v", parameter addresses some of this limitation, it is at best as a crude approximation to reflect the diversities of a country as large and multifaceted as the US.

Finally, while not strictly a limitation, it is worth noting a key difference between CIMS and more traditional micro-economic models. The latter models usually use an optimization framework, defined by microeconomic theory, whereby firms or consumers seek to maximize a utility function subject to constraints. Factoring into this optimization decision by agents would include traditional financial costs, but also other variables, such as intangible costs. The outcome of these optimization decisions are demand functions for technologies and other products. CIMS, by contrast, derives demand functions through the outputs of its market share algorithm, without a, explicit utility function. However, CIMS can still be viewed as consistent with standard neoclassical utility theory, as decision makers are trying to minimize costs as per the market share algorithm, and thereby maximize utility for a given budget constraint.

3. Abundant Low Cost Natural Gas and Deep GHG Reductions for the United States

3.1 Introduction

Governments at Paris in 2015 again signed a declaration that temperature rise should not exceed 2 degrees Celsius to reduce the risk of dangerous climate change, and the associated deleterious consequences. To achieve this target, signatories pledged to reduce substantially their Greenhouse Gas (GHG) emissions through long-term strategies requiring deep emissions cuts from nearly every sector of the economy. Unfortunately, the prevailing weak (or non-existent) policy in most countries may not send sufficient signals for a deep de-carbonized energy system in 20-30 years. The lifetime of many technologies exceeds those timescales, and so investment decisions today will have implications for many years into the future.

Although many near zero-emitting technology options have improved their business case substantially in recent years (e.g. solar PVs, electric vehicles), and thus have improved their competitive position under weaker policy signals, so too have their fossil fuel competitors in certain key markets. In North America, technological breakthroughs in the extraction of shale and other unconventional natural gas sources have substantially increased the estimated low-cost supply of natural gas, thereby improving the economics of gas-utilizing technologies. While combustion of natural gas is less-emissions intensive per unit energy than coal and conventional crude oil, it is more emissions intensive than renewables and other sources like nuclear. In this chapter I ask two interrelated research questions:

i) Do lower natural gas prices affect the cost of achieving an 80% reduction in annual emissions for the US economy relative to 2005 levels by 2050?

ii) Are cost differences due to the gas price exacerbated when there is a delay in the communication of the necessary stringent policy to achieve this reduction to firms and households?

To answer these questions, I model two scenarios with differing knowledge of future policy trajectory in conjunction with two scenarios with a low and high natural gas price. The first policy trajectory scenario evaluates a case where policymakers announce a credible and stringent policy well in advance of its later implementation, allowing firms and households

time to incorporate it into their current decision-making without delay. The second policy trajectory evaluates a case where governments do not make such an announcement and, in the interim period between present day and the implementation of the policy, firms and households do not seriously consider the prospect of future stringent policy when making their current investments. Under this second case, policymakers then decide to pursue a stringent policy that is delayed and surprises investors.[8] Using the CIMS-US energy-economy model, I evaluate the cost of achieving the aforementioned 80% target under each scenario, with cost being defined as the necessary carbon price to achieve the target, reflecting the marginal cost of mitigation.

In situations without a delay in policy communication, cheaper natural gas, may necessitate a higher carbon price to achieve a stringent emissions reduction target, such as the 80% target, by disincentivizing energy efficiency, conservation, or the switch to lower-emitting options. In addition, it may promote greater natural gas consumption and production, resulting in higher upstream emissions from natural gas, which may be more difficult to fully mitigate than those of other fuels. More abundant natural gas might combine with a communication delay to increase the cost of achieving a stringent target by making the energy system increasingly "gas-committed". In energy, that is usually because many investments consist of major capital projects with very low operating costs. While the capital cost component of these projects is treated as sunk in future decisions to switch to lower-emitting sources, lower gas prices may lower operating costs further necessitating a higher carbon price, or other policy response, to switch paths.

Regarding the first of my two research questions, several papers have examined the implications of abundant natural gas on emissions under different policy assumptions. In the context of current policies, work from the 26th Energy Modelling Forum (Huntington, 2013), an inter-model comparison project focusing on the implications of abundant gas for

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[8] Firms may factor in an internal carbon price as part of their investment decisions, yet there appears to be little academic literature estimating what level of carbon price they consider likely. A survey by the Carbon Disclosure Project, a UK based NGO, which found these implicit carbon prices to range between $6-$60/tonne (CDA, 2014). Even the high end of this range is low relative to those carbon prices necessary to reach stringent targets. Furthermore, these values apply to the context of large emitters. It is unclear if smaller or medium size emitters, whose individual emissions might be low but whose combined emissions might be quite large, make the same internal calculations. Likewise, Bistline (2015) searches 14 Western utility integrated resource plans and finds that 8 of the 14 utilities consider a no-policy scenario by 2025 to be a serious possibility. In their range of possible carbon policies, only 36% of the utilities in the study extend their range high enough to include the expected 2025 tax value consistent with the proposed Waxman-Markey bill.

the US, found abundant gas to modestly change 2050 emissions- ranging from a -3% to 3%. Similarly, Newell & Raimi (2014) found abundant gas to only slightly alter economy-wide GHG emissions. Whether emissions increase or decrease depends on modelling assumptions about methane leakage. Shearer et al. (2014), find cumulative emissions for the US between 2013 and 2055 to be slightly lower under scenarios of high gas supply, while at the global level, McJeon et al. (2014) find increased natural gas use to not discernibly reduce the trajectory of global GHG emissions, changing CO_2 emissions by between -2% to 11%, relative to conditions with lower gas use. My results from this chapter show cheap natural gas to increase US emissions in 2050 relative to scenarios with scarce gas by a magnitude that is in line with the above literature estimates— ranging from 1.75% to 9%.

Papers exploring the interaction of abundant gas and stringent policy include Brown, Gabriel, & Egging, 2010, who find lower cost gas to lower slightly the economic cost of achieving a 2050 emissions reduction target of 83% below 2005 levels. By contrast, Jacoby, O'Sullivan, & Paltsev, 2011, find abundant natural gas results in a slightly higher cost for the US to meet a similarly stringent emissions reduction target.[9] My results from this chapter correspond to the findings by Jacoby et al., 2011— that abundant and cheap gas is costlier (which I show by a higher necessary carbon price) to achieve the target relative to scenarios with scarce gas. I also find, however, that the magnitude of the difference in cost between the gas price scenarios is relatively small, in line with the above studies.

At the time of writing, there has been little empirical work to explicitly investigate the combined effects of lower cost natural gas, and a policy delay that I described earlier in this section. However, certain papers have looked at elements of this delay in communication of stringent policy. Bertram et al. (2015) examine how weak near-term policies may generate what they call a long-term carbon lock-in, as the energy system is later forced to switch from a trajectory of weak policy to one of stringent policy. Using a global model, they find a substantial carbon lock-in stemming from greater coal use in

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[9] Specifically, they note *"The cost of the policy under current expectation, calculated as above as the net present value of the reduction in welfare over the period of 2010-2050, is about $3.3 trillion (a 3.1% reduction in 2050), whereas if the shale resource were not economic that cost would be $3.0 trillion (a 2.8% reduction in 2050). The slightly lower cost in the no-shale scenario is due to the lower emissions in the corresponding no policy reference, and therefore the lower effort required to meet the 50% target." Pg 16.*

electricity under weak near-term targets, and that this commitment drives substantial premature coal retirements and higher required carbon prices with the later pursuit of stringent policies. Johnson et al. (2015) quantify the magnitude of these premature coal retirements. Similarly, Riahi et al. (2015) summarize the results of the AMPERE study, a cross-model comparison project investigating the implications of near-term fossil fuel investments on the global energy system's ability to achieve stringent targets consistent with limiting global warming to 2^0C. They found that across the nine models, weak near-term policies to 2030 increase mitigation costs to reach stringent targets by 2050, and also increase the risk that these targets become unattainable.

While not explicitly focusing on the role of increased natural gas supply on driving this emissions commitment, some of the above papers do vary the expectations of the future policy to evaluate how these expectations affect the ease of later achieving targets, which is a similar methodological approach to what I use in this chapter. Another paper by Hilaire, Bauer, Kriegler, & Baumstark (2015) investigates interactions of policy scenario timing with varying gas availability to achieve a 2°C target, examining the integration of a delay in policy communication with abundant natural gas. They find abundant gas scenarios, when combined with a policy delay, to result in larger cumulative GHG emissions and greater mitigation costs relative to scenarios with less gas.

My results are similar to all these papers in that I find it slightly harder to achieve a stringent target when there is a delay in communication of policy. In addition, I find a slightly higher carbon charge is required to achieve the target when there is a delay in the communication of policy *and* in where natural gas is abundant relative to when it is scarce.[10] This latter finding aligns with the work by Hilaire et al. (2015), although the drivers of the results in the two studies differ. The latter identifies trends in the global power sector to be the main driver of this effect, whereby I find abundant gas increases the cost of delay due to its effect on many sectors of the economy- particularly the changes it induces in end use and in upstream energy extraction. My use of a hybrid energy-economy model, with a high degree of technological resolution for the United States, may cause this difference from Hillaire et al. (2015), who use a global integrated assessment model.

Section 3.2 of this chapter outlines the methods and scenarios used to evaluate my

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[10] Throughout this paper, carbon, as in the context of a carbon charge used here, is shorthand for CO_2.

research questions, while Section 3.3 describes the main results under business as usual. Section 3.4 presents the results under policy, while section 3.5 provides a sensitivity analysis exploring alternative cases. Section 3.6 then concludes with policy implications.

3.2 Methods and Scenarios

To answer the questions set out in the previous section, the study combines two scenarios that presumed different prices and utilizations of natural gas with simulations representing a delay and no delay in communicating the eventual path of the climate policy.

3.2.1 Gas Price Scenarios

Figure 3-2 shows the relationship between gas prices and cumulative production for the two gas-price scenarios.[11] These figures illustrate the demand-supply equilibrium price at different levels of cumulative production for the two gas scenarios when run through the model. The curves are upward sloping as they are underpinned by an upward sloping supply curve (please refer to **Appendix B**) which is increasing to reflect higher costs of extraction of more marginal resources with increasing cumulative production.

Figure 3-1: Cumulative Production vs. Natural Gas Price

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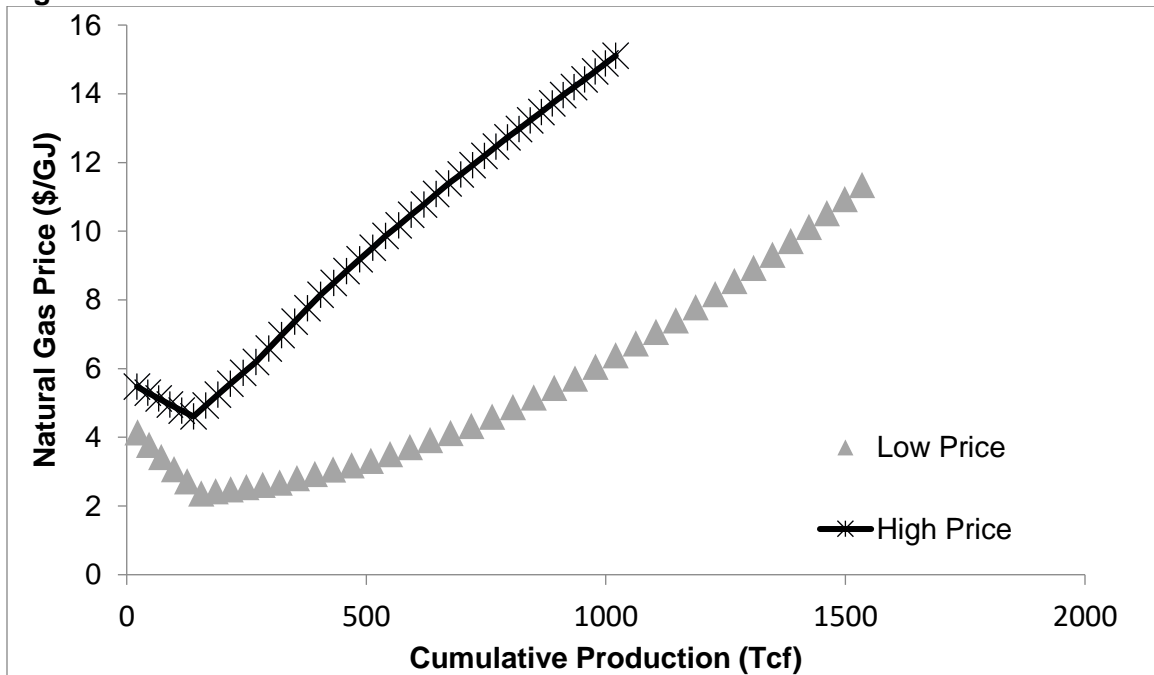
[11] Average price across all sectors (weighted by consumption by sector)

The low-price scenario represents the prevailing reality with the US endowment of abundant natural gas. I calibrated the natural gas supply curve underpinning this scenario so that the CIMS-US model solves to produce 2015 Henry Hub price data. The relationship between price and cumulative production for this low-price scenario corresponds to the optimistic P10 case present in MIT's "The Future of Natural Gas" report.[12] The high-price scenario is a counterfactual that represents a hypothetical world without the US natural gas revolution. It combines the price response from the MIT study's P90 case, taking the AEO2008 gas price forecast as the simulation's start value for gas prices in 2010.[13] This earlier AEO forecast represents gas prices before the full extent of the recent gas boom become apparent. Consequently, this scenario results in lower gas production, leading to higher gas prices, and a faster rise in gas prices over time.

Given how CIMS-US is not a global model, a possible limitation of these curves is their exclusion of international trade in gas, which may cause a modest understatement of the US supply picture in the near-term due to the exclusion of net imports from Canada, Mexico, and any LNG from overseas suppliers. Historically US net-imports reached a high in 2005 at 16% of US consumption, before the US moved from the position of net importer to net exporter of gas in 2017 (EIA, 2018c). The EIA forecasts gas exports to reach about 18% of total US consumption by 2040. This is a substantial quantity, which could raise prices by more than what I forecast in CIMS. However, excluding exports likely does not affect my simulations by a large degree because CIMS' forecast for cumulative domestic gas consumption exceeds the EIA's estimate by about 24% in 2040 under the low-price scenario. Consequently, some of exports projected by the EIA would have been absorbed domestically in CIMS, and thus already reflected in its gas price.

3.2.2 Policy simulations- communications delay and no delay:

For each gas price scenario, simulations were performed under prevailing and hypothetical US climate policies. The latter simulations model the implications of natural gas price on the carbon price necessary for the US to achieve an 80%

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[12] Representing the production arising from the highest 10% productivity wells. Originally the curve's price/cumulative production relationship was calibrated to the MIT study's reference case. However, due to the actual developments in natural gas markets seen since 2011, where economically viable gas options have proved more abundant than previously believed, the more optimistic P10 choice was chosen. The curve is continuous and upward sloping as per Figure 3-2.

[13] Representing the lowest 10% productivity wells.

reduction in emissions from 2005 levels by 2050. I also model how the gas price achieves this target under two different assumptions about firm and household expectations about future policy.

The first assumption about expectations is a case where policymakers communicate a credible policy well in advance of its introduction, such that consumers and firms readily incorporate it into their current decision-making. In other words, there is no delay in announcing the eventual policy, introduced in 2025, giving firms and households time to adjust in the interim. I refer to model runs with this set of assumptions as runs with foresight. The second assumption about expectations is a case where the government delays explicitly communicating the intention to introduce a binding policy to achieve their stringent target. Consequently, firms and households do not consider the target when making their present investment decisions. In 2025 policymakers recognize the need to pursue the stringent policy, and introduce it, which comes as a surprise to firms and households. I refer to the model runs with this policy shock, or delayed announcement, as runs with no-foresight. With both the foresight and no-foresight settings, firms and households have knowledge of the future carbon-price schedule once the policy is implemented.

This approach follows the two-step process used by Bertram et al. (2015). In that paper, the models initially ran myopically, with no expectation of the future policy until its introduction in 2030. The authors then compared these results to scenarios where the models ran with foresight in order to calculate the delta of the carbon price between the scenarios.

To measure the interaction between foresight setting and gas price, I used a similar differences-of-differences approach. First, I compared the proportionate difference in carbon price between the foresight and no-foresight cases for a given gas price scenario.[14] Since the expectation is for carbon prices to be higher when households and firms do not anticipate the policy, irrespective of the gas price, I must control for this effect before determining the gas price's impact. Second, I compared the differences across foresight cases for each gas-price scenario to one another, in order to see whether changing the

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[14] As noted by Bertram et al. (2015), *"Since carbon prices reflect the marginal costs of mitigation in each time period, the prices in 2050 can serve as proxies for the difficulty and/or necessity of mitigating CO_2…"* Pg 69.

gas price increased or decreased this proportionate difference. This allowed me to discern how differences in the gas price alone might affect the impact of foresight on the ease of achieving the target.

This foresight that agents may have about climate policy, enabling them to factor in future carbon prices in the model, contrasts with agent's perception of future fuel prices. Regarding the latter, agents in CIMS use current fuel prices in their decision making. This different assumption of foresight for different future prices reflects a fundamental difference in their nature, with carbon taxes being certain as per government announcement[15], but with fuel prices being market-driven and uncertain. This current treatment of future, uncertain, energy prices in turn reflects an assumption of bounded rationality, where firms and households are using available information regarding the current fuel price to make decisions about future fuel prices.   It is unclear if by assuming more forward-looking agents in CIMS, the model will solve for more or less natural gas in the current period. If firms and households accurately project a similar rise in gas prices to 2050 that CIMS uses, than I would expect current use of natural gas to decline. However, I would expect greater use of gas if agents mistakenly project lower gas costs in the future due to perceived abundance.

3.2.3 Retrofit/Replacement decision in CIMS:

The previous section identified mechanisms by which lower natural gas prices might make it harder to achieve a given target. Mentioned was how in the delay, or no-foresight, setting abundant gas may make the energy system increasingly "gas-committed", such that it becomes harder (requires a higher carbon price) to abandon the prevailing gas-utilizing investments and switch to lower emitting technologies. With a delay in the communication of stringent policy, firms and households make present day decisions about technology choice without consideration of a future policy that penalizes carbon emissions. The long lifespan of energy technologies means that those emitting carbon will influence the energy system for years after their introduction, and will eventually require a more stringent carbon charge to shift the system toward a low-emission path. This higher carbon price may be necessary to:

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[15] Carbon prices are uncertain, however, in the context of cap-and-trade.

i)   induce potentially costly retrofits/replacements to convert natural gas utilizing technologies to lower-emissions alternatives that are consistent with the climate target; or

ii)   force emissions reductions from other sources and sectors at a comparably high abatement cost to offset the higher emissions from the greater use of gas.

Given how I would expect a greater share of natural gas-utilizing technologies under business-as-usual conditions with lower gas prices, in order to meet a stringent target later on, these gas-utilizing technologies will either need to be retrofit at some cost, or abandoned and replaced with lower-emissions alternative before the end of their useful life. CIMS models both the ability of some technologies to be retrofit with end-of-pipe pollution control technologies- e.g. by adding carbon capture onto an existing process- or the ability of the capital stock to be prematurely replaced if it is economically justified under an extreme change in technology, market, or policy conditions. Figure 3-2 below, for example, illustrates pathways by which CIMS can retrofit or replace natural gas technologies into lower emitting alternatives for the power sector.

Figure 3-2: Flow Chart Demonstrating Replacement Possibilities for Natural Gas Power Generation Technologies
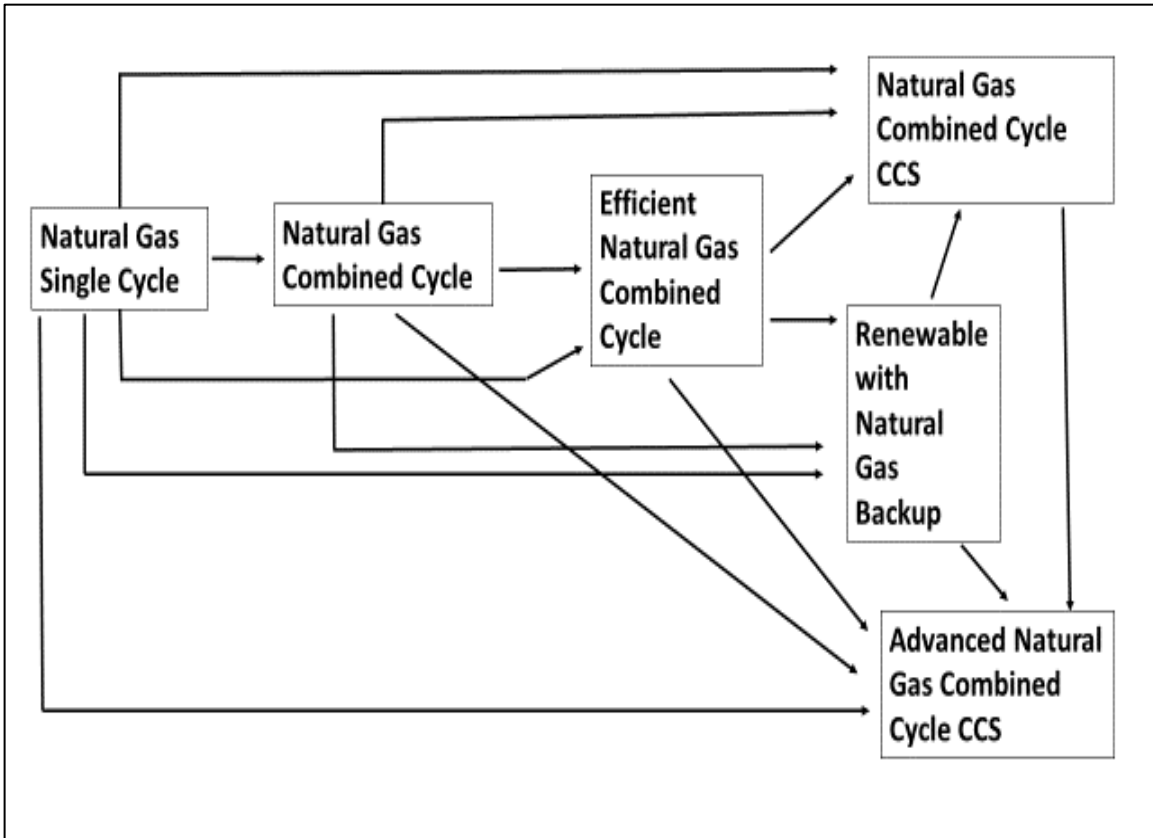
This economic justification for a retrofit or replacement in CIMS occurs if the marginal cost of production of the prevailing technology (O&M, energy, and emissions costs) exceeds the discounted lifecycle costs of the prospective replacement technology. I define mathematically an agent's decision to switch from a gas-utilizing technology, to a zero-emitting alternative using renewable fuel, in equation 3.1 below. Equation 3.1 is a simplified version of the CIMS competition algorithm that was introduced in Chapter 1, which I use to represent the economic rationale behind the retrofit decision. I assume no intangible costs as a simplifying measure. Also, since this is meant to represent an individual firm decision at the micro level, the v parameter that was introduced in chapter 1 is no longer relevant.

$$[\sum_{t=1}^{n}(MC_{GAS} - MC_{RENEW}) + \sum_{t=1}^{n}(EC_{GAS} - EC_{RENEW}) + \sum_{t=1}^{n}(Tax_{GAS} - Tax_{RENEW})]/(1 + r)^t > RC_{RENEW}$$

Equation 3.1

Where:

MC_{GAS} = annual maintenance and operating costs for a gas-utilizing technology
MC_{RENEW} = annual maintenance and operating costs for a technology using renewable fuel
EC_{GAS} = annual energy cost for a gas-utilizing technology
EC_{RENEW} = annual energy cost for a technology using renewable fuel
Tax_{GAS} = annual carbon taxes paid by a gas-utilizing technology
Tax_{RENEW} = annual carbon taxes paid by a technology using renewable fuel
RC_{RENEW} = Incremental capital cost to retrofit from a gas technology to a renewable technology
r = discount rate
t= time

Assuming EC_{RENEW} = 0 , and Tax_{RENEW} = 0, Equation 3.1 simplifies to equation 3.2 below:

$$[\sum_{t=1}^{n}((MC_{GAS} - MC_{RENEW}) + \sum_{t=1}^{n}(EC_{GAS}) + \sum_{t=1}^{n}(Tax_{GAS})]/(1+r)^t > RC_{RENEW}$$

Equation 3.2

Reorganizing to make T a function of EC_{GAS}, we are left with equation 4.3 below.

$$\sum_{t=1}^{n}(Tax_{GAS})] > RC_{RENEW} * (1+r)^t - [\sum_{t=1}^{n}((MC_{GAS} - MC_{RENEW}) + \sum_{t=1}^{n}(EC_{GAS})]$$

Equation 3.3

Equation 3.3 illustrates how decreases in the gas price would make the right-hand side of the above inequality larger, necessitating a higher carbon price to trigger this retrofit/replacement decision, all else being equal. For emission reductions targets that are stringent, and which necessitate a switch away from gas and towards zero-emissions technologies, higher carbon prices will therefore be needed to achieve the target when the gas price is low. On the other hand, for weaker targets where the favorable emissions profile of natural gas relative to coal and oil may make gas-utilizing technologies consistent with these targets, lower gas prices could make these targets easier to achieve by enhancing gas technologies' competitiveness.

3.3 Results: Business as Usual

Before the carbon-price simulations, I model a business as usual (BAU) case, with only existing policies, in order to understand the key drivers affecting fuel use and emissions under both gas-price scenarios before any stringent policies are introduced. The flagship policy in this suite of existing policies is the Clean Power Plan (CPP), modelled as a performance standard on the power sector to achieve a 30% reduction in power sector

emissions below 2005 levels, and to maintain that reduction between 2030 and 2050.[16] This 30% reduction is the approximate reduction the EPA claims would arise from an aggregation of the eventual statewide policies making up the CPP. Interestingly, I achieve this reduction naturally under the low-price scenario without requiring any additional policy levers. Most of this is due to the switching to natural gas from coal, although there is uptake of non-emitting technologies (e.g. renewable) by 2030 as well. The high gas price scenario, by contrast, requires a binding intensity standard to achieve this 30% reduction.[17]

3.3.1 Fuel consumption trends

Figure 3-3 below shows the resulting annual natural gas consumption projections under this BAU for these two scenarios.

Figure 3-3: Annual US Natural Gas Consumption

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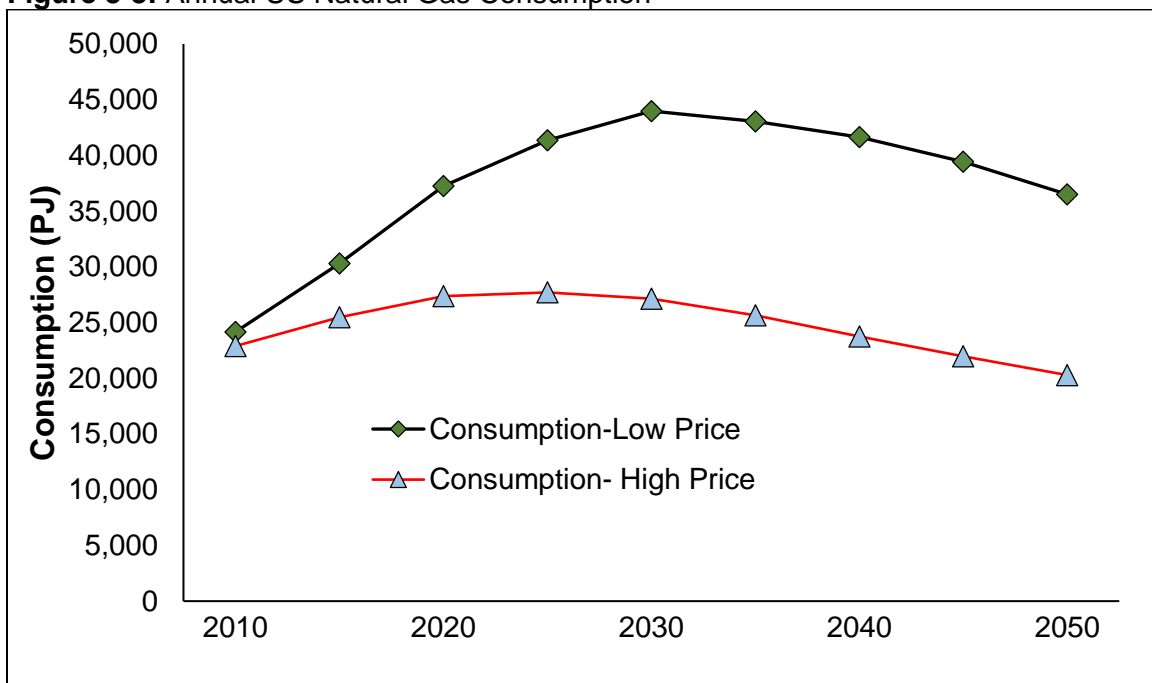
[16] The CPP was initially introduced by President Obama in 2015 and so was in preparation to enter into force while work on this chapter was progressing. Of course, in 2017 President Trump began the process to rescind the Plan.

[17] Also included in the BAU projections are the following policies: national aggregation of statewide renewable portfolio standards, existing tax production credits for wind and solar up to 2022 (when they are scheduled to be phased out), the Regional Greenhouse Gas Initiative, the California Cap and Trade Plan, and the EPA clean air standards as of 2012 factored into the price of new coal plants.

As expected, annual gas consumption is higher in the low-price scenario, and these differences in consumption between scenarios remain substantial for most years of the study. In both scenarios, natural gas use peaks midway in the simulation, although slightly later under the low-price scenario. After peaking, gas use declines in both scenarios, driven by the steady price appreciation of natural gas as greater gas consumption causes a shift to higher-cost natural gas sources along the upwards-sloping supply curve. The rate of decline in annual natural gas consumption is, of course, faster when gas prices are high, and so annual gas use by 2050 is 80% higher under the low-price scenario. Prices for other forms of energy- Refined Petroleum Products (RPP), coal, and electricity - are increasing between 2010 and 2040 as per the EIA's Annual Energy Outlook forecast in 2014.[18] The prices for these fuels are the same for both natural gas price scenarios.

The above fuel-price dynamics drive the major BAU trends in fuel use, which Figure 3-4 disaggregates by sector for both price scenarios.

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[18] I extrapolate the Annual Energy Outlook 2014 trend for the years 2040 to 2050.

Figure 3-4: Energy Consumption (Exajoule) by Fuel Type by Sector

Low Natural Gas Price Scenario   High Natural Gas Price Scenario
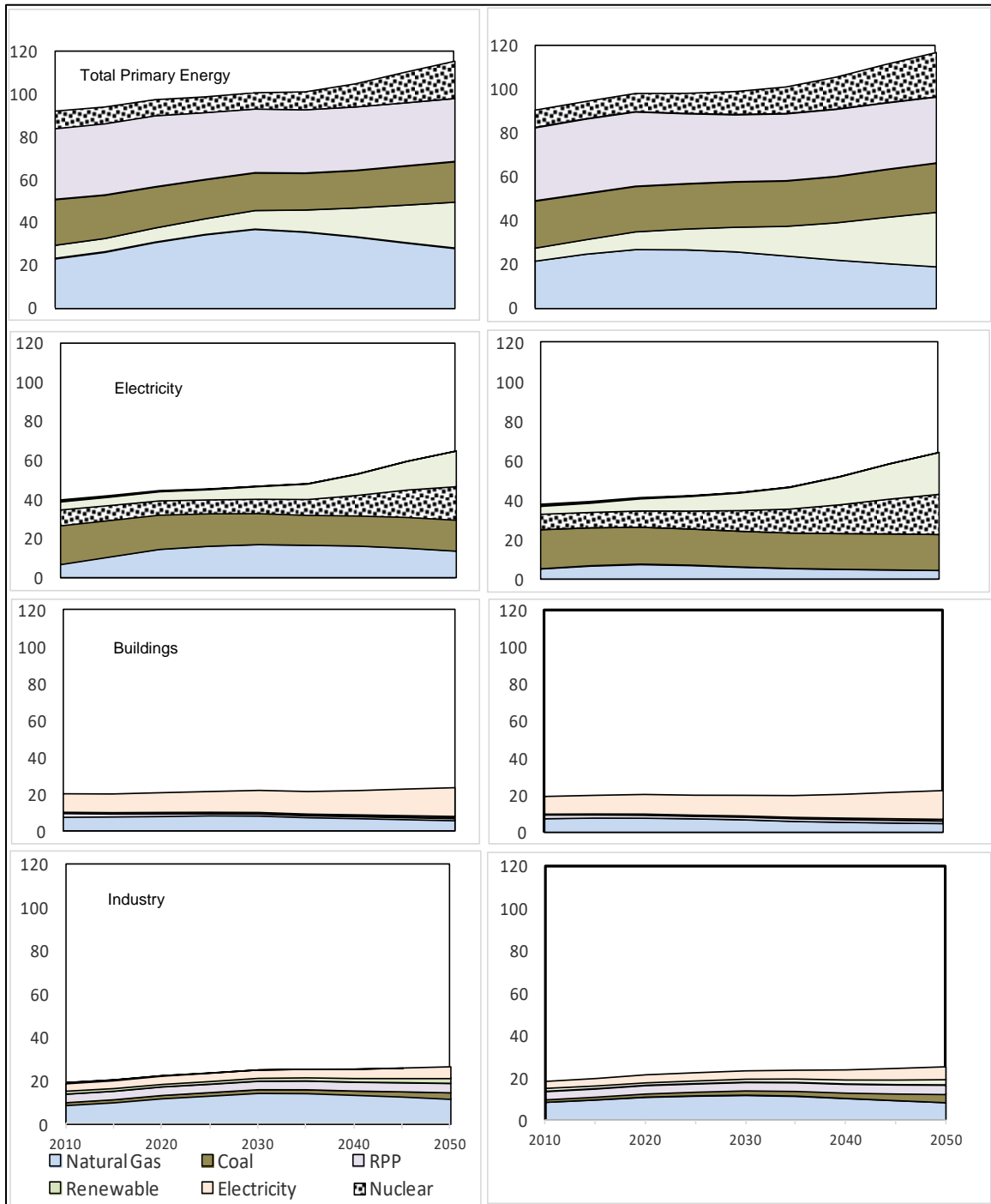
Under low-price conditions, natural gas becomes the predominant fuel in the US economy, rising from 26% of total annual primary energy consumption in 2010 to a peak of 44% in

2030. In the high-price scenario, gas use peaks at only 28% of total annual primary energy use in 2025 before falling to 17% of the total by 2050. This compares to its 2050 share resting at 32% under the low price case.

Electricity generation is the sector where natural gas sees the greatest increase over the simulation. At its peak, gas consumption in electricity more than doubles in the low-price scenario and increases by 25% in the high-price scenario, relative to their respective 2010 values. Electricity generation is also where I observe the greatest inter-scenario difference in gas consumption– by 151% or 7.85 EJ– by 2050. 51% of the difference between the scenarios with regards to annual gas consumption by 2050 is due to differences in gas consumption in the electricity sector. Electricity is also the catalyst for a major feedback effect generated by the model, driving much of the economy-wide gas price increases witnessed in the later years of the simulation.

For industry, annual gas use peaks at 86% and 44% above its starting value for the low and high-price scenarios respectively. Annual gas use in the combined residential and commercial buildings sector (hereafter referred to simply as buildings) peaks at 19.5% and 1.7% above its 2010 value for the low and high-price scenarios, and actually declines in absolute use relative to its 2010 value under both scenarios by 2050. Changing the gas price did not significantly alter trends in transportation, where gas use is negligible under both scenarios. While gas use in freight transport is higher in the low-price scenario, the difference between the scenarios ranges by about 5% over the whole forecast period.

Figures 3-5 and 3-6 below compare the projections for CIMS for electricity and industry respectively to those of a number of other US modelling teams who participated in the 31st Energy Modelling Forum (EMF31) "North American Natural Gas Markets in Transition". The EMF brings together the leading US modelling teams from industry, government, and academia on collaborative modelling projects to identify points of convergence and divergence between the models on specific topics of policy relevance. Alongside these modelled projections, I include the historic data point for 2015 and a linear extrapolation of the 2010-2017 historic data out to 2020. EMF performed this modelling effort before 2015, and so the values provided by the models for 2015 were projections that may, or may not, align to historic data.

Figure 3-5*:* Projections of Natural Gas use in Electricity across EMF 31 Participants
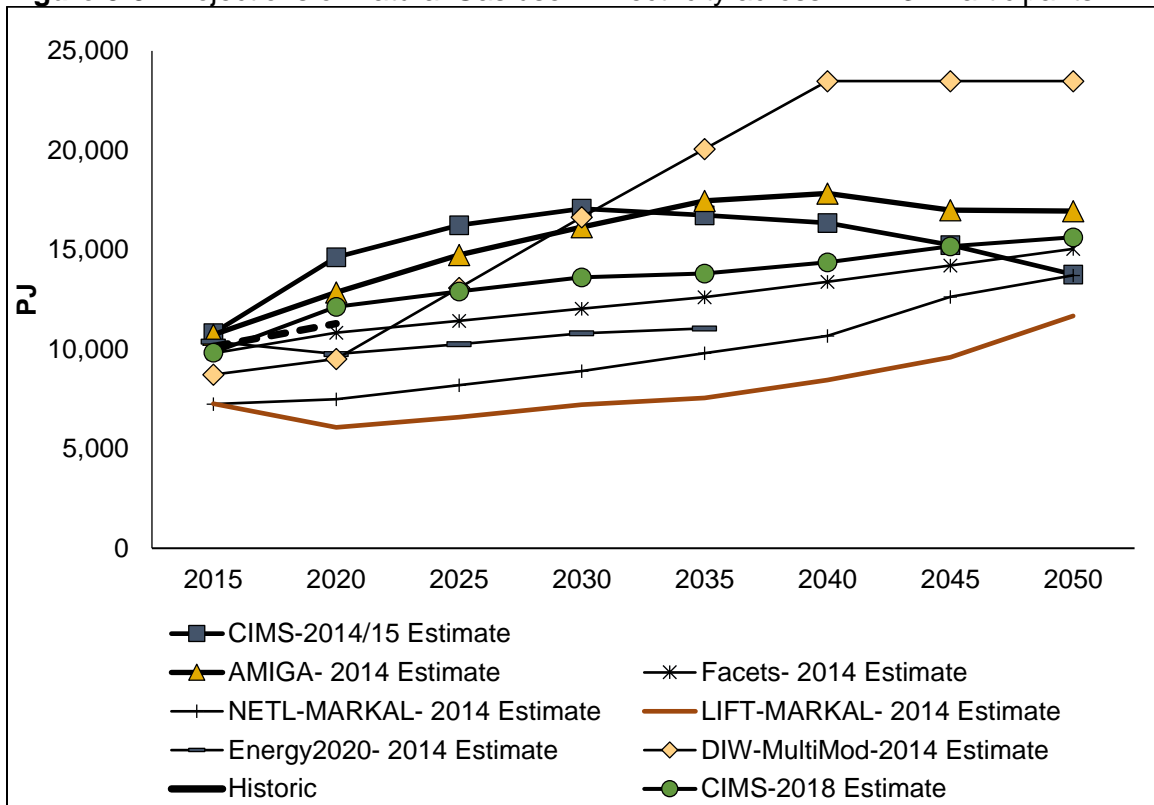
Figure 3-6: Projections of Natural Gas use in Industry across EMF 31 Participants
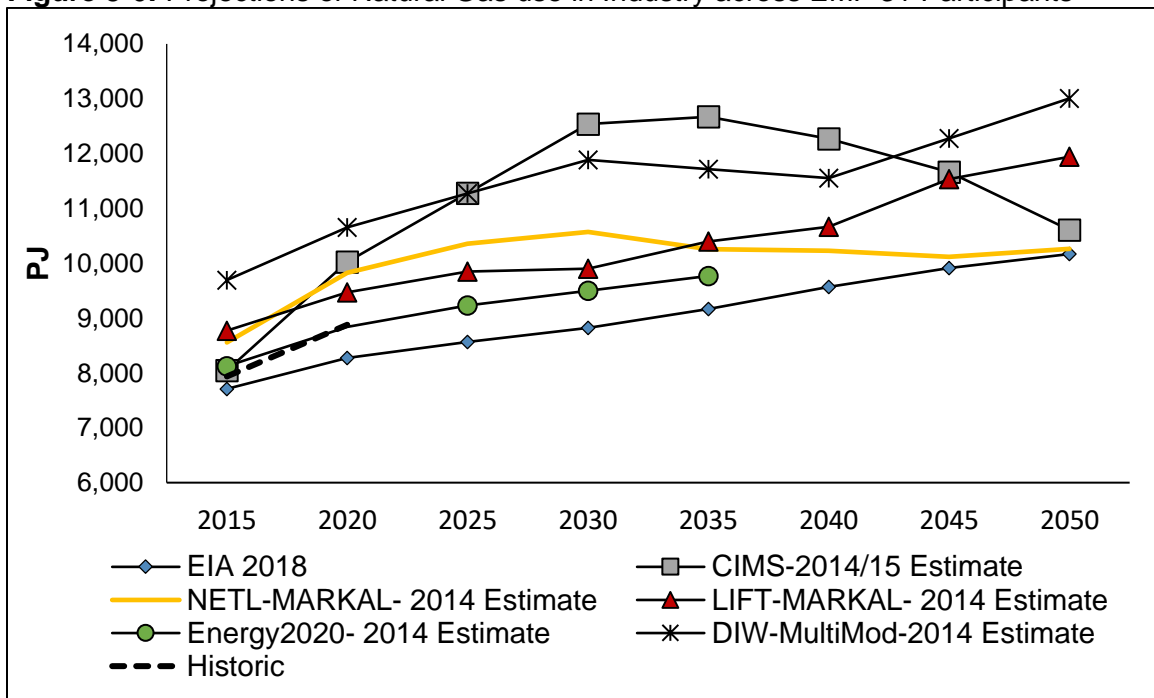
*Excludes lease fuel and pipeline fuel

In addition, I include two projections for CIMS in the first figure for the power sector. The CIMS 2014/15 estimate was my projection made in 2014, which differs from my updated natural gas use projections (CIMS 2018), which I used in the subsequent chapter in this thesis. Evident was that CIMS 2014/15 projected higher gas in the intervening 2020 to 2030 period than any of the other models. However, beyond 2030, the relatively high level of natural gas use in electricity began pushing gas prices up, and electricity generation from natural gas down, to levels more in line with the other modelling teams. The more recent CIMS forecast sees a more gradual rise of gas use in electricity in the near-term that continues out to 2050. More moderate near-term gas use in electricity prevents the extent of the gas-price appreciation witnessed in earlier runs, and also averts the concave shape of the gas consumption curve that was evident with CIMS 2014/15.

Driving these different forecasts for electricity are the reductions in renewable generation costs that have occurred over the last four years, which were higher than I originally anticipated in 2014/2015. Although most pronounced were the declines in solar PV costs, the decline with the largest practical impact was the drop in onshore wind capital costs from ~$1980/KW in 2015 to $1657/KW in 2018 as well as an increase in average wind capacity factors. These improvements in wind technology have considerably improved onshore wind's competitiveness vs. natural gas in the near-term, and, more so than any other factor, explains the lower natural gas use in the more recent CIMS projection.

This chapter, which was based on my published paper with Mark Jaccard in 2016, continues to use the 2014/15 projections, although the CIMS 2014/15 estimate might overstate the extent of gas-commitment due to the near-term surge in gas use in electricity. The CIMS 2014/15 and CIMS 2018 forecasts are similar in the quantity of natural gas use, and the dynamics regarding that use, for most other sectors of the economy besides electricity.

A key insight from this analysis of the business as usual trajectory is that a low natural gas price is no substitute for additional policy efforts required to achieve deep cuts in GHG emissions by mid-century. By 2050, emissions under the low-price scenario are only 18% below 2005 levels, an insufficient reduction relative to the level needed to stabilize global temperatures.[19] Furthermore, 2050 emissions for the low-price scenario actually exceeds

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[19] Pg 18 of the IPCC's 5th Synthesis Report Summary for Policymakers (IPCC, 2014) provides an extremely useful diagram relating percentage declines of global emissions from 2010 levels by

those of the high-price scenario- 5.19 Gt CO_2e compared to 4.76 Gt CO_2e- suggesting that low gas prices might actually worsen the US emissions trajectory. Clearly, additional policies are required to achieve emissions levels consistent with ambitious targets. However, the possibility of low gas prices expediting said policies remains plausible, as discussed in section 3.4.

I decompose this emissions difference between gas-price scenarios in Figure 3-7, which displays the absolute difference in annual 2050 emissions between the scenarios, for sectors where significant differences exist, as well as the total emissions difference. Positive values represent higher emissions in the low-price scenario over the high-price scenario. In the figure, I separate emissions from industry into those from manufacturing and those from upstream resource extraction.

Figure 3-7: Difference in Annual Emissions in 2050 (MtCO$_2$e): Low- Natural Gas Price Scenario Emissions less High- Natural Gas Price Scenario Emissions

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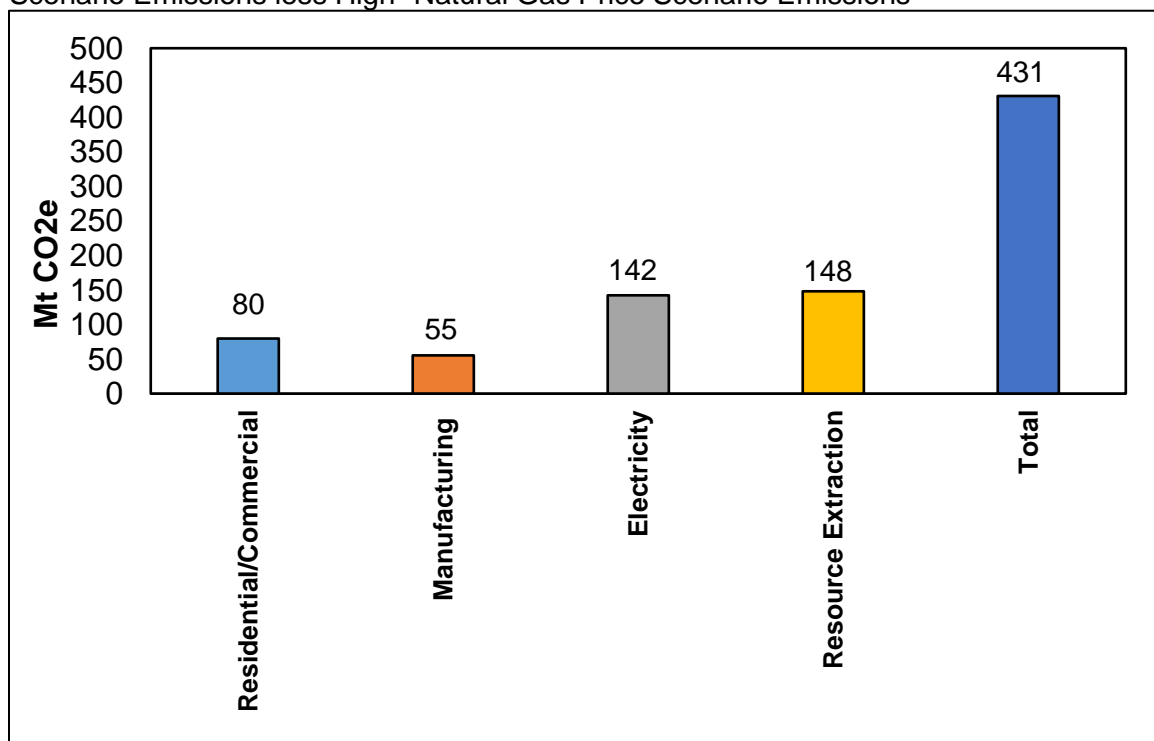
2050 to projected temperature increase which, in turn, is related to the increased risk of phenomena such as extreme weather events and species extinction. A 1.75 degree increase would result in a "medium" risk across the examined phenomena. To stabilize global temperatures at 1.75 degrees Celsius, global emissions would need to decrease by about 50% in 2050 below 2010 levels. While a subjective assertion, many acknowledge that developed countries will have to bear much of this burden to provide less-developed countries a chance to expand their energy use in line with economic growth.

All sectors see higher emissions under the low-price scenario. The major differences occur in residential and commercial, the "other" manufacturing sector, electricity, and upstream natural gas extraction. The higher emissions in electricity is the net effect of reductions in emissions from coal-to-gas substitution, and increases from emissions due to natural gas displacing nuclear and renewables. Furthermore, the higher gas use in the economy under this scenario results in incremental emissions arising from the upstream extraction of the natural gas itself. This occurs because the upstream emissions intensity of natural gas production (extraction, processing, and distribution) from both conventional and unconventional sources is 11t CO_2e/PJ of natural gas consumed, which is greater than the upstream emissions intensity for coal, the main fuel that natural gas is replacing, calculated at 3t CO_2e/PJ of coal consumed.[20]

The cautious interpretation of these figures is a necessity. The way the CPP was operationalized in CIMS means that under the low-price scenario, the CPP is non-binding, while it proved binding under the high-price scenario. Consequently, some of the emissions declines under the high-price scenario relative to the low-price scenario are due to the addition of the CPP in that case. Re-running the high-price scenario without the CPP results in emissions in 2050 being only 84 Mt CO_2e below the low price scenario, compared to about 430 Mt CO_2e before.[21]

Furthermore, there are important differences with respect to the timing of emissions between the two scenarios. Figure 3-8 below shows the emissions difference with positive values representing higher emissions in the low-price scenario for the entire simulation. For an apples-to-apples comparison, I do not model the CPP in the high-price scenario. Evident from the figure is that emissions are actually lower under the low-price scenario early on in the simulation, before flipping by 2025 where the high-price scenario starts

[20] There is a great deal of uncertainty regarding the associated methane emissions from natural gas extraction, and in particular shale gas, within the academic literature (see Howarth, Santoro, & Ingraffea, 2011 and Cathles et al., 2012 for an introduction). Consequently, I calculated the methane emissions intensity from gas extraction in CIMS to match that estimated by the EPA in their 2013 US GHG Inventory. Calibrating ensured that methane emissions intensity in natural gas extraction calculated by CIMS for 2005 and 2010 closely followed the historic values calculated by the EPA. I did a similar exercise for CO_2 emissions, where I estimated the historic combustion emissions from EIA data of lease-fuel consumed in natural gas extraction. I then calibrated the combustion emissions intensity to match this historic data. See Figure F-1 in Appendix F.

[21] In addition, lower emissions are now occurring in electricity by 2050 under the low-price scenario relative to the high-price scenario, which was not the case previously.

seeing lower annual emissions relative to the low-price scenario. This finding illustrates an important trade-off between the scenarios, where lower gas prices can result in near-term emissions reductions relative to the high-price scenario, at the expense of relatively higher emissions later on.

Figure 3-8: Difference in Emissions (MtCO$_2$e): Low-Natural Gas Scenario Emissions less High-Natural Gas Scenario Emissions (No CPP)
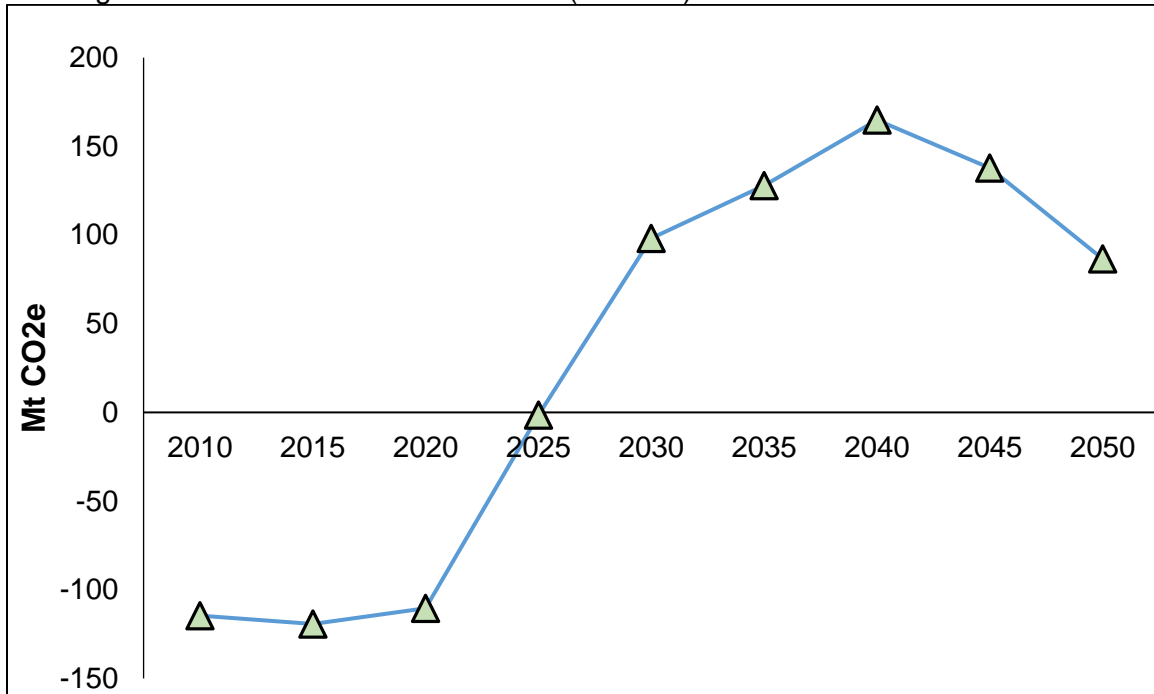
3.4 Results: Carbon Pricing Policy

I simulated an increasing carbon tax schedule, with 100% revenue recycling, to reduce 2050 GHG emissions by 80% below 2005 levels.[22] Each gas-price scenario was run under: i) a foresight setting where the average of the simulation's future carbon price is considered in current decision making due to the policy trajectory being announced without delay;[23] and ii) a no-foresight setting, where agents lack knowledge of future carbon prices until the policy is implemented. With both foresight settings the tax begins to take effect in 2025, however, it is only the foresight case where firms and households

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[22] This is a redistribution of revenues to households and industry so that the tax is carbon-neutral.
[23] Not the foresight traditionally in the economics literature of agents optimizing across time.

have the ability to anticipate the tax and plan accordingly. Table 3-1 below summarizes all of the policy scenarios ran for this exercise:

Table 3-1: List of Scenarios

Natural Gas Price	Foresight Setting
Low	Foresight – Firms & households have knowledge of the impending 2025 start date by 2015.
Low	No Foresight- Firms & households do not have knowledge of the policy until 2025
High	Foresight – Firms & households have knowledge of the impending 2025 start date by 2015.
High	No Foresight- Firms & households do not have knowledge of the policy until 2025

When agents have foresight of the policy, they may begin to choose technologies that are consistent with a low-GHG future, even when the policy is not yet in place. By contrast, it is likely that the pre-policy trajectory without foresight should closely follow the BAU trend. The absence of foresight, therefore, may result in decisions about technology choice that are inconsistent with future climate policy, and may make that policy harder to achieve once introduced.

Thus, I expect difficulties to meet a stringent target when gas is abundant and firms and consumers lack foresight of the policy. Under these conditions, the energy system will adopt gas-utilizing technologies at a level that is inconsistent with the 80% reduction target, and so would require a higher carbon price to achieve a 2050 emissions target. As discussed in section 3.2, I measured the interaction between forecast setting and gas price by first calculating the proportionate difference in carbon necessary price between forecast settings for a given gas price scenario before then comparing between the gas-price scenarios. This allowed me to discern how differences in the gas price alone might affect the impact of foresight on the ease of achieving the target.

Figure 3-9 below shows the required carbon price schedule for each gas-price and foresight permutation.[24]

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[24] Since the carbon prices are a schedule over time, I took the discounted present value of the charge over 2025-2050 period (the years in the simulation where the policy is implemented) to ascertain the magnitude of the necessary carbon price by scenario. I used a 6% discount rate. CIMS does not solve for an optimal carbon charge path to achieve an exogenous target. Consequently, I iteratively ran multiple simulations with varying price rates until one achieved a

Figure 3-9: Carbon price schedule to reach the 80% reduction target
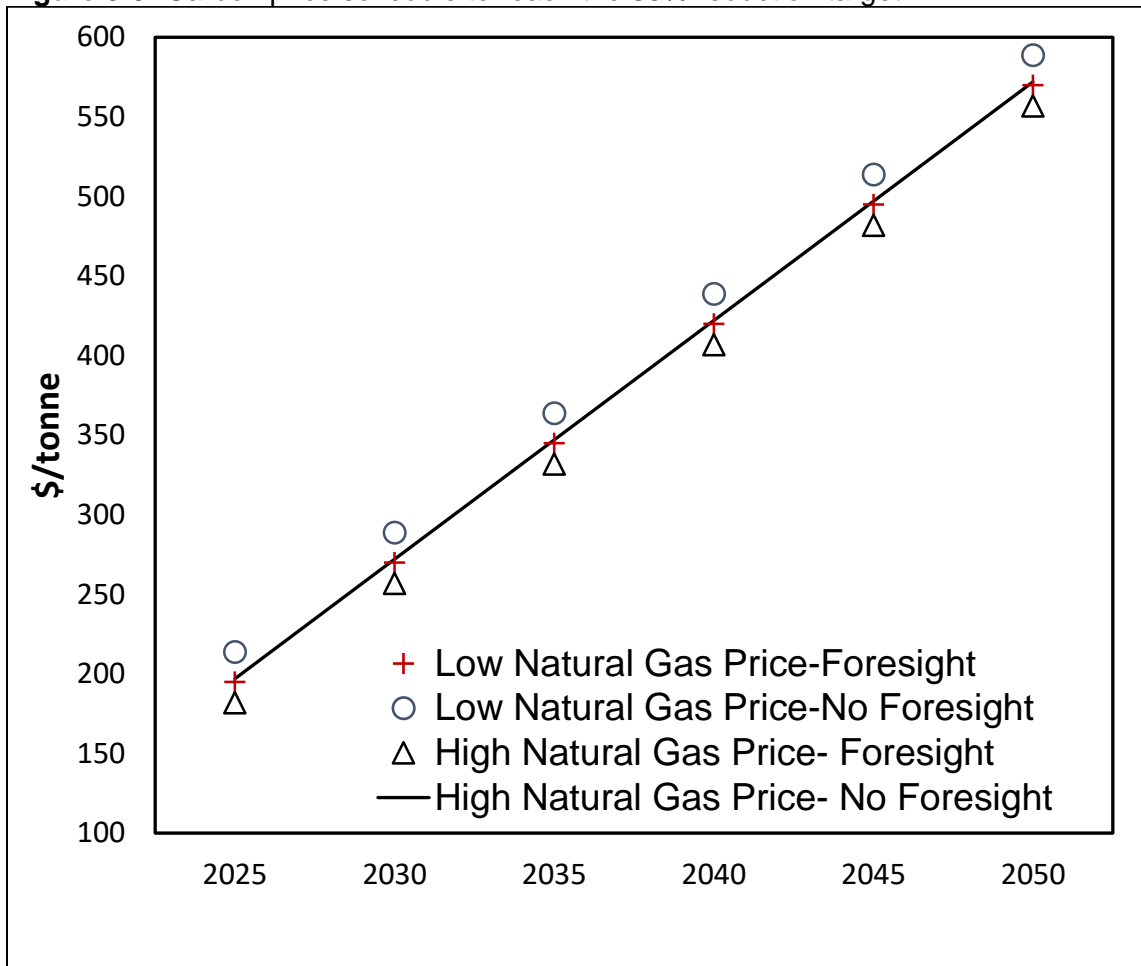
Four key findings are apparent from this figure:

i)   if natural gas is plentiful, and its price therefore lower, then the price on carbon must be somewhat higher to achieve the GHG reduction target for a given foresight setting. One can see this by comparing the curves between the gas-price scenarios for a given foresight scenario, for instance, by comparing the triangle and + icons for the foresight scenarios, or by comparing the X and circle icons for the no-forecast scenario.

ii)   Foresight of future carbon pricing reduces the carbon price required to achieve the target in both gas-price scenarios, indicating a substantial amount of sub-optimal decisions about technology when policy is

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given target. To maintain consistency across the runs, I assumed the carbon price increases by a constant amount ($75) between each five-year increment.

unanticipated. Once can see this latter effect by comparing the foresight vs. the no foresight case for the low-price scenario (by comparing the + and circle icons) or for the high-price scenario (by comparing the triangle to the X).

iii) There is a proportionately greater difference in the discounted carbon price- 6.2% percentage points compared to 5.1% percentage points- between the different foresight settings with plentiful gas relative to when gas is less plentiful. This indicates some additional costs arising from the interaction of the lack of anticipation of the policy with the lower gas price.

iv) For findings i-iii, however, it appears that these differences in cost are actually quite small. A more formal incorporation of uncertainty in some of the key parameters, such as the gas price, may potentially negate much (or perhaps all) of this difference

Figure 3-10 illustrates the required emissions reductions by sector to achieve the economy-wide target across both foresight settings and gas-price scenarios.[25]

Figure 3-10: Emission Reductions between 2020 and 2050 (Mt CO2e)

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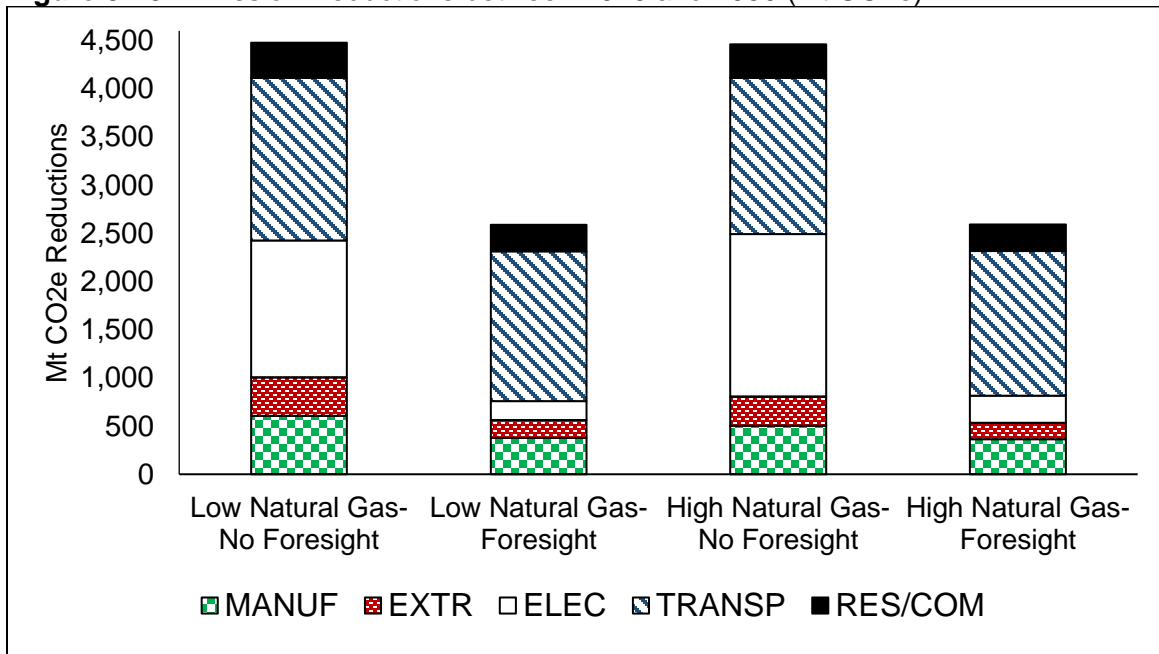
[25] Comparing reductions between 2020- the final interval solved by CIMS prior to the introduction of the policy in 2025- to 2050.

Evidently, the reductions required over this period are far lower under the foresight settings, due to firms and households reducing their emissions in anticipation of the more stringent policy without delay. In addition, although not particularly evident from the graph, the low-price scenario requires slightly more emissions reductions over the same timeframe- by about 17Mt- when policy is unanticipated. Furthermore, the sectors where the reductions are occurring differ by gas-price scenario, with the low-price scenario witnessing more reductions from the extractive sectors, transportation, and manufacturing, while the high-price scenario witnesses greater reductions from electricity.[26]

Figure 3-11 further emphasizes some of these findings, by providing the difference in required emissions reductions between foresight settings for each gas price scenario— measured as emissions under the no-foresight setting less emissions under the foresight setting. The figure shows the low-price scenario requiring greater emissions reductions, in both absolute quantity, as well as from sectors such as transport, energy extraction, and manufacturing. The higher marginal abatement costs in these sectors drives the higher required carbon price, and the proportionately greater difference in discounted carbon price between foresight settings, under the low-price scenario.

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[26] Due to there being more gas in the economy before the introduction of the policy and the upstream emissions intensity of gas.

Figure 3-11: Emission Reductions between 2020 and 2050- Difference between Foresight Setting per Natural Gas-Price Scenario (Mt CO_2e)
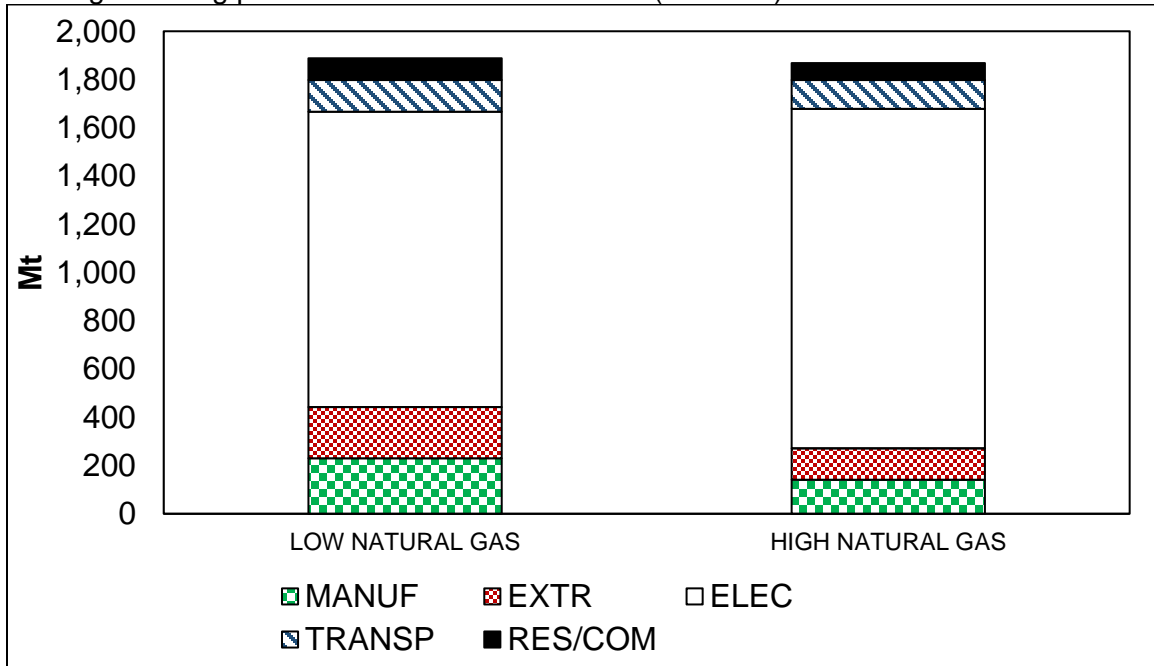
Despite large amounts of natural gas and coal-fired electricity occurring under both price-scenarios absent foresight of the policy, reductions in carbon emissions from electric power are still possible through CCS, which proves to be instrumental in obtaining the necessary emissions reductions from electricity. This echoes a finding of Johnson et al. (2015), who note how allowing models to retrofit coal plants with CCS, without any temporal constraints or bottlenecks, can substantially reduce the phenomenon of stranded investments in coal generation when policy is unanticipated.[27] Similarly, Riahi et al. (2015) note how weak near-term policies force the energy system to rely largely on CCS and bio-CCS to meet stringent targets later. I evaluate the implications of CCS's key role in allowing today's capital stock investments in fossil fuel-fired electricity to be consistent with later ambitious climate policy in a sensitivity analysis later in this chapter.

While the above figures analyze the emissions dynamic using comparative statics between the scenarios in 2050, figure 3-12 below illustrates the emissions pathways for the four gas price and policy expectations.

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[27] I do not impose a market penetration constraint on CCS retrofits.

Figure 3-12: Emissions Trajectory by Scenario
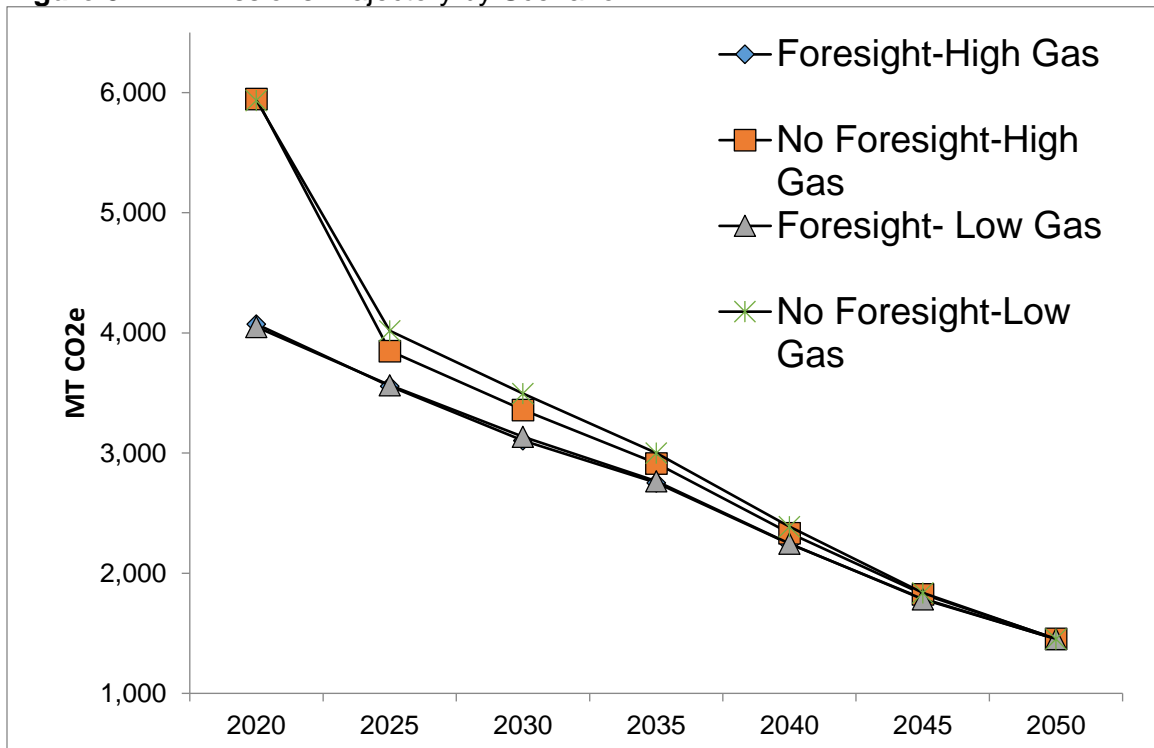
Differences between the foresight and no-foresight curves for a given gas price scenario indicate inertia that needs to be overcome in order for emissions to converge to the 2050 target. This difference in foresight and no-foresight scenarios (grey and yellow lines) is higher for the low-price scenario than for the high price scenario (blue and orange lines), indicating more emissions that will eventually need to be mitigated when policy is delayed and gas prices are lower. This gap between the yellow and orange lines represents incremental emissions occurring solely from differences in gas price that will later need to be mitigated. Mitigating these emissions for the low-price scenario necessitates higher emissions reductions occurring elsewhere in the economy. These reductions are more expensive than what optimally would have been pursued had firms and households been given the proper signals as to the carbon price trajectory earlier in the simulation.

Figure 3-13 below illustrates the differences across sectors between the low-price scenario without foresight and the high-price scenario without foresight. Positive values represent sectors where emissions are higher in the low-price scenario relative to the high-price scenario.

Figure 3-13*: Emissions Difference- Low-Price Scenario without Foresight minus High-Price Scenario without Foresight
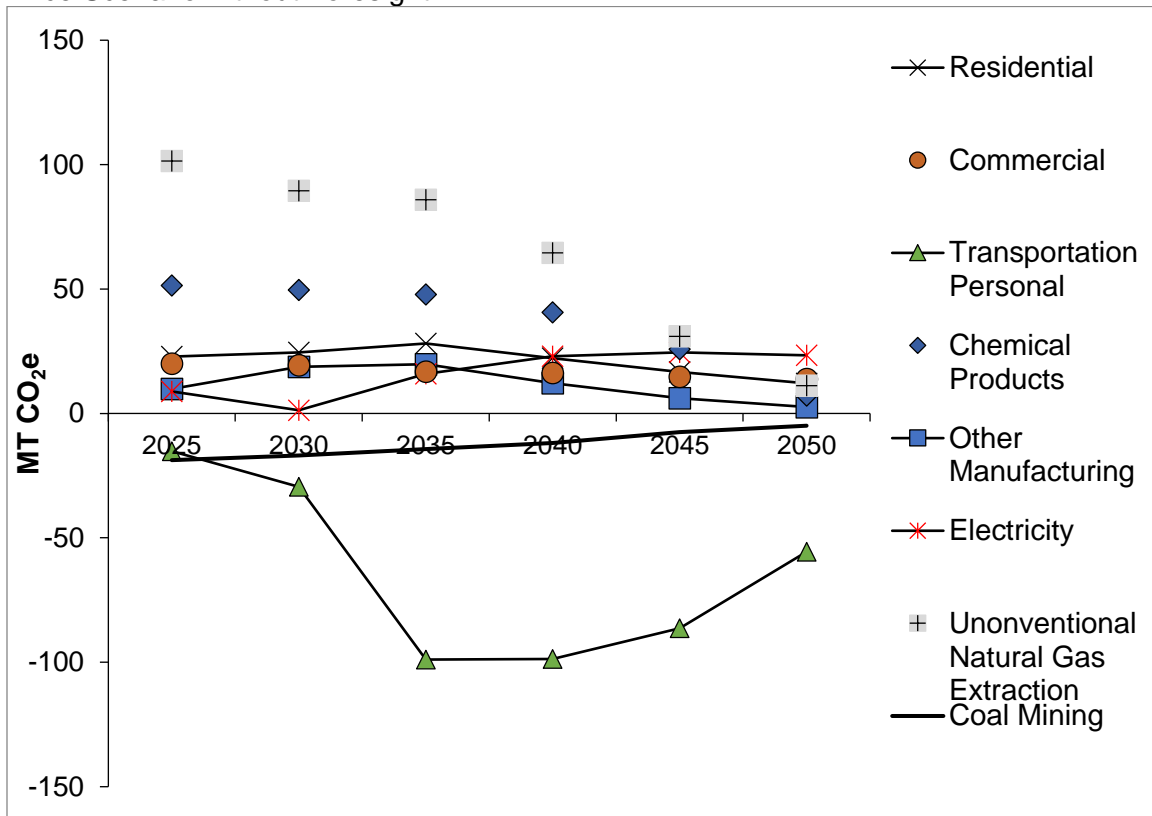
Much of this difference is occurring in several key sectors of the economy, each with *differing driving forces. In the case of the end use and power sectors, the mechanism* driving these differences is the difference in gas prices that either inhibit, or promote, the switch to lower-emitting alternatives. As an illustrative case to show this phenomenon, I provide a more detailed description of the dynamics occurring in steam generation for chemicals manufacturing, as Figure 3-13 shows considerable differences between the scenarios for this sector.

Lower-emitting alternatives that can generate the high-quality steam required for chemicals manufacturing in CIMS are limited to retrofitting the existing boilers and cogeneration units to CCS, electric boilers, transitioning to more energy efficient options, or using by-product gas, with substantially lower emissions. Figures 3-14 and 3-15 below illustrates the adoption of different types of steam generators (both boilers and cogeneration units) in chemicals manufacturing for the high and low-price scenarios respectively.

Figure 3-14: Steam generators in Chemicals Manufacturing- High-Price Scenario

- ◇ % CCS or Electric- Foresight
- ■ % ByProduct-Foresight
- ▲ % NaturalGas-Foresight
- — % CCS or Electric- No Foresight
- ● % ByProduct- No Foresight
- ┼ % NaturalGas- No Foresight
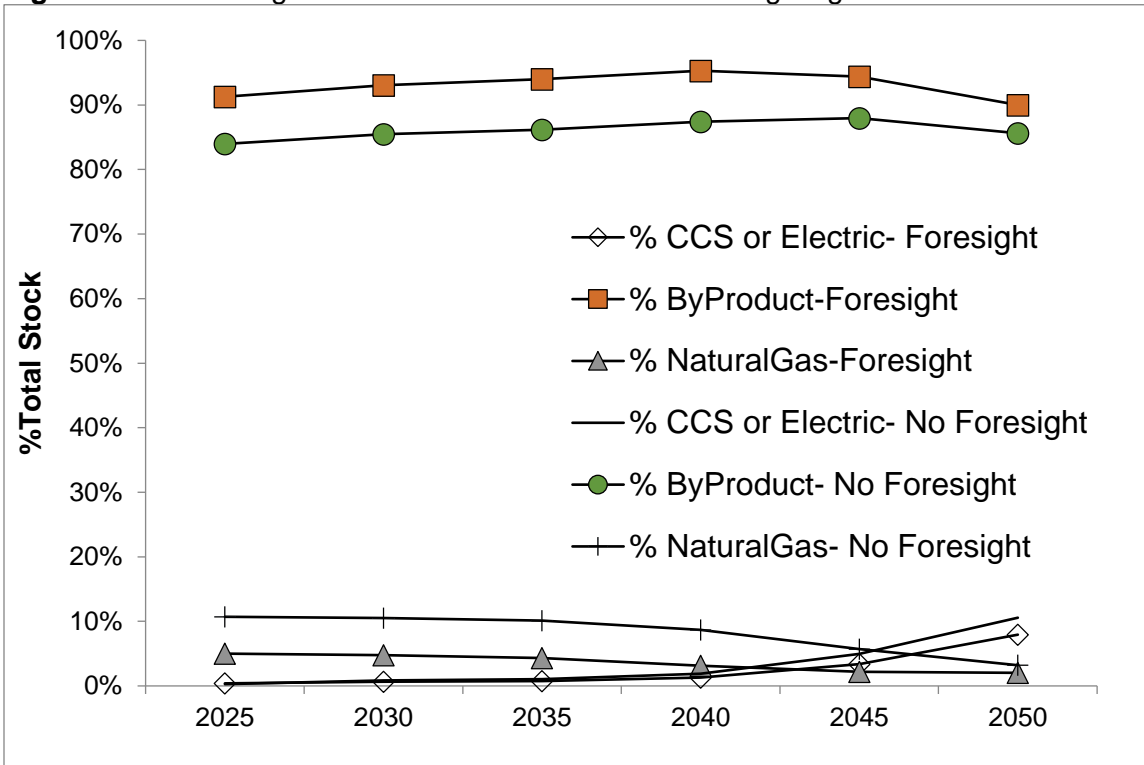
Figure 3-15: Steam generators in Chemicals Manufacturing- Low-Price Scenario

- ◇ % CCS or Electric- Foresight
- ■ % ByProduct- Foresight
- ▲ % NaturalGas- Foresight
- — % CCS or Electric- NoForesight
- ● % ByProduct- NoForesight
- ┼ % NaturalGas- NoForesight
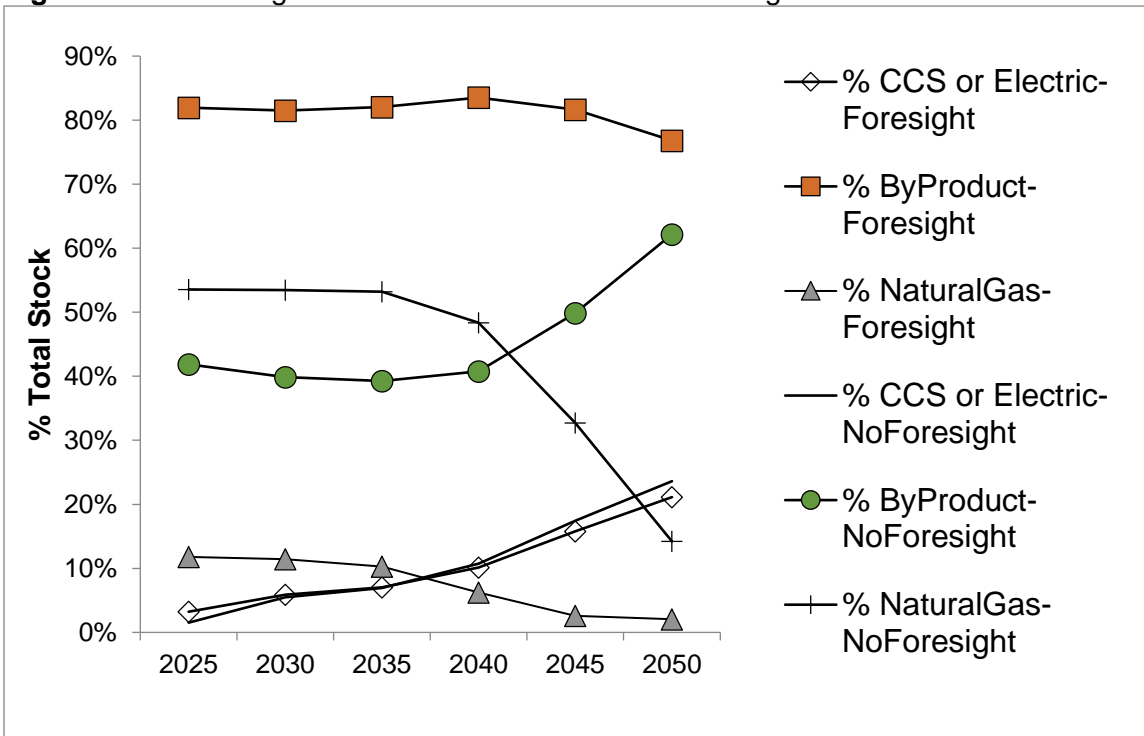
Figure 3-14 shows the technology trajectories for the high-price scenario being practically the same with and without foresight. By contrast, the low-price scenario in figure 3-15 shows a divergence in trajectories, with foresight of the impending carbon price resulting in much less natural gas use, and greater use of by-product gas, than when the policy occurs without foresight. This aligns with the hypothesis of how abundant natural gas, combined with expectations about the persistence of weak climate policy, will incentivize the continued use of natural gas at the expense of alternatives with lower emissions. Similar factors are at play for the other end use sectors shown in figure 3-13.

By contrast, the differences in emissions in upstream natural gas and personal transportation are due to different factors. The relatively higher upstream natural gas emissions under the low-price scenario is simply due to there being more natural gas used in the US energy system under this scenario. For the personal transportation sector, figure 3-13 shows lower emissions under the low-price scenario relative to the high-price scenario. These lower emissions, however, have nothing to do with natural gas use in personal transport, which is negligible under all policy scenarios, but instead is a consequence of the higher carbon price under the low-price scenario causing incremental emissions reductions in personal transport. These reductions become necessary in this scenario, in order to compensate for higher emissions occurring in other sectors of the economy where greater gas use, combined with a policy delay, inhibits their cost-effective mitigation.

A counterpoint to the argument laid out in this chapter is that, even though the requisite carbon price is higher, it might still be possible that the overall costs of the low natural gas price path are lower due to lower natural gas prices reducing overall energy costs. At the heart of this critique is that there are multiple measures of the cost of delay. Addressing this critique, the figure 3-16 shows the proportionate decrease in the average unit cost of output between the low and high-price scenarios arising due to the lower gas prices in the low-price scenario. I then compare this value to the increase in average unit cost occurring due to the higher carbon price in that scenario. Evident from the figure is that the higher carbon price induced by abundant gas in the low-price scenario increases unit costs by a greater proportion than the lower natural gas price decreases unit costs. This suggests that my main finding regarding natural gas hindering the cost-effectiveness of stringent climate policy is robust to one alternative measure of cost. However, other measures of

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cost, such as measures of welfare loss, were not evaluated in this study and could perhaps yield a different outcome.

Figure 3-16: Proportionate difference in unit cost of output between low and high gas price scenario arising from lower natural gas prices and higher carbon prices.
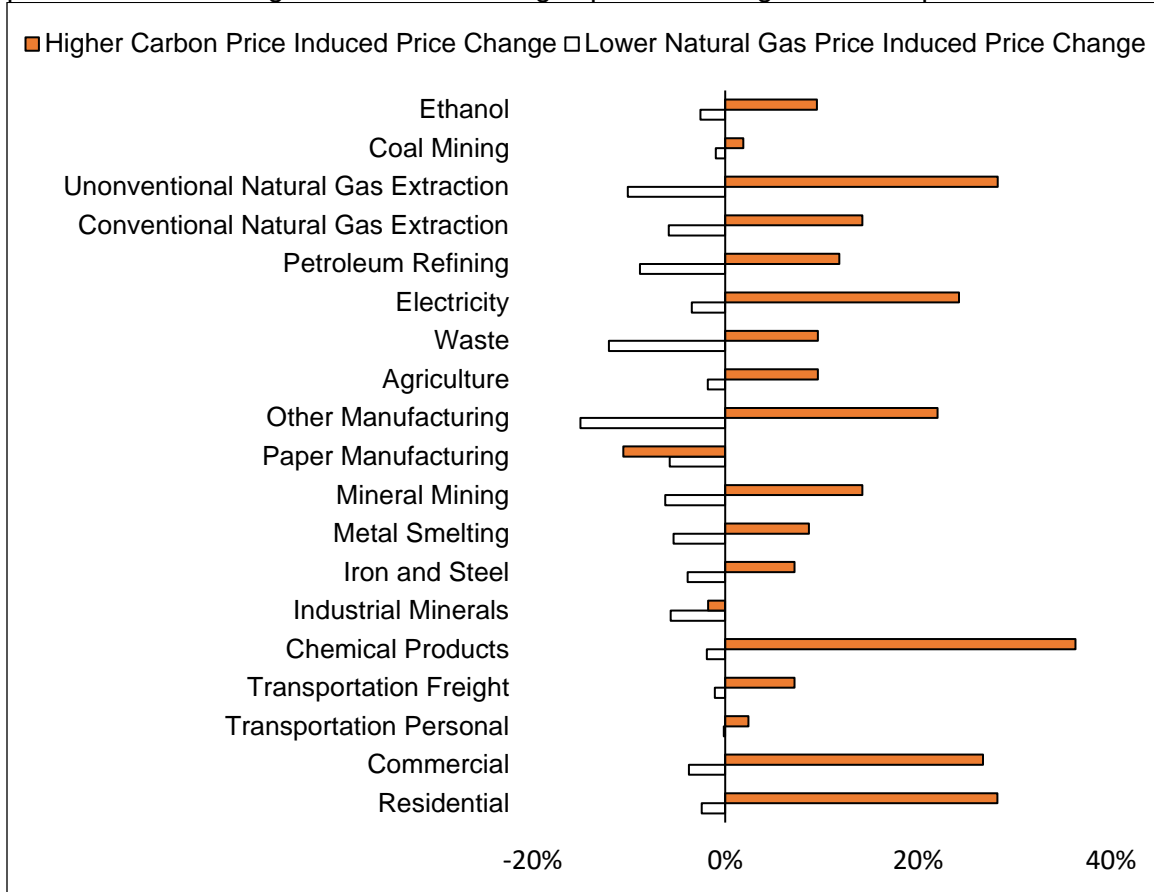
3.5 Sensitivity Analysis

I conducted a sensitivity analysis to test the robustness of the above findings to three alternative model specifications as described in Table 3-2 below.

Table 3-2: Alternative Specifications and Rationale

Specification	Description	Rationale
Base Case	Scenario in 3.4	Base case for comparing the alternative specifications
High CCS Cost	Increases the capture cost of all CCS	I found CCS to be important in meeting the target when the policy was unanticipated. To what extent does increasing the cost of CCS make the

Specification	Description	Rationale
	technologies by 100%	stringent target harder to achieve, and does it affect the low-price scenario disproportionally?
Constrained Nuclear	Constrains Nuclear so that no new nuclear plants are built post 2015.	Nuclear is a technology where social, public perception, and political factors can prohibit new nuclear plants from being sited and built. Consequently, this specification constrains nuclear in order to discern how limiting this key technology influences the results.
Low Cost Nuclear	Decreases the Capital Cost of baseload nuclear technologies by 15% starting in 2015	I examine if decreasing the cost of a source of low-GHG baseload electricity affects the results. Given that nuclear is a technology consistent with stringent climate targets, if it is found to be more economic under BAU, the system may become less fossil-fuel committed prior to the policy, potentially making the policy easier to achieve. This decline might occur due to claims that US nuclear faces almost a 22% cost penalty due to the financing risk borne out of the experience of cost overruns occurring with nuclear in the 1980s (MIT, 2010). Removing this risk, perhaps via successful demonstration projects to show that it is possible to complete nuclear plants on time (suggested in MIT's 2010 report "The Future of the Nuclear Fuel Cycle"), might make nuclear an economically attractive option again. To remain conservative in my assumptions, I assume only a 15% decrease in capital costs

The results to the sensitivity analysis are in Figures 3-16 and 3-17 below. Figure 3-16 illustrates the carbon price schedule under the alternative specifications pertaining to the no-foresight case for the low-gas scenario, while 3-17 illustrates the proportionate difference between foresight settings for both gas-price scenarios under the alternative specifications.[28] To interpret Figure 3-17, a value of 5% means that the discounted carbon price over the given sensitivity run needs to be 5% higher under the no-foresight setting, versus when foresight of the policy is present. The gap between the icons, representing the different gas-price scenarios, indicates the extent of the proportional difference in carbon price between forecast settings for the gas-price scenarios.

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[28] Only the low-price scenario without foresight case is displayed to ensure legibility of the figure. The directional impact of the high-price scenario and foresight cases is the same across alternative specifications.

Figure 3-17: Carbon price schedule to reach 80% reduction target- Sensitivity Run Cases (Low Price Scenarios without Foresight)
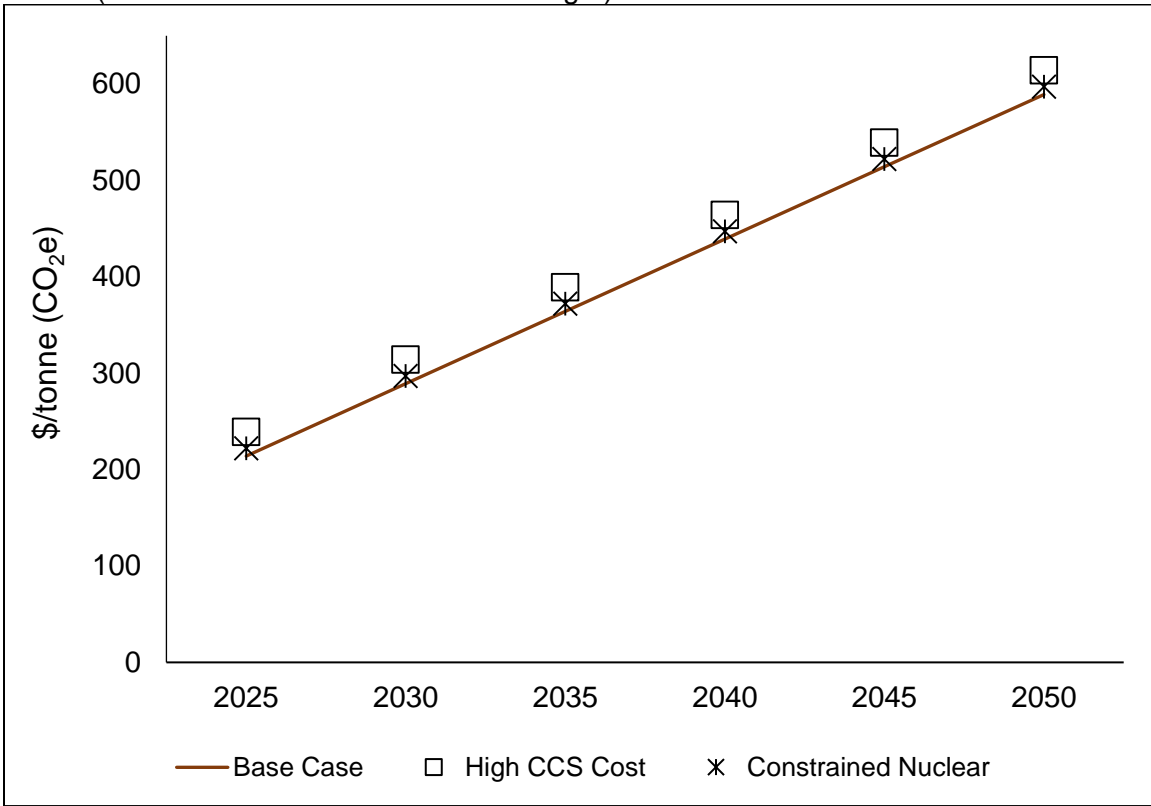
Figure 3-18: Proportionate Difference in Carbon Price between Foresight Settings per Natural Gas-Price Scenario- Sensitivity Run Cases
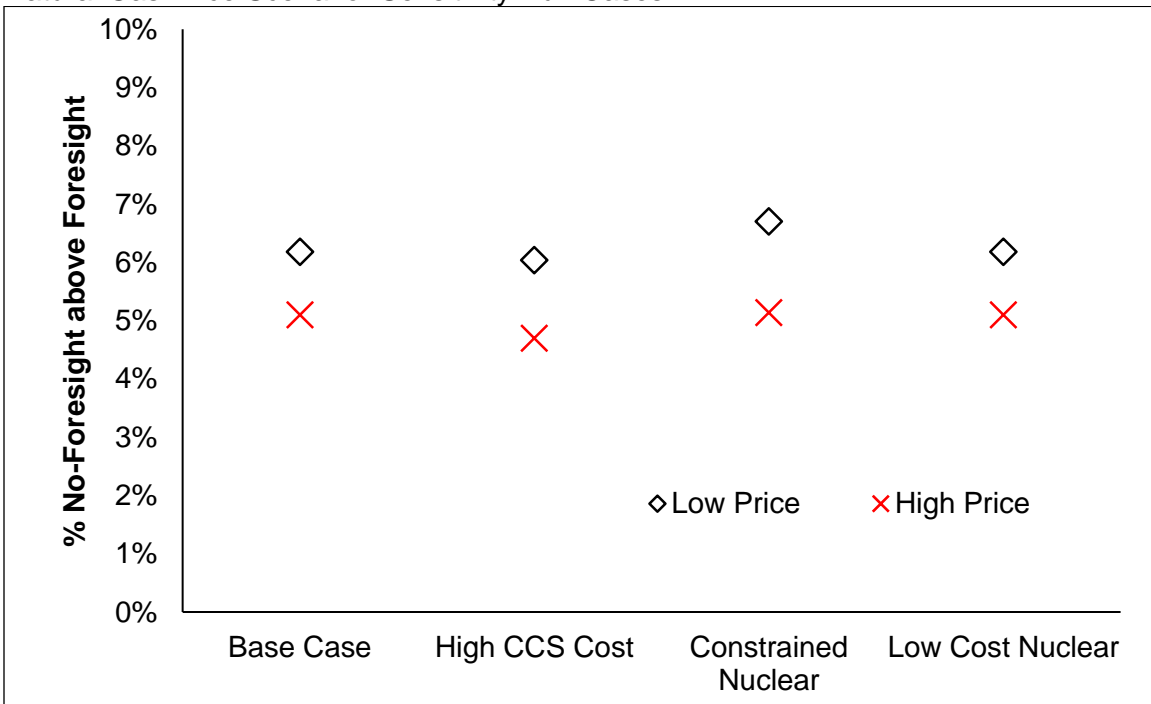
Two interesting findings stem from these figures. Firstly, only two of the three sensitivity runs actually see increases in the absolute magnitude of the necessary carbon price in settings without foresight— these being the constrained nuclear and higher CCS cost scenarios. The specification reducing nuclear capital costs has no effect on the requisite carbon price in any scenario. Secondly, these increases occur under both gas-price scenarios, and so none of the alternative specifications result in a meaningful change in their proportionate difference from the base case (the gap between the icons in Figure 3-17). For instance, the nuclear constrained specification shows the largest proportionate difference between foresight settings between the gas-price scenarios, a difference of only 1.55% compared to a difference of 1.1% between the gas-price scenarios under the base case.

3.6 Conclusions and Policy Implications

In this paper, I use the CIMS-US energy-economy simulation model to project the role of abundant natural gas in the US energy system. I use these projections to discern how abundant gas may interact with a future climate policy and expectations about that policy. The results suggest that, under BAU, lower gas prices have important longer-term implications for the energy system as low-gas prices result in natural gas becoming the dominant fuel midway through the simulation, and results in gas remaining an important fuel source for the economy by 2050. The analysis also shows how, under BAU, low gas prices result in higher annual emissions by 2050, and that neither price-scenario came close to bringing emissions levels in line with ambitious climate targets. However, abundant gas does result in short-term emissions reductions prior to 2025 relative to scenarios with less gas

Regarding the implications of lower gas prices on achieving a stringent US climate policy, defined here as an 80% reduction in annual emissions from 2005 levels by 2050, abundant gas actually makes it slightly harder to achieve such a target under carbon-pricing policy. This finding is consistent across foresight settings. Furthermore, lower gas prices also slightly exacerbate the difference in carbon price between foresight settings, requiring higher carbon prices when policy is unanticipated by firms and households. However, this gas-price effect on the carbon price is secondary to that of firms and households level of anticipation of the policy. In other words, when firms have foresight of the policy, there is only a small difference in the carbon price arising due to natural gas availability. Overall,

the cost differences stemming from variations in either gas price or foresight setting, the major findings of this chapter, are quite small and perhaps would not be evident if more robust treatment of uncertainty for key parameters, such as natural gas prices, were incorporated in the analysis. I acknowledge this to be a limitation of my analysis.

However, although abundant gas may not hamper achieving stringent climate targets in conjunction with policy, it does not necessarily help. Thus, enthusiasm of the prospect for gas as a panacea for climate policy may be misguided. The findings of this chapter suggest that abundant gas is at best, neutral, and at worst slightly detrimental to support a policy that achieves a stringent climate target for the US. An important caveat to this claim, however, is that low-cost natural gas may make it easier to get a stringent climate policy, as a means to achieve a stringent climate target, implemented in the first case. This is because in the near-term, low-cost natural gas enables an early mitigation avenue through the substitution to natural gas from coal in electricity. While this may be true, an important finding of this paper is that this initial benefit may come at a later cost as the system seeks to wean itself off gas to meet targets that are more stringent later. Thus, policymakers must carefully weigh this trade off as they consider the benefits and costs of abundant gas.

Another important consideration is how the findings of this paper may be limited to the US and other North American jurisdictions like Canada where natural gas is abundant. By way of contrast, China and India are both heavily dependent on coal and also have longer timescales than advanced economies to decarbonize. In the Asian context, substitution from coal to natural gas in the near term could be a net benefit in the fight against climate change. Not only would the switch from coal to gas directly reduce power sector emissions, but the increased flexibility that natural gas generation brings to the grid through its quick ramping rates could improve the integration of intermittent renewables in these economies, thereby helping to decarbonize electricity further.

Overall, for US climate policy to be cost effective, the policy conversation should shy away from the price of gas and, instead, steps should ensure the implementation of policy sooner rather than later, and that the policy is communicated well in advance of its implementation date without delay. This will give relevant actors adequate time to prepare, by making more economical technology investment decisions that align with stringent emissions cuts.

4. Implications of a US Electricity Emissions Policy for Emissions in Uncovered Sectors

4.1 Introduction

De-carbonizing electricity is a crucial step in putting humanity on a path to limit global warming to 2 degrees Celsius. For one, generation of electricity is a large source of emissions, making up almost 42% of global energy-related CO_2 emissions in 2015 (IEA, 2017a). Furthermore, because electricity is a form of secondary energy, with zero emissions at the point of end-use, a decarbonized grid can reduce emissions in end use sectors of the economy through electrification. A number of such power sector targeted policies have been introduced globally. Although repealed, the US Clean Power Plan (CPP) introduced a GHG reduction policy for the US power sector that established state-specific CO_2 emissions targets, while giving states flexibility on the policy approach to take (EPA, 2017).[29] Other examples from the US include state-based renewable portfolio-standards, regional cap and trade policies (e.g. New England's Regional Greenhouse Gas Initiative), and subsidy policies for clean energy (e.g. the 2005 Energy Policy Act and its production tax credits for solar, wind, and nuclear).[30] Outside the US, other jurisdictions have also introduced policies specifically targeting the power sector such as Germany's feed-in-tariff, or Ontario's feed-in-tariff combined with its mandatory phase out of coal-fired electricity.

This sector-specific approach may help overcome political acceptance challenges of targeting the whole economy simultaneously with policy, or may help achieve near-term emissions reductions that buys time for reductions in other sectors with more challenging abatement options.[31] However, the major drawback of this approach is the distortion of

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[29] For example, the policy allowed states to pursue either a mass-based or intensity-based policy.

[30] California's Western Climate Initiative is another other key US climate initiatives, but do not only target the power sector.

[31] For example, de-carbonizing electricity might enable time for breakthroughs to drive down costs for industrial carbon-capture and storage, which could be a key abatement option for sectors like cement and iron and steel (Leeson et al., 2017).

incentives across sectors at the margin, as the policy prices emissions and energy differently between the sectors that are subject to the policy, and the uncovered sectors, which are not. Although earmarked for electricity, a power sector policy will affect energy use and emissions across the economy due to electricity being a large consumer of fuels, and due to electricity being an energy input for other sectors in the economy. In this chapter I ask two related research questions:

i)   Does policy targeting only the electricity sector affect GHG emissions in sectors not covered by policy (consisting of the industrial, residential, commercial, agricultural, and transportation sectors—hereafter referred to as the uncovered sectors) and in what direction?

ii)   How can policymakers design electricity sector policy to minimize the increase of GHG emissions?

To answer these questions, I ran several US power-sector policies of varying designs through an energy-economy model with a high degree of technological explicitness, the CIMS-US model. At the same time, I assumed no policy for the uncovered sectors of the economy. Power sector policies that I modelled included a carbon tax where revenue is kept within general revenue and not directly redistributed back to consumers or firms, an emissions intensity standard for electricity with tradeable permits, a coal-phase out, as well as a coal phase out combined with a clean electricity standard. In addition, I modelled a hypothetical scenario that reflects the priorities of the current US administration where electricity generation from coal is subsidized. I chose these policy scenarios as they reflect much of the variation in existing electric sector policies, and each is expected to result in differing impacts on economy-wide fuel prices and so, on uncovered sector emissions. I measure the uncovered sector emissions impact by calculating an inter-sectoral emission leakage rate— the change in uncovered sector emissions induced by the power-sector policy, divided by the reduction in power sector emissions due to the policy— which is a relative measure of emissions change in the uncovered sector.

Overall, while there has been much work done to compare the impacts of variants of electricity sector policy on the sector itself, to my knowledge this is the first paper with a focus on the impacts of such a policy on the rest of the economy that is not covered by policy. Regarding the former body of literature, recent papers have analyzed the economic impacts of the proposed US CPP, using such metrics as welfare and mitigation costs. Paul, Palmer, & Woerman (2014) used an electricity model to compare various power

sector policies according to economic welfare, alongside other metrics. As expected, they find carbon-pricing policies to have the highest net social welfare, followed by rate-based tradeable performance standards (TPS), that loses some economic efficiency by subsidizing output, and then by variations of a clean electricity standard, whose efficiency decreases the more prescriptive it becomes in terms of allowable mitigation options. Similar work by Burtraw, Linn, Palmer, & Paul (2014) models the impacts of differing credit allocations on the efficacy of a cap-and-trade policy. They find approaches that distribute credits to utilities lead to very small changes in average electricity prices compared with those where governments collect credit revenues through auctions. They note, however, that while perhaps possessing a political advantage, the lower electricity prices create less incentive for conservation or energy efficiency investments, and are thereby less economically efficient.

Anticipation around the CPP has also spurred investigation into a number of policy considerations that go beyond the assessment of welfare implications under idealized conditions. For instance, Goulder, Hafstead, & Williams (2016) investigated policy effectiveness of electricity-sector policy in a "second-best" world with prevailing taxes in the economy. They find a clean electricity standard, depending on its design and stringency, could be *more* cost-effective than an equivalent carbon pricing policy by generating a smaller implicit tax on pre-taxed factors of production, offsetting the disadvantages of a clean electricity standard associated with its prescriptive nature. Similarly, a number of studies look at how policy design could reduce geographic leakage of emissions that may arise: i) in the context of differing policy stringency for the power sector *between* jurisdictions; and ii), in the context where some power sources *within* a jurisdiction are covered but not others (see Palmer, Burtraw, Paul, & Yin, 2017 for a review).

This paper's examination of a power sector policy on emissions in the uncovered sectors is an extension of this leakage literature, although it uses a sectoral rather than a geographic lens to evaluate leakage. As mentioned, currently a comprehensive examination of leakage from the power sector to the uncovered sectors is lacking. While Bistline et al. (2018) report the impact of an electricity sector policy on energy prices in other sectors for a number of energy economy models, they do not detail the emissions implications of these price changes, nor do they unpack their dynamics and drivers. Similarly, Rivers and Jaccard (2010) note the potential for emissions increases in sectors

covered by less stringent policy alongside sectors under more stringent policy, and indicate how policy design might encourage or diminish this phenomenon. However, they do not find a noticeable impact on emissions in the sectors faced with less stringent policy. This chapter provides the first detailed investigation into leakage from the power sector to the uncovered sectors, and how this leakage is affected by power sector policy design. My use of a technology-rich energy economy model enables a deep-dive into the uncovered sectors and their emissions drivers, providing a novel contribution to the literature.

Overall, I found the emissions impacts arising from a power sector policy on the uncovered sectors of the economy to vary by policy design, with some causing a substantial emissions increase in the uncovered sectors relative to business-as-usual (BAU), while others actually causing a decrease in emissions from these sectors. I also found that when emissions in the uncovered sectors are increasing, that the increase is concentrated in a handful of sectors of the economy. For this, and other reasons, policymakers have design levers at their disposal with which to mitigate some of this adverse effect.

I structure the remainder of this chapter as follows. Section 4.2, provides background on the climate policy regime in various countries, while section 4.3 outlines the methods and scenarios. Sections 4.4 and 4.5 describe the scenario results for electricity and the uncovered sectors respectively. Section 4.6 performs a sensitivity analysis, while Section 4.7 then concludes with key policy implications.

4.2 Climate Policy in Advanced Economies

The politics of climate change is such that many of the world largest emitters- China, India, Brazil- are expected to remain on a slower emissions reduction trajectory to provide the opportunity to expand energy use, and associated emissions, in tandem with economic growth and poverty reduction. This suggests that advanced economies will need to bear the brunt of emissions reductions over the next forty years, buying time for emerging economies to first stabilize their emissions, and then start the process towards a de-carbonized economy. Frequently seen emissions reduction targets for developed countries generally amount to a 70%-90% reduction in GHGs from 1990 or 2005 levels by 2050 (IPCC, 2014). Achieving a target of this magnitude will require reductions in practically every sector of the economy. As such, Table 4-1 shows the results of modelling

studies included in the deep de-carbonization pathways project, which charted emissions-reduction pathways to limit global temperature increase to 2°C. These scenarios showed deep de-carbonization requiring significant reductions in end use sectors- transportation, buildings, industry.

Table 4-1: Reductions by Sector

Paper	Target	Country	Electricity & Fossil Fuel Production	Transport	Buildings	Industry
Bataille et al., 2015	90% below current levels by 2050	Canada	21 Mt (Electricity) 167Mt (Fossil Fuel Extraction)	238MT	79MT	85MT
Pye et al., 2015	86% below 2010 levels	UK	117Mt (110% below 2010 levels)	98.5MT (81% below 2010)	58MT (55% below 2010 levels)	56MT (81% below 2010)
Williams et al., 2014	80% below 1990 levels by 2050- US	US	Included in other sectors.	1347-1861MT (Including net reductions from electricity)	799-1025MT (Including net reductions from electricity)	806-1141MT (Including net reductions from electricity)

Modelers and analysts project reductions from these end use sections to be challenging, with reductions tending to occur in the later years of many de-carbonization pathways under optimal or idealized policy, i.e. a well- announced carbon tax progressively increasing with time and covering all emitting sectors of the economy. The IPCC (2014, Figure 6-35, p480) shows greater emissions reductions occurring from industry between 2030 and 2050 than between 2010 and 2030- a 50% reduction vs. only a 6% reduction respectively. Similar findings were present for buildings, with most of the reductions occurring after 2050. By contrast, modelling studies found the global economy to achieve a full de-carbonization of electricity in 2050, with significant reductions by 2030. This temporal dimension is predominantly due to the differing abatement costs from these sectors, with abatement costs in end use being higher than in the power sector.[32]

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[32] For an illustrative example of a marginal abatement cost curve for the global economy, please refer to Figure 2.14 in the IEA's 2008 Energy Technology Perspectives, which shows higher abatement for fuel switching and CCS for industry than electricity and energy efficiency measures (across all ends use) and the scale of global emissions in this category.

In Table 4-2 below, I describe the prevailing policies in the major high-emitting advanced economies.[33] Almost all jurisdictions target electricity with varying degrees of stringency, while other sectors' coverage tends to be minimal at best. Where economies have economy-wide cap and trade schemes or carbon taxes in place, they are mostly set at levels that are too low to induce meaningful reductions in these sectors.

Table 4-2: Policy Regime by Jurisdiction (Green = Relatively Strong; Yellow = Moderate Red = absent or clearly insufficient)

Jurisdiction	Electricity	Buildings	Manufacturing and Fossil Fuel Extraction	Cross Cutting Policy
Germany	Renewable Energy Act- Feed in Tariff to 2017. Replaced by competitive auction system 2017.	Zero-energy building standard for new buildings starting in 2021 2 billion€ in low-interest loans for retrofitting buildings	**Mandatory energy audit** every four years for all large companies – Energy Audit to save 3.4 million tonnes of CO_2, per year	**EU ETS**
Japan	20–22% of electricity from nuclear, 22–24% renewable by 2030. Feed-in tariff and general funding for distribution networks to help achieve renewable target.	2017 revised building energy efficiency standards. Applies to all new builds including residential buildings from 2020 onward. Aims to reduce the average net primary energy consumption of newly constructed buildings and houses to zero by 2030	NA	**Global Warming Tax** - price about $US 3/t CO_2 in 2016.
Canada	Phase out of coal-fired electricity by 2030 (electricity)	Covered by PCF	Covered by PCF	Economy wide carbon price- Carbon price to begin at $10/tonne in 2018 and rise to $50/tonne in 2023. Currently government is deliberating on backstops to reduce the effective tax paid by certain industries.

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[33] I exclude transport policies as the transport sectors are not the focus of this paper's analysis. However, may jurisdictions are starting to impose more stringent policies in this sector.

Jurisdiction	Electricity	Buildings	Manufacturing and Fossil Fuel Extraction	Cross Cutting Policy
Australia	NA	NA	**Safeguard mechanism** to limit emissions increases from large industrial sources to a baseline emissions level. Applies to ~140 facilities with direct emissions of more than 100 ktCO2e.	**Australia's Emissions Reduction Fund- (ERF)-** reverse auction mechanism to purchase abatement- voluntary
US	Clean Power Plan (repealed), New Source Performance Standards Production Tax Credit until 2022	NA	New Source Performance Standards (Methane Regulations)	NA
California	**Electricity:** Renewable Portfolio Standard	**Buildings:** Green Building Standard	NA	**CARB Cap and Trade-** ~$15/tonne
Texas	Renewable Portfolio Standard - above 10% of the state's capacity by 2025	NA	NA	NA
Pennsylvania	Renewable Portfolio Standard- by 2021, 8% of Pennsylvania's electricity must be supplied by Tier 1 resources, (renewable) and 18% (alternative)	Pennsylvania established a statewide building code through in 2005.	NA	NA

Jurisdiction	Electricity	Buildings	Manufacturing and Fossil Fuel Extraction	Cross Cutting Policy
France	Already low- will be replacing its displaced nuclear with renewable (France committed to reduce its share of nuclear generation to 50%)	Covered in carbon Tax	Covered in EU ETS	Carbon tax n 2016 for the use of fossil fuels not covered by the EU ETS Currently US$24/tCO2e Trajectory for the tax rate to gradually increase until 2030, to €100/tCO2e Applies to natural gas, heating oil, coal, and transport fuels not covered by the EU ETS EU ETS

*Policies for jurisdictions from Climate Action Tracker, (2018a)

4.3 Methods and Scenarios

4.3.1 Theoretical Framework

Figure 4-1 below provides a framework as to how a power sector policy might change uncovered sector emissions that do not have a policy in place. On the left-hand side of the figure, the policy design and stringency of the covered electricity sector creates the incentives to adopt cleaner generation technology, thereby changing the fuel mix for the power sector relative to BAU. Moving rightward on this figure, changes to fuel use in electricity will then alter energy prices in the uncovered sectors via two mechanisms: i) by increasing or decreasing the demand, and thus the price, for coal and natural gas; and ii) by changing the cost of generation, which will alter the electricity price facing the uncovered sectors. The stringency and policy design also influences the energy price in the uncovered sectors via the extent to which carbon prices are passed on to final consumers in their electricity bills.

Changes in the prices facing the uncovered sectors will then affect decisions around technology choice, decisions around energy use, and, potentially, to decisions around final product demand for those sectors. All of these factors will change uncovered sector emissions. A feedback loop also would run from the uncovered sectors to the covered power sector, as technology choice within uncovered sectors influences those sectors'

fuel mix, which in turn influences economy-wide fuel prices and investment decisions in electricity.

Figure 4-1: Schematic of Dynamics
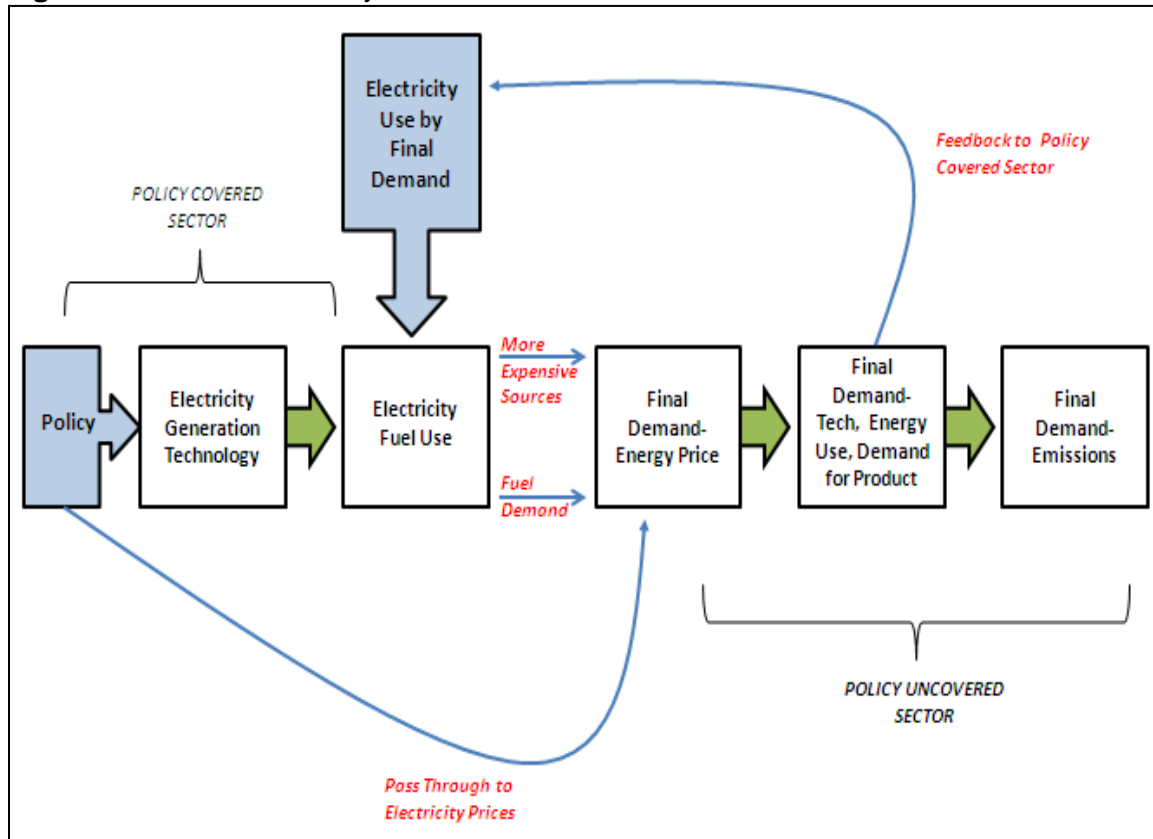
The above schematic is not comprehensive, in that it reflects an economy in autarky. Another pathway by which policy in the power sector could influence emissions in the uncovered sector is through international trade and leakage across jurisdictions. For example, by making domestic goods more expensive relative to foreign goods, the policy might promote the purchase of foreign goods at the expense of domestic goods. This would decrease emissions from the uncovered sectors through a reduction in economic activity (and increase emissions somewhere else in the world), CIMS-US is not a global model, and therefore does not track this impact on emissions elsewhere in the world. However, CIMS models the impact of inter-jurisdictional leakage on US emissions through Armington elasticities, where the demand for a domestic good falls, as its prices rises relative to that of a foreign substitute.

Furthermore, the above schematic does not include some other macroeconomic feedbacks. For example, increases in the price of a fuel would raise the price of products that use that fuel as an input, thereby resulting in less disposable income for households who purchase those products. This in turn means less spending by that household on other emitting products, and subsequently lower emissions. CIMS also captures this income effect through the aforementioned elasticities.

4.3.2 Scenarios

The interconnectedness and extent of feedbacks emphasizes the benefit of an integrated approach. As such, I modeled several power sector policies, either market-based or command-and-control, to project their impact on emissions in the uncovered sectors using the CIMS-US energy-economy model. The policies I modeled are as follows:

- Business-as-usual (BAU)
- Carbon pricing in the power sector- revenues not recycled to consumers but instead added to general government revenues
- Intensity-based performance standard for the power sector where plants earn/surrender credits if their emissions intensity, measured in CO2e/kwh, is below/above a certain level
- A phase out of coal (without CCS) in the power sector by 2040
- A phase out of coal (without CCS) in the power sector combined with a required (70%) share of clean electricity by 2040 (defined here as renewable, nuclear, or CCS)- a clean electricity portfolio standard
- A BAU "minus" scenario, where I removed federal electricity sector policies discouraging coal before 2025.[34] I also removed the additional 3% hurdle rate on coal before 2025 and added subsidies on coal generation.

Mentioned previously was how these policy scenarios were chosen to reflect variation in existing electric sector policies. In addition, each is expected to result in differing impacts on economy-wide fuel prices (as per the mechanisms in figure 4-1), from which to obtain a diversity of drivers on emissions in the uncovered sectors. This diversity will enable me to determine whether the design of the power sector policy influences the direction and magnitude of the change in uncovered sector emissions, which were my main research questions of interest. Below I describe these scenarios in detail, as well as the hypothesized impact each would have on prices, and emissions, in the uncovered sectors.

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[34] Assumes the ideologies / policies of the current US administration remains until 2025.

The BAU scenario includes key existing US power sector policies. The main ones being the states' renewable portfolio standards, the tax production credits for wind and solar to 2022, the Regional Greenhouse Gas Initiative, California's Western Climate Initiative, and the 2015 EPA New Source Performance standards, which bans new coal without CCS. I calibrated energy price forecasts, technology performance and cost parameters for electricity, as well as sector demand for the power and uncovered sectors, to the Energy Information Agency's 2018 Annual Energy Outlook reference scenario.

I modelled two carbon price policies to achieve the following reduction targets relative to 2005 levels: i) a 32% decline in power sector emissions by 2030 as an interim target before rising to a 60% decline by 2040; and ii) a 32% decline by 2030 rising to a 90% decline by 2040. The 2030 target reflects the projected outcome of the aggregated state-specific policies under the CPP, while the 2040 targets were set to reflect varying stringency of power sector policy. The 90% decline in power sector emissions aligns with the, pre-Trump, Mid-Century Strategy that came out of the Paris Agreement (Climate Action Tracker, 2018b).

I modelled the carbon price to reflect a policy design where the proceeds of the carbon price are kept in general revenue rather than being recycled to firms and households. Electricity prices would rise in the model via i) the GHG price passed through to the end consumer and ii) the incremental investment cost of more expensive generation sources being passed on to the consumer. Natural gas prices would rise or fall depending on the policies impact on natural gas use in electricity, while I expect coal prices to fall barring uptake of coal CCS. The final impact on uncovered emissions would depend on the rate of increase in electricity prices relative to the direction and rate of change of natural gas and coal prices.

Another market-based policy I modelled was the intensity standard, where I calculated- a priori- an emissions rate that facilities would need to meet to achieve a 90% reduction in total electricity sector emissions by 2040. This translated to a 90% reduction in power sector emissions intensity, which I modelled exogenously. In an ideal world, a priori projections of electricity generation (the denominator) and emissions (the numerator) under carbon pricing would allow the rate-based policy to achieve the same emissions reductions. However, in reality, output may deviate from the forecast due to interactive effects between the rate-based policy and the rest of the economy, and so emissions in

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the power sector may consequently differ from the target. Whether the policy is, in practice, more or less stringent than originally designed will depend on whether actual electricity generation lies below or above the forecast (Burtraw et al., 2014).

Within CIMS, I modelled the intensity-based standard as a tax-and-rebate tradeable permit policy. Utilities who perform better than the standard earn credits on the amount that their emissions intensity is below the intensity standard specified above. Given that I modeled the intensity standard to be a 90% reduction in emissions intensity, renewables, nuclear, and CCS plants would receive credits while fossil fuel generation without CCS would have to pay credits. Facilities that receive credits can trade these credits to more emissions-intensive utilities, who must surrender credits to offset their emissions above the standard. Given that utilities that exceed the standard earn sellable credits, costs and benefits of the policy are redistributed within the sector, which would prevent upward pressure on rates, and so there is no pass through of the GHG price to the electricity price paid by final consumers. Thus, I expect the effect of the policy on electricity prices to be less than in the no-recycling case above, however I still expect some increase as the policy forces adoption of more expensive generation sources. [35]

A major difference in the impact of the above policies on electricity prices is therefore due to the pass-through of GHG prices to consumers of electricity. Woo et al., (2017) provides a review of the literature on pass-through, in addition to estimating the pass-through of California's carbon price on the wholesale electricity prices for the Western US. They find the existing literature to be inconclusive regarding the extent of the pass-through on electricity prices, with one study out of eight finding no pass-through, but four finding considerable (near-100%) pass-through. Generally, if the own-price elasticity of demand is highly inelastic, the pass-through is expected to be close to 100%, whereas this would decrease the more elastic the own-price elasticity (Woo et al., 2017). The scenarios I explore in this research should therefore be thought of as binding cases, and so the

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[35] While the 2015 US Clean Power Plan (CPP) did inspire the decision to model the rate-based standard, the policy modelled in this paper differs from the CPP in some important respects. For one, the planned CPP was to impose different targets on a state-by-state basis, recognizing the very different electricity generation mixes across the US. The CPP was also flexible, and states could tailor whether to go with a rate-based or mass-based standard. Finally, the CPP faced a hard stop at 2030, and it is unclear what would replace it to achieve the deeper reductions required for the mid-century target.

difference between them due to pass-through may not be as pronounced in some markets where demand for electricity is more elastic.

For the coal phase-out policy, the elimination of coal's use in the power sector is, in-and-of-itself, the target. Thus, emissions may, or may not, meet a percentage reduction target depending on the residual generation mix after the phase out. I modeled the coal phase out in CIMS by adjusting the retirement age for all coal-fired power without CCS, forcing their retirement by 2040. As a variant to the above, I combined a coal phase-out with a clean electricity portfolio standard (CES), which would require 70% of total generation to be from clean, near-zero emissions sources by 2040. The rationale for modelling this policy is to ensure that natural gas does not entirely replace the eliminated coal, and so ensure deeper reductions than what would occur from a one-to-one coal-to-gas substitution in electricity. I expect the coal-phase to result in a greater increase in natural gas prices relative to electricity prices in the uncovered sector, as this policy will result in increased gas use in electricity to replace the displaced coal. Although new investments would be required for the power sector, the favorable competitive position of natural gas generation is unlikely to raise rates by much. By contrast, adding the CES to the coal-phase out may temper this increased use of natural gas in electricity, driving up electricity prices.

Finally, given the energy and emissions policy changes since the replacement of President Obama by Trump in 2016, I also modelled a BAU "minus" scenario, which includes:

- The removal of the EPA's New Source Performance Standards that effectively ban new coal without CCS, for the 2020-2025 period.
- The introduction of a subsidy to coal by the amount of coal's non-fuel operating and maintenance costs
- A removal of the additional 3% hurdle rate on coal before 2025 reflecting increased investor sentiment towards coal

Although this scenario would likely see a considerable increase in emissions for the electric sector- making the policy's knock-on impacts on uncovered sector emissions trivial by comparison, I would actually expect a reduction in emissions in manufacturing where natural gas would substitute for coal in sectors where the latter fuel is still prominent.

4.3.3 Energy Prices

Given my primary interest is in discerning the effects that an electricity sector policy has on energy prices, and thereby energy use and emissions in the uncovered sectors, CIMS's capabilities to endogenize relevant energy price is of key importance in order to generate internally consistent results. Overall, the key energy sources where US demand and economic activity can substantially influence US prices are electricity and natural gas, both of which are endogenous to the model.

By contrast, the underlying crude oil and coal prices are exogenous. While the US remains the largest oil consumer in the world, very little of this is in the electricity sector, and so I do not expect electricity sector policy to change the price of oil facing the uncovered sectors. Coal too is a globally traded commodity, and while the US does use a considerable amount of coal in its power sector, it has become a relatively small player in global coal markets due to the rise of China and India. Currently the US makes up only 5% of global demand of coal, which is not limited to the power sector. Thus, I begin my runs with a working assumption that changes in coal use in the US power sector due to climate policy do not greatly affect coal prices facing the uncovered sectors.[36] To mitigate risks around this assumption, I model a low-coal price scenario for the uncovered sectors as a sensitivity run later in this chapter.

4.3.4 Power Sector Assumptions

To model the power sector within the structure of CIMS, I divide electricity demand into baseload, shoulderload, and peakload based on their approximate splits of total demand- 67%, 31.3%, and 1.7% respectively. These splits were derived from the shape of several load duration curves- Texas, North Carolina, New England and New York- which, taken together, are fairly representative of US load as a whole (Hadley, 2007; Kassakian et al., 2011; Denholm & Margolis, 2007).

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[36] The price of coal varies by quality and heat content of coal (rank and grade), how it is mined (underground or surface), and geographic location, with transport costs playing a large role (EIA, 2018h). US Appalachian coal prices are priced as such in global spot markets for coal, but move in correlation with other coal price indicators from different deposits (British Petroleum, 2018). In 2017 the US exported about 5% of the total thermal coal it produced (EIA, 2018i)

Within each split, electricity generation options compete to meet the demand for that split. Different generation options compete in each split based on their relative economics and their ability to ramp up in order to load-follow. In the baseload share, therefore, all technologies are able to compete as load-following is not a necessary attribute for this split. For example, intermittent renewables are able to compete in this share without any financial penalty. In the splits that require load-following, namely the shoulderload and peakload splits, intermittent renewables require battery storage in order to be able to match increasing load. In addition to battery-storage, for this split I model a renewable-natural gas hybrid technology that operates as its own micro grid where firm natural gas capacity matches intermittent renewable at a ratio of 1:2. Also, for these load-following splits, nuclear is not allowed to compete until the advent of advanced high-temperature gas reactors (post-2030), which are expected to have a faster ramp rate, and thus superior load-following capability relative to the current fleet of nuclear reactors. All other technologies can compete in the shoulderload split. The peakload split is limited to generation from gas and oil- both with and without CCS- and hydro. I assume the share of total electricity demand for each split to remain constant throughout the simulation run.

I acknowledge that this approach for modelling electricity deviates from many of the prevailing modelling approaches, which use hourly, or even sub-hourly, dispatch models to model generation. These latter approaches have the advantage of modelling real-world system operations, where generators bid for the right to generate according to marginal cost of generation, and the system operator aligns generators in a dispatch order of lowest to highest marginal cost. CIMS does not do this, and so may overstate or understate generation from a particular source due to this division of electricity generation into three discrete sub-markets. For example, if a technology wins part of the market share competition in baseload, the model will assume that the plant is always running at its full capacity factor specified in the model. In reality, even baseload sources with firm capacity (e.g. nuclear or coal plants) do not always run at their idealized (90%) capacity factor due to the economics of the markets they operate in, or due to technical reasons.

In addition, CIMS may overstate the potential for intermittent renewables to make up the generation mix by allowing intermittent generators to compete, penalty free, within the baseload split. This means that, in theory, the grid could achieve ~68% intermittent renewable in CIMS before incurring costs associated with additional flexibility measures-which in CIMS is only represented by battery storage and through the natural gas/hybrid

system described above. While it may be possible for intermittent renewable to achieve such high levels of penetration without the need for battery storage, it likely won't be costless as investments in flexibility (e.g. additional transmission, pumped storage, smart grid investments) will be needed to balance the system. Thus, as currently designed, CIMS may overstate the potential for intermittent renewables.

Table 4-3 below illustrates the power sector capital cost inputs and assumptions for CIMS, while the following Table 4-4 compares these to a number of other sources in the literature. O&M and efficiency data for generation options used in CIMS are located in appendix C.

Table 4-3: Power Sector Capital Cost Inputs and Assumptions- CIMS

Tech	Avail	Capital Cost- 2010 ($/KW 2005)	Capital Cost- 2020 ($2005/KW)	Capital Cost- 2025 ($2005/KW)	Cost Trend
Coal	2000	Same as 2020	$2560	Same as 2020	No Declines
Coal-30% CCS	2020	Same as 2020	$5089	Same as 2020	Capture Portion Endogenous (LR=15%)
Coal- 90% CCS	2020	Same as 2020	$5628	Same as 2020	Capture Portion Endogenous (LR=15%)
Natural gas combined cycle (NGCC)	2000	Same as 2020	$982	Same as 2020	No Declines
Advanced NGCC	2010	Same as 2020	$1108	Same as 2020	No Declines
ADV NGCC w CCS	2020	Same as 2020	$2175	Same as 2020	Capture Portion Endogenous (LR=15%)
Single Cycle Gas Turbine	2000	Same as 2020	$1107	Same as 2020	No Declines
Adv comb turbine*	2010	Same as 2020	$680	Same as 2020	No Declines
Nuclear	2000	Same as 2020	$5946	Same as 2020	No Declines
Biomass	2000	Same as 2020	$3837	Same as 2020	No Declines
Geothermal	2000	Same as 2020	$2746	Same as 2020	No Declines
Hydro	2000	Same as 2020	$2898	Same as 2020	No Declines
Onshore Wind	2000	$1855	$1336	Same as 2020	Exogenous up to 2025; No Declines thereafter

Tech	Avail	Capital Cost- 2010 ($/KW 2005)	Capital Cost- 2020 ($2005/KW)	Capital Cost- 2025 ($2005/KW)	Cost Trend
Solar PV	2010	$5822	$1315	$1179	Exogenous up to 2025; Endogenous Thereafter (LR = 10%)
Small Modular Reactor (SMR)	2030	NA	NA	$5946 (2030)	Endogenous (LR = 10%)
Intermittent Renewable with Battery Storage*	2025	NA	NA	$5054	Endogenous (LR = 15%)

*Shoulderload only

Table 4-4: Power Sector Capital Cost Inputs and Assumptions- Other Models

Technology	Capital Cost by Source (2020 Availability)- $2005			
	EPRI (2018)	Lazard (2017)	IEA (2017)	NETL (2018)
Coal	$2409	$2380 - $6380	$1750	Same as EIA
Coal-30% CCS	$3827	NA	NA	Same as EIA
Coal- 90% CCS	$4091	NA	$4365	Same as EIA
Natural gas combined cycle (NGCC)	$1073	$555-$1036	$794	Same as EIA
Advanced NGCC	NA	$555-$1036	NA	Same as EIA
ADV NGCC w CCS	$2109	NA	$2421	Same as EIA
Single Cycle Gas Turbine	$755	NA	$397	Same as EIA
Adv comb turbine*	NA	$635-$794	NA	Same as EIA
Nuclear	$5127	$5158-$9365	$4166	Same as EIA
Biomass	$4227	$1288-$3151	$2041	Same as EIA
Geothermal	$4973	$3278-$5245	$2222	$3969
Hydro	$1818	NA	$2250	$4772
Onshore Wind	$1418 (1281-1554)	$952-$1350	$1383	$1335
Solar PV	$1190	$866-$1105	$1350	$688-$930

Technology	Capital Cost by Source (2020 Availability)- $2005
	(1063-1772)

*Shoulderload only

4.3.5 Inter-Sectoral emission leakage rate

Under each policy scenario, I tallied the emissions projections from CIMS occurring in all sectors of the economy in order to assess the effectiveness of each policy on: i) GHG reductions achieved from the power sector; and ii) GHG reductions achieved economy-wide. Mentioned previously was the rigour that CIMS can bring to this type of analysis for the uncovered sectors, due to its technological explicitness and detailed representation of these sectors.

I measure the emissions impact of electricity sector policy on the uncovered sectors by calculating an inter-sectoral emission leakage rate, which is the change in uncovered sector emissions induced by the policy, divided by the change in power sector emissions due to the policy. This is a relative measure of increased emissions in the uncovered sector. A high leakage rate means that there is a large increase in emissions for the uncovered sectors, relative to the reductions in electricity induced by the policy. A low leakage rate could be due to few absolute emissions changes in the uncovered sectors, but also due to any emissions changes in those sectors being small relative to the magnitude of the power sector reductions induced by the policy. "Negative leakage" might occur when uncovered sector emissions are lower after the introduction of the power sector policy relative to BAU.

4.4 Results and Discussion: Power Sector

Figure 4-2 below illustrates the GHG emissions trends for the power sector, as a percent below 2005 levels, by scenario to 2040. A number of illustrative findings stem from this figure. The first is that CIMS does an excellent job of mimicking the historic trend of power sector emissions under the reference case, as the US has witnessed actual declines in emissions in the power sector by 28% since 2005.[37] Although the projections from CIMS show a slight deceleration of this trend in the next 10 years, the second key finding from this figure is that CIMS achieves the projected 32% reduction purported to come from the

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[37] CIMS also backcasts very well to historic data for the electricity generation mix as per Appendix A.

CPP without any additional policy measures to BAU. This result implies that should certain states with high power-sector emissions intensities impose measures under the CPP that achieve incremental reductions to BAU, the actual reductions from the CPP may potentially exceed the 32% reduction projected by the US Government.

Figure 4-2: Power Sector Emissions (Percentage below 2005 levels)
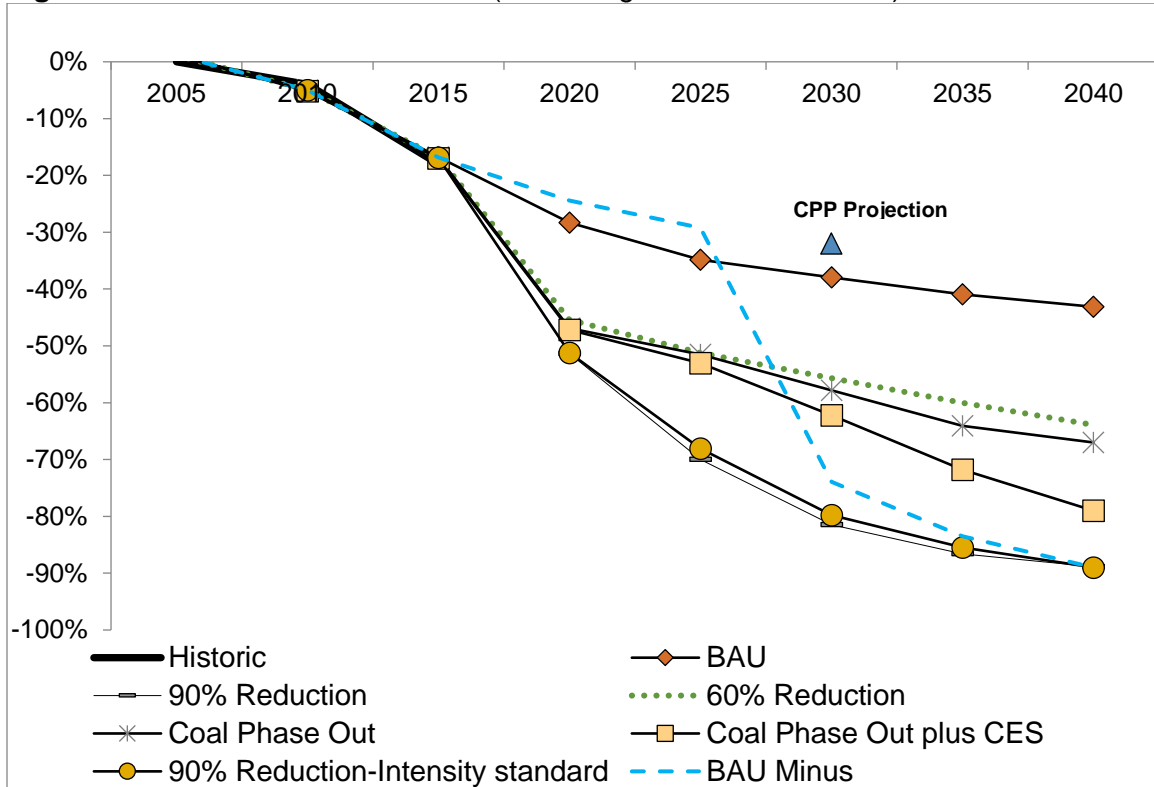
Regarding emissions under the policy scenarios, the carbon pricing policies achieve their stated emissions targets by design. The intensity standard, by contrast, does not guarantee a quantity of emissions reductions, but instead guarantees a reduction in fleet-wide intensity for the power sector. For the 90% target, the level of intensity standard modelled here does result in comparable emissions by 2040 relative to the carbon pricing policy, although the rate at which it achieves that target is somewhat slower than under carbon pricing.

The coal phase out, and coal phase out combined with a CES, were command-and-control regulations that prescribed a certain technology mix for the power sector (an absence of coal and a certain fraction of clean sources). Thus, these policies did not explicitly state an emissions reductions target. From my projection, I find the resulting decrease in power-

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sector emissions for these policies to lie between the 60% and 90% reductions from the weak and stringent carbon pricing policies. The BAU "minus" scenario, as expected, has higher emissions than BAU for the 2020 to 2025 period, as incremental coal generation is favored under this scenario at the expense of natural gas use that would otherwise occur. After 2025, the emissions decline needs to be steeper and the policy response, in terms of the magnitude of the required carbon price, needs to be stronger to achieve the same 2040 target.

The Figures 4-3 and 4-4 below illustrate the electricity generation mix for the BAU and the stringent policy scenario without revenue recycling. The BAU scenario sees a rapid increase in natural gas use in electricity generation and has natural gas becoming the dominant source of electricity generation over much of the simulation. This increased natural gas use primarily replaces coal and, to a lesser extent, nuclear. Generation from renewables increases from 17% in 2017 to 31% in 2040. Much of the growth of renewables is due to favorable economics, with declining capital costs seen for onshore wind to 2025, and considerable declines for solar until the end of the simulation. Also in line with existing trends in US electricity markets is the gradual decline of nuclear across the policy simulations by 2040.

The results for the stringent policy scenario in Figure 4-4 show non-hydro renewables becoming the dominant source of generation, making up 51% of the total. Coal is no longer a meaningful source of electricity in the US power sector under stringent policy, while natural gas makes up only 31% of total generation by 2040. While roughly the same as its current proportion, this is considerably below its 2040 share under BAU. Another important difference is that two-thirds of this natural gas generation under the policy scenario comes from facilities coupled with CCS. Nuclear's share is virtually identical as under BAU.

Figure 4-3: Electricity Generation Mix BAU
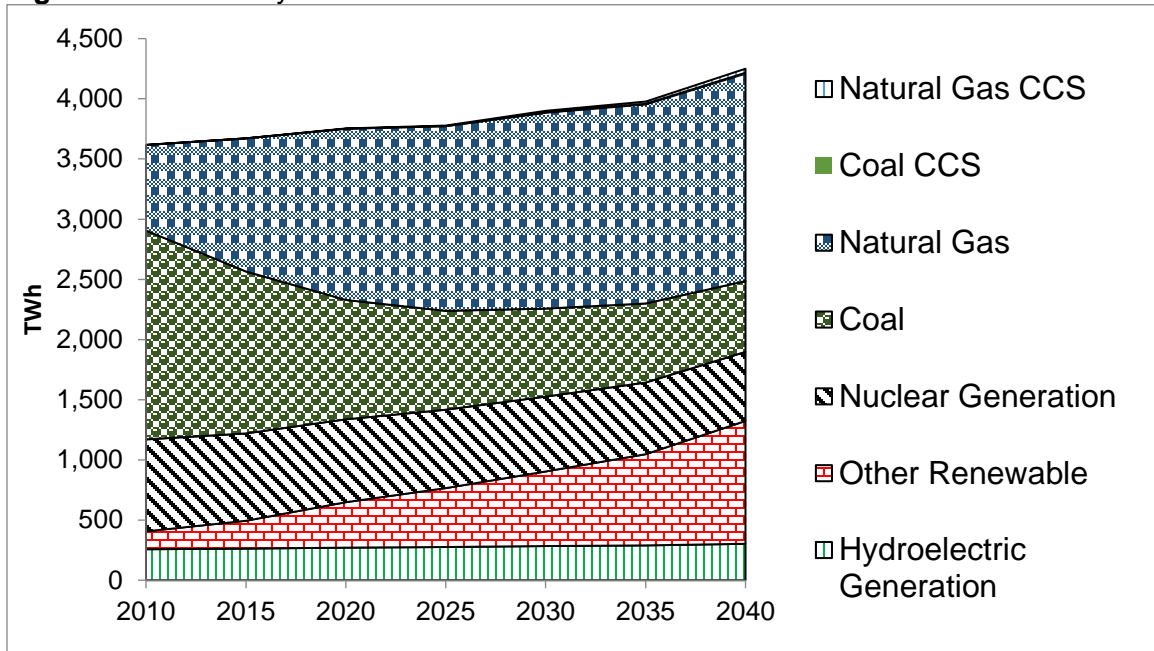
Figure 4-4: Electricity Generation Mix Stringent Policy Scenario- No revenue recycling
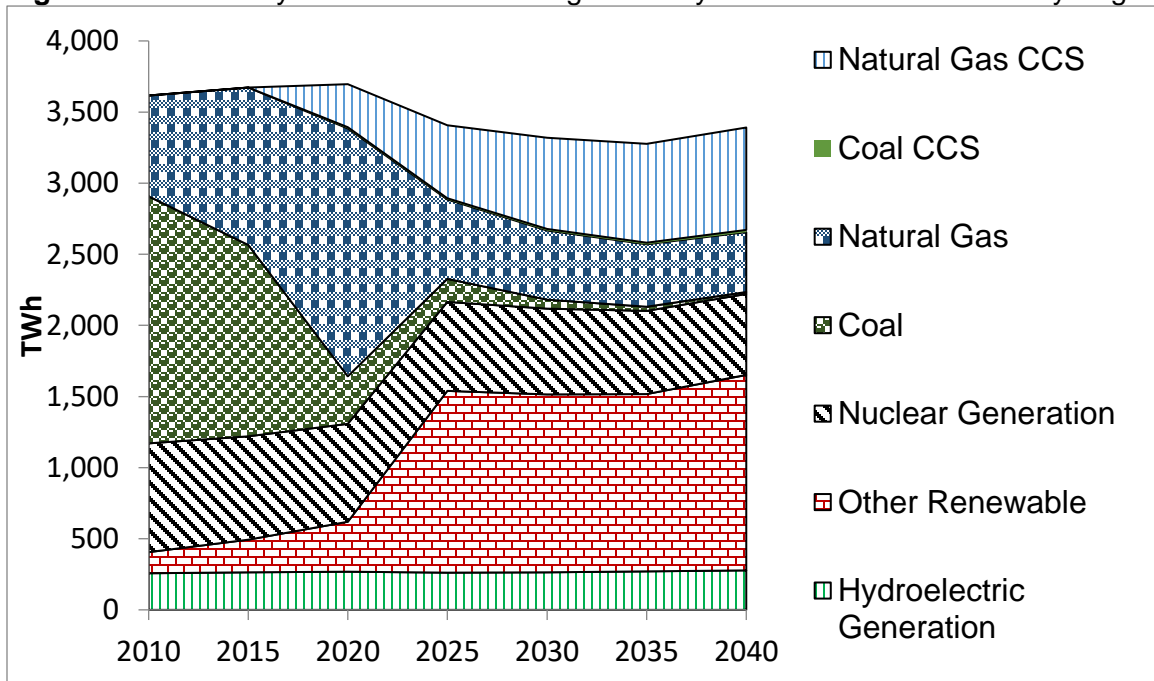
Other figures in Appendix D illustrate the generation mix in the remaining policy scenarios. I find an increase in the use of natural gas in most scenarios, even the BAU minus scenario. A notable exception is under the weaker carbon pricing scenarios where the carbon price is not high enough to induce natural gas with CCS and so natural gas use declines in 2040 relative to current levels.

4.5 Results and Discussion: Uncovered Sectors

Figure 4-5 below illustrates the inter-sectoral emission leakage rate for the scenarios. Under the Coal Phase Out and Coal Phase Out plus CES policies, overall leakage to the uncovered sectors is negative, indicating that emissions reductions are occurring in both the power sector and the uncovered sectors under these policy designs. The figure also shows the sectoral composition of the leakage.

Overall, where there is net positive leakage, it can be quite significant, approaching up to 12% of the reductions in the power sector under some scenarios. The figure also illustrates that this leakage is primarily concentrated in the residential, chemicals, and other manufacturing sectors. By contrast, the other uncovered sectors witness a negligible emissions response, while emissions from the upstream fossil fuel sectors witness negative leakage due to the greater use of renewables in electricity generation.

Figure 4-5: Leakage rate by policy (percentage)
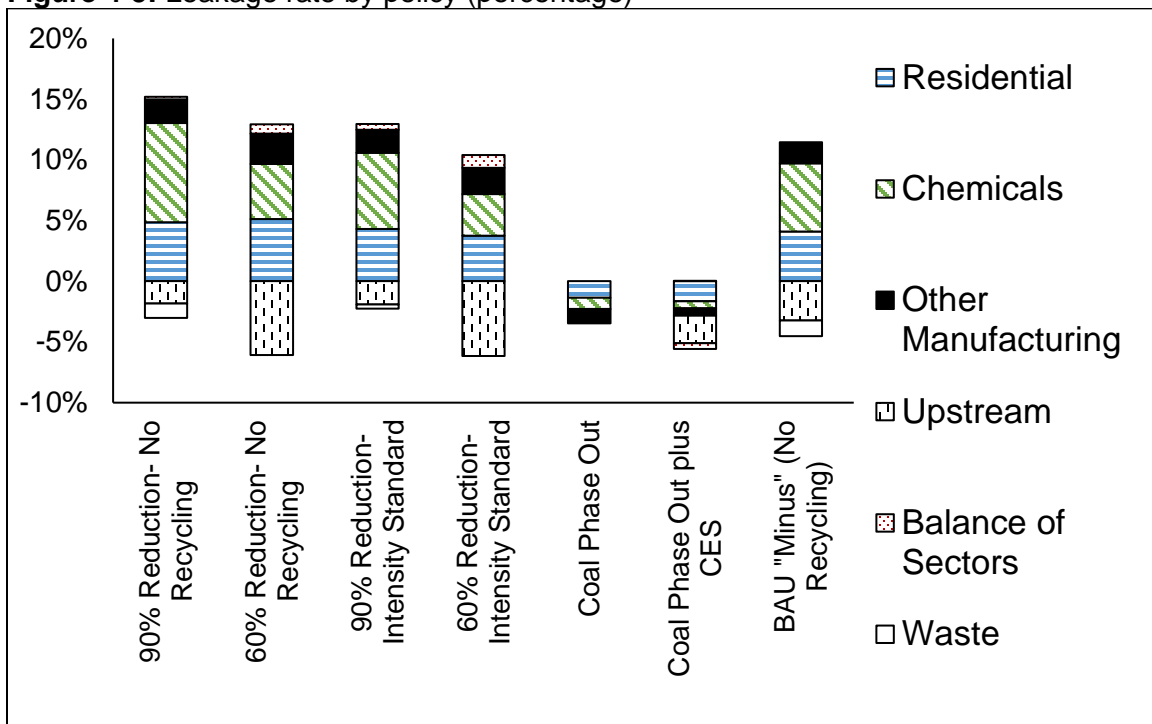
*Other Manufacturing includes sub-sectors of food, fabricated metal products, machinery, computers, wood products, transport equipment, plastics, and a balance of all other manufacturing products. Waste includes emissions from methane that can be mitigated by either flaring or producing electricity from incineration. Upstream includes emissions from natural gas extraction, processing and transmission, crude oil extraction, and coal mining.

As expected, the design of the power sector policy influences the direction and magnitude of the change in uncovered sector emissions relative to BAU. Firstly, carbon-pricing policies inducing greater reductions from the power sector witness higher relative emissions leakage than less stringent policies. Secondly, the carbon-pricing policy, which does not have any form of revenue recycling, has higher relative leakage than the intensity-based standard, which is a policy of comparable stringency but that recycles revenue to the electricity sector. Thirdly, as mentioned previously, the command-and-control phase-out policies witness negative leakage, which contributes to the aggregate emissions reductions for these policies. Despite this positive feature, total emissions reductions for these command-and-control policies are still below any of the stringent market-based policies due to fewer reductions occurring from electricity.

The figures 4-6 to 4-8 provide insight to the rationale for these emissions trends by illustrating the difference in 2040 energy use from BAU for the three uncovered sectors with the largest emissions increase— residential, chemicals, and other manufacturing.

Figure 4-6: Difference in Energy use from BAU- Residential (annual 2040)
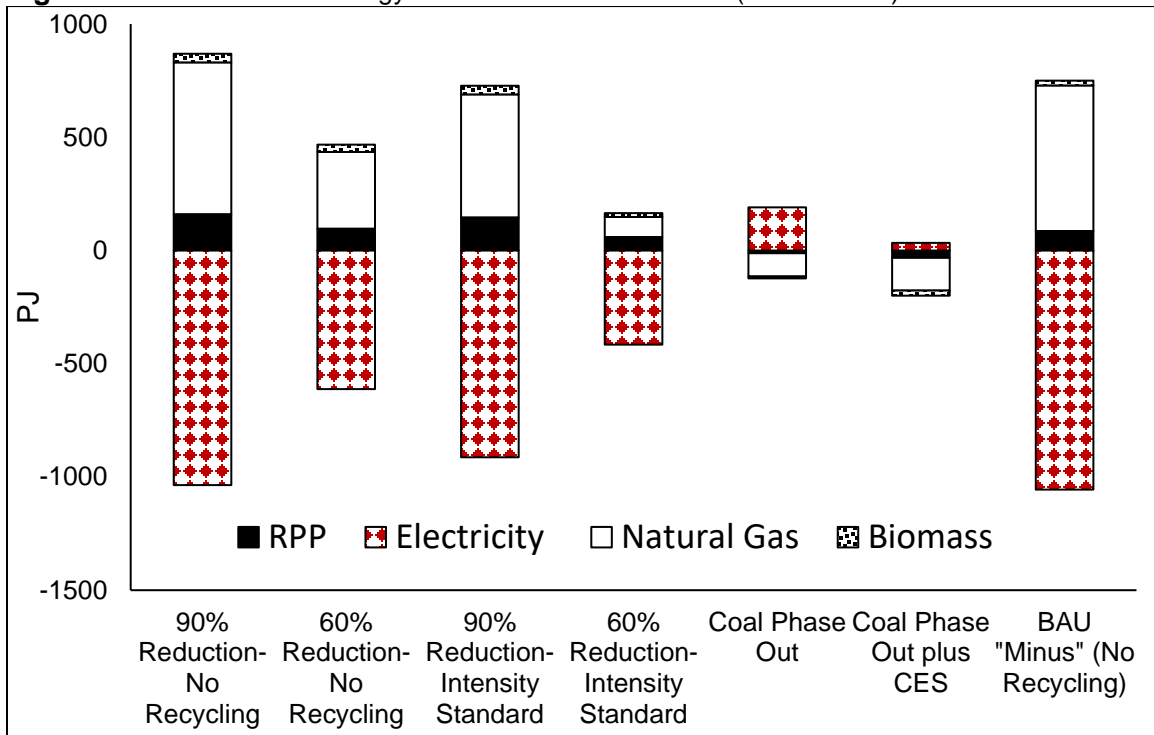
Figure 4-7: Difference in Energy use from BAU- Chemicals (2040)

Legend: RPP ▪ Electricity ▦ Natural Gas ☐ Coal ▦ By-Product Gas ▥

X-axis: 90% Reduction-No Recycling | 60% Reduction-No Recycling | 90% Reduction-Intensity Standard | 60% Reduction-Intensity Standard | Coal Phase Out | Coal Phase Out plus CES | BAU "Minus" (No Recycling)

Y-axis: PJ (-1500 to 1500)
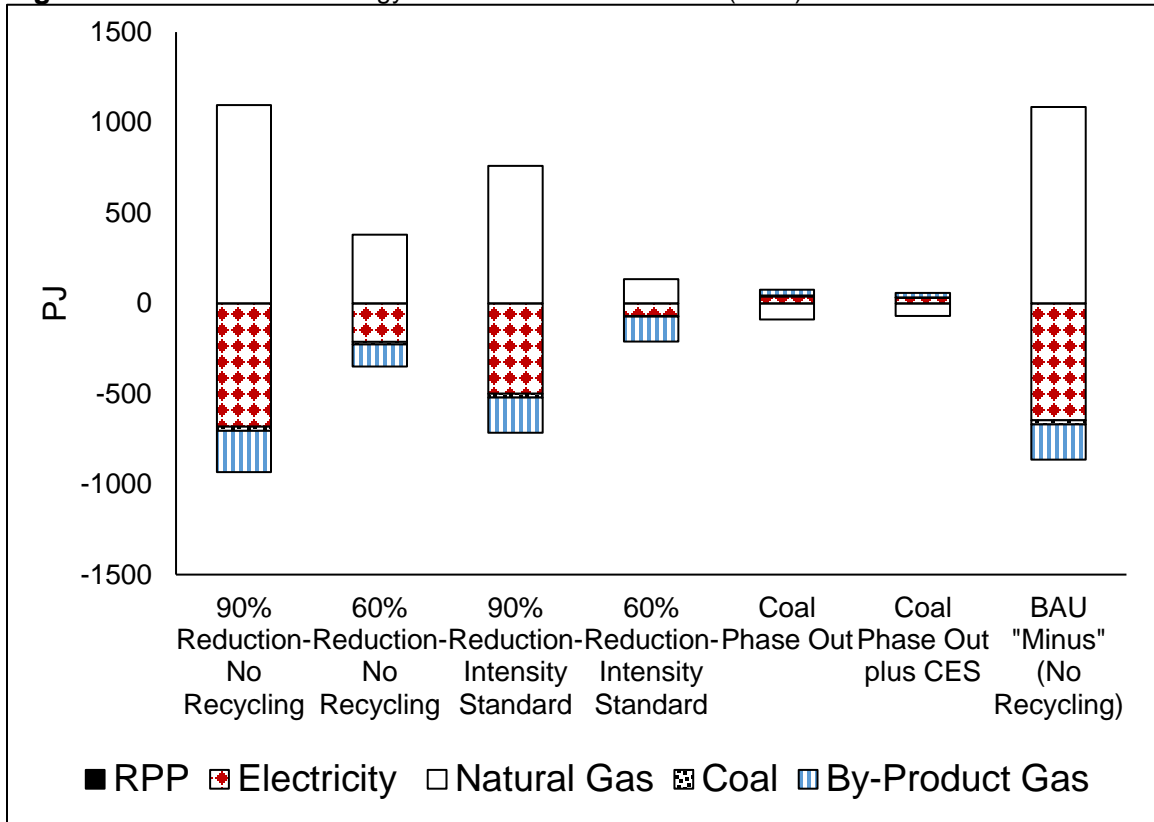
Figure 4-8: Difference in Energy use from BAU- Other Manufacturing (2040)

Legend: RPP ▪ Electricity ▦ Natural Gas ☐ Coal ▦ Biomass ▥

X-axis: 90% Reduction-No Recycling | 60% Reduction-No Recycling | 90% Reduction-Intensity Standard | 60% Reduction-Intensity Standard | Coal Phase Out | Coal Phase Out plus CES | BAU "Minus" (No Recycling)

Y-axis: PJ (-500 to 500)
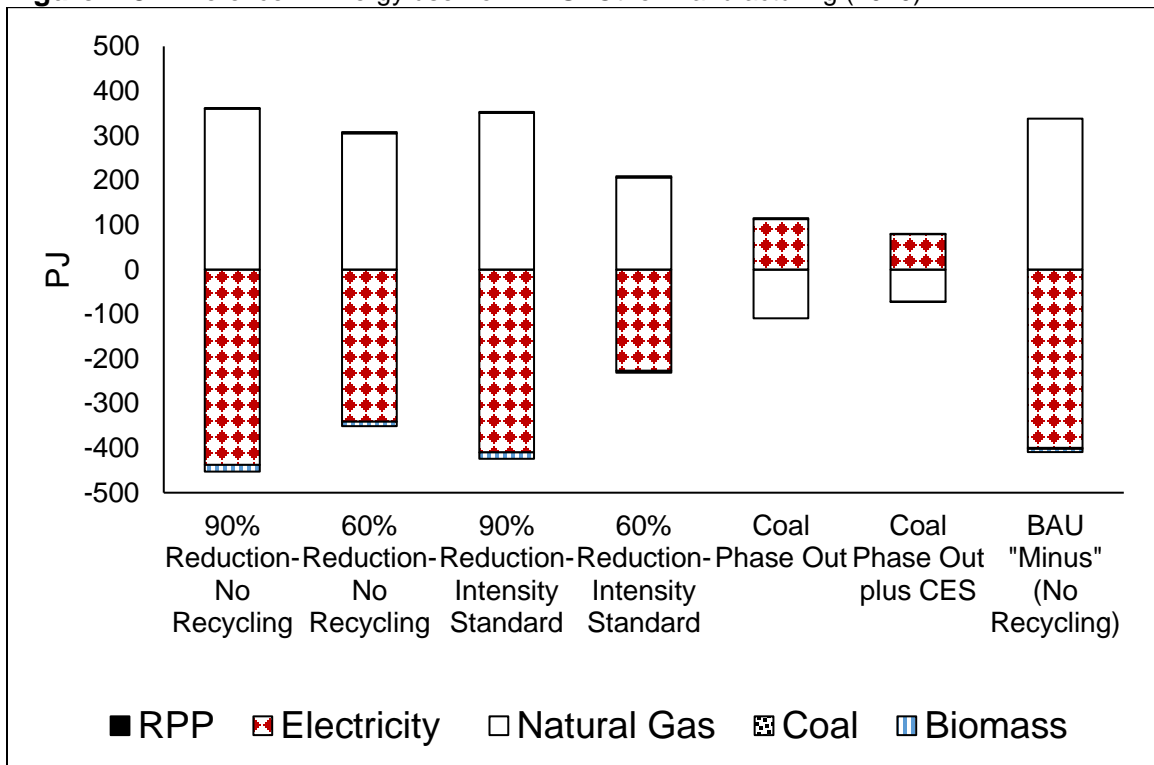
For all these sectors, the market-based policies induce more natural gas use, and less electricity use, compared to BAU. In contrast, the command-and-control regulations saw the opposite effect, a move away from natural gas and towards electricity, which caused the net reductions under these policies. The other manufacturing sector witnesses what is essentially a pure electricity-to-gas substitution, with other fuels' involvement being minimal. While substitution from electricity to gas is also the primary form of fuel switching occurring in the residential sector, residential also experiences a noticeable increase in RPP use under the carbon pricing policies.

The chemicals sector is the major driver of the differences in uncovered emissions between the policies, particularly the carbon-pricing policy. Driving these higher emissions is the magnitude of the electricity-to-gas substitution, exceeding that of any other sector, as well as the decreased use of by-product gas, with its lower emissions intensity than natural gas, relative to BAU.

Figure 4-9 below shows the importance in relative price changes between the policy scenarios and BAU in explaining the energy use and emissions differences between the scenarios. Those policies which see the greatest increase in uncovered sector emissions relative to BAU, and thus the highest relative leakage, are those where electricity prices are increasing by a greater extent than natural gas prices. This change in relative prices proceeds to favor gas-utilization at the expense of electrification of the end use sectors. While some scenarios show increases in the electricity price relative to BAU by 70%, which is evidently high, these increases are likely an upper bound of the possible price increase induced by the carbon price scenarios. I modelled these carbon-price scenarios such that utilities were fully able to pass through the carbon price costs to the consumer.

Figure 4-9: Percent price difference from BAU by fuel and sector
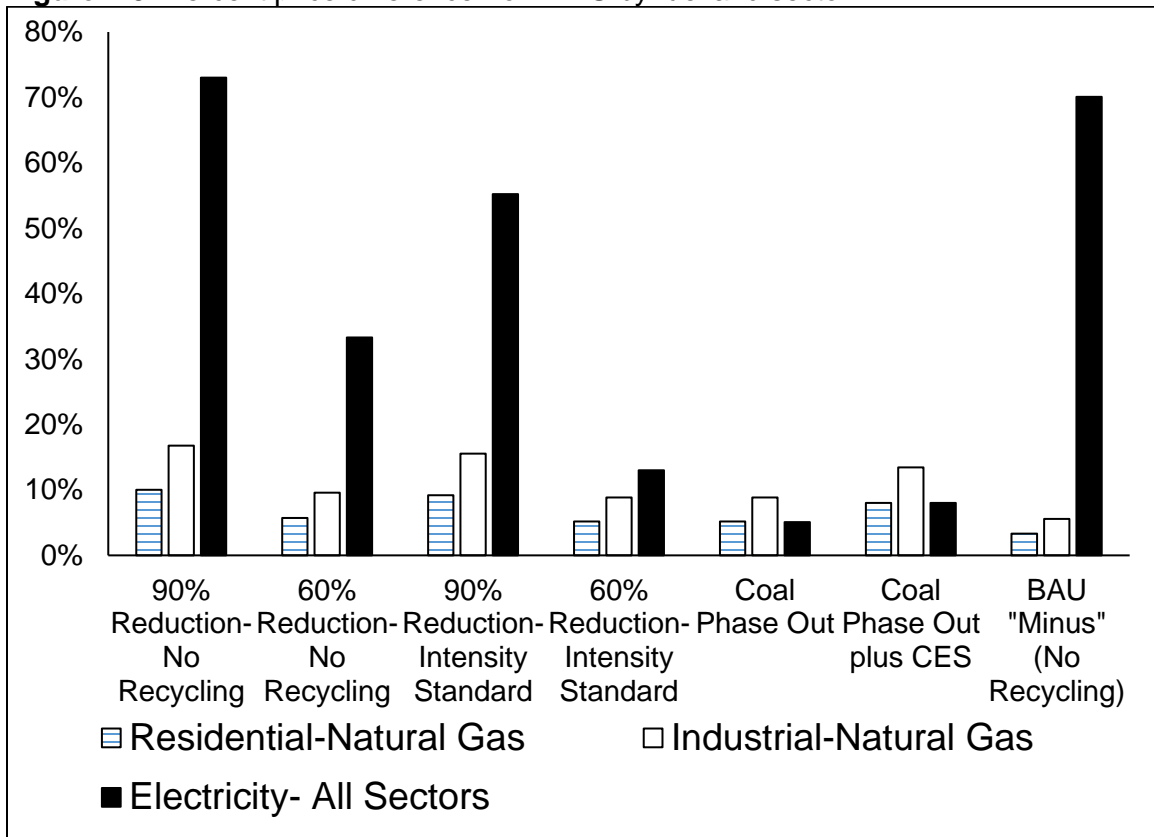
Factors driving up the electricity price, and that are common across the market-based policy scenarios, are that the carbon price induces a shift to more expensive generation sources, reflected in higher rates, as well as the pass through of the costs of emitting utilities needing to purchase credits described above. However, as expected the design of the policy plays a key role in the magnitude of this price increase. Less stringent market-based policies induce less of a price change, due to the lower carbon price incentivizing less costly generation technology and there being lower carbon costs. Amongst more stringent policies, those where revenues are redistributed to the power sector by utilities that can earn and sell credits, see less upward pressure on electricity prices, less of an electricity-to-gas substitution, and less emissions relative to BAU.

The non-market based policies face a different dynamic, as there is no price on carbon being passed-through to consumers. While electricity prices are higher than BAU under these scenarios, due to the costs associated with forced early retirement of some coal plants, and the switching to costlier generation, the magnitude of the increase is quite low given the extent of the power sector emissions reduced. The consequence is that

electricity prices do not increase by enough to induce the fuel substitution seen under the stringent market-based policies, and so emissions do not increase from the electricity-to-gas substitution seen under the latter.

Using the technological explicitness of CIMS to delve further into chemicals production, the sector driving much of the perverse result with respect to uncovered emissions, I observe differences in the adoption of cogeneration, as well as the type of technology used for cogeneration, across the policy scenarios. Figure 4-10 below illustrates projections for steam production between 2030 and 2040 from cogeneration in chemicals under BAU, alongside two market-based designs of the stringent policy modelled in this chapter. The chemicals industry has historically been one of the largest adopters of cogeneration, a phenomenon that has been increasing in recent years due to low natural gas prices. The BAU scenario reflects this preponderance of cogeneration in chemical manufacturing, which makes up almost 87% of the total steam production in the industry by 2040. This trend is accentuated under the policy scenarios, where the new energy prices facing the uncovered sectors induces further switching to cogeneration for heat and power. Consequently, cogeneration use in chemicals is about 6.5% higher under the policy cases relative to the reference scenario.

Figure 4-10: Cogeneration use in Chemicals by a Selection of Scenarios
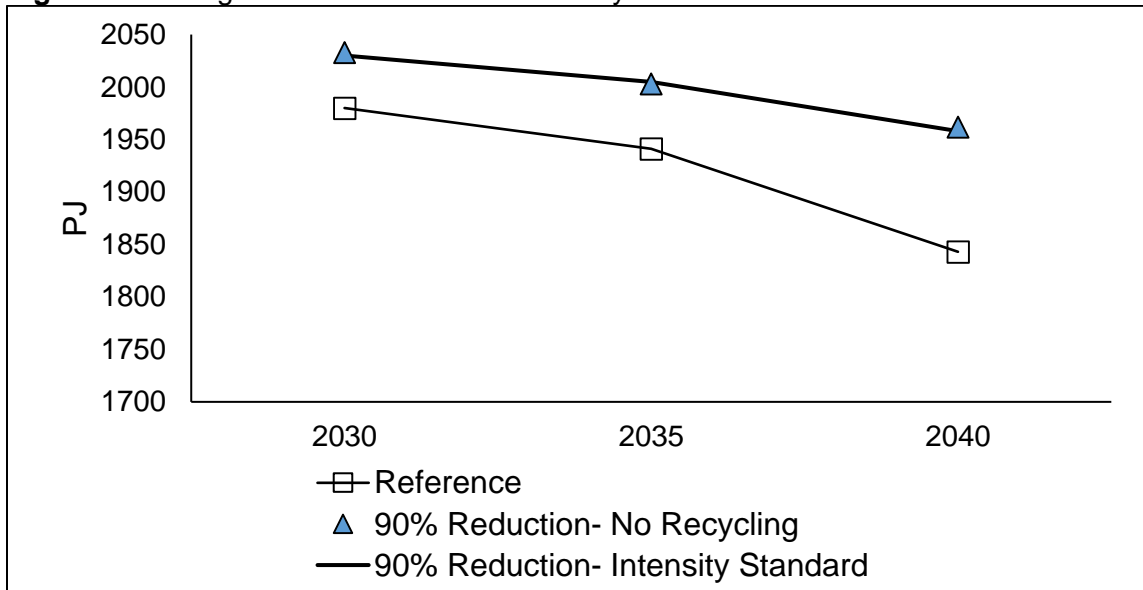
However, also clear from Figure 4-10 is that the absolute energy produced from cogeneration under the two policy scenarios does not differ practically from one another,

despite their differences from BAU. The explanation of the emissions differences in chemicals between these scenarios is rather due to there being important differences in *type* of fuel they use for cogeneration. From Figure 4-11, we see carbon pricing without revenue recycling to result in greater adoption of natural gas cogeneration at the expense of by-product gas generation, with the former having higher emissions intensities than the latter.

Figure 4-11: Technology use for cogeneration
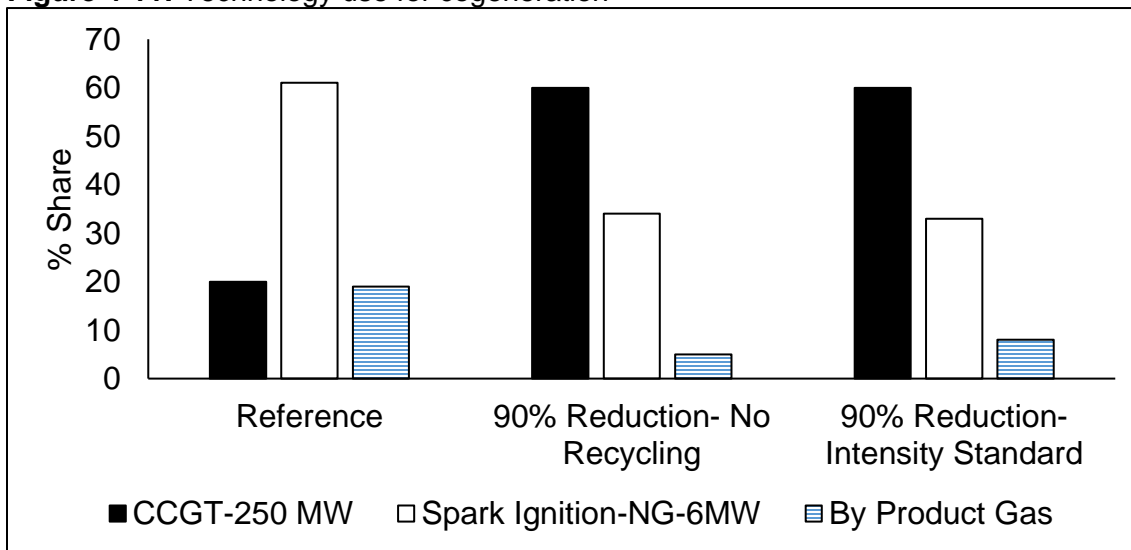
The other manufacturing sector also witnesses an increase in cogeneration, especially in the scenario without revenue recycling. To limit the increase in uncovered sector emissions, policymakers will need to address this finding concerning cogeneration in considering the design of a power sector policy. In the sensitivity analysis to follow, I show that simply by expanding the policy to cover cogeneration units can substantially reduce this perverse effect, and prevent much of the leakage of emissions from the power sector to the uncovered sectors arising from cogeneration.

In contrast to the chemicals and other manufacturing sectors, I find increased residential sector emissions arising due to a broad movement from electric to natural gas appliances, with no particular area standing out. For example, under BAU, 23% of the cooking ranges are electric, which decreases to 16% under stringent policy when revenues are not recycled, and to 19% under the intensity standard. These electric ranges are more than twice as efficient at the point of end use as the standard natural gas range they are replacing- requiring about 56% less energy input- and result in no emissions at the point

of end use. Other areas that see significant changes by 2040 are furnaces, where 37% are electric under BAU, but 100% become gas-powered under the policy cases. Water heaters are another example of this "de-electrification", being 44% electric in 2040 under BAU, but become only 14% and 23% electric under the carbon pricing and intensity standard policies respectively.

4.6 Sensitivity Analysis

Building on the work above, I conducted a sensitivity analysis on two key input variables— the coal and natural gas prices in the uncovered sectors. As mentioned previously, coal prices are exogenous to CIMS US. While globally the US has become a less influential actor on the price of coal in recent decades, a downward shift in the demand curve for coal would result in a decrease in the price of coal as per the own-price elasticity of the relevant supply curve for coal. Work by Dahl and Duggan (1996) calculated the elasticity of supply for Appalachian coal to range from 0.41 to 7.9. Taking the midpoint of 4.15, I use this elasticity to approximate the coal-price change that would occur due to the policy-induced reduction in coal use in the power sector. I then reran the model with those coal prices in electricity and industry to how this affects the results for both these sectors.[38] Next, I ran CIMS with higher and lower natural gas prices, taken from the EIA's 2018 Annual Energy Outlook low oil and gas resource scenario. While natural gas prices were endogenous to CIMS in the other runs, I ran the model with fixed gas prices at the new price levels for the purpose of this sensitivity.

I performed the above analysis on only a subset of the policy scenarios, the carbon price without revenue recycling and the intensity standard, both to achieve the 90% reduction target, as these scenarios yielded the largest emissions response. For these policies and sensitivities, Figure 4-12 compares the leakage rate alongside to those calculated for the base policy runs.

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[38] The purpose of re-running the price change in electricity was to see if there was an impact on continued coal use within electricity itself. Overall, the roughly 20% decline in coal price was insufficient to incent any meaningful retention of coal-fired generation (new coal-fired generation without CCS was made unavailable to reflect the EPA's 2015 New Source Performance Standards).

Figure 4-12: Leakage rate by policy (percentage)
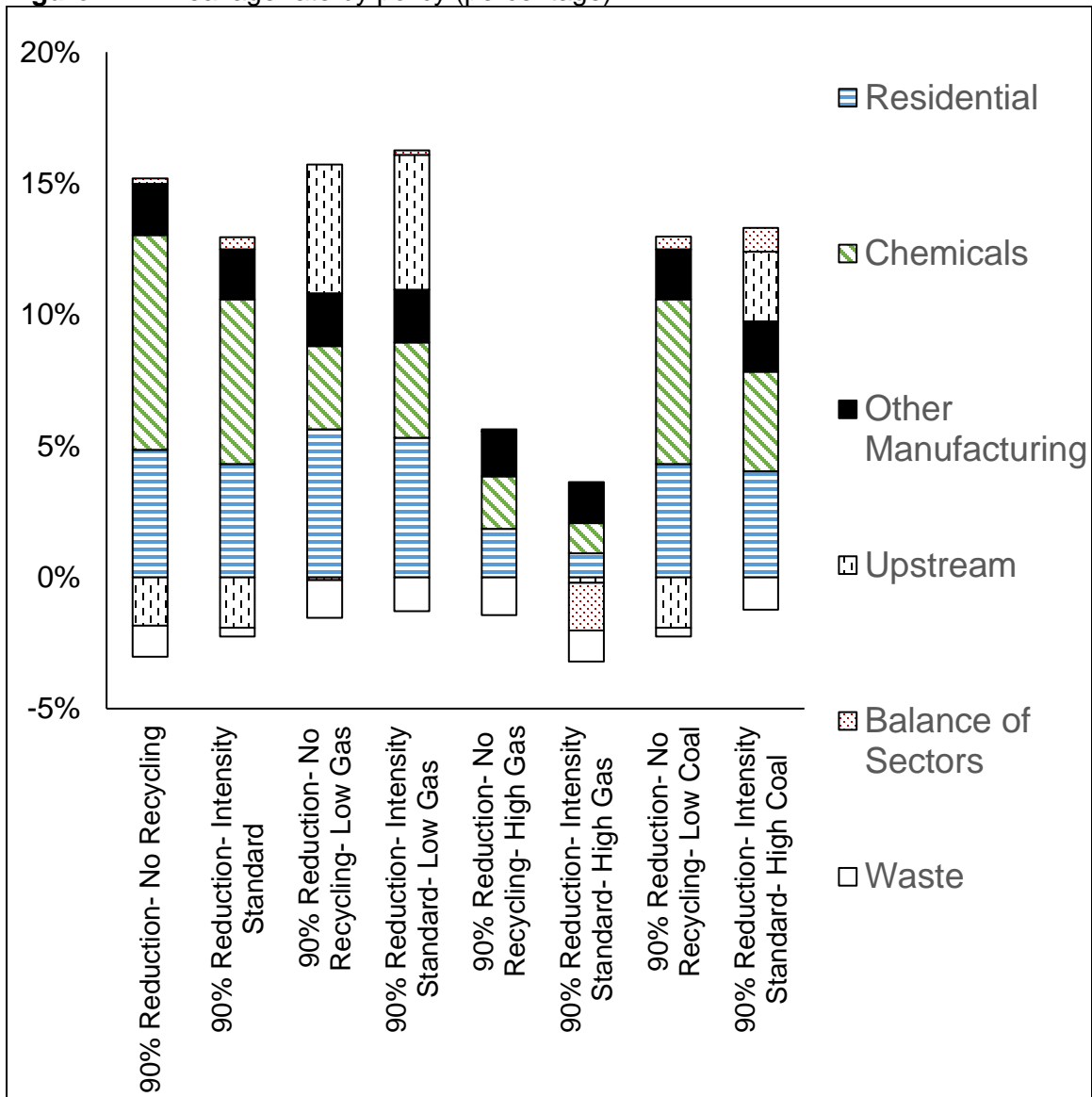
Evident from the figure is the substantial impact on leakage from altering the gas price. Given how the substitution to natural gas from electricity in the uncovered sectors was identified as a key driver in causing the higher emissions for certain sectors, the extent to which natural gas use in the uncovered sectors was discouraged through higher prices would reduce uncovered sector emissions and result in lower leakage. By extension, combining the two effects of revenue recycling to electricity, through an intensity standard, with high natural gas prices, results in the lowest leakage rate across all market-based policy scenarios modelled in this chapter.

Sectors where the higher natural gas price reduced emissions the most were predominantly sectors identified previously as important: chemicals, the upstream emissions and the residential sector. Interestingly, other manufacturing, which was identified as an important sub-sector driving emissions increases before, does not see a large change in emissions under this sensitivity. This contrasts with the commercial sector, where emissions decrease by about 20Mt from BAU under the intensity standard.

Although overall leakage rates were higher in scenarios with low gas prices, as expected, an unusual finding from these runs was that the leakage rates from chemicals manufacturing was lower than under the reference policy scenarios. Even though gas prices were lower, these scenarios induced greater use of by-product gas in cogeneration for chemicals, driving lower emissions from chemicals for these sensitivity runs.

Finally, I ran an additional variation on the policy scenarios that expanded the coverage of the carbon price to electricity generation by industry through cogeneration, noting the earlier finding of the importance of cogeneration in driving leakage. Figure 4-13 below provides the percentage leakage for this additional policy run that covers cogeneration, alongside the leakage rates from the original scenarios where cogeneration is not covered.

Figure 4-13: Percentage leakage- Cogeneration covered

90
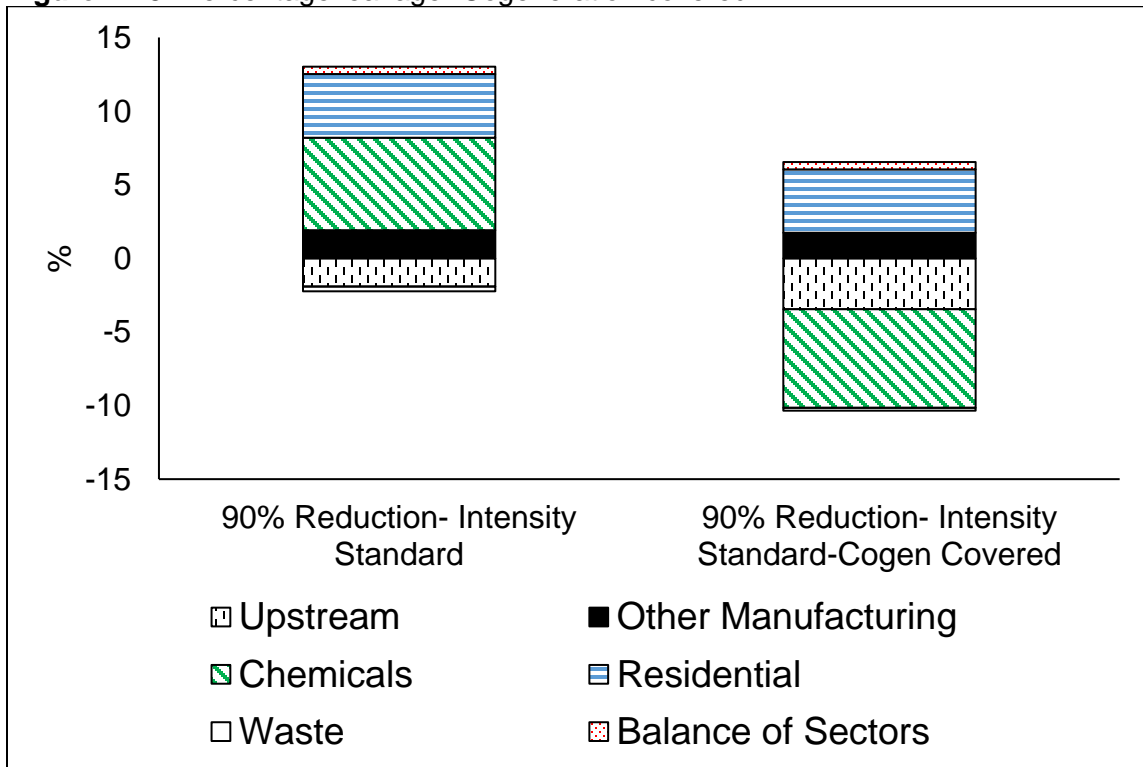
By covering cogeneration, the intensity standard now results in lower leakage than before, and actually results in net negative leakage to the uncovered sectors. As expected, emissions declines are most concentrated in chemicals, where emissions actually decrease relative to BAU under this policy design.

4.6 Conclusion

This paper assesses the emissions impacts of various designs of power sector policy on the rest of the economy, the uncovered sectors, which I model without climate policy. I use an energy-economy model with a high degree of technological explicitness, CIMS, to compare the variation in the uncovered sectors' emissions for several market-based power sector policies as well as two command-and-control policies.

Overall, I find substantial variation in the uncovered sectors' emissions based on the design and stringency of the policy. Measured by the leakage rate, I find inter-sectoral leakage to vary across electricity sector policies- ranging from negligible to a significant 12% of total power sector emissions. This leakage is highest under carbon pricing scenarios without recycled revenues and is lowest under a coal phase out combined with a clean electricity standard. The rationale for these differences is that policy design affects the relative natural gas and electricity price facing the uncovered sectors under each scenario, resulting in differing energy mixes and differing emissions levels. The market-based policies witness electricity price increases facing the uncovered sectors that are several times higher than the natural gas price increases facing these sectors, resulting in a switch from electricity to gas and higher emissions. The command-and-control policies, by contrast, do not witness similar price movements in electricity, and actually see negative net emissions in the uncovered sectors due to less upstream emissions from fossil-fuel extraction and less natural gas price movement relative to other emitting fuels.

These differences in emissions were found most concentrated in three sectors: residential, other manufacturing, and especially chemicals- where differences in fuels used for cogeneration occurred when electricity prices rose by more than natural gas prices. These findings prompted sensitivities around the design of the power sector policy for the carbon price to cover cogeneration. This change in policy coverage considerably reduced leakage arising from the policy.

Overall, the emissions reductions from a power sector policy alone, even if it were possible to eliminate all emissions from electricity generation, would be insufficient to achieve long-term emissions stabilization targets for the US. Meeting these targets requires substantial reductions to occur in other sectors. If regulators wish to continue along a sector-specific policy route, an understanding of how an early power sector policy facilitates, or perhaps hinders, later de-carbonization of the other sectors of the economy is important. Thus, a recommendation stemming from this chapter is that policymakers should consider extending carbon pricing policies for the electricity sector to cover cogeneration in industry as well. This would prevent counter-productive leakage of emissions from the power sector to industries like chemicals.

In a similar vein, seeing as much of the leakage was found to be due to switching from electricity to natural gas in the uncovered sectors, a more ambitious policy recommendation would be to apply a low-level carbon price to the end use sectors of the economy that might disincentivize this de-electrification of end use. A modest price on carbon in the end use sectors could also reduce leakage by incentivizing reductions in other areas of end use (e.g. switching from oil to natural gas), that could offset some of the leakage caused by switching from electricity to natural gas. This modest carbon price could be used as a springboard to achieve more aggressive end use sector reductions at a later date.

The version of CIMS US I used is aggregated at the national level, and does not explicitly model the regional diversity in the US power sector. Thus, a potential limitation to this study is that the results may change if different grids in the US were explicitly modeled. In addition, for jurisdictions with a power sector policy but without policy for the uncovered sectors, the results may not hold if key uncovered sectors driving the policy- such as chemicals or upstream oil and gas- are not present in a given economy. Furthermore, an electricity sector policy may worsen leakage in jurisdictions primarily using coal for industrial activity, should the power sector policy cause a widespread switch away from coal. This latter phenomenon might arise in China or India, so design of such a power sector policy may be especially important for those large jurisdictions.

5. Exploring ways to Reduce Greenhouse Gas Emissions from Heavy Trucks: Assessing the Potential Role of Natural Gas

5.1 Introduction

Freight transport by heavy trucks presents a challenge to reduce the transportation sector's GHG emissions. Unlike personal transportation from cars and buses, inter-urban freight transport by heavy trucks involves much larger vehicles, substantially greater distances travelled, and predominantly occurs over areas with low population density. These considerations may make it harder for this segment of the transport sector to achieve emissions reductions relative to personal transport, where recent cost declines by electric vehicles (EVs), and plug-in-hybrid electric vehicles (PHEV), have made these technologies attractive to consumers when combined with subsidy policies in some markets.[39] By contrast, sales of electric truck (Etrucks) have barely nudged, perhaps a consequence of cost, drivers' range anxiety concerns associated with prevailing electric batteries, and a lack of inter-city charging infrastructure. These considerations with heavy trucks might pave the way for some other suite of technological mitigation options, other than Etrucks, for reducing emissions from this sub-sector. Understanding the mitigation options for heavy trucking is important, for this sub-sector is a growing share of total emissions, and so major reductions will likely be required to achieve deep de-carbonization of the economy. For instance, while Canadian GHG emissions from the transportation sector grew by 42% between 1990 and 2015, emissions from freight trucks actually tripled over this same period (Environment and Climate Change Canada, 2018).

The use of natural gas has become disruptive in US electricity generation, especially in concert with policies to reduce GHG emissions from electricity. The abundance of natural gas in North America warrants an investigation of whether a similar development might occur with heavy trucking. Natural gas alone is only a partial de-carbonization measure for heavy trucks, providing a 20%-30% GHG reduction from diesel emissions, and possibly less if there are significant upstream emissions associated with producing, processing,

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[39] Norway recently achieved 55% annual market share of EVs. Promoting this development was a combination of high fuel taxes, cheap electricity, and generous tax incentives for purchasing EVs over conventional internal combustion engines (ICE) vehicles.

and transporting the natural gas. However, one could make the case for natural gas heavy trucks to act as a bridge to a full de-carbonization, by reducing emissions in the near-term under weak policy, and then by continuing to reduce emissions as the stringency of the policy increases via the blending of natural gas with renewable natural gas (RNG).[40] RNG is promising due to its potential use in existing natural gas vehicles without the need for any engine modifications.

Therefore, this chapter asks the following questions:

i)   is there a role for heavy trucks powered by natural gas, either in pure form or blended with renewable natural gas (RNG), in reducing freight sector GHG emissions?

ii)   can natural gas heavy trucks act as a bridge-fuel to a full de-carbonization of trucking, via progressively increasing blend rates with RNG?

To answer these questions, I model stringent policies to reduce emissions from the Ontario freight sector using CIMS Canada— a technology-explicit energy economy model of the Canadian economy that is disaggregated by province. Previous studies that modelled the heavy trucking sector under stringent climate policy generally did so as part of larger economy-wide studies. Not focusing on a specific sector, like freight, these studies understandably did not examine a particular mitigation option, like natural gas trucks, in detail. Three recent Canadian studies exploring deep GHG reductions-Pathways to De-carbonization in Canada (Bataille et al., 2015), Vass and Jaccard (2017), and the Trottier Energy Futures Project (The Canadian Academy of Engineering, 2016), found natural gas to play little role in the transition, with mode switching to electric rail, trucks with biofuels, and hydrogen trucks being the preferred options under stringent climate policy. Other studies looked specifically at freight, but did not focus primarily on natural gas trucks. Muratori et al. (2017) examined freight reductions globally, and found a growing use of natural gas in freight with stringent climate policy by 2100. They also found emissions reductions from freight by 2050 to be limited. It appears these outcomes were due to limited mode switching between trucks and more-energy efficient rail under stringent policy, and limited adoption of electricity in freight. In contrast to Muratori et al.

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[40] Sources of RNG are methane captured from landfills, wastewater treatment facilities, or agricultural waste- as well biomass-derived synthetic methane.

(2017), my analysis shows it is feasible to considerably de-carbonize the freight sector by 2050 within the context of broader emissions reductions in Ontario.

Recent work by Lepitzki and Axsen (2018) used a variation of the CIMS model to simulate the overall effects of a suite of transportation policies to reduce GHG emissions for both personal transport and freight transport in BC, as well as to discern whether a low carbon fuel standard is complementary (incremental) or redundant to other transport policy within this suite of policies. This is a particularly timely analysis, as Canada is planning to implement a Federal Clean Fuel Standard, requiring reductions in the lifecycle carbon intensity of fuels. They find that for the freight sector, the LCFS is complementary in every period of the simulation, and across all policy scenarios. They also find the incremental impacts of the LCFS to be proportionally larger for freight than for personal transport. While they found significant adoption of renewable diesel, electric trucks, and hydrogen under moderate and ambitious policy, they also found some potential for natural gas, making up 10% of the fuel split for trucks under these policy scenarios. They did not assess the potential for RNG in their analysis.

With a detailed examination of one technology being outside their scope, these papers reported on the broad possible outcomes of their respective modeling exercises for the freight sector at a high level. Another strain in the literature provides detailed analysis to determine the switch point between natural gas and diesel, exploring the economic feasibility for natural gas trucks after varying a large number of techno-economic variables surrounding the technology. For instance, work by Askin, Barter, West, & Manley (2015) combine simulation modeling with parametric analysis of key factors influencing the competition between conventional diesel, advanced efficiency diesel, and natural gas vehicles for the US heavy truck segment. After doing so, they find diesel trucks to remain the dominant form of truck transport to 2050. Other work, such as that of Krupnik (2010), compares the economics of natural gas trucks to diesel trucks for the heavy truck segment by varying key private investment decisions such as fuel price differences, assumptions about distance travelled, fuel economy, discount rate, etc. The paper finds payback periods for natural gas trucks that are favorable (5-12 years) for representative values of the aforementioned parameters at a 10% discount rate, but not favorable at a 31% discount rate (which may be more representative of the actual discount rate that consumers discount such new technologies). Jaffe et al., 2015 provided a similar analysis, finding a favorable (under 3 yr) payback period for natural gas trucks with an annual

mileage greater than 120,000 miles. While these papers put a detailed focus on the potential for natural gas vehicles relative to diesel, they do so in the absence of climate policy.

In this chapter, I seek to bridge the gap between these two strains in the literature by assessing the feasibility of natural gas trucks, combined with RNG blending, to reduce heavy freight sector emissions in the Canadian province of Ontario. As a feasibility study, I will evaluate the practicality of natural gas trucks as an economic mitigation option under various policy and cost scenarios. Such an assessment is important as several governments see natural gas trucks as a potential mitigation option and are supporting the technology with policies.[41] Thus, this chapter can provide insight as to whether these policies are well placed to deliver reductions for the freight sector.

This chapter contributes to the literature in several ways. Firstly, it provides a more granular focus on the competitiveness of natural gas trucks when situated within the broader freight sector, enabling one to assess their competitiveness relative to other heavy truck options, such as biofuels, electric and hydrogen vehicles, but also with other modes for moving freight such as rail. Secondly, the chapter assesses penetration of the above technologies by interacting techno-economic parameters of the vehicles in question with carbon pricing scenarios aimed at achieving deep, economy-wide GHG reductions. A detailed parametric sensitivity analysis identifies the key variables driving the potential for natural gas trucks. Finally, I model the extent to which natural gas blending with RNG might be used a bridge fuel to de-carbonize the freight sector. This latter aspect, to my knowledge, is a novel contribution to the literature.

Under stringent policy, I find the de-carbonization of rail to result in most of the emissions declines from the freight sector. However, I also find RNG blending with natural gas can play a key role in de-carbonizing the remaining heavy truck stock, depending on the RNG price. Secondly, I find greater use of RNG blending with natural gas heavy trucks as a least-cost abatement option, under a well-communicated stringent policy, rather than as a bridge fuel between a weaker policy and a delayed transition to a more stringent policy. This second finding suggests that other technical options might better fulfill the bridging role discussed earlier.

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[41] For instance, Ontario's Green Commercial Vehicle Program includes subsidies for natural gas trucks, alongside electric trucks.

Finally, I model a sensitivity scenario that witnesses a confluence of favorable developments for natural gas trucks, which see them make significant inroads in heavy trucking. Unfortunately, without a stringent climate policy, this worsens the energy use and emissions profile of the sector. While substantial emission reductions can still be achieved when coupled with a carbon price, the reductions rely on substantial RNG-blending and, thus, a reliable source of RNG at reasonable cost.

I structured the chapter as follows. Section 5.2 provides a background on technological mitigation options for the heavy truck sector and reviews trends in the freight sector for Ontario; Section 5.3 outlines the modelling framework, the key modelling assumptions, and the policy scenarios. Sections 5.4 and 5.5 describe the main results for the business-as-usual and policy scenarios respectively. Section 5.6 then conducts a sensitivity analysis, while Section 5.7 concludes with key policy implications.

5.2 Background

5.2.1 Technological Options for Emissions Reductions in Heavy Trucking

Mentioned in the introduction was how key characteristics of heavy trucks have to date made this a challenging area to realize emissions reductions. Table 5.1 below provides a qualitative assessment of the relevant economic factors underlying technology-choice decisions. Evident from this table is that that there are important differences for each option, with many of these differences having clear implications for the expected competitiveness of the various technologies.

Table 5-1: Qualitative Assessment of alternative heavy truck engine/fuel configurations vs. diesel

Vehicle Type	Drivers Promoting Use	Drivers inhibiting use
Diesel	• Incumbent technology • Infrastructure readily in place • Lowest capital cost- mass produced with ramped-up supply chains and mature technology • Relatively low fuel price on average over past fifty years	• Variable fuel costs • GHGs- risk of more stringent carbon price or other carbon policy
Diesel-More Efficient	• Energy cost savings • Infrastructure readily in place • Partial emissions reduction	• Likely an asymptote to potential efficiency gains. Likely requires replacement

Vehicle Type	Drivers Promoting Use	Drivers inhibiting use
	• Mature, well understood technology- less capital cost premium vs. alternatives to standard diesel	• under more stringent climate policy • Capital cost premium vs. baseline diesel
Biofuels	• Biodiesel can be blended to 20% to reduce the carbon content of diesel in the short term. • Blending can utilize existing infrastructure • Renewable diesel is compatible with existing charging infrastructure and can be blended up to 100% • Biodiesel dedicated engines for further reductions are possible with only a minimal engine modification • Biodiesel dedicated engines see less capital cost premium vs. alternatives to standard diesel • Range is comparable to diesel	• Fuel price of second generation biofuels, (required for upscaling the technology while not reducing land for food use) is very high relative to fossil fuels • Biodiesel dedicated engines have a capital cost premium over conventional diesel and also require separate refueling infrastructure
Natural Gas[42]	• Very low energy cost given current natural gas prices • Moderate GHG reduction vs. standard and medium efficiency diesel engines • Range is comparable to diesel	• Range penalty vs. diesel • Dedicated Infrastructure required • Higher Capital Costs vs. prevailing diesel trucks, although not by as much as electric or hydrogen
Renewable Natural Gas	• Possibly less expensive than diesel • Can be almost 100% GHG free • Integrates seamlessly into natural gas engines and infrastructure. • Natural gas engines can burn up to 100% RNG	• RNG will add to fuel costs vs. natural gas only. No incentive without carbon policy • Uncertainties with availability • Requires natural gas engines and recharging infrastructure
Electric	• Very low GHGs for most of Canada (predominantly GHG free grid)	• Range very low (150km before recharging)

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[42] Natural gas trucks can either have a dedicated natural gas engine design, a bi-fuel engine design so that the engine can run on either gasoline or natural gas, and a so-called duel-fuel engine, where diesel assists with ignition but the engine primarily runs on natural gas (DOE Alternative Fuels Data Centre, 2018a). An additional distinction is how the fuel is stored before being delivered to the engine, either as a gas in compressed natural gas vehicles (CNG) or as a liquid is liquefied natural gas vehicles (LNG) (Westport, 2013). CNG's energy density is substantially less than LNG (Westport, 2013).

Vehicle Type	Drivers Promoting Use	Drivers inhibiting use
	• Costs have been declining rapidly • Low variable cost in some jurisdictions	• Capital cost *very* high vs. reference • Dedicated infrastructure required
Hydrogen	• Potentially near-zero emissions depending on the primary energy source • Potentially abundant	• Dedicated refueling and storage infrastructure needed • Technological advances required to drive down cost. Currently faces a massive capital cost premium to diesel • Range is lower (about half) that of diesel
Rail	• General alternative to trucking as a way to move heavy land freight. • Lowest energy use per tonne kilometre travelled option • Lower GHG per tonne kilometre travelled than trucking.	• Lacks convenience due to fixed timetables and routes • New routes requires substantial upfront investment

Table 5-1 lists drivers of the competitiveness of key alternatives, alongside natural gas trucks, which can serve to mitigate emissions from the freight sector. Etrucks are one mitigation option, but one whose fundamental issue is their prevailing range of about 150km, with increases in battery size resulting in a trade-off of lower fuel efficiency, thereby hampering further range improvements. Other issues with Etrucks are recharging time and purchase cost. Thus, the technology would need substantial cost declines, advances in the energy density of batteries, and a major infrastructure development along highways and other high freight traffic routes, before becoming viable at a large scale. On the other hand, lifecycle emissions for this option would be practically zero with Ontario's 90% emissions-free grid. Capital costs have been declining rapidly due to the cost improvements of batteries. Hydrogen trucks could potentially be another near-zero emissions option, but face even more challenging conditions in terms of capital cost premium and need for recharging infrastructure than do electric trucks.

Biofuels, produced from a variety of raw materials utilizing a number of diverse processes, are another option. Depending on the type of material and process, experts distinguish between conventional and advanced (or second and third generation) biofuels. Conventional biofuels use mature conversion technologies (fermentation for instance) to

convert the energy content of grains, oilseeds, animal fats, and waste vegetable oils to fuels. By contrast, advanced biofuels use ligno-cellulosic feedstocks derived from agricultural and forestry residues, or novel oil-based sources such as algae, and use advanced conversion processes such as pyrolysis or gasification. In the context of trucking, biodiesel is the end product if produced from oil-based sources while drop-in biofuels (renewable diesel) could be produced from ligno-cellulosic and grain-based feedstocks, in addition to oil-based sources (US DOE Alternative Fuels Data Centre, 2018b). The latter are similar enough to petroleum-based diesel for use in a regular internal combustion engine without modifying the engine, and can utilize the existing diesel distribution infrastructure. Blending the former with standard diesel fuels to reduce its emissions intensity up to about 20%, and using biodiesel as the primary fuel for trucks with a dedicated engine, are ways oil-based biodiesel can contribute to mitigating climate change in heavy trucking.

Advanced biofuels may be necessary to upscale biofuel production and meet expanding demand while minimizing the land use footprint of biofuels more generally. The IPCC fifth assessment report, in its chapter on Agriculture, Forestry, and Other Land Use notes how, *"Achieving high deployment levels [of biofuels] would require, amongst others, extensive use of agricultural residues and second-generation biofuels to mitigate adverse impacts on land use and food production."* (IPCC, 2014.)

Improvements in the fuel efficiency of internal combustion engines (ICE) burning diesel is another possibility to reduce GHG emissions from heavy trucking. Like efficiency options in other sectors of the economy, new efficient trucks have a capital cost premium over less efficient vintages. The fuel savings, however, could make these options economic over their lifetime from a purely financial perspective. This option can at best be a partial de-carbonization due to possible diminishing returns to efficiency over time. Another possible factor limiting the effectiveness of efficiency as a mitigation tool is the possibility of the rebound effect. As defined in the energy literature, the rebound effect has a direct and indirect component. The "direct" rebound effect occurs when a reduction in the operating cost of using an energy service increases its demand. Indirect rebound effects occur when lower life-cycle costs for energy services, because of a profitable energy efficiency investment, may result in greater disposable income for households to spend on new products, which could raise economy-wide energy demand due to the associated energy in producing said products (Gillingham, Kotchen, Rapson, & Wagner, 2013).

Another option may be to move heavy freight by rail rather than by truck. The rail option would use less energy per unit of freight demanded and thus could lower emissions via lower overall energy use in the freight sector.[43] Fuel switching within the rail sector to electric or biodiesel trains would reduce emissions even further. The major downside to using rail is its lack of flexibility with its fixed timetables and routes. Consequently, trucks have a significant advantage in terms of flexibility over rail.

The quantitative analysis in this paper examines the tipping points in key variables that might drive the adoption of one technological option over the other. Using the preliminary qualitative assessment as a guide, some of these key variables might be (but are not limited to) assumptions about rate of vehicle cost declines, assumptions about fuel cost dynamics, as well as assumptions about future climate policy. These technological options are not all-or-nothing options, as a mix would likely occur under stringent but flexible deep de-carbonization policies in heavy freight. However, varying assumptions for the above variables may result in significant differences in the magnitude of the market share going to certain technologies that would still be worth investigating.

5.2.2 Ontario Freight Sector

I chose Ontario as a case study because, at the time I conceived of the research project, Ontario was a member of the California-Quebec GHG emissions cap-and-trade system (the Western Climate Initiative or WCI), and was also developing an suite of climate policies in its climate plan with the aim to achieve aggressive GHG targets, including policies for the transportation sector. This changed with the new Ontario government in 2018, which has withdrawn Ontario from the WCI. These targets sought to reduce Ontario's GHGs by 15% per cent below 1990 levels by 2020, 37% below 1990 levels by 2030, and 80% below 1990 levels by 2050 (Government of Ontario, 2017). In addition, Ontario is Canada's largest province by population and GDP, representing about 26% of Canada's total freight sector emissions. It also has substantial manufacturing linkages to the US and has a significantly large freight transport need.

GHGs from the Ontario freight sector have increased substantially, from 14.1Mt in 1990 to 23.4Mt in 2013, due to the continued upward trend in sector economic activity, and due

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[43] Freight demand is generally represented by tonne kilometers travelled (tkt), representing the transport of one tonne of goods over a distance of one kilometre (Eurostat, 2018).

to oil-derived diesel trucks being the most economic heavy truck option. While the emissions increase for Ontario is large, it is not unique for North America and many comparable jurisdictions have witnessed a similar trend (Eom, Schipper, & Thompson, 2012). Figure 5-1 below breaks the emissions increase in freight by sub-segment, illustrating how emissions from heavy trucks have been the driving force behind this trend, having increased by a greater amount in absolute terms, and at a faster rate, than all other sub-segments.

Figure 5-1: Freight GHG emissions broken down by freight transportation mode
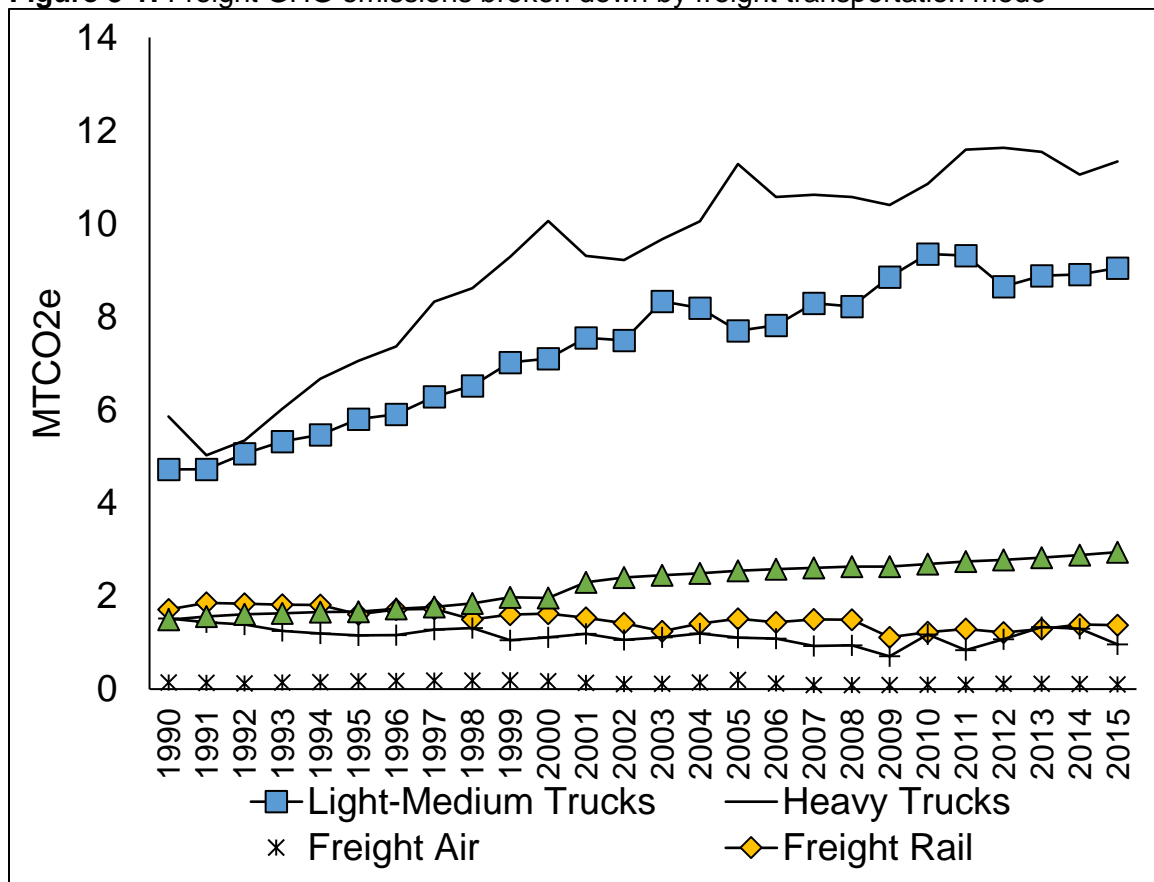
Source: NRCan, National Energy Use Database 2017

Figure 5-2 illustrates energy use trends for the sector over the same period. An increase in energy use by over 30%, combined with the energy profile still being predominantly petroleum based, explains much of the GHG emissions increase in the previous figure.

Figure 5-2: Freight energy use by fuel type (PJ)
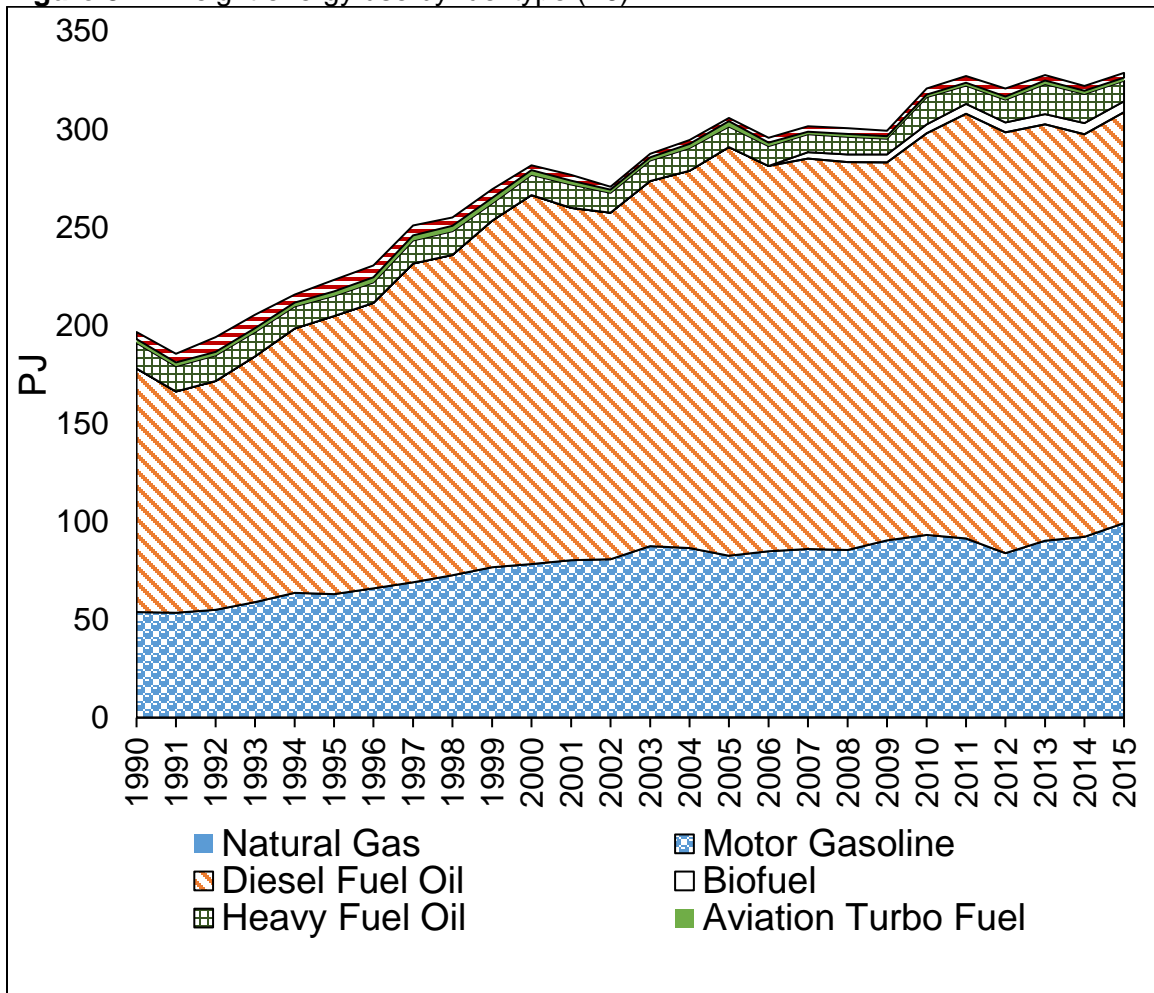
Source: NRCan, National Energy Use Database 2017

5.3 Modelling Framework

5.3.1 CIMS Market Competition

To assess the conditions under which natural gas long-haul freight trucks might be a plausible option for deep GHG reductions in Ontario's freight sector, this paper uses the CIMS-Canada energy-economy model to forecast the emissions trend in freight under various policy simulations. I provided a detailed description of CIMS in Chapter 2. Mentioned in that chapter, CIMS is a technology-explicit bottom up model, where the modeller specifies technologies and fuels, which then compete to make up the capital stock of a given sector to meet an initially exogenous demand for energy services. The model solves for outputs, such as emissions and energy use, as an aggregation of technologies that win in this competition and make up the sector's capital stock. CIMS

simulates competition and solves for intervals of five years between the years 2005 and 2050. Although my research in this chapter is essentially a partial-equilibrium analysis concentrated on a particular sector, the use of CIMS allows me to situate emissions reductions in the freight sector alongside Ontario's pursuance of economy-wide policy targets, in order to contextualize the emissions reductions achieved by freight relative to those of other sectors. In addition, CIMS has the ability to make different assumptions about firm and household expectations regarding future carbon pricing, a feature I use in some of the policy scenarios I ran for this analysis (described in section 5.3.5).

The competition is based on tangible financial parameters (e.g. capital costs, fuel costs, a financial cost of capital), but also on intangible parameters representing the additional risks that might be inherent in a novel technology, or intangible costs that might occur due to how customers perceive certain qualitative differences of a given technology. At a conceptual level these parameters are well understood, and have a rich literature (see McCollum et al., 2017 for a recent review for the transport sector).

Intangible costs are important when evaluating transportation, as range anxiety, concerns about refueling ability due to lack of refueling infrastructure, and long refueling times are factors that would likely make it much harder for new technologies to displace incumbents. I represent these intangible costs in CIMS as fixed and declining intangible costs. Fixed intangible costs represent intangible costs that are unlikely to change over the simulation period, perhaps due to there being some residual negative perception to novel technologies for a certain fraction of the population by 2050. Declining intangible costs, however, decline with increasing adoption of the technology, as increased visibility of the technology reduces the apprehension/uncertainty surrounding it (Axsen et al., 2009). Declining intangible costs may also arise because of greater availability of this type of trucks and the necessary refueling network. The formula below describes the rate of decline of intangible costs (Bataille, 2007):

$$I_t = \frac{I_0}{1 + [A \times \exp(k \times NMS_{t-5})]} \qquad \text{(Equation 5.1)}$$

Where:

- I_t is the intangible cost in time t
- I_0 is the initial intangible cost,
- A represents the shape of the curve

- K represents the rate of decline
- NMS(t-5) represents the percent of the new market share in from the previous run.

For freight, CIMS initially divides its demand into land, marine, and air freight, based on historic data, which are then extrapolated for the remainder of the simulation. For the 2005 to 2050 period, the splits are exogenously set so that 0.4% of Ontario freight demand comes from air, 14.5% from water, and the remaining 85.1% from land. These splits remain constant throughout the simulation. Within the air and marine freight segments, technologies compete directly to meet demand. Within the land freight segment, demand is divided by light/medium freight and heavy freight based, again, on historic splits and forecasts. Light/medium freight represents trucking on short-haul routes, and for fixed urban/delivery routes such as garbage disposal. Trucks, hauling much lighter loads than their heavy truck counterparts, meet the entirety of the demand of the light/medium freight segment and do not compete with heavy freight as they are assumed to serve different market segments. Rail and heavy trucks, however, compete with one another based on their relative economics to meet heavy freight demand.

In addition, CIMS enables a representation of fuel competition that is separate from the competition of the choice of vehicle purchase. This allows agents to increase the biofuel content of their fuel if it makes economic sense to do so as per CIMS market share simulation. In CIMS, the fuels to power fossil fuel engines- diesel and natural gas fuels- can be blended with biofuels in increments ranging from pure diesel and natural gas (no blending) at one end of the spectrum, to 100% renewable diesel and RNG on the other. These increments compete on the basis of cost to meet a given demand for fuels, with greater blending rates rising costs relative to the pure fossil fuel option. This representation provides a more wholesome set of mitigation options than if agents were restricted to purchasing new alterative fueled vehicles. Critically, it enables a realistic representation of drop-in biofuels in the model, which are fungible with prevailing diesel and natural gas engines and infrastructure.

Figure 5-3 below provides a schema of the freight sector in CIMS, and the competition nodes, as described above. Circled in red is the area in the freight sector where the current analysis is focused.

Figure 5-3: Freight Sector and Competition Nodes in CIMS
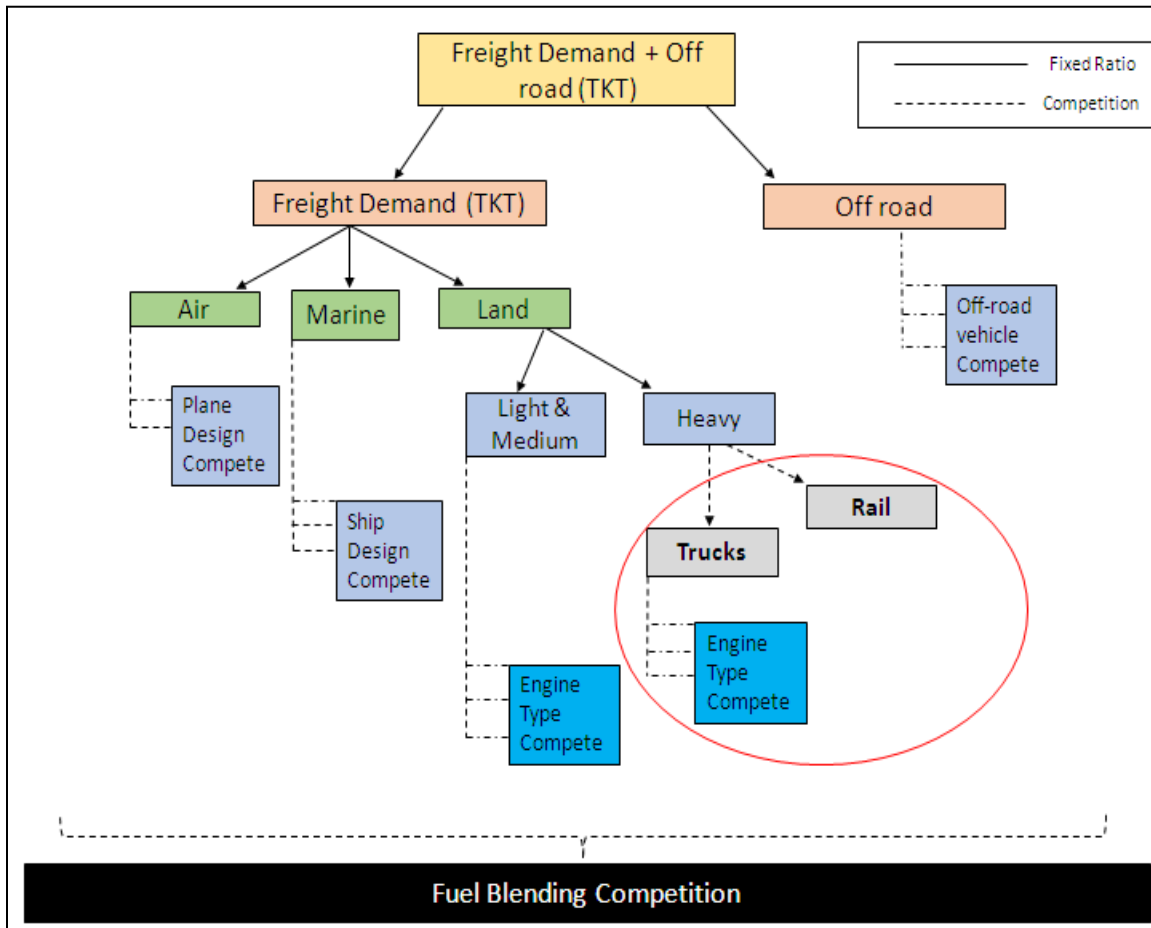
5.3.2 Engines and Vehicle Choice in CIMS

A set of technologies, such as electric, diesel, natural gas, hydrogen, and plug-in-hybrid trucks, compete in the heavy truck sub-segment according to their capital and variable costs, as well as their intangible costs. I provide the explicit capital costs and maintenance costs for these technologies in table 5-2 below

The US categorizes vehicles under eight weight classes under the Federal Highway Administration (FHWA). Class 7 and Class 8 vehicles are considered heavy vehicles under this classification, with weights of 26,001lbs-33,000lbs and >33,000lbs respectively. Examples of long-haul trucks under these classifications include medium semi-tractors and high-profile semis under class 7, with semi sleepers and the heaviest semi tractors

under class 8 (US DOE Alternative Fuels Data Centre, 2018c). I categorized all of these trucks (class 7 and class 8) as heavy trucks for the CIMS model.

Table 5-2: Capital and Maintenance Cost

Technology	2018 Capital Cost ($2005 CDN)	Maint. Cost ($2005 CDN)	Output (tonne kilometers travelled)	Life	Avail
Heavy Trucks					
Conventional Diesel[I]	$109,214	$11,078	486,216	10	2000-2010
Med Efficient Diesel[II]	$113,363	$11,078	486,216	10	2000-2015
High Efficient Diesel[III]	$125,500	$11,078	486,216	10	2000-2020
Highest Efficiency Diesel[IV]	$140,000	$11,078	486,216	10	Entire Simulation
LNG[V]	$180, 457	$12,106	486,216	10	Entire Simulation
ETrucks[VI]	$185,164	$7384	486,216	10	2010-2050
Dedicated Biodiesel[III]	$136,518	$11,078	486,216	10	Entire Simulation
Hydrogen[VII]	$354,415	$7384	486,216	10	2015-2050
Plug-in-Hybrid EV[VIII]	$138,872	$7384	486,216	10	Entire Simulation
Light-Medium Trucks					
Conventional Diesel[I]	$69,545	$4056	30,722	10	2000-2010
Med Efficient Diesel[II]	$72,187	$4056	30,722	10	2000-2015
High Efficient Diesel[III]	$79,916	$4056	30,722	10	2000-2020
Highest Efficiency Diesel[III]	$89,149	$4256	30,722	10	Entire Simulation
CNG[IV]	$118,230	$4461	30,722	10	Entire Simulation
ETrucks[VIII]	$164,989	$2704	30,722	10	2010-2050
Dedicated Biodiesel[IX]	$87,200	$4056	30,722	10	Entire Simulation
Hydrogen[IX]	$183,154	$2704	30,722	10	2015-2050
Plug-in-Hybrid EV[VIII]	$123,741	$2704	30,722	10	Entire Simulation

Sources: [I]Den Boer et al., 2013; [II]CALSTART, 2015, [III]Adjusted from Personal Transport ratios in CIMS, [IV]CALSTART, Inc, 2013; [V]DOE, 2011; Marbek, 2011 [VI]TESLA Semi, ET one, [VII]Fulton & Miller, 2015 [VIII] Pelletier et al., 2014, [IX]Adjusted from same ratio as heavy trucks

Some of these capital costs decline over the course of the simulation due to the processes of technological improvement, upscaling, and learning-by-doing (McDonald and Schrattenholzer, 2001). I treated this rate of decline exogenously in CIMS. The rationale for this assumption is that Ontario is a small jurisdiction on the global scale, and that the commercial truck market is a globally integrated market. Thus, learning and technological advances occurring elsewhere in the world will be applicable to Ontario and reflected in the vehicle price.

A major phenomenon in the energy sector over the past several years has been the dramatic cost decline witnessed for electric batteries on a $/KW basis (See Nykvist and Nilsson, 2015), as well as other elements of an electric vehicle. A consequence of these, and other, advances is that the price of Etrucks have declined from over $CDN300k to $CDN185k (new TESLA Semi) in real terms.[44] The expectation would be for declines to continue occurring in the future, at a similar rate per cumulative doubling. To derive the extent of the cost decline going forward, the simulations for this study assumed a certain number of cumulative doublings globally by 2045 per technology, and a given rate of decline per technology. Table 5-3 provides a summary of these assumptions for heavy trucks.

Table 5-3: Summary of Learning Assumptions for Heavy Trucks

Technology	Learning Rate	Source for Learning Rate	# Cumulative Doublings by 2045	Source-Cumulative doublings	2040 % below 2015 Value
ETrucks	9% Battery, 5% Power Electric	Nykvist and Nilsson, 2015	5.5	IEA Forecast (assume spillovers from advances in PEV)	32%
Plug-in-Hybrid	10% Battery, 5% Power Electric	Nykvist and Nilsson, 2015	5.5	IEA Forecast (assume spillovers from	20% (achieves parity with diesel trucks)

[44]This may understate the cost of EVs as TESLA vehicles and especially trucks may not fully reflect production costs, being loss leaders to build market share.

Technology	Learning Rate	Source for Learning Rate	# Cumulative Doublings by 2045	Source-Cumulative doublings	2040 % below 2015 Value
				advances in PEV)	
Hydrogen	25% (Whole vehicle)	Fox, Axsen, & Jaccard, 2017	5.5	NA	62%
Natural Gas	5% (Whole vehicle)	Judgment (lower rates- more established technology - uptake having already occurred in parts of the world)	3	Judgment (less spillover from advances in PEV)	27%
Biodiesel	3% (Whole vehicle)	Judgment (lower rates- more established technology and uptake having already occurred in parts of the world)	3	Judgment (less spillover from advances in PEV)	17%(achieves parity with diesel trucks)
Advanced High Efficiency Diesel	1.75% (Whole vehicle)	Judgment (lower rates - more established technology and uptake having already occurred in parts of the world)	3	Judgment (less spillover from advances in PEV)	6%

5.3.3 Fuels and Upstream Emissions

These technologies also require fuel inputs suitable to their respective engines. For diesel and natural gas fuels, various blends of biodiesel, drop-in-biofuels (renewable diesel), and RNG compete against a pure diesel or pure natural gas option respectively in a separate fuel choice competition module as described earlier. By tracking these technologies and

fuels, CIMS estimates a sector's energy use and emissions via the fuel-use characteristics of the technologies chosen and the emission intensities of the fuels consumed.

A given fuel's emissions consist of both the downstream and upstream elements. Downstream emissions refers to those emissions from the actual use of the fuel at the point of combustion. For the transport sector, the literature refers to these downstream emissions as the tank-to-wheels (TTW) emissions. Upstream emissions include those emissions occurring from the extraction/harvesting, processing, and transporting of the fuel to the point of end use. The treatment and modelling of upstream emissions is an important consideration, for while most research points to natural gas trucks having a TTW emissions intensity that is 20% lower than diesel, there is substantial variation in the literature with respect to the full upstream, or well-to-wheels (WTW), emissions of natural gas vehicles.[45]

Thus, I considered the full WTW emissions of natural gas trucks, alongside the WTW emissions of other energy sources, in this analysis. Being an integrated model, CIMS can track these emissions, as well as track technological developments in the upstream sectors that may affect the WTW value over time should producers in these sectors undertake abatement measures.

This is important, for at the time of writing Canada intends to enact regulations that reduce methane emissions from upstream oil and gas production by 40-45% below 2012 levels by 2025, a feat that would substantially de-carbonize upstream natural gas production and reduce the WTW emissions of natural gas in transportation. In addition, many mitigation measures for upstream natural gas are considered "low-hanging" fruit in the fight against climate change, and so further abatement measures beyond the regulations may be feasible with limited additional policy action. I assume that the government will meet the regulations, and so I exogenously modelled a 40% reduction in upstream natural gas' methane emissions relative to 2012 levels by 2025. I assumed further reductions to

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[45] Natural gas vehicles are identified by some as having higher emissions intensity than diesel depending on the upstream emissions from producing and processing the gas, as well as whether the natural gas is domestically produced or imported (as the additional energy requirements of transport and liquefaction would add considerable emissions). See Krupnick (2010) for a summary of papers published before 2010. See Camuzeaux et al. (2015) and Curran et al. (2014) for recent papers pertaining to natural gas trucks and natural gas cars respectively. See Tong, Jaramillo, & Azevedo (2015) as an example of a paper finding increased WTW emissions for natural gas relative to diesel

methane emissions by 80% below 2012 levels by 2045. For combustion emissions in the upstream natural gas sector, CIMS projected emissions intensity reductions, finding a modest 10% intensity improvement under the reference scenario by 2050 relative to 2015 values. The policy scenarios, however, witnessed a 70% improvement over the same period. Combining these combustion emission reductions with the result of the methane regulations, upstream emissions for natural gas vehicles from Canadian natural gas become close to negligible by 2050 under stringent policy.

Tempering considerations surrounding upstream natural gas emissions for Canada is the fact that the percentage of Ontario natural gas demand met by Canadian sources is declining due to the prevalence of the Marcellus shale gas development in nearby Ohio and Pennsylvania. Navigant (2014) estimates that between 2014 and 2020, the percentage of Ontario demand met by Western Canadian supplies will drop from 74% to 42%, while imports from the Marcellus development will increase from 13% to 41%. Thus, I track developments in this phenomenon, as well as in potential mitigation occurring in the Marcellus development, in this analysis. Given that CIMS Canada does not model the US natural gas sector, I use the trend in US upstream natural gas emissions intensity from the CIMS US model to 2050 **(Appendix F)** under business as usual conditions. For the US, I assumed no significant policies to reduce emissions from the sector as a conservative measure.

Diesel too is a fuel whose percentage of Ontario demand originating from Canadian sourced crude is declining due to expanding US oil production. Using data from Canada's National Energy Board (NEB), imports of Ontario diesel in 2016 came from both Western Canada and the US in proportions of 74% from Western Canada and 26% from the US. I assume these proportions to remain fixed for the rest of the simulation as a simplifying assumption. Thus, the emissions intensity of Ontario diesel is the weighted average of various sources from these two regions under the reference case. CIMS then calculates further reductions arising under the policy case. I assume US emissions intensity from their shale oils to decline at a similar rate of their shale sources of natural gas, reflecting technological progress, but no substantive GHG reduction policy.

I tracked upstream emissions for other fuels used in freight transport using CIMS. Electricity emissions for the province of Ontario are relatively low thanks to an electricity mix that is 90% GHG free following the province's aggressive coal plant phase-out in the

period 2004-2014. Under the policy scenarios, emissions from electricity decline even further, making upstream electricity emissions negligible by 2050. I calculated upstream emissions for biodiesel using CIMS for both reference (9 g/MJ) and policy (~3 g/MJ) scenarios. As was the case with diesel and natural gas, the emissions intensity of the upstream emissions for biofuels declines as policy induces less-GHG intensive harvesting and production processes. Upstream RNG or renewable diesel is not broken out into a separate sector for which to perform a similar calculation, so I assume the same upstream emissions for RNG and renewable diesel that are occurring with biodiesel.

Figures 5-4a and 5-4b graphically depict these trends in upstream emissions for both the reference and policy cases.

Figure 5-4a: Upstream Emissions- Alternative Fuel Vehicles
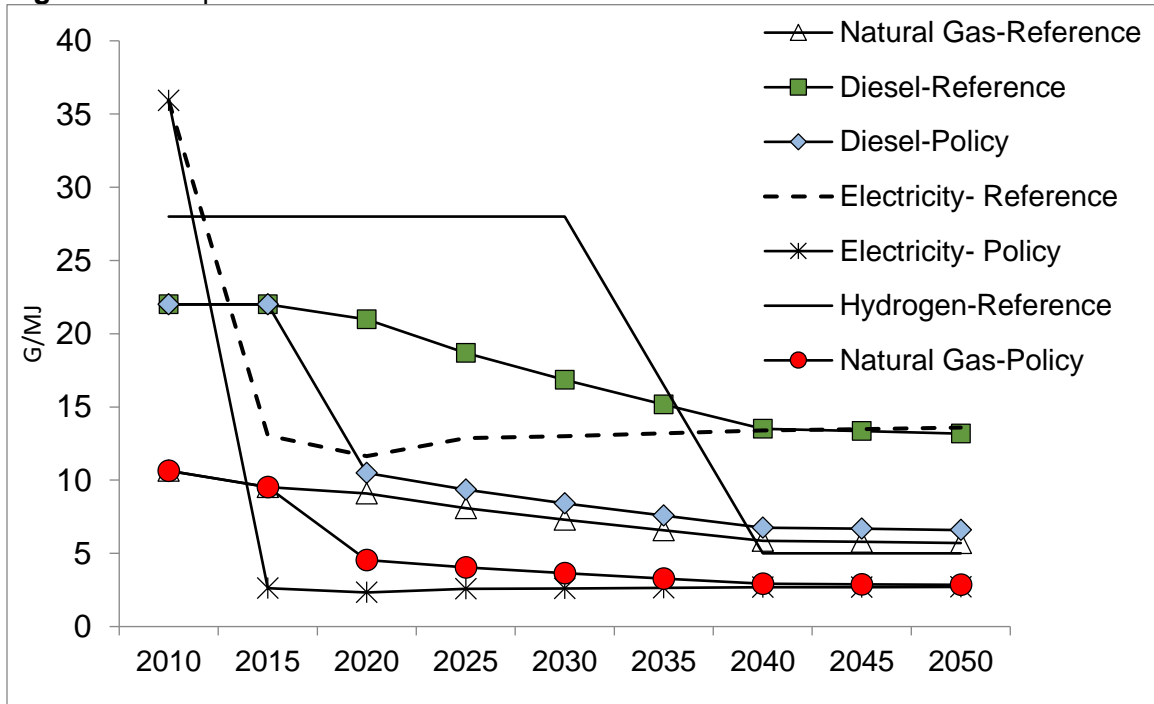
Figure 5-5b: Upstream Emissions- Biofuels
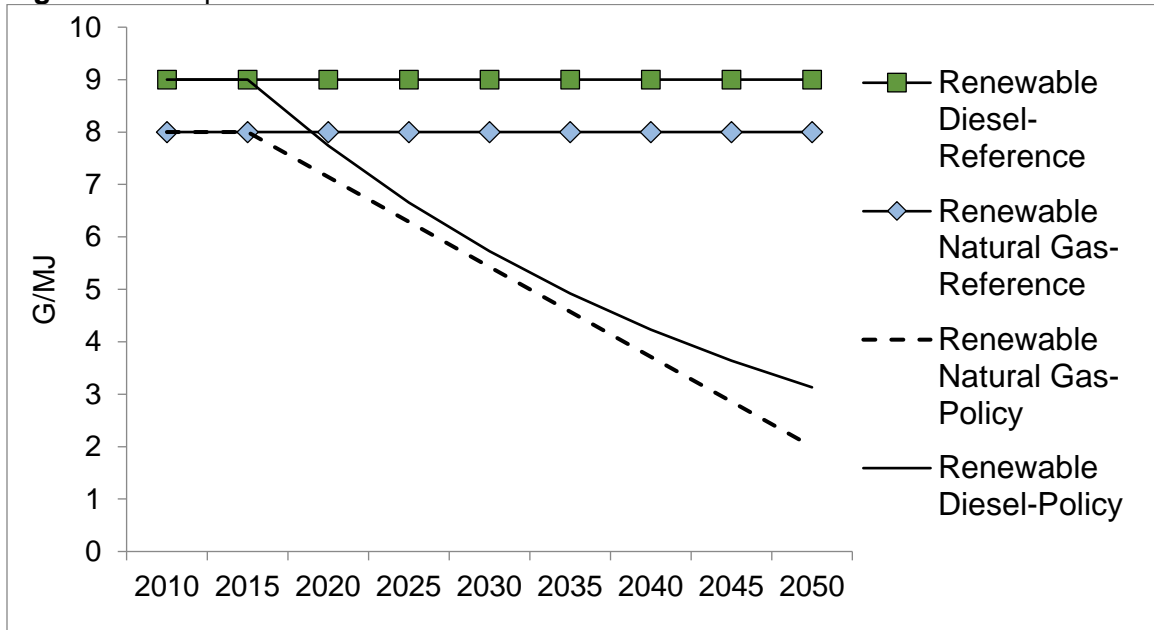
CIMS is capable of endogenous pricing of some fuels, solving in an integrative manner, so that supply equals demand (plus/minus exports/imports) and developments in one sector influence the other sectors. For instance, uptake of biofuels in the paper industry would raise the price of biofuels facing other sectors. For the purposes of this chapter, this endogeneity only applies to one energy form, electricity, as it is the only fuel type where exports and imports to Ontario are severely limited by transmission capacity to the US and other Canadian provinces. Thus, demand and generation in the province fundamentally drive the electricity price in Ontario, with net exports being a small percentage of total generation (Ontario IESO, 2018).

Natural gas too is a transmission capacity constrained fuel; however, I treat it as exogenous in the model due to most of its production occurring outside Ontario (Western Canada and the US). I assumed sufficient capacity to meet Ontario's Natural gas demand and growth in demand over the simulation. Transport options for other fuels, such as coal and petroleum products, is such that a global market for these fuels exists and so their prices are exogenous to the model. Ontario's small consumption of these fuels relative to the global total means that changes in consumption in Ontario would not influence their price. I obtained price trends for diesel, natural gas, and electricity from the most recent AEO 2018 forecast, and then adjusted them to reflect differences in the Canadian context (e.g. higher diesel prices to reflect higher refining margins and taxes).

Two key fuels whose pricing strategy deserves further mention are biofuels and RNG. Being regularly traded across jurisdictions, I modelled biofuels exogenously. However, I made some fundamental assumptions about the price trajectory of biofuels over the course of the simulation. Changes to the price over time represent the cost of different biomass feedstocks and pathways, as well as assumptions about the availability of biomass from a given pathway. I thereby divided the price of biofuels into two periods. The period pre-2030 represents the continued use of biofuels from oils and fats and prices over this period are declining due to upscaling of these markets and learning-by-doing. Between 2025 and 2030, however, the global system begins transitioning to advanced biofuels using lignocellulostic feedstocks and conversion processes such as Fischer-Tropsch and pyrolysis. Prices rise in 2030 from the switch to these more advanced sources. However, this price increase is assumed to be temporary due to eventual cost declines of advanced biofuels that arise due to upscaling, the formation of consolidated supply chains, and learning-by-doing.[46,47] As such, cost declines of biofuels from these advanced processes are realized between 2030 and 2050, such that by 2050 the cost of biofuels begins to approach that of conventional diesel.

RNG was a new fuel for CIMS added to the model for this study. To reflect changes in the price of this fuel for blending with natural gas vehicles, I constructed a RNG supply curve for Canada, where the price of RNG varies as a function of its cumulative production. The upward sloping curve reflects the increasing cost of production as less costly sources of RNG for Canada (methane from solid waste) gives way to more expensive alternatives (gasified biomass and RNG from agricultural sources).[48] I converted the cost of RNG to prices facing the end user for transportation by adding the cost premium between RNG production and natural gas extraction and processing to the final sale price (about $9/GJ). Since RNG, like renewable diesel, benefits from its ability to integrate seamlessly into the existing infrastructure, I added no additional infrastructure costs in transmitting and distributing the RNG from the producer to the final consumer. I fed changes in demand of RNG into the supply curve to generate changes in cost from moving along the supply

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[46] Currently, FT and pyrolysis processes have a cost premium of 112% and 170% above diesel respectively (Mitkidis, Magoutas, & Kitsios, 2018).

[47] The IEA forecasts a learning rate of 20% for these fuels (IEA, 2011).

[48] See Appendix E for a more detailed description.

curve. I then added these new costs to the model, which would temper demand when I re-ran the model.

A limitation to this approach is that CIMS represents RNG in the freight sector only, despite other potential applications for RNG to de-carbonize natural gas in other sectors, such as buildings and industry. Thus, I made two assumptions about the extent of RNG use by the rest of the Canadian economy, and thus its price, which I ran as alternative scenarios. The first assumes that RNG adoption only occurs in the Ontario freight transport sector and nowhere else in the economy. This scenario represents a lower bound of RNG price where I iterate changes in RNG price from the supply curve based on the cumulative consumption that is occurring in the Ontario freight sector. At the other extreme, I assume widespread adoption of RNG in Canada to de-carbonize natural gas across all sectors, starting at 2035. For this high RNG price scenario, 2040 reaches the maximum extent of cost on the supply curve.

Figure 5-5 below illustrates the price trajectories of these, and other key fuels for the sector on a GJ basis.

Figure 5-6: Energy Prices ($/GJ)
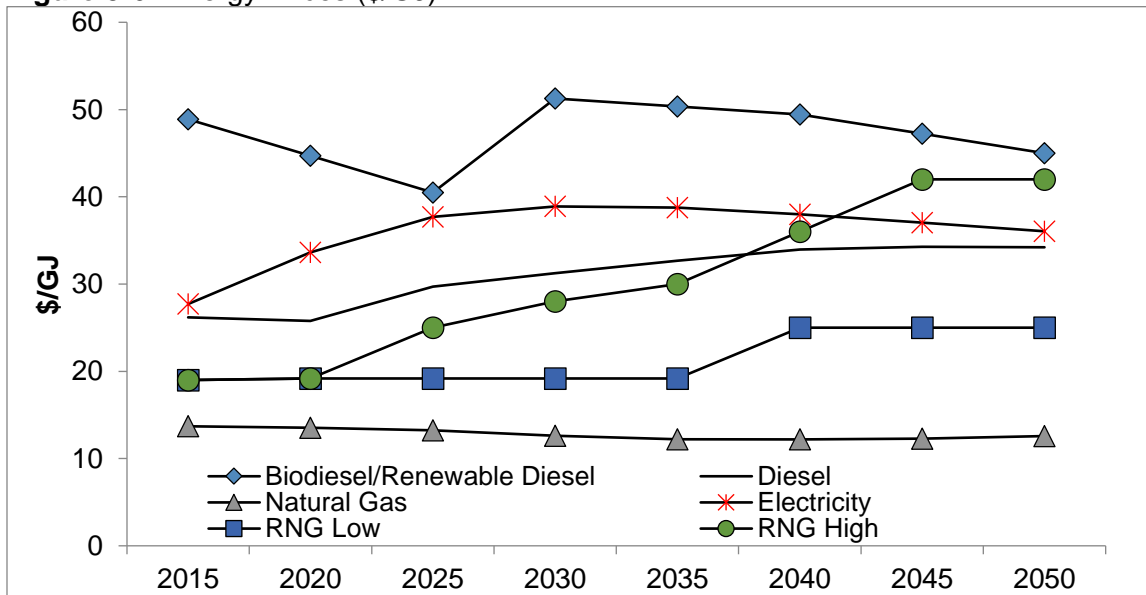
*N.B. The natural gas prices presented in Figure 5-5 are higher than those presented elsewhere in this thesis as the above prices reflect the prices facing the end user in transportation, which are significantly higher than natural gas spot prices or plant gate prices (natural gas prices for utilities). These price differences are due to a lack of economies of scale in distribution to the many dispersed transportation end users.

5.3.4 Key Technology Choice Parameters

Key parameters in this techno-economic assessment are the CIMS "i", "r", and "v" parameters described previously in chapter 2. Modelling these implicit choice parameters is admittedly challenging due to the need to convert these drivers of consumer decision-making into values that can be explicitly modelled. This section provides a deeper dive into my justifications for these parameters in CIMS.

 The "i" parameter represents any intangible costs that might be felt by purchasers of a technology that aren't reflected in its purchase price. As an example pertaining to vehicles, consumers may be apprehensive about the lack of range, coupled with a lack of abundant recharging stations, of alternative fueled vehicles that require new charging infrastructure. For instance, McCollum et al., 2017 looks at the literature for incorporating behavioral choice parameters, including intangible costs, into integrative assessment models. Their analysis concluded that intangible factors play a large role in alternative vehicle adoption, and they subjectively assessed these factors based off the strength of their evidence from the literature. They found the highest evidence for intangible costs to occur when there are needs for a separate refueling network, when there are few alternative brands, when battery recharging time (for electric vehicles) is long, when warranties may be absent, and when vehicle range and refueling availability are poor. This evidence base provides justification to apply intangible costs to technologies that are i) novel with limited market penetration, ii) require alternative fuels with refueling infrastructure; and iii) have lower ranges than prevailing diesel engines. From the table in section 5.2 describing the qualitative adoption drivers, I applied intangible cost parameters to electric trucks, plug-in-hybrid trucks, natural gas trucks, hydrogen and dedicated biotrucks, based off the criteria i-iii.

Axsen et al. (2009) empirically derived an "i" parameter for electric vehicles in personal transportation using stated and revealed-preference surveys. While exact results depend on the econometric specification, they found values for these intangibles to include declining intangible costs that are nearly 33% above the explicit purchase price for electric vehicles (but that decline rapidly with increased market share). Recent CIMS researchers such as Fox et al. (2017), and Vass & Jaccard (2017), provide intangible costs based of the findings of previous CIMS researchers coupled with their own literature review and judgment. The above work, however, pertained to personal transport and not to freight.

To my knowledge, a survey of the freight sector that is comparable to Axsen et al. (2009) has yet to be undertaken. This would be an interesting area for future research as a firm understanding of intangible parameters would be essential in understanding the dynamics of this sector. In the meantime, I calculate the magnitude of the intangible cost for heavy electric trucks, plug-in-hybrid trucks, hydrogen and dedicated bio-trucks using the values that prior researchers obtained for personal transport and applying them to trucks at the same ratio of intangible cost to financial capital cost.

For natural gas trucks, I applied a different methodology to calculate intangible costs based off simulations generated by CIMS for the adoption of heavy natural gas trucks over the 2005-2015 period. When allowed to compete without intangibles, CIMS calculates adoption of natural gas trucks that exceed the actual historic data. Thus, I incrementally applied intangibles to this technology so that CIMS accurately backcasts to actual adoption for Ontario. As mentioned, there is strong a priori reason to believe intangibles would apply to natural gas trucks, and so the lack of adoption of this technology, despite its favorable business case as predicted by a simple cash-flow analysis, must be due to intangibles that such an analysis would not capture.

The "v" parameter, a parameter between 1 and 100, governs the slope of the logistic function that determines market share. Higher values of v mean that the technology competition becomes more sensitive to the life-cycle cost of a technology, the probability distribution around life-cycle cost is tighter around the mean, and firms and households are modelled as more homogenous is their needs relative to when v parameters are low. While a specific parameter to CIMS, the v parameter is analogous to an elasticity of substitution between the competing technologies, as it represents the sensitivity of adoption of these technologies to their relative prices. Mau et al. (2008) and Horne, Jaccard, & Tiedemann (2005), and Axsen et al., (2009) all find v parameters of about 5 for personal transport, while Rivers & Jaccard (2005) find a v parameter of 1.4 for industrial boilers and co-generators. Most of the parameters in CIMS lie between 0.4 and 50, with 10 being the most common value.

While the personal transport sector is likely a very heterogenous market due a wide range of personal factors influencing purchase decisions[49], in commercial trucking I model

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[49] e.g. attribution of new technology like EVs to images of intelligence, responsibility, environmental stewardship, and national support (Axsen and Kurani, 2013).

purchase decisions to be based more on the underlying business case. Thus, I model the competition of trucks to be more homogenous, with a value of 15, reflecting the higher end of this parameter across sectors in the CIMS model. I acknowledge that there is significant uncertainty regarding this parameter, which does not have a firm empirical basis in the literature. I conduct sensitivity analysis on this parameter in section 5.6.

There is a body of evidence within the transport economics literature of cross-price elasticities of mode choice between rail and truck in freight, which represent the change in mode share for a percent change in price of the substitute mode (see Oum, 1979; Friedlaender & Spady, 1980; and Abdelwahab 1998). Prices used to measure these cross-price elasticities are usually measured by freight shipping fees, which would include such factors as technology and fuel costs, among other cost considerations. The values from the empirical literature are generally positive indicting substitution between rail and truck in freight, giving credibility to the structure of CIMS which endogenously models this inter-modal competition. Other research suggests that the decision between mode choice for land-based heavy freight truck vs. rail tends to be a function of many factors, such as cargo type, economic structure (Schewel & Schipper, 2011; Schipper & Grubb, 2000; Eom et al., 2012), country-specific congestion conditions (Kamakate & Schipper, 2009), and other considerations such as reliability, ease of access, delay time, and availability of loading/unloading equipment (Moschovou & Giannopoulos, 2012; Arencibia, Feo-Valero, García-Menéndez, & Roman, 2015).[50] This latter body of research indicates that for this competition node between rail and freight, a lower v parameter is appropriate to represent this heterogeneity in consumer preferences. For the v parameter of 5 that I chose for this node, I calculated the elasticity of mode choice between rail and truck generated from CIMS to be 1.92, which is within the range found in the literature of 0.9 to 2.5.

The r parameter represents the implicit real discount rate (r parameter), which is the time-preference of firms and households and how they trade-off the future vs. the present in their purchasing decision. I modelled an r parameter of 25%, which is the default CIMS r parameter for freight. This r parameter is close to the midpoint of the range found in the survey by Train (1985) of 2% to 45% for personal transportation, and is comparable to work by CIMS researchers for personal transport by Mau et al. (2008), Axsen et al., 2009,

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[50] As an example of what is meant by economic structure, economies where bulk commodities make up a large fraction of economic activity tend to favour rail over truck transport.

and Horne, Jaccard, & Tiedemann (2005) of 21%-40%, 21% and 22.5% respectively. These values contrast to explicit real discount rates of about 5-10% used in most cash-flow analysis, with the range reflecting the risk of the investment.

Table 5-4 below illustrates the values for used in CIMS for key "i", "r", and "v" parameters and the justification/source for each.

Table 5-4: "r", "I", and "v" parameters-CIMS Freight

Parameter	Value	Source/Justification
V parameter-Motors	15	Judgment. Modelled commercial trucking purchase decisions to be based more on the underlying business case than other sectors like personal transport, making the competition of truck motors more homogenous. A value of 15 reflects the higher end of this parameter across sectors in the CIMS model.
V parameter-heavy truck/rail mode choice	5	Lower v parameter to represent higher heterogeneity in consumer preferences as found in the literature. Yields elasticities of mode choice between rail and truck that are within the range found in the literature.
Fixed Intangible Cost parameter-heavy truck/rail mode choice	21% above truck	Yields elasticities of mode choice between rail and truck that are within the range found in the literature. Rail should face higher intangible cost relative to truck due to rails limitations in terms of flexibility and areas serviced.
R parameter	25%	Default CIMS parameter representing agent's rate of time preference for end use applications. Within literature range pertaining to r parameter estimates for personal vehicles.
Declining Intangibles-Biodiesel, Hydrogen, Electric Trucks, Plug-in-Hybrid	**Heavy:** ETrucks-$95,000 PHETrucks-$71,000 Hydrogen-$107,000 Biodiesel-$80,000 **Light Medium:** ETrucks-$47,500	Declining intangible costs associated with alternative truck motors are similarly required due to technological unfamiliarity and the need to establish refueling infrastructure for the alternative fuels. I assume these to be in similar proportions to the financial capital cost of the vehicles in question as per Fox et al., 2017 for personal transportation. In their paper, the relative declining intangible costs corresponded to challenge to establishing refueling infrastructure; (e.g. PHEVs not being as reliant on new charging infrastructure as EVs, and thus would see a lower declining intangible cost than the latter) with values being based on a scan of the

Parameter	Value	Source/Justification
	PHETrucks-$35,700 Hydrogen-$53,400 Biodiesel-$40,000	literature. I justify my assumption on the basis that the same logic would apply to trucking.

Light-medium trucks, because they usually travel repetitive routes with shorter hauls, were given relatively lower intangible costs as a fraction of their purchase price. |
| Declining Intangibles-Natural Gas Trucks | LNG Heavy Trucks-$60,000

CNG Light Medium Trucks-$30,000 | Declining intangible costs are necessary for natural gas trucks due to unfamiliarity of the technology and a current lack of recharging infrastructure. In addition to this theoretical justification, backcasts of the freight sector in Ontario without intangible costs for natural gas trucks result in greater natural gas truck adoption than shown by the historical data. The intangible costs that are applied to natural gas trucks, were chosen so that adoption of natural gas trucks in the 2005-2015 period reflects the historical reality. |
| Declining intangibles rate and shape | Rate 0.0065 Shape: 40 | Similar to used for personal vehicles in Fox et al. (2017) and Axsen et al. (2009) |
| Fixed Intangible Costs | **Heavy:** ETrucks-$7,500 PHETrucks-$0 Hydrogen-$7,500 Biodiesel-$7,500 Natural Gas-$7,500 | Some fixed intangibles would also be necessary due to residual intangible costs among a certain fraction of the population to alternative fuel vehicles.

Similar to declining intangible costs, I took the values used in Fox et al. (2017) for personal transport and pro-rated them to heavy trucks based on their proportion of capital costs.

However, I did not include these for light-medium trucks due to range anxiety not being an issue for the repetitive urban routes associated with this segment. |
| Recharging Infrastructure Costs | Not included | Some firms may find private recharging infrastructure at the warehouse to be important in the early days of the roll out of alternate vehicle technologies until public charging infrastructure becomes widespread. However, I did not include these costs for this transition period. |

Declining intangible costs, as mentioned previously, represent declining costs due to increasing consumer acceptance that arise from witnessing use of the technology from other buyers and more abundant recharging infrastructure. These are treated endogenously to the model as a location-specific phenomenon (Fox et al., 2017).

Overall, there is a large degree of uncertainty surrounding many of these key parametric assumptions. Consequently, section 5.6 provides a sensitivity analysis on some of the more uncertain parameters on the key policy scenarios in the next section.

5.3.5 The Policy Scenarios

I ran four scenarios with differing assumptions about climate policy and knowledge about the carbon price trajectory over the simulation period: a reference, a strong carbon constraint, a weak carbon constraint, and a slow ramp up case. The slow ramp up case reflects a scenario where firms and households have limited prior knowledge of an initially slow carbon price trajectory that ramps up rapidly in later years. This contrasts with the remainder of the carbon price scenarios where firms and households have full foresight of a linearly increasing carbon price trajectory to 2050 upon announcement of the policy. The concept of foresight reflects firm and household knowledge about the future policy. With full foresight, knowledge of the simulation's future carbon price is available and considered by individuals and firms making decisions about vehicle investments.[51] With limited foresight, agents lack knowledge of future carbon prices until the policy is finally implemented. The case of full foresight might arise if policymakers announce the ramp up of carbon prices to 2050 in a visible, transparent and credible manner. By contrast, a limited foresight case might occur if a stringent policy later follows initially weak (or non-existent) climate policy, and the mid-stream change in trajectory occurs relatively suddenly without warning. I vary this foresight in the model by changing a built-in feature of CIMS.

I modeled the slow ramp up with imperfect foresight scenario to test whether natural gas trucks could play a role as a bridging technology, as natural gas trucks could make inroads when policy is weak, and then incrementally de-carbonizing trucks further by blending with RNG as the policy suddenly becomes more stringent.

I describe the scenarios in more detail in Table 5-5 below:

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[51] As was noted in chapter 3, foresight here is not foresight found traditionally in the economics literature- of an agent optimizing across time.

Table 5-5: Scenario Description

Scenario	Policy	Comments
Reference (existing freight sector policies for Ontario as of 2016)	• Greener Diesel Mandate- 2% biodiesel mandate starting in 2014, followed by a 4% mandate in 2017, • Subsidy of 50% of the incremental purchase price of Electric and Natural Gas Trucks • Provincial fuel taxes • Heavy Duty Vehicle and Engine GHG Emission Regulations (Introduced first in 2014 and then updated in 2017)	This scenario does not include the planned Federal Clean Fuel Standard, requiring reductions in the lifecycle carbon intensity of fuels. The program is expected to result in incremental emissions reductions of 30Mt by 2030. Consulting firm Navius used CIMS to model a 10% reduction in the carbon intensity of energy consumption in transportation by 2030 to achieve the overall reduction of close to 30 MtCO2e in 2030 (Wolinetz, Peters, Sawyer, & Stiebert, 2017). Their policy design of the CFS resulted in incremental emissions reductions from freight by about 10Mt across Canada due to greater uptake of biodiesel and renewable diesel primarily. Of interest is that it results in a slight (1 percentage point) increase in tkt from natural gas trucks for Canada. Overall impact for Ontario will cause a small deviation from existing trends.
Strong Policy	• Carbon price begins at $120/tonne in 2020 and increases linearly to $570/tonne by 2050 • Foresight of policy. Fleet operators have time to adjust their vehicle purchase decisions in a manner that they see as optimal over time	Involves a gradually rising carbon price that achieves, as close as possible, an 80% reduction in GHGs below 2005 levels by 2050 starting in 2020 for Canada, which is consistent with the limiting of global warming to 2 degrees above pre-industrial levels.
Strong Policy- Limited Foresight	• Limited foresight where fleet operators lack knowledge of the future carbon price trajectory until 2035, when, finally, a clear path to 2050 is articulated • Slow ramp up of the carbon price pre-2035, starting at $30/tonne in 2020. The carbon price increases rapidly post-	Represents a world where policymakers are more hesitant to engage in stringent climate policy and instead implement partial interim measures. Test of a bridge-fuel/technology hypothesis

Scenario	Policy	Comments
	2035 to achieve the same $570/tonne rate by 2050.	
Weak Policy	• Lower carbon price starting at $23/tonne in 2020 and rising to $150/tonne in 2050. Fleet operators have foresight of the price trajectory.	Starting value In line with current Pan Canadian Framework commitments with modest growth after 2030.

5.4 Results: Business as usual reference case

Figure 5-6 below illustrates energy use trends for the freight sector under the BAU scenario. Petroleum products, predominantly diesel, remain the largest source of energy in freight, with little uptake of any alternative vehicles over the remainder of the simulation. There is an increase in biofuel blending and renewable diesel beginning around 2020. By 2050, the blend rate in a litre of diesel purchased at the pump is approximately 13% biofuels- up from 2%-4% today. Natural gas also sees some uptake later on in the simulation as diesel prices begin to rise relative to natural gas prices.

Figure 5-7: Reference case Energy Mix (PJ)

Legend:
- Natural Gas
- Electricity
- Refined Petroleum Products
- Biodiesel
- Renewable Natural Gas
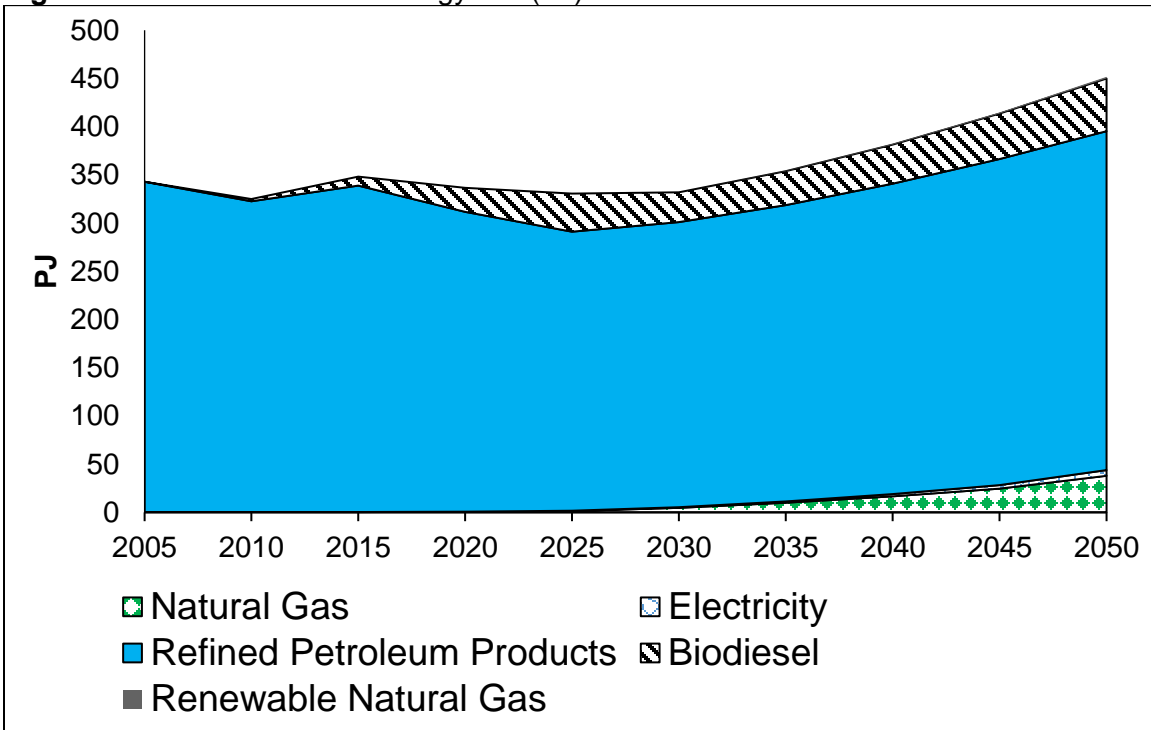
Petroleum products essentially remain dominant due to increasing shares of more efficient diesel engines, mandated by policy, and a nearly flat diesel price as per the forecasts in the latest AEO2018. In past versions of the AEO, diesel prices were rising for later years of the simulation, which resulted in a greater use of alternative fuels. For instance, in previous runs using AEO2016 diesel prices, I noticed an uptake of electric trucks around 2030 in the light-medium truck segment, having a substantial impact on emissions and the energy mix for the freight sector. While the higher diesel prices under AEO2016 were the catalyst for this transition in the light-medium segment, it was aided by other modelling assumptions discussed previously such as strong declining capital costs, as well as the neighbour effect reducing intangible costs with increased market share. In addition, the light-medium freight segment involves shorter and repetitive routes, such as municipal garbage collection, and so lower intangible costs relative to total capital costs were justified for Etrucks in this segment relative to heavy freight.

Figure 5-7 below illustrates the projected and historic trends in downstream (tank-to-wheel) emissions for freight. Evidently, emissions in CIMS closely follows the historical trends in both metrics up to 2015. Afterwards, emissions begin to decline in line with falling energy use due to increases in the fuel efficiency of diesel trucks, as well as from increased fuel switching to biodiesel. These factors reduce emissions to 21 $MtCO_2e$ by 2025. However, after 2025, I did not model any further mandated diesel emissions intensity improvements, and so energy use and emissions begin to rise in line with increased economic activity for the sector. The result in that emissions in 2050 lie approximately 14% above the current level.

Figure 5-8: Reference case Emissions Trends (MTCO$_2$e) for Freight
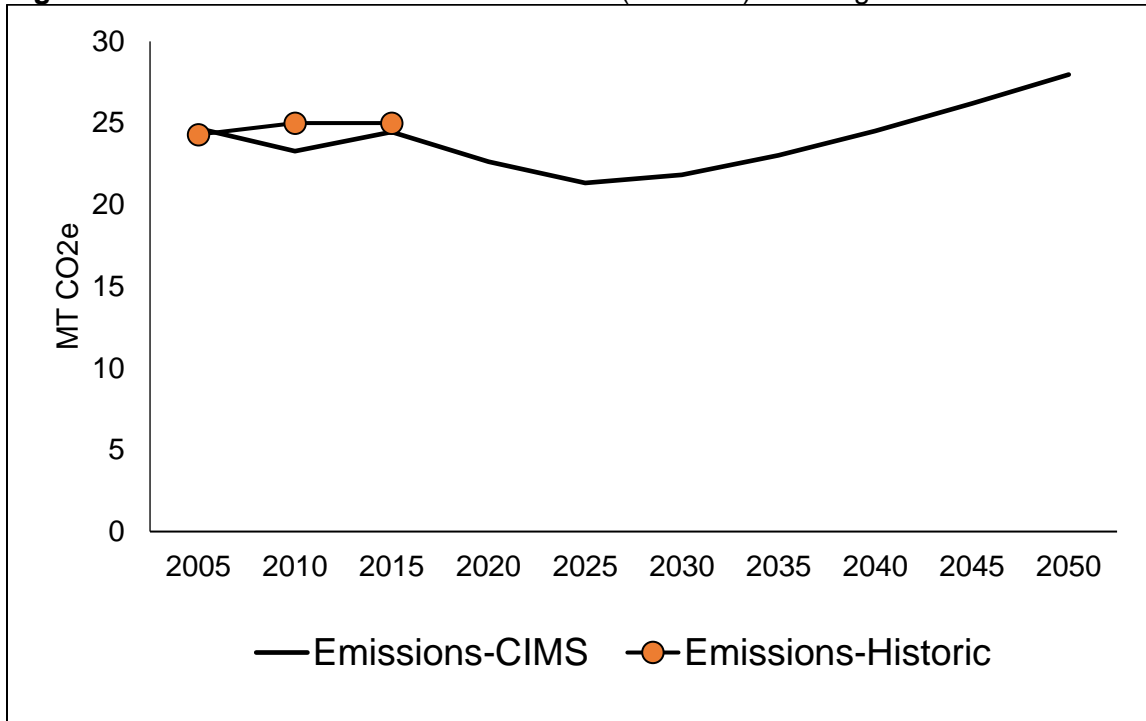
While figures 5-6 and 5-7 pertain to all sources of freight transport to provide an overall picture, figure 5-8 and 5-9 hone in on heavy freight, the focus of this paper. Figure 5-8 below breaks emissions down by a selection of key sub-segments in freight. Heavy trucking emissions decline from a peak in 2015 to about 8.5 Mt by 2035, before starting to increase again to 10.6 Mt by 2050. These trends mirror the dynamics witnessed by the freight sector as a whole, with the initial decline in emissions due to improved efficiency and lower overall energy use is then followed by emissions increases as the rate of growth in sector activity outpaces the rate of further efficiency improvements. Similar dynamics are at play for light-medium trucks.

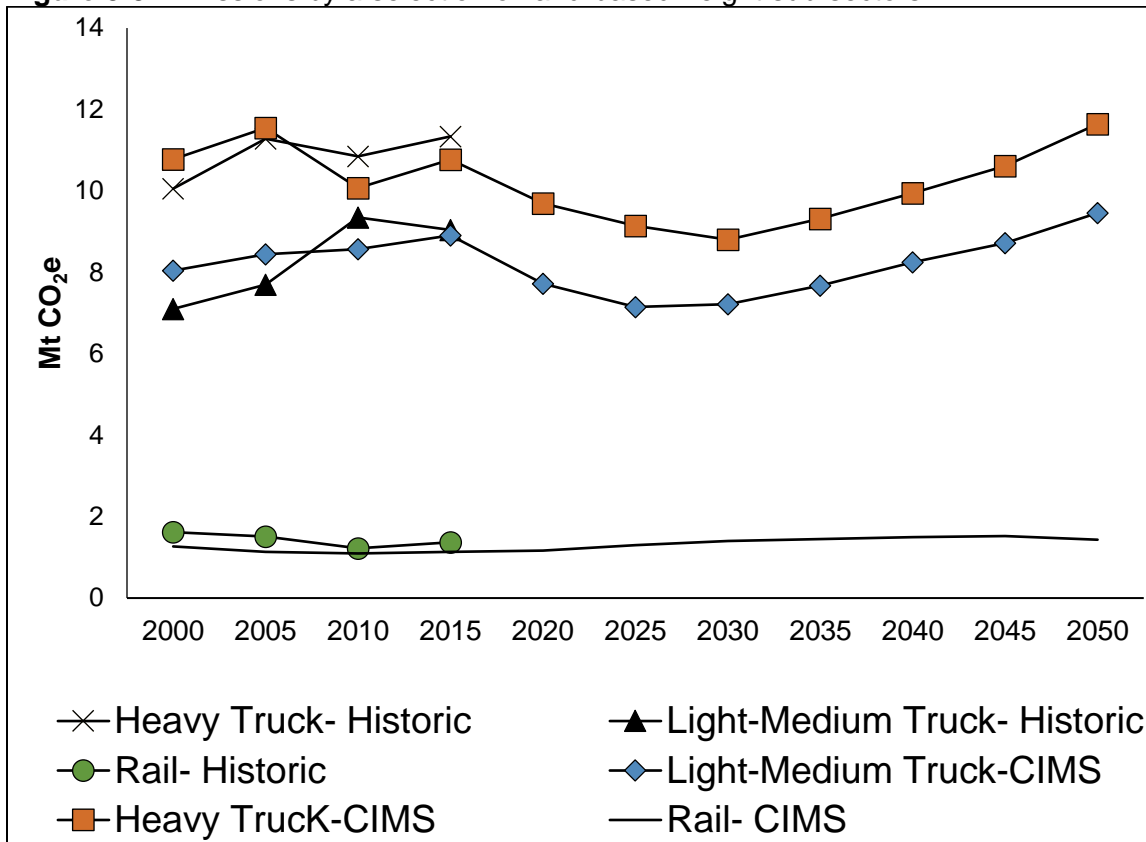**Figure 5-9:** Emissions by a selection of land-based freight sub-sectors

Figure 5-9, examines fuel substitution in the heavy freight sub-sector in more detail. Key trends here also mirror the overall trend in energy use for freight. As with the latter, diesel remains the overwhelming fuel of choice in heavy trucks, despite some inroads by biofuels as well as limited uptake of natural gas vehicles. As was also the case with total freight, my results show an initial decline in total energy use by heavy trucks, declining from a peak of around 160 PJ to 130 PJ by 2030. Part of this decline is due to the uptake of more energy efficient trucks driven by Canada's heavy-duty vehicle GHG standards introduced in 2014 and tightened in 2017. However, another factor contributing to the decline is a mode shift away from trucks and toward rail to move heavy land-based freight.
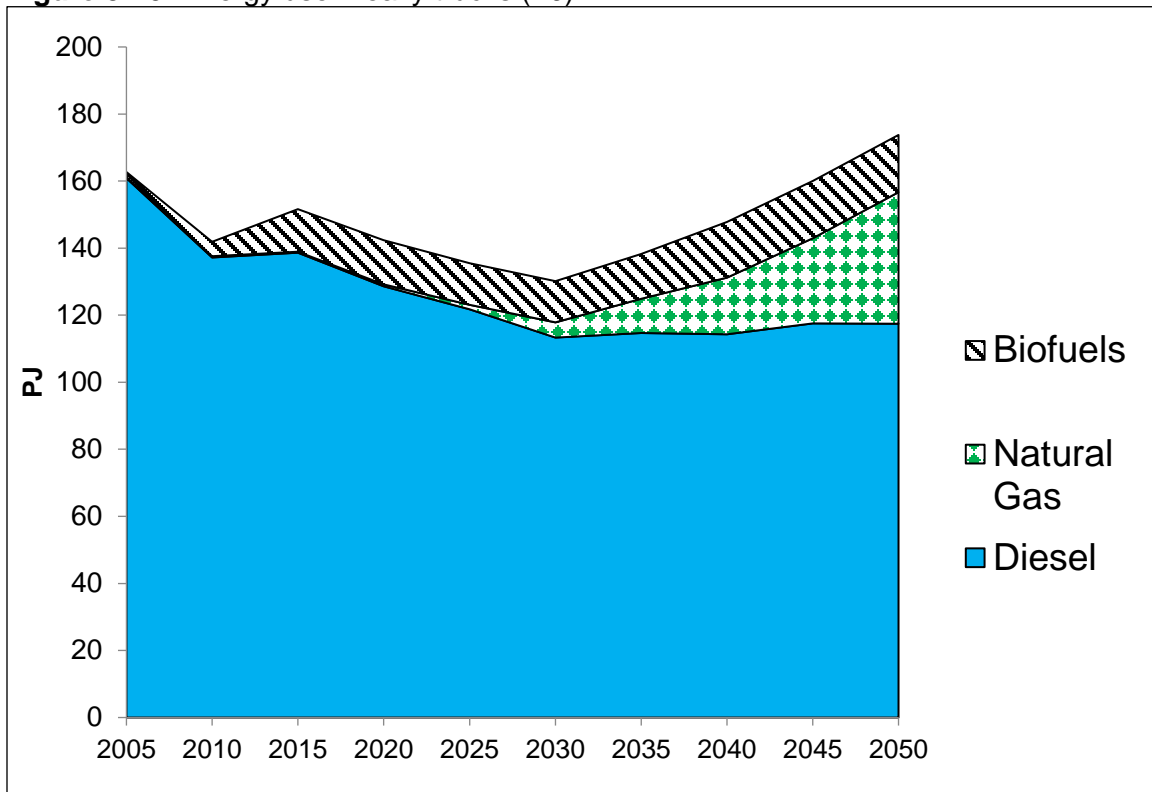
Figure 5-10: Energy use- heavy trucks (PJ)

Figure 5-10 below illustrates this trend, showing how after 2020 there is an increase in heavy rail's share of heavy land-based freight movement at the expense of heavy trucks. Causing this trend is the increase in the cost of trucking relative to rail on a lifecycle basis, a result of regulation forcing costlier (but more efficient) heavy trucks into the market, as well as a rising cost of diesel. This has consequences for emissions in the heavy freight sector due to the superior energy intensity of rail vs. trucks, effectively providing a double benefit for the freight sector stemming from the aforementioned regulations forcing the purchase of more efficient diesel trucks.

Figure 5-11 exemplifies this benefit, by comparing emissions under a simulation where I allow mode shifting between rail and heavy truck, to a second projection where I do not allow this mode shift to occur. Emissions from heavy trucks are consequently higher under the no-mode-shift simulation. This dynamic between heavy rail and heavy trucks, and its consequent impact on the emissions of heavy freight, is a theme that reoccurs later in this chapter as I assess the evolution of the freight industry under differing scenarios.

Figure 5-11: Heavy Truck vs. Rail share of Heavy Land Freight
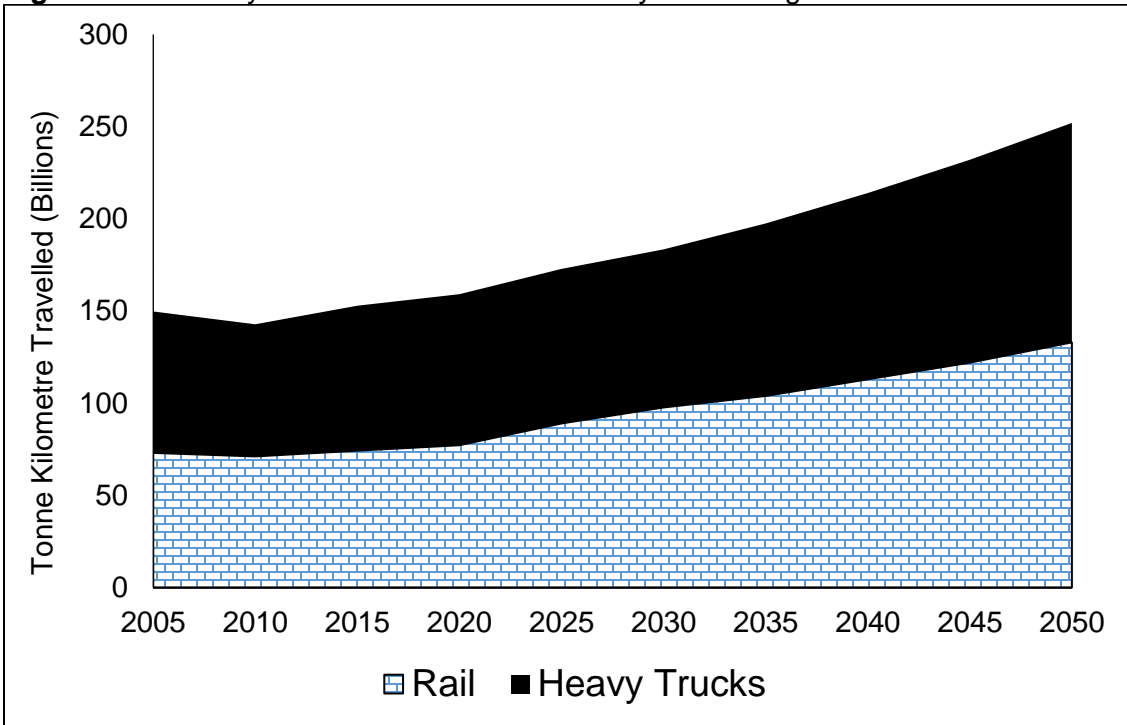
Figure 5-12: Emissions from heavy trucks: mode switching allowed vs. no mode switching
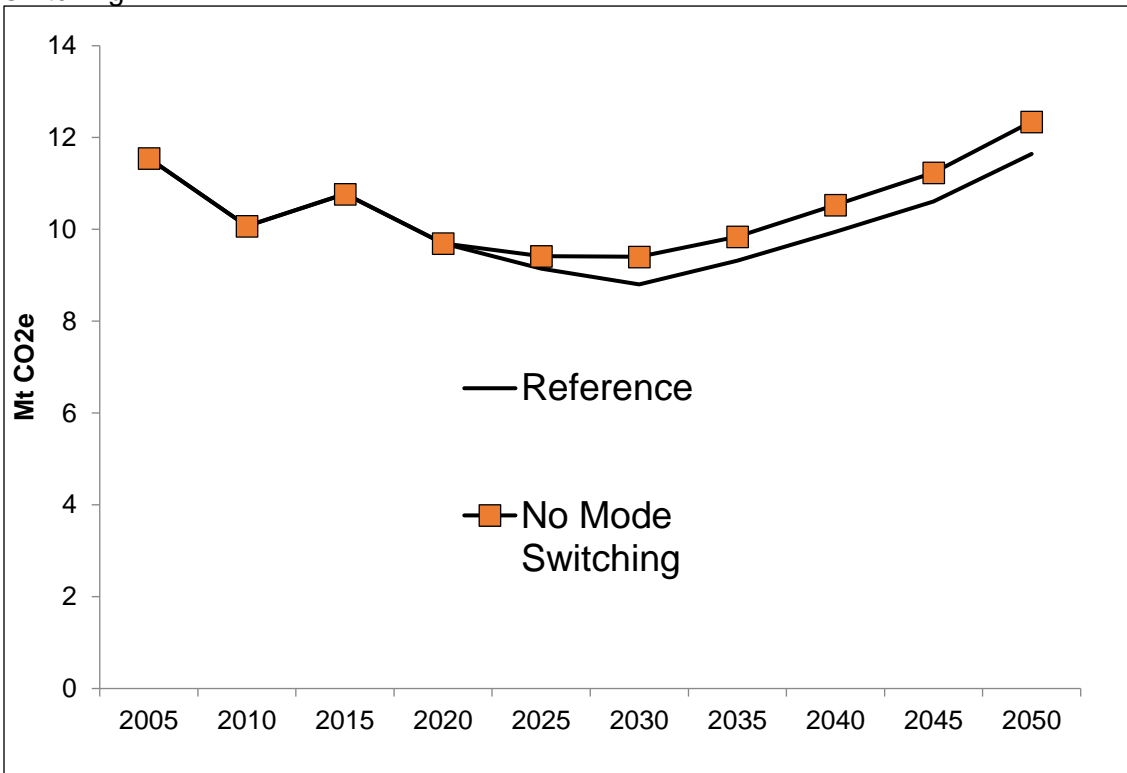
5.5 Results: Policy

In addition to the preceding projections under BAU, I assess the dynamics of the freight sector under three carbon-constrained cases: i) the strong constraint with foresight and measured ramp up, ii) a strong constraint with limited foresight plus slow ramp up, and iii) a weak policy with foresight. Figure 5-12 illustrates emissions for the total freight sector under each scenario. Emissions for the freight sector decrease precipitously across the two strong policy scenarios, with the freight sector as a whole approaching near-complete de-carbonization with regards to annual emissions by 2050. The lack of foresight of the carbon price with the ramp up policy; however, influences the timing of the emissions reductions for this scenario relative to the scenario with foresight causing reductions to occur later under the former scenario. Consequently, cumulative emissions are lower by about 15% under the foresight scenario. Under the weak scenario, annual emissions in 2050 remain relatively high, declining by only 4Mt relative to the baseline- a 15 % decline.

Figure 5-13: Emissions (MTCO2e) for freight under the four scenarios
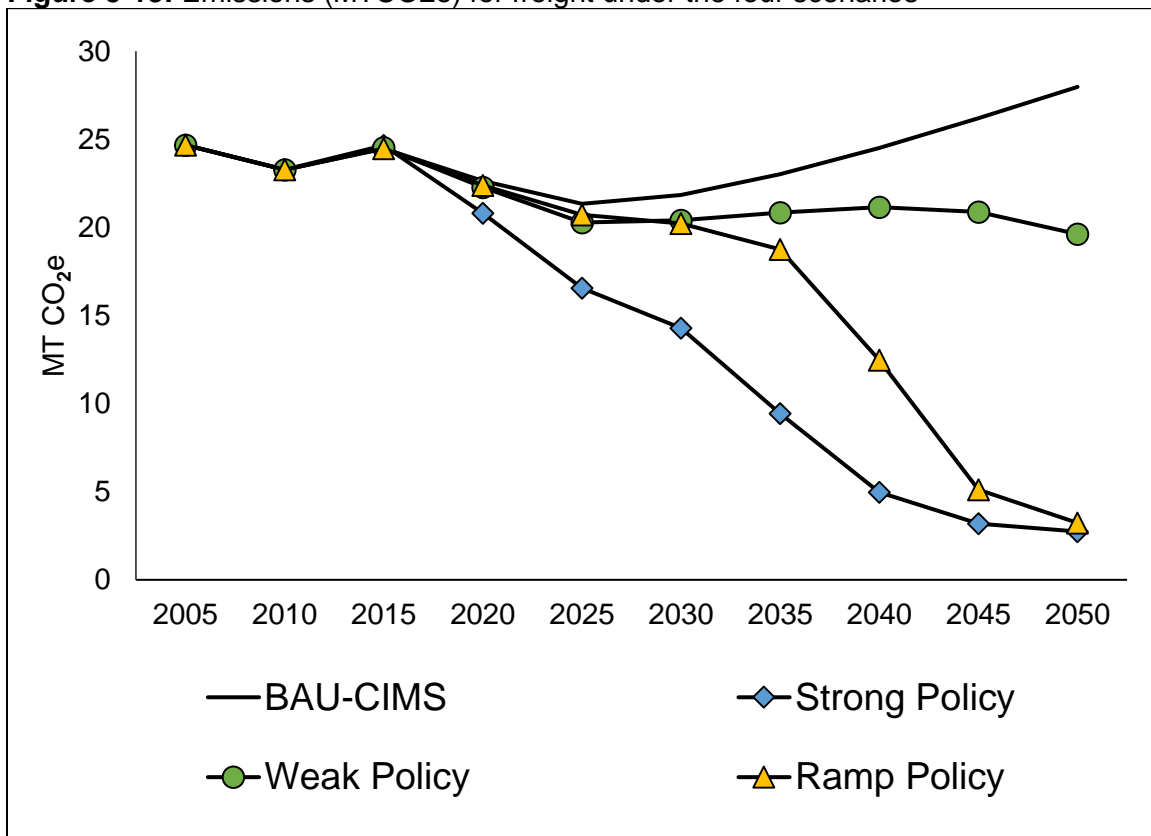
Figure 5-13 below breaks down the drivers of this decline in freight emissions across policy scenarios by showing the segments that comprise Ontario's land-based in 2030 and 2050. In addition, I ran each policy scenario with two assumptions about the future price of RNG:

i) a low RNG price scenario, where RNG uptake is limited to freight transport in Ontario and so RNG costs remain low; and

ii) A high RNG scenario, where I assume higher RNG costs due to a greater uptake of RNG elsewhere in other sectors and jurisdictions across Canada.

Figure 5-14: TKT broken out by source under reference and policy scenarios
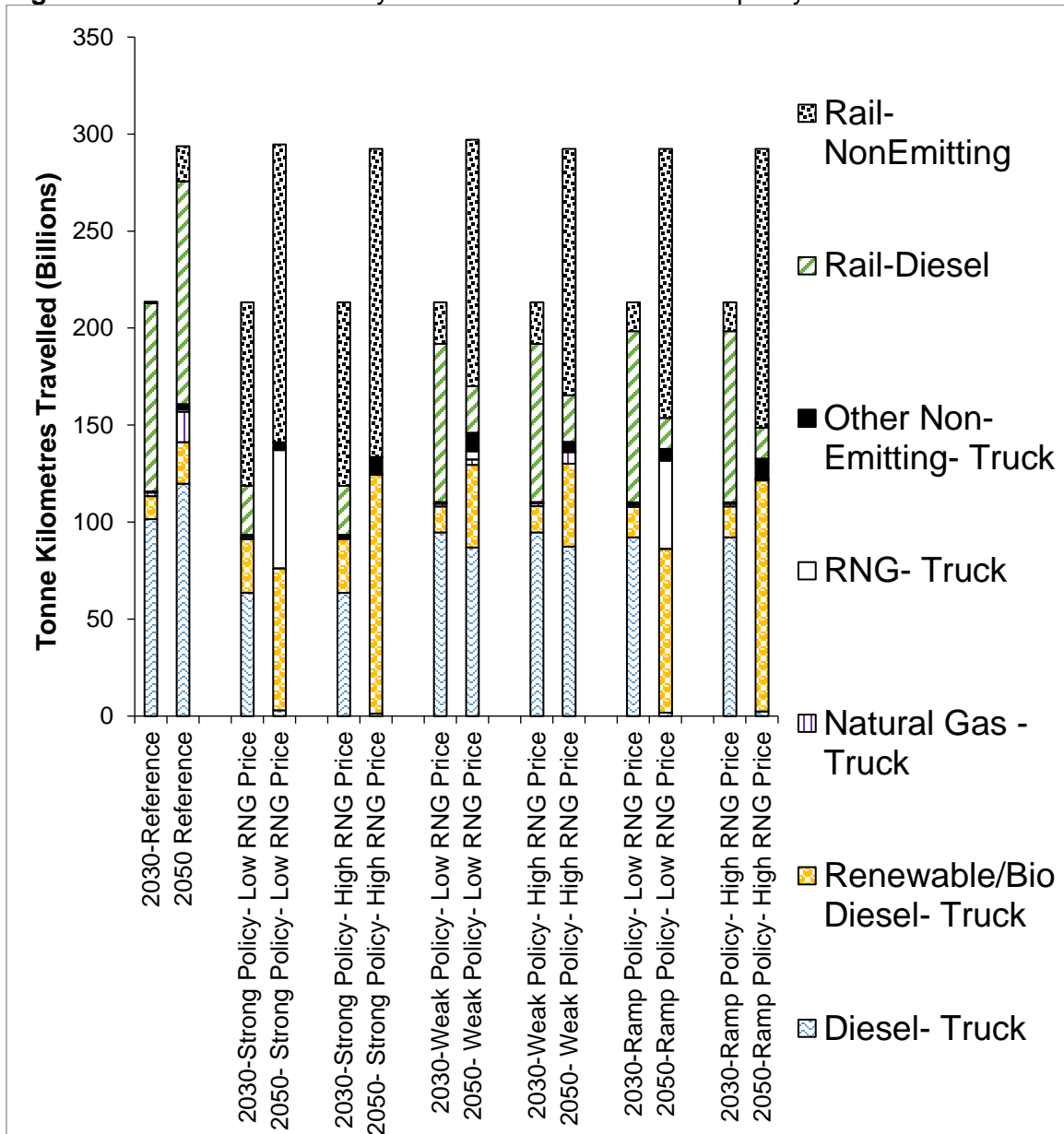
Several key insights are evident from the above figure. Firstly, across policy scenarios, rail moves a greater percentage of total land-based freight due to its superior fuel-economy on a tonne kilometer travelled of freight basis. Under weak policy scenarios, the rail stock remains mainly powered by diesel in 2030, but moves to a greater share of non-emitting rail (mainly electric) by 2050. Under strong policies, the rail stock is practically completely de-carbonized by 2050, and the mechanism for that de-carbonization is primarily through electrification, adding about 26PJ in electricity demand on the grid

This finding poses challenges, for it suggests that in order to achieve the emissions targets set out under the strong policy at least cost, over 70% of land-based heavy freight will need to be moved by rail (up from about 50% currently). This is a considerable increase, and it is unclear to what extent the rail infrastructure in Ontario will require additional investments in track to make it possible, and whether the timing of the necessary investments is feasible. Another challenge is that we do not know what the economy of Ontario will look like in 2040, and whether freight by rail will make sense to move the type of goods that Ontario will be producing. Currently, the largest products moved by rail are agricultural products, resources/minerals, and metals and machine products (Railway Association of Canada, 2017). Many of these are relatively low value bulk commodities that can easily fill up a rail container and make the purchase of the container by the shipper worthwhile through economies of scale. Should the Ontario economy depart even further from this economic model, is a future where ~70% of freight is moved by rail very realistic?

As an additional scenario, I re-ran both the strong policy and ramp policy with rail's share of total land-based heavy freight being exogenously limited to 50% of the total. This was done to ascertain if higher carbon prices would be required in case the low-cost abatement option of expanding the rail stock were not available. It appears that for the same carbon price, emissions reductions from freight are practically the same, irrespective of whether there is a constraint on the extent of mode switching to rail. This indicates that emissions reductions from low-emitting trucks can substitute for the reductions originally made by rail, implying that deep reductions from freight are not dependent on an expansion of the rail stock.

For de-carbonizing trucks, biofuels- both RNG and renewable diesel- appear to be the option of choice rather than other non-emitting trucks such as electric or hydrogen trucks. Despite higher fuel costs in most cases, their ability to blend seamlessly with the prevailing

diesel or natural gas engines give them a noted advantage, especially when weighed against the considerable intangible and capital costs associated with the alternatives. Natural gas vehicles with RNG fuel actually saw significant adoption in the stringent carbon price scenario with foresight, making it one of the least-cost de-carbonization option when agents accounted for carbon prices over the entirety of the simulation. The above result is dependent on low RNG prices, as RNG is not economic under the high RNG price scenario. Renewable diesel becomes the fuel of choice to decarbonize heavy trucks when the RNG price is high and vice versa.

However, natural gas trucks do not seem to be fulfilling a bridge-fuel role, where they would capture market share as part of an early emissions mitigation policy prior to further de-carbonizing the sector through the blending with RNG as the policy became more stringent. I designed the slow ramp up scenario without complete foresight to represent this possibility. In actuality, this scenario saw less RNG penetration than the strong policy. Even at lower carbon prices, higher efficiency diesel proves a more cost-effective way to achieve emissions reductions than natural gas. As the carbon price then increases over the simulation, renewable diesel blends with conventional diesel to serve this bridging function.

5.6 Sensitivity Analysis

I conducted a parametric sensitivity analysis on key uncertain parameters in this study in order to discern the magnitude of changes to the model outputs from changing these parameters. Table 5-6 provides a list of the uncertain variables, the magnitude of the input variation quantified, and the justification for each.

Table 5-6*: List of uncertain variables

Uncertain Variable	Variation Quantified	Justification for variation
Intangibles- Truck Motors	+/- 50%	No literature basis
Intangibles rail	+/- 50%	No literature basis
EV; No of Cumulative Doublings by 2050;	Base 5.5; High 7.25; Low 3.5	Differences based off variations in global EV adoption under differing IEA scenarios (IEA, 2017b). High scenario represents IEAs most aggressive penetration scenario.
Biofuel Cost	+/- 10%	Based off of IEA forecasts – High and low price scenarios

Uncertain Variable	Variation Quantified	Justification for variation
Life	+/- 50% (Base:10 years)	Krupnik (2010) identifies that trucks could have a useful life of only 5 years.
V Parameter- Heavy truck /rail mode choice	+/- 50%	No literature basis
V Parameter- Motors	+/- 33%	No literature basis
R Parameter	45%/10%	Upper bound: Applied to non-conventional trucks and rail options. Upper bound represents the upper bound of the values in Train (1985). Lower Bound: Value frequently used in typical cash flow analysis. Assumed all vehicles has the same discount rate - no additional premium for novel technologies

I provide the results from the parametric analysis in the following four tornado diagrams, showing the magnitude of the change in the following outputs for freight transport: natural gas consumed, biodiesel/renewable diesel consumed, renewable natural gas consumed, and emissions. The values in the figures represent the change relative to the reference case for each input change across the four outputs above. The movement of the bar diagram to the left represents an increase in the output in question, while movements to the right represents a decrease. For input variables, which cause major changes in output variables, I indicate in a label alongside the bar the magnitude and direction of the change in input variable that caused that output variable change. For example, figure 5-14 has a label of -33% beside the bar for "V parameter motor". This means that driving this change in natural gas use in freight, represented by the length of the bar, was a 33% decrease in the v parameter for truck motors. Movements in the bar in the opposite direction are, conversely caused by a 33% increase in the v parameter for truck motors, which would cause a decrease in natural gas use.

Each figure provides this analysis for both the BAU and the stringent policy. I did not conduct a similar exercise for the weak and ramp policies, due to the impact of varying the input parameters being smaller for these policy scenarios than with the stringent policy. All of the runs below assumed low RNG prices.

Figure 5-15: Natural Gas Use in Freight- Sensitivity to Input Parameters
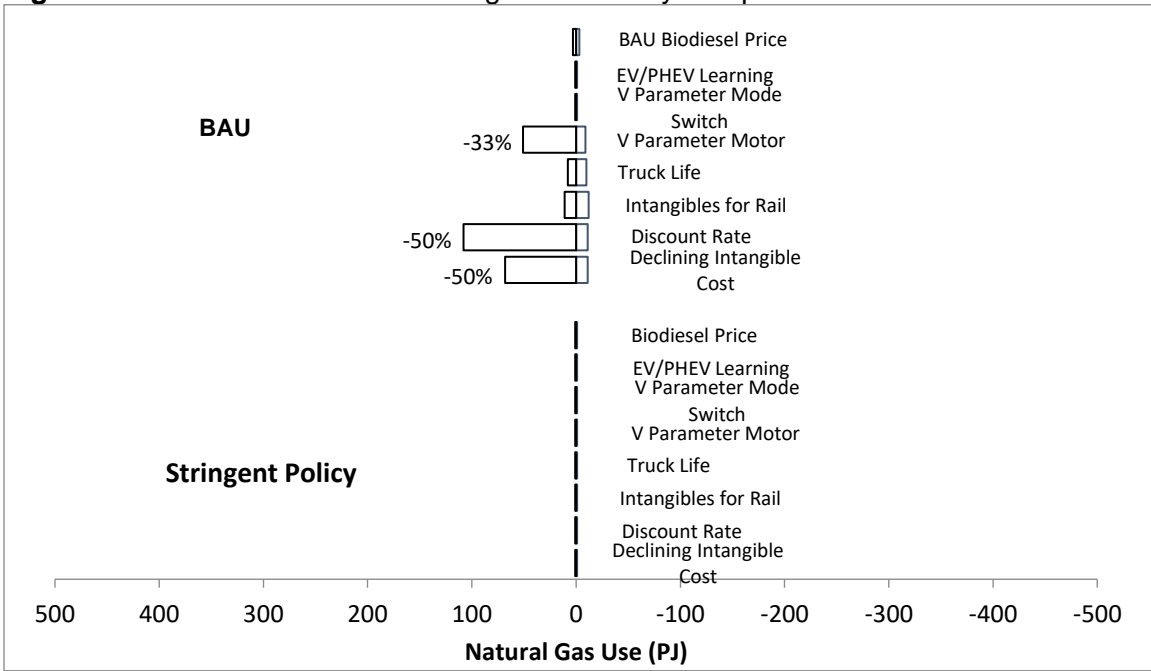
Figure 5-16: Biodiesel Use in Freight- Sensitivity to Input Parameters
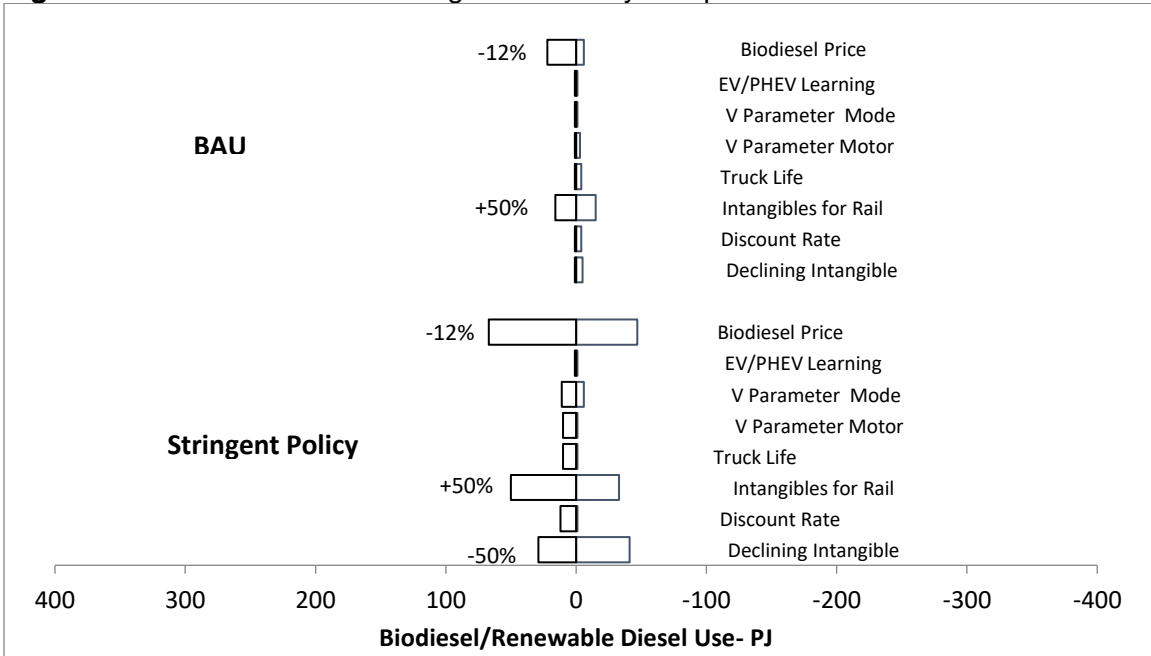
Figure 5-17: Renewable Diesel & Biodiesel Use in Freight- Sensitivity to Input Parameters
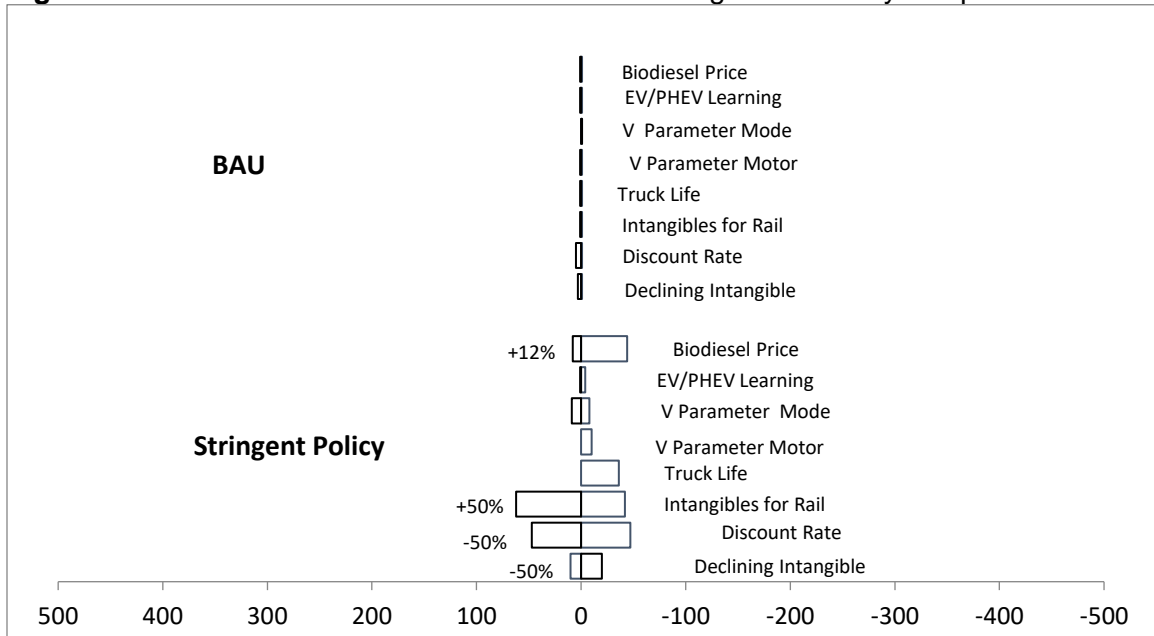
Figure 5-18: Freight Emissions- Sensitivity to Input Parameters
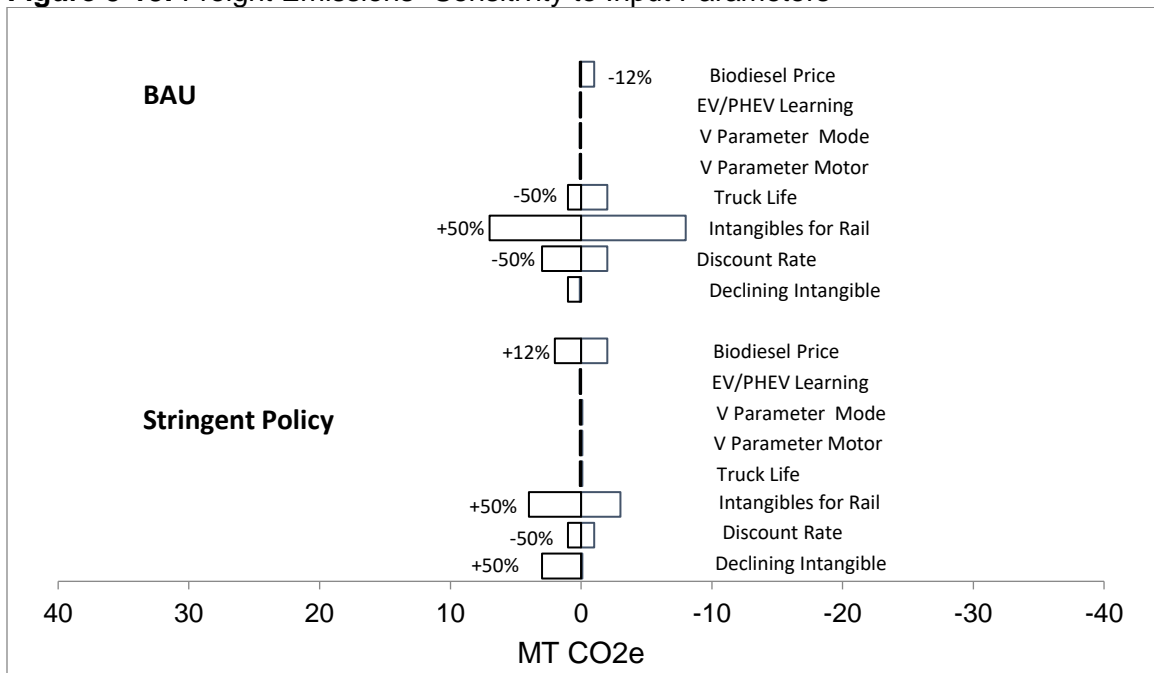
Important variables that are common across the four figures include the intangible cost parameter for rail and the declining intangible cost parameters (for trucks). Of secondary impact is the price of biodiesel, which influences the competition under the policy scenario between RNG and renewable diesel. Of particular interest was the sensitivity of natural gas vehicles to the discount rate, as figure 5-14 illustrates quite dramatic increases in

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natural gas use in freight upon reducing the discount rate to 12% for all technologies. The intuition behind this finding it that the lower discount rate gives more weight to the energy cost savings further out into the future, which would favor natural gas trucks under projected natural gas prices. The lower discount rate also influences the policy scenarios in figures 5-15 and 5-16, as it makes RNG more competitive under policy, at the expense of biodiesel and renewable diesel, when RNG prices are low. Also interesting from figure 5-17 is how the lower discount rate actually causes an increase in emissions, by 5Mt, under BAU. This appears counterintuitive due to natural gas' lower lifecycle emissions than diesel, and is a finding that I will discuss further in this section.

Another key finding from this investigation is how electric trucks barely penetrate in any scenario, not even under conditions of highly favorable/rapid learning for Etrucks and PHEVs. My main reason for not providing a tornado figure for electricity use in freight, alongside the other figures, was that varying these parameters had a negligible impact on electricity's uptake in freight.

While the above parametric analysis is valuable, another track for sensitivity analysis would be alternative scenario construction, where I vary multiple variables simultaneously in order to discern their joint impact on the result. In particular, I found that varying the discount rate had a considerable impact on the uptake of natural gas trucks under BAU, indicating its sensitivity to changing economic conditions. While it may be challenging to target the discount rate, representing agent's time preference, with policy, it would be interesting to see what other fundamental techno-economic variables can be manipulated for natural gas trucks to cause a similarly favorable uptake. Thus, I constructed two alternative scenarios that vary assumptions about vehicle technological progress and future energy prices. The first scenario (Scenario A) is a Favorable Gas Scenario, where a number of favorable conditions arise for natural gas trucks. Natural gas prices under this scenario are lower than the reference, corresponding to declines that reflect the EIA's high natural gas productivity case. The scenario also witnesses aggressive technological progress for heavy natural gas trucks relative to the reference case, such that capital costs of heavy natural gas trucks decline by 37%, compared to the 27% they declined previously. Biodiesel and electric vehicles parameters remain the same as under the reference case.

The second scenario (Scenario B) combines the improvements to natural gas trucks assumed in Scenario A with improvements in heavy electric trucks and biodiesel/renewable diesel. In this scenario, I assume the starting value for intangible costs of heavy electric Trucks to be 60% below the reference case, reflecting a greater extent of charging infrastructure and improvements in battery development. I also assume improved electric truck technological progress through a faster exogenous rate of decline and a lower eventual cost decline. I also assume the same decline in biodiesel/renewable diesel prices as per the parametric analysis above.

I first ran all of the above scenarios under BAU, and then under the carbon pricing policies described previously. For the BAU case, figures 5-18 and 5-19 below illustrate the emissions, total energy consumption, and total natural gas consumption for the freight sector under Scenarios A and B, and how they compare to the reference run in the preceding section.

Figure 5-19: Emissions across Sensitivity Scenarios and Reference Scenario
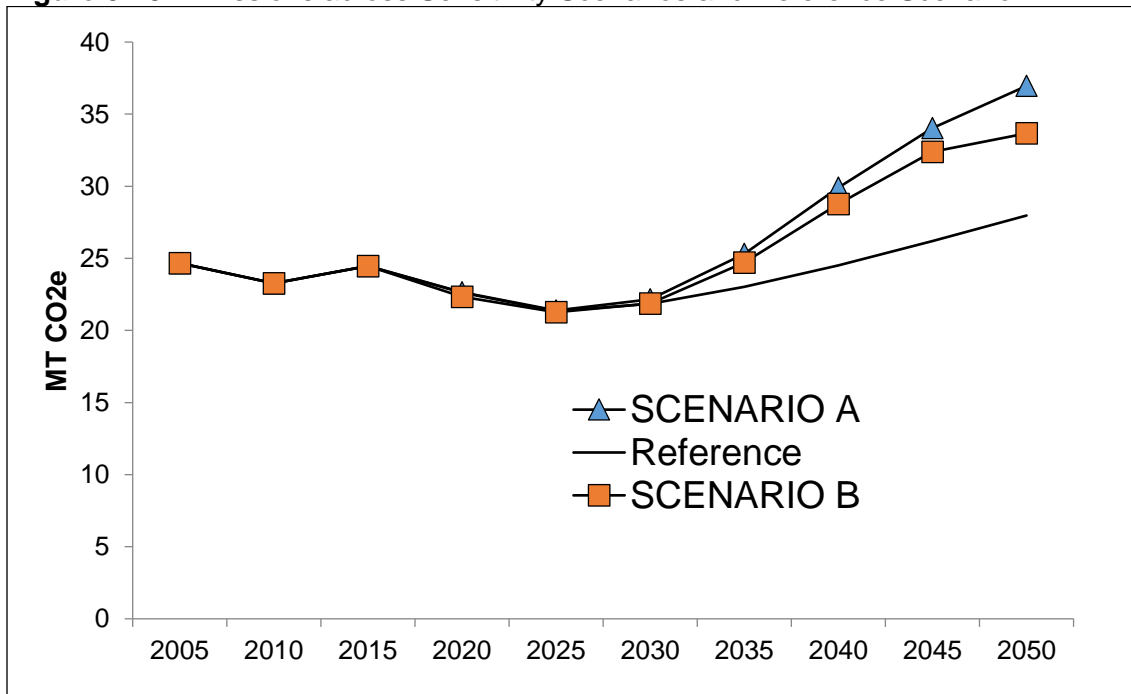
Figure 5-20: Natural Gas use in Freight: Reference vs. Sensitivity Scenarios (PJ)
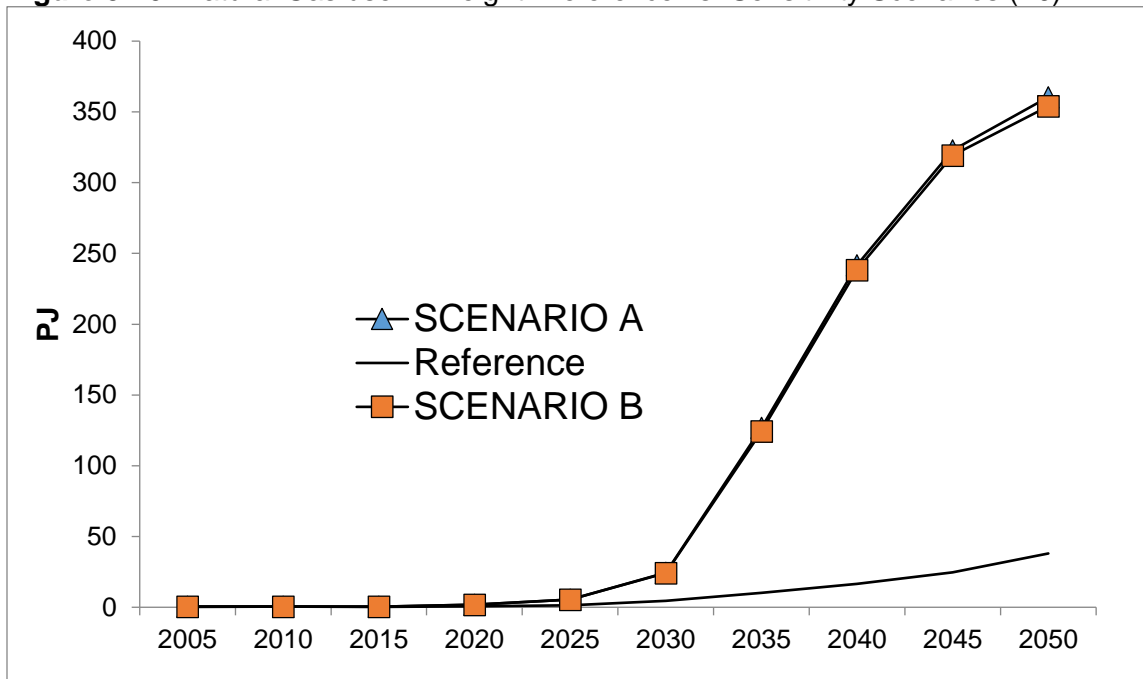
As was the case with the parametric assessment when lower discount rates resulted in greater adoption of natural gas trucks, emissions actually increase in this scenario, by 32%, over the reference in 2050. The reason for this increase is due to the overwhelming increase in natural gas use in freight, beginning around 2030, and stemming from the combination of lower cost natural gas trucks and lower natural gas prices that were part of the scenario. Running sensitivity scenario B, we see that optimistic parameters for electric trucks and renewable diesel can only partially offset the dramatic adoption of natural gas trucks in scenario A, and so emissions are still substantially higher than the reference. Despite the improvements to electric trucks assumed under scenario B, it was lower biofuel prices that offset some of the emissions in scenario A, as electric trucks still did not feature in the projections. Figure 5-19 shows natural gas consumption in freight is practically the same in Scenario A and B, which points to the fact that rather than displace natural gas, the lower biofuel price is actually displacing some of the remaining diesel in freight, and so is reducing emissions through that mechanism.

This result deserves further explanation, as normally an increase in natural gas displacing diesel should not result in an increase in emissions for the freight sector. However, of critical importance is that this increase in gas use appears to only slightly displace other fuels, with most of it adding to the sector's energy consumption. This dramatic increase in

energy use in freight is partially due to natural gas vehicles displacing more efficient diesel, but it is also due to natural gas trucks capturing a greater proportion of heavy land-based freight's market share at the expense of more efficient rail as demonstrated by figure 5-20 below.

Figure 5-21: Heavy trucks share of freight moved as a percentage of total heavy freight
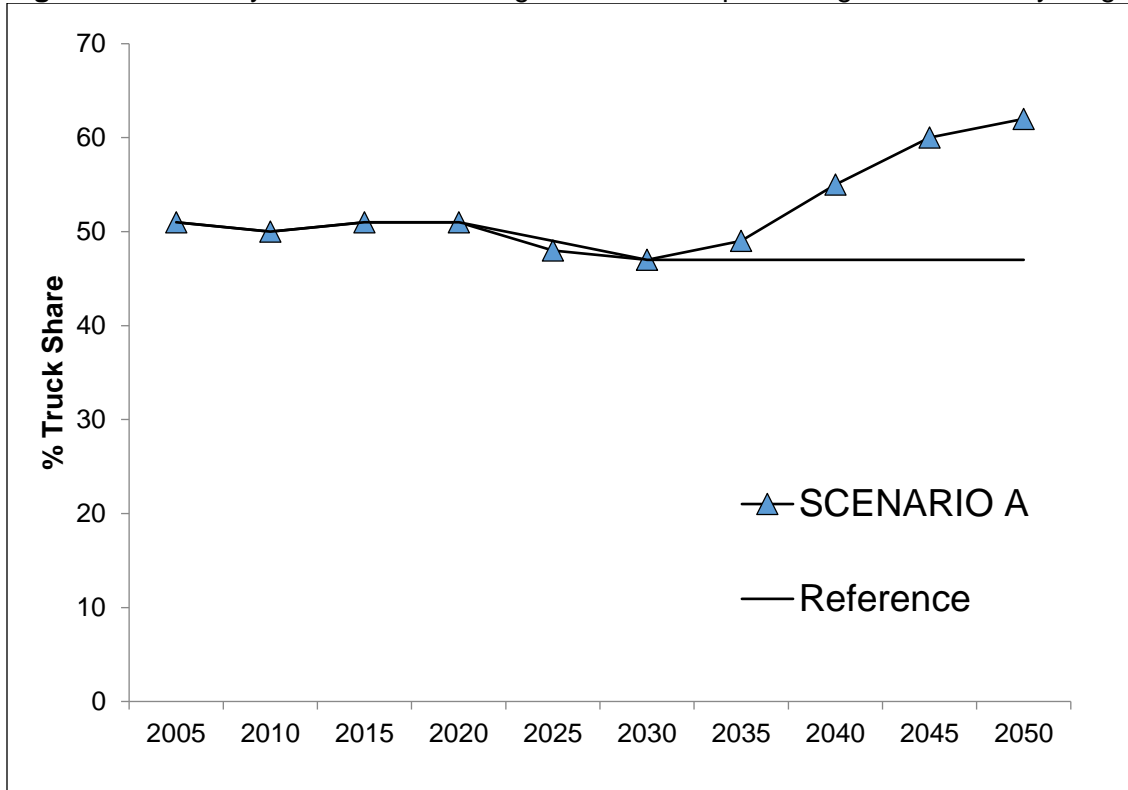
Evident from the figure is how improvements in natural gas vehicle technology and the economics facing natural gas trucks, increases the use of heavy trucks in moving heavy land-basedfreight relative to trains. Since the energy use per tkt is substantially higher in heavy trucks compared to rail, this switch from rail to trucks results in greater energy consumption overall to move the same amount of tonnage. Thus, the resulting increase in energy use and corresponding emissions increase. This is a major counterintuitive result, as one would normally expect the lower emissions intensity of natural gas trucks to result in fewer, rather than more, freight emissions with increasing market penetration of natural gas trucks. To summarize, lower natural gas prices, coupled with improvements in natural gas truck technology, make it cheaper to move freight by natural gas truck than by rail, thereby increasing fossil-based energy use in the Ontario freight sector, and its resulting emissions.

Combining this sensitivity case with the carbon pricing policies described earlier, however, still results in a deep de-carbonization of the freight sector, as the magnitude of the carbon price remains sufficient to de-carbonize the system. What does change, however, is that the deep emissions reductions now depend to a greater extent on blending RNG to reduce the emissions profile of the increased number of natural gas trucks. RNG use in freight now doubles relative to the same carbon scenario without these favorable gas conditions.

5.7 Conclusions and Policy Recommendations

In this chapter, I examined the potential of natural gas trucks, and their blending with RNG, to serve as an abatement measure for the Ontario freight sector. I also investigated whether natural gas trucks can act as a bridging technology to reduce emissions in the near-term under weak policy, and then continue to reduce emissions as the stringency of the policy increases via RNG blending.

In the absence of carbon pricing policy, I project emissions levels for heavy trucks and freight in 2050 that lie above current emissions. Under this business-as-usual condition, emissions decline out to 2030 due to the ratcheting up of fleet-wide intensity standards. After 2030, however, emissions declines bottom out, before rising again in line with increased sector activity. The above suggests the need for more stringent policy after 2030 should policymakers wish to see greater emissions reductions from this sector. In addition, the paucity of electric truck adoption under the reference scenario, despite the considerable subsidies available for these vehicles under the Ontario Green Commercial Vehicle Incentive Program, indicates that without further measures, this program is unlikely to be effective in its goal to stimulate the adoption of electric trucks in Ontario.

Adding a weak carbon price in 2020, which starts in line with the current Pan-Canadian Framework commitments, and which grows modestly from that commitment after 2025, results in only a 4% decline for the freight sector by 2050 compared to the reference case. Stringent policy scenarios, by contrast, result in substantial emissions declines for all segments of the freight sector, including heavy trucks. Although the de-carbonization of rail contributes to much of these declines, RNG blending with natural gas can potentially play a substantial role to de-carbonize the remaining heavy truck stock, but this depends critically on the RNG price.

Also of interest was how, for the lower bound of RNG prices, RNG blending with natural gas trucks saw greater adoption as a least-cost abatement option under well-communicated policy, relative to the ramp scenarios where foresight of the eventual carbon policy only becomes present much later in the simulation. Under the latter scenario, one might have expected greater adoption of natural gas with RNG, with the rationale being that natural gas trucks might gain market share under weaker policies, and then gradually reduce their emissions intensity via RNG blending as the policy becomes more stringent. This was not the case, however, as the combination of highly efficient diesel trucks, with a similar ability to reduce the emissions intensity of the fuel by blending with drop-in renewable diesel, proved a more promising bridge fuel/technology suite under weak carbon prices.

Finally, a confluence of factors yielding a favorable gas scenario could see natural gas vehicles make significant inroads in heavy trucking. Unfortunately, this worsens the energy use and emissions profile of the sector under BAU as energy intensive heavy trucks move more freight than by rail. This transport mode shift for heavy freight was an unexpected result, highlighting the benefit of an integrated modelling approach of the freight sector. Despite these developments, the system can still achieve substantial emission reductions when coupled with a carbon price. However, to do so increases the importance of RNG-blending, and thus the importance of a reliable source of RNG at reasonable cost.

A key caveat to these findings is the high degree of uncertainty inherent with some of the technology inputs, particularly the intangible cost parameters which do not have a strong empirical justification for the freight sector. Although I partially address this with a deterministic sensitivity analysis, I acknowledge the lack of a more in-depth Monte Carlo simulation to be a limitation in this analysis.

Although this analysis focuses on the province of Ontario, there are broader implications of these results for jurisdictions where both natural gas and RNG are relatively cheap *and* where rail is already used predominantly for moving freight, such as other parts of Canada or the US. Conversely, jurisdictions such as Europe and Asia where natural gas is expensive, and where the rail system is geared toward passenger transport, are unlikely to see similar results. Some findings, however, may be more broadly applicable. For instance, I expect my finding of the relative lack of competitiveness of electric trucks

relative to biofuels- either RNG or renewable diesel- to also be true in many other jurisdictions, except for a few with very low electricity prices such as Quebec or Norway.

Suggested policy implications stemming from these results are that policies subsidizing natural gas trucks, and investments in natural gas vehicle infrastructure, could be misguided if GHG emission reductions are the primary target of these policies. These investments might favor natural gas trucks over less energy and emissions intensive rail, thereby increasing overall emissions from the freight sector. Investments in RNG supporting policies, however, may be justified as a mitigation option for heavy trucks under some of the most stringent climate policies. I also found renewable diesel to be an important fuel in this regard. For both these fuels, while some feedstocks are currently commercially available, more advanced conversion pathways may require government policy to help speed up their deployment, and to overcome technical and integration challenges.

In addition, rail's importance in reducing freight sector emissions was a central finding across many of the scenarios assessed in this chapter. Government may have a role in ensuring the rail sector is primed for making potentially extensive and costly investments in both new track and upgrading. Although privatized in 1995, the scale of the rail investments required under the stringent carbon policy scenario may require mechanisms like public-private partnerships (perhaps via loan guarantees or trough expansion of the Infrastructure Canada Bank) to share risk and keep the cost of capital low.

Like the findings in other chapters of this thesis, natural gas provides, at best, a minor benefit to emissions reductions and fighting climate change for freight. On the other hand, natural gas trucks could potentially be counterproductive for such purpose if policy is not in place to ensure the coupling of investments in natural gas trucks with RNG.

6. Conclusions: Tying It Together

Abundant North American natural gas in recent years has had a tremendous impact on many aspects of the continent's energy system. My simulations in this thesis point to a continued impact of the abundant gas phenomenon going forward. In scenarios representing the prevailing low gas price conditions, high natural gas consumption levels are seen in the US economy, with gas use nearly doubling by 2030 relative to 2010, and resting 53% above 2010 levels by 2050. The consequence of abundant gas for the climate is lower emissions in the near-term (between 2010 and 2025), especially in the power sector, relative to a scenario with higher gas prices.

This could be viewed as a welcome development in the fight against climate change, making it easier to achieve near-term climate targets in the electricity sector. For instance, I found abundant gas achieved the target set out by the, now defunct, Clean Power Plan (CPP) for 2030[52] without any incremental policy levers. By contrast, if gas prices were high, achieving the CPP target would have required additional measures between 2020 and 2030.

However, these reductions would be largely concentrated in the power sector and are a short-term phenomenon. I found abundant gas to actually increase emissions by 2050, relative to the simulation where gas is less plentiful, due to abundant gas driving higher emissions elsewhere in the economy, particularly in upstream emissions associated with greater natural gas extraction. Most importantly, the combination of the policies under BAU with abundant natural gas were shown to be insufficient to achieve 2050 climate targets, a finding consistent with every preceding modelling study on the subject. Stringent climate policies, in addition to those already under BAU, are needed to achieve deeper climate reductions by 2050.

In this regard, abundant natural gas is likely to hinder deep-GHG reductions under stringent policy, as I found that the abundant gas scenarios required a slightly higher carbon price than the scenarios where natural gas is scarce. I also found this difference in carbon price between scenarios with abundant and scarce gas to be exacerbated when there is a delay in announcing stringent climate policy, making its introduction

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[52] 30% below 2005 levels by 2030.

unanticipated by firms and households. The relatively stronger carbon price that is required when policy is unanticipated in the presence of abundant gas is due to cheap gas incentivizing a larger proportion of the energy system to switch to gas-utilizing technology in the intervening years prior to a stringent policy intervention, making the system more gas-committed.

In addition, I found abundant natural gas to worsen carbon leakage from the power sector to end use sectors when the former is subject to conditions of stringent carbon policy while the latter is not. This is primary due to abundant natural gas keeping natural gas prices in end use sectors relatively low, while the stringent power sector policy could increase electricity prices in these sectors. This results in greater emissions for some sectors due to substitution away from electrification and towards higher-emitting natural gas.

Overall, the above narrative illustrates an important trade-off between the scenarios, where lower gas prices can result in near-term emissions reductions relative to the high-price scenario, and may make near-term climate targets in certain sectors easier to achieve, while making more stringent, long-term, targets harder to achieve. This timing of emissions reductions, however, is an important consideration as the near-term reductions may actually be worth the additional cost later. While a country's 2050 climate targets are almost universally expressed as a percentage reduction below a base year, carbon's impact on the climate is a consequence of cumulative emissions, and so policymakers should be thinking in terms of a carbon budget of allowable emissions (see Meinshausen et al., 2009; IPCC, 2014). With that in mind, near-term reductions can possibly be regarded as more valuable than reductions occurring in the future, saving some of the carbon budget now to provide humanity with space to maneuver later.

However, this near term-benefit should not be overplayed. Actual near-term emissions reductions due to abundant gas are quite small relative to total US emissions, with annual emissions being only about 1.5% lower than scenarios with scarce gas at the greatest point of difference. Differences in cumulative emissions between the scenarios over the near term are even less pronounced, being only 0.5% lower under abundant gas relative to the scarce gas scenarios by 2020. Thus, this overall emissions benefit of abundant gas in the near-term is quite small, with the benefits only manifesting themselves in the power sector, while emissions are higher in other sectors of the economy.

Further compromising the benefit of near-term power sector emissions reductions due to abundant gas could be a situation where substantial technology improvements, or considerably lower natural gas prices, drive the adoption of a natural gas utilizing technology at the expense of a lower emitting alternative. The sensitivity analysis in chapter 5 demonstrates this phenomenon, where natural gas trucks displaced the more energy efficient diesel-based rail, resulting in considerably higher emissions in freight transport than under conditions where gas prices were higher and natural gas trucks were costlier. The presence of low gas prices may induce innovation in gas-utilizing technologies, which may cause these cost reductions for natural gas trucks to arise.

Chapter 5 also showed that in such cases, RNG becomes an important route for de-carbonization in the heavy trucking sector should natural gas trucks see an enhancement in their competitive position. However, this also means that the sector could become potentially dependent on RNG in the future the longer it evolves absent carbon pricing, creating a risk that the sector will become dependent on a certain technology or fuel. As seen with the Ontario case study, the limiting factor to RNG's applicability as a mitigation option for heavy trucks is the supply of low-cost sources. These could become quickly exhausted if use of RNG expands beyond the trucking sector. While the marketability of RNG might induce technological innovation in this area to shift the supply curve down, it is unclear if this would occur far enough and fast enough to make this a low-cost mitigation option for trucking.

Overall, there are five overarching policy recommendations stemming from this thesis. Firstly, echoing work done elsewhere, a stringent, well-articulated, and technology neutral climate policy, whether it be carbon pricing or technology neutral regulations, is necessary to drive the majority of the necessary emissions reductions to achieve a deep de-carbonization of the North American energy system. While some jurisdictions have introduced carbon pricing- either via a carbon tax or via cap and trade- the approximate carbon price that is necessary to limit the rise in global temperatures to 2 degrees above pre-industrial levels is far above anything currently in place. The action of fuel switching to natural gas alone is insufficient, and, while giving the economy some near-term respite in emissions growth, my research suggests will make it harder to achieve stringent climate targets at a later date.

Secondly, in the absence of such a credible policy path, natural gas, while lowering near-term emissions, can hinder deep emissions reductions later as the energy system becomes more gas-committed and harder to switch to a lower emissions intensity pathway. Thus, my second policy recommendation is for governments to implement strategies to accelerate development and deployment of strategic investments in a number of "hedge" technologies, complementing prevailing efforts by the private sector, to improve their performance and lower cost. These hedge technologies are those that could readily lower emissions from a gas-committed system by lowering the emissions intensity of natural gas utilizing technologies. One possibility might be to develop new sources of RNG, or to find ways to enhance the yield from existing sources, which could allow an increase of RNG use in a variety of end uses beyond the trucking example examined here, while another might be further develop natural gas coupled with CCS. Presently, these technologies are largely unproven and the likelihood of their successful deployment contains considerable uncertainties.

Thirdly, if policymakers wish to pursue a power sector policy without commensurate policy elsewhere in the economy, policymakers should design such a policy to minimize leakage of emissions to other sectors, perhaps by considering the redistribution of revenues generated by carbon pricing within the electricity sector, or by expanding the policy to cover cogeneration. More ambitious would be to add a modest price on carbon in the end use sectors as an interim measure that can then be used as a springboard to achieve more aggressive end use sector reductions at a later date.

Fourthly, rail's importance in reducing freight sector emissions was a central finding, and so government may have a role in enabling the requisite investments expediting its expansion. Given the substantial financing costs associated with these capital-intensive projects, support might take the form of public-private partnerships to share risk and keep the cost of capital low.

Finally, some governments invest in natural gas utilizing technology deployment and R&D programs using climate change mitigation as a justification. However, my research suggests that this is disingenuous as the minor climate benefits of adoption of these technologies may be overwhelmed by the challenges they create.

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Appendix A

CIMS-US Power Sector: Backcasts/Forecasts

The following figures compare EIA historic data (2005 to 2017) to CIMS simulations for fuel use in electricity generation under BAU. Evident from these figures is how CIMS generally backcasts the historic data well, although there are sort short-term deviations from year-to-year.

Figure A-1: CIMS vs. EIA/AEO Natural Gas use in Electricity Generation (EJ)
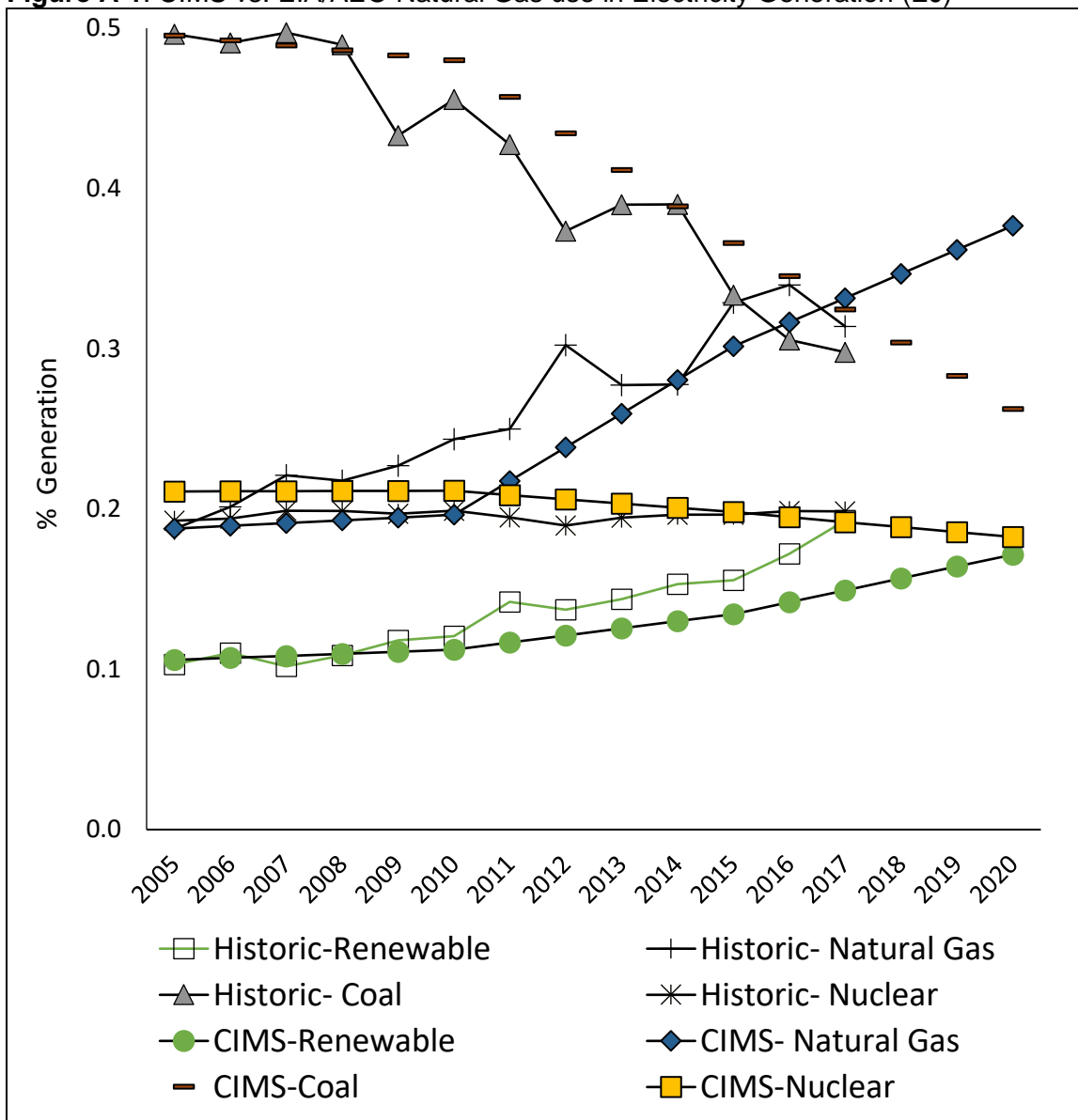
CIMS-US End Use: Backcasts/Forecasts

As another check, I ensured that the simulations in CIMS roughly capture historic trends and values in end use. Table A-1 below provides estimates for the end use sectors of residential, commercial, industry, and transport. Generally, the estimates are accurate (within 10%) with a few notable exceptions. For instance, CIMS substantially understates RPP use in the residential sector (by about 13%) in 2005. However, the difference was negligible by 2010. Similarly, while CIMS understates and overstates natural gas use in commercial sector and electricity use in industry respectively in 2005, these differences become less pronounced by 2010.

Industrial RPP sees the most substantial difference between CIMS and the historic data – over 50%- however this is a definitional issue with the EIA data including chemical RPP feedstocks and construction energy use in its data while CIMS does not (these sectors are not covered in CIMS). Understanding the reason for this discrepancy also explains a large part in explaining the differences in total industry energy use and total primary energy use.

Finally, another major outlier is with respect to coal consumption in industry. The difference appears to be with respect to coal use outside of manufacturing but within industry, as CIMS matches the available data well for coal use in manufacturing.

Table B-1: End Use Sectors CIMS vs. Historic

	CIMS-PJ		Historic- PJ		% Difference	
	2005	**2010**	**2005**	**2010**	**2005**	**2010**
Residential-Total	11,582	11,466	12,182	12,161	-4.92	-5.71
Residential-Gas	4,972	4,773	5,218	5,146	-4.72	-7.24
Residential-Electricity	4,862	5,029	4,893	5,204	-0.64	-3.37
Residential - RPP	1,328	1,183	1,531	1,187	-13.2	-0.37
Commercial-Total	8,615	8,792	8,864	9,021	-2.81	-2.54
Commercial-Gas	2,638	3,074	3,242	3,339	-18.63	-7.94
Commercial-Electricity	4,795	4,917	4,590	4,789	4.47	2.69

	CIMS-PJ		Historic- PJ		% Difference	
Transportation-Total	28,185	27,844	29,912	29,076	-5.78	-4.24
Industry-Ngas	8,372	8,673	8,287	8,588	1.03	0.99
Industry-Elect	4,157	3,410	3,669	3,495	13.33	-2.42
Industry-RPP	3,867	3,777	10,162	8,621	-61.95	-56.19
Industry-Coal	1,501	1,459	2,062	1,721	-27.19	-15.23
Industry- Coal (Manufacturing Only)	1,452		1,466		-1	
Industry-Total (No Cogen)	20,801	19,930	26,257	24,907	-20.78	-19.98
Total Primary Energy Use	95,950	93,545	105,797	103,407	-9.31%	-9.54%

 *In all cases, the directional trend between CIMS and Historic are the same. i.e. CIMS is moving the same way as the historic trend

Appendix B

CIMS US: Natural Gas Supply Curve

A key innovation to the CIMS-US model performed in this thesis is to endogenize the price of natural gas. I did this by linking an upward-sloping natural gas supply curve to the model, where increasing use of natural gas in the economy will result in higher natural gas prices over time as producers extract from less favorable sites at higher cost of extraction.

As a starting point for calibration, existing supply curves from the MIT EPPA model- used to inform the 2011 MIT Future of Natural Gas study were used.[53] These curves depict the extraction cost of US natural gas (in $/mmbtu) on the y-axis that is a function of cumulative production of US natural gas (in tcf) on the x-axis for three scenarios with differing assumptions about well productivity. The mean scenario assumes natural gas well productivity in the future to reflect the mean well productivity of historic wells. The USP90 scenario reflects future well productivity that is lower than 90% of historic well productivity, whereas the USP10 scenario reflects future well productivity representing that of the 10% most productive wells.

Once I generated the supply curve, I linked it to CIMS-US via a soft-linked excel supply curve tool, created by Jotham Peters of Navius research. The supply curve tool was programmed in VBA, and allowed the modeller to set the functional form, intercept, and slope parameters. As per the shape of the curve, the tool adjusts natural gas prices in CIMS as greater production occurs. I did this adjustment via an iterative process where changes in gas demand would result in an imbalance of prices on the demand and the supply side. The tool provides new prices to remove the imbalance for the model, influencing supply and demand for natural gas and thereby resulting in a new supply and demand price for natural gas. This process would continue until the natural gas supply and demand prices are equal.

I initially calibrated the supply curve to the MIT/EPPA mean scenario. However, as time has passed between 2012 and now, it became apparent that gas prices were even lower than what the mean scenario was forecasting. Consequently, I altered the supply curve

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[53] The data for which was graciously provided to me by Dr. Sergey Paltsev of MIT

parameters so that the resulting 2015 Henry Hub gas price was close to the actual 2015 value. Figure C-1 below illustrates the resulting calibrated supply curve for the CIMS low price scenario that the figure shows is closer to the P10 scenario than the mean scenario. It also shows the resulting calibration for the high price scenario, which, representing a best guess of the likely evolution of the gas price prior to the shale gas revolution is even below the p90 scenario.

Figure B-1: Natural Gas Supply Curve Calibration
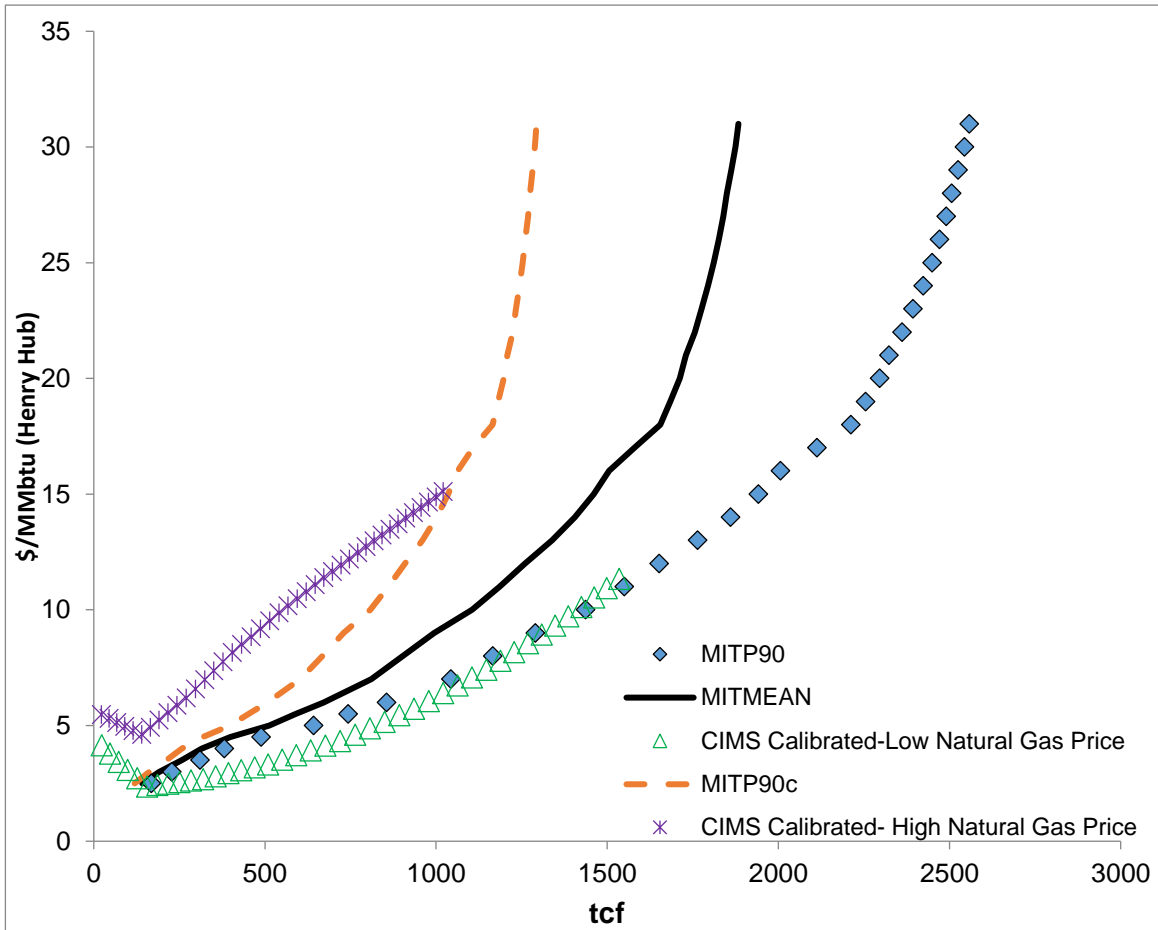
The curve begins operating in CIMS in 2011. For the 2005 time step, gas prices are set exogenously to reflect historic values. For the 2010 time step, gas prices represent historic values for the low price scenario, but the 2010 values for the high price scenario represent the forecasted gas price for 2010 by the EIA prior to the gas revolution being apparent (taken from the EIA's AEO2008 forecasts).

Appendix C

Electricity O&M and Efficiencies

Table C-1: O&M costs and efficiencies (Calibrated to AEO 2014)

Technology	Fixed O&M ($/KW)	Variable O&M ($/MWh)	Heat Rate (BTU)
Scrubbed Coal New	$35	$3.9	8800
COAL CCS	$67	$7.8	10738
Natural Gas CCS	$27	$5.8	7523
Conv Gas Combined Cycle	$13	$3.1	7050
Advanced Gas Combined Cycle-	$13	$2.8	6430
Conventional Combust Turbine	$6	$13.4	10745
Advanced Combust Turbine	$6	$9.0	9750
Advanced Nuclear	$81	$1.9	10460
Biomass	$91	$4.6	13500
Geothermal	$99	$8.8	9760
Conv hydro	$13	$2.3	NA
Wind	$26	$0.0	NA
Offshore Wind	$48	$0.0	NA
Solar PV	$15	$0.0	NA

For the CIMS shoulder and peakload segments, the capital cost for each technology is kept the same, however, the output and variable costs are adjusted to reflect the fact that they are only operating a certain fraction of the time.

Appendix D

Electricity Generation Mix

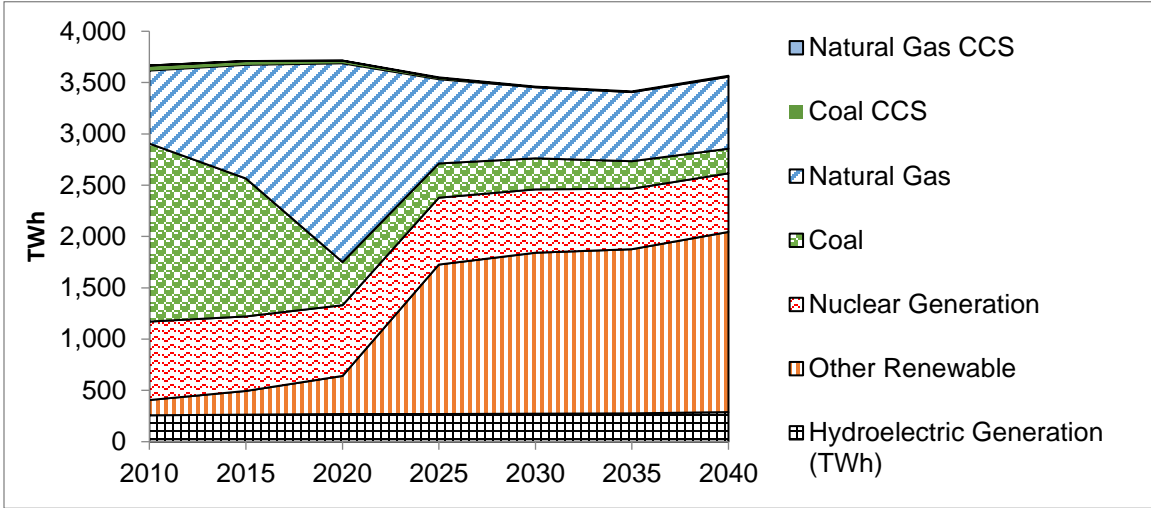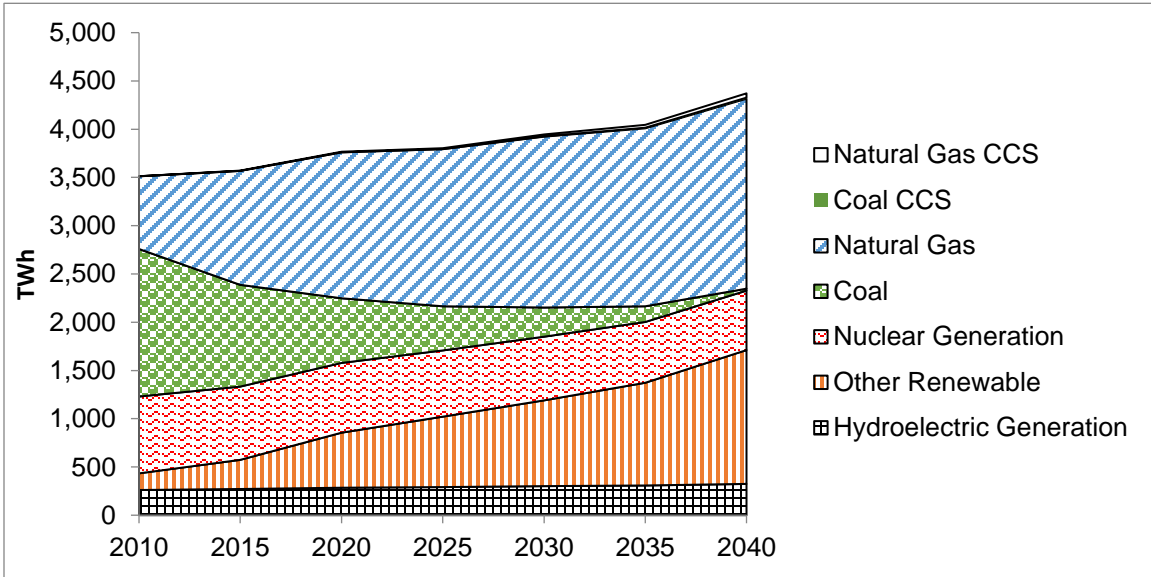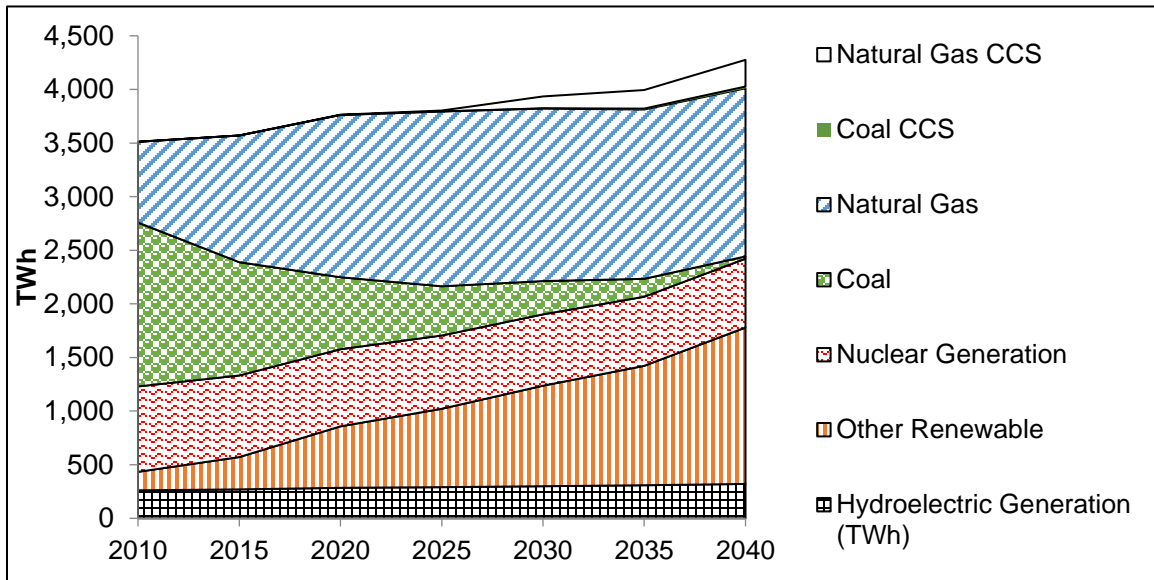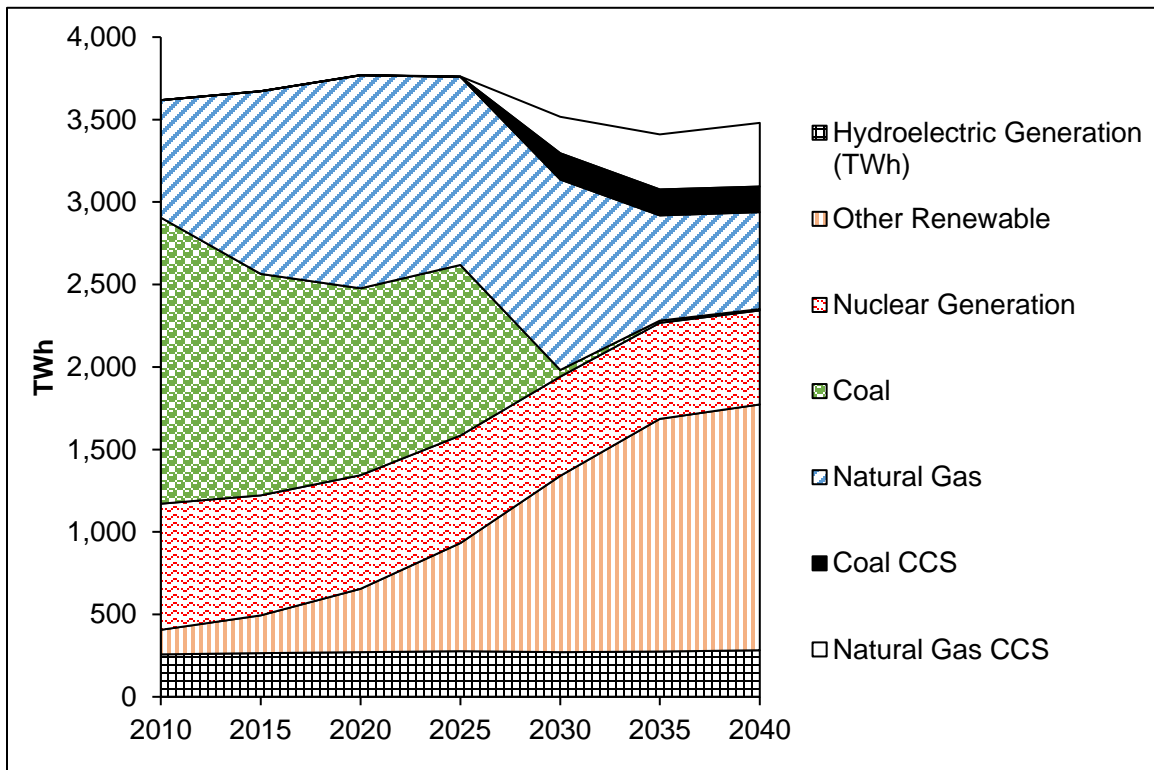**Figure D-1:** Less-stringent policy- No revenue recycling

Figure D-2: Coal Phase Out

Figure D-3: Coal Phase Out + CES

Figure D-4: BAU Minus Scenario

Appendix E

RNG Supply Curve

For this chapter, renewable natural gas or RNG was added as a new fuel for use in the transportation sector in Ontario. To reflect the interplay of the availability of this resource and price, a supply curve was constructed which related RNG production costs to production.

Feedstocks for RNG include agricultural crop residues, animal manure, woody biomass, municipal solid waste and bio-waste from wastewater. From these feedstocks, RNG is produced via pathways of anaerobic digestion or gasification. The former uses the decomposition of organic materials, generally municipal solid waste or agricultural waste, by microbes to produce the biogas, which is either used on site for electricity generation or can be upgraded to produce RNG. The latter converts organic matter, generally woody biomass, into a syngas at high temperature, which can then be converted into RNG through an additional step called methanation (CANMET, 2014).

Canada's RNG potential translates to production of 1400 PJ per year for over 50 years as the currently available resource- or about 70 EJ of total production (Abboud et al., 2010). From this amount, I constructed a supply curve based on availability by feedstock as a fraction of the total, and cost per source as per Table E-1 Below. Where there are large cost ranges, such as with woody biomass, I divided the quantity for that feedstock into equal $1 increments between $10 and $25 so that there is a gradually upward sloping curve.

Table E-2: RNG Options, Quantity, and Cost

| Source of Feedstock and Conversion Pathway	%Of total*	$/GJ**
Landfill/Wastewater Gas	6%	$10.5/GJ
Landfill/Wastewater Aerobic Digestors	7%	$9.5/GJ - $15/GJ
Agriculture Aerobic Digestors	9%	$30/GJ
Agriculture Gasification	26%	$12-25/GJ
Woody Biomass Gasification	51%	$12-25/GJ

*Abboud et al., 2010
**Jaffe et al., 2016

The cost differences from the various sources above reflect differences in capital intensity of production, the level of specialized technology and infrastructure, as well as differences in methane yields and feedstock costs (Jaffe et al., 2016). The production costs for RNG formed the basis of the end-user costs for RNG facing consumers in the transport sector. To convert these production costs into final end user RNG cost, the price for natural gas at the point of end use in transportation was adjusted by the ratio of the difference between the production cost of natural gas and the production cost of the RNG, which includes all taxes and other distribution costs.

The resulting supply curve is Figure E-1 below, which also illustrates the corresponding cumulative RNG use for the low RNG stringent policy scenario, which was found to use the most RNG from my base simulations.

Figure E- 1: RNG Supply Curve for Canada
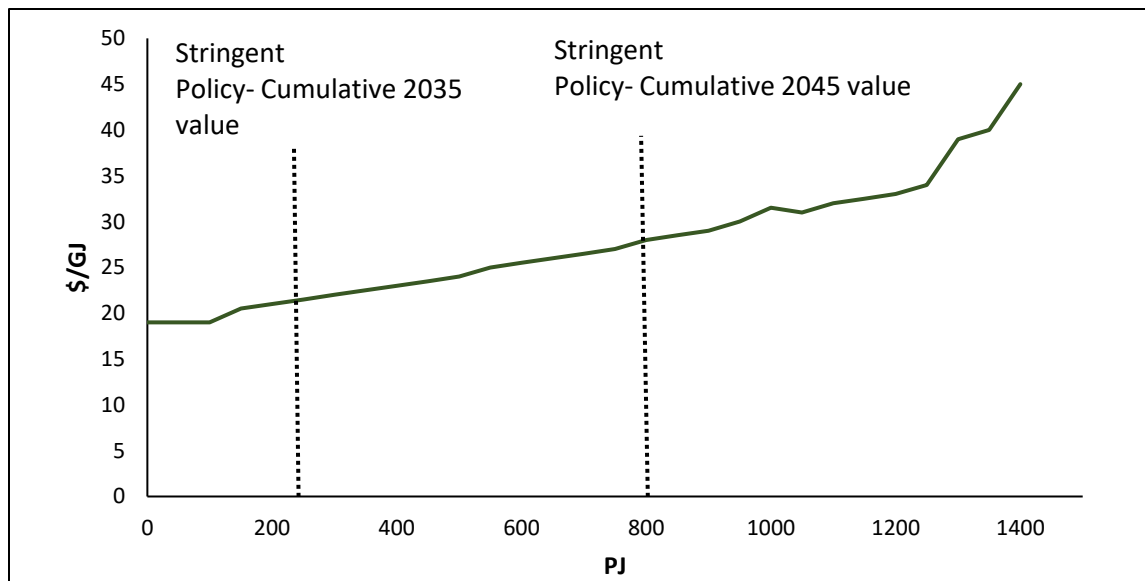
Appendix F

Upstream Natural Gas Emissions-CIMS US

There is a great deal of uncertainty regarding the associated upstream[54] methane emissions from natural gas, and in particular shale gas, within the academic literature (see Howarth et al., 2011 and Cathles et al., 2012 for an introduction). Consequently, the methane emissions intensity from natural gas extraction, processing, and distribution in CIMS was chosen to closely match that estimated by the EPA in their 2013 US GHG Inventory. Calibrating ensured that methane emissions intensity in upstream natural gas calculated by CIMS for 2005, 2010, and 2015 closely followed the historic values calculated by the EPA. I performed a similar exercise for CO_2 emissions, where I calibrated CIMS so that its estimated combustion emissions intensity matched historic combustion emissions from EIA data of lease/pipeline/plant-fuel consumed in natural gas extraction, processing, and distribution.

Table F-1 below provides the key data points and their sources that I used in this calibration exercise. Figure F-1 then compares the historic upstream emissions intensity of natural gas to both historic and forecasted values calculated by CIMS under business-as-usual. The figure shows the declining emissions intensity trend to continue with CIMS, but at a declining rate.

Table F-1: Emissions Calibration

Variable	2005	2010	2015	Source
Historic- CH_4 (in CO_2e)	159	144	162.4	EPA Sources and Sinks, 2017
CIMS CH4 (in CO_2e)	159	170	166	CIMS
Historic- CO_2 Process	30	32	42.2	EPA Sources and Sinks, 2017
Lease/Pipeline/Plant Fuel Consumed in Natural Gas Extraction (MMCf)	1,695,543	1,959,751	2,254,573	EIA, 2017
Historic CO_2 Combustion	92.29	106	122	Lease/Pipeline/Plant Fuel * Natural Gas emissions Intensity

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[54] Includes Extraction, Processing, and Distribution

Variable	2005	2010	2015	Source
Historic CO_2	122.29	138	164.2	Sum of Historic- CO2 Process and Historic- CO_2 Combustion
CIMS CO_2	119.10	146.59	185.33	CIMS
Intensity Historic	0.57	0.47	0.44	Calculations (Above emissions/EIA Gross Production Data from Gas Wells)
Intensity CIMS	0.55	0.49	0.43	CIMS

Figure F-1: CIMS vs. Historic Upstream Natural Gas Emissions Intensity
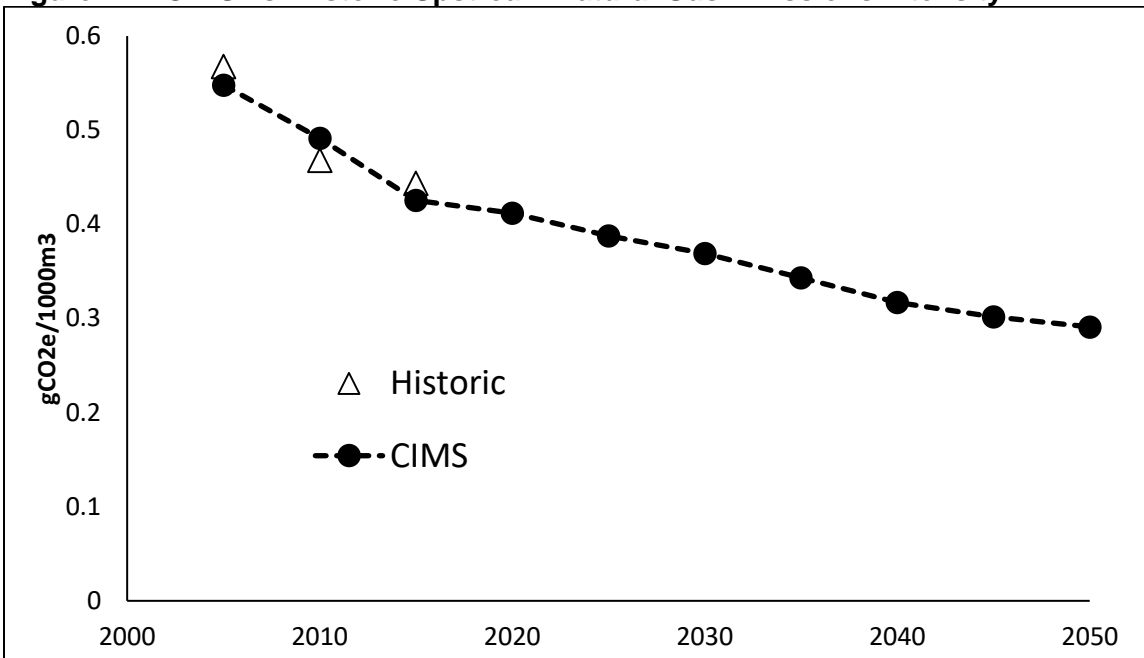
The emissions of upstream natural gas also depends on the emissions associated with the various plays, as some plays have higher formation CO2 and other play-specific emissions. As such, I expanded the Natural Gas extractive sector in CIMS to separate production by play. Natural gas in split between "conventional" and "unconventional" sources, with conventional being divided between on and offshore to reflect some of the differences between production in those two environments. Unconventional gas includes tight and shale gas, with shale gas including the major US shale plays- Haynesville, Barnett, Fayetteville, Marcellus/Utica, and Woodford.

For the base year in the simulation (2000), I split unconventional and conventional gas as per historic data from the EIA. Similarly, within the unconventional gas category, I split production in the base year as per historic data (93% Tight Gas, 7% Barnett Shale). I assume all incremental gas production from 2010 onwards is unconventional, and I linked the unconventional gas extraction sector to the natural gas supply curve described earlier. Production from conventional sources is declining exogenously at a fixed schedule as per EIA's AEO.

Production per shale gas play is endogenous to the model, as plays compete with each other, and with tight gas plays, for market share in the unconventional natural gas space. I based the competition between plays on the financial economics of each play as per Table F-2 below, which illustrates the wellhead gas price at which the natural gas producer can achieve a 10% internal rate of return (MIT, 2010). As was the case with the supply curve described in Appendix B, I initially calibrated costs to the MIT/EPPA mean scenario (p50). However, as time has passed between 2012 and now, it became apparent that gas prices were even lower than what the mean scenario was forecasting, and so I used the P20 scenario costs for my analysis.

Table F-2: Extraction Cost by Shale Gas Play

	Barnett	Fayetteville	Haynesville	Marcellus/Utica	Woodford	Tight**
P20-$/Mcf*	4.27	3.85	3.49	2.88	4.12	3.65
P50-$/Mcf*	6.53	5.53	5.12	4.02	6.34	5.225
P90-$/Mcf*	11.46	8.87	13.42	6.31	17.04	

*Represent the Midcost of Each
**I calculated Tight Gas extraction costs from the average of costs from the Pinedale, Piceance, and Uinta formations (Morgan Stanley, 2009)