LIFE CYCLE ANALYSIS OF THE USE OF METHANOL FOR MARINE TRANSPORTATION

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Abstract

This research presents a life-cycle emissions and energy analysis of methanol for marine transportation. We apply a total fuel cycle analysis methodology with best available data to evaluate "well-to-propeller" emissions for vessel operations using methanol. The analysis includes emissions calculations along the entire fuel pathway, including feedstock extraction, processing, distribution, and use of methanol in vessels. The report focuses on near-term methanol production technologies, and current system conditions as reported in models and literature. Focusing on greenhouse gas and criteria pollutant emissions, we compare methanol life-cycle emissions with those for other marine fuels, including liquefied natural gas, low sulfur marine fuel, and heavy-fuel oil blends. Our results indicate that for greenhouse gases, methanol compares favorably to conventional fuel and liquefied natural gas only when renewable feedstock such as forest residue and landfill gas is used. For nitrogen oxides, sulfur oxides, and particulate matter, methanol performs similar to liquefied natural gas and better than conventional petroleum fuel. Given that current research in marine systems on "tank to propeller" emissions does not include data for many pollutants, significant additional research studies are needed for a fuller assessment of life-cycle methanol performance. Decision makers can use these results to inform decisions related to increasing the use of methanol in marine transportation systems, and adoption of advanced/alternative fuels in general.

1 Introduction

1.1 Purpose

The marine transportation sector recognizes the need to and has committed to reduce emissions from ocean-going vessels (*1, 2*), in order to reduce documented health impacts (*3-5*) and to meet other environmental performance targets (*6-8*)). One approach is to replace conventional petroleum based fuels (residual oil and distillates) with alternative fuels, such as methanol (*9-11*). Given its chemical composition (CH_3OH), methanol has the potential to reduce certain types of pollution at the vessel stack (end-use) compared to conventional fuels (*12*). However, as demonstrated in the life-cycle analysis literature, fuels that have advantages at the point of use may still carry large emissions penalties when fuel production processes are considered (*13*).[1]

The purpose of this research is to investigate emissions associated with the use of methanol fuel for waterborne freight transportation. Using best available data reflecting recent research on methanol production and use, we apply a total fuel cycle analysis (TFCA) methodology to evaluate "well-to-hull" (W2H) emissions for vessel operations. The analysis – a type of life cycle analysis (LCA) for fuel production and use – evaluates emissions along the entire fuel pathway, including extraction, processing, distribution, and use of particular fuels in vessels. We conduct our analyses for a variety of methanol fuel pathways and vessel types assembled into cases specific to several U.S. routes, and compare results to other alternative and conventional fuels in these cases.

1.2 Scope Summary

This project report describes application of a TFCA model capable of evaluating total fuel cycle emissions for the production, distribution, and use of methanol in the marine sector; and to apply that model to a specific case study to compare emissions results across a range of conventional and alternative fuels, including

[1] The extreme example of this is battery-powered electric propulsion. Such propulsion emits zero pollution at end-use; however, pollution may be created in electricity generation process, especially if this electricity is produced from fossil fuels.

liquefied natural gas (LNG), 0.1% sulfur marine distillate oil (MDO), 0.5% sulfur MDO, and traditional residual heavy fuel oil (HFO). For this study, we quantified total fuel cycle (TFC) emissions (carbon dioxide [CO_2], nitrogen oxides [NO_x], particulate matter [PM_{10}], and sulfur oxides [SO_x]) for marine engine systems used on typical maritime transport vessels. We model these emissions on a mass (gram or milligram) per energy (megajoule, MJ) unit. In these per-mass and/or per-energy units, the report provides general insights, and can be quickly applied in future projects to any specific vessel types and service routes.

1.3 Report Organization

Section 2 presents an introduction and background of TFCA, and motivation for considering methanol fuel as an alternative to current petroleum marine fuels. Section 3 describes the methodology used. Section 4 presents the key findings of the analysis. Finally, Section 5 presents overall conclusions and describes areas of further research. The report also includes several appendices related to this analysis, but beyond the project's original scope.

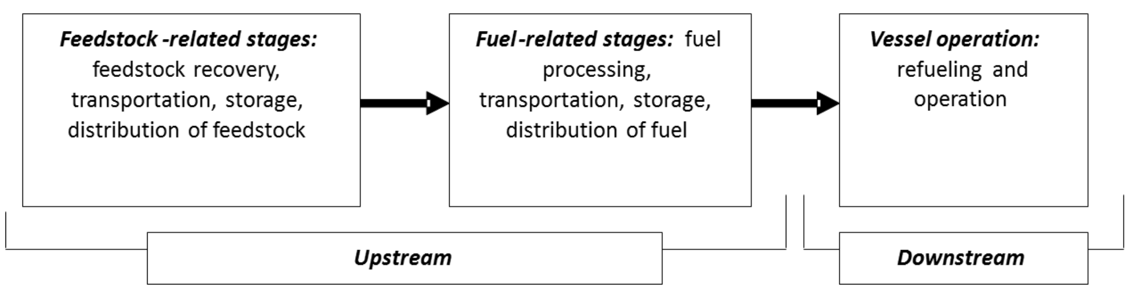
2 Background

2.1 Overview of Total Fuel-Cycle Analyses (TFCA)

TFCA enables calculation of the total emissions profile associated with the use of a given fuel in a vessel. Total fuel cycle analysis accounts for emissions along the entire "fuel cycle," which includes the following stages, also depicted in Figure 1:

- *Feedstock-related stages* – encompassing the extraction of the raw material through delivery to the refinery;
- *Fuel-related stages* – encompassing the delivery of a fuel from the refinery to the vessel; and,
- *Vessel operation* – encompassing the use of the fuel in the vessel itself.

Figure 1. Components of a total fuel cycle analysis showing Upstream ("Well-to-Tank") and Downstream ("Tank-to-Propeller") activities.



Many pathways exist to get fuel from the ground to the ship (*14, 15*) (*16*), and a number of these pathways will be evaluated in this study. Looking at the emissions from multiple pathways can help analysts evaluate those fuel production pathways that may incur the least energy use or emissions penalties compared to others.

Fuel cycle analyses were first published in the life-cycle analysis (LCA) literature as a subset of product life-cycle quantification, and mainly aimed at economic or carbon metrics (*17, 18*). TFCA became a specialized and unique type of LCA as alternative fuels were considered for both air quality and carbon emissions (*19-21*), and as dedicated models focused on current and alternative pathways for transportation fuel (*16, 22, 23*). TFCA became even more critical with the emergence of Low-Carbon Fuel Standards regulation and recognition of the importance of land use change (LUC) and emerging extraction methods (e.g., fracking).

In these models and studies, ship activity was only considered as a transportation and distribution function; this necessary but minor element of the fuel pathway did not contribute significantly to TFCA totals, so placeholder inputs were used in a generic context. As shipping energy inputs have become better studied by the U.S. Maritime Administration, other federal agencies, and international bodies like the International Maritime Organization (IMO), the value of specific TFCA for commercial vessels became apparent.

With regard to marine vessels and marine fuels, the TFCA emissions require specialized understanding of "downstream" or operational characteristics of these vessels and fuels. Work in this vein was first developed through funded research supported by the U.S. Maritime Administration (MARAD), and published in several papers (*24, 25*). In addition, the State of California commissioned a study that evaluated uncertainty in fundamental inputs for TFCA from commercial marine vessels (*10*).

2.2 Interest in Methanol as a Potential Marine Fuel

Methanol as a potential marine fuel has attracted interest internationally, partly motivating the US Maritime Administration's sponsorship of this work on fuel cycle analysis. Several internationally-registered vessels currently operate using methanol, include passenger ferry vessels and several tankers. A recent meeting of the IMO Marine Safety Committee (*26*) reported enough interest in methyl/ethyl alcohol as a marine fuel to invite the International Organisation for Standardization (ISO) to consider "a standard for methyl/ethyl alcohol as a marine fuel; and a standard for methyl/ethyl alcohol fuel couplings."

Several attributes supporting interest in methanol as a marine fuel are documented by Bromberg and Cheng (*27*). Liquid methanol fuels can be blended or used directly in spark-ignited engine systems with modest modifications. Marine engines designed for methanol combustion can achieve engine efficiencies similar to diesel combustion; and emissions from such engines are reported to meet or exceed current pollutant emission regulations, with no additional safety concerns relative to traditional marine fuels. Literature describes lower toxicity than gasoline, and suggests that unplanned releases would biodegrade more quickly than traditional petroleum fuels.

A recent study (*28*) on the potential for converting selected categories of smaller vessels to methanol operation found "lower particulate emissions and reduced NOx emissions for the concepts tested." Also, for smaller vessels, bunkering processes for methanol may be similar enough (i.e., truck-based) such that the barrier to supplying methanol could be reasonably low compared with traditional fuels. One motivating interest related to this report is that when methanol is produced from renewable biomass, methanol may offer some greenhouse gas (GHG) advantages compared with other marine transportation fuel options in the longer term (*27, 28*).

2.3 Motivation for Using Alternative Fuels

The International Convention for the Prevention of Pollution from Ships (MARPOL) was adopted by the IMO in 1973 to address the issue of pollution from ships entering the marine environment. MARPOL has been amended several times as new information about the causes, effects, and extent of marine pollution has been discovered. Annex VI was first adopted in 1997 to address air pollution, specifically SO_x and NO_x. Subsequent changes have decreased the allowed emissions and created ECAs with even stricter emissions requirements. As petroleum-based residual marine fuels tend to have high sulfur content, these stricter requirements have led to exploration of different fuels – such as methanol – for marine transportation.

The literature is clear that methanol fuel can reduce local pollutants from vessel operations; however, the advantages from a GHG emissions perspective remain uncertain. Methanol fuel production pathways can be relatively energy intensive compared to petroleum pathways, and the leakage of CH_4 that accompanies natural gas extraction and distribution (a major feedstock for methanol) may have important GHG impacts. However, advanced fuels may be cleaner, i.e., produce fewer emissions, than traditional fuels; this can support current federal legislation that ships control harmful air emissions and that ports reduce their regional contribution to criteria pollutant non-attainment under the Clean Air Act (*29*).[2] Since the International Maritime Organization has committed to reductions in both local pollution and GHG emissions, decision makers find it important to look at the life-cycle emissions generated by methanol fuels compared to traditional marine bunkers.

2.4 Consideration of Methanol for Marine Vessels

The emissions signature of methanol may satisfy all current, pending, and proposed standards for marine vessel operations. Recently, the shipping industry has joined other sectors in considering the merits of methanol as a feasible, economical, and low-emitting alternative to traditional petroleum fuels. For these reasons, methanol is emerging as an attractive fuel in some markets (*28, 30*). The emergence of market-ready reciprocating internal combustion engines capable of methanol operation in maritime service makes studies such as this one more important for industry leaders and policy decision makers.

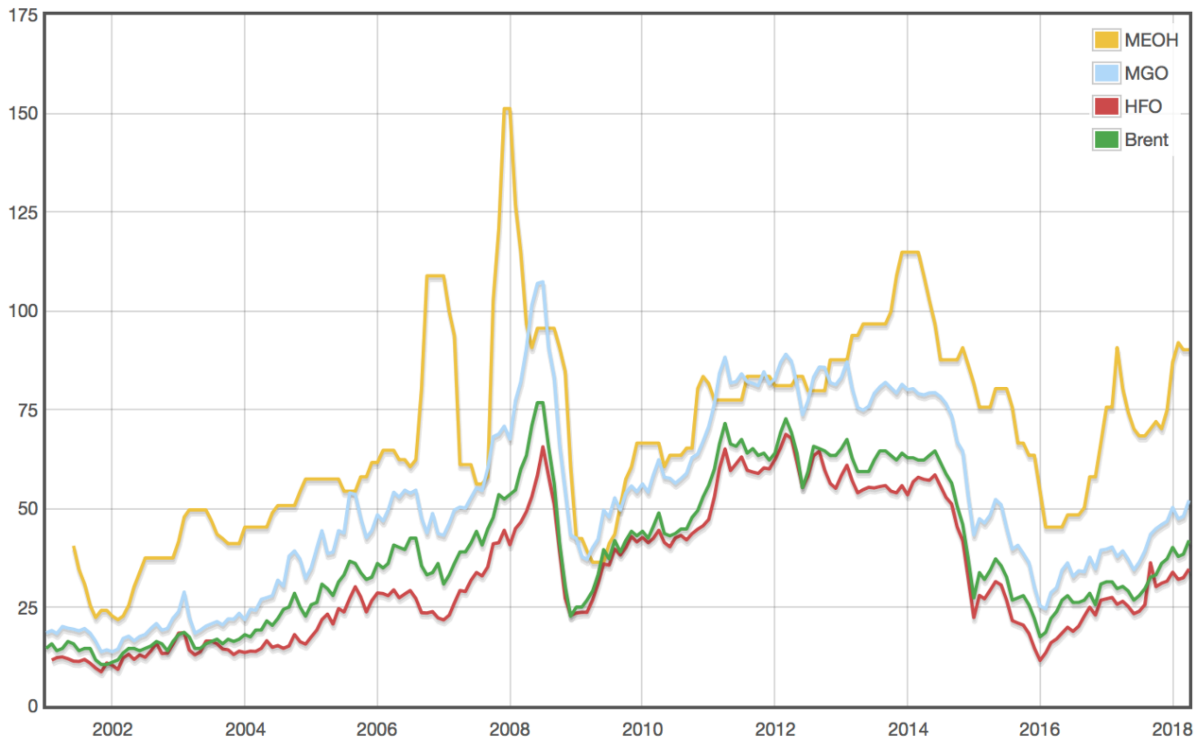
Of course, existence of the technology is not the only thing considered when deciding whether or not to switch to alternative fuels. Operators are also looking at cost and technical feasibility issues, including:

- the ability to operate within and beyond emission control areas, without the need for aftertreatment of exhaust gases for traditional pollutants;
- the price differentials for MeOH versus other marine fuels, including residual heavy fuel oil;
- the existence of infrastructure networks for obtaining MeOH fuel; and,
- attractive financing of MeOH vessels in fleet modernization/replacement strategies.

While these factors fall outside of the scope of this project, it is worth noting that recent studies investigating the potential fit for methanol as a niche or mainstream marine fuel recognize some of these as barriers, and others as relative advantages compared to other advanced fuels (e.g., liquefied natural gas) (*12, 13, 28, 30*). For example, recent trends in the prices of crude oil and methanol present a challenging reality for the methanol industry when compared on a per energy unit basis, as shown in Figure 2.

[2] Also see domestic regulations for marine engine emissions: 40 CFR Part 1042; 40 CFR Part 1043; 40 CFR Part 1065; 40 CFR Part 1068; 40 CFR Part 80; 40 CFR Part 89; and 40 CFR Part 94.

Figure 2. Historical price of crude oil and methanol showing the increasing price differential between these two fuels that has emerged since 2005. (Source: http://marinemethanol.com/meohprice)



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3 Methodology

3.1 Models

In order to conduct our TFCA, two models were used: GREET and TEAMS. These models calculate total energy and emissions for a variety of fuels over the total fuel cycle and have been extensively discussed in peer-reviewed published literature (*14, 23, 24, 31, 32*).

The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model was developed by Argonne National Laboratory (ANL). GREET allows researchers to examine the well-to-wheels emissions for a wide variety of fuels obtained using over 100 different pathways. Older versions of GREET focused solely on light-duty vehicles (LDVs). However, GREET has limited applications for marine vessels, as it does not allow for modification of vessel characteristics at the end-use stage. This weakness severely limited its use for our purposes. Therefore, we turned to TEAMS to capture the operations stages of the fuel life-cycle.

The Total Energy and Environmental Analysis for Marine System (TEAMS) model was developed with support from MARAD to assist TFCA modeling for marine vessels. TEAMS was used in previous evaluations by these authors for MARAD (*9, 10*). The advantage of TEAMS is that it offers greater flexibility for modeling the downstream (i.e., end-use) stages of the fuel cycle (i.e., vessel fuel use).

3.2 Fuel Properties

We use fuel property assumptions shown in Table 1.

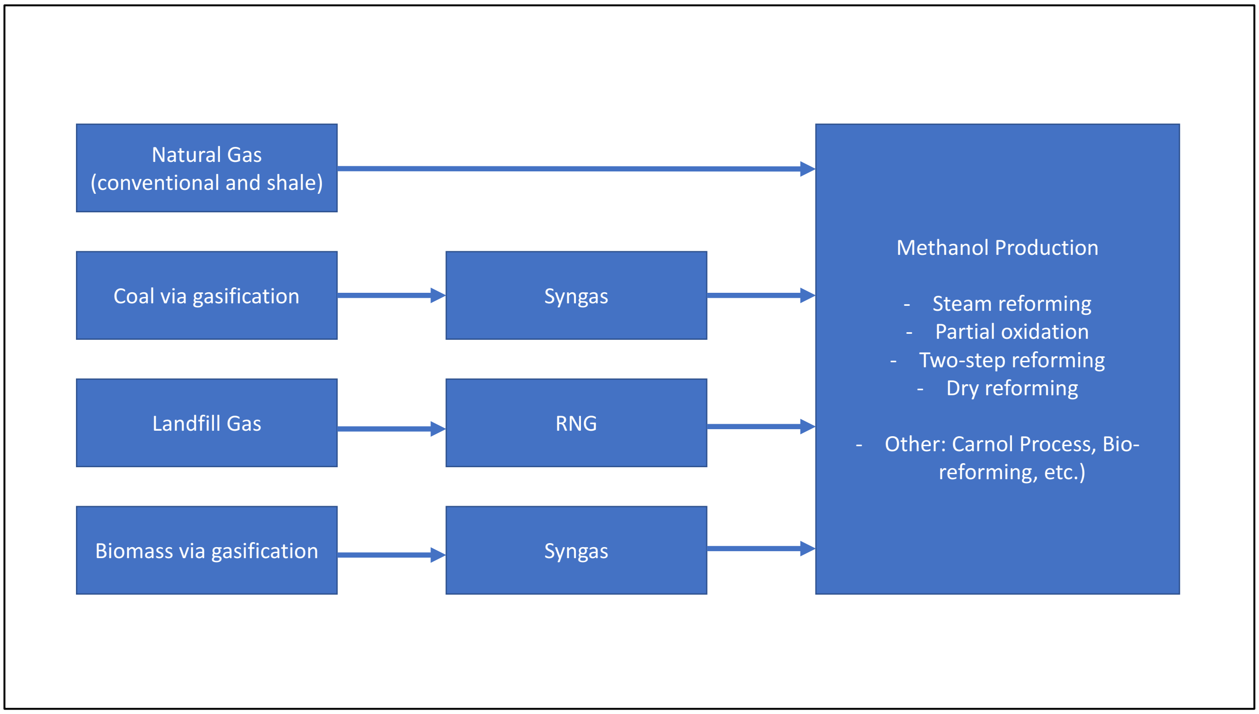
Table 1. Fuel properties for fuels evaluated in this study.

Fuel	Low Heating Value (BTU/gal)	Density (grams/gal)	Carbon Ratio (% by weight)	Sulfur Ratio (ppm by weight)
Residual Oil as Bunker Fuel for Ocean Vessels	140,353	3,752	86.8%	27,000
Methanol	57,250	3,006	37.5%	0
Liquefied Natural Gas	74,720	1,621	75%	0

3.3 Methanol Upstream (“Well-to-Tank”) Production

Methanol to serve the marine sector can be produced in many ways. A summary of production pathways evaluated in this report are shown in Figure 3 and Table 2 and reflect a spectrum of twelve different pathways.

Figure 3. Generic production pathways for the production of methanol showing potential feedstock (first column), intermediate products (middle column), and production processes (last column).



In this work, we follow the GREET convention regarding assignment and aggregation of emissions with respect to methanol in a multi-product fuel processing system. The production of methanol is based on standard industry practices, with and without electricity and steam co-products (see pathway descriptions below). "Co-product analysis" represents a methodological approach that assigns to the primary product (i.e., methanol) the emissions impacts (positive or negative) related to the production of the co-product (i.e., steam or electricity). with the. For example, if the production of methanol generates electricity as a co-product, then the emissions that *would have been* generated from electricity production elsewhere is subtracted from the emissions of the methanol production process. Co-product analysis may either increase or decrease overall emissions for methanol production, depending on the type of electricity generation (in this example) the methanol production is offsetting.

Pathways are indicated by alphabetic codes in Table 2. Our base assumptions are shown in Table 3. A more detailed description of methanol pathways considered in this work is presented below.

- **Methanol Pathway A**. This pathway represents a traditional pathway for the production of methanol. The feedstock in this pathway is North American natural gas (NANG). Because we are not modeling production from a particular natural gas field, we adopt default assumptions from Argonne National Lab's GREET model regarding natural gas feedstock qualities. Here, we assume that 51.5% of the feedstock comes from shale production 48.5% comes from conventional recovery practices. We assume that this gas is transported to methanol production facilities via pipeline over a distance of 100 miles.[3] Once produced, we assume the methanol is transported to bulk terminals using an industry average mix of pipeline, rail, and transport options; in this case, we assume transport from Canada to US terminals occurs via pipeline and rail, and transport from domestic

[3] Note that we do not model a *specific* production facility, but instead take the GREET approach of modeling a production facility and site that represents an industry average.

production facilities to bulk terminals occurs through barge, pipeline, rail, and truck (see Table 2 for specific distances). We assume transport from bulk terminals to refueling sites occur via truck.[4]

- **Methanol Pathway B**. This pathway is identical to Pathway A, with the exception that we include electricity as a co-product in the production of methanol.
- **Methanol Pathway C**. This pathway is identical to Pathway A, with the exception that we include steam as a co-product in the production of methanol.
- **Methanol Pathway D**. This pathway depicts methanol production from non-North American Natural Gas (NNANG) sourced from flare gas. The pathway assumes that a methanol production facility is relatively close to the feedstock location, and that natural gas only travels 10 miles by pipeline to that production facility (i.e., the methanol is produced at NNA plants). Consistent with other TFCA analyses, this pathway also assumes that if not for using this flared gas for methanol production, it would have released carbon dioxide through its combustion; therefore, the shift of flared gas to methanol production creates an emissions credit in TFCA accounting, which is reflected by a negative emissions value in tables that follow. We adopt standard production assumptions for this pathway; however, because this is NNANG, the methanol must be shipped via ocean tanker to US shores (assumed 5900 miles) and then shipped to bulk terminals using barge, rail, and truck. Product is then moved to refueling facilities via truck.
- **Methanol Pathway E**. This pathway is identical to Pathway D, with the exception that we include electricity as a co-product in the production of methanol. This means that not all the feedstock input is converted into methanol output (some is used to generate electricity) and so emissions per MJ methanol output are higher in cases where electricity (or steam, see Pathway F) is produced.
- **Methanol Pathway F**. This pathway is identical to Pathway D, with the exception that we include steam as a co-product in the production of methanol. See Pathway E for explanation on emissions accounting impacts due to electricity or steam co-production.
- **Methanol Pathway G**. This pathway depicts methanol production from NNANG, but sourced from conventional recovery techniques. Pipelines move this natural gas to production facilities where standards processes are assumed to convert the natural gas to methanol. That methanol is then shipped to US ports via ocean tanker, and then to bulk terminals using barge, rail, and truck. As with other pathways, methanol then moves from the terminal to refueling sites via truck.
- **Methanol Pathway H**. This pathway is identical to Pathway G, with the exception that we include electricity as a co-product in the production of methanol. See Pathway E for explanation on electricity co-production.
- **Methanol Pathway I**. This pathway is identical to Pathway G, with the exception that we include steam as a co-product in the production of methanol. See Pathway E for explanation on steam co-production.
- **Methanol Pathway J**. This pathway relies on forest residue as the primary feedstock for methanol, and demonstrates the potential use of biomass more generally. Biomass to methanol production efficiencies are presented in Table 4. We assume such biomass is transported to the methanol production facility via truck, and that methanol is produces using standard gasification and production processes as outlined in GREET. The methanol is then moved to bulk terminals using barge, rail, and truck; and then to refueling sites via truck.
- **Methanol Pathway K**. This pathway uses landfill gas as the feedstock for methanol production. A key assumption in this pathway is that the methanol production facility is assumed to be co-located with the landfill gas, so no transportation is necessary to the production facility. We do adopt an approach in this pathway consistent with Pathway D, where energy and emissions credits are attributed to the methanol production assuming that this landfill gas would have normally been flared, if not for the fact that this pathway captures and processes that landfill gas into usable

[4] The importance of transportation distance assumptions is evaluated in a later sensitivity analysis in this report.

methanol. We assume that the methanol terminal is also co-located with the landfill, and methanol produced on-site is transported directly to refueling facilities via truck.

- **Methanol Pathway L**. This pathway assumes that coal is used as feedstock for methanol production. Coal to methanol production efficiencies are presented in Table 4. We assume coal is transported from mines to production facilities primarily via rail and truck. That coal is then gasified using standard gasification techniques, and that gas is converted into methanol. We provide steam production credits for this pathway. Once produced, we assume the methanol is transported to terminals via barge, rail, and truck; and then to refueling sites via truck.

Comparison fuel pathways are summarized below:

- **Residual Oil Pathway M**. This pathway assumes standard production of residual oil from crude oil feedstock.
- **Liquefied Natural Gas Pathway N**. This pathway represents production of LNG from North American natural gas sources.
- **Liquefied Natural Gas Pathway O**. This pathway represents production of LNG from non-North American natural gas sources.
- **Liquefied Natural Gas Pathway P**. This pathway represents production of LNG from gas that would normally be flared at the production site.

There are many assumptions that define each of the pathways presented in this work. One assumption that we consider explicitly is the transportation distance traveled between different nodes in the production process. Although the results contained in the body of this report are for our default assumptions, Appendix A provides a sensitivity analysis regarding transportation distances.

Another important set of assumptions relate to the efficiencies and emissions related to natural gas recovery and methanol production. These were vetted by experts in the field (personal communication from D Ferguson, *Enerkem*, email via G Dolan, 25 March 2018). Because we realize that different production facilities and processes may have different efficiency and emissions profiles, we conduct a sensitivity analysis on these values in Appendix B.

Table 2. Overview of methanol production and distribution pathways with key variables identified (inputs used in TEAMS/GREET 2017)

Methanol Pathway Code	Feedstock	Transportation of Feedstock to Production Facility	Production Facility Notes	Transportation to Bulk Terminal	Transportation to Refueling Facility
A	North American Natural Gas (Average from Shale [51.5%] and Conventional Recovery [48.5%])	Pipeline (100%/100 mi)	Standard / No Co-Products	To US from Canada: Mix (Pipeline – 8.5%/600 mi; Rail – 8.5%/700 mi. Remainder (83%) domestic. To Terminal: Mix (Barge – 10%/520 mi; Pipeline – 20%/550 mi; Rail – 20%/650 mi; Truck – 50%/80 mi.)	Truck (100%/30 mi)
B	North American Natural Gas (Average from Shale [51.5%] and Conventional Recovery [48.5%])	Pipeline (100%/100 mi)	Standard / Electricity Co-Product	To US from Canada: Mix (Pipeline – 8.5%/600 mi; Rail – 8.5%/700 mi. Remainder (83%) domestic. To Terminal: Mix (Barge – 10%/520 mi; Pipeline – 20%/550 mi; Rail – 20%/650 mi; Truck – 50%/80 mi.)	Truck (100%/30 mi)
C	North American Natural Gas (Average from Shale [51.5%] and Conventional Recovery [48.5%])	Pipeline (100%/100 mi)	Standard / Steam Co-Product	To US from Canada: Mix (Pipeline – 8.5%/600 mi; Rail – 8.5%/700 mi. Remainder (83%) domestic. To Terminal: Mix (Barge – 10%/520 mi; Pipeline – 20%/550 mi; Rail – 20%/650 mi; Truck – 50%/80 mi.)	Truck (100%/30 mi)
D	Non-North American Flared Gas	Pipeline (100%/10 mi)	Standard / No Co-Products	To US: Ocean Tanker – 100%/5900 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
E	Non-North American Flared Gas	Pipeline (100%/10 mi)	Standard/ Electricity Co-Product	To US: Ocean Tanker – 100%/5900 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
F	Non-North American Flared Gas	Pipeline (100%/10 mi)	Standard / Steam Co-Product	To US: Ocean Tanker – 100%/5900 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
G	Non-North American Conventional Recovery	Pipeline (100%/100 mi)	Standard / No Co-Products	To US: Ocean Tanker – 100%/3000 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
H	Non-North American Conventional Recovery	Pipeline (100%/100 mi)	Standard / Electricity Co-Product	To US: Ocean Tanker – 100%/3000 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
I	Non-North American Conventional Recovery	Pipeline (100%/100 mi)	Standard / Steam Co-Product	To US: Ocean Tanker – 100%/3000 mi To Terminal: Mix (Barge – 40%/520 mi; Rail - 20%/700 mi; Truck – 40%/80mi)	Truck (100%/30 mi)
J	Biomass (Forest Residue)	Truck (100%/90 mi)	No export	Mix (Barge – 40%/520 mi; Rail – 20%/700 mi; Truck – 40%/80 mi.)	Truck (100%/30 mi)
K	Landfill Gas	Onsite	Energy and emissions credits included	Truck (100%/30 mi)	
L	Coal	Rail (92.6%/740 mi); Truck (5.3%/150 mi); Pipeline (2.1%/320 mi)	Steam export	Mix (Barge – 40%/520 mi; Rail – 20%/700 mi; Truck – 40%/80 mi.)	Truck (100%/30 mi)

Table 3. Feedstock recovery, processing, and methanol production efficiencies (MJ/MJ) and emissions (g/GJ or g/MJ).

Natural Gas Recovery and Processing	
Overall efficiency of recovery and processing	95%
Methane leakage rate (g/MJ)	0.09
Carbon dioxide venting (g/MJ)	0.77
Greenhouse gas intensity (gCO2e/MJ)	7.6
Methanol Production	
Overall efficiency for methanol production	67%
Natural gas feedstock input efficiency (MJ/MJ)	1.45
Natural gas process fuel input (MJ/MJ)	0.013
Electricity input (MJ/MJ)	0.040
Steam co-product credit (MJ/MJ)	0.11

Table 4. Biomass to methanol and coal to methanol production efficiencies.

Biomass to Methanol Production	
Biomass gasification without export	58%
Biomass gasification with export	43%
Coal to Methanol Production	
Coal gasification without export	58%
Coal gasification with export	43%

Note: "With export" and "without export" represent cases where the gasification process is designed to generate additional electricity for export (i.e., beyond the minimal amounts needed for internal processes); in cases "with export" some of the energy in the feedstock is used to produce additional exported electricity, and therefore overall efficiencies are lower.

4 Findings

This section presents the model output for the production stages (upstream) and operational stages (downstream) methanol analysis. The findings include corresponding results for petroleum marine fuels and for natural gas fuel. These observations lead to natural groupings of results that we report in the Section 5.

4.1 Production (Upstream) Findings

The upstream well to use results from our emissions analysis for each of these pathways is shown in Table 5. For other fuels explored in this report, we use previously published values for upstream production emissions (*11-13, 33*). As shown in the well-to-tank table, the results can be grouped according to characteristic patterns. Methanol from flared gas and landfill gas exhibit the best upstream performance, with upstream net-GHG reductions; methanol from biomass (i.e., forest residue) demonstrates similar performance, with low but increased upstream net-GHG emissions. This can be considered similar to recent results from the SUMMETH program (*30*). Natural gas upstream production emissions largely mirror the upstream emissions for methanol derived from natural gas, as expected. With regard to upstream emissions, LNG typically performs better because of the additional processing for methanol. Compared with fossil fuels, upstream findings for methanol (and natural gas) perform generally better than coal and not as good as petroleum marine fuels on a GHG basis, and upstream criteria pollutant emissions are similar or higher, typically, for methanol and natural gas than for fossil fuels, due to the additional upstream processing of these fuels. Other comparisons include that non-North American natural gas sources demonstrate more variability, given model input defaults, than North American natural gas sources.

Table 5. Default well-to-use (WTU) results for each production pathway by pathway code showing emissions per MJ methanol output (output from TEAMS/GREET 2017)

Pathway Code	Feedstock	CO2 (g/MJ)	CH4 (g/MJ)	N2O (mg/MJ)	GHG100 (g/MJ)	VOC (mg/MJ)	CO (mg/MJ)	NOx (mg/MJ)	PM2.5 (mg/MJ)	SOx (mg/MJ)
Methanol										
A	North American Natural Gas	20.54	0.23	0.52	27.65	24.72	36.15	56.69	12.84	17.21
B		21.27	0.23	0.49	28.49	24.90	36.67	56.70	13.23	11.96
C		19.87	0.22	0.32	26.73	22.59	20.93	32.21	12.48	26.23
D	Non-North American Flared Gas[a]	-60.0	0.16	-1.12	-50.0	22.98	3.88	49.86	12.45	57.18
E		-10.0	0.21	0.02	-0.22	25.40	27.82	94.10	16.19	52.16
F		-50.0	0.17	-1.26	-50.0	22.09	-7.29	30.11	12.58	67.73
G	Non-North American Conventional Recovery	21.86	0.23	0.55	29.02	26.02	40.18	91.00	15.31	38.19
H		22.60	0.23	0.53	29.86	26.21	40.71	91.03	15.70	32.94
I		21.20	0.22	0.36	28.10	23.89	24.97	66.53	14.96	47.20
J	Biomass (Forest Residue)	4.83	0.009	0.06	5.15	2.04	8.93	24.91	1.07	3.13
K	Landfill Gas[b]	-40.0	0.40	-0.97	-30.0	-12.4	-34.7	-1.18	-4.20	29.53
L	Coal	120.0	0.25	0.07	130.0	25.06	7.00	31.03	2.66	13.80
Petroleum										
M	Residual Oil	10.31	0.15	0.18	14.95	5.51	11.67	30.05	1.73	15.38
Natural Gas										
N	LNG - NA Natural gas	11.82	0.29	0.17	20.65	7.51	19.53	29.23	0.91	13.07
O	LNG - NNA Natural Gas	13.22	0.29	0.21	21.91	8.86	22.49	61.5	3.18	35.18
P	LNG - From Flared Gas	-50	0.18	-0.954	-40	6.21	-4.97	9.74	-0.658	35.15

[a]WTU emissions for flared gas may be negative due to assumptions about the alternative use of the fuel. WTU analyses assume that flared gas would have emitted CO2 through combustion at the production site. Since that gas is now being used to make methanol, there is an emissions "credit" attributed to flared gas, and so emissions are negative for the feedstock stage of production.

[b]WTU emissions for Landfill Gas may be negative due to similar assumptions for flared natural gas.

4.2 Operational (Downstream) Findings

Downstream emissions factors were compiled from the literature (*11-13*). Table 6 presents those values by type of marine engine. On a GHG basis, the literature provides insufficient data to make comparisons on a CO_2-equivalent basis (missing methane [CH_4] and nitrous oxide [N_2O]), but we can evaluate differences in carbon dioxide emissions. Combustion conditions and fuel properties matter to the downstream net-GHG estimates. Spark-ignited (Otto cycle) engines typically have higher methane emissions (methane slip) than auto-ignited (Diesel cycle) engines. Residual fuels that are typically less processed and higher in sulphur also have longer hydrocarbon chain molecules associated with higher carbon dioxide emissions. Table 6 associates lower NOx and higher PM with spark-ignited engines, and different sulphur emissions according to the fuel sulphur contents; in the absence of published test data for some criteria pollutants (e.g., VOC and CO), this work assigns similar values across engine types while acknowledging these may in-fact differ.

Table 6. Summary of vessel combustion emission factors for traditional fuels and for methanol.

Pollutant (g/MJ)	CO_2 g/MJ	CH_4 g/MJ	N_2O mg/MJ	GHG_{100} g/MJ	VOC mg/MJ	CO mg/MJ	NOx (mg/MJ)	$PM_{2.5}$ (mg/MJ)	SOx (mg/MJ)
Natural Gas Engine									
Diesel – Ignited	55.93	0.0872	1.896	58.88	89.11	203.8	2352	0.6636	0.2844
Spark – Ignited	55.49	0.6247	1.896	73.48	23.70	203.8	224.7	4.740	0.2844
Petroleum Fueled Engine									
Low-S Diesel	73.20	0.0047	1.896	73.84	88.16	407.6	2351	69.20	9.480
High-S Diesel	79.73	0.0047	1.896	80.36	88.16	407.6	2351	69.20	245.5
Methanol Fueled Engine									
Lower-bound	59.50						280.0	4.300	0.2844
Central Estimate	65.83						342.5	4.300	0.2844
Upper-bound	69.00						400.0	4.300	0.2844

5 Results and Conclusions

5.1 Results Summaries

The results of our analysis are found in Tables 7 through 9.

Table 7. Upstream ("Well-to-Tank") results for four key pollutants.

Upstream Results	CO_2 (g/MJ)	NOx (mg/MJ)	$PM_{2.5}$ (mg/MJ)	SOx (mg/MJ)
Methanol Pathways A through C (NA Natural Gas)	20.56	48.53	12.85	18.47
Methanol Pathways D through F (NNA Flared Gas)	-40.00	58.02	13.74	59.02
Methanol Pathways G through I (NNA Conventional Gas)	21.89	82.85	15.32	39.44
Methanol Pathway J Biomass (Forest Residue)	4.83	24.91	1.07	3.13
Methanol Pathway K Landfill Gas	-40.00	-1.18	-4.20	29.53
Methanol Pathway L (Coal)	120.00	31.03	2.66	13.80
Residual Oil (General Performance)	10.31	30.05	1.73	15.38
LNG (Natural Gas - both NA and NNA)	12.52	45.37	2.05	24.13
LNG (Flared Gas)	-50.00	9.74	-0.66	35.15

Table 8. Downstream ("Tank-to-Propeller") results for four key pollutants.

Downstream Results	CO_2 (g/MJ)	NOx (mg/MJ)	$PM_{2.5}$ (mg/MJ)	SOx (mg/MJ)
Methanol Pathways A through C (NA Natural Gas)	65.83	342.55	4.30	0.28
Methanol Pathways D through F (NNA Flared Gas)	65.83	342.55	4.30	0.28
Methanol Pathways G through I (NNA Conventional Gas)	65.83	342.55	4.30	0.28
Methanol Pathway J Biomass (Forest Residue)	65.83	342.55	4.30	0.28
Methanol Pathway K Landfill Gas	65.83	342.55	4.30	0.28
Methanol Pathway L (Coal)	65.83	342.55	4.30	0.28
Residual Oil (General Performance)	79.73	2351.04	69.20	127.51
LNG (Natural Gas - both NA and NNA)	55.93	1288.33	2.70	0.28
LNG (Flared Gas)	55.93	1288.33	2.70	0.28

Table 9. Upstream and downstream combined ("Well-to-Propeller") results for four key pollutants.

Combined Upstream-Downstream Results	CO_2 (g/MJ)	NOx (mg/MJ)	$PM_{2.5}$ (mg/MJ)	SOx (mg/MJ)
Methanol Pathways A through C (NA Natural Gas)	86.39	391.08	17.15	18.75
Methanol Pathways D through F (NNA Flared Gas)	25.83	400.57	18.04	59.31
Methanol Pathways G through I (NNA Conventional Gas)	87.72	425.40	19.62	39.73
Methanol Pathway J Biomass (Forest Residue)	70.66	367.46	5.37	3.41
Methanol Pathway K Landfill Gas	25.83	341.37	0.10	29.81
Methanol Pathway L (Coal)	185.83	373.58	6.96	14.08
Residual Oil (General Performance)	90.04	2381.09	70.93	142.89
LNG (Natural Gas - both NA and NNA)	68.45	1333.70	4.75	24.41
LNG (Flared Gas)	5.93	1298.07	2.04	35.43

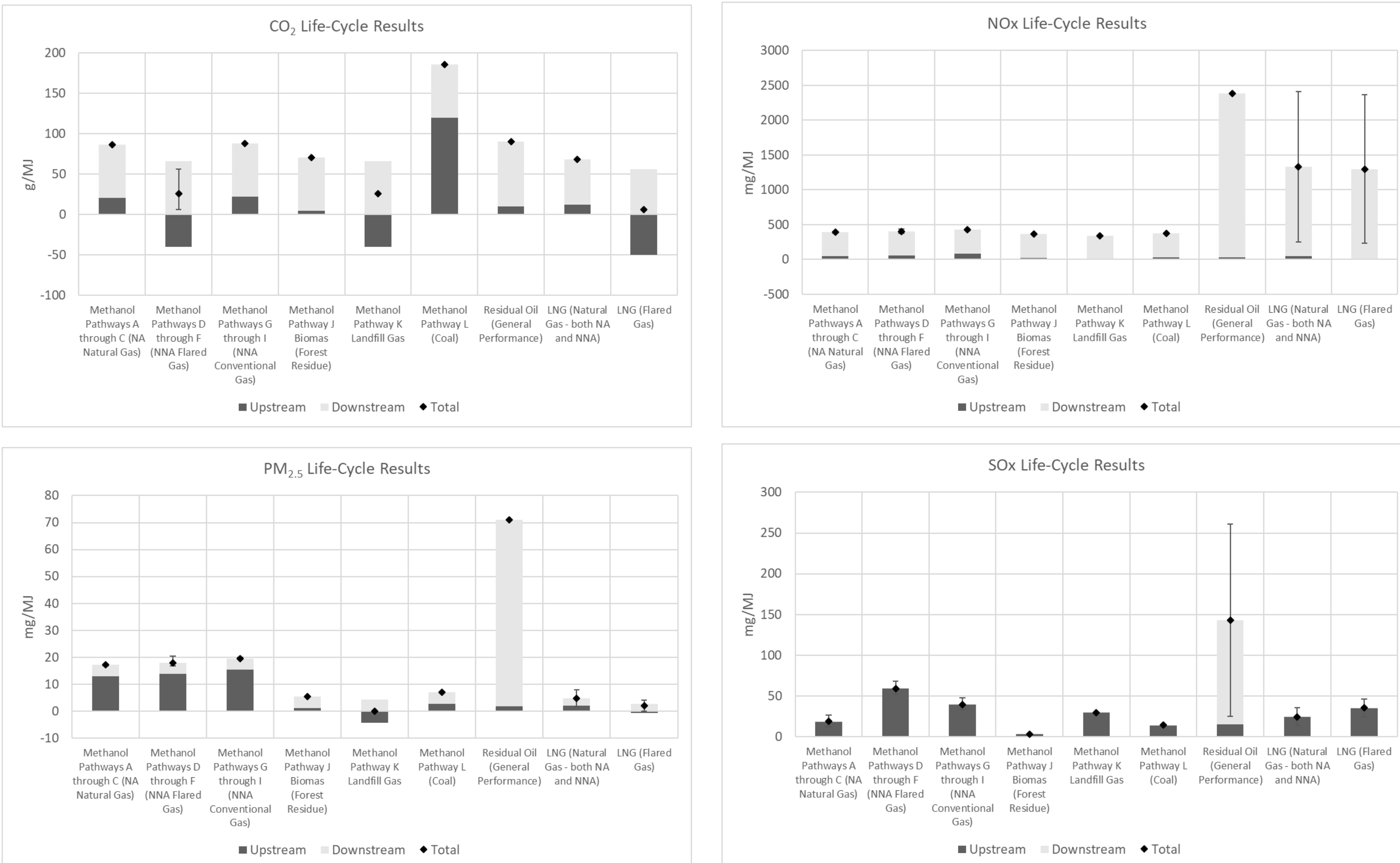


Figure 4. Summary of Life-Cycle Results for Methanol Compared with Residual Oil and LNG, for CO_2, NOx, $PM_{2.5}$, and SOx. Bars represent different conditions (e.g., high- and low-sulphur petroleum fuel, diesel and spark ignited gas engines, and high and low values in the methanol literature.

5.2 Conclusions

Marine transportation methanol emissions across a "well-to-propeller" life-cycle are dependent on both upstream fuel pathways and downstream maritime propulsion technologies. This report considers near-term methanol production technologies and current system conditions, as reported in models and literature. Focusing on greenhouse gas and criteria pollutant emissions, our comparison of methanol life-cycle emissions with those for other marine fuels, including liquefied natural gas, low sulfur marine fuel, and heavy-fuel oil blends indicates that methanol offers low-polluting performance in the downstream phases of maritime systems, and that carbon dioxide performance may be similar to comparator marine fuels. For nitrogen oxides, sulfur oxides, and particulate matter, methanol performs similar to liquefied natural gas and better than conventional petroleum fuel. Decision makers can use these results to inform decisions related to increasing the use of methanol in marine transportation systems, and adoption of advanced/alternative fuels in general.

This work has identified five key insights related to the emissions impacts of using methanol as a marine fuel.

1. Methanol CO_2 life cycle emissions are more similar to LNG than different. Life-cycle LNG-derived methanol performs similarly to LNG generally, and for greenhouse gases, methanol compares favorably to conventional fuel and liquefied natural gas when renewable (i.e., forest residue and landfill gas) feedstock is used.
2. Variability among pathways for producing methanol largely determine the variability of comparisons among methanol, petroleum, and natural gas marine fuels. Upstream CO_2 contributions determine the differences among methanol pathways net-CO_2.
3. Additional research in downstream emissions needs to include measured emissions rates for methanol fuels. GHG_{100} results are not readily available due to paucity of information for CH_4 and N_2O. This work presented full life-cycle results for the four emission species supported by currently available data.
4. Similar upstream processing and downstream maritime technologies for methanol and natural gas fuels result in similar life-cycle performance. For example, NOx life-cycle results for methanol are similar to LNG on spark-ignited processes, mainly because methanol is a spark-ignited fuel.
5. Even where downstream pollutant emissions are low, upstream pathways that include higher-emitting processes can offset downstream clean-fuel characteristics. Unless methanol upstream is "renewable" or from coal, the net PM impacts for methanol are higher than for LNG, although better than for marine petroleum fuels. SOx impacts for methanol are similar to LNG impacts and depend upon the upstream processes. "Renewable" methanol upstream processes help reduce methanol life-cycle SOx; under these conditions, methanol may perform better than LNG by emitting less SOx.

Given that current research in marine systems on "tank to propeller" emissions does not include data for many pollutants, significant additional research studies are needed for a fuller assessment of life-cycle methanol performance. This report recommends field testing for additional GHGs such as N2O and CH4 to enable fuller assessment of CO2-equivalence and better comparison with LNG fuel.

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8 Appendix A. An Example of Using GREET 2017 to Conduct TFCA Sensitivity Analysis for Methanol: Transportation

8.1 Summary

This appendix demonstrates the use of GREET 2017 to evaluate methanol production pathways. The example we use is one in which we evaluate the relationship of emissions to transportation and distribution distances within production pathways. For this analysis, we ran four cases for each pathway discussed in the report: (1) zero out distances for transportation of feedstock to production facilities; (2) zero out distances for transportation of methanol from production facilities to bulk terminals; (3) zero out distances for transportation from bulk terminals to refueling facilities; and (4) zero out all distances. The goal of the analysis is twofold. First, we want to provide an example case to demonstrate how methanol production can be modeled using the GREET modeling framework. Second, we want to explore the specific question of whether emissions from methanol production pathways are elastic with respect to transportation distances within those pathways. If the answer is that emissions are highly elastic to transportation distances, then analysts needs to take great care in acquiring and verifying these distances for different TFCA cases; if the answer is that emissions are relatively inelastic to transportation distances, then concern about "getting the transportation distances right" are less important.

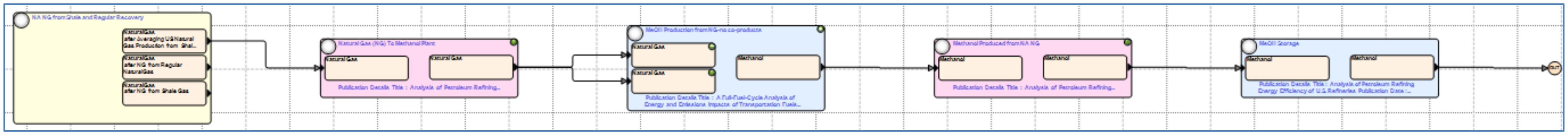
8.2 Pathways A, B and C

We refer readers to Table 2 in the report for an overview of pathways evaluated. In this section, we demonstrate the process for addressing transportation distances for pathways A, B, and C. We show in Figure 5 the transportation pathway from feedstock to refueling site.

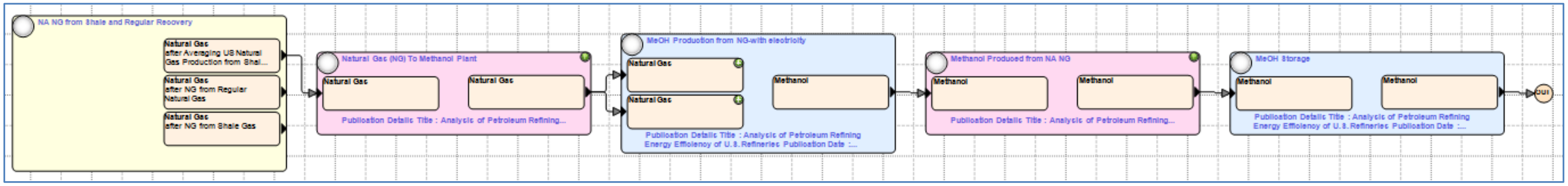
Amending the transportation distances from feedstock extraction to production facility is shown in Figure 6. By double clicking on the *Natural Gas to Methanol Plant* box, users can display the *Transportation Process Editor* from feedstock to production facilities. Once in this editor, users double-click the pipeline in order to show its parameters. For this sensitivity analysis, we zeroed the pipeline distance from the default 100 miles to "0". Using a similar approach, we modified the transportation distances from the production facility to the refueling site, a process shown in Figure 7.

Figure 5. Overview of pathways A, B, and C related to transportation of feedstock from extraction to production facility to refueling site.

Pathway A:



Pathway B:



Pathway C:

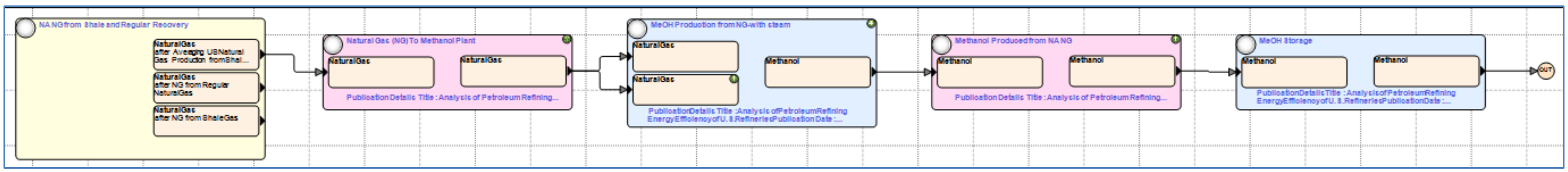
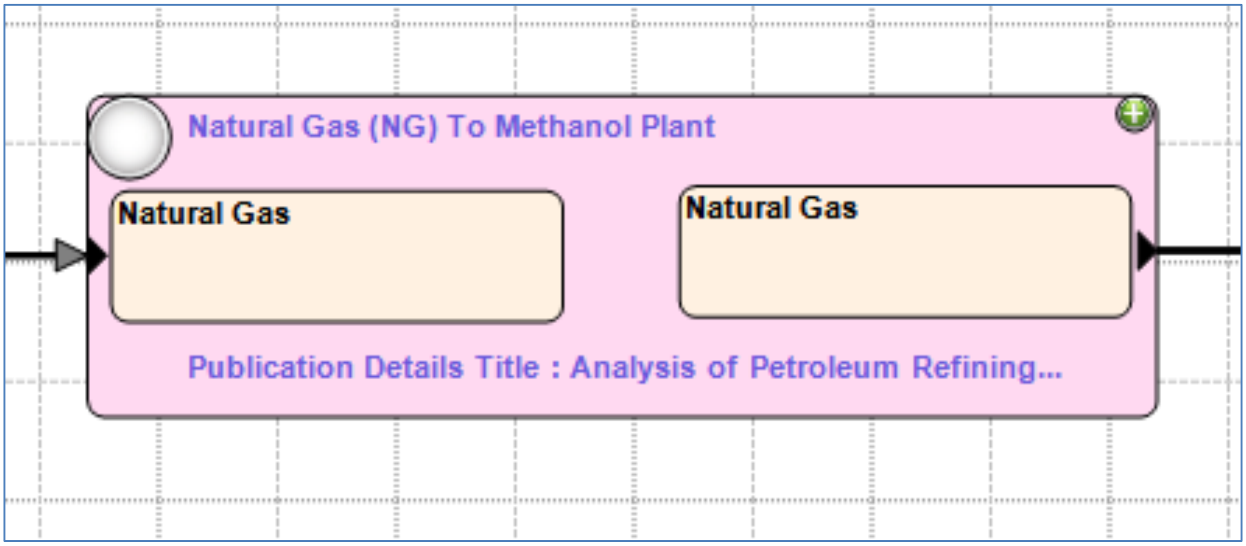


Figure 6. Modification of transportation distances from feedstock recovery to methanol production facility for pathways A, B, and C.



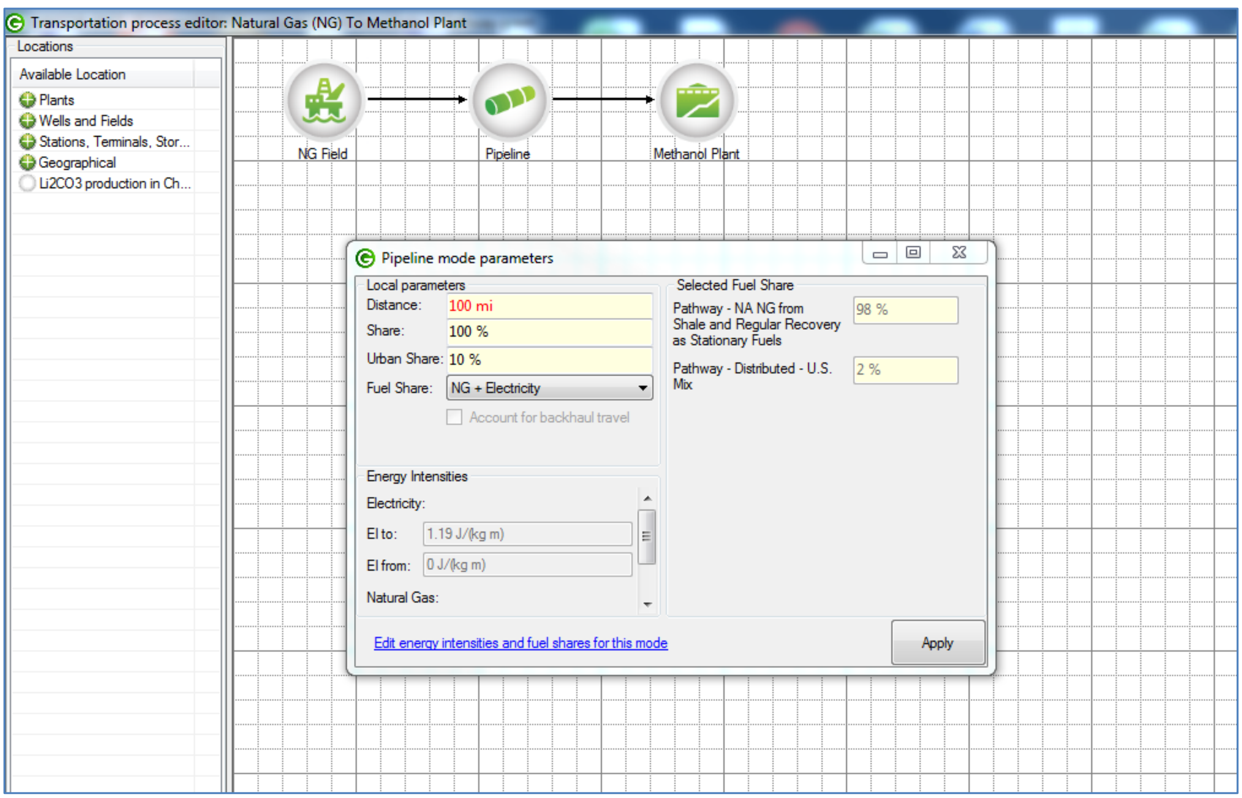
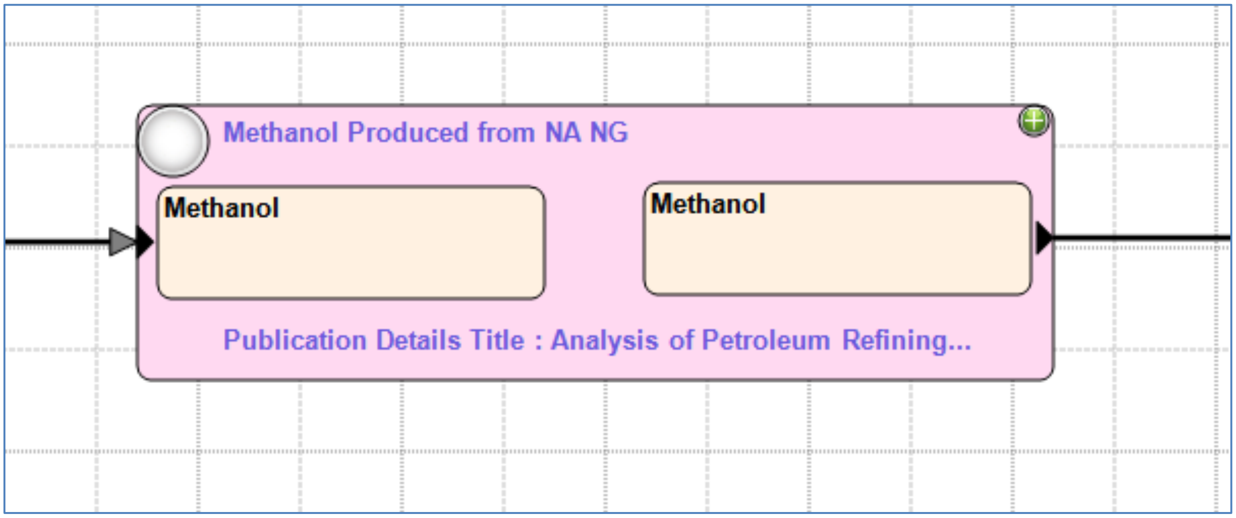
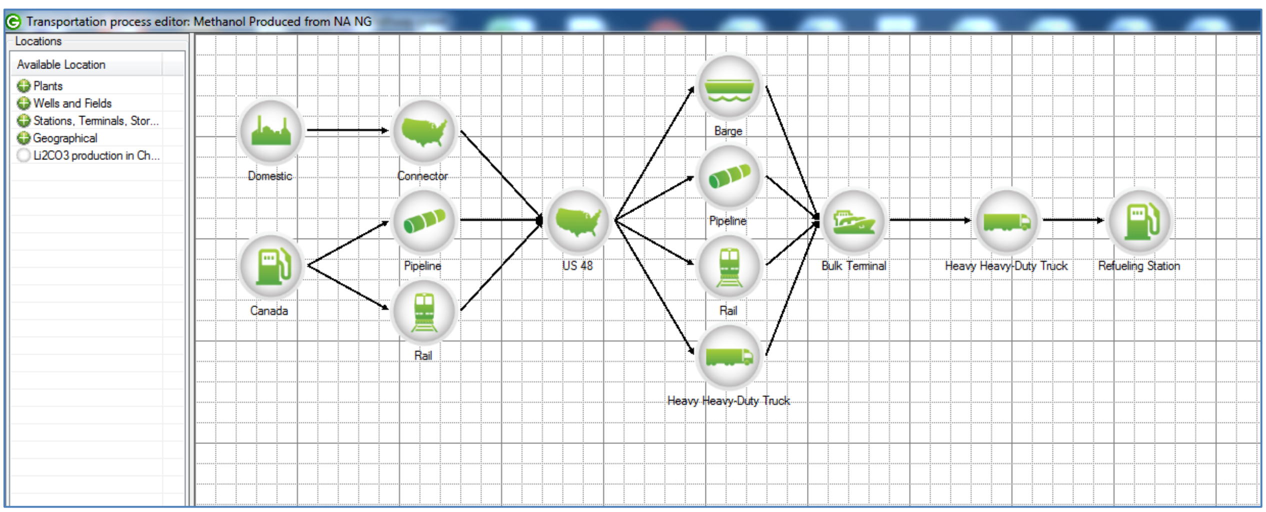


Figure 7. Modification of transportation distances from methanol production facility to refueling site for pathways A, B, and C.





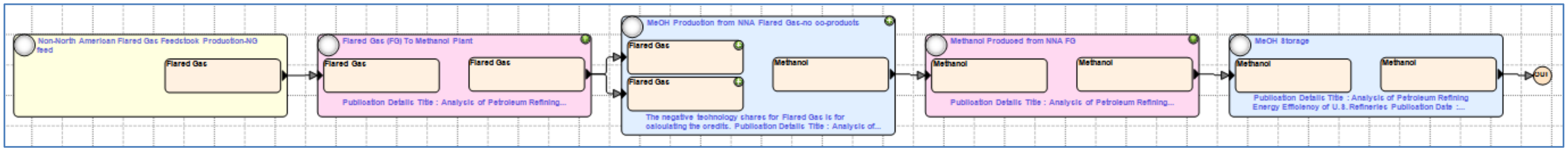
8.3 Pathways D, E, and F

We approach pathways D, E, and F similarly as above. We refer readers to Table 2 in the report for an overview of these pathways. In this section, we demonstrate the process for addressing transportation distances for pathways D, E, and F. We show in Figure 8 the transportation pathway from feedstock to refueling site.

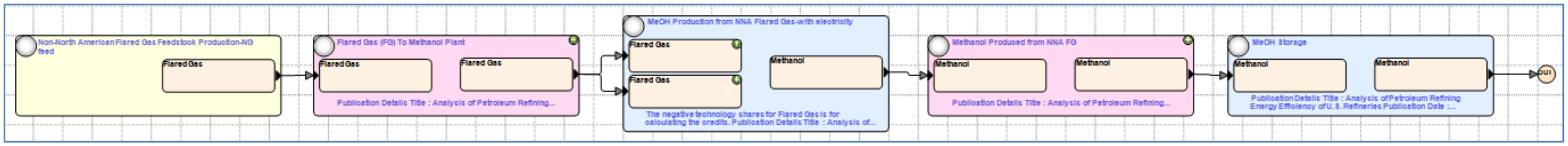
Amending the transportation distances from feedstock extraction to production facility is shown in Figure 9. By double clicking the *Flared Gas to Methanol Plant* box, users can display the *Transportation Process Editor* from feedstock to production facilities. Once in this editor, users double-click the pipeline in order to show its parameters. For this sensitivity analysis, we zeroed the pipeline distance from the default 10 miles to “0”. Using a similar approach, we modified the transportation distances from the production facility to the refueling site, a process shown in Figure 10.

Figure 8. Overview of pathways D, E, and F related to transportation of feedstock from extraction to production facility to refueling site.

Pathway D:



Pathway E:



Pathway F:

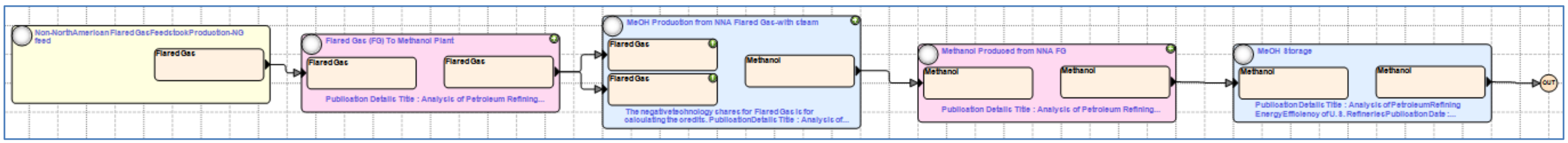
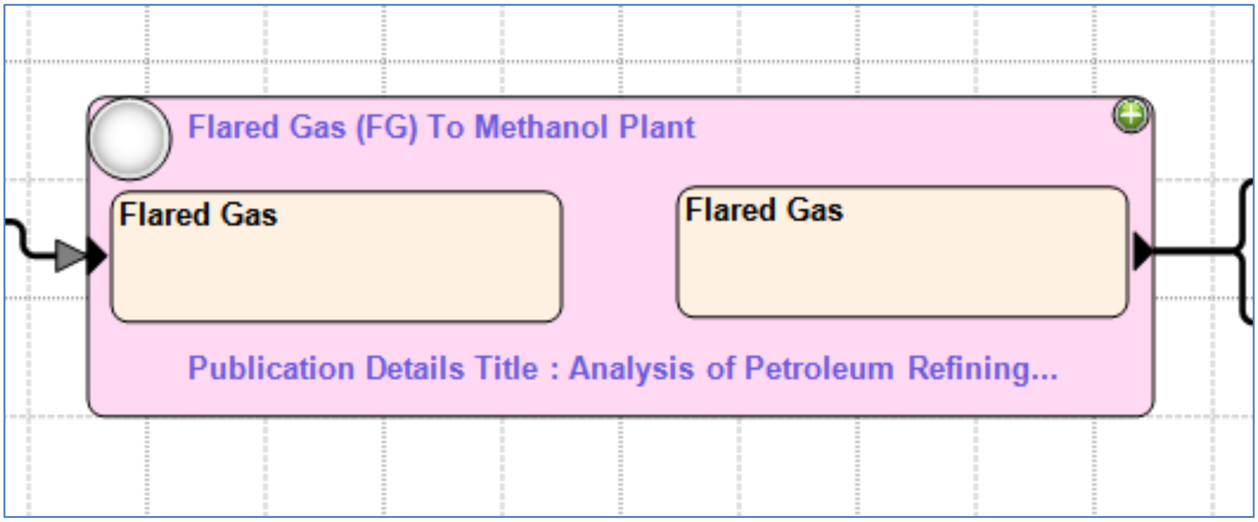


Figure 9. Modification of transportation distances from feedstock recovery to methanol production facility for pathways D, E, and F.



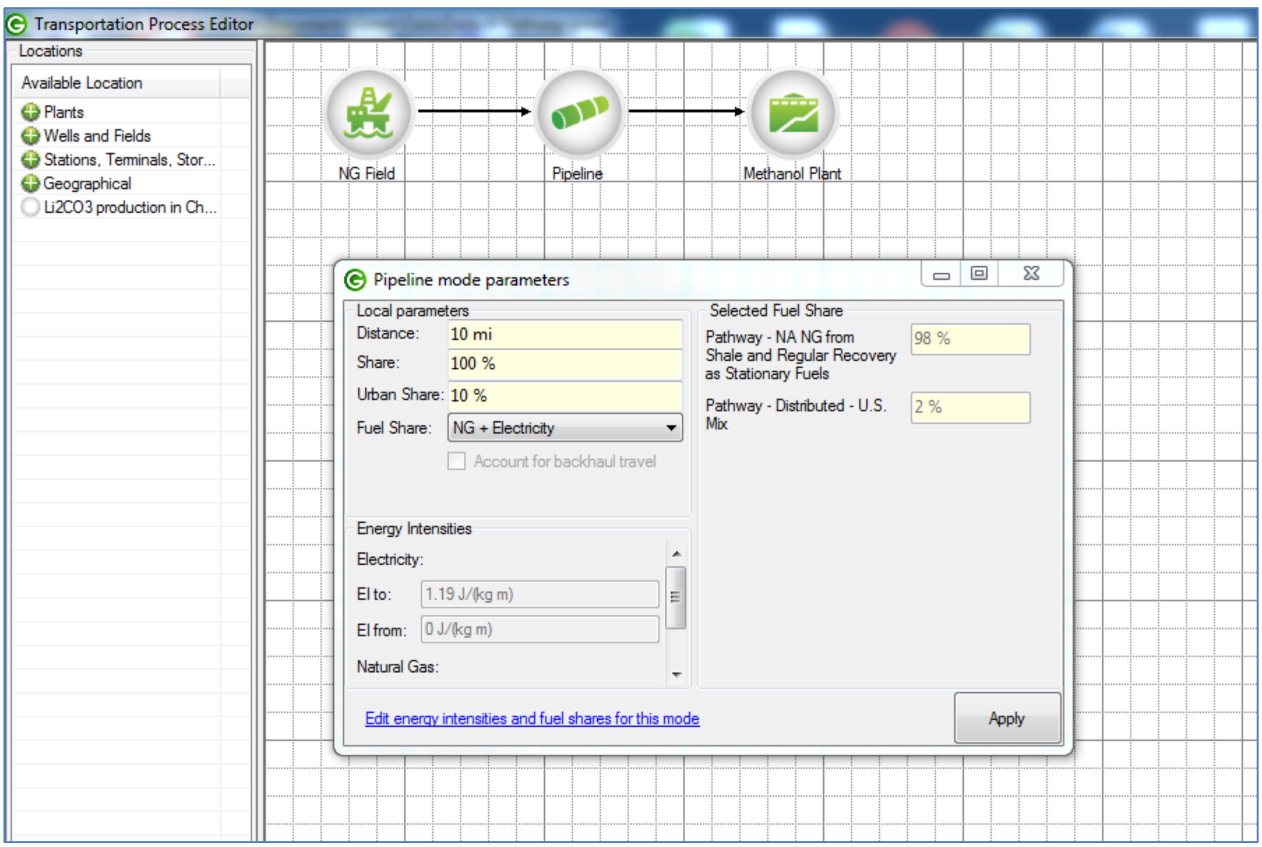
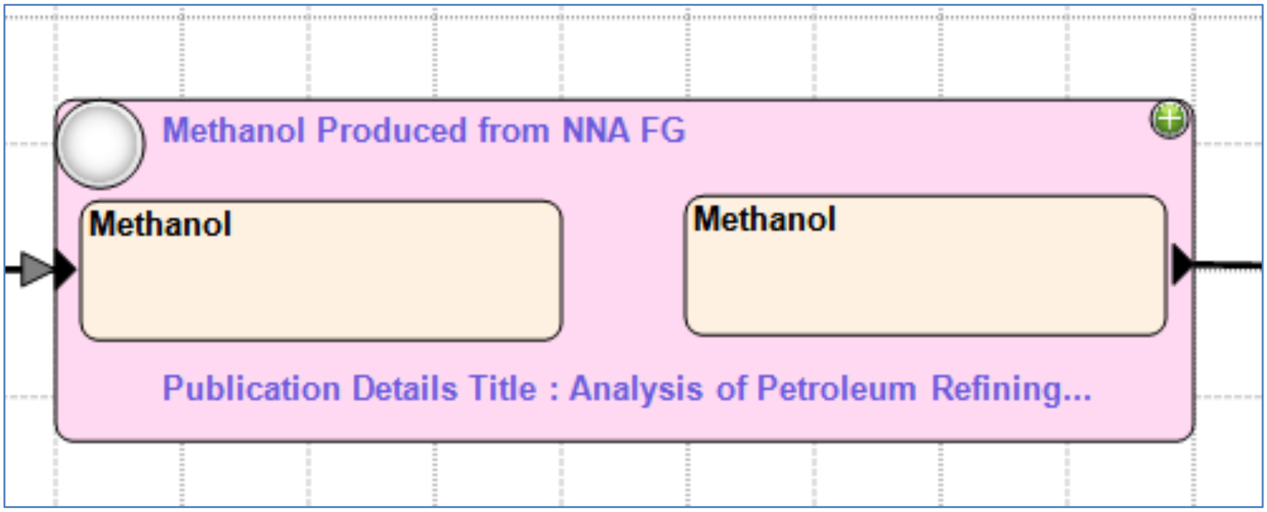
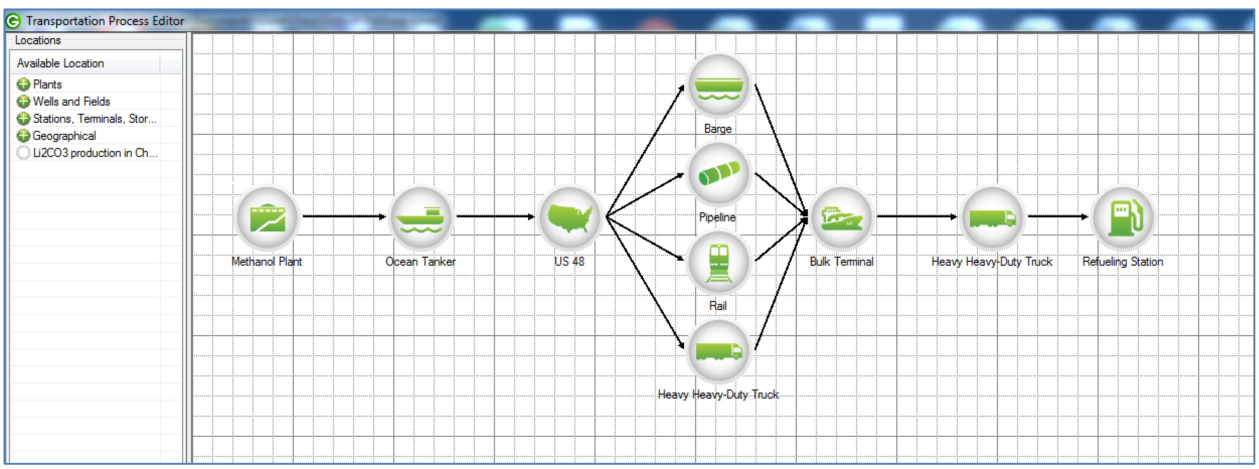


Figure 10. Modification of transportation distances from methanol production facility to refueling site for pathways D, E, and F.





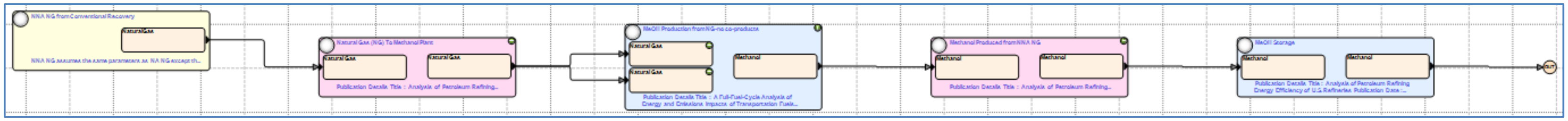
8.4 Pathways G, H, and I

We approach pathways G, H, and I similarly as above. We refer readers to Table 2 in the report for an overview of these pathways. In this section, we demonstrate the process for addressing transportation distances for these pathways. We show in Figure 11 the transportation pathway from feedstock to refueling site.

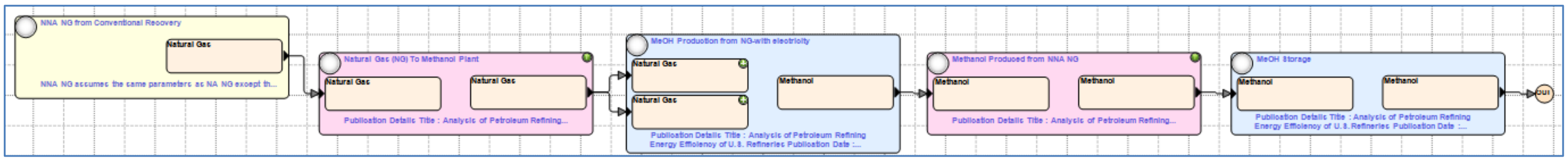
Amending the transportation distances from feedstock extraction to production facility for Pathway G, H, and I is shown in Figure 12. By double clicking the *Natural Gas to Methanol Plant* box, users can display the *Transportation Process Editor* from feedstock to production facilities. Once in this editor, users double-click the pipeline in order to show its parameters. For this sensitivity analysis, we zeroed the pipeline distance from the default 100 miles to "0". Using a similar approach, we modified the transportation distances from the production facility to the refueling site, a process shown in Figure 13.

Figure 11. Overview of pathways G, H, and I related to transportation of feedstock from extraction to production facility to refueling site.

Pathway G:



Pathway H:



Pathway I:

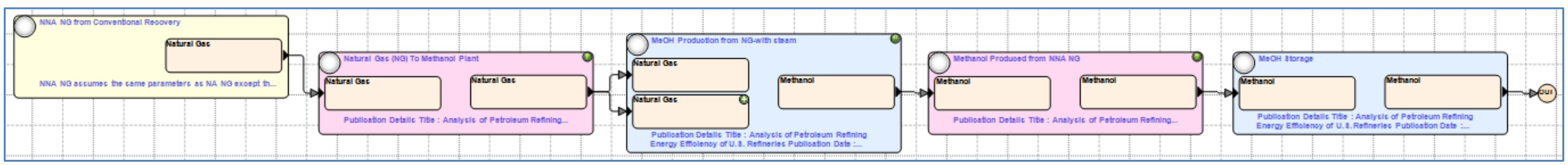
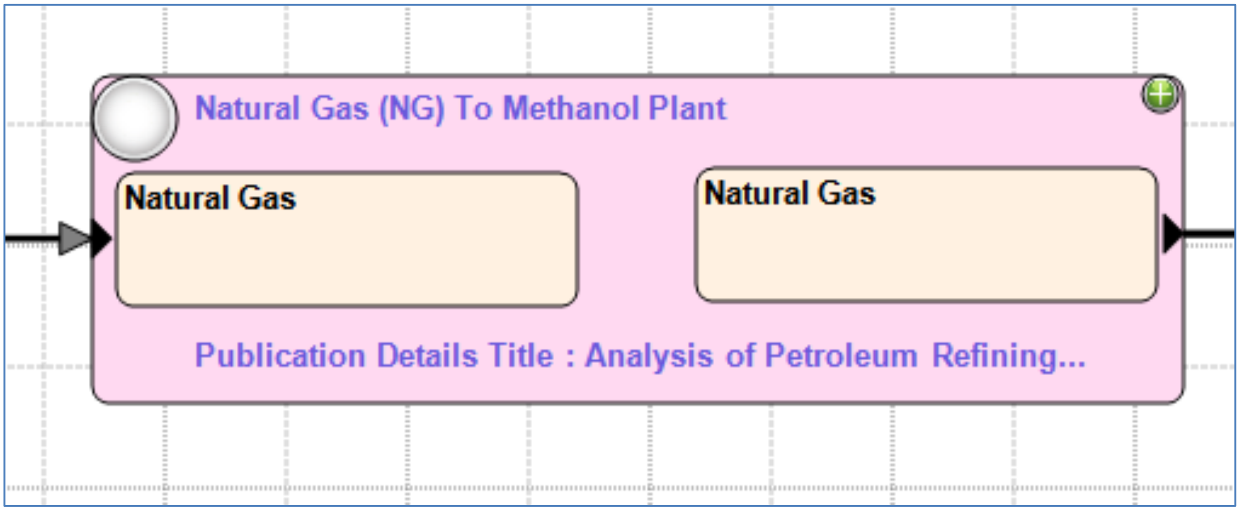


Figure 12. Modification of transportation distances from feedstock recovery to methanol production facility for pathways G, H, and I.



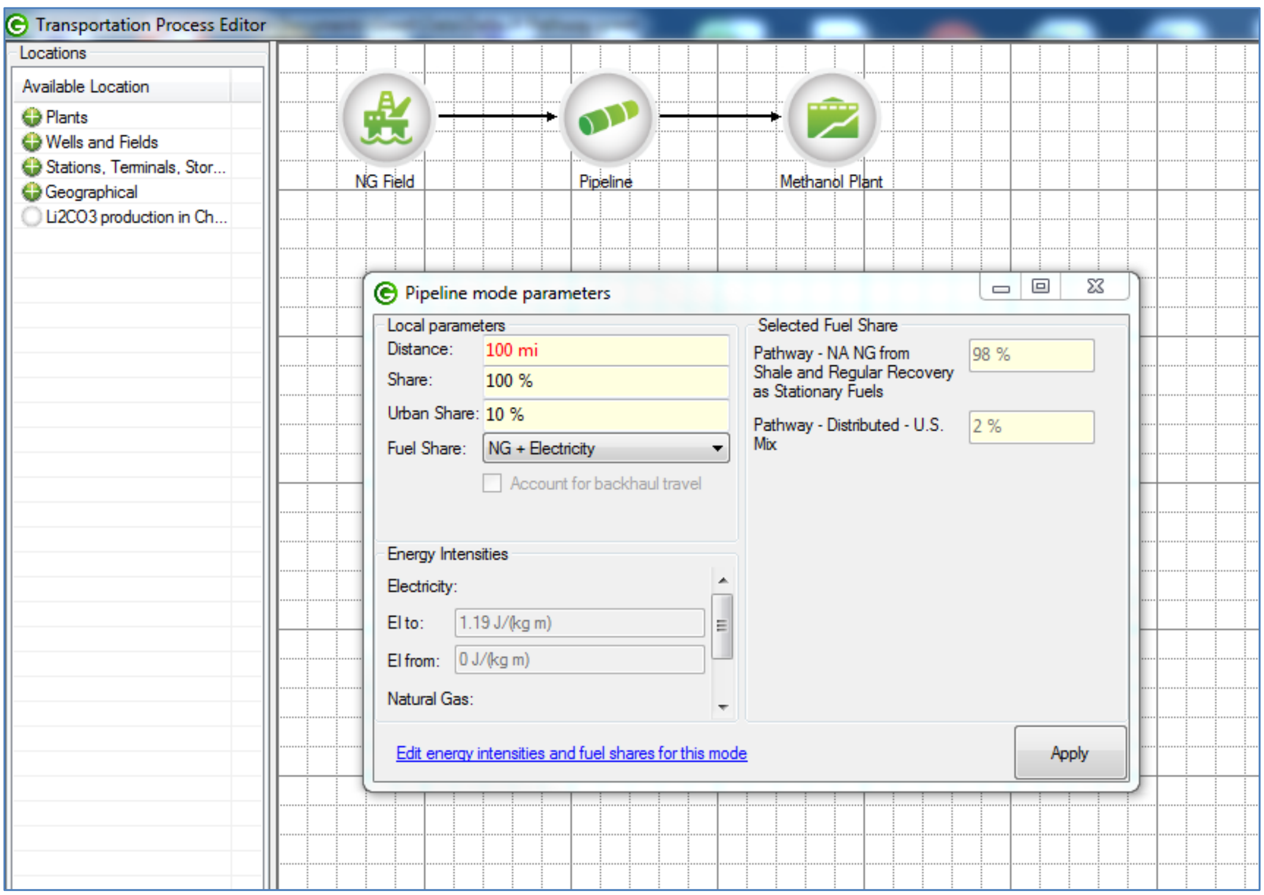
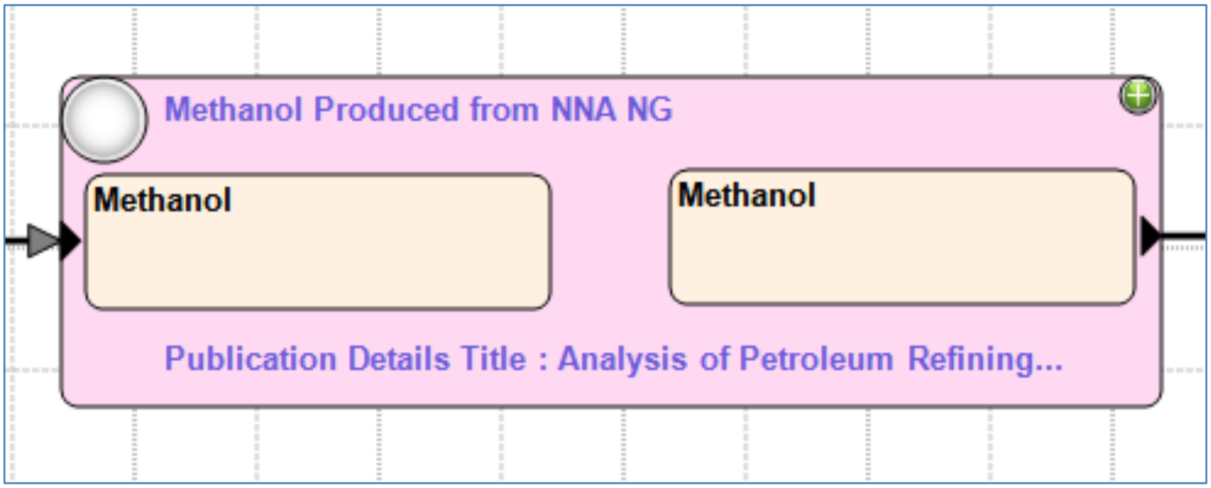
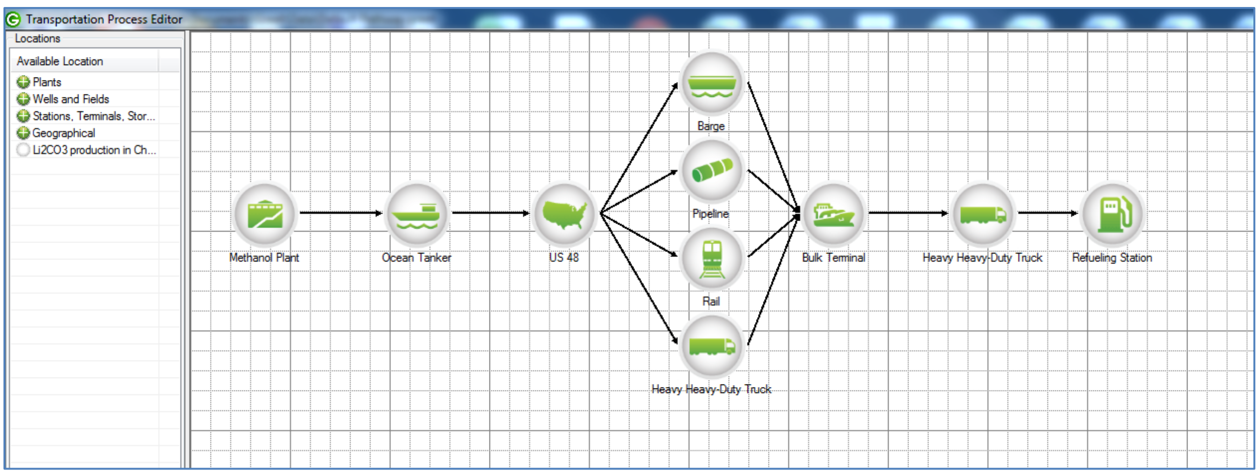


Figure 13. Modification of transportation distances from methanol production facility to refueling site for pathways G, H, and I.





8.5 Pathway J

We refer readers to Table 2 in the report for an overview of pathway J. In this section, we demonstrate the process for addressing transportation distances for this pathway. We show in Figure 14 the transportation pathway from feedstock to refueling site, in this case through a gasification intermediate process.

Amending the transportation distances from feedstock extraction to production facility is shown in Figure 15 and Figure 16. By double clicking on the *Biomass for Methanol, DME and FT Diesel Production* box, users can display the *Mix Editor* for the biomass pathway. Clicking the *Forest Residue Production for Ethanol* hyperlink will display a subset pathway for forest residue transportation to the ethanol plant (which is also used for methanol production analyses). By right clicking the *Forest Residue Transportation to Ethanol* box and selecting the "Edit this Process" choice, users can modify transportation distances for trucks moving biomass. We changed truck distances from 90 miles to 0 miles for this sensitivity analysis.

Using a similar approach as above, we modified the transportation distances from the production facility to the refueling site, a process shown in Figure 17.

Figure 14. Overview of pathway J related to transportation of feedstock from extraction to production facility to refueling site.

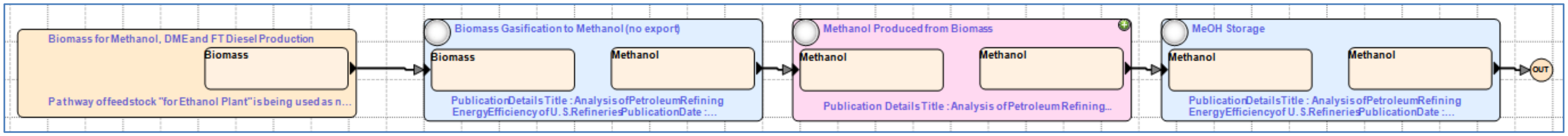
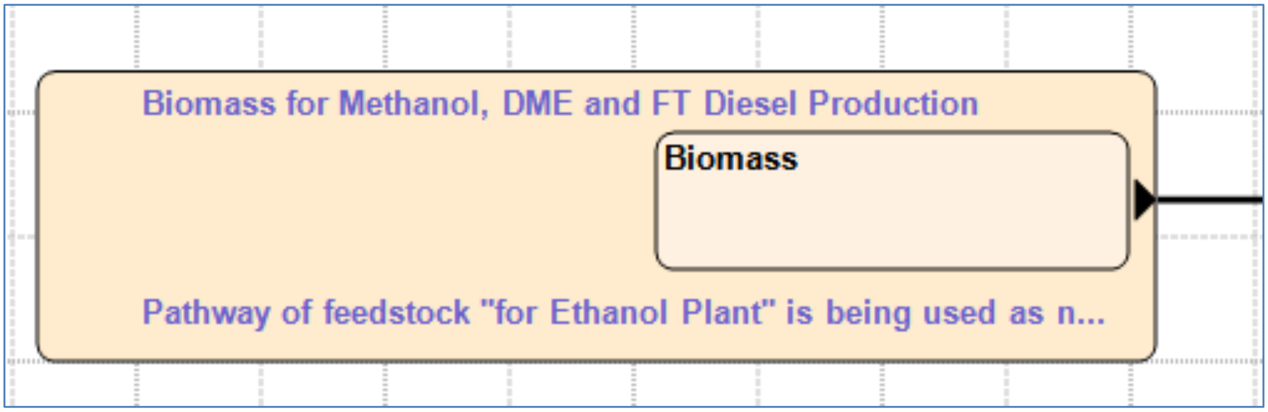


Figure 15. Modification of transportation distances from feedstock recovery to methanol production facility for pathway J.



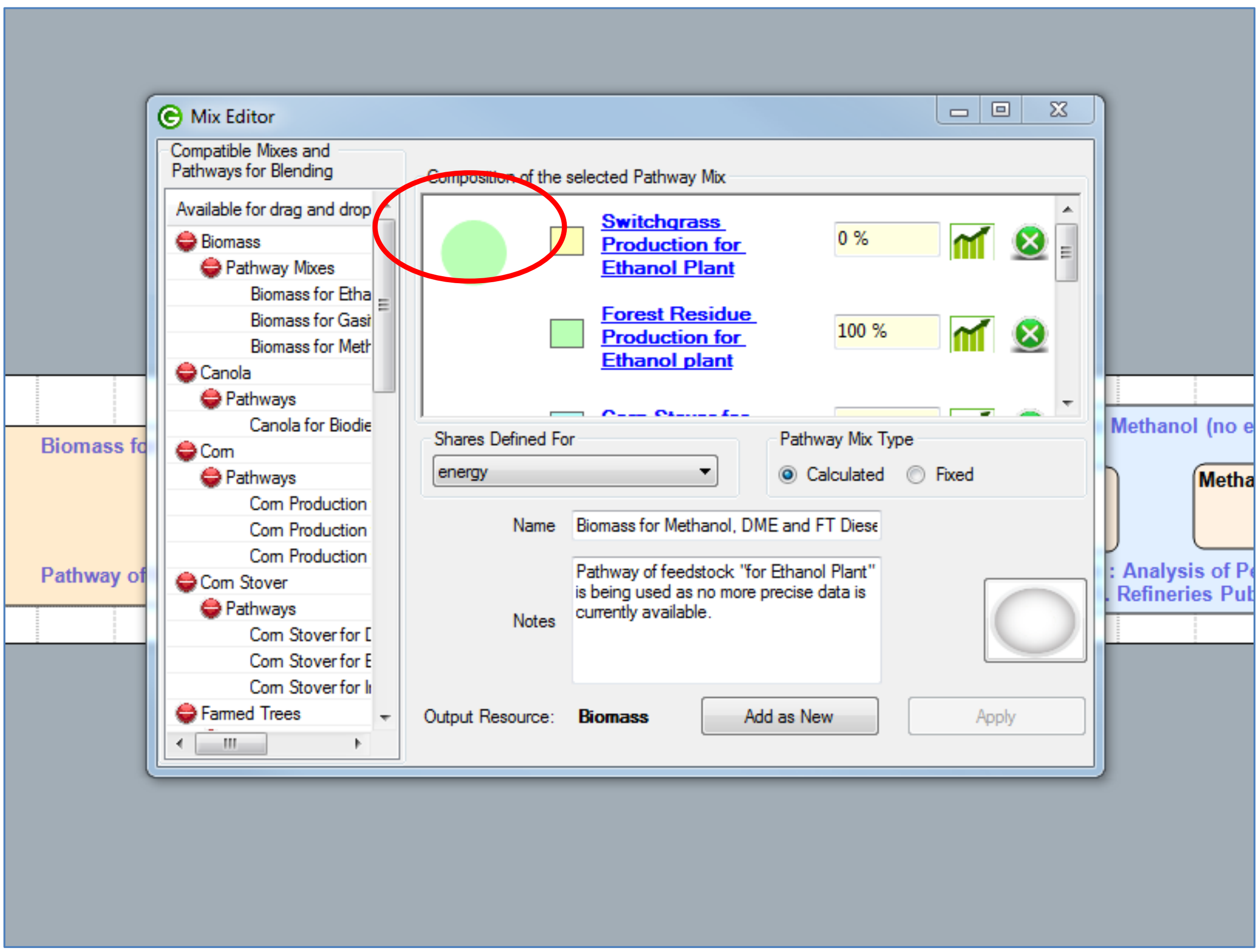
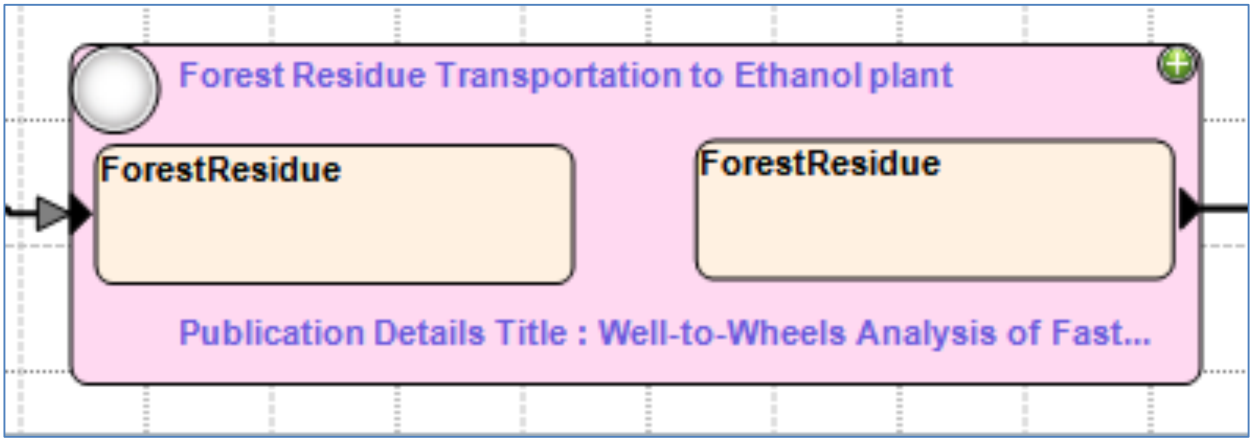


Figure 16. Modification of transportation distances from methanol production facility to refueling site for pathway J.



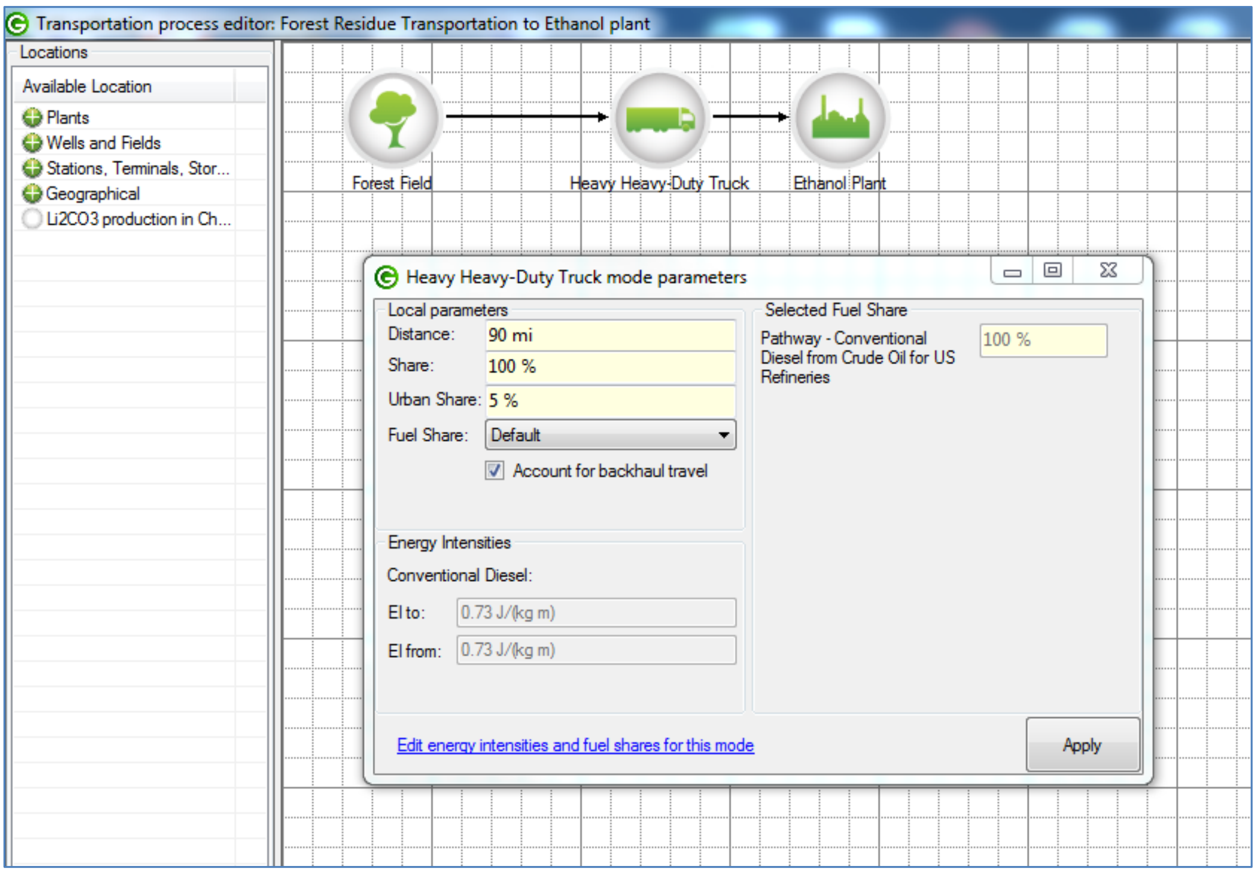
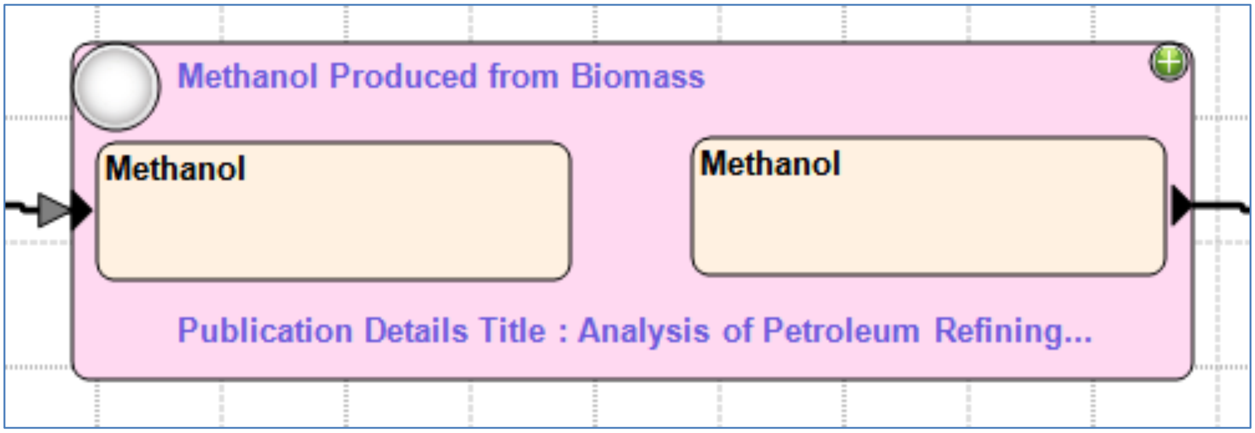
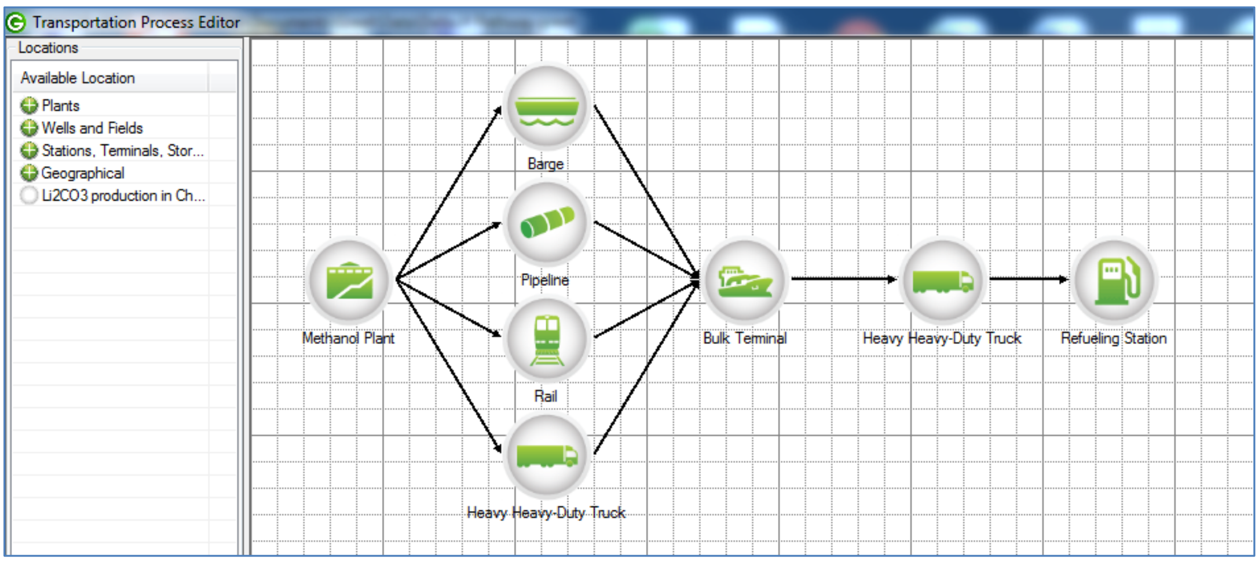


Figure 17. Modification of transportation distances from methanol production facility to refueling site for pathway J.





8.6 Pathway K

We refer readers to Table 2 in the report for an overview of pathway K. In this section, we demonstrate the process for addressing transportation distances for this pathway. We show in Figure 18 the transportation pathway from feedstock to refueling site.

Because methanol production for pathway K is conducted on-site at the landfill, transportation of feedstock is already set at zero. To adjust the transportation distance of methanol from the bulk terminal to the refueling facility, we modified the *Methanol Produced from Landfill Gas* process shown in Figure 19 through the *Transportation Process Editor* to change the truck distance from 30 miles to zero.

Figure 18. Overview of pathway K related to transportation of feedstock from extraction to production facility to refueling site.

Pathway K:

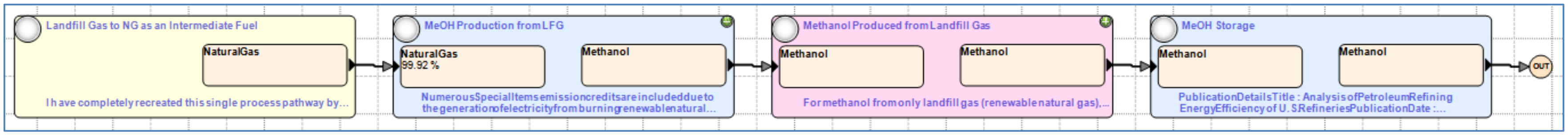
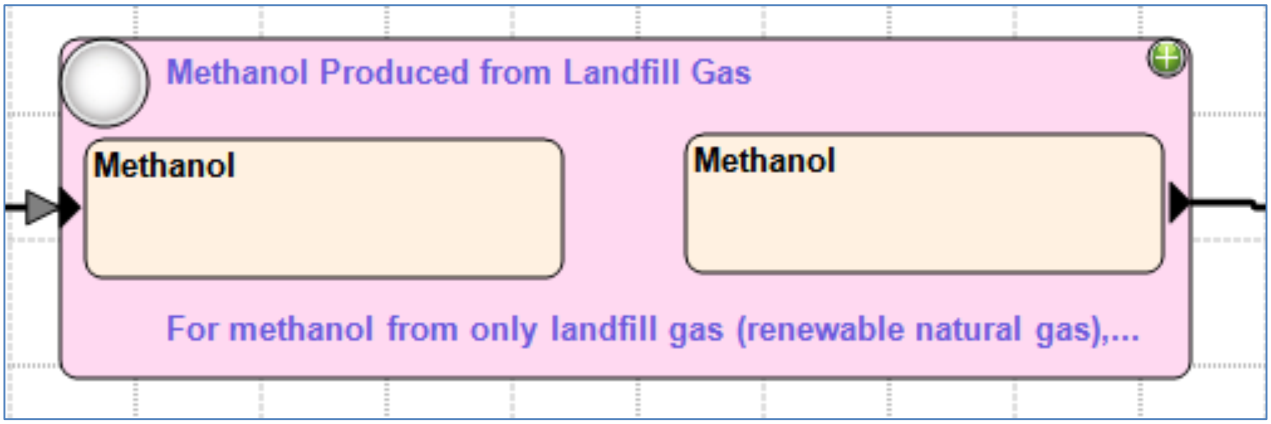
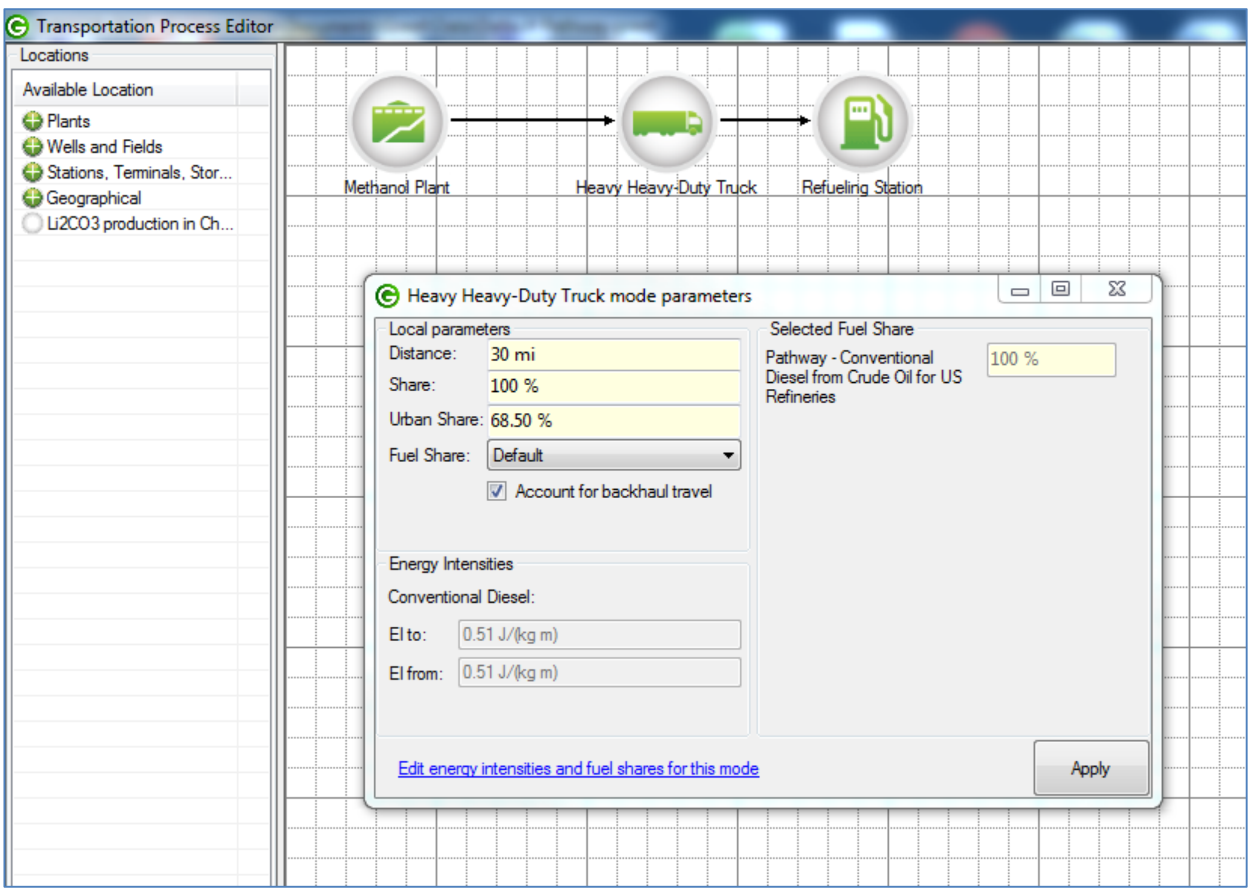


Figure 19. Modification of transportation distances from methanol production facility to refueling facility for pathway K.





8.7 Pathway L

We refer readers to Table 2 in the report for an overview of pathway L. In this section, we demonstrate the process for modifying transportation distances for this pathway. We show in Figure 20 the transportation pathway from feedstock to refueling site.

Amending the transportation distances from feedstock (coal) extraction to production facility is shown in Figure 21Figure 6. By double clicking the *Coal to H2 Central Plant* box, users can display the coal subset pathway. Right clicking the *Bituminous Coal for Central Hydrogen Plant, FTD Plan, Methanol Plant, and DME Plant Use* allows users to change transport distances, as shown in Figure 21. Once in this editor, users double-click the transport options to show and edit its parameters. For this sensitivity analysis, we zeroed all distances of moving coal from mine to production facility.

Using a similar approach as above, we modified the transportation distances from the production facility to the refueling site, a process shown in Figure 22.

Figure 20. Overview of pathway L related to transportation of feedstock from extraction to production facility to refueling site.

Pathway L:

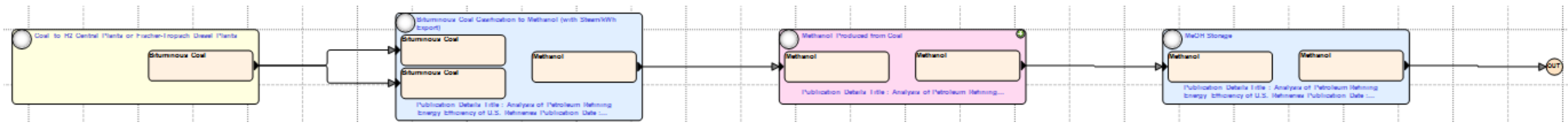


Figure 21. Modification of transportation distances from coal feedstock to methanol production facility for pathway L.

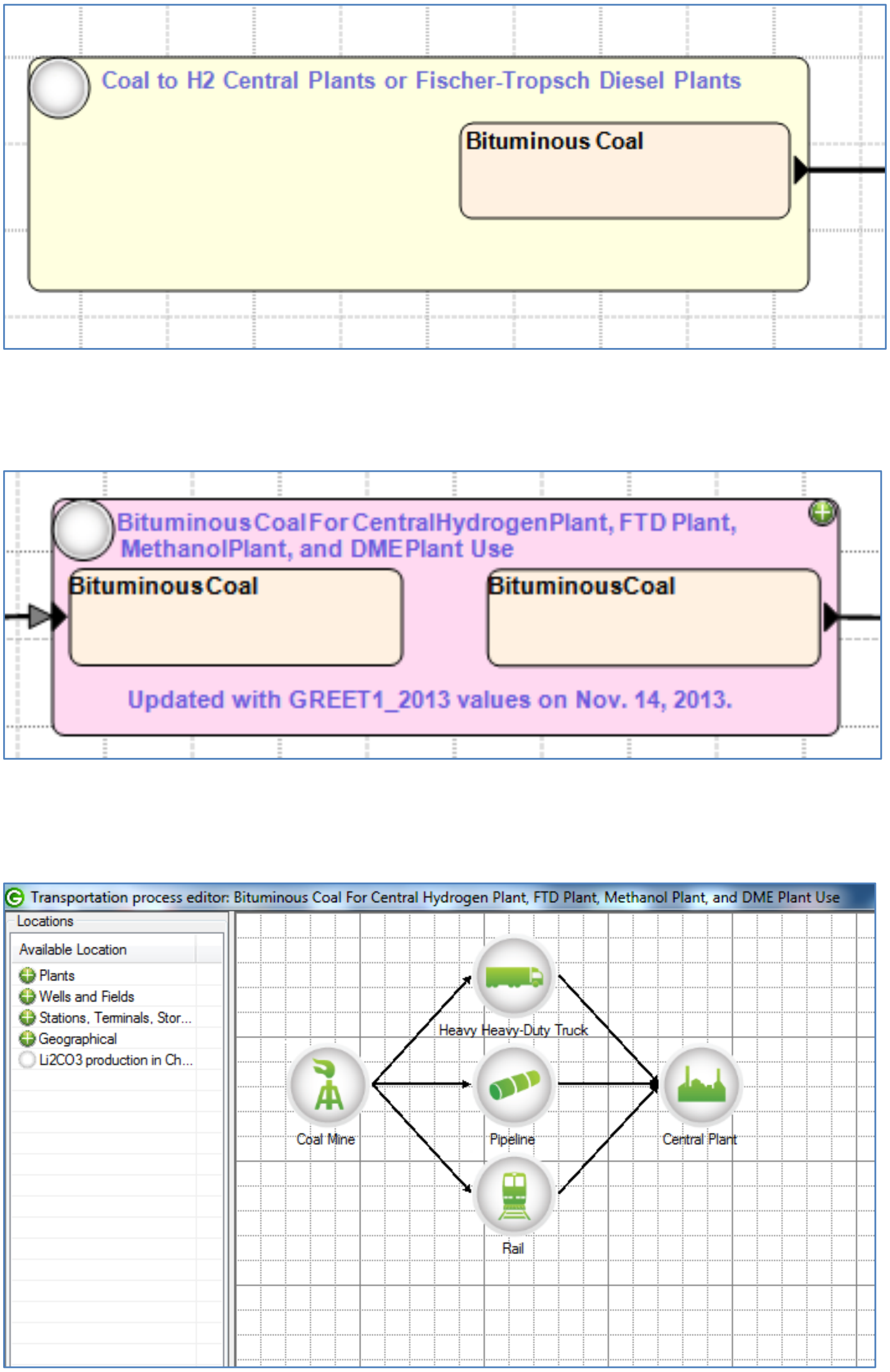
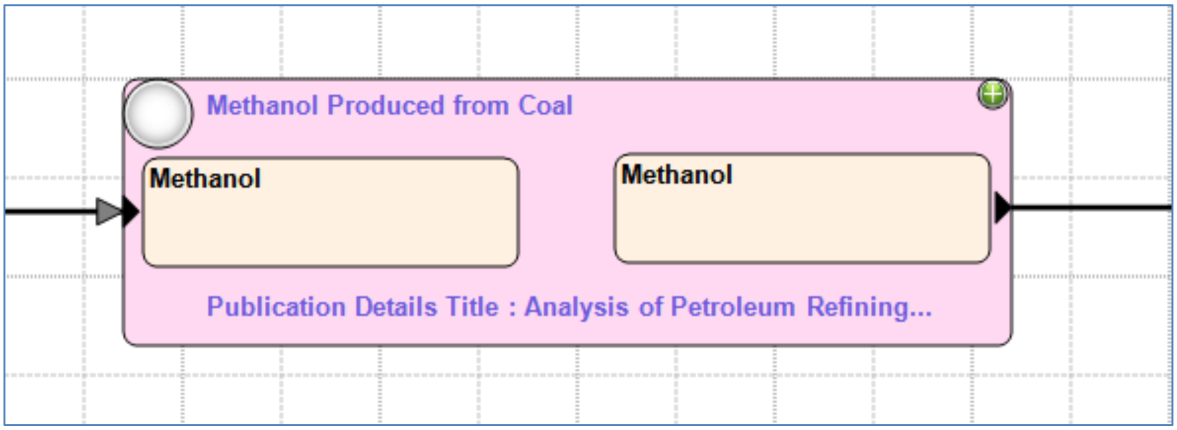
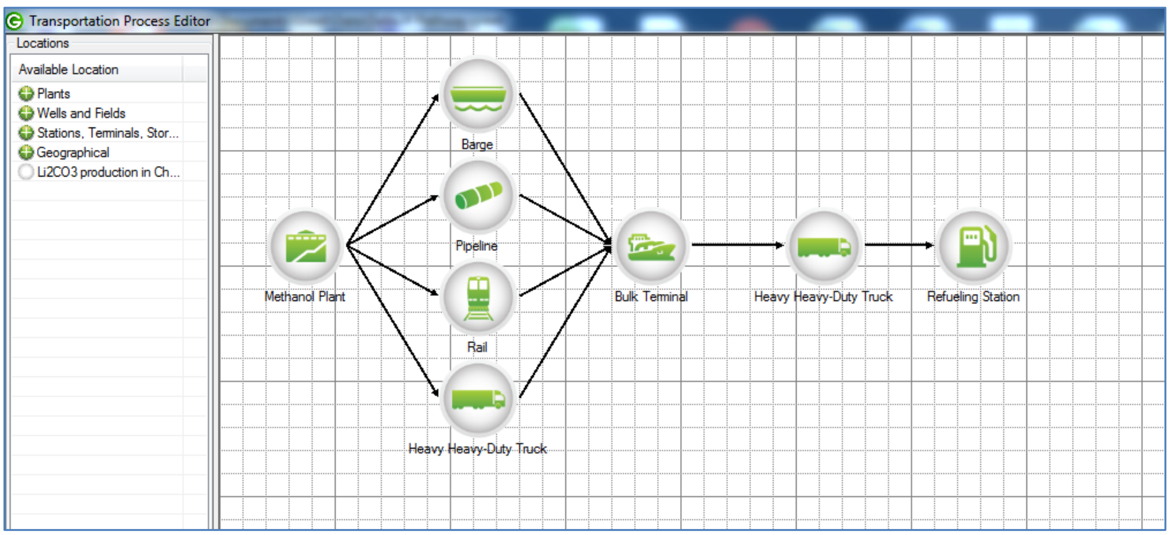
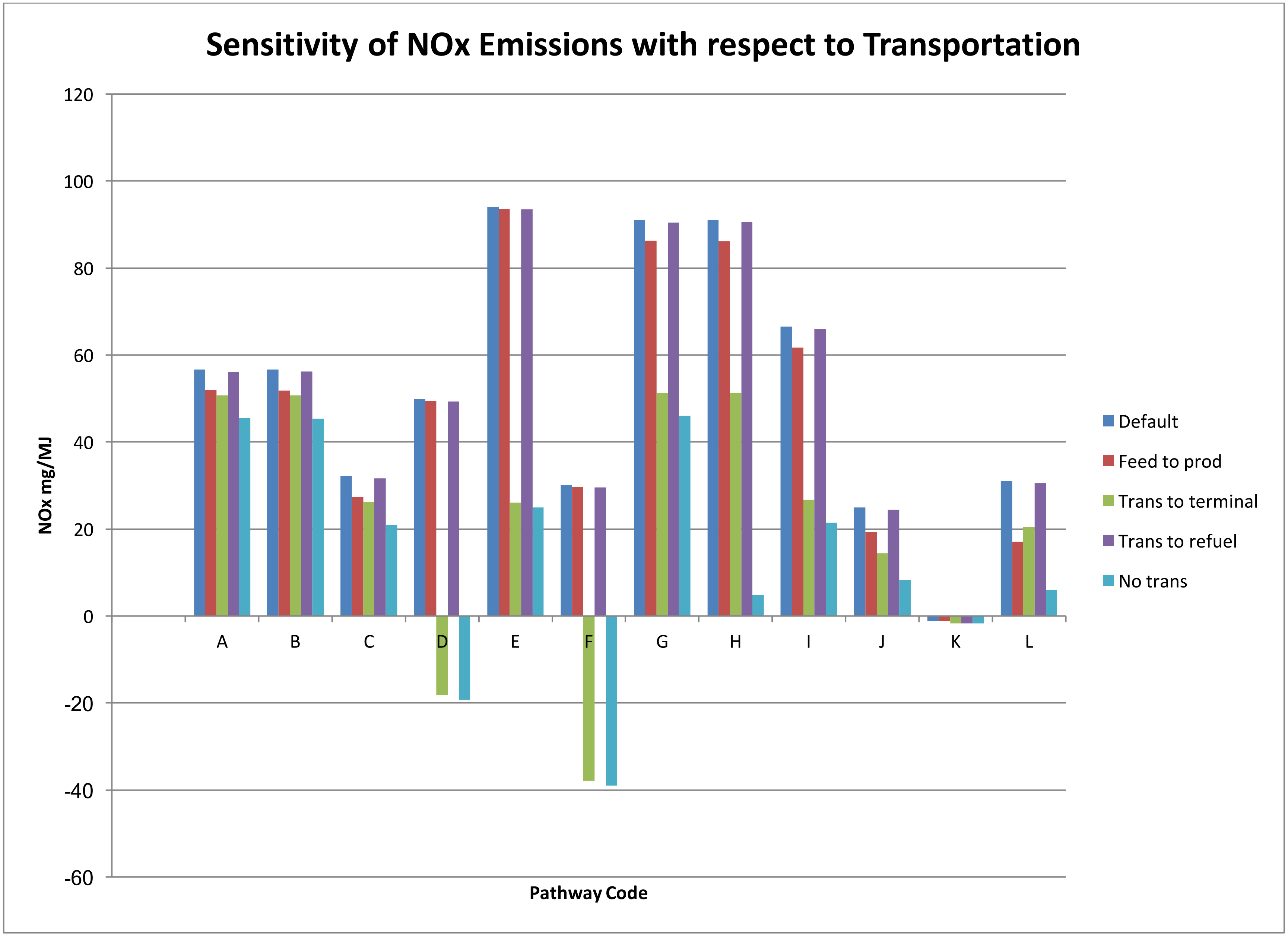


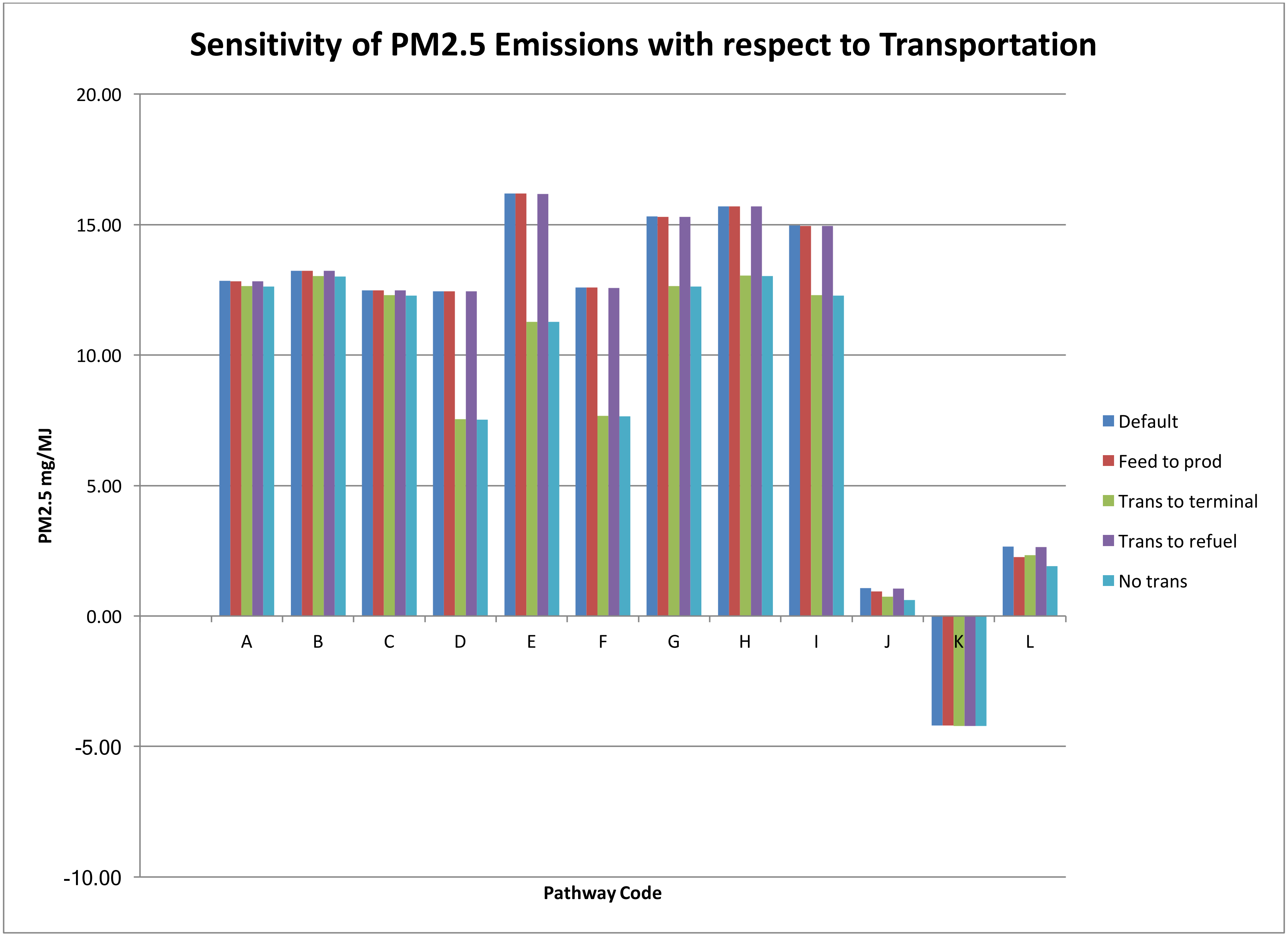
Figure 22. Modification of transportation distances from methanol production facility to refueling site for pathway L.

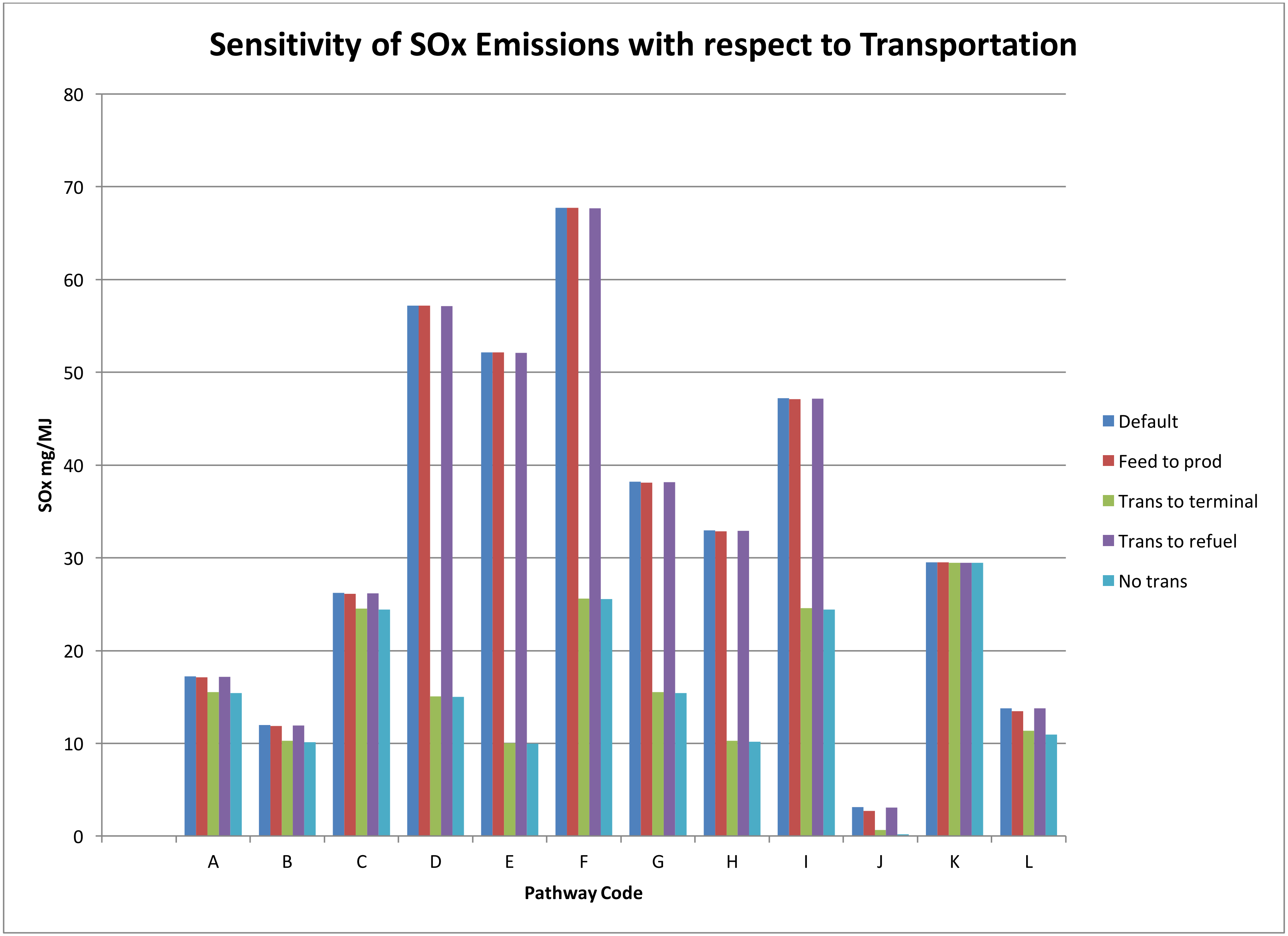





Sensitivity of GHG100 Emissions with respect to Transportation
150
100
50
0
-50
-100
GHG100 g/MJ
A
B
C
D
E
F
G
H
I
J
K
L
Pathway Code
Default
Feed to prod
Trans to terminal
Trans to refuel
No trans


Sensitivity of NOx Emissions with respect to Transportation
120
100
80
60
40
20
0
-20
-40
-60
NOx mg/MJ
A
B
C
D
E
F
G
H
I
J
K
L
Pathway Code
Default
Feed to prod
Trans to terminal
Trans to refuel
No trans


Sensitivity of PM2.5 Emissions with respect to Transportation
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
PM2.5 mg/MJ
A
B
C
D
E
F
G
H
I
J
K
L
Pathway Code
Default
Feed to prod
Trans to terminal
Trans to refuel
No trans


Sensitivity of SOx Emissions with respect to Transportation
SOx mg/MJ
0
10
20
30
40
50
60
70
80
A
B
C
D
E
F
G
H
I
J
K
L
Pathway Code
Default
Feed to prod
Trans to terminal
Trans to refuel
No trans

9 Appendix B. Sensitivity Analysis on Group Efficiency Values

9.1 Summary

In this appendix, we explore the impact of different methanol production efficiency assumptions on GHG emissions. We find that emissions are parametrically sensitive to assumptions about efficiency, and that emissions related to methanol production systems will be reduced as production efficiencies improve. However, because fuel production emissions only make up a small part of the overall total fuel cycle emissions profile, these efficiency improvements will have only a modest effect on total fuel cycle emissions.

9.2 Approach

We conducted a sensitivity analysis for pathways A, B, C, and J using the methanol production efficiencies shown in Table 10 (60%, 70%, and 80%). As mentioned in the body of this report, the current industry standard for methanol production is ~65%. The results are shown for pathways A, B, and C in Figure 23.

Table 10. Greenhouse gas emissions values for four fuel production pathways under three group efficiency assumptions.

Pathway Code	Feedstock	GHG100 Emissions (g/MJ)		
		60% Efficiency	70% Efficiency	80% Efficiency
A	North American Natural Gas	32.31	27.65	24.15
B		31.86	27.25	23.8
C		30.37	25.07	21.09
J	Biomass (no export)	5.73	5.03	4.53

Figure 23. Sensitivity of greenhouse gas emissions with respect to methanol production efficiency.