The Economic Impacts of Changes to the Specifications for the North American Rail Tank Car Fleet

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Glossary

Abbreviations

AEO	EIA Annual Energy Outlook
ANS	Alaska North Slope
BAU	Business as Usual
bbl	Barrel
b/c/y	barrels moved by one railcar in a year
bpd	Barrels per day
Btu	British thermal unit, used to measure fuels by their energy content.
CAFE	Corporate Average Fuel Economy standards to improve the fuel economy of U.S. vehicles first enacted in 1975 that are periodically updated
CAPP	Canadian Association of Petroleum Producers
cpg	Cents per gallon
DOT	U.S. Department of Transportation
DPR	Detailed Production Report, ICF's proprietary play-level natural gas, natural gas liquids (NGL), and oil production model
E&P	Exploration and production of oil and gas resources
EF	Eagle Ford crude oil, a light sweet oil produced in Texas
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
FOB	Free on Board
GDP	Gross Domestic Product
HHFT	High-hazard flammable train
IEA	International Energy Agency
IMPLAN	Impact Analysis for Planning (IMPLAN) Model, an input-output economic model

MMbbl	Million barrels of oil or liquids
MMbpd	Million Barrels per Day
PADD	Petroleum Administration for Defense District
PHMSA	Pipeline Hazardous Materials Safety Administration
NAICS Codes	North American Industrial Classification System Codes
SERC	State Emergency Response Commission
TBD	Thousand barrels per day
WCS	Western Canadian Select crude oil, a heavy, sour crude blend produced in western Canada, derived largely from oil sands
WTI	West Texas Intermediate

Terms Used

Bitumen – an extra heavy crude oil type characterized by high viscosity and low API gravity.

Class 3 flammables – flammables with flash point of greater than 140º F such as ethanol, gasoline, jet fuel, and conventional and tight crude oil.

Crude Oil Types

Light crude oil –Crude oil that is typically defined as having an API gravity above 35.0 degrees (alternative breakpoints are also used). For exhibits in this report, light crude is defined as 35.0 degrees and higher to correspond with breakpoints of certain DOE/EIA historical data series. Bakken tight oil, West Texas Intermediate (WTI), and Light Louisiana Sweet (LLS) are types of light crude oil.

Medium crude oil –Crude oil that is typically defined as having an API gravity starting somewhere between 25 degrees and 35 degrees (breakpoint of light crude). For exhibits in this report, medium crude is defined as ranging from 25.1 to 34.9 degrees to correspond with breakpoints of certain DOE/EIA historical data series. Crude oil from the Alaska North Slope (ANS), West Texas Sour (WTS), and Basrah (Iraqi) are examples of medium crude oil.

Heavy crude oil – Heavy crude oil is defined has having an API gravity below the lower breakpoint of medium crude oil. For exhibits in this report, heavy crude is defined as 25.0 degrees and lower. The term “extra heavy oil” is defined has having API gravity below 10.0 degrees. Railbit, dilbit (Western Canadian Select, WCS), and Maya (Mexican) are examples of heavy crude oil.

Dilbit – a mixture of bitumen diluted with roughly 30% diluent to facilitate pipeline transportation of the bitumen.

Diluent – a diluting agent used to dilute the viscosity of bitumen to facilitate bitumen pipeline transportation. Typical diluents include lease condensate, pentanes plus from gas processing plants, butane, synthetic crude, and light crudes.

Economic Terms

Direct Impacts – represent the immediate impacts (e.g., employment or output changes) in Sector A due to greater demand for and output from Sector A. These are the immediate impacts (e.g., employment or value added changes) in a sector due to an increase in output in that sector.

Indirect Impacts – represent the impacts outside of Sector A in those industries that supply or contribute to the production of intermediate goods and services to Sector A. These are impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by the changes in direct output.

Induced or "Multiplier Effect" Impacts – represent the cumulative impacts of spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. Examples include a restaurant worker who takes a vacation to Florida, or a store owner who sends children to college, based on higher income that arises from the initial activity of crude oil production. These are impacts on all local and national industries due to consumers' consumption expenditures rising from the new household incomes that are generated by the direct and indirect effects flowing through to the general economy. The term is used in industry-level input-output modeling and is similar to the term Multiplier Effect used in macroeconomics.

Lease Condensate – a light liquid hydrocarbon produced from non-associated natural gas wells. *(Note: Non-associated natural gas wells are natural gas wells that are not associated with oil production.)* Lease condensate is typically transported to market by adding it to the crude oil stream after extraction from natural gas streams.

Legacy Cars – refers to DOT 111 Specifications tank cars. DOT 111 cars comprise the most common type of tank cars currently used in the U.S. and Canada.

Manifest Train – is a type of freight train that carries more than one category of goods or commodity, and unload goods carried at several locations along a route. Manifest trains differ from unit trains in that unit trains typically carry only one type of commodity and move from the origin to one destination only.

Netback Price (or Value) – The value of a product at the place of production (such as oil at the wellhead) calculated as the market sales value minus the costs of delivering the product to the market.

Oil and Gas Supply Chain Activities

Upstream Oil and Gas Activities – consist of all activities and expenditures relating to oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long-term well operation.

Midstream Oil and Gas Activities – consist of all activities and expenditures downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.

Downstream Oil and Gas Activities – consists of all activities and expenditures in the areas of refining, distribution, and retailing of oil and natural gas products.

Packing Groups (PGs) – the Pipeline and Hazardous Materials Safety Administration (PHMSA) separates materials transported by rail into several packing groups. For this analysis, ICF assumed light oil, such as Bakken tight oil, would be included in Packing Group 1 (PG1), the category with the lowest initial boiling point. Dilbit and railbit are included in PG2, as well as ethanol and other flammables. Materials that may fall into PG3 (materials that have the highest initial boiling point) would include products such as raw bitumen. For this study, ICF did not include PG3 materials in the analysis.

Petroleum Administration for Defense Districts (PADDs) – five PADDs were created during World War II to allocate fuels across the country. Note that PADD 1 (East Coast) is divided up into three sub-regions. See Appendix A for a map of the United States by PADD.

Railbit – a mixture, similar to dilbit, wherein diluent is added to bitumen to facilitate rail transportation (generally at a lower, roughly 15%, blend ratio than that needed for pipeline transport).

Shale gas and liquids – recoverable volumes of gas, condensate, and crude oil from development of shale plays. Tight oil plays include those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota (also see: tight oil). *(Note: Associated gas refers to natural gas produced from wells also producing oil.)*

Tight oil – tight oil is light crude oil or condensate contained in petroleum-bearing formations of low permeability, including shales, carbonates, sandstone and combinations of several lithologies. Economic production of tight oil typically involves the application of the same horizontal well and multi-stage hydraulic fracturing technologies that are used to produce shale gas. Although often produced from shales, tight oil should not be confused with oil shale, which is shale rich in kerogen (fossilized organic matter from which hydrocarbons may be generated under high heat and pressures).

Unit Train – is a type of freight train that typically carries only one category of goods or commodity from the origin to one destination. Unit trains differ from manifest trains in that manifest trains can carry several commodity types, loading and unloading goods at several locations along a route.

Conversion Factors

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

Energy Content of Other Liquids

Condensate 1 barrel = 5.3 MMBtu = 0.91 BOE

Assumed Model Factors	***API Gravity***	***Pounds/Gallon***
Shale Crude	40.7º	6.846
Dilbit	20.5º	7.755
Railbit	15.0º	8.047
Ethanol	51.5 º	6.580

1 Executive Summary

U.S. tight oil production and Canadian oil sands production have fundamentally altered the North American energy landscape. As production has risen, rail transportation of crude oil has grown significantly to accommodate the rapidly expanding production. In August in response to the rising role of crude by rail, PHMSA released a proposed rule that would, in part, require tank cars carrying flammable liquids (e.g., crude oil, ethanol and other flammables) to meet certain standards by certain dates in order to continue operating.

To understand the impact of PHMSA's proposed regulation, ICF International developed an economic impact model to represent: 1) the existing fleet and its normal retirement outlook; 2) retrofit and new build costs and capacities; and 3) demands for crude, ethanol and petrochemicals moved by rail over the 2014 to 2024 period ("study period"). The model uses these inputs to determine the optimal economic path to meet the proposed regulations. In the event of insufficient qualified railcars, the model utilizes estimated costs of alternative options (e.g., pipeline, trucking, shut-in production, etc.) to reflect how the volume displaced by railcar shortages would be managed. The model outputs are used to estimate the broader U.S. and Canadian economic impacts in terms of changes to consumer costs, gross domestic product (GDP) effects, and job effects.

1.1 Key Findings

1) The costs to comply with the proposed regulation are driven by 1) the capacity to retrofit railcars to PHMSA's proposed Option 1, 2 and 3 standards; 2) the cost and time required to perform the retrofits; 3) the capacity to build new tank cars and their costs; 4) the number of cars requiring retrofitting; and 5) the demand for crude oil movements by rail in the U.S. and Canada over the study period.

2) Assumptions used by PHMSA in their Regulatory Impact Analysis are systematically optimistic and lead to unrealistically low impacts. By contrast, the assumptions used by ICF reflect lower capacity to retrofit rail cars, greater time and cost required to retrofit cars, and substantially higher demand for crude by rail service, particularly if Keystone XL is denied. This study used the Railway Supply Institute's (RSI) cost estimates for each individual retrofit component. Assumptions related to the time needed to perform retrofits were developed by the ICF Team based on inputs from RSI and various industry participants including shippers and rail car maintenance shops.[1]

3) The model results indicate that the proposed regulations and timing would not be possible without extensive scrapping of the existing legacy fleet in 2018 and 2019. Furthermore, compliance would entail the displacement of substantial volumes of crude oil, ethanol, and other flammables onto alternative transportation modes – including

[1] ICF used the Railway Supply Institute's (RSI) 7-2-2014 retrofit capacity estimate of 5,700 cars per year after a one year ramp-up, cost estimates –based on PHMSA and RSI estimates of individual enhancements- that are 65% to 160% greater than PHMSA's, and estimates of rail car demand which are roughly larger than PHMSA's by 20,000 railcars in 2015 to 40,000 railcars in 2020. (These railcar demand figures would be even larger if KXL was not constructed.)

trucking – for several years until new build capacity for railcars allows the movement to move back to rail transport. These impacts could negatively affect GDP and employment in the U.S. and Canada.

In summary, the rule would require too many cars to be retrofitted in too short of a time period given the existing and expected retrofitting capacity and expected increasing demand for rail transportation. These factors result in significant impacts to production, consumer costs, and even U.S. and Canadian GDP and employment.

1.2 Details

The ICF model determines the overall transportation cost to the oil/rail industry to deliver crude, ethanol, and other flammables to the market in a "Business as Usual"[2] case as well as the three options proposed by PHMSA. All four cases are examined under both a scenario that assumes KXL is approved (and operational in 2017) and a second scenario in which KXL is denied and the demand for transporting crude by rail is correspondingly higher.

The model outputs indicates that the cost of retrofitting and the limited capacity to retrofit results in a large number of railcars being scrapped or re-purposed (Exhibit 1-1), in large part because they could not be retrofitted before the binding phase-out date or before demand could eventually be met by newbuilds.

Exhibit 1-1: Railcars Scrapped/Repurposed

Case	Scrapped or Repurposed Railcars (No.)	
	With KXL	Without KXL
Business as Usual	0[3]	0
Option 1	86,457	83,661
Option 2	84,631	83,682
Option 3	71,482	63,267

Source: ICF

The inability to retrofit railcars in time for the proposed regulation compliance dates requires substantial volumes of crude oil, ethanol and other flammables to be shifted to alternative, more costly means of transportation or, in some cases, result in shut-in crude oil production. The degree of impact increases should Keystone XL be denied, which requires an additional 700,000 barrels per day to be moved by rail above the base forecast increase (Exhibit 1-2).

[2] The "BAU" case assumes the same growth in demand for crude oil by rail (U.S. and Canada) and the same new build and retrofit capacities and costs and fleet retirements as the option cases, but assumes new railcar demands are met by new CPC 1232 jacketed railcars.

[3] Excludes normal retirements over the period

Exhibit 1-2: Total Volumes Displaced by Year, in Thousand Barrels per Day (TBD) and Tank Cars (Cars)

Year	With Keystone XL						Without Keystone XL					
	Option 1		Option 2		Option 3		Option 1		Option 2		Option 3	
	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars
2018	177	5,931	162	5,412	200	6,693	250	8,366	250	8,366	144	4,804
2019	530	21,953	467	19,697	198	7,675	1212	46,451	1157	44,379	482	20,359
2020	183	6,131	164	5,477	0	0	454	16,469	396	14,276	178	5,964
2021	0	0	0	0	0	0	85	2,844	5	176	0	0

Source: ICF

Note: This exhibit shows amounts of crude oil and other flammable liquids that were expected to be transported by rail in the U.S. and Canada that will have to be transported by other means (or not produced) due to shortages of compliant rail tank cars. It also shows the minimum number of tank cars that would be needed to move those volumes.

The volumes that can no longer be moved by rail are alternatively moved by various means, including some crude by pipeline, but the movements are primarily by truck, including as much as 150,000 barrels per day of ethanol and 150,000 barrels per day of other flammables in the most constrained year (2019). These volumes, as well as a substantial volume of crude oil, must move long distances by truck to replace rail.

The cost implications of each of these cases is substantial versus a BAU case, which is based on meeting increased crude oil demand from the construction of new CPC 1232 jacketed crude cars. The exhibit below summarizes the annualized cost of each option using cost and timing assumptions for retrofits and new builds and forecasted commodity demand growth by rail and displaced volume alternatives developed by ICF International (Exhibit 1-3). For example, PHMSA's Option 1 has annualized costs above business as usual of $12.8 billion if KXL is approved and $22.8 billion if KXL is denied.

Exhibit 1-3: 2014-2024 Annualized Costs

Case	Total Annualized Cost (MM$)				Annualized Cost vs BAU (MM$)		
	BAU	Option 1	Option 2	Option 3	Option 1	Option 2	Option 3
Keystone XL Approved	$2,131	$14,893	$13,771	$10,193	$12,762	$11,640	$8,062
Keystone XL Denied	$3,574	$26,392	$24,352	$14,076	$22,818	$20,778	$10,502

Source: ICF Model Output based on defined assumptions

Note: This exhibit shows the costs of new and retrofitted rail tank cars and, when needed, alternative modes of transportation or the opportunity cost of shutting in production of crude oil. The cost of new and retrofitted tank cars are "annualized" or spread out over the remaining lives of the cars. This exhibit shows such annualized costs summed only over the years 2014 to 2024 for the U.S. and Canada.

Impact of PHMSA Proposed Regulations – Consumer Costs, GDP, and Jobs

There are several additional impacts the proposed regulations will have on the broader U.S. and Canadian economies. These impacts stem from increased rail transportation costs for crude oil, ethanol, and other flammables, and a shift from rail transportation to much more expensive trucking and/or periods of shut-in crude production, particularly in the critical 2018-2019 period when the proposed regulations begin to require use of new or retrofitted railcars. The shift is required due to the inability to retrofit the existing fleet in time due to limited shop capacity and the time to complete retrofits. As noted, the situation will be significantly worse if the Keystone XL pipeline is not approved, as this will require an additional 700,000 barrels per day, intended to be moved by pipeline, to be added to the crude by rail demand.

The higher transport costs for crude could reduce producer netbacks at the wellhead and reduce the incentives to invest in new productive capacity for crude oil. The resulting lower productive capacity, combined with possible transport bottlenecks that may force shut-in of productive capacity for some period of time, will reduce U.S. and Canadian oil production. Lower U.S. and Canadian oil production will, in turn, put upward pressure on world oil prices, which could be one source of higher prices for U.S. and Canadian consumers.

Exhibit 1-4 below shows the expected changes to U.S. and Canadian oil production in barrels per day. The highest impact occurs in 2019 when the combined U.S. and Canadian production declines by as much as 613,000 barrels per day. These reductions in production adversely affect U.S. and Canadian GDP and jobs and they put upward pressure on world oil prices, which the ICF modeling suggests could increase by as much $1.35/bbl in the peak impact year.

Exhibit 1-4: 2015-2024 U.S. and Canadian Crude Oil Production Changes

Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
	U.S. Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(1,693)	(3,191)	(7,870)	(17,552)	(26,483)	(31,566)	(34,097)	(35,094)	(34,114)	(21,296)	(191,660)
Option 2	-	(1,693)	(3,191)	(7,870)	(13,630)	(19,236)	(22,686)	(24,313)	(24,874)	(24,767)	(15,807)	(142,260)
Option 3	-	-	-	(3,880)	(9,222)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	(12,378)	(86,644)
Without Keystone XL												
Option 1	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	(46,412)	(417,705)
Option 2	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	(46,412)	(417,705)
Option 3	-	-	-	(3,880)	(9,176)	(16,234)	(21,024)	(23,355)	(24,385)	(23,605)	(17,380)	(121,659)
Case	Canadian Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(2)	(38,028)	(41,230)	(34,626)	(21,927)	(4,173)	(3,164)	(2,129)	(1,243)	(16,280)	(146,522)
Option 2	-	(1)	(27,660)	(30,021)	(21,421)	(21,395)	(3,214)	(2,440)	(1,641)	(953)	(12,083)	(108,746)
Option 3	-	(1)	(18,675)	(20,497)	(10,498)	-	-	-	-	-	(12,418)	(49,671)
Without Keystone XL												
Option 1	-	(92)	(44,998)	(73,083)	(578,996)	(165,886)	(33,453)	(7,250)	(4,843)	(2,798)	(101,267)	(911,399)
Option 2	-	(93)	(44,998)	(73,082)	(523,160)	(145,681)	(31,070)	(4,697)	(3,121)	(1,801)	(91,967)	(827,703)
Option 3	-	(1)	(27,721)	(30,128)	(21,518)	(21,540)	(3,391)	(2,533)	(1,678)	(966)	(12,164)	(109,476)
Case	U.S. + Can. Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(1,696)	(41,219)	(49,100)	(52,177)	(48,410)	(35,739)	(37,261)	(37,223)	(35,357)	(37,576)	(338,182)
Option 2	-	(1,695)	(30,852)	(37,892)	(35,052)	(40,632)	(25,900)	(26,753)	(26,515)	(25,720)	(27,890)	(251,011)
Option 3	-	(1)	(18,675)	(24,378)	(19,720)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	(15,146)	(136,316)
Without Keystone XL												
Option 1	-	(1,786)	(48,190)	(84,629)	(612,694)	(221,707)	(104,071)	(86,071)	(86,368)	(83,591)	(147,679)	(1,329,107)
Option 2	-	(1,786)	(48,189)	(84,628)	(556,858)	(201,502)	(101,689)	(83,517)	(84,646)	(82,594)	(138,379)	(1,245,409)
Option 3	-	(1)	(27,721)	(34,008)	(30,694)	(37,775)	(24,416)	(25,888)	(26,064)	(24,570)	(25,682)	(231,137)

Source: ICF modeling results

Other factors that could lead to higher costs to consumers include higher shipping costs for petroleum products and higher shipping costs for ethanol that will be blended into gasoline. Such higher consumer costs reduce spending on non-energy consumer goods and services reducing output and jobs in those sectors. As shown in Exhibit 1-5 below, potential higher consumer costs for gasoline and other petroleum products are estimated to be in the range of \$14.4 to \$22.8 billion in the 2015 to 2024 period in the scenario where Keystone XL is approved. In the scenario where Keystone XL is not approved, constraints on crude, petroleum products and ethanol are more severe and so potential consumer cost impacts are estimated to increase even more to the range of \$21.0 to \$45.2 billion.

Exhibit 1-5: 2015-2024 U.S. and Canadian Consumer Cost Changes versus BAU

Case	2015-2024 Consumer Cost Changes ($ Billion)					
	With Keystone XL			Without Keystone XL		
	U.S.	Canada	Total	U.S.	Canada	Total
Option 1	$17.8	$5.0	**$22.8**	$37.6	$7.6	**$45.2**
Option 2	$16.6	$4.8	**$21.4**	$36.4	$7.5	**$43.9**
Option 3	$12.5	$1.9	**$14.4**	$16.4	$4.6	**$21.0**

Source: ICF modeling results

Note: This exhibit shows the higher cost of gasoline and petroleum products paid by U.S. and Canadian consumers over the period 2015 to 2024. These higher costs reflect higher world oil prices (due to lower U.S. and Canadian crude production), higher costs to move petroleum products to rail-dependent consumer markets and the higher cost of moving ethanol to consumer markets.

The net effect on U.S. and Canadian gross domestic product (GDP) tends to be negative in that gains in some sectors (i.e., rail car construction and retrofits, oil pipeline services, barging and trucking) are offset by reductions in crude oil production and non-energy consumer goods. Likewise the effect on employment tends to be negative over the entire period. Job gains in rail car construction and retrofits are estimated to occur in the early years but are overtaken by job losses when the higher transport costs and constraints are fully felt. The net U.S. and Canadian GDP and job effects are shown in Exhibit 1-6 and Exhibit 1-7 for a multiplier effect of 1.3 (representing a tight economy with little slack) and a multiplier effect of 1.9 (representing a more loose economy with available labor and capital that can accommodate economic expansion). The net GDP impacts are mostly negative due to lost production of oil and reach $20.3 billion per year in the peak year under the no-KXL scenario. Peak net job losses in U.S. and Canada could be as high as 97,000 jobs in the no-KXL scenario and occur in oil production and non-energy consumer goods.

Exhibit 1-6: 2015-2024 U.S. and Canadian GDP Changes

Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
	Lower-Bound U.S. + Can. Oil GDP Changes ($ Million, multiplier effect=1.3)											
With Keystone XL												
Option 1	($9)	($676)	($2,537)	($2,818)	($2,947)	($2,864)	($2,658)	($2,725)	($2,787)	($2,773)	($2,279)	($22,794)
Option 2	($8)	($641)	($2,201)	($2,459)	($2,445)	($2,512)	($2,245)	($2,281)	($2,322)	($2,324)	($1,944)	($19,438)
Option 3	($20)	($99)	($1,132)	($1,788)	($1,715)	($1,501)	($1,528)	($1,543)	($1,559)	($1,577)	($1,246)	($12,462)
Without Keystone XL												
Option 1	($10)	($621)	($2,512)	($3,534)	($13,891)	($6,485)	($4,307)	($4,047)	($4,172)	($4,181)	($4,376)	($43,760)
Option 2	($8)	($587)	($2,410)	($3,412)	($12,673)	($5,956)	($4,126)	($3,857)	($3,995)	($4,017)	($4,104)	($41,041)
Option 3	($20)	($59)	($1,391)	($1,989)	($1,949)	($2,040)	($1,794)	($1,838)	($1,878)	($1,853)	($1,481)	($14,811)
Case	Upper-Bound U.S. + Can. Oil GDP Changes (million U.S. dollars per year, multiplier effect=1.9)											
With Keystone XL												
Option 1	($13)	($988)	($3,708)	($4,118)	($4,307)	($4,186)	($3,884)	($3,983)	($4,074)	($4,052)	($3,331)	($33,313)
Option 2	($12)	($937)	($3,217)	($3,594)	($3,573)	($3,672)	($3,281)	($3,334)	($3,394)	($3,397)	($2,841)	($28,411)
Option 3	($29)	($144)	($1,655)	($2,613)	($2,507)	($2,194)	($2,234)	($2,255)	($2,279)	($2,304)	($1,821)	($18,214)
Without Keystone XL												
Option 1	($15)	($907)	($3,671)	($5,165)	($20,303)	($9,478)	($6,294)	($5,915)	($6,098)	($6,111)	($6,396)	($63,957)
Option 2	($12)	($858)	($3,522)	($4,987)	($18,522)	($8,705)	($6,030)	($5,638)	($5,839)	($5,871)	($5,998)	($59,984)
Option 3	($29)	($87)	($2,033)	($2,906)	($2,848)	($2,981)	($2,621)	($2,686)	($2,745)	($2,708)	($2,164)	($21,644)

Source: ICF modeling results

Exhibit 1-7: 2015-2024 U.S. and Canadian Employment Changes

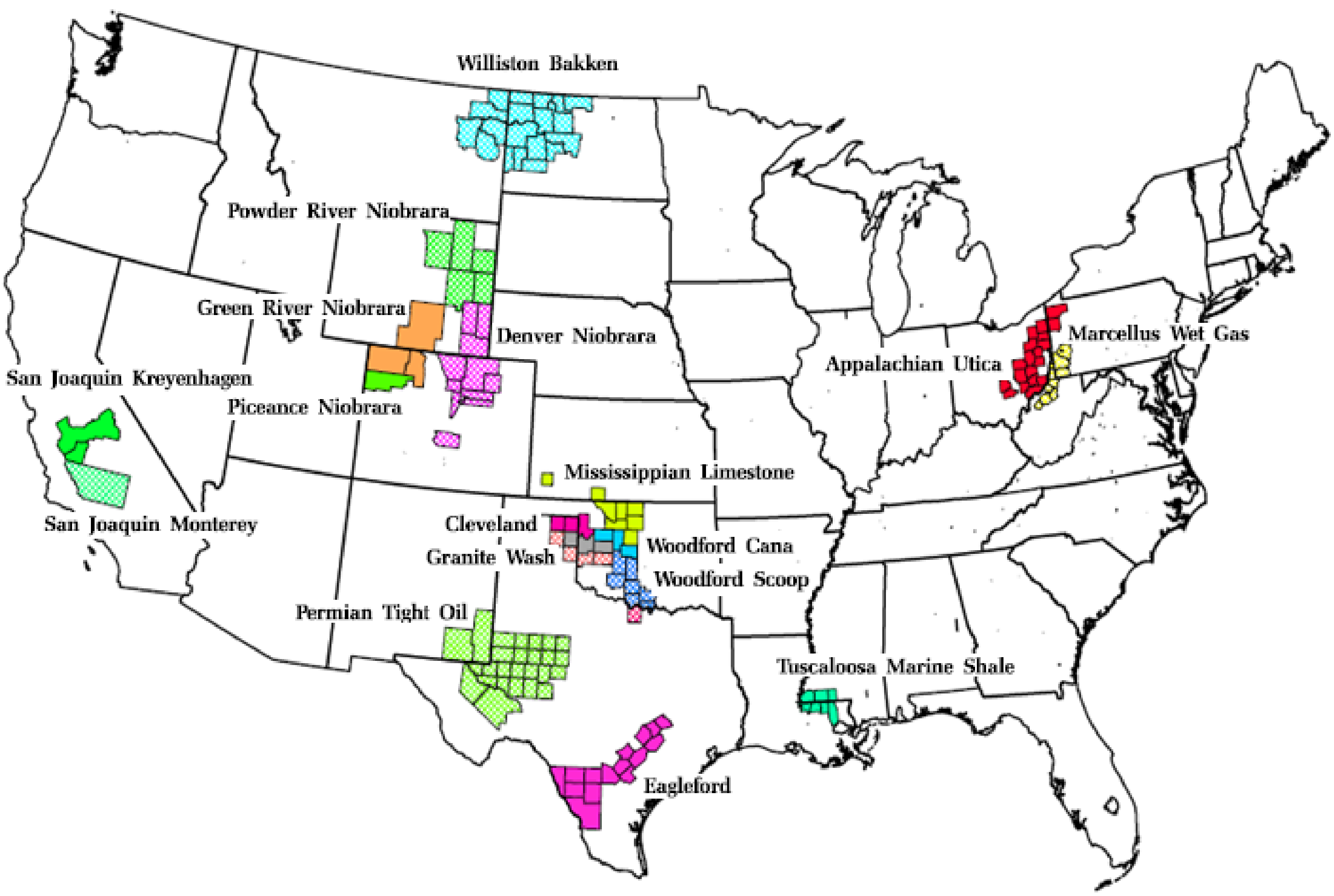
Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
	Lower-Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.9)										
With Keystone XL											
Option 1	896	22,391	25,924	10,223	(334)	(10,916)	(13,697)	(16,338)	(13,595)	(16,122)	(1,157)
Option 2	836	20,489	25,993	10,407	(637)	(12,279)	(11,363)	(13,826)	(11,001)	(13,686)	(507)
Option 3	676	20,087	28,226	15,759	(17,035)	(10,825)	(8,061)	(10,426)	(7,833)	(9,504)	106
Without Keystone XL											
Option 1	893	22,449	24,571	(18,399)	(87,372)	(24,035)	(26,372)	(25,520)	(22,916)	(25,464)	(18,217)
Option 2	836	20,602	22,911	(19,736)	(79,990)	(23,686)	(27,983)	(24,926)	(22,172)	(24,825)	(17,897)
Option 3	676	19,816	25,910	(693)	1,738	(10,021)	(9,950)	(12,562)	(9,735)	(12,344)	(717)
Case	Upper-Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.9)										
With Keystone XL											
Option 1	(63)	(4,894)	(18,386)	(20,411)	(21,260)	(20,694)	(19,110)	(19,582)	(20,020)	(19,916)	(16,434)
Option 2	(60)	(4,655)	(16,062)	(17,928)	(17,786)	(18,258)	(16,251)	(16,506)	(16,801)	(16,811)	(14,112)
Option 3	(139)	(898)	(8,662)	(13,280)	(12,733)	(11,256)	(11,292)	(11,398)	(11,519)	(11,637)	(9,281)
Without Keystone XL											
Option 1	(72)	(4,513)	(18,213)	(25,369)	(97,032)	(45,760)	(30,527)	(28,733)	(29,606)	(29,668)	(30,949)
Option 2	(60)	(4,281)	(17,505)	(24,529)	(88,598)	(42,100)	(29,274)	(27,419)	(28,381)	(28,532)	(29,068)
Option 3	(139)	(627)	(10,452)	(14,671)	(14,351)	(14,985)	(13,128)	(13,436)	(13,725)	(13,551)	(10,907)

Source: ICF modeling results

2 Introduction

U.S. tight oil production and Canadian oil sands production have fundamentally altered the North American energy landscape, with new production sources creating demands for additional infrastructure to connect these new supply sources with traditional demand markets. Key production regions for tight oil include the Bakken in North Dakota and Montana, the Permian Basin in Texas and New Mexico, the Eagle Ford in Texas, and the Niobrara in Colorado and Wyoming, as shown in the exhibit below. Production from oil sands is concentrated in Alberta, Canada.

Exhibit 2-1: Key Tight Oil and Wet Shale Gas Regions



Source: ICF

Note: Gray blocks in Oklahoma indicate overlapping plays.

While U.S. and Canadian crude oil production continues to grow at a rapid clip, the infrastructure needed to connect these new supplies to traditional demand markets has lagged. Pipelines historically transported imported crude from the Gulf Coast into the Midwest refiners. As production from the Bakken region began to grow, takeaway capacity lagged. Pipelines moved some crude into the Midwest (reducing needs from the Gulf Coast); however, pipelines have not been a viable option to either East Coast or West Coast refiners.

With East Coast refiners dependent upon light sweet crude, similar to Bakken, the economics to supply the East Coast by rail became very favorable. As a result, rail transport of crude oil has grown significantly as a feasible alternative to pipelines, which take significantly longer to permit and construct.

However, a number of recent railcar derailments involving the transport of crude oil have led the industry and the U.S. and Canadian governments to consider additional regulatory measures to make the fleet of railcars transporting crude oil, ethanol and other flammables (i.e., Class 3 materials) more resilient to the impact of derailments. In particular, in August PHMSA proposed regulations that would set requirements for high-hazard flammable trains (HHFTs), which are defined as trains with 20 or more Class 3 flammable liquid cars. Specifically, the proposed regulations aim to[4]:

- Better classify mined liquids and gases, including additional sampling,
- Assess rail route risks,
- Establish protocols for notifying State Emergency Response Commissions (SERCs) or similar state entities when trains carrying one million gallons of Bakken crude oil pass through the state, and
- Require new cars and retrofitted railcars to meet specific safety requirements with a compliance timetable set to have commodities identified as packing group 1, transported in new or retrofitted railcars by October 1, 2017, packing group 2 by October 1, 2018, and packing group 3 by October 1, 2020.

The PHMSA-proposed tank car safety specification regulations are identified in the exhibit below. PHMSA proposed three levels of improved railcar standards, identified as options 1, 2, and 3 below. The exhibit also identifies specifications currently in operation.

[4] 49 CFR § 171, 172, 173, et al. Hazardous Materials: Proposed Rules. Pp. 45017-20.

Exhibit 2-2: Proposed PHMSA Tank Car Options

Safety Feature	Proposed PHMSA Options			DOT 111A100W1 Specifications (currently in operation)
	1: PHMSA/Federal Railroad Administration (FRA) Designed Tank Cars	2: Association of American Railroads (AAR) 2014 Tank Car	3: Enhanced Casualty Prevention Circular (CPC) 1232 Tank Car	
Bottom outlet handle	Handle removed/designed to prevent handle operation during train accident	Handle removed/designed to prevent handle operation during train accident	Handle removed/designed to prevent handle operation during train accident	Handle optional
Gross rail load (lbs.)	286,000	286,000	286,000	263,000
Head shield type	Full-height, ½-inch thick	Full-height, ½-inch thick	Full-height, ½-inch thick	Optional, bare tanks half height, jacketed tanks full height
Pressure relief valve	Reclosing device	Reclosing device	Reclosing device	Reclosing device
Shell thickness	9/16-inch minimum	9/16-inch minimum	7/16-inch minimum	7/16-inch minimum
Jacket	11-gauge weather-tight jacked minimum made from A1011 steel or equivalent	11-gauge weather-tight jacked minimum made from A1011 steel or equivalent	11-gauge weather-tight jacked minimum made from A1011 steel or equivalent	Jackets optional
Tank material	TC-128 Grade , normalized steel	TC-128 Grade , normalized steel	TC-128 Grade , normalized steel	TC-128 Grade , normalized steel
Top fittings protection	Toxic inhalation hazard (TIH) system, nozzle capable of sustaining rollover accident at 9 mph	Equipped per AAR specifications (appendix E, paragraph 10.2.1)	Equipped per AAR specifications (appendix E, paragraph 10.2.1	Not required, but optionally equipped per AAR specifications (appendix E, paragraph 10.2.1
Thermal protection system	In accordance with § 179.18	In accordance with § 179.18	In accordance with § 179.18	Optional
Braking	Electronic controlled pneumatic brakes (ECP)	Distributed power (DP) or two-way end-of-train (EOT) device	DP or EOT device	Not required

Source: 49 CFR § 171, 172, 173, et al. Hazardous Materials: Proposed Rules. Pp. 45018-19.

ICF Resources, LLC ("ICF", a subsidiary of ICF International) and its subcontractors, Hellerworx, AllTranstek LLC, and FTR, were tasked with analyzing how possible changes to specifications for the North American rail tank car fleet might affect the available capacity and costs of crude oil rail transport and how those factors might, in turn, affect the economics of U.S. and Canadian crude oil production, crude oil production levels and general economic measures such as GDP and employment. In addition, Appendix D includes detailed tables on these economic measures, as well as tax revenues.

These issues are examined under the overarching assumptions that U.S. regulations will require all Canadian rail movements to meet the PHMSA proposed regulation due to the increasing number of cars that will be required to cross borders. In addition, the study assumes that, despite the fact that the retrofit requirement would apply only to railcars used in trains with more than 20 cars containing a flammable commodity, all Class 3 railcars will need to be retrofitted. The reason for this is that is unreasonable for a rail shipper to know with confidence that a particular train will exceed the limit of railcars as a manifest train may pick up cars for shipment at multiple locations.

Some of the other assumptions used in this study are identical to PHMSA assumptions published with the proposed regulation – for example the initial railcar fleet for crude, ethanol and other flammables. However, many other assumptions differ from those used by PHMSA based on this study's more robust analysis of petroleum, ethanol, and rail transportation trends, costs and capacities. These assumptions used in the ICF analysis lead to a more constrained market for tank car services under the proposed regulations. For example, based on industry data and analysis performed by the ICF team, this analysis indicates that 1) the capacity to retrofit railcars is significantly lower than the PHMSA assumptions; 2) the time and costs required to retrofit the existing railcar fleet are greater than the PHMSA assumptions, and 3) the demand for crude by rail service will be substantially higher than PHMSA's assumptions and would be even higher if Keystone XL were to be denied.[5]

This study examines a number of factors that influence the ability and cost to align the rail fleet with PHMSA's proposed options as well as the Business As Usual[6] case. Factors integrated into the analysis include:

- Outlook for crude production growth and crude by rail movement volumes for the U.S. and Canada in the 2014-2024 period ("Study Period") under both a scenario that assumes KXL is approved (and operational in 2017) and a second scenario in which KXL is denied and the demand for transporting crude by rail is higher.
- Estimates of ethanol and "other flammables" movements by rail over the study period.
- Estimates of average barrel movements per railcar per year for crude, ethanol and other flammables.
- Anticipated retrofit and new-build costs, including actual cost of the new or retrofitted cars to the PHMSA Option 1, 2 and 3 standards. This study used the Railway Supply Institute's (RSI) cost estimates for each individual retrofit component. Assumptions related to the time needed to perform retrofits were developed by the ICF Team based on inputs from RSI and various industry participants including shippers and rail car maintenance shops.

[5] ICF uses RSI's 7-2-2014 retrofit capacity estimate of 5,700 cars per year after a one year ramp-up, cost estimates –based on PHMSA and RSI estimates of individual enhancements- that are 65% to 160% greater than PHMSA's, and estimates of rail car demand which are roughly larger than PHMSA's by 20,000 railcars in 2015 to 40,000 railcars in 2020 (these figures would be even larger if KXL was not constructed).

[6] The "BAU" case assumes the same growth in demand for crude oil by rail (U.S. and Canada) and the same new build and retrofit capacities and costs and fleet retirements as the option cases, but assumes new railcar demands are met by CPC 1232 jacketed railcars.

- Time required and the opportunity cost (lost revenue) to retrofit the cars – both out of service time (origin to shop to origin), and shop capacity time.
- Impact of retrofit weight added on railcar volume capacity.
- Shop capacity constraints, using information from RSI in the model, augmented by a detailed survey of rail repair shops by AllTranstek which estimated an even lower level of capacity than RSI.
- Assessment of the base fleet normal retirement age based on data from RSI to forecast normal fleet turnover.[7]
- Capacity and costs of alternative transport modes (such as pipeline, barge, truck, and/or shutting in oil production) that could be used when tight timetables reduce the railcar fleet qualified to move commodities under the proposed regulation. Also the impacts of employing alternative transportation modes on the costs to deliver ethanol and other flammables (including gasoline, diesel, jet and multiple petrochemical products and feedstocks).
- Impact of potentially higher rail transport cost on the East Coast refiners who have significantly increased their use of North American crudes and reduced dependence on foreign oil in 2013 and 2014.
- Impact of potential increased transportation costs and railcar shortages on crude oil production, petroleum markets, and costs to the economy.

These assumptions and the use of an ICF-developed model enable analysis of the ability and cost of the rail industry to build and retrofit cars consistent with the proposed regulations in the timeframe required for compliance with packing groups 1, 2, and 3 timetables.

This report presents the findings of this study by first presenting in Section 3 the Methodology used to develop the railcar model and to determine the transportation and cost impacts of the proposed regulation. Section 4 details the numerous assumptions used for demand, cost and capacity data used in the analytical model and the rationale for those assumptions. Section 5 presents the results of the study in terms of U.S. and Canadian economic impacts, railcars required to be scrapped or repurposed due to the limitations of the industry and the compliance timetable, and the impact on crude and other Class 3 commodities transport ability. Section 6 presents conclusions. Section 7 includes several appendices.

[7] Barken, Chris; Rapik Saat; Xiang Liu; and Todd Treichel. "Class 111 Tank Car Fleet Analysis." Slides 11, 13, 15, and 16. Railtec, the University of Illinois at Urbana-Champaign, 15 October 2013: Urbana, IL.

3 Study Methodology

3.1 Study Steps

This study assessed three PHMSA railcar safety regulations, relative to a Business As Usual (BAU) case, including cases with and without the Keystone XL Pipeline. The time horizon assumed was between 2014 and 2024, with impacts starting in 2017, the first year regulations take effect. The study was undertaken in the following tasks:

3.1.1 *Task 1: Preparation of Data Needed for Transportation Model Development*

The first task included preparation of initial information needed to estimate compliance costs and effects on rail transport capacity for crude, ethanol and other flammables under three regulatory scenarios:

- A business as usual (BAU) scenario
- PHMSA Proposed Option 1 railcar standard
- PHMSA Proposed Option 2 railcar standard
- PHMSA Proposed Option 3 railcar standard

The key elements deemed critical for the analysis of the BAU and proposed PHMSA Options included the following:

1. Translating each proposed standard into specific tank car design characteristics. ICF developed a spreadsheet wherein each row is a design characteristic and each column is a proposed standard. The spreadsheet indicated in each cell whether that characteristic is required under the appropriate standard.
2. Reviewing Umler, RSI/ARCI, FTR and other railcar databases to estimate existing tank car fleet characteristics (numbers, tank car design, and age profile) in the U.S. and Canada. There was considerable variation in the numbers due to when the information was collected, as well as what was considered a "crude" car (i.e., whether or not railcars were consistently or occasionally used in crude service). The clearest data point appeared to be the RSI estimates included as Table TC-4 in the PHMSA RIA[8] which were updated as late as June 18, 2014. These fleet inventories were used in the ICF analysis. Information on tank car design, fleet age etc. was also used to help assess retrofit requirements and normal retirement.
3. Determining whether and how the design characteristics called for by the proposed standard could be retrofitted to meet the proposed PHMSA standards and the costs and constraints to doing so. This work included:
    a. Characterizing the scope and costs of possible retrofit requirements
        - Scope of possible retrofit requirements

[8] RSI presentation at the NTSB rail safety forum April 22, 2014, update provided on June 18, 2014.

- Cost of each component (e.g., Full Height Head Shields, etc.)
- Differences in designs of existing fleet (some newer railcars may require less retrofitting, for example)
- Projected total retrofit costs by railcar type.
- Projected timing to complete retrofit by item (or groupings of items) by car type. This includes estimates of actual shop time to do the work as well as the time from the origin location to the repair shop, cleaning time, qualification time, shop time and then return to the origin point (i.e., time out of service).

b. Assessing the type of tank car facility capability needed

- Oven for complete car stress relieving
- Ability to jacket a complete car
- Ability to produce full height head shields (or truck in)
- Steel - supply (jackets, head shields, tank material)

c. Estimating industry capacities

- New car production capacity - existing and possible future additions
- Retrofit capacity - existing and possible future additions
- Type of facilities required for retrofit/ remanufacturing
- Industry tank car repair shop capacity considerations – increasing demand for requalification for all tank cars, general repair demand, coating/linings, qualified labor

d. Assessing supply chain constraints

- Facilities, capabilities, labor, steel, materials, railcar components, tank car components, valves, coating/linings, castings
- Lead times/cycle times

e. Estimating impacts on car capacities

- Effects on railcar volume capacity of new specification requirements for retrofits
    - Additional weight needed for compliance and impact on capacity
    - Use of 286,000 pound bearing trucks versus 263,000 pound trucks

f. Characterizing decision process for compliance

- Economic and financial considerations to owners based on available options
    - Repurpose versus retrofit versus scrap
- Economic and risk management considerations

g. Other considerations

- Alternative markets for existing cars (i.e., non-ethanol/crude)

4. Estimating current and future fleet utilization over the next 10 years (i.e., demand for tank car capacity based on estimated additional crude and other commodity movements by rail in each future year).
    a. Oil production trends were taken from the ICF forecast as presented in our crude oil export study for API.[9] Assumptions for cross-border and large intra-U.S. pipelines were taken from that study or based on more recent announcements of pipeline projects. Assumptions of incremental crude movements by rail were based on 2013 actual movements in the U.S. (primarily sourced from the Bakken) and estimated forward based on anticipated additional rail unloading facilities planned on the East and West Coasts. Canadian crude by rail forecast was derived from the 2014 CAPP crude by rail study. (The assumptions and analysis are detailed in Section 4.)
    b. Ethanol and other flammable volumes are assumed similar to volumes identified in the 2012 AAR Class 3 Volume Analysis. The rationale is that gasoline demand is flat and ethanol is linked at a 10% blend. Other flammable demands are also deemed flat versus 2012. If growth had been assumed for both ethanol and other flammables, the study results would have shown higher costs and greater railcar shortages. The 2012 rail volumes were 597,000 bpd of ethanol and 591,000 bpd other flammables.[10]

3.1.2 Task 2: Construct Railcar Balance Model

The Railcar Balance Model is a linear programming (LP) model that simulates how the Class 3 rail tank car inventory in the U.S. and Canada will be operated and modified through the year 2024 on a Business as Usual basis and under the proposed PHMSA regulations . See Appendix C for snapshots of the model setup. Within the model, the market for Class 3 rail transport services is divided into the following **commodity submarkets**:

1. Crude Oil Packing Group 1
2. Crude Dilbit Packing Group 2
3. Crude Railbit Packing Group 2
4. Ethanol Packing Group 2
5. Other Flammable Liquids Packing Group 2

The demand for rail services is an exogenous input into the model and is specified in terms of barrels of each of the six commodities that must be transported each year and the “efficiency” of transportation in terms of the barrels per year that a “standard size” railcar could transport of that commodity (see Section 4). The “standard size” car is defined as having a 30,000 gallon

[9] ICF International. “The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs,” Section 3.3. The American Petroleum Institute (API), 31 March 2014: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/LNG-primer/API-Crude-Exports-Study-by-ICF-3-31-2014.pdf

[10] Derived from pp. 5-7 from Association of American Railroads (AAR) Bureau of Explosives. “Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail.” AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf

nominal capacity which would be filled (if weight limits were not binding) to 99% of nominal capacity or 29,700 gallons.

The inventory of existing and new tank cars is divided into the following six **tank car types**:

1. CPC 1232 Bare (i.e., unjacketed)
2. CPC 1232 Jacketed
3. 1MM or 3MM Non-CPC Bare (i.e., cars with recertification thresholds of 1 or 3 million miles)
4. 1MM Non-CPC Jacketed
5. pre-1MM Bare Crude (the oldest category with less than 1 million mile recertification thresholds)
6. New Standard New Builds (cars that would be built to comply with one of the three options for new PHMSA standards).

The Railcar Balance Model seeks to find the least-cost solution for satisfying the increasing demand for rail transport services for the five-commodity submarket subject to a variety of constraints. The **decision variables** that comprise the solution in the model include (for each year from 2015 to 2024):

- Build new tank cars
- Retrofit old tank cars
- Use alternative (non-rail) transportation options, or
- Do not produce the commodity.

The **objective function** that is minimized by the model is the sum of the present value of all annualized costs including the costs of retrofitting cars (described below), net cost of building new cars (described below), the cost of using alternative modes of transportation in the event insufficient numbers of qualified cars are available, and the opportunity cost of shutting in production. The cost of new and retrofitted tank cars are “annualized” or spread out over the remaining lives of the cars so that decisions that lead to different periods of service (e.g., building a new car with a 35-year life versus retrofitting an old car with a remaining 20-year life) can be properly compared to each other. When cars are retrofitted, the lost revenues during the time out of service are treated as a cost. When existing cars are prematurely replaced by new cars, the value of the re-purposed or scrapped car is treated as revenue that offsets part of the cost of the new tank car and produces the “net” cost of the new car.

For each commodity submarket, the model tries to solve for the number of tank cars to be retrofitted and newly built such that the tank car capacity is sufficient to move the targeted barrels of commodity given the expected railcar efficiency.[11] If there is a gap between demand for railcars and supply of railcars (available inventory, retrofitted cars, and newly built cars), that

[11] Also accounted for is that car type must match commodity (e.g., heating coils or jackets for cars hauling railbit).

gap can be filled by alternative methods of transportation including pipeline, barge & truck, and truck. In extreme situations when there are insufficient compliant railcars and alternative transportation modes are used to their assumed capacities, reduced production of crude oil or other commodities may be required to balance the market. The model calculates the volumes of commodities that use alternative transportation modes or are shut in terms of annual barrels and also in terms of equivalent number "shortage cars." Cost assumption details are in Section 4).

As with all LP models, the Railcar Balance Model's solution is affect by a number of **constraints.** The key constraints are as follows:

- Within each submarket and year the available tank car capacity (including "shortage cars") must be equal to or greater than demand. (These are called the "market balance" constraints.)
- New car builds in each year must be equal to or less than new car construction capacity.
- Total shop days used for retrofits must be equal to or less than the annual estimated industry capacity to retrofit railcars.
- Retrofits of cars within each tank car type category over the ten-year forecast must be equal to or less than the beginning inventory of those cars (includes backlogged new cars now on order) less normal retirements expected in that period.
- The annual use of alternative transportation options within each commodity submarket must be equal to or less than the assumed capacity by option (e.g., pipeline, truck & barge, truck only).
- For the years 2015 and 2016, minimum new builds reflect our estimates of order backlogs based on documents from RSI and ICF analysis of industry sources.[12]

3.1.3 Task 3: Perform Model Cases to Assess Impact of PHMSA Proposal versus BAU Case

Using the data prepared in Task 1 and the model developed in Task 2, scenarios were studied with the model to identify the transportation cost impacts of PHMSA's proposed Standards (Options 1, 2 and 3) versus a Business as Usual case. These cases were performed using volume by rail demands for crude, ethanol, and other flammables over the study period as referenced in Task 1 and detailed in Task 4 (Assumptions) for cases with and without approval of Keystone XL. Model outputs included:

1. Estimated tank car retirements, retrofits, and new builds (in terms of tank car number and barrel volumes) under each regulatory scenario over the next 10 years.
2. Estimated incremental costs for retrofitted and new tank cars in terms of $/car and how those capital costs translate into higher $/car/month lease rates (or equivalent monthly

[12] Railway Supply Institute (RSI). "Workshop on Trends in Sources of Crude Oil," slide 9. California Energy Commission (CEC), 25 June 2014.

ownership costs). We considered whether and how out-of-service times for cars being retrofitted might impact lease rates.

3. Using out-of-service times we developed under Step 3, the average retrofit time per tank car (for each category of tank car) and total annual capacity losses due to time out-of-service for retrofits for each standard was determined.
4. Then, taking into account existing fleet, retirements, retrofits, new builds and out-of-service times for each regulatory scenario, the model estimated railcar capacity for each of the next ten years.
5. The estimated deficiency (if any) between the forecasted demand for railcars (see Task 4, Bullet 1) and the estimated railcar capacity under each regulatory scenario was determined by the model.
6. Any shortage in railcar availability to meet forecasted movement demand was "costed" in the model based on possible alternative options for each of the commodities to reach market. These assumptions, detailed in Section 4, included possible use of pipelines, barge or truck for crude oil and truck movement for ethanol and other flammables. The model also provided a cost to shut in crude production if no other feasible option was available.

The model output consisted of an assessment of costs versus the BAU case, plus identification of the number of railcars that needed to be scrapped or repurposed, new and retrofitted railcar production for each year and shortages of railcars and estimated volumes of crude, ethanol, and other flammables which would require alternative modes of movement due to shortages. These results summarized the direct transportation cost impacts of the regulations. These impacts will also have an effect on the overall economy, which is developed in Task 4 below.

3.1.4 Task 4: Economic Impact Assessment of Proposed PHMSA Standard vs. BAU

The purpose of this task was to estimate the oil market and general economic consequences of the rail tank car cost increases and any capacity shortfalls estimated in Task 3 for the PHMSA proposed standards. The oil market consequences include higher crude transport costs, lower U.S. and Canadian crude oil production (higher transport costs lead to lower netback wellhead costs), higher world crude costs due to lower North American production, higher transport cost for ethanol and petroleum products, and higher petroleum product costs for consumers. These oil market changes, together with reduced spending on consumer goods (caused by higher costs for petroleum products) then lead to various impacts on U.S. GDP, jobs and tax revenues. The work to estimate these economic impacts was done in the following steps:

- Using its proprietary oil market models, ICF estimated how the changes in transport cost computed in Task 3, would impact U.S. and Canadian wellhead costs and production levels. This process included iterating a simple model of the world oil market to capture the feedback between lower North American oil production and world oil costs. The higher transport costs and bottlenecks caused by the proposed PHMSA regulations reduce North American wellhead oil costs in basins where rail is used as a marginal transport mode (Bakken, Niobrara, and western Canada) which then reduces production levels. The reduced North American production levels then raise world crude costs, which causes a partial rebound in wellhead costs. The overall impact after iterating to a solution on cost effects is slightly higher world crude costs but lower North American wellhead crude costs and production levels in basins that rely on rail.

- Put annual changes in U.S. direct industry outputs related to oil well drilling, oil well operating expenses, tank car construction and retrofit, non-rail transport services and consumer spending caused by the proposed PMSHA standard into an economic impact model based on the IMPLAN input/output model. This framework is similar to that used by ICF for API crude oil export study.[13] The study computes how changes in outputs by sector (direct impacts) track through the economy to affect other sectors and the economy as a whole (indirect and induced impacts).

This study assessed a number of specific direct output changes associated with the PHMSA cases relative to the Business As Usual (BAU) Case. These direct impacts include:

1. Expenditures on tank car retrofits and new tank car manufacturing: Relative to the BAU Case, the three PHMSA cases lead to more expenditures to retrofit and replace cars. While this will not directly impact GDP[14], these expenditures will mean modest gains in employment at shop car facilities and railcar and materials manufacturing centers. ICF derived the number of jobs required for car retrofits and new tank cars based on the output-per-employee ratio in this industry category.
2. Expenditures on alternative modes of transportation: The PHMSA cases require noncompliant cars to cease hauling flammables after certain dates, which may lead to the use of non-rail modes of transportation such as pipelines, barges, and trucks. This additional demand for alternative transportation modes will mean an increase in expenditures and jobs to support a capacity expansion (i.e., capital expenditures) of these modes. Jobs in this category are calculated using output-per-employee ratios.
3. Value of scrapped and repurposed cars: All railcars will eventually be scrapped, though a number of railcars that are not economic to retrofit (either due to time constraints imposed by impending deadlines or due to the fact that the retrofit cost may exceed the useful value of the car) are scrapped or used for other purposes. Scrapping a car displaces some steel production (as the car is sold for scrap metal), while repurposing a car negates the need for a new car, thus displacing some employment in those displaced sectors, while creating a modest positive employment impact for scrap yards.
4. Upstream investment and production changes: The upstream production changes are a result of lower wellhead costs for crude and transportation capacity bottlenecks. Supply constraint on railcars will force some oil shippers to find alternate transportation modes, such as pipelines, barges, and trucks. However, these alternative modes may not be

[13] ICF International. "The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs," Section 3.4. The American Petroleum Institute (API), 31 March 2014: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/LNG-primer/API-Crude-Exports-Study-by-ICF-3-31-2014.pdf

[14] Gross Domestic Product (GDP) is based on the total value of all "final" products and service produced in a country in one year. For purposes of this analysis, transportation by rail and other modes are considered "intermediate" services which impact GDP only indirectly by changing the volumes and prices of final products.

able to accommodate the entire additional demand requirements. Thus, some oil producers will be forced by transportation capacity bottlenecks to shut-in oil wells, thereby reducing production. In addition, complying with the PHMSA regulation will likely increase the cost of transporting crude oil. Higher transportation costs can reduce wellhead crude netbacks and thus could mean less investment in well development, leading to lower production. The changes in capital and operating expenses for oil production are used to estimate the effects on jobs and the reduction in crude production is used in estimating GDP impacts.

5. Consumer impacts: Higher world oil costs and higher transportation costs for products carried by rail, including ethanol, could increase the costs consumers face for gasoline (which contains ethanol) and other petroleum products. These higher costs for energy products could decrease the amount of income consumers can spend on non-energy goods, which would negatively impact GDP and employment in non-energy sectors.

The indirect and induced economic impacts were then computed and added to the direct impacts to produced final economic impacts estimates. (See Appendix D for detailed economic impact estimates.) The indirect impacts are based on IMPLAN input/output matrices and account for the purchases of goods and services by companies that provide the direct output. The induced effects (also called multiplier effects) represent additional economic activity that would come about as the income earners associated with the direct and indirect impacts spend their income. There is considerable speculation as to the exact multiplier effect, thus, ICF applied a range to reflect this uncertainty. ICF assumed a range of 1.3-1.9 for the GDP multiplier effect, meaning that every $1.00 in direct and indirect GDP contributions led to an additional $0.30-$0.90 in induced economic activity. Similar to GDP, ICF applied two values for the multiplier to arrive at a range of induced employment impacts, based on IMPLAN input/output matrices.

The estimated impacts on government revenues include income, property and sales taxes related to incremental GDP and oil royalties from drilling on federal lands. These estimates were based on various factors derived from historical data. See Appendix D for detailed findings on government revenues.

4 Key Study Assumptions

The following section includes a discussion of key assumptions used for this study.

4.1 Key Transportation Issues by Product Type

The potential ramifications of railcar shortages to the crude, ethanol, and other flammable markets are serious in terms of both higher costs of fuels and potential for supply disruptions. The specific mechanism that will drive costs may depend on who owns the railcars that do comply and how those parties will capture or share the premiums that those cars most clearly will have in a market short of qualified railcars. A combination of inadequate retrofit capacity, limited new build capacity, higher crude by rail movement demands, and the PHMSA proposed deadlines in October 2017 and October 2018 could result in significant costs to consumers and the economy.

This section details what assumptions were integrated into the model and the research, analysis and reasoning that lies behind those assumptions. The assumptions for railcars and retrofits are presented first, followed by the assumptions for crude, ethanol and other flammable liquid transportation demands.

4.2 Railcar Cost and Retrofit Assumptions

4.2.1 Railcar Regulation Timing and Commodity Classifications

The study uses phase-out periods as defined in the PHMSA proposed regulations. Specifically, the proposed rule provides industry a period from January 1, 2015 to October 1, 2017 to use existing cars for PG1 materials. PG2 materials can be moved in existing railcars through October 1, 2018, and PG3 materials to October 1, 2020.[15] This study assumed that all domestic shale crude would be classified as PG1, and assumed Canadian dilbit, railbit, ethanol, and all 'other flammables' would be classified as PG2. Movements of dilbit and railbit will reduce the barrels loaded per car from roughly 700 with Bakken and other PG1 crudes down to 620 for dilbit and 590 for railbit, based on the specific densities of the crude, dilbit, and railbit.

4.2.2 Railcar Fleet, New Builds, and Retrofits

<u>Existing Fleet and Backlog</u>

Knowing the composition of the tank car fleet is critical to estimating the impact of the proposed rule. The railcar fleet data in Table 8 of the PHMSA proposal was current as of midyear 2014 and is the basis of most of the fleet analysis in the study.[16] Critically, PHMSA assumed that only cars in HHFT trains would be impacted by the proposed regulations; however, this study

[15] *49 CFR § 171, 172, 173, et al. Hazardous Materials: Proposed Rules. P. 45043.*

[16] *49 CFR § 171, 172, 173, et al. Hazardous Materials: Proposed Rules. P. 45025.*

assumes that all existing Class 3 railcars would be impacted by the proposed regulations.[17] Additionally, new crude cars on order are assumed to be 75% jacketed CPC 1232 cars and 25% non-jacketed, and the backlog of cars is assumed to consist of 35,140 crude cars.[18]

New Build Cost Assumptions

The estimated cost of new build railcars in the BAU Case, as well as for the proposed PHMSA Options 1, 2, and 3 are based on AllTranstek's analysis:

- BAU: $155,000 for a jacketed CPC 1232 cars and $159,000 for a coiled and jacketed CPC 1232 car
- PHMSA Option 1: $173,500 for a jacketed Option 1 car and $177,500 for a coiled and jacketed Option 1 car
- PHMSA Option 2: $164,500 for a jacketed Option 2 car and $168,500 for a coiled and jacketed Option 2 car
- PHMSA Option 3: $155,000 for a jacketed Option 3 car and $159,000 for a coiled and jacketed Option 3 car

Retrofit Cost Assumptions

The costs to retrofit existing railcars to meet the proposed PHMSA standards were estimated to be significantly higher than the costs suggested by PHMSA in the proposed regulation. Retrofit costs will vary depending on the PHMSA option being considered as well as the particular type of railcar being retrofitted (CPC or legacy, Bare or already Jacketed, etc.). The ICF team utilized the same numbers provided in the RIA (Table TC-6) by the RSI, however the cost assessment was considerably different.[19]

For example, the ICF team estimated the costs to modify an existing CPC 1232 bare car to meet the new PHMSA standards (including adding a jacket, FHHS, etc.) to be between $47,200 and $54,200, depending on the specific PHMSA option. This is significantly higher than PHMSA's assumed costs of between $26,230 and $32,900. The primary difference in these costs is that the ICF estimate includes the full cost of the full height head shields. Specifically, PHMSA only included an additional $400 for the cost of steel, whereas RSI estimated a full height head shield, which requires specialized equipment to manufacture, to cost $17,500. In addition, PHMSA assumes that there will be a 10% discount applied to total retrofit costs. The costs assumed for this study do not assume this based on industry input that costs are more

[17] The reason for this is that it is unreasonable for a rail shipper to know with confidence that a particular train will exceed the limit of railcars, as a manifest train may pick up cars for shipment at multiple locations, hence it will be necessary for all cars to be compliant.

[18] Railway Supply Institute (RSI). "Workshop on Trends in Sources of Crude Oil," slide 9. California Energy Commission (CEC), 25 June 2014.quoted a backlog of 37,800 railcars (slides 16 and 17). ICF assumed a portion of these cars (about 2,500) were back logged for ethanol or other flammable service.

[19] PHMSA. "Draft Regulatory Impact Analysis (RIA)." Docket No. PHMSA-2012-0082, HM-251. DOT, July 2014.

likely to escalate than to be discounted. The exhibit below shows retrofit cost comparisons between the ICF modeled costs by option, relative to those assumed by PHMSA.

Exhibit 4-1: Retrofit Costs above the BAU Case

Tank Car Type	ICF Assumptions			PHMSA Assumptions		
	PHMSA Option 1	PHMSA Option 2	PHMSA Option 3	PHMSA Option 1	PHMSA Option 2	PHMSA Option 3
CPC-1232 bare tank car	$54,200	$49,200	$47,200	$32,900	$28,900	$26,730
CPC-1232 jacketed tank car	$32,700	$27,700	$2,700	N/A	N/A	N/A
DOT pre-CPC-1232 bare tank car	$75,700	$70,700	$68,700	$33,400	$28,400	$26,230
DOT pre-CPC-1232 jacketed tank car	$71,700	$66,700	$41,700	N/A	N/A	N/A
DOT pre 1996 bare tank car	$75,700	$70,700	$68,700	N/A	N/A	N/A

Source: ICF Analysis, PHMSA Notice of Proposed Rulemaking

Note that the cost difference to retrofit legacy cars may be even higher than the CPC example since the ICF team contends that new trucks may be required to upgrade those cars to new standards.

Retrofit Out of Service Time

Retrofit out of service time was estimated at up to 155 days for bare DOT111 cars and 147 days for DOT111 jacketed cars, depending on the PHMSA option considered. Retrofitting bare and jacketed CPC 1232 cars takes about 20-30 days' less time. Shop time is a part of that time and the total out of service time reduces overall crude loading capacity and lease revenue. PHMSA estimated 56 days total out of service time to retrofit a CPC 1232 car versus up to 130 days by the ICF team. For older cars, PHMSA estimated 84 days versus up to 155 days by the ICF team.[20] The exhibit below shows the ICF model's estimated days out of service by option, relative to those assumed by PHMSA.

Exhibit 4-2: Estimated Total Days Out of Service

Tank Car Type	ICF Assumptions			PHMSA
	PHMSA Option 1	PHMSA Option 2	PHMSA Option 3	All Cases
CPC-1232 bare tank car	130	126	126	56
CPC-1232 jacketed tank car	116	112	70	N/A
DOT pre-CPC-1232 bare tank car	155	151	151	84
DOT pre-CPC-1232 jacketed tank car	147	143	101	N/A
DOT pre 1996 bare tank car	155	151	151	N/A

Source: ICF Analysis, PHMSA Draft Regulatory Impact Analysis

Note that the current time to complete a million-mile qualification is 90-120 days, and all of the legacy cars will need to have a qualification inspection and repair done before any retrofits can be done.

[20] PHMSA. "Draft Regulatory Impact Analysis (RIA)." Docket No. PHMSA-2012-0082, HM-251. DOT, July 2014. P. 86, Table TC-9.

Retrofit Shop Capacity

Retrofit shop capacity is a critical variable in the ability of the rail industry to perform the required retrofits to meet the proposed compliance timetable.

AllTranstek performed an analysis of retrofit shop capacity to identify the maximum annual retrofits which may be reasonably expected. The AllTranstek analysis is based on a survey of more than half of the largest railcar repair shops and announced retrofit shop expansions. The study suggests an ability to retrofit about 2,883 cars in 2015 increasing to 3,711 in 2018.[21] This figure is lower than the RSI estimate of 5,700 cars per year, however it may be more accurate since a considerable number of shops responded.

The model used the RSI number of 5,700 retrofit cars per year, since it was deemed more conservative and yet is also well below the PHMSA estimate of 22,062 annually starting in 2016 through 2018 (66,185 cars in total).[22] At a minimum, the annual retrofit capacity assumed by PHMSA is almost four times the annual retrofit capacity estimated by RSI, and six times as great as AllTranstek.

Retrofit Weight Assumptions

The retrofit work will add weight to most of the fleet (depending on the specific proposal), and in some cases, this will reduce the volume of liquids that can be moved on a railcar (i.e., if the railcar was weight limited in the base, not volume limited). The analysis determined the weight impact, assuming a base tare for both 263,000 pound cars and 286,000 pound cars (the PHMSA proposal tare is used for the 286,000 pound car and 3,000 pounds less for the 263,000 pound car tare). The additional weight of each retrofit option (new jacket, full height head shield, etc.) determined the reduction in capacity (volume). The impact may be different for each option and for each commodity, since specific gravities vary by commodity. For example, adding a Jacket and Full Height Head Shield to a bare CPC 1232 car to carry ethanol may not affect load capacity since the added weight may still allow the same volume of ethanol to be loaded. This may not be true for crudes, which are heavier per gallon.

PHMSA assumed there would be no weight impacts stemming from the change in regulation, whereas ICF estimated the potential weight impact for each type of railcar and for each commodity. As noted, the reason weight impacts are important is that adding material for stronger tank cars limits the total carrying capacity, based on weight restrictions. Heavier retrofitted cars, thus, have less carrying capacity. This means that more retrofitted cars will be needed to carry the equivalent volumes carried in unretrofitted cars, which PHMSA does not account for.

[21] AllTranstek. "Tank Car C Shop Estimated Capacity for Retrofit," slide 5. AllTranstek, 2 June 2014.

[22] PHMSA. "Draft Regulatory Impact Analysis (RIA)." Docket No. PHMSA-2012-0082, HM-251. DOT, July 2014. P. 89.

New Build Railcar Capacity

The capacity to build new tank cars currently totals 33,800[23] cars per year, 10,000 of which are typically used for non-class 3 commodities, such as pressurized gases, edible oils and other edible products, and non-class 3 chemicals. This study assumes 23,800 new class 3 cars (i.e., cars for crude oil, ethanol, and other flammables) can be built each year. RSI has provided estimates as high as 27,600 cars per year, and as low as 20,400 cars for crude, ethanol, and other flammables.[24]

[Note that PHMSA assumed the same overall new build capacity from RSI (footnote 16) at 33,800 cars per year, but did not account for the fact that a portion of those cars were for other purposes than crude and other Class 3 commodities. PHMSA assumed that 20,300 cars would be constructed in 2014, driven by demand for crude cars, with new car growth moderating to 5,800 annually between 2016 through 2019. These PHMSA assumptions on new builds do not include construction of new cars needed to replace 23,237 legacy cars which PHMSA assumed to be converted to oil sands service (this study assumed this conversion does not happen, as cars in Canada must meet TC-140 standards). If including the PHMSA-assumed new builds needed to replace 15,450 jacketed and 7,787 unjacketed legacy cars converted to Canadian oil sands service that need to be replaced by October 1, 2018, PHMSA's total new builds would be the 43,537 cars over the 2014-2019 period.[25] This actual new build production is well below this study's results that require use of all 23,800 new build railcar capacity for at least five years in all cases to achieve conversion. This difference is primarily because of PHMSA's significantly higher retrofit capacity than Industry projection (described below).]

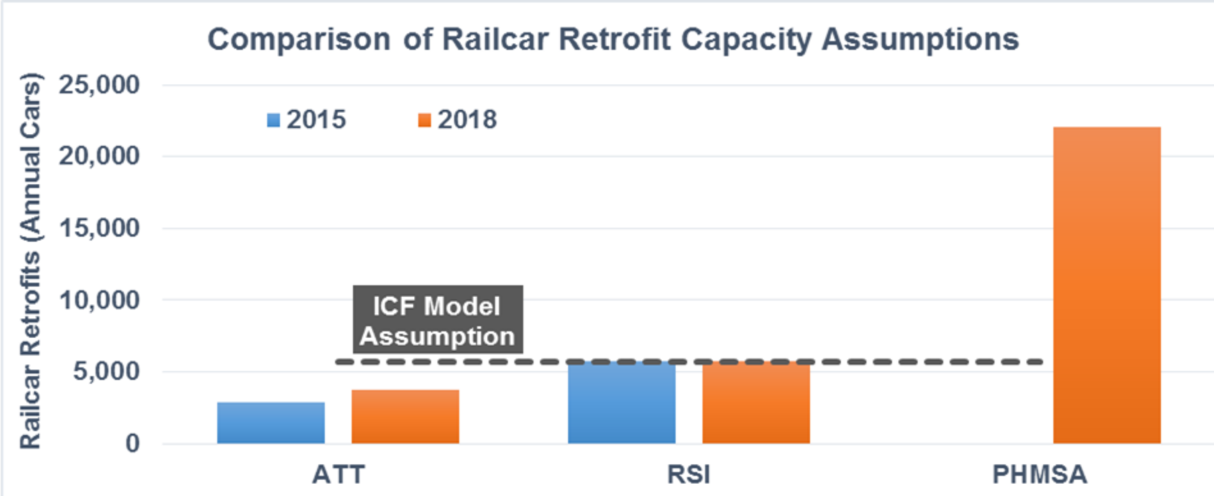
Exhibit 4-3 below compares several of the key assumption differences graphically. As noted, in each case PHMSA employed optimistic estimates for key parameters.

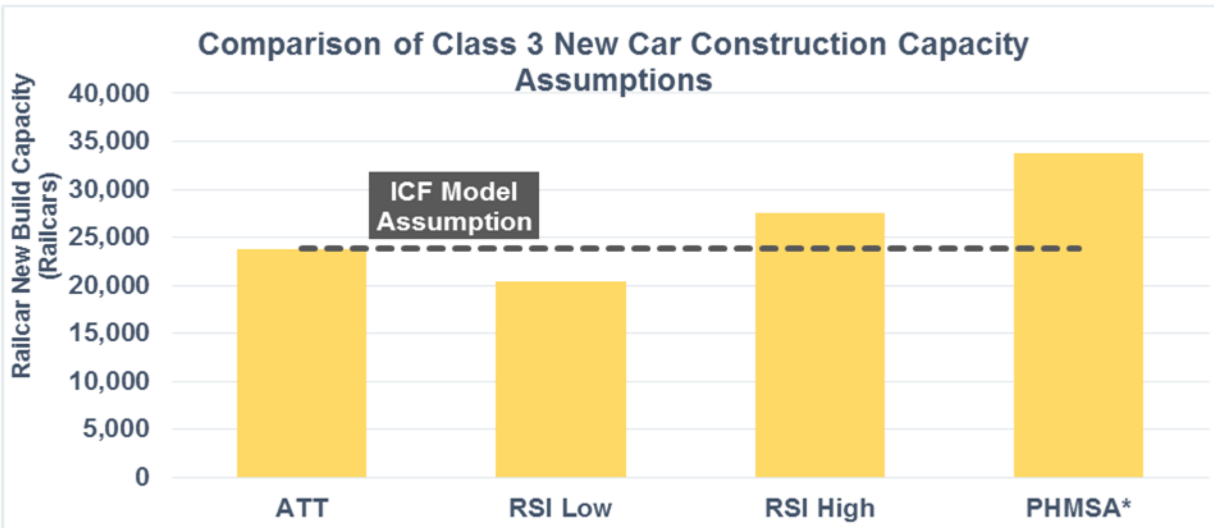
[23] 49 CFR § 171, 172, 173, et al. Hazardous Materials: Proposed Rules. P. 45053.

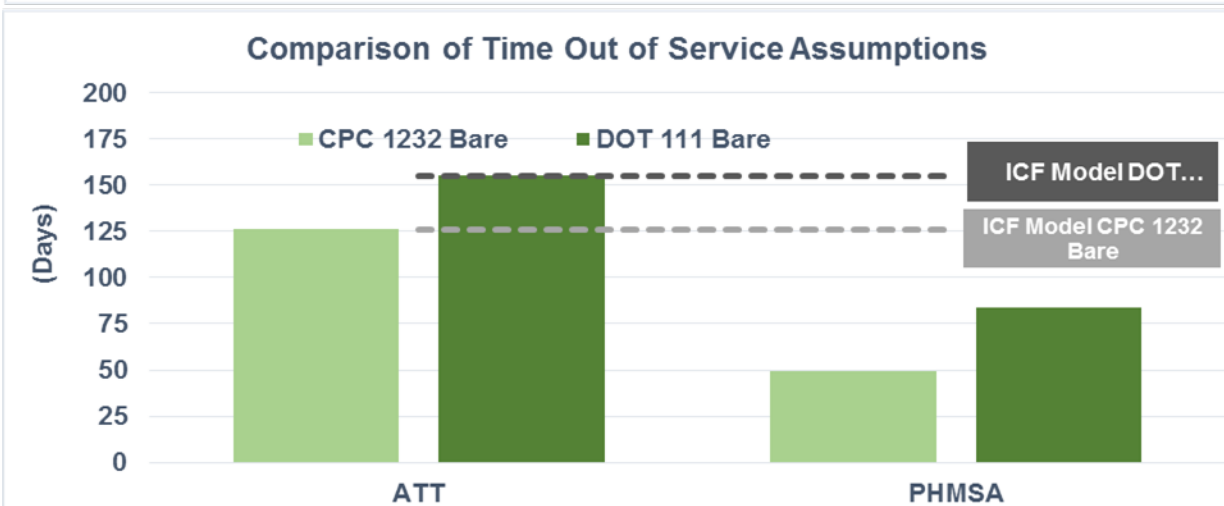
[24] Railway Supply Institute (RSI). "Workshop on Trends in Sources of Crude Oil," slide 9. California Energy Commission (CEC), 25 June 2014. Also June 16, 2014 presentation to OMB, Slide 22; 34,000 cars per year times 60% for crude.

[25] PHMSA. "Draft Regulatory Impact Analysis (RIA)." Docket No. PHMSA-2012-0082, HM-251. DOT, July 2014. Pp. 90, 109.

Exhibit 4-3: Key Model Differences from PHMSA Assumptions







Source: ICF analysis of various compiled sources

** PHMSA assumed 33,800 tank cars per year, but did not specify Class 3 tank car capacity, rather assuming all capacity could be allotted to crude-carrying cars*

Other Assumptions

Finally, this study assumed that railcars that cannot be retrofitted by the deadline will either be scrapped or re-purposed. Given the model outputs, which indicated that a significant number of railcars may not be able to be retrofitted in time, ICF assumed that 75% of those railcars would be scrapped. This may be necessary even for railcars that are approaching their typical 35 year economic life. The remaining 25% of the railcars that cannot be retrofitted are assumed to be re-leased for other purposes, and that they will earn 80% of a new CPC 1232 car lease rate.

It will be a challenge for PHMSA to determine an implementation timeline for its new regulations that can accommodate growing future needs to move crude by rail given the capacity of the railcar industry to manufacture new railcars and retrofit the older cars to new standards. The new tank car manufacturing plants are currently backlogged several years and many repair shops are already at 75% of capacity and even basic railcar requalifications are taking 90-120 days instead of the normal 45-60 days. The ICF team's assessment of the PHMSA cost and capacity assumptions for the retrofit and new build factors is that PHMSA has seriously understated 1) the number of cars that would need retrofitting, 2) the physical ability to retrofit those cars in order to meet the compliance deadlines, and 3) the costs impacts of the requirements to meet the compliance deadlines.

4.3 Crude Oil Outlook – Production and Movement by Rail Assumptions

The growth in crude oil production in the United States through hydraulic fracturing, and the growth in Canada from oil sands has been enabled by rapid development of railcar loading and unloading facilities, particularly in the U.S. and increasingly in Canada. The railcar transport has enabled tight oil crude primarily from the Bakken region in North Dakota to move to refineries in the Gulf Coast as well as the East Coast and West Coast refiners. Canadian crudes have moved by rail to Eastern Canada coastal refineries, several U.S. East Coast refineries and also Gulf Coast refineries.

The ICF team recognized that the future movement of crude oil by railcar is a critical variable in the analysis of the impact of the PHMSA proposed regulation. Even assuming that other regulated Class 3 commodities (ethanol and other flammables) remain at their recent levels of railcar movements, the continued growth in domestic tight oil production and Canadian crude production will require an increase in crude by rail movements.

To estimate this increase, ICF relied on its own forecast of crude and lease condensate production increases from the primary tight oil and wet shale gas basins as well as the Canadian Association of Petroleum Producers (CAPP) June 2014 Canadian production outlook. Additionally, CAPP published a report in May of 2014 on Canadian Crude by Rail Outlook, which ICF relied on for rail forecast demands for Canadian crude.

The sections below describe the basis for the ICF domestic crude production forecast, and also describe how ICF determined the volume of domestic crude that would move by rail over the study period.

4.3.1 Crude Production Outlook

ICF's crude production assessment is primarily based upon ICF analysis of public domain maps and data, with the information processed through a proprietary tight oil assessment and economics model. ICF relied on CAPP forecasts for future BAU Canadian crude production and crude by rail movements and adjusted these values in the model for the impact cases.

ICF focused on only four domestic tight oil basins as potential sources for crude by rail movements. These were the Bakken region, the Niobrara, the Permian and the Eagle Ford. It is certainly possible other new markets may evolve over the study period, but this study includes estimates of additional rail movements from only these four.

Exhibit 4-4 shows the projected growth in crude production for each of the tight oil basins as well as Canada from 2013-2024. Production is expected to increase by over a million barrels per day in the Bakken and Permian regions, 700,000 barrels per day in the Eagle Ford, and over 500,000 barrels per day in the Niobrara. Canadian production grows by over 2 million barrels per day. This is over 5 million barrels per day growth in total.

More pertinent to the proposed PHMSA deadline for tight oil and lease condensate (PG1) of October 1, 2017, production growth by that date alone from the four largest U.S. basins will be over 1.9 million barrels per day greater than 2013, with associated demands on rail transportation to move the volumes to market.

Exhibit 4-4: Crude Oil and Condensate Production Forecast

Year	Estimated Crude Oil and Condensate Production (bpd)				
	Canadian	Bakken[26]	Niobrara	Permian	Eagle Ford
2013	3,589,427	1,113,416	150,706	1,714,493	825,776
2014	3,825,636	1,339,582	208,681	1,875,830	1,093,243
2015	4,022,583	1,516,230	257,960	2,004,260	1,213,809
2016	4,165,553	1,673,370	304,020	2,126,134	1,273,264
2017	4,309,130	1,804,121	388,337	2,223,548	1,338,261
2018	4,455,201	1,925,233	463,010	2,320,518	1,403,316
2019	4,626,465	2,017,610	510,111	2,427,576	1,460,398
2020	4,816,900	2,099,700	564,812	2,570,113	1,506,417
2021	5,026,916	2,131,472	607,847	2,622,749	1,537,882
2022	5,211,064	2,158,519	633,439	2,664,185	1,527,486
2023	5,330,920	2,166,294	657,882	2,692,133	1,520,783
2024	5,530,309	2,168,020	679,841	2,707,219	1,515,260

Source: ICF Detailed Production Report (DPR) and ICF's Crude Export Study (ICF International. "The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs," Section 3.3. The American Petroleum Institute (API), 31 March 2014: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/LNG-primer/API-Crude-Exports-Study-by-ICF-3-31-2014.pdf)

[26] Includes Williston Basin

4.3.2 Crude Movements by Rail

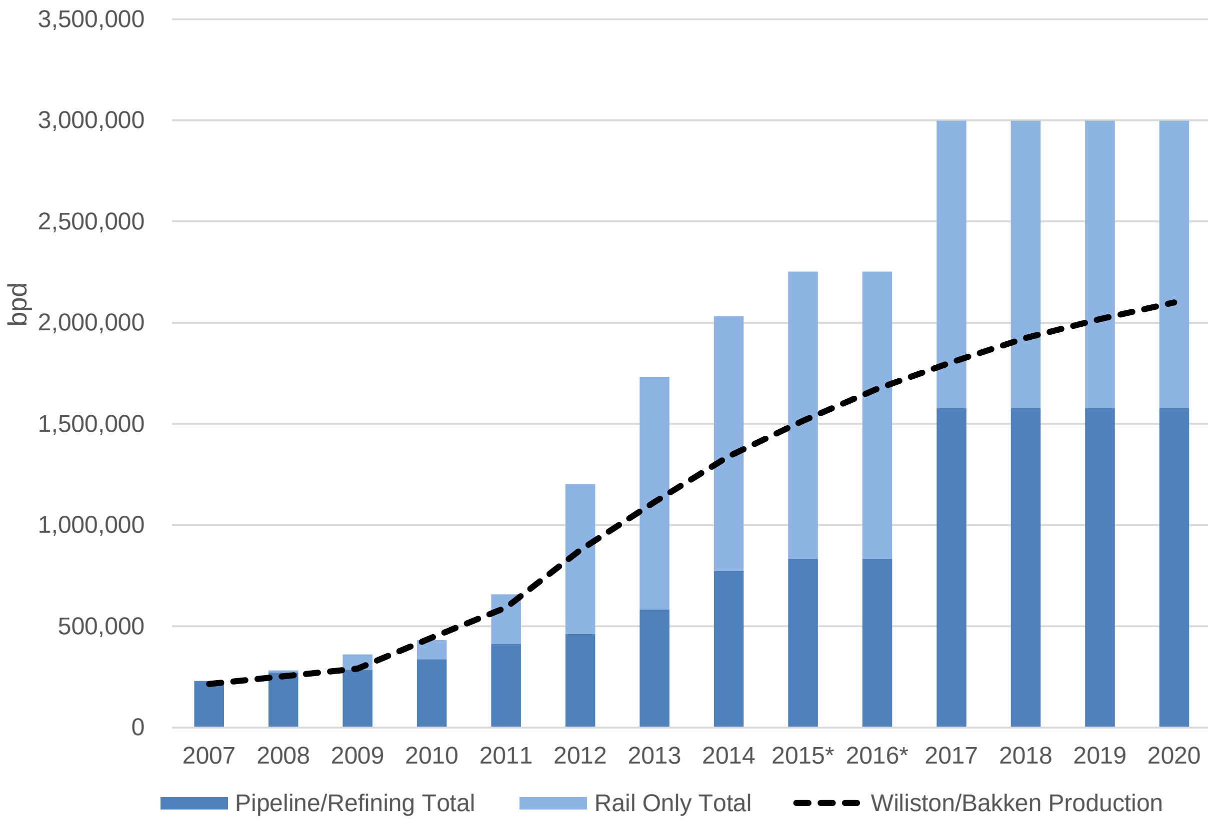
This study examined the trend in crude oil rail movements in the U.S. and the likelihood of that trend continuing. It was important to determine whether the impact of possible infrastructure constraints (pipelines) may continue to require movement of crude by rail to transport new U.S. shale production as well as Canadian production. To do this we assessed the potential for increased crude by rail movements from the four major U.S. Basins and the Canadian production to determine the future demand growth for crude railcars.

Bakken Movement Outlook

Rail movement of Bakken oil production is expected to increase from 2013 through 2017, consistent with production growth in a ratio consistent with the 2013 ratio (roughly 63% rail and 37% pipeline). Rail loading capacity appears adequate to meet needs through 2020, but new facilities may be needed dependent upon the location of new production. Bakken pipeline movements have typically been below capacity (<50% capacity) in 2013 as economics for rail to the East Coast and other markets has driven Bakken demand. If Brent prices decrease relative to WTI, East Coast refiners could back away from rail, and then producers may look to move via pipeline to other markets. If U.S. crude oil exports remain constrained by current policy, it is likely that increased light crude production will keep West Texas Intermediate (WTI) based pricing below Brent, and keep East Coast refiner rail demands high.

The exhibit below shows Bakken pipeline and rail shipment capacity from 2010 to 2020 based on known assets and announced projects (see detail in Appendix B). The total takeaway capacity exceeds forecast production and is anticipated to continue based primarily on recent new announced pipelines (Energy Transfer Partners and Enterprise).

Exhibit 4-5: Forecast Bakken Production and Takeaway Capacity, bpd



Sources: North Dakota Pipeline Authority. "Oil Transportation Table." North Dakota Pipeline Authority, October 1, 2014. Available at: http://northdakotapipelines.com/oil-transportation-table/. ICF International. "The Impacts of U.S. Crude Oil Exports on Domestic Crude Production, GDP, Employment, Trade, and Consumer Costs." The American Petroleum Institute (API), 31 March 2014: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/LNG-primer/API-Crude-Exports-Study-by-ICF-3-31-2014.pdf

Note: Chart assumes one year delay to 2017 for Keystone XL, and assumes all pipelines are fully utilized (this was not the case in 2013 so actual rail shipments were greater than shown on the table). No new Bakken sourced pipelines after KXL are assumed (or in planning).

The bulk of U.S. railcar movements have originated in the Bakken, hence the assumptions on future movements by rail from this region are important to the demand for railcars. The North Dakota Pipeline Authority estimated roughly 700,000 barrels per day of crude was moved from the Bakken/Williston basin by rail in 2013.[27] The U.S. total was roughly 775,000 barrels per day (407,000 railcar loadings).[28] ICF examined EIA data to determine where the bulk of the rail movements in 2013 were destined.

While EIA does not publish inter-PADD rail movements, it is possible to estimate crude by rail movements to PADD Districts by subtracting regional crude production and PADD-to-PADD crude oil movements via pipeline, tanker, and barge from the region's total domestic crude

[27] North Dakota Pipeline Authority. "Estimated North Dakota Rail Export Volumes." North Dakota Pipeline Authority, 15 October 2014: Bismarck, ND. Available at: https://ndpipelines.files.wordpress.com/2012/04/nd-rail-estimate-10-15-2014.jpg

[28] Association of American Railroads (AAR) Bureau of Explosives. "AAR reports crude oil traffic up for 2013, week 10 traffic remains mixed." AAR, 13 March 2014. Available at: https://www.aar.org/newsandevents/Press-Releases/Pages/2014-03-13-railtraffic.aspx

receipts. This calculation indicates that East Coast refinery receipts of domestic crude oil by rail were roughly 460,000 barrels per day (bpd) in the first half of 2014, and movements to PADD 3 and 5 about 316,000 barrels per day and 186,000 barrels per day respectively. [29] The estimation method shows a compelling trend to higher rail movements from 2012 to all regions, primarily PADD 1, as shown on Exhibit 4-6.

Exhibit 4-6: Crude Oil Supply Adjustments

Year	Estimated Railcar Movements from PADD 2 (TBD)			
	PADD 1	PADD 3	PADD 5	Net In
2012 1H	(27)	149	36	158
2012 2H	72	227	82	381
2013 1H	232	356	106	695
2013 2H	291	311	114	716
2014 1H	461	316	186	963

Source: U.S. Energy Information Administration. "Petroleum Supply Monthly." EIA, September 29, 2014: Washington, DC. Available at: http://www.eia.gov/petroleum/supply/monthly/

These numbers show that PADD 1 rail deliveries have grown consistently over the period. Also, these numbers will exclude any Bakken crude delivered wholly by rail through Canada to Irving Oil in New Brunswick (which has received both U.S. and Canadian Bakken).

The overall "net in" numbers, however, make sense with what appears to be happening in the market. For example:

- PADD 1 refiners are using more and more Bakken as rail unloading infrastructure has been added. Rail terminals in Albany are seeing unit train deliveries and then movements out by barge to East Coast refiners and vessels to Canada. Philadelphia area refiners and in Delaware and New Jersey have added both rail and barge receiving capability on site and through third party facilities.

- As PADDs 1 and 5 have ramped up, PADD 3 rail movements seem to be stable. Increased shipments of light crude from the Permian, and pipelines from Cushing into the U.S. Gulf Coast may be tempering rail movements into PADD 3 (but more rail will likely come into PADD 3 from Canada as increased heavy Canadian may need to move into the U.S. Gulf Coast to find a market as aforementioned Canadian supply grows)

- Rail movements have steadily increased into PADD 5 – primarily to Puget Sound refiners who have added rail unloading facilities. There are a number of additional rail offloading sites on the West Coast in the permitting process, so potential may exist for significantly more volume. It is possible some movement may also be taking place from West Texas into California, but this has not been confirmed.

[29] EIA Publication, "This Week in Petroleum", April 30, 2014

- The total volume in 2013 (roughly 700,000 barrels per day) is very consistent with the North Dakota Pipeline estimates of crude by rail from the Bakken region, and comprises a very high percentage of the 407,000 railcar loadings in 2013 cited by AAR (about 775,000 barrels per day).[30] Thus, we believe a very high percentage of total domestic crude rail movements originate in the Bakken.

As a result of the continued increases in demand for Bakken crude on the East Coast, and with strong potential for growth into PADD 5 (dependent on permitting of multiple crude by rail to tanker terminals in Washington State), ICF believes that incremental Bakken production will continue to be moved more by rail than pipeline.

[Please see Appendix E for an analysis of Crude Rail Unloading capacity in the U.S., which was done to assure that additional shale movements can be received in destination markets. Also, Appendix F includes an analysis of the delivered cost of Bakken crude to PADD 1 refiners versus Nigerian crude, which indicates that economics continue to support receipt of domestic crude versus foreign sweet.]

Niobrara, Permian and Eagle Ford Movement by Rail Outlook

This study assumed incremental production from the Niobrara would move 40% by rail, with incremental Permian production increasing from an estimated 1% in 2014 to 6% of production by rail by 2017 (it was assumed pipeline capacity would grow quickly to match further Permian production growth).

The study assumes that no rail movements would occur from the Eagle Ford Basin. These assumptions are identified in Exhibit 4-7 below. It should be noted that the actual evolution of railcar movements may certainly involve more volumes of Eagle Ford and Permian crude than this study assumes, as well as crudes from other tight oil basins which may emerge, or new areas such as the Uinta Basin. Conversely, Bakken movements by rail may be less than forecast if Bakken volumes by pipeline are at a higher percentage than assumed in the study. Overall, the forecast growth in U.S. crude production is likely to continue to rely heavily on rail.

[30] Association of American Railroads (AAR) Bureau of Explosives. "AAR reports crude oil traffic up for 2013, week 10 traffic remains mixed." AAR, 13 March 2014. Available at: https://www.aar.org/newsandevents/Press-Releases/Pages/2014-03-13-railtraffic.aspx

Exhibit 4-7: Assumed Proportion Moved by Rail

Year	Assumed Proportion Moved by Rail (%)			
	Bakken	Niobrara	Permian	Eagle Ford
2013	63%	40%	1%	0%
2014	63%	40%	2%	0%
2015	63%	40%	4%	0%
2016	63%	40%	5%	0%
2017	63%	40%	6%	0%
2018	63%	40%	6%	0%
2019	63%	40%	6%	0%
2020	63%	40%	6%	0%
2021	63%	40%	6%	0%
2022	63%	40%	6%	0%
2023	63%	40%	6%	0%
2024	63%	40%	6%	0%

Source: ICF

4.3.3 Canadian Rail Outlook

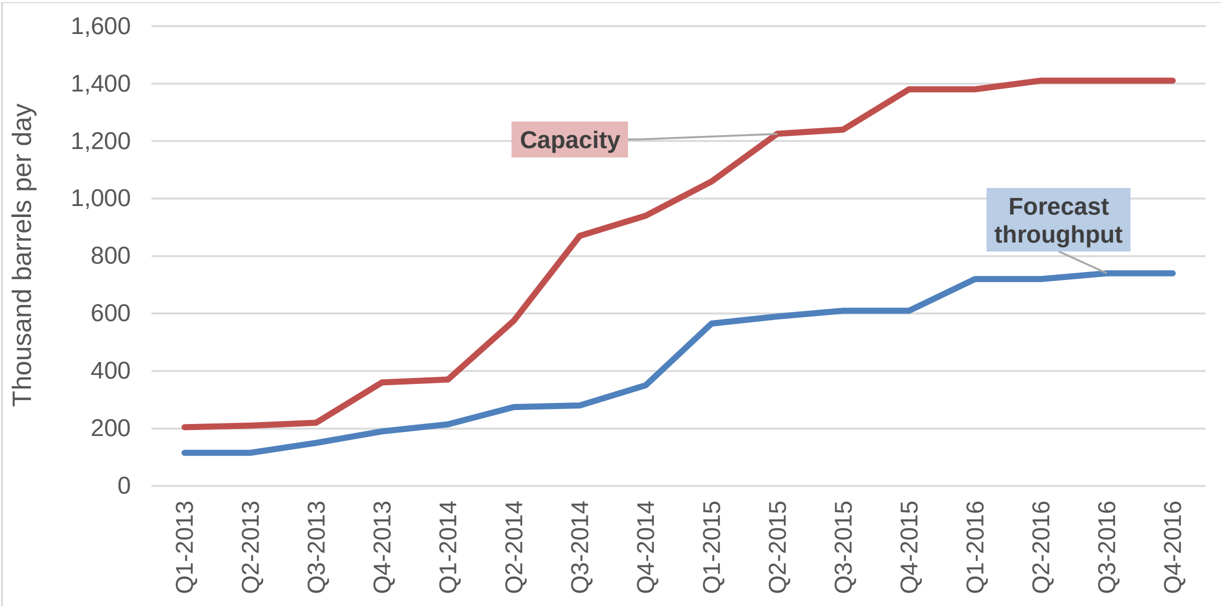
Western Canada railcar loadings increased from 100,000 bpd in early 2013 to 200,000 bpd by year end[31]. CAPP forecasts the railcar loadings will increase to 400,000 bpd by year end 2014, 600,000 bpd early in 2015, and 700,000 bpd in 2016. Initial data from Statistics Canada indicate this trend is already starting. Assuming the bulk of these movements initially are dilbit at about 600 barrels per railcar, the increased volume of 400,000 bpd by early 2015 would require 667 cars loaded daily.

With a likely destination market of the U.S. Gulf Coast, a cycle time of 18 days (16 for transit and 2 for loading/unloading) would result in a need for about 12,000 additional railcars to move the additional 400,000 bpd growth from the end of 2013 to early 2015.[32] AllTranstek has indicated that over two-thirds of the orders for new crude railcars are for Canadian service – corroborating the anticipated increased Canadian shipments. The exhibit below reproduces the CAPP crude by rail forecast.

[31] CAPP March 2014 Crude by Rail Forecast http://www.capp.ca/getdoc.aspx?DocId=242427

[32] 400,000 bpd/600 bbl/car = 667 cars loaded daily. Assume 100 cars per train and 18 days cycle time: 667 cars daily * 18 days cycle time is 12,006 cars required.

Exhibit 4-8: Western Canada Rail Capacity vs. Throughput Forecast



Source: The Canadian Association of Petroleum Producers (CAPP). "Transporting Crude Oil by Rail in Canada." CAPP, March 2014: Calgary, AB. Available at: http://www.capp.ca/getdoc.aspx?DocId=242427&DT=NTV

ICF utilized the CAPP Rail forecast to reflect increasing railcar demands for Canadian crude. The CAPP volumes were assumed to be dilbit; however, it is reasonable to assume that there may be some raw bitumen, railbit and conventional crudes moved by rail. For the study, we assumed volumes moved in 2014 were all dilbit, and beginning in 2015 volumes were half dilbit and half railbit (the railbit volumes were adjusted to reflect only 15% diluent versus 30% in dilbit). This assumption was made to recognize that producers and refiners may move toward more railbit to minimize overall transport costs, although railbit cars can hold fewer barrels of crude)

For cases where Keystone XL was assumed to not be operational by 2017, this study increased rail movements by 200,000 bpd in 2017, 300,000 bpd in 2018 and 200,000 bpd in 2019, for a total of 700,000 bpd (we also assumed a 50/50 mix of dilbit and railbit based on bitumen content, not 50/50 mix of carloads).

Ethanol and Other Flammable Liquids Railcar Demand Estimates

Ethanol: Ethanol is blended with gasoline blendstocks in a 90/10 ratio (gasoline blendstock/ethanol) to satisfy EPA regulations for gasoline. The distribution of ethanol is primarily via railcar movements from the Midwest, in addition to truck movements from Midwest and regional ethanol plants to distribution terminals. Ethanol is categorized as a "Packing Group 2" commodity within Class 3 flammables and, therefore, must be moved on new or retrofitted railcars no later than October 1, 2018 according to the PHMSA proposed rules. According to 2012 Waybill data, ethanol is transported long distances to distribution hubs, but also shorter distances by rail from distribution hubs to other smaller hubs. Over 300,000 railcars were loaded with ethanol in 2012 and moved to regional hubs, with a total volume loaded of 581,633 barrels per day.[33]

There is no clear indication that gasoline demands are going to increase (which would raise ethanol demands), nor is there compelling evidence that increased ethanol blends in gasoline (E-15, E-85) will occur in the foreseeable future. Additionally, ethanol markets are likely going to remain geographically similar to 2012 (high gasoline demands on the East and West Coast, etc.). Therefore, the model assumes that ethanol railcar demands over the study period will mirror the 2012 data

<u>Other Flammable Liquids</u>: Other than crude oil and ethanol, which accounted for over 70% of Class 3 commodities moved by rail in 2013, the remaining commodities are called “other flammable liquids”. These products include some normal refined product (gasoline, diesel, jet) as well as a number of petrochemical feedstocks and refinery by-products (methanol, toluene, xylene, styrene monomer, benzene, vinyl acetate and many more). These volumes totaled 547,733 barrels per day loaded on railcars in 2012[34]. Virtually all of these products are also Packing Group 2 and hence would require all railcars to be either new or retrofitted by October 1, 2018 according to the PHMSA proposed rules.

This category of commodities is involved in either directly supplying regional terminals with refined product, or in the movement of chemical products or feedstocks between manufacturing facilities and chemical plants. For the purposes of this study, ICF assumed that the Other Flammable Liquids logistics patterns would remain identical to 2012 over the study period, and hence the 2012 railcar demand numbers were used in ICF’s model.

For both ethanol and other flammables liquids, any increase in demands over the study period would further constrain railcar supply.

4.3.4 Railcar Demand Summary

Exhibit 4-9 details the year-by-year railcar demand assumptions used in the ICF model for each type of commodity based on the analysis in this section of the report. The exhibit shows the assumptions for both a “with Keystone XL” and “without Keystone XL” case.

Denial of Keystone XL is estimated to add another 640,000 bpd crude by rail (350,000 dilbit and 290,000 railbit). Total crude by rail is assumed to increase from about 900,000 bpd in 2013 to 2.1 MMbpd by 2017 and 2.3 MMbpd by 2019 (and 2.9 MMbpd in 2019 if Keystone XL is denied).

[33] Derived from pp 5-7 from the Association of American Railroads (AAR) Bureau of Explosives. “Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail.” AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf

[34] Derived from pp 5-7 from the Association of American Railroads (AAR) Bureau of Explosives. “Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail.” AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf

Exhibit 4-9: Rail Transportation Demand by Product

Year	Railcar Demand (bpd)					
	Crude PG1	Crude Dilbit PG2	Crude Railbit PG2	Ethanol PG2	Other Flammable Liquids PG2	Other Flammable Liquids PG3
With KXL						
2014	963,179	280,000	0	581,633	547,773	0
2015	1,136,601	296,875	244,485	581,633	547,773	0
2016	1,279,955	365,000	300,588	581,633	547,773	0
2017	1,422,991	370,000	304,706	581,633	547,773	0
2018	1,534,821	370,000	304,706	581,633	547,773	0
2019	1,618,161	370,000	304,706	581,633	547,773	0
2020	1,700,204	370,000	304,706	581,633	547,773	0
2021	1,740,551	370,000	304,706	581,633	547,773	0
2022	1,770,278	370,000	304,706	581,633	547,773	0
2023	1,786,620	370,000	304,706	581,633	547,773	0
2024	1,797,394	370,000	304,706	581,633	547,773	0
Without KXL						
2014	963,179	280,000	0	581,633	547,773	0
2015	1,136,601	296,875	244,485	581,633	547,773	0
2016	1,279,955	365,000	300,588	581,633	547,773	0
2017	1,422,991	470,000	387,059	581,633	547,773	0
2018	1,534,821	620,000	510,588	581,633	547,773	0
2019	1,618,161	720,000	592,941	581,633	547,773	0
2020	1,700,204	720,000	592,941	581,633	547,773	0
2021	1,740,551	720,000	592,941	581,633	547,773	0
2022	1,770,278	720,000	592,941	581,633	547,773	0
2023	1,786,620	720,000	592,941	581,633	547,773	0
2024	1,797,394	720,000	592,941	581,633	547,773	0

Source: ICF analysis based on industry data. Association of American Railroads (AAR) Bureau of Explosives. "Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail." AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf. Canadian Association of Petroleum Producers (CAPP). "Transporting Crude Oil by Rail in Canada." CAPP, March 2014. Available at: http://www.capp.ca/getdoc.aspx?DocId=242427. Kringstad, Justin. Presentation at the Platts Rockies Oil & Gas Conference. Platts, 14 April 2014: Denver, CO. Available at: http://ndpipelines.files.wordpress.com/2012/04/kringstad-platts-april-14-2014.pdf.

Exhibit 4-10 compares the ICF crude forecast estimate with the PHMSA estimate presented in the Regulatory Impact Assessment[35]. The PHMSA forecast appears to reflect U.S. railcar movements only, and shows railcar loadings per year from 2015 to 2034. ICF converted the PHMSA railcar loadings to barrels per day to develop the chart in Exhibit 4-10.[36]

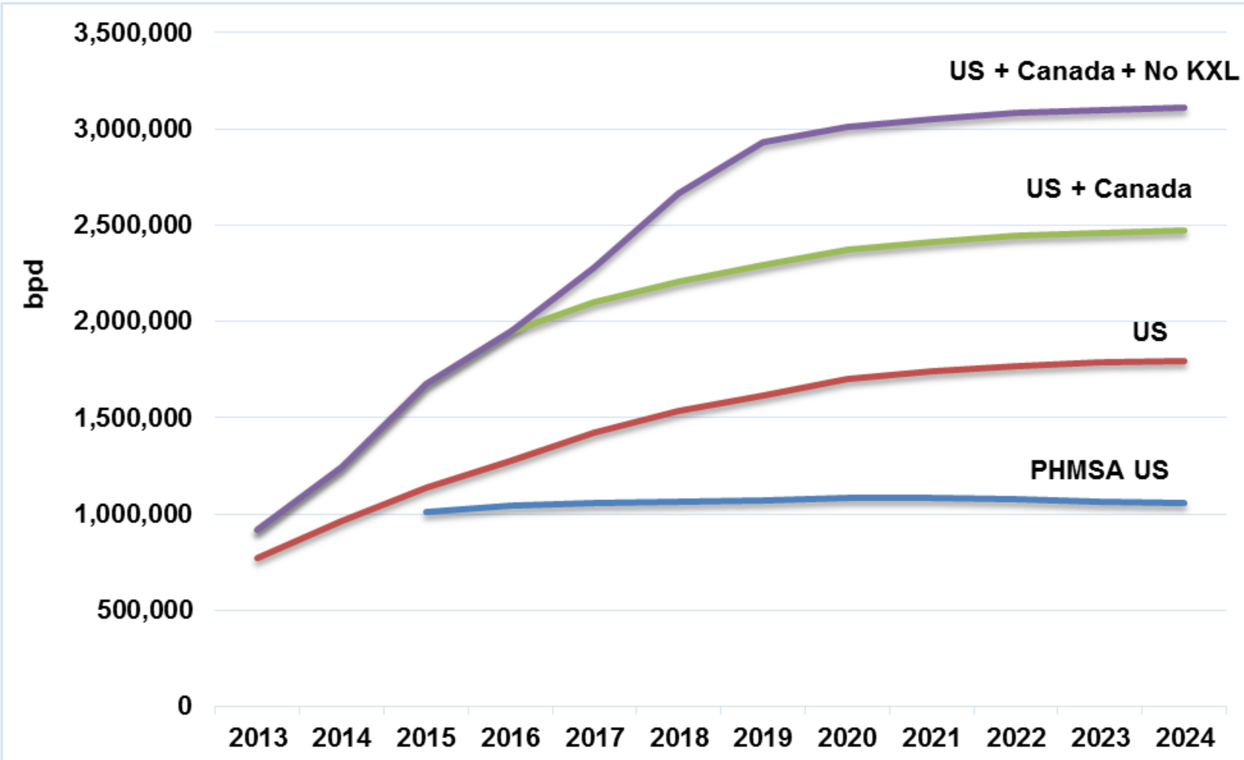
The PHMSA analysis does not appear to recognize the continued growth for domestic crude movements by rail beyond 2015, nor does it recognize the need for continued growth of

[35] RIA, page 36 presents PHMSA crude railcar loadings per year beginning in 2015.

[36] ICF assumed 695 barrels per railcar.

Canadian crude rail movements on North American railcar demand (including the demand in new build shops and retrofit shops). Finally, the impact of a Keystone XL denial is also not considered.

Exhibit 4-10: Crude Oil by Rail Transportation Forecasts



Source: ICF model output based on defined assumptions. PHMSA. "Draft Regulatory Impact Analysis (RIA)." Docket No. PHMSA-2012-0082, HM-251. DOT, July 2014. P. 36.

4.3.5 Efficiency of Railcar Movements

Based on total volume of crude loaded in 2013 and estimated available railcars, this study developed an efficiency factor for the average number of barrels of crude moved per car per year (b/c/y). The factor is slightly different for Dilbit and Railbit compared to shale crude due to lower cargo volume per railcar. A similar assessment was made for ethanol and other flammable cars based on 2012 Waybill data.[37] This study assumed that the efficiency will remain the same over the study period (crude could potentially have a higher efficiency factor if all incremental crude demand is met by unit trains). These data provide the model with a mechanism to optimize the use of the qualified railcar fleet (new and retrofitted capacity) given the demand outlook for the commodities.

To construct the efficiency factor, data on rail movements were needed. The baseline 2013 crude oil rail movements were derived from the AAR-stated data that 407,000 railcars of

[37] Surface Transportation Board. "2012 Public Use Waybill Sample." Surface Transportation Board, 2014: Washington, D.C. Available at: http://www.stb.dot.gov/stbpdocs/Waybill/PublicUseWaybillSample2012.zip

crude oil were loaded in 2013 in the U.S.[38] Canadian railcar loadings in 2013 (and forecast out to 2017) were estimated by CAPP.[39] The railcar movements for ethanol and other flammables were based on 2012 Waybill data.[40] This study assumed that ethanol and other flammable railcar loadings would stay consistent over the study period with 2012 data. This assumption was judged reasonable, given that gasoline demands are projected to be flat and ethanol growth in the gasoline pool has not materialized (E15, E85, etc.). In addition, other flammable movements are primarily transportation fuels (mainly Canada) and petrochemicals (methanol, benzene, styrene monomer, etc.), for which this study assumed stable demand. An argument could be made that growth in the petrochemical business due to low cost feedstocks from shale gas could occur, in which case the analysis would understate the demand for railcars.

Exhibit 4-11: Railcar Efficiency Assumptions

Year	Railcar Efficiency (bbl/car/year)					
	Crude PG1	Crude Dilbit PG2	Crude Railbit PG2	Ethanol PG2	Other Flammable Liquids PG2	Other Flammable Liquids PG3
2014	10,907	10,585	10,000	7,148	8,019	8,019
2015	10,907	10,585	10,000	7,148	8,019	8,019
2016	10,907	10,585	10,000	7,148	8,019	8,019
2017	10,907	10,585	10,000	7,148	8,019	8,019
2018	10,907	10,585	10,000	7,148	8,019	8,019
2019	10,907	10,585	10,000	7,148	8,019	8,019
2020	10,907	10,585	10,000	7,148	8,019	8,019
2021	10,907	10,585	10,000	7,148	8,019	8,019
2022	10,907	10,585	10,000	7,148	8,019	8,019
2023	10,907	10,585	10,000	7,148	8,019	8,019
2024	10,907	10,585	10,000	7,148	8,019	8,019

Source: ICF analysis of historical trends

4.3.6 Alternatives to Rail Transport for Crude, Ethanol, and Other Flammable Liquids

As crude movements by rail grow, the proposed PHMSA regulation requires all domestic tight oil to be moved in retrofitted or new railcars by October 1, 2017 (Packing Group 1), and all other crude, including Canadian dilbit and railbit (Packing Group 2) to be moved in new or retrofitted railcars by October 1, 2018 (this is the same time as all ethanol and other flammable movements must be in new or retrofitted cars).

[38] Association of American Railroads (AAR) Bureau of Explosives. "AAR reports crude oil traffic up for 2013, week 10 traffic remains mixed." AAR, 13 March 2014. Available at: https://www.aar.org/newsandevents/Press-Releases/Pages/2014-03-13-railtraffic.aspx

[39] The Canadian Association of Petroleum Producers (CAPP). "Transporting Crude Oil by Rail in Canada." CAPP, March 2014: Calgary, AB. Available at: http://www.capp.ca/getdoc.aspx?DocId=242427&DT=NTV

[40] Surface Transportation Board. "2012 Public Use Waybill Sample." Surface Transportation Board, 2014: Washington, D.C. Available at: http://www.stb.dot.gov/stbpdocs/Waybill/PublicUseWaybillSample2012.zip

This situation creates significant stress on the supply of rail tank cars for all commodities. With insufficient railcar capacity to move all the Class 3 commodities with retrofitted or new cars, there are alternative options that may be considered to move these commodities at higher cost, or potentially to have crude producers shut in crude production. This section discusses the alternative options utilized in the model for the impacted commodities.

Crude Alternatives:

U.S.

1. Use existing spare pipeline capacity from the Bakken. Current infrastructure has spare pipeline capacity, and this may continue to exist in future years. Pipeline movements would not be able to move crude to East or West Coast refiners, and would likely result in a depression of Bakken as well as WTI prices as more shale crude would move into the Gulf Coast than might otherwise be economic. The pipeline cost itself would be on an uncommitted[41] basis, and the total costs could be about equivalent to rail costs. In addition, loss of Bakken to East and West Coast refiners could threaten their economic stability and increase foreign imports, likely at a cost of up to $5/barrel more. ICF estimates that producers may need to lower wellhead value by about $4 per barrel to make the additional Bakken more attractive to Gulf Coast refiners.

2. Use trucks. Crude moves by truck in the Bakken to gathering points for railcar loading, and on occasion moves Bakken into Canada for pipeline inputs. However, with a significant shortage of railcars, trucks may need to be used on a massive scale to move Bakken. One option may be to move the crude to the Minneapolis region where it may be able to be loaded on barges and sent to the Gulf Coast. This may have limited capacity; alternatively trucks can move the crude to refiners directly in Puget Sound or the St. Louis area, or to distribution hubs such as Cushing, OK (where pipelines can access Gulf Coast refiners). The truck movements are all roughly 1,200 miles (except Minneapolis) and would cost about $23 above the alternative rail cost[42] to get to the Gulf Coast (about $4/barrel lower to get to Puget Sound refiners). We estimate about 50,000 barrels per day could move by truck/barge, and perhaps 250,000 barrels per day by longer haul truck.

3. Beyond this, we believe the price of Bakken at the wellhead may become so low that producers will need to shut in production at an even higher opportunity cost.

Canadian

Canadian oil sands crude has fewer options than domestic shale crude. ICF assumed that pipelines in Canada into the U.S. would be at capacity. With railcars limited, trucks moving from

[41] Uncommitted tariffs are higher than tariffs for committed parties who agree to long term use of the pipeline well before the pipeline is operational.

[42] The rail movement would be to Cushing, Oklahoma where the crude would then move by pipeline to the Gulf Coast. The $23 reflects the total cost of rail plus pipeline.

Edmonton or Hardisty would need to carry the crude to Cushing or Houston at costs as much as $45 per barrel above rail transport cost. Given the heavy, high sulfur quality of most of the oil sands, it is possible this alternative may not be viable and may precipitate some producers to shut in production due to very low net backs. With no pipeline alternatives, and no marine capability from the oil sands regions, it is likely reduced railcars will impede Canadian oil growth.

In the event Keystone XL is not approved for construction, the need to move crude by rail from Canada may double, as Keystone is expected to move almost 700,000 barrels per day of oil sands crude.

Ethanol Transport Alternatives

Over 300,000 railcars were loaded with ethanol in 2012 and moved to regional hubs, with a total volume loaded of 581,633 bpd.[43] Ethanol typically moves by truck from the major rail distribution hubs to regional terminals where ethanol is blended with gasoline blendstock for delivery to service stations.

In the event of a disruption in railcar availability, it is likely several events could occur in the ethanol market:

1. Refiners could see reduced ethanol availability at their nearby regional hubs and could attempt to arrange trucking from the Midwest manufacturing plants or better supplied regional hubs.
2. The railcar shortages could bid up the market cost of ethanol at the regional hubs, which could be necessary to cover the marginal cost of truck transport. ICF estimates this market cost increase could be as high as 50 cents per gallon of ethanol to reach high gasoline demand coastal areas.[44] In addition, railcar shortages will raise the cost of rail transport as tank car lease rates could increase significantly.
3. Assuming trucks are available (which may or may not be the case), ethanol producers may still be able to get a reasonable netback price at the ethanol plant gate, but refiners could see a much higher cost for fuel.
4. Since the situation under the PHMSA regulatory proposal (based on model results) is likely to persist for several years, refiners may also seek imported ethanol barrels to help reduce their cost of supply. The economics of ethanol imports depends on a number of factors, including the wholesale market prices in the U.S. and Brazil, freight rates, import duties, etc. The market in Brazil is dependent upon whether it is more economical to make ethanol, or produce cane sugar.

[43] Derived from pp 5-7 from the Association of American Railroads (AAR) Bureau of Explosives. “Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail.” AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf

[44] This level spike occurred in 2006 as the ethanol mandate was put in place and limited access to ethanol drove prices up substantially over wholesale gasoline price and triggered imports.

5. The multiple variables make it difficult to forecast the outcome for this study, however, the outcomes will be either:
    a. If higher ethanol costs are passed through to the terminal loading racks, the annual impact to consumers could exceed $6.6 billion.[45] This is the assumption employed in this study.
    b. If imports are economic, the additional supply exogenous to the U.S. market could push ethanol prices back down to some degree but this would force U.S. ethanol plants to reduce production. This could make ethanol plants uneconomic and threaten U.S. manufacturing and farm-related jobs. This could also reduce the demand for trucking but at the expense of the U.S. ethanol industry as well as the farmers growing corn to meet ethanol demand.
6. In addition to the threat of higher costs and/or loss of jobs, there is the risk that ethanol may not be physically available if railcars are not accessible. Access to trucks may be problematic (especially since they will also be in demand for crude and other flammables), and failure to have ethanol available to blend into the gasoline blendstock could leave some distribution terminals periodically with no merchantable gasoline to load onto trucks for service stations.[46]
7. Ethanol has very limited options to move by alternative means than rail or truck. It cannot move in pipelines due to technical issues[47], and there are no marine pathways from the Midwest production region to the East or West Coast.

<u>Other Flammable Liquids Transport Alternatives</u>

Other than crude oil and ethanol, which accounted for over 70% of Class 3 commodities moved by rail in 2013, the remaining commodities are called “other flammable liquids”. These products include some normal refined product (gasoline, diesel, jet) as well as a number of petrochemical feedstocks and refinery by-products (methanol, toluene, xylene, styrene monomer, benzene, vinyl acetate and many more). These volumes totaled 547,733 bpd loaded on railcars in 2012[48]. Virtually all of these products are also Packing Group 2 and hence would require all railcars to be either new or retrofitted by October 1, 2018 according to the PHMSA proposed rules.

This category of commodities is involved in either directly supplying regional terminals with refined product, or in the movement of chemical products or feedstocks between manufacturing facilities and chemical plants. Alternative transportation options would primarily be trucking for

[45] An increase in the price of ethanol of up to $0.50 per gallon could result in an increase of up to $0.05 per gallon in the price of E10. The $6.6 billion in higher consumer costs are calculated as $0.05 times 42 gal/bbl times 8,600,000 bpd gasoline sold times 365 days/yr.

[46] The gasoline blendstock is roughly 84 octane and needs the ethanol to meet octane specs and also key distillation and drivability specifications.

[47] Affinity to water prevents moving ethanol through petroleum product pipelines.

[48] Derived from pp 5-7 from the Association of American Railroads (AAR) Bureau of Explosives. “Annual Report of Non-accident Releases of Hazardous Materials Transported by Rail.” AAR, 2012. Available at: http://www.nar.aar.com/index_21_1824751116.pdf

many of these movements.[49] There is wide variability in origin, destination and travel distance among the different "other flammable liquids" commodities now being shipped by rail:

<u>Gasoline, Diesel and Jet</u> – about 250,000 barrels per day were moved by rail in 2012 in the U.S. and Canada, with Canada having 2/3 of the loadings. Most U.S. product movements to terminals are via pipeline or barge, with a few rail movements (Albany, NY to Burlington VT, for example). In Canada, most terminals are located near refineries in major population centers (Sarnia, Toronto, Montreal etc.). However, there are a number of remote terminals in British Columbia, Saskatchewan, and Ontario with limited or no access to pipelines who receive product by rail. The alternative for these locations will likely either be truck or no supply. This could create some regional price anomalies to attract more truck volumes to these regions at higher cost.

<u>Petrochemicals</u> – about 300,000 barrels per day of other flammable commodities were also transported by rail in 2012. Some of these were unspecified hydrocarbons, but most were petrochemical materials as noted above. For these products, about 70% of the volume was loaded in the U.S. as opposed to Canada and to a lesser degree Mexico. The movement of the petrochemical products is normally most effective by rail. Pipelines are not available and barge movements may be possible for unprocessed feedstocks, but for products such as styrene monomer, xylene, benzene, methanol, etc. contamination may be a concern for barge movements.

Assumptions used in this analysis reflect that as much as 150,000 barrels per day (roughly 25% of the "other flammable liquids" movements) may have the potential to shift to truck at a significant cost penalty versus rail. The displacement of railcars has the potential to seriously impact the flow between refiners and petrochemical facilities, which could lead to reductions in throughput at both facilities to manage inventories if rail movements are not replaced in a timely manner. It is unclear whether refiners or chemical manufacturers may absorb the higher cost of transportation as it may depend on specific supply contracts, the accessibility of alternative feedstock supplies from overseas and market competition for the product. Chemical producers may not be able to pass on the higher costs to intermediate processors or consumers since the producers may face threats from imported specialty products.

If refiners need to shut down chemical extraction facilities (that extract benzene, toluene and xylene from reformate), they may need to export those products or blend them back into gasoline. Reformulated gasoline specifications may make this difficult to do and still make on specification product.

Alternative Transport Cost Summary

Exhibit 4-12 shows the assumptions used in the model for alternative transportation costs by commodity and by mode. The assumption that additional trucking will be available impacts

[49] Barging with marine equipment may be possible in some cases, but these would normally already be in use if more economic or feasible. In addition, for chemical materials product quality integrity and small movement sizes could also be issues that limit the practicality of barging.

crude, ethanol and other flammable alternative costs. While model options include the volumes shown below as possible alternatives, the maximum trucking case evaluated (Option 1, Keystone XL not approved) employs the full 150,000 b/d each of ethanol and other flammable liquids trucking as well as about 133,000 b/d of PG1 crude trucking. This level of shipping Class 3 commodities would require about 6,000 trucks be shifted from other services or be newly built to manage the additional load.

Exhibit 4-12: Alternative Transportation (Shortage Car) Costs and Capacities by Product

Mode	Crude PG1		Crude DB PG2		Crude RB PG2		Ethanol PG2		Other Flam. Liq. PG2		Other Flam. Liq. PG3	
	bpd	$/bbl	bpd	$/bbl	bpd	$/bbl	bpd	$/bbl	bpd	$/bbl	bpd	$/bbl
Pipeline	200,000	$4	Not allowed	-	Not allowed	-	Not allowed	-	Not allowed	-	Not allowed	-
Barge & Truck	50,000	$9	Not allowed	-	Not allowed	-	Not allowed	-	Not allowed	-	Not allowed	-
Truck	250,000	$23	100,000	$46	100,000	$46	150,000	$24	150,000	$24	50,000	$24
Shut-in Production	Unlimited	$28	Unlimited	$29	Unlimited	$29	Unlimited	$100	Unlimited	$100	Unlimited	$100

Source: ICF team analysis of industry sources

In summary, the analysis assumes that any deficiencies in railcar availability could potentially impact all commodities and that different commodities would have alternative costs to either sustain movements to customers or to reduce production. The model shows only that crude oil would be shut-in, as it would be essential that ethanol continue to be delivered to customers, as well as other flammable liquids. There are different cost tiers assigned to crude, ethanol, and other flammable liquids. For example, it may be possible for Bakken crude to move on underutilized pipelines to some degree if railcars were not available (although this could harm refiners on the East and West Coast who have no pipeline alternative). Once the pipelines have been used, then it may be possible to truck crude to a marine destination. Finally, trucking alone may be needed to avoid shut-in losses. Similarly, if ethanol and other flammable liquids no longer have adequate railcars available, it is assumed that truck movements would have to be extended well beyond the normal delivery range at an obviously much higher cost and potential for short supply.

4.4 Other Assumptions

Noted earlier but re-stated here, the proposed regulation indicates that the modified or new railcars must be used on any train with more than 20 cars shipping regulated products. This implies that some railcars may not need conversion. However, it is very unlikely that rail operators will be able to modify train schedules such that only the right kind of cars are available. Hence, the study assumes all railcars must be retrofitted, retired or replaced with new build rail cars.

5 Key Study Findings

In the event that regulations are implemented as currently proposed, the regulations will increase the cost to transport crude and other Class 3 commodities above the BAU case. The study indicates that the degree of cost can vary based on the stipulations in the regulation, primarily regarding the retrofit timing and the assumed limitations in railcar shop retrofitting and new build capacity. If new standards could be aligned with the ability of the rail industry to retrofit existing railcars and build railcars to the new standards while meeting the added demands from increased crude production, the overall compliance costs and cost to the U.S. and Canadian economies would be reduced.

5.1 Petroleum Transport and Cost Impacts of PHMSA Proposed Regulations

This study developed an economic impact model to represent the existing fleet and its normal retirement outlook, retrofit and new build costs and capacities and demands for crude, ethanol and petrochemicals moved by rail over the 2014 to 2024 period ("study period"). The model uses these inputs to determine the optimal economic path to meet the proposed regulations. In the event of insufficient qualified railcars, the model utilizes estimated costs of alternative options (pipeline, trucking, shut-in production, etc.) to reflect how the volume displaced by railcar shortages would be managed. The model outputs are used to estimate the broader U.S. and Canadian economic impacts in terms of changes to consumer costs, GDP effects, and job effects.

ICF's findings indicate that the proposed regulations and timing would not be possible without extensive scrapping of the existing legacy fleet in 2018 and 2019. Cars are scrapped in the forecast when (a) their remaining lives are too short to make retrofits economic, or (b) they cannot be retrofitted before the compliance date due to limits in shop capacity and there is insufficient growth in demand for railcars after the compliance date to make retrofits economically justified at that time.

Overall, the potential ramifications of estimated railcar shortages to the crude, ethanol and other flammable markets are serious, impacting consumers by both higher costs of fuels and possible supply disruptions. Given the parameters in the ICF analysis for retrofit and new build capacities and growing demands for crude by rail movements, the PHMSA proposed deadlines in October 2017 and October 2018 are not feasible without significant costs to consumers and the economy.

Key drivers of the model results include 1) the capacity to retrofit railcars to PHMSA's proposed Option 1, 2 and 3 standards; 2) the cost and time required to perform the retrofits; 3) the capacity to build new tank cars and their costs; and 4) the demand for crude oil movements by rail in the U.S. and Canada over the study period. Some of the assumptions used in this study differ from those used by PHMSA and lead to a more constrained market for tank car services. For example, we have estimated that the capacity to retrofit railcars is lower, that the time and cost required to retrofit are greater, and that the demand for crude by rail service will be substantially higher than PHMSA's assumptions and would be even higher if Keystone XL is denied.[50] The ICF model determines the overall compliance cost to the oil/rail industry to deliver crude, ethanol and other flammables to the market in a "Business as Usual"[51] case as well as the three PHMSA proposed options, all under both a scenario that assumes KXL is approved (and operational in 2017) and a second scenario in which KXL is denied and the demand for transporting crude by rail is higher.

The model results – based on input from the rail industry[52] on retrofit and new build capacity, costs and timing, as well as the outlook for increased demand for crude movements by rail from the U.S. and Canada – indicate that it would not be possible to comply with the proposed regulations timeframe without extensive scrapping of the existing legacy fleet in 2018 and 2019.[53] Furthermore, compliance would entail the displacement of substantial volumes of crude oil, ethanol, and other flammables on to alternative transportation modes – including trucking – for several years until new build capacity for railcars will allow the movement back to normal rail transport. The model results indicate that the cost of retrofitting and the limited capacity to retrofit requires that the number of railcars needed to be scrapped or re-purposed is as shown in Exhibit 5-1.

Exhibit 5-1: Railcars Scrapped/Repurposed

Case	Scrapped or Repurposed Railcars (No.)	
	With KXL	Without KXL
Business as Usual	0[54]	0
Option 1	86,457	83,661
Option 2	84,631	83,682
Option 3	71,482	63,267

Source: ICF team analysis of industry sources

The inability to retrofit railcars in time for the proposed regulation dates requires substantial volumes of crude oil, ethanol, and other flammables to be shifted to alternative, more costly means of transportation or in some cases result in shut-in crude oil production. The degree of impact increases should Keystone XL be denied, which requires an additional 700,000 barrels per day to be moved by rail above the base forecast increase (See Exhibit 5-2).

[50] ICF uses RSI's 7-2-2014 retrofit capacity estimate of 5,700 cars per year after a one year ramp-up, cost estimates –based on PHMSA and RSI estimates of individual enhancements- that are 65% to 160% greater than PHMSA's, and estimates of rail car demand which are roughly larger than PHMSA's by 20,000 railcars in 2015 to 40,000 railcars in 2020 (these figures would be even larger if KXL was not constructed).

[51] The "BAU" case assumes the same growth in demand for crude oil by rail (U.S. and Canada) and the same new build and retrofit capacities and costs and fleet retirements as the option cases, but assumes new railcar demands are met by CPC 1232 jacketed railcars.

[52] Railway Supply Institute (RSI) and AllTranstek

[53] Legacy cars refer to DOT 111 Specifications tank cars. DOT 111 cars comprise the most common type of tank cars currently used in the U.S. and Canada.

[54] Excludes normal retirements over the period

Exhibit 5-2: Total Volumes Displaced by Year, in Thousand Barrels per Day (TBD) and Tank Cars (Cars)

Year	With Keystone XL						Without Keystone XL					
	Option 1		Option 2		Option 3		Option 1		Option 2		Option 3	
	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars	TBD	Cars
2018	177	5,931	162	5,412	200	6,693	250	8,366	250	8,366	144	4,804
2019	530	21,953	467	19,697	198	7,675	1212	46,451	1157	44,379	482	20,359
2020	183	6,131	164	5,477	0	0	454	16,469	396	14,276	178	5,964
2021	0	0	0	0	0	0	85	2,844	5	176	0	0

Source: ICF

Note: This exhibit shows amounts of crude oil and other flammable liquids that were expected to be transported by rail in the U.S. and Canada that will have to be transported by other means (or not produced) due to shortages of compliant rail tank cars. It also shows the minimum number of tank cars that would be needed to move those volumes.

The volumes that can no longer be moved by rail are alternatively moved by various means, including some crude by pipeline, but the movements are primarily by truck, including as much as 150,000 barrels per day ethanol and 150,000 barrels per day other flammables in the most constrained year (2019). These volumes, as well as a substantial volume of crude oil, must move long distances by truck to replace rail.

The cost implications of each of these cases is substantial versus a BAU case, which is based on meeting increased crude oil demand from the construction of new CPC 1232 jacketed crude cars. The exhibit below summarizes the annualized cost of each option using cost and timing assumptions for retrofits and new builds and forecast commodity demand growth by rail and displaced volume alternatives developed by this study (See Exhibit 5-3). For example, PHMSA's Option 1 has annualized costs above business as usual of $12.8 billion if KXL is approved and $22.8 billion if KXL is denied.

Exhibit 5-3: 2014-2024 Annualized Costs

Case	Total Annualized Cost (MM$)				Annualized Cost vs BAU (MM$)		
	BAU	Option 1	Option 2	Option 3	Option 1	Option 2	Option 3
Keystone XL Approved	2,131	14,893	13,771	10,193	12,762	11,640	8,062
Keystone XL Denied	3,574	26,392	24,352	14,076	22,818	20,778	10,502

Source: ICF modeling results

Note: This exhibit shows the costs of new and retrofitted rail tank cars and, when needed, alternative modes of transportation or the opportunity cost of shutting in production of crude oil. The cost of new and retrofitted tank cars are "annualized" or spread out over the remaining lives of the cars. This exhibit shows such annualized costs summed only over the years 2014 to 2024 for the U.S. and Canada.

5.2 Impact of PHMSA Proposed Regulations on U.S. and Canadian Oil Prices, GDP, and Employment

The proposed regulations will have multiple impacts on the broader U.S. and Canadian economies. The impacts stem from increased rail transportation costs for crude oil, ethanol and other flammables, and a shift from rail transportation to much more expensive trucking costs and/or periods of shut-in crude, particularly in the critical 2018-2019 period when the proposed regulations begin to require use of new or retrofitted railcars. The shift is required due to the inability to retrofit the existing fleet in time due to limited shop capacity and the time to complete retrofits. The situation will be significantly worse if the Keystone XL pipeline is not approved, as this will require an additional 700,000 barrels per day, intended to be moved by pipeline, to be added to the crude by rail demand.

The higher transport costs for crude could reduce producer netbacks at the wellhead and reduce the incentives to invest in new productive capacity for crude oil. The resulting lower productive capacity, combined with possible transport bottlenecks that may force shut in of productive capacity for some period of time, reducing U.S. and Canadian oil production. Lower U.S. and Canadian oil production could, in turn, put upward pressure on world oil prices, which could be one source of higher costs for U.S. and Canadian consumers.

The exhibit below show the expected changes to U.S. and Canadian oil production in barrels per day. The highest impact occurs in 2019 when the combined U.S. and Canadian production declines by as much as 613,000 barrels per day. These reductions in production adversely affect U.S. and Canadian GDP and jobs and they put upward pressure on world oil prices, which the ICF modeling suggests could go higher by as much $1.35/bbl in the peak impact year.

Exhibit 5-4: 2015-2024 U.S. and Canadian Crude Oil Production Changes

Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
	U.S. Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(1,693)	(3,191)	(7,870)	(17,552)	(26,483)	(31,566)	(34,097)	(35,094)	(34,114)	(21,296)	(191,660)
Option 2	-	(1,693)	(3,191)	(7,870)	(13,630)	(19,236)	(22,686)	(24,313)	(24,874)	(24,767)	(15,807)	(142,260)
Option 3	-	-	-	(3,880)	(9,222)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	(12,378)	(86,644)
Without Keystone XL												
Option 1	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	(46,412)	(417,705)
Option 2	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	(46,412)	(417,705)
Option 3	-	-	-	(3,880)	(9,176)	(16,234)	(21,024)	(23,355)	(24,385)	(23,605)	(17,380)	(121,659)
Case	Canadian Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(2)	(38,028)	(41,230)	(34,626)	(21,927)	(4,173)	(3,164)	(2,129)	(1,243)	(16,280)	(146,522)
Option 2	-	(1)	(27,660)	(30,021)	(21,421)	(21,395)	(3,214)	(2,440)	(1,641)	(953)	(12,083)	(108,746)
Option 3	-	(1)	(18,675)	(20,497)	(10,498)	-	-	-	-	-	(12,418)	(49,671)
Without Keystone XL												
Option 1	-	(92)	(44,998)	(73,083)	(578,996)	(165,886)	(33,453)	(7,250)	(4,843)	(2,798)	(101,267)	(911,399)
Option 2	-	(93)	(44,998)	(73,082)	(523,160)	(145,681)	(31,070)	(4,697)	(3,121)	(1,801)	(91,967)	(827,703)
Option 3	-	(1)	(27,721)	(30,128)	(21,518)	(21,540)	(3,391)	(2,533)	(1,678)	(966)	(12,164)	(109,476)
Case	U.S. + Can. Oil Production Changes (bpd)											
With Keystone XL												
Option 1	-	(1,696)	(41,219)	(49,100)	(52,177)	(48,410)	(35,739)	(37,261)	(37,223)	(35,357)	(37,576)	(338,182)
Option 2	-	(1,695)	(30,852)	(37,892)	(35,052)	(40,632)	(25,900)	(26,753)	(26,515)	(25,720)	(27,890)	(251,011)
Option 3	-	(1)	(18,675)	(24,378)	(19,720)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	(15,146)	(136,316)
Without Keystone XL												
Option 1	-	(1,786)	(48,190)	(84,629)	(612,694)	(221,707)	(104,071)	(86,071)	(86,368)	(83,591)	(147,679)	(1,329,107)
Option 2	-	(1,786)	(48,189)	(84,628)	(556,858)	(201,502)	(101,689)	(83,517)	(84,646)	(82,594)	(138,379)	(1,245,409)
Option 3	-	(1)	(27,721)	(34,008)	(30,694)	(37,775)	(24,416)	(25,888)	(26,064)	(24,570)	(25,682)	(231,137)

Source: ICF modeling results

The factors that could lead to higher costs for consumers include higher shipping costs for petroleum products and higher shipping costs for ethanol that will be blended into gasoline. Additionally, higher crude oil costs (see prior paragraph) increase the cost of petroleum products, which can increase consumer costs. Such higher consumer costs reduce spending on non-energy consumer goods and services reducing output and jobs in those sectors. As shown in Exhibit 5-5 below, potential higher consumer costs for the U.S. and Canada for gasoline and other petroleum products are estimated to be in the range of $14.4 to $22.8 billion in the 2015 to 2024 period in the scenario where Keystone XL is approved. In the scenario where Keystone XL is not approved, constraints on crude, petroleum products and ethanol are more severe and so potential U.S. and Canadian consumer cost are estimated to increase even more to the range of $21.0 to $45.2 billion.

Exhibit 5-5: 2015-2024 U.S. and Canadian Consumer Cost Changes versus BAU

Case	2015-2024 Consumer Cost Changes ($ Billion)					
	With Keystone XL			Without Keystone XL		
	U.S.	Canada	Total	U.S.	Canada	Total
Option 1	$17.8	$5.0	**$22.8**	$37.6	$7.6	**$45.2**
Option 2	$16.6	$4.8	**$21.4**	$36.4	$7.5	**$43.9**
Option 3	$12.5	$1.9	**$14.4**	$16.4	$4.6	**$21.0**

Source: ICF modeling results

Note: This exhibit shows the higher cost of gasoline and petroleum products paid by U.S. and Canadian consumers over the period 2015 to 2024. These higher costs reflect higher world oil prices (due to lower U.S. and Canadian crude production), higher costs to move petroleum products to rail-dependent consumer markets and the higher cost of moving ethanol to consumer markets.

The net effect on U.S. and Canadian GDP tends to be negative in that gains in some sectors (railcar construction and retrofits, oil pipeline services, barging and trucking) are offset by reductions in others (crude oil production and non-energy consumer goods). Likewise the effect on employment tends to be negative over the entire period. Job gains in railcar construction and retrofits are estimated to occur in the early years, but are overtaken by job losses when the higher transport costs and constraints are fully felt. The net U.S. and Canadian GDP and job effects are shown in Exhibit 5-6 and Exhibit 5-7 for a multiplier effect of 1.3 (representing a tight economy with little slack) and a multiplier effect of 1.9 (representing a looser economy with available labor and capital that can accommodate economic expansion). The net GDP impacts are mostly negative due to lost production of oil and reach $20.3 billion per year in the peak year under the no-KXL scenario. Peak net job losses could be as high as 97,000 jobs in the no-KXL scenario and occur in oil production and non-energy consumer goods.

Exhibit 5-6: 2015-2024 U.S. and Canadian GDP Changes

Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
	Lower-Bound U.S. + Can. Oil GDP Changes ($ Million, multiplier effect=1.3)											
With Keystone XL												
Option 1	($9)	($676)	($2,537)	($2,818)	($2,947)	($2,864)	($2,658)	($2,725)	($2,787)	($2,773)	($2,279)	($22,794)
Option 2	($8)	($641)	($2,201)	($2,459)	($2,445)	($2,512)	($2,245)	($2,281)	($2,322)	($2,324)	($1,944)	($19,438)
Option 3	($20)	($99)	($1,132)	($1,788)	($1,715)	($1,501)	($1,528)	($1,543)	($1,559)	($1,577)	($1,246)	($12,462)
Without Keystone XL												
Option 1	($10)	($621)	($2,512)	($3,534)	($13,891)	($6,485)	($4,307)	($4,047)	($4,172)	($4,181)	($4,376)	($43,760)
Option 2	($8)	($587)	($2,410)	($3,412)	($12,673)	($5,956)	($4,126)	($3,857)	($3,995)	($4,017)	($4,104)	($41,041)
Option 3	($20)	($59)	($1,391)	($1,989)	($1,949)	($2,040)	($1,794)	($1,838)	($1,878)	($1,853)	($1,481)	($14,811)
Case	Upper-Bound U.S. + Can. Oil GDP Changes (million U.S. dollars per year, multiplier effect=1.9)											
With Keystone XL												
Option 1	($13)	($988)	($3,708)	($4,118)	($4,307)	($4,186)	($3,884)	($3,983)	($4,074)	($4,052)	($3,331)	($33,313)
Option 2	($12)	($937)	($3,217)	($3,594)	($3,573)	($3,672)	($3,281)	($3,334)	($3,394)	($3,397)	($2,841)	($28,411)
Option 3	($29)	($144)	($1,655)	($2,613)	($2,507)	($2,194)	($2,234)	($2,255)	($2,279)	($2,304)	($1,821)	($18,214)
Without Keystone XL												
Option 1	($15)	($907)	($3,671)	($5,165)	($20,303)	($9,478)	($6,294)	($5,915)	($6,098)	($6,111)	($6,396)	($63,957)
Option 2	($12)	($858)	($3,522)	($4,987)	($18,522)	($8,705)	($6,030)	($5,638)	($5,839)	($5,871)	($5,998)	($59,984)
Option 3	($29)	($87)	($2,033)	($2,906)	($2,848)	($2,981)	($2,621)	($2,686)	($2,745)	($2,708)	($2,164)	($21,644)

Source: ICF modeling results

Exhibit 5-7: 2015-2024 U.S. and Canadian Employment Changes

Case	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
	Lower-Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.9)										
With Keystone XL											
Option 1	896	22,391	25,924	10,223	(334)	(10,916)	(13,697)	(16,338)	(13,595)	(16,122)	(1,157)
Option 2	836	20,489	25,993	10,407	(637)	(12,279)	(11,363)	(13,826)	(11,001)	(13,686)	(507)
Option 3	676	20,087	28,226	15,759	(17,035)	(10,825)	(8,061)	(10,426)	(7,833)	(9,504)	106
Without Keystone XL											
Option 1	893	22,449	24,571	(18,399)	(87,372)	(24,035)	(26,372)	(25,520)	(22,916)	(25,464)	(18,217)
Option 2	836	20,602	22,911	(19,736)	(79,990)	(23,686)	(27,983)	(24,926)	(22,172)	(24,825)	(17,897)
Option 3	676	19,816	25,910	(693)	1,738	(10,021)	(9,950)	(12,562)	(9,735)	(12,344)	(717)
Case	Upper-Bound U.S. + Can. Oil Employment Changes (number of workers, multiplier effect=1.9)										
With Keystone XL											
Option 1	(63)	(4,894)	(18,386)	(20,411)	(21,260)	(20,694)	(19,110)	(19,582)	(20,020)	(19,916)	(16,434)
Option 2	(60)	(4,655)	(16,062)	(17,928)	(17,786)	(18,258)	(16,251)	(16,506)	(16,801)	(16,811)	(14,112)
Option 3	(139)	(898)	(8,662)	(13,280)	(12,733)	(11,256)	(11,292)	(11,398)	(11,519)	(11,637)	(9,281)
Without Keystone XL											
Option 1	(72)	(4,513)	(18,213)	(25,369)	(97,032)	(45,760)	(30,527)	(28,733)	(29,606)	(29,668)	(30,949)
Option 2	(60)	(4,281)	(17,505)	(24,529)	(88,598)	(42,100)	(29,274)	(27,419)	(28,381)	(28,532)	(29,068)
Option 3	(139)	(627)	(10,452)	(14,671)	(14,351)	(14,985)	(13,128)	(13,436)	(13,725)	(13,551)	(10,907)

Source: ICF modeling results

6 Conclusion

Rail has allowed U.S. and Canadian crude oil production to surge by moving crude oil to markets where pipelines are at capacity or do not exist. In the BAU Case assumed for this study, rail continues to move much of the crude oil and condensate from the Bakken, increasingly from Canada and the Niobrara, and will gradually increase from the Permian (mostly to the West Coast). These movements of crude would about double 2013 rail movements to almost 2.1 million barrels per day by 2017 and go to 2.5 million barrels per day in 2024. Demand for rail transportation of crude would be even higher at 3.1 million barrels per day in 2024 if the Keystone XL Pipeline were not approved.

ICF's analysis indicates that, based on input from the rail industry[55] regarding retrofit and new build capacity, costs and timing, as well as the outlook for increased demand for crude movements by rail from the U.S. and Canada, the proposed PHMSA regulations could not be met without extensive scrapping of the existing legacy fleet in 2018 and 2019. Furthermore, compliance would entail the displacement of substantial volumes of crude oil, ethanol and other flammable liquids on to alternative transportation modes – including trucking – for several years until new build capacity for railcars catches up to demand for normal rail transport of crude and other Class 3 commodities.

The inability to retrofit railcars in time for the proposed regulation dates requires substantial volumes of crude oil, ethanol and other flammable liquids to be shifted to alternative, more costly means of transportation or in some cases result in shut-in crude oil production. The cost implications of each of these cases is substantial versus a BAU Case, which is based on meeting increased crude oil demand from the construction of new CPC 1232 jacketed crude cars.

ICF's analysis indicates more severe impacts to the U.S. economy from PHMSA regulations than assumed by PHMSA for several reasons, which are included below.

1) <u>Retrofit capacity</u> – PHMSA assumes that capacity exists for 22,062 retrofits per year *versus* a capacity of 5,700 retrofits per year used by ICF based on RSI data.
2) <u>New build capacity</u> – PHMSA uses RSI's new build capacity of 33,800 tank cars per year and assumes all of this capacity can be used to supply Class 3 service, while the ICF analysis reflects that 10,000 cars per year are constructed for other than Class 3 purposes. *(Note that the PHMSA study does not require use of that new build capacity because of the overstated PHMSA retrofit capacity and the understated PHMSA demand for additional crude by rail transport.)*
3) <u>Legacy car conversion to oil sands service</u> – PHMSA assumed 23,237 cars will be converted to oil sands service *versus* the ICF analysis, which assumes that does not happen (cars in Canada must meet TC-140 standards).

[55] Railway Supply Institute (RSI) and AllTranstek

4) Crude oil rail movements – PHMSA underestimated the growth in rail movements of crude oil *versus* what the ICF analysis assumed, and did not consider the Keystone XL Pipeline scenarios, as denial of the pipeline would mean an increase in crude rail movements. Rather than showing U.S. and Canadian oil by rail volume forecasts as ICF did, PHMSA showed annual railcar demand for crude service, which ICF converted to volumes to conclude that the PHMSA assumptions underestimated crude movement by rail.

5) Retrofit costs – PHMSA's estimates of retrofit costs were consistently lower than estimates based on data from RSI and others in the industry and used in the ICF analysis. For example, for a CPC 1232 bare car, PHMSA estimated retrofit costs at between $26,230 and $32,900, depending on the option versus the ICF estimate of between $47,200 and $54,200.

6) Retrofit out of service times – PHMSA's estimates for time out of service were consistently lower than the estimates from industry used by ICF. For example, PHMSA estimated 56 days for a CPC 1232 bare car *versus* this study's assumption of between 126 and 130 days, depending on PHMSA option being considered.

7) Weight impacts – PHMSA assumed no weight impacts on tank car capacity from the change in regulation, which ICF did include. The reason weight impacts are important is that adding material for stronger tank cars often limits the total carrying capacity, based on weight restrictions. Heavier retrofitted cars, thus, have less carrying capacity. This means that more retrofitted cars will be needed to carry the equivalent volumes assumed in unretrofitted cars, which PHMSA does not account for.

8) Impacted fleet – PHMSA assumed that only HHFT trains are impacted, though the ICF model included impacts to all trains since it is very unlikely that railroads can always insure no more than 20 Class 3 railcars will be in a train.

9) Scrapping of cars – PHMSA also assumed that no legacy cars would be discarded, even older cars for which the remaining useful life of the car may be too short to justify retrofit costs. The ICF model allowed for scrapping, and its impact on rail capacity.

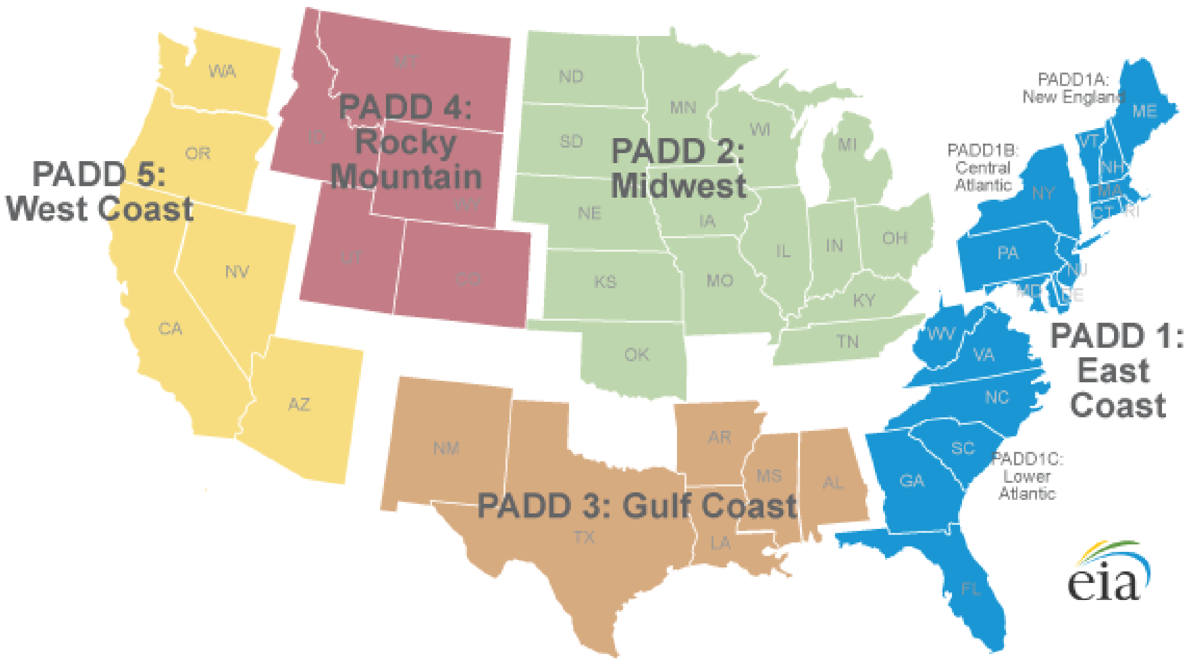
The impacts ICF estimated for Class 3 rail service will have effects on the broader U.S. and Canadian economies, as well, stemming from increased rail transportation costs for crude oil, ethanol, and other flammables, and a shift from rail transportation to much more expensive trucking costs and/or periods of shut-in crude, particularly in the critical 2018-2019 period when the proposed regulations begin to require use of new or retrofitted railcars.

The factors that could lead to higher costs for consumers include higher cost of crude oil, higher shipping costs for petroleum products and higher shipping costs for ethanol that will be blended into gasoline. This study found that compliance costs and alternative transportation of crude oil could potentially increase consumer costs for gasoline and other petroleum products by $14.4 to $22.8 billion in the 2015 to 2024 period in the scenario where Keystone XL is approved, or $21.0 to $45.2 billion without Keystone XL. Additionally, higher consumer costs reduce spending on non-energy consumer goods and services, reducing output and jobs in those sectors, with impacts to GDP and employment in the U.S. and Canada.

7 Appendices

Appendix A: Petroleum Administration for Defense Districts (PADD)

Exhibit 7-1: Map of U.S. by PADD



Source: U.S. Energy Information Administration (EIA). "Gasoline and Diesel Fuel Update." EIA, accessed October 7, 2014: Washington, DC. Available at: http://www.eia.gov/petroleum/gasdiesel/diesel_map.cfm

Appendix B: U.S. Williston Basin Crude Oil Export Options

Exhibit 7-2: U.S. Williston Basin Crude Oil Export Options

	Year End System Capacity (b/d)													
Region	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015***	**2016***	**2017**	**2018**	**2019**	**2020**
Butte Pipeline	92,000	104,000	118,000	118,000	145,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Butte Expansion (Q3 2014)	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Tesoro Mandan Refinery	58,000	58,000	58,000	58,000	58,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000
Enbridge Mainline North Dakota	80,000	110,000	110,000	161,500	185,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000
Enbridge Bakken Expansion Program	-	-	-	-	25,000	25,000	145,000	145,000	145,000	145,000	145,000	145,000	145,000	145,000
Plains Bakken North (Up to 70,000 BOPD)	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Enbridge Sandpiper* (QI 2017)	-	-	-	-	-	-	-	-	-	-	225,000	225,000	225,000	225,000
TransCanada Keystone XL* (100,000 BOPD, Timeli	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dakota Prairie Refinery (Q4 2014/QI 2015)	-	-	-	-	-	-	-	-	20,000	20,000	20,000	20,000	20,000	20,000
Thunder Butte Refinery (2015)	-	-	-	-	-	-	-	-	20,000	20,000	20,000	20,000	20,000	20,000
Dakota Oil Processing Refinery (2015)*	-	-	-	-	-	-	-	-	20,000	20,000	20,000	20,000	20,000	20,000
Energy Transfer Partners Bakken Pipeline* (Late 201	-	-	-	-	-	-	-	-	-	-	320,000	320,000	320,000	320,000
Enterprise Products Partners* (Q3 2017, W.B. Est. 2	-	-	-	-	-	-	-	-	-	-	200,000	200,000	200,000	200,000
Hiland Partners Double H Pipeline (Q3 2014, Up to 1	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Pipeline/Refining Total	**230,000**	**272,000**	**286,000**	**337,500**	**413,000**	**463,000**	**583,000**	**773,000**	**833,000**	**833,000**	**1,578,000**	**1,578,000**	**1,578,000**	**1,578,000**
EOG Rail, Stanley, ND (Unit)	-	-	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000
Dakota Plains, New Town, ND (Unit)	-	-	-	20,000	30,000	30,000	30,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
High Sierra, Donnybrook, ND (Manifest)	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Crestwood COLT Hub, Epping, ND (Unit)	-	-	-	-	-	120,000	120,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Hess Rail, Tioga, ND (Unit)	-	-	-	-	-	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Bakken Oil Express, Dickinson, ND (Unit)	-	-	-	-	100,000	100,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Savage Services, Trenton, ND (Unit)	-	-	-	-	-	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000
Enbridge, Berthold, ND (Unit)	-	-	-	-	-	10,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Great Northern Midstream, Fryburg, ND (Unit)	-	-	-	-	-	-	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Musket, Dore, ND (Unit)	-	-	-	-	-	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Plains, Ross, ND (Unit)	-	-	-	-	20,000	20,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000
Plains - Van Hook, New Town, ND (Unit)	-	-	-	-	-	35,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000
Global/Basin Transload, Stampede, ND (Unit)	-	-	-	-	-	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Global/Basin Transload, Zap, ND (Unit: Capacity Est	-	-	-	-	20,000	40,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Enserco, Gascoyne, ND (Unit)	-	-	-	-	-	-	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000
Northstar Transloading - Fairview, MT (Q3 2014) (Unit	-	-	-	-	-	-	-	20,000	180,000	180,000	180,000	180,000	180,000	180,000
Rail Only Total	-	10,000	75,000	95,000	245,000	740,000	1,150,000	1,260,000	1,420,000	1,420,000	1,420,000	1,420,000	1,420,000	1,420,000
All Transportation Total	**230,000**	**282,000**	**361,000**	**432,500**	**658,000**	**1,203,000**	**1,733,000**	**2,033,000**	**2,253,000**	**2,253,000**	**2,998,000**	**2,998,000**	**2,998,000**	**2,998,000**
Wiliston/Bakken Production	**215,007**	**252,733**	**290,236**	**444,193**	**592,514**	**877,854**	**1,113,416**	**1,339,582**	**1,516,230**	**1,673,370**	**1,804,121**	**1,925,233**	**2,017,610**	**2,099,700**
Required Rail	**(14,993)**	**(19,267)**	**4,236**	**106,693**	**179,514**	**414,854**	**530,416**	**566,582**	**683,230**	**840,370**	**226,121**	**347,233**	**439,610**	**521,700**

* Project still in the review or proposal phase

Note: Data updated as of October 1, 2014.

Sources: North Dakota Pipeline Authority. "Oil Transportation Table." North Dakota Pipeline Authority, October 1, 2014. Available at: http://northdakotapipelines.com/oil-transportation-table/. ICF Detailed Production Report (DPR).

Appendix C: Railcar Balance Transportation Model Snapshots

The following exhibits are snapshots of the railcar balance model to give some insights into the model setup and properties.

Exhibit 7-3: Tank Car Volumes, Weights, and Capacities

		Tank Car Category	Tank Volume (gallons)	Outage (unusable volume)	Usable Tank Volume (gallons)	Weight Limit (pounds)	Tare Weight (pounds)	Max. Cargo Weight (pounds)	Commodity weight (#/gal.)	Capacity by Weight (gallons)	Final Capacity Before Retrofits (gallons)
	1	CPC-1232 Bare Crude PG1	30,000	1.0%	29,700	286,000	75,200	210,800	6.846	30,792	29,700
	2	CPC-1232 Jacketed Crude PG1	30,000	1.0%	29,700	286,000	80,800	205,200	6.846	29,974	29,700
	3	1MM or 3MM Non-CPC Bare Crude PG 1	30,000	1.0%	29,700	263,000	64,800	198,200	6.846	28,951	28,951
	4	1MM Non-CPC Jacketed Crude PG1	30,000	1.0%	29,700	263,000	64,800	198,200	6.846	28,951	28,951
	5	pre-1MM Bare Crude PG1	30,000	1.0%	29,700	263,000	64,800	198,200	6.846	28,951	28,951
	6	New Standard New Build Crude PG1	30,000	1.0%	29,700	286,000	80,800	205,200	6.846	29,974	29,700
	7										
	8										
	1	CPC-1232 Bare Crude DB PG2	30,000	1.0%	29,700	286,000	75,200	210,800	7.755	27,182	27,182
	2	CPC-1232 Jacketed Crude DB PG2	30,000	1.0%	29,700	286,000	80,800	205,200	7.755	26,460	26,460
	3	1MM or 3MM Non-CPC Bare Crude DB PG	30,000	1.0%	29,700	263,000	64,800	198,200	7.755	25,558	25,558
	4	1MM Non-CPC Jacketed Crude DB PG2	30,000	1.0%	29,700	263,000	64,800	198,200	7.755	25,558	25,558
	5	pre-1MM Bare Crude DB PG2	30,000	1.0%	29,700	263,000	64,800	198,200	7.755	25,558	25,558
	6	New Standard New Build Crude DB PG2	30,000	1.0%	29,700	286,000	80,800	205,200	7.755	26,460	26,460
	7										
	8										
	1	CPC-1232 Bare Crude RB PG2	30,000	1.0%	29,700	286,000	75,200	210,800	8.047	26,196	26,196
	2	CPC-1232 Jacketed Crude RB PG2	30,000	1.0%	29,700	286,000	80,800	205,200	8.047	25,500	25,500
	3	1MM or 3MM Non-CPC Bare Crude RB PG	30,000	1.0%	29,700	263,000	64,800	198,200	8.047	24,630	24,630
	4	1MM Non-CPC Jacketed Crude RB PG2	30,000	1.0%	29,700	263,000	64,800	198,200	8.047	24,630	24,630
	5	pre-1MM Bare Crude RB PG2	30,000	1.0%	29,700	263,000	64,800	198,200	8.047	24,630	24,630
	6	New Standard New Build Crude RB PG2	30,000	1.0%	29,700	286,000	80,800	205,200	8.047	25,500	25,500
	7										
	8										
	1	CPC-1232 Bare Ethanol PG2	30,000	1.0%	29,700	286,000	75,200	210,800	6.58	32,036	29,700
	2	CPC-1232 Jacketed Ethanol PG2	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	3	1MM or 3MM Non-CPC Bare Ethanol PG2	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	4	1MM Non-CPC Jacketed Ethanol PG2	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	5	pre-1MM Bare Ethanol PG2	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	6	New Standard New Build Ethanol PG2	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	7										
	8										
	1	CPC-1232 Bare Flammable PG2	30,000	1.0%	29,700	286,000	75,200	210,800	6.58	32,036	29,700
	2	CPC-1232 Jacketed Flammable PG2	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	3	1MM or 3MM Non-CPC Bare Flammable P	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	4	1MM Non-CPC Jacketed Flammable PG2	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	5	pre-1MM Bare Flammable PG2	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	6	New Standard New Build Flammable PG2	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	7										
	8										
	1	CPC-1232 Bare Flammable PG3	30,000	1.0%	29,700	286,000	75,200	210,800	6.58	32,036	29,700
	2	CPC-1232 Jacketed Flammable PG3	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	3	1MM or 3MM Non-CPC Bare Flammable P	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	4	1MM Non-CPC Jacketed Flammable PG3	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	5	pre-1MM Bare Flammable PG3	30,000	1.0%	29,700	263,000	64,800	198,200	6.58	30,122	29,700
	6	New Standard New Build Flammable PG3	30,000	1.0%	29,700	286,000	80,800	205,200	6.58	31,185	29,700
	7										
	8										
New Tanks Cars	Reg1	BAU	30,000	1.0%	29,700	286,000	80,800	205,200			
	Reg2	PHMSA Option 1	30,000	1.0%	29,700	286,000	85,500	200,500			
	Reg3	PHMSA Option 2	30,000	1.0%	29,700	286,000	85,500	200,500			
	Reg4	PHMSA Option 3	30,000	1.0%	29,700	286,000	80,800	205,200			
	Reg5	Undefined Case	30,000	1.0%	29,700	286,000	80,800	205,200			

Source: ICF model inputs. Crude DB stands for dilbit, crude RB stands for railbit.

Exhibit 7-4: Railcar Demand Setup

Rail Car Demand Case #1

with KXL	Crude PG1		Crude DB PG2		Crude RB PG2		Ethanol PG2		Other Flam. Liq. PG2		Other Flam. Liq. PG3	
	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year
2014	963,179	10,907	280,000	10,585	0	10,000	581,633	7,148	547,773	8,019	0	8,019
2015	1,136,601	10,907	296,875	10,585	244,485	10,000	581,633	7,148	547,773	8,019	0	8,019
2016	1,279,955	10,907	365,000	10,585	300,588	10,000	581,633	7,148	547,773	8,019	0	8,019
2017	1,422,991	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2018	1,534,821	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2019	1,618,161	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2020	1,700,204	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2021	1,740,551	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2022	1,770,278	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2023	1,786,620	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019
2024	1,797,394	10,907	370,000	10,585	304,706	10,000	581,633	7,148	547,773	8,019	0	8,019

Rail Car Demand Case #2

w/o KXL	Crude PG1		Crude DB PG2		Crude RB PG2		Ethanol PG2		Other Flam. Liq. PG2		Other Flam. Liq. PG3	
	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year	Demand for Rail Transport in bpd	Efficiency bbl/car/year
2014	963,179	10,907	280,000	10,585	0	10,000	581,633	7,148	547,773	8,019	0	8,019
2015	1,136,601	10,907	296,875	10,585	244,485	10,000	581,633	7,148	547,773	8,019	0	8,019
2016	1,279,955	10,907	365,000	10,585	300,588	10,000	581,633	7,148	547,773	8,019	0	8,019
2017	1,422,991	10,907	470,000	10,585	387,059	10,000	581,633	7,148	547,773	8,019	0	8,019
2018	1,534,821	10,907	620,000	10,585	510,588	10,000	581,633	7,148	547,773	8,019	0	8,019
2019	1,618,161	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019
2020	1,700,204	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019
2021	1,740,551	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019
2022	1,770,278	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019
2023	1,786,620	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019
2024	1,797,394	10,907	720,000	10,585	592,941	10,000	581,633	7,148	547,773	8,019	0	8,019

Source: ICF model inputs based on defined assumptions

Exhibit 7-5: Railcar Weight Gain, Retrofit Downtime, and Other Factors Setup

	Regulatory Case #2							
	PHMSA Option 1	Regulation Says This Type May be Used Thru (w/o retrofit)	Retrofit Weight Gain (pounds)	Retrofit or New Cost ($/car)	Retrofit Downtime (days)	"C Shop" Workdays per Car to Retrofit	Fraction of Prematurely Retired Cars that is Re-purposed (remainder	Leasing Value of Re-purposed Cars as Fraction of Crude
1	CPC-1232 Bare Crude PG1	2017	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Crude PG1	2017	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Crude PG 1	2017	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Crude PG1	2017	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Crude PG1	2017	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Crude PG1			$ 173,500				
1	CPC-1232 Bare Crude DB PG2	2018	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Crude DB PG2	2018	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Crude DB PG2	2018	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Crude DB PG2	2018	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Crude DB PG2	2018	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Crude DB PG2			$ 177,500				
1	CPC-1232 Bare Crude RB PG2	2018	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Crude RB PG2	2018	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Crude RB PG2	2018	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Crude RB PG2	2018	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Crude RB PG2	2018	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Crude RB PG2			$ 177,500				
1	CPC-1232 Bare Ethanol PG2	2018	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Ethanol PG2	2018	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Ethanol PG2	2018	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Ethanol PG2	2018	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Ethanol PG2	2018	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Ethanol PG2			$ 173,500				
1	CPC-1232 Bare Flammable PG2	2018	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Flammable PG2	2018	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Flammable PG2	2018	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Flammable PG2	2018	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Flammable PG2	2018	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Flammable PG2			$ 173,500				
1	CPC-1232 Bare Flammable PG3	2021	20,750	$ 54,200	130	36	25%	80%
2	CPC-1232 Jacketed Flammable PG3	2021	9,000	$ 32,700	116	29	25%	80%
3	1MM or 3MM Non-CPC Bare Flammable PG3	2021	22,950	$ 75,700	155	46	25%	80%
4	1MM Non-CPC Jacketed Flammable PG3	2021	13,400	$ 71,700	147	42	25%	80%
5	pre-1MM Bare Flammable PG3	2021	22,950	$ 75,700	155	46	25%	80%
6	New Standard New Build Flammable PG3			$ 173,500				

Source: ICF model inputs based on defined assumptions

Appendix D: Economic Impact Results Tables

All results herein are incremental differences from the BAU Case, rather than absolute values. The study also assessed case impacts for the U.S. and Canada separately, with results below including the U.S. and Canada, the U.S. only, and Canada only.

Exhibit 7-6: Total U.S. and Canadian Crude Oil Production Changes by Case

Production Changes (bpd)	Total U.S. & Canada											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	-	(1,696)	(41,219)	(49,100)	(52,177)	(48,410)	(35,739)	(37,261)	(37,223)	(35,357)	*(37,576)*	**(338,182)**
Option 2	-	(1,695)	(30,852)	(37,892)	(35,052)	(40,632)	(25,900)	(26,753)	(26,515)	(25,720)	*(27,890)*	**(251,011)**
Option 3	-	(1)	(18,675)	(24,378)	(19,720)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	*(15,146)*	**(136,316)**
Without Keystone XL												
Option 1	-	(1,786)	(48,190)	(84,629)	(612,694)	(221,707)	(104,071)	(86,071)	(86,368)	(83,591)	*(147,679)*	**(1,329,107)**
Option 2	-	(1,786)	(48,189)	(84,628)	(556,858)	(201,502)	(101,689)	(83,517)	(84,646)	(82,594)	*(138,379)*	**(1,245,409)**
Option 3	-	(1)	(27,721)	(34,008)	(30,694)	(37,775)	(24,416)	(25,888)	(26,064)	(24,570)	*(25,682)*	**(231,137)**

Source: ICF modeling results

Exhibit 7-7: U.S. Crude Oil Production Changes by Case

Production Changes (bpd)	U.S. Only											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	-	(1,693)	(3,191)	(7,870)	(17,552)	(26,483)	(31,566)	(34,097)	(35,094)	(34,114)	*(21,296)*	**(191,660)**
Option 2	-	(1,693)	(3,191)	(7,870)	(13,630)	(19,236)	(22,686)	(24,313)	(24,874)	(24,767)	*(15,807)*	**(142,260)**
Option 3	-	-	-	(3,880)	(9,222)	(12,642)	(14,401)	(15,308)	(15,627)	(15,564)	*(12,378)*	**(86,644)**
Without Keystone XL												
Option 1	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	*(46,412)*	**(417,705)**
Option 2	-	(1,693)	(3,191)	(11,546)	(33,698)	(55,821)	(70,618)	(78,820)	(81,525)	(80,793)	*(46,412)*	**(417,705)**
Option 3	-	-	-	(3,880)	(9,176)	(16,234)	(21,024)	(23,355)	(24,385)	(23,605)	*(17,380)*	**(121,659)**

Source: ICF modeling results

Exhibit 7-8: Canadian Crude Oil Production Changes by Case

Production Changes (bpd)	Canada Only											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	-	(2)	(38,028)	(41,230)	(34,626)	(21,927)	(4,173)	(3,164)	(2,129)	(1,243)	*(16,280)*	**(146,522)**
Option 2	-	(1)	(27,660)	(30,021)	(21,421)	(21,395)	(3,214)	(2,440)	(1,641)	(953)	*(12,083)*	**(108,746)**
Option 3	-	(1)	(18,675)	(20,497)	(10,498)	-	-	-	-	-	*(12,418)*	**(49,671)**
Without Keystone XL												
Option 1	-	(92)	(44,998)	(73,083)	(578,996)	(165,886)	(33,453)	(7,250)	(4,843)	(2,798)	*(101,267)*	**(911,399)**
Option 2	-	(93)	(44,998)	(73,082)	(523,160)	(145,681)	(31,070)	(4,697)	(3,121)	(1,801)	*(91,967)*	**(827,703)**
Option 3	-	(1)	(27,721)	(30,128)	(21,518)	(21,540)	(3,391)	(2,533)	(1,678)	(966)	*(12,164)*	**(109,476)**

Source: ICF modeling results

Exhibit 7-9: Total U.S. and Canadian GDP Changes

Lower-Bound GDP Changes (U.S.$ million)	Total U.S. & Canada											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($9)	($676)	($2,537)	($2,818)	($2,947)	($2,864)	($2,658)	($2,725)	($2,787)	($2,773)	*($2,279)*	**($22,794)**
Option 2	($8)	($641)	($2,201)	($2,459)	($2,445)	($2,512)	($2,245)	($2,281)	($2,322)	($2,324)	*($1,944)*	**($19,438)**
Option 3	($20)	($99)	($1,132)	($1,788)	($1,715)	($1,501)	($1,528)	($1,543)	($1,559)	($1,577)	*($1,246)*	**($12,462)**
Without Keystone XL												
Option 1	($10)	($621)	($2,512)	($3,534)	($13,891)	($6,485)	($4,307)	($4,047)	($4,172)	($4,181)	*($4,376)*	**($43,760)**
Option 2	($8)	($587)	($2,410)	($3,412)	($12,673)	($5,956)	($4,126)	($3,857)	($3,995)	($4,017)	*($4,104)*	**($41,041)**
Option 3	($20)	($59)	($1,391)	($1,989)	($1,949)	($2,040)	($1,794)	($1,838)	($1,878)	($1,853)	*($1,481)*	**($14,811)**

Upper-Bound GDP Changes (U.S.$ million)	Total U.S. & Canada											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($13)	($988)	($3,708)	($4,118)	($4,307)	($4,186)	($3,884)	($3,983)	($4,074)	($4,052)	*($3,331)*	**($33,313)**
Option 2	($12)	($937)	($3,217)	($3,594)	($3,573)	($3,672)	($3,281)	($3,334)	($3,394)	($3,397)	*($2,841)*	**($28,411)**
Option 3	($29)	($144)	($1,655)	($2,613)	($2,507)	($2,194)	($2,234)	($2,255)	($2,279)	($2,304)	*($1,821)*	**($18,214)**
Without Keystone XL												
Option 1	($15)	($907)	($3,671)	($5,165)	($20,303)	($9,478)	($6,294)	($5,915)	($6,098)	($6,111)	*($6,396)*	**($63,957)**
Option 2	($12)	($858)	($3,522)	($4,987)	($18,522)	($8,705)	($6,030)	($5,638)	($5,839)	($5,871)	*($5,998)*	**($59,984)**
Option 3	($29)	($87)	($2,033)	($2,906)	($2,848)	($2,981)	($2,621)	($2,686)	($2,745)	($2,708)	*($2,164)*	**($21,644)**

Source: ICF modeling results

Note: Lower-bound GDP changes assume multiplier effect of 1.3, and upper-bound GDP changes assume multiplier effect of 1.9.

Exhibit 7-10: U.S. GDP Changes

Lower-Bound GDP Changes (U.S.$ million)	U.S. Only											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($3)	($245)	($313)	($426)	($737)	($1,075)	($1,382)	($1,485)	($1,555)	($1,551)	*($877)*	**($8,772)**
Option 2	($3)	($235)	($354)	($474)	($694)	($826)	($1,080)	($1,145)	($1,188)	($1,201)	*($720)*	**($7,200)**
Option 3	($6)	($31)	($87)	($326)	($542)	($696)	($742)	($770)	($786)	($792)	*($478)*	**($4,778)**
Without Keystone XL												
Option 1	($3)	($227)	($208)	($273)	$3,389	($728)	($2,318)	($2,848)	($3,031)	($3,093)	*($934)*	**($9,340)**
Option 2	($3)	($216)	($177)	($237)	$2,955	($861)	($2,302)	($2,834)	($3,010)	($3,066)	*($975)*	**($9,751)**
Option 3	($6)	($19)	($41)	($252)	($455)	($626)	($918)	($1,005)	($1,063)	($1,056)	*($544)*	**($5,441)**
Upper-Bound GDP Changes (U.S.$ million)	**U.S. Only**											
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-24 Annual Avg**	**2015-24 Sum**
With Keystone XL												
Option 1	($4)	($359)	($457)	($623)	($1,078)	($1,572)	($2,019)	($2,171)	($2,273)	($2,266)	*($1,282)*	**($12,822)**
Option 2	($4)	($343)	($517)	($693)	($1,014)	($1,207)	($1,579)	($1,673)	($1,737)	($1,755)	*($1,052)*	**($10,522)**
Option 3	($9)	($45)	($127)	($476)	($792)	($1,017)	($1,084)	($1,126)	($1,149)	($1,157)	*($698)*	**($6,982)**
Without Keystone XL												
Option 1	($5)	($332)	($304)	($399)	$4,954	($1,064)	($3,387)	($4,162)	($4,430)	($4,520)	*($1,365)*	**($13,649)**
Option 2	($4)	($316)	($258)	($346)	$4,319	($1,258)	($3,364)	($4,141)	($4,399)	($4,482)	*($1,425)*	**($14,249)**
Option 3	($9)	($27)	($59)	($369)	($666)	($915)	($1,342)	($1,469)	($1,553)	($1,543)	*($795)*	**($7,952)**

Source: ICF modeling results

Note: Lower-bound GDP changes assume multiplier effect of 1.3, and upper-bound GDP changes assume multiplier effect of 1.9.

Exhibit 7-11: Canadian GDP Changes

Lower-Bound GDP Changes (U.S.$ million)	Canada Only											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($6)	($430)	($2,224)	($2,392)	($2,209)	($1,789)	($1,276)	($1,240)	($1,232)	($1,222)	*($1,402)*	**($14,020)**
Option 2	($6)	($406)	($1,848)	($1,985)	($1,751)	($1,687)	($1,164)	($1,136)	($1,134)	($1,123)	*($1,224)*	**($12,240)**
Option 3	($13)	($68)	($1,045)	($1,462)	($1,173)	($805)	($786)	($773)	($773)	($785)	*($768)*	**($7,683)**
Without Keystone XL												
Option 1	($7)	($394)	($2,304)	($3,261)	($17,281)	($5,757)	($1,989)	($1,199)	($1,141)	($1,088)	*($3,442)*	**($34,421)**
Option 2	($6)	($371)	($2,233)	($3,176)	($15,628)	($5,095)	($1,824)	($1,024)	($985)	($951)	*($3,129)*	**($31,293)**
Option 3	($13)	($41)	($1,350)	($1,736)	($1,493)	($1,414)	($875)	($833)	($815)	($798)	*($937)*	**($9,368)**
Upper-Bound GDP Changes (U.S.$ million)	**Canada Only**											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($9)	($629)	($3,251)	($3,495)	($3,229)	($2,615)	($1,865)	($1,812)	($1,801)	($1,786)	*($2,049)*	**($20,492)**
Option 2	($8)	($594)	($2,700)	($2,901)	($2,560)	($2,465)	($1,702)	($1,660)	($1,657)	($1,641)	*($1,789)*	**($17,888)**
Option 3	($20)	($99)	($1,528)	($2,137)	($1,714)	($1,176)	($1,149)	($1,130)	($1,130)	($1,148)	*($1,123)*	**($11,231)**
Without Keystone XL												
Option 1	($10)	($575)	($3,367)	($4,765)	($25,257)	($8,414)	($2,907)	($1,753)	($1,668)	($1,591)	*($5,031)*	**($50,307)**
Option 2	($8)	($542)	($3,264)	($4,641)	($22,841)	($7,447)	($2,666)	($1,496)	($1,440)	($1,389)	*($4,573)*	**($45,734)**
Option 3	($20)	($60)	($1,974)	($2,538)	($2,182)	($2,067)	($1,279)	($1,217)	($1,191)	($1,166)	*($1,369)*	**($13,694)**

Source: ICF modeling results

Note: Lower-bound GDP changes assume multiplier effect of 1.3, and upper-bound GDP changes assume multiplier effect of 1.9.

Exhibit 7-12: U.S. and Canadian Employment Changes

Lower-Bound Employment Changes (No.)	Total U.S. & Canada										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	896	22,391	25,924	10,223	(334)	(10,916)	(13,697)	(16,338)	(13,595)	(16,122)	*(1,157)*
Option 2	836	20,489	25,993	10,407	(637)	(12,279)	(11,363)	(13,826)	(11,001)	(13,686)	*(507)*
Option 3	676	20,087	28,226	15,759	(17,035)	(10,825)	(8,061)	(10,426)	(7,833)	(9,504)	*106*
Without Keystone XL											
Option 1	893	22,449	24,571	(18,399)	(87,372)	(24,035)	(26,372)	(25,520)	(22,916)	(25,464)	*(18,217)*
Option 2	836	20,602	22,911	(19,736)	(79,990)	(23,686)	(27,983)	(24,926)	(22,172)	(24,825)	*(17,897)*
Option 3	676	19,816	25,910	(693)	1,738	(10,021)	(9,950)	(12,562)	(9,735)	(12,344)	*(717)*
Upper-Bound Employment Changes (No.)	**Total U.S. & Canada**										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	(63)	(4,894)	(18,386)	(20,411)	(21,260)	(20,694)	(19,110)	(19,582)	(20,020)	(19,916)	*(16,434)*
Option 2	(60)	(4,655)	(16,062)	(17,928)	(17,786)	(18,258)	(16,251)	(16,506)	(16,801)	(16,811)	*(14,112)*
Option 3	(139)	(898)	(8,662)	(13,280)	(12,733)	(11,256)	(11,292)	(11,398)	(11,519)	(11,637)	*(9,281)*
Without Keystone XL											
Option 1	(72)	(4,513)	(18,213)	(25,369)	(97,032)	(45,760)	(30,527)	(28,733)	(29,606)	(29,668)	*(30,949)*
Option 2	(60)	(4,281)	(17,505)	(24,529)	(88,598)	(42,100)	(29,274)	(27,419)	(28,381)	(28,532)	*(29,068)*
Option 3	(139)	(627)	(10,452)	(14,671)	(14,351)	(14,985)	(13,128)	(13,436)	(13,725)	(13,551)	*(10,907)*

Source: ICF modeling results

Note: Lower-bound employment changes assume multiplier effect of 1.3, and upper-bound employment changes assume multiplier effect of 1.9.

Exhibit 7-13: U.S. Employment Changes

Lower-Bound Employment Changes (No.)	U.S. Only										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	818	20,973	30,889	19,816	10,603	(3,834)	(9,593)	(12,175)	(9,831)	(12,190)	*3,548*
Option 2	763	19,215	29,356	18,238	8,744	(5,217)	(7,673)	(10,042)	(7,586)	(10,085)	*3,571*
Option 3	635	18,177	28,937	21,577	(10,972)	(8,072)	(5,655)	(7,831)	(5,508)	(6,993)	*2,430*
Without Keystone XL											
Option 1	817	20,985	30,407	(368)	6,670	4,258	(17,215)	(20,957)	(18,991)	(21,565)	*(1,596)*
Option 2	763	19,254	28,743	(2,589)	5,427	1,435	(19,289)	(21,002)	(18,794)	(21,366)	*(2,742)*
Option 3	635	17,880	28,224	6,236	9,424	(3,648)	(7,000)	(9,552)	(7,138)	(9,575)	*2,549*

Upper-Bound Employment Changes (No.)	U.S. Only										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	(20)	(1,752)	(2,245)	(3,057)	(5,261)	(7,630)	(9,809)	(10,542)	(11,032)	(11,005)	*(6,235)*
Option 2	(19)	(1,678)	(2,528)	(3,389)	(4,957)	(5,904)	(7,722)	(8,184)	(8,494)	(8,586)	*(5,146)*
Option 3	(44)	(267)	(683)	(2,360)	(3,909)	(5,005)	(5,380)	(5,589)	(5,711)	(5,750)	*(3,470)*
Without Keystone XL											
Option 1	(22)	(1,624)	(1,520)	(1,998)	23,309	(5,227)	(16,288)	(19,974)	(21,250)	(21,682)	*(6,628)*
Option 2	(19)	(1,552)	(1,302)	(1,747)	20,301	(6,147)	(16,178)	(19,875)	(21,104)	(21,500)	*(6,912)*
Option 3	(44)	(181)	(361)	(1,852)	(3,309)	(4,518)	(6,600)	(7,214)	(7,626)	(7,578)	*(3,928)*

Source: ICF modeling results

Note 1: Lower-bound employment changes assume multiplier effect of 1.3, and upper-bound employment changes assume multiplier effect of 1.9.

Note 2: Negative employment impacts are likely to continue beyond 2024 due to continuing lower oil production. If employment impacts were calculated over a longer time period, it is likely they would, on average, be negative.

Exhibit 7-14: Canadian Employment Changes

Lower-Bound Employment Changes (No.)	Canada Only										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	78	1,417	(4,964)	(9,593)	(10,938)	(7,082)	(4,104)	(4,163)	(3,764)	(3,932)	*(4,705)*
Option 2	72	1,274	(3,364)	(7,830)	(9,381)	(7,062)	(3,691)	(3,783)	(3,416)	(3,601)	*(4,078)*
Option 3	41	1,910	(711)	(5,818)	(6,063)	(2,753)	(2,406)	(2,595)	(2,325)	(2,512)	*(2,323)*
Without Keystone XL											
Option 1	76	1,464	(5,836)	(18,030)	(94,042)	(28,293)	(9,157)	(4,563)	(3,925)	(3,899)	*(16,621)*
Option 2	72	1,348	(5,833)	(17,147)	(85,417)	(25,121)	(8,694)	(3,924)	(3,378)	(3,459)	*(15,155)*
Option 3	41	1,936	(2,314)	(6,929)	(7,686)	(6,372)	(2,950)	(3,010)	(2,597)	(2,769)	*(3,265)*
Upper-Bound Employment Changes (No.)	**Canada Only**										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg
With Keystone XL											
Option 1	(44)	(3,142)	(16,140)	(17,354)	(16,000)	(13,064)	(9,301)	(9,040)	(8,988)	(8,911)	*(10,198)*
Option 2	(42)	(2,977)	(13,534)	(14,539)	(12,829)	(12,354)	(8,529)	(8,322)	(8,307)	(8,226)	*(8,966)*
Option 3	(95)	(632)	(7,979)	(10,919)	(8,824)	(6,251)	(5,912)	(5,809)	(5,808)	(5,887)	*(5,812)*
Without Keystone XL											
Option 1	(50)	(2,889)	(16,693)	(23,371)	(120,341)	(40,533)	(14,239)	(8,759)	(8,357)	(7,986)	*(24,322)*
Option 2	(42)	(2,729)	(16,203)	(22,783)	(108,899)	(35,953)	(13,096)	(7,544)	(7,277)	(7,033)	*(22,156)*
Option 3	(95)	(446)	(10,091)	(12,819)	(11,042)	(10,467)	(6,529)	(6,221)	(6,099)	(5,973)	*(6,978)*

Source: ICF modeling results

Note: Lower-bound employment changes assume multiplier effect of 1.3, and upper-bound employment changes assume multiplier effect of 1.9.

Exhibit 7-15: U.S. and Canadian Government Revenue Changes

Lower-Bound Government Revenue Changes (U.S.$ millions)	Total U.S. & Canada											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($4)	($286)	($1,150)	($1,268)	($779)	($1,208)	($1,072)	($1,091)	($1,111)	($1,105)	*($907)*	**($9,074)**
Option 2	($4)	($271)	($988)	($1,093)	($549)	($1,074)	($917)	($926)	($939)	($939)	*($770)*	**($7,700)**
Option 3	($8)	($42)	($520)	($797)	($226)	($616)	($623)	($627)	($632)	($640)	*($473)*	**($4,731)**
Without Keystone XL												
Option 1	($4)	($262)	($1,152)	($1,623)	($6,432)	($2,950)	($1,728)	($1,539)	($1,575)	($1,571)	*($1,884)*	**($18,836)**
Option 2	($4)	($248)	($1,108)	($1,571)	($5,806)	($2,685)	($1,645)	($1,452)	($1,494)	($1,498)	*($1,751)*	**($17,511)**
Option 3	($8)	($25)	($647)	($901)	($346)	($878)	($726)	($735)	($747)	($736)	*($575)*	**($5,749)**
Upper-Bound Government Revenue Changes (U.S.$ millions)	**Total U.S. & Canada**											
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-24 Annual Avg**	**2015-24 Sum**
With Keystone XL												
Option 1	($5)	($418)	($1,681)	($1,853)	($1,374)	($1,765)	($1,567)	($1,595)	($1,624)	($1,615)	*($1,350)*	**($13,497)**
Option 2	($5)	($396)	($1,444)	($1,598)	($1,038)	($1,570)	($1,340)	($1,353)	($1,373)	($1,372)	*($1,149)*	**($11,489)**
Option 3	($12)	($62)	($760)	($1,165)	($565)	($901)	($911)	($916)	($924)	($935)	*($715)*	**($7,151)**
Without Keystone XL												
Option 1	($6)	($384)	($1,684)	($2,372)	($9,636)	($4,311)	($2,525)	($2,250)	($2,302)	($2,296)	*($2,777)*	**($27,766)**
Option 2	($5)	($363)	($1,619)	($2,296)	($8,721)	($3,924)	($2,404)	($2,122)	($2,184)	($2,189)	*($2,583)*	**($25,827)**
Option 3	($12)	($37)	($946)	($1,317)	($741)	($1,283)	($1,060)	($1,075)	($1,092)	($1,076)	*($864)*	**($8,639)**

Source: ICF modeling results

Note: Lower-bound government revenue changes assume multiplier effect of 1.3, and upper-bound government revenue changes assume multiplier effect of 1.9.

Exhibit 7-16: U.S. Government Revenue Changes

Lower-Bound Government Revenue Changes (U.S.$ millions)	**U.S. Only**											
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-24 Annual Avg**	**2015-24 Sum**
With Keystone XL												
Option 1	($1)	($84)	($107)	($146)	$258	($369)	($474)	($510)	($533)	($532)	*($250)*	**($2,498)**
Option 2	($1)	($80)	($121)	($163)	$273	($283)	($371)	($393)	($408)	($412)	*($196)*	**($1,959)**
Option 3	($2)	($11)	($30)	($112)	$325	($239)	($254)	($264)	($270)	($271)	*($113)*	**($1,128)**
Without Keystone XL												
Option 1	($1)	($78)	($71)	($94)	$1,673	($250)	($795)	($977)	($1,040)	($1,061)	*($269)*	**($2,694)**
Option 2	($1)	($74)	($61)	($81)	$1,524	($295)	($789)	($972)	($1,032)	($1,052)	*($283)*	**($2,833)**
Option 3	($2)	($6)	($14)	($86)	$354	($215)	($315)	($345)	($365)	($362)	*($136)*	**($1,356)**
Upper-Bound Government Revenue Changes (U.S.$ millions)	**U.S. Only**											
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-24 Annual Avg**	**2015-24 Sum**
With Keystone XL												
Option 1	($1)	($123)	($157)	($214)	$141	($539)	($693)	($745)	($779)	($777)	*($389)*	**($3,887)**
Option 2	($1)	($118)	($177)	($238)	$163	($414)	($542)	($574)	($596)	($602)	*($310)*	**($3,099)**
Option 3	($3)	($15)	($44)	($163)	$239	($349)	($372)	($386)	($394)	($397)	*($188)*	**($1,884)**
Without Keystone XL												
Option 1	($2)	($114)	($104)	($137)	$2,210	($365)	($1,162)	($1,428)	($1,519)	($1,550)	*($417)*	**($4,171)**
Option 2	($1)	($109)	($89)	($119)	$1,992	($432)	($1,154)	($1,421)	($1,509)	($1,537)	*($438)*	**($4,379)**
Option 3	($3)	($9)	($20)	($126)	$282	($314)	($460)	($504)	($533)	($529)	*($222)*	**($2,216)**

Source: ICF modeling results

Note: Lower-bound government revenue changes assume multiplier effect of 1.3, and upper-bound government revenue changes assume multiplier effect of 1.9.

Exhibit 7-17: Canadian Government Revenue Changes

Lower-Bound Government Revenue Changes (U.S.$ millions)	Canada Only											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-24 Annual Avg	2015-24 Sum
With Keystone XL												
Option 1	($3)	($202)	($1,043)	($1,122)	($1,036)	($839)	($598)	($581)	($578)	($573)	*($658)*	**($6,575)**
Option 2	($3)	($191)	($867)	($931)	($821)	($791)	($546)	($533)	($532)	($527)	*($574)*	**($5,742)**
Option 3	($6)	($32)	($490)	($686)	($550)	($378)	($369)	($363)	($363)	($368)	*($361)*	**($3,605)**
Without Keystone XL												
Option 1	($3)	($185)	($1,081)	($1,529)	($8,105)	($2,700)	($933)	($562)	($535)	($510)	*($1,614)*	**($16,143)**
Option 2	($3)	($174)	($1,047)	($1,489)	($7,330)	($2,390)	($855)	($480)	($462)	($446)	*($1,468)*	**($14,676)**
Option 3	($6)	($19)	($633)	($814)	($700)	($663)	($411)	($391)	($382)	($374)	*($439)*	**($4,393)**
Upper-Bound Government Revenue Changes (U.S.$ millions)	**Canada Only**											
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-24 Annual Avg**	**2015-24 Sum**
With Keystone XL												
Option 1	($4)	($295)	($1,525)	($1,639)	($1,514)	($1,226)	($875)	($850)	($845)	($838)	*($961)*	**($9,611)**
Option 2	($4)	($279)	($1,267)	($1,361)	($1,201)	($1,156)	($798)	($779)	($777)	($770)	*($839)*	**($8,392)**
Option 3	($9)	($46)	($716)	($1,002)	($804)	($552)	($539)	($530)	($530)	($538)	*($527)*	**($5,266)**
Without Keystone XL												
Option 1	($5)	($270)	($1,579)	($2,235)	($11,845)	($3,946)	($1,363)	($822)	($782)	($746)	*($2,359)*	**($23,593)**
Option 2	($4)	($254)	($1,531)	($2,177)	($10,712)	($3,493)	($1,250)	($702)	($675)	($652)	*($2,145)*	**($21,450)**
Option 3	($9)	($28)	($926)	($1,190)	($1,024)	($969)	($600)	($571)	($559)	($547)	*($642)*	**($6,423)**

Source: ICF modeling results

Note: Lower-bound government revenue changes assume multiplier effect of 1.3, and upper-bound government revenue changes assume multiplier effect of 1.9.

Appendix E: Assessment of Refinery and Terminal Crude Unloading Capacity

To ensure that the assumptions and inputs to the model were reasonable, ICF undertook an assessment of refinery and terminal crude unloading capacity. ICF found that there has been significant investment to increase deliveries by rail into U.S. and Canadian refineries both directly or indirectly. Direct would be via specific facilities at refineries to handle unit trains. Indirect would be unit trains to distribution hubs where the crude is then moved into the refineries by either marine or local pipeline connections. Based on an analysis of published information on rail unloading facilities, there are over 2.3 million bpd of rail receiving capacity today, and an additional 2.1 million bpd in the under-construction/planning/permitting stage (Exhibit 7-18).

Exhibit 7-18: Combined Refinery and Terminal Crude Unloading Capacity

Current and Planned	Crude Unloading Capacity (bpd)				
	PADD 1	PADD 2	PADD 3	PADD 5	Total
Current	815,000[56]	50,000	1,261,500	287,600	2,414,100
Planned	300,000	22,500	914,500	1,010,000	2,247,000
Total	**1,115,000**	**72,500**	**2,176,000**	**1,297,600**	**4,661,100**

Source: Company websites, SEC filings, and investor materials.
Reuters. "FACTBOX - U.S. crude by rail projects; Valero to start up Port Arthur TX project." Chicago Tribune, February 12, 2014: Houston, TX. Available at: http://articles.chicagotribune.com/2014-02-12/news/sns-rt-usa-cruderail-factbox-20140210_1_bpd-port-arthur-tx-canadian-crude-production

Note that there is currently far more unloading capacity than actual rail movements (U.S. plus Canadian loadings were about 885,000 bpd in 2013), and that significantly more rail expansion is currently in the planning and permitting stage. The bulk of the new capacity is in PADD 3 and PADD 5, which may reflect anticipated movement of Canadian oil sands to refineries in those markets.

The apparent "overbuild" of railcar receiving capacity likely reflects the desire of refiners and producers to have optionality on crude sales and purchases. It also reflects that to get economies of scale a unit train facility is clearly more desirable than manifest deliveries, and this may result in more receipt capacity than may be needed every day. Based on the estimated volumes of delivery into each PADD in January and February of 2014 (854,000 bpd), it appears that current utilization of railcar unloading facilities is about 36%.

Of the current unloading capacity, about 70% is based at terminals for subsequent movement to refineries and the balance is directly at refineries (Exhibit 7-19). Terminal receipts are by far the most prevalent in the Gulf Coast, where terminals represent over 90% of existing receipt capability (and terminals represent over 90% of new railcar unloading capacity). This reflects both the congested space at refineries for receiving full unit trains of crude oil and the existing integration of terminals such as St. James, LA and others to the refineries via pipeline connections and marine access.

[56] Includes potential shipments to Irving Oil in Canada from Albany via barge, which totaled 37,000 bpd in 2013

Exhibit 7-19: Current Refinery and Terminal Crude Unloading Capacity Breakdown

Mode	Crude Unloading Capacity (bpd)				
	PADD 1	PADD 2	PADD 3	PADD 5	Total
Refinery Direct	340,000	0	146,000	187,000	673,000
Via Terminal	475,000	50,000	1,115,500	100,600	1,741,100
Total Current	815,000	50,000	1,261,500	287,600	2,414,100

Source: Company websites, SEC filings, and investor materials.
Reuters. "FACTBOX - U.S. crude by rail projects; Valero to start up Port Arthur TX project." Chicago Tribune, February 12, 2014: Houston, TX. Available at: http://articles.chicagotribune.com/2014-02-12/news/sns-rt-usa-cruderail-factbox-20140210_1_bpd-port-arthur-tx-canadian-crude-production

Overall, the scope of the capacity growth in railcar unloading assets indicates that the industry is gearing for a continued increase in rail movements. This is likely due to the continued economics to get advantaged shale crude to East and West Coast refiners (since pipeline alternatives may be very costly), as well as the anticipated growth in oil sands crude and the slow development of pipeline options to move the crude. The bottom line is that assuming railcar standards are met, the rail receiving infrastructure is being developed to accommodate significantly more rail deliveries than current levels.

Canadian Refineries

Canadian refineries Irving Oil St. John and Valero Quebec have direct rail receiving capabilities (145,000 bpd and 60,000 bpd, respectively). Using direct rail receipts, Irving Oil receives about 50,000 bpd of WCS and Valero receives about 20,000 bpd of light crude. Irving Oil also receives Bakken crude oil railed to Albany, NY and barged to the facility. In 2013, 37,000 bpd of crude oil was railed to Buckeye's Albany facility and barged or shipped to Irving Oil's refinery.

Appendix F: Economics of Rail versus Foreign Imports for East Coast Refiners

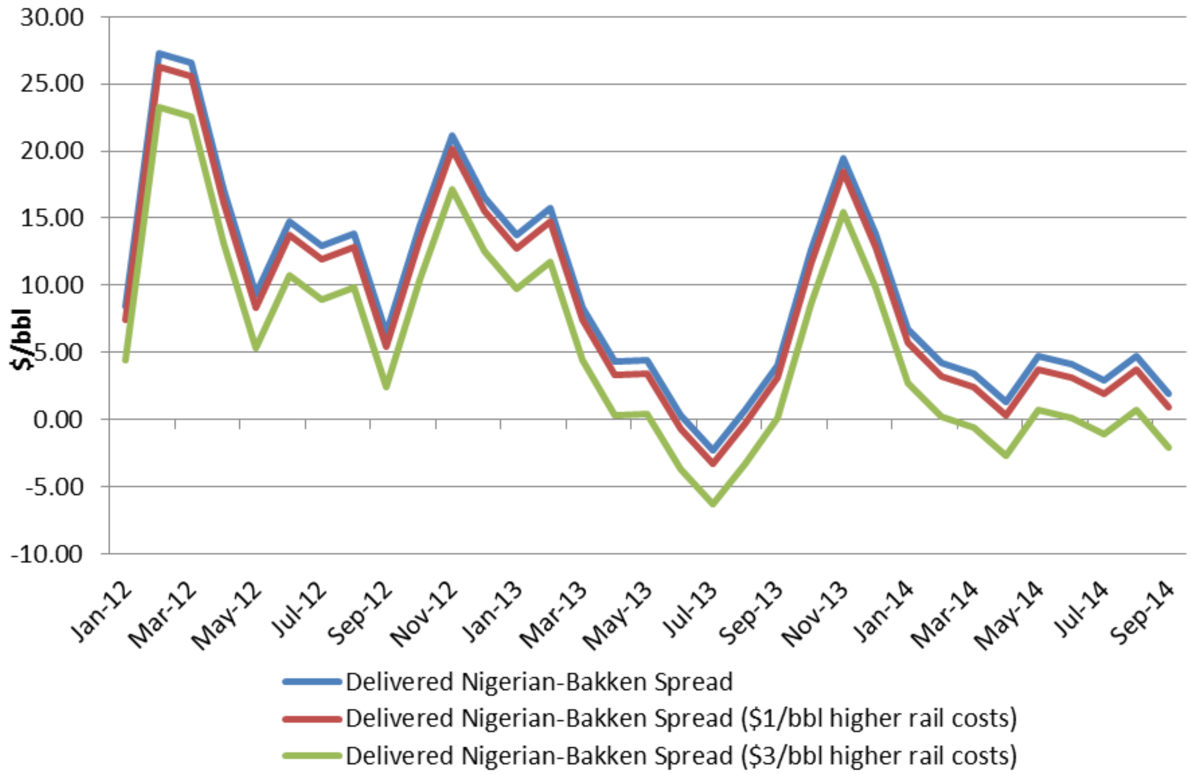
The decision to purchase crude for East Coast refiners has historically involved the identification of the most economic foreign light crude, since virtually all refineries on the East Coast are configured to process lighter crude oil.[57] The development of tight oil in the Bakken began to alter that process in 2011 as the crude was priced at a discount due to logistics constraints. East Coast refiners developed rail receiving facilities and midstream parties (Global, Buckeye, Enbridge, Plains) recognized the need for staging rail receipts and providing access to refineries. The parties primarily invested in building rail receiving assets in conjunction with existing storage in Albany (NY), Philadelphia (PA), and Yorktown (VA) where crude could be moved by marine assets to refiners or, in several cases, short pipelines.

The growing infrastructure allowed refiners to consider Bakken as an alternative with rail delivery, either directly or indirectly through third party terminals. Refinery economics considers both the landed cost of the crude at the refinery gate as well as the relative value of the crude within the refinery processing configuration. Each refinery has a different relative value for the same crude – often dollars per barrel different depending upon the existing configuration and constraints. Decisions on crude selection can swing on differences of as little as 25 cents per barrel.

However, looking at the estimated landed cost of the Bakken crude compared to foreign crude, it is very apparent that the drive to process domestic crude was very high for East Coast refiners. The exhibit below assumes that East Coast refiners purchased Nigerian crude, which has typically been priced at a $2/barrel premium to Brent for the grades typically processed on the East Coast, and the crude was delivered for a nominal additional $2/barrel marine freight. Bakken crude is loaded at rail facilities near the wellhead, and it is assumed priced at a premium of $2/barrel above the wellhead price to cover trucking costs to the rail loading facility (this is also about a $2/barrel discount from the Clearbrook, MN pipeline price). With these assumptions, the landed cost incentive for Bakken is shown in the chart below (Exhibit 7-20).

[57] The exceptions are the PBF refineries in Delaware City, Del and Paulsboro, NJ who have cokers and can run heavier grades.

Exhibit 7-20: Comparison of Delivered Bakken to Delivered Nigerian, $/bbl Bakken Advantage



Source: Bloomberg pricing, ICF analysis, Hellerworx rail rates

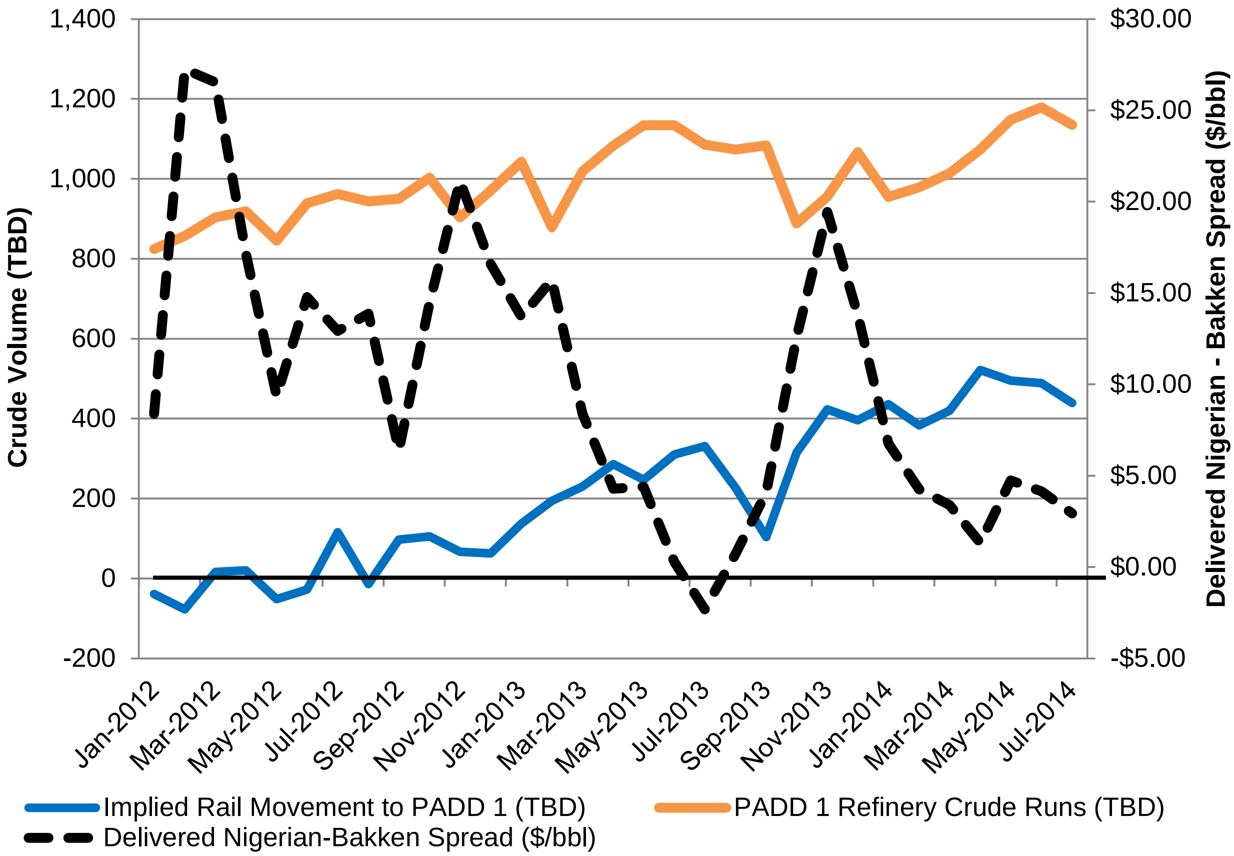
The economics have been sensitized to base railcar rates to the East Coast, and the railcar rates include $1.50/bbl for both loading and unloading fees. The comparison is sensitized for $1 and $3/bbl higher rail fees, which could reflect either inflated lease costs or additional costs to barge product to the refinery destination. The incentive, particularly through spring of 2013, to move Bakken crude to East Coast refineries was incredibly strong.

The benefit has become less substantive since early 2013, averaging about $6/bbl versus over $15/bbl in 2012 and early 2013. The primary reason for this is that the Bakken volumes moving to the East Coast by rail began increasing substantially in 2013 as East Coast refineries and terminals began operating their new assets and processing crude. Prior to 2013 there was limited ability to receive the crude and Bakken discount could not be fully realized by East Coast refiners. The refiners have “bid up” the value of Bakken and in fact have been pulling volume away from Bakken area pipelines, which are not fully loaded now.

Despite the dip in the Bakken advantage in mid-2013 and the more narrow advantage in 2014, refiners have not appeared to reduce the volume of Bakken moved by rail, based on EIA data.

The exhibit below shows PADD 1 crude adjustment volumes (which are implied rail volumes) monthly versus the monthly spread.

Exhibit 7-21: PADD 1 Crude Runs, Domestic Runs, and Nigerian-Bakken Price Spread



Source: Bloomberg.
U.S. Energy Information Administration. "East Coast (PADD 1) Supply Adjustment of Crude Oil." EIA, accessed February, 2014. Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRUA_R10_2&f=M
U.S. Energy Information Administration. "East Coast (PADD 1) Refinery Net Input of Crude Oil." EIA, accessed February, 2014. Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRRO_R10_1&f=M

Note that the chart shows that the decline in the Bakken advantage in July 2013 appeared to reduce PADD 1 rail deliveries a month or two later. There was also a decline in refinery runs in late 2013, however this seemed to be timed well after the decline in the Bakken advantage had ended and is more likely turnaround related. The months of October and November, despite lower crude runs had higher Bakken/domestic shipments as the positive economic advantages for running Bakken strengthened. Overall, this analysis supported the conclusion that East Coast refiners would continue to have an incentive to increase rail movements of Bakken crude.

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