BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ROUTE APPROVAL OF KEYSTONE XL PIPELINE PROJECT, PURSUANT TO MAJOR OIL PIPELINE SIDING ACT	**APPLICATION NO: OP-003** **DIRECT TESTIMONY OF EXPERT LORNE STOCKMAN**

State of Virginia)

) ss.

City of Staunton)

On Behalf of

Landowner Intervenors

June 6, 2017

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I. BACKGROUND AND EXPERIENCE

1Q. Please state your name, position, and business address.

A. My name is Lorne Stockman. I am the Senior Research Analyst at Oil Change International. My business address is 714 G St. SE #202, Washington, DC 20003.

2Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Landowner Intervenors.

3Q. Would you briefly describe your educational and professional background?

A. For the past twenty years I have performed research and written reports on the petroleum and energy industries and economics, with a particular emphasis on the risks faced by investing in projects related to economically marginal crude oil developments. My research experience includes analysis of climate change and energy, the political economy of oil, transitions in energy markets, energy security, and financial risk. I hold a Master's Degree from King's College London. My qualifications may be found in my Curriculum Vitae, attached to this report as Attachment LS-1.

4Q. Are you familiar with the Keystone XL Project (the "Project") and its related application before the Nebraska Public Service Commission ("Commission") pursuant to Neb. 21 Rev. Stat. § 57-1401 *et seq*.?

A. Yes. I have reviewed the Application. If approved, the Project would allow TransCanada Keystone Pipeline, L.P. ("Keystone") to construct, operate, and maintain a 36-inch diameter crude oil pipeline and ancillary facilities. The Project is designed to transport up to 830,000 barrels per day of crude oil from Hardisty, Alberta, Canada, to Steele City, Nebraska. The possible sources of crude oil that would be transported on the Project include oil extracted in Alberta and in the Williston Basin. There are two "onramps" for the Project: one in Hardisty, Alberta, and the other near Baker City, Montana. Oil from these upstream onramps would be transported to Steele City, at which location the Project would connect to an existing 36-inch diameter pipeline that is owned by Keystone and transports crude oil from Steele City to a Keystone terminal near

Cushing, Oklahoma. Upon arrival in Cushing, the crude oil would be delivered to other pipelines that would transport this crude oil to a number of possible locations, including but not limited to oil refineries in Kansas, Oklahoma, Texas, and Louisiana, and to export facilities on the Gulf of Mexico.

The Project would increase Keystone's capacity to transport crude oil from the Tar Sands Region in northern Alberta and conventional oil fields in western Canada. Most of the crude oil transported by the Project would be diluted bitumen or "dilbit." Bitumen is a heavy petroleum oil that is extracted from the Tar Sands Region of Western Canada by surface mining or by *in situ* extraction using wells into which steam is injected. Since bitumen is too viscous to flow through typical crude oil pipelines, to decrease its viscosity bitumen is mixed with a diluent comprised of lighter petroleum oils. The industry uses a variety of substances, such as natural gas condensate and synthetic crude oil, for diluent.

The Project could also transport light crude oil extracted from the Williston Basin in western North Dakota and eastern Montana. This being said, the construction of the Dakota Access Pipeline ("DAPL") has created excess takeaway capacity from the Williston Basin, such that it is unlikely that significant quantities of Williston Basin crude oil would be transported by the Project.

5Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information with regard to whether the Project is in the "public interest" in accordance with Section 23.07 of the Commission's Major Oil Pipelines permit regulations. Specifically, this testimony contains evidence that Keystone has not committed to construct the Project and the market-related reasons why it is unneeded and unlikely to be built, such that approval of construction of the Project is not in the public interest. In particular, this testimony provides evidence related to the following:

- the relationship between oil price and the development of additional crude oil supply available for export from western Canada;

- an evaluation of western Canadian crude oil historical supply available for export and supply forecasts showing that future supply for export from western Canada will be limited;
- current Canada to U.S. import pipeline capacity and utilization and the potential impact of other proposed import pipelines;
- the record levels of crude oil supply in storage in Oklahoma and the U.S. Gulf Coast and the implications of this glut on demand for additional oil import capacity into this region;
- the lack of growth in domestic consumer demand for petroleum and the current demand trends that will suppress demand growth in the future, and the growth of U.S. crude oil production; and
- the growth in exports of crude oil and petroleum products from the U.S.

6Q. Would you describe your professional experience related to determining need for petroleum infrastructure?

A. I have worked as a research analyst on the oil and gas industry for nearly 20 years and have been specifically focused on the North American industry for over ten years. My primary focus in the last ten years has been the Canadian oil sands sector as well as the shifting trends in U.S. supply and demand.

II. THE NEED FOR THE PROPOSED KEYSTONE XL PIPELINE DEPENDS ON GROWTH IN WESTERN CANADIAN CRUDE OIL PRODUCTION, WHICH IS UNLIKELY TO INCREASE SUBSTANTIALLY

7Q What is the commercial basis for the Keystone XL Pipeline?

A. The primary commercial basis for the Keystone XL Pipeline is to transport crude oil from Alberta, Canada, to Cushing, Oklahoma, and the U.S. Gulf Coast, and particularly refineries and ports in Texas and Louisiana. It will be needed only if: (a) additional new crude oil supply is available for export in the future; and (b) the capacity of other pipelines and railroads to transport this new supply crude oil supply is insufficient or less economic than the proposed Keystone XL Pipeline. At any given time, there is a limited demand for crude oil transportation services. Building more pipeline capacity than the total crude oil supply available for transport is uneconomic and needlessly increases the cost of petroleum fuels. Conversely, building too little pipeline capacity can result in the use of more expensive transportation options, such as rail.

8Q Have you examined any data related to the potential for growth of crude oil supply for export from western Canada?

A. Yes. I have examined the impact of oil price on the rate of development of crude oil extraction projects in western Canada. Specifically, I have reviewed the costs of: (a) developing new extraction operations, (b) transporting western Canadian crude oil to market, (c) refining heavy western Canadian crude oil relative to refining other types of crude oil.

9Q What is the relationship between oil price and the rate of growth of western Canadian crude oil supply?

A. With regard to the development of new oil extraction projects in Canada, at a minimum the price paid for the crude oil produced by new projects must be high enough to pay for the cost to extract the crude oil from the ground, prepare it for market, ship it to market, and provide a return on investment that is sufficient to attract investors and financiers. Should the combination of these costs be greater than the market price of the particular grade of crude oil produced by a project, then Canadian oil project developers would need to either: (a) build anyway and plan to sell at a loss; or (b) delay or terminate their project development efforts.

Since late 2014, oil prices have slumped and currently remain well below the average breakeven cost required for new oil sands projects to go forward. The price paid for western Canadian crude oil has been too low relative to the cost of building new projects to attract significant new investment in oil extraction and processing facilities, with the result that the Canadian oil industry has not substantially increased the overall supply of crude oil available for export from Canada for over two years. Most in the industry today believe this is a structural market shift characterized by the flexibility of

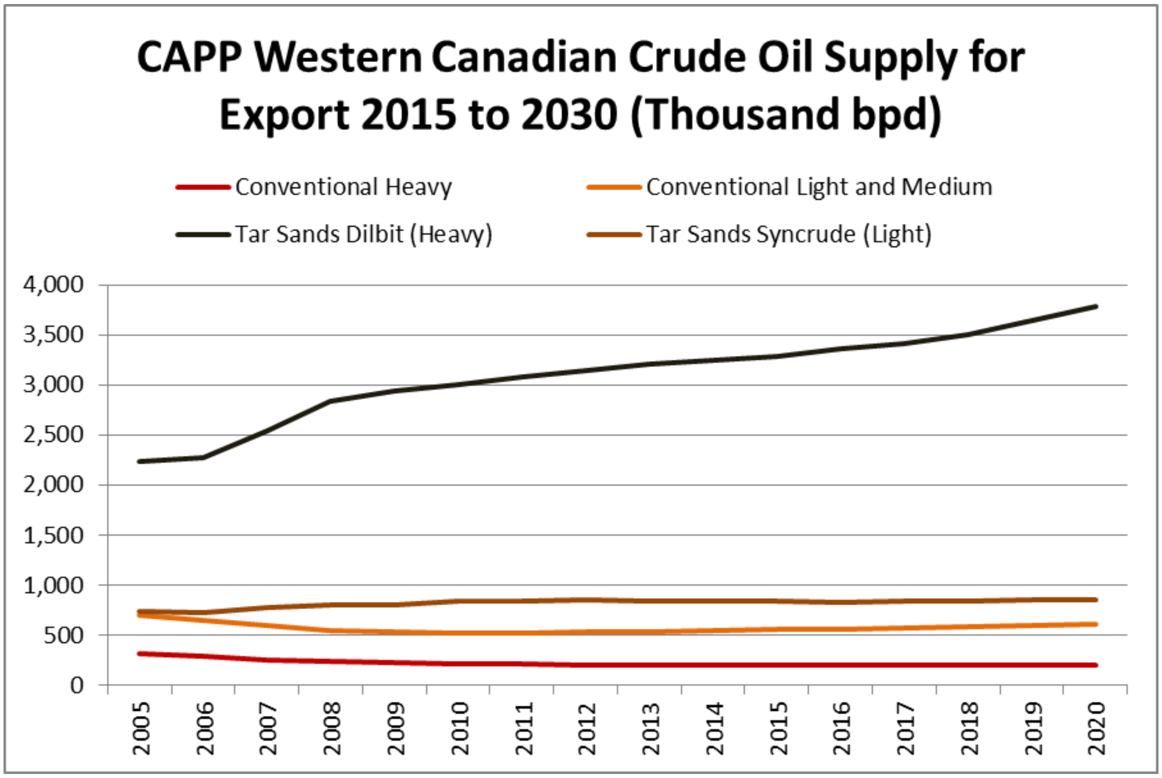
U.S. shale oil production and tepid global demand growth and have labeled the current oil price era as "lower for longer."

The main source of western Canadian oil production is in the province of Alberta, which produces:

- conventional light, medium, and heavy crude oil;
- unconventional light hydrofracked crude oil from shale formations in the Williston Basin; and
- unconventional crude oil from the "oil sands" or "tar sands," which is exported in the form of synthetic crude oil ("syncrude") and dilbit.

The petroleum deposit in the tar sands region is comprised of a thick viscous hydrocarbon called bitumen. Attachment LS-2. It is found in generally shallow formations mixed with sand, clay and water. Shallower formations may be exploited via open pit mining, but deeper formations can be accessed only via steam injection technologies. Mined bitumen requires intensive processing to separate the sand and clay from the bitumen. The steamed or "*in situ*" production results in relatively pure bitumen but only after weeks of pumping steam underground to liquefy the bitumen enough to be extracted through production wells. These extraction methods are resource intensive relative to 'conventional' methods, with the result that the vast majority of western Canadian oil production is significantly more expensive to extract than 'conventional" crude oil. Attachment LS-3.

The following charts of Canadian Association of Petroleum Producers ("CAPP") data show different views of the same 2016 forecast of western Canadian crude oil supply available for export by type. The data used to generate these charts is from the CAPP June 2016 report on Crude Oil Forecasts, Markets and Transportation ("2016 CAPP Report"), Appendix B.2 Attachment LS-4. Although I do not agree that dibit extraction will grow to the extent forecast by CAPP, these charts are useful because they show that the industry forecasts that dilbit is the only type of crude oil supply for export that might increase to any significant degree over time.


CAPP Western Canadian Crude Oil Supply for Export 2015 to 2030 (Thousand bpd)
Conventional Heavy
Conventional Light and Medium
Tar Sands Dilbit (Heavy)
Tar Sands Syncrude (Light)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2005
2006
2007
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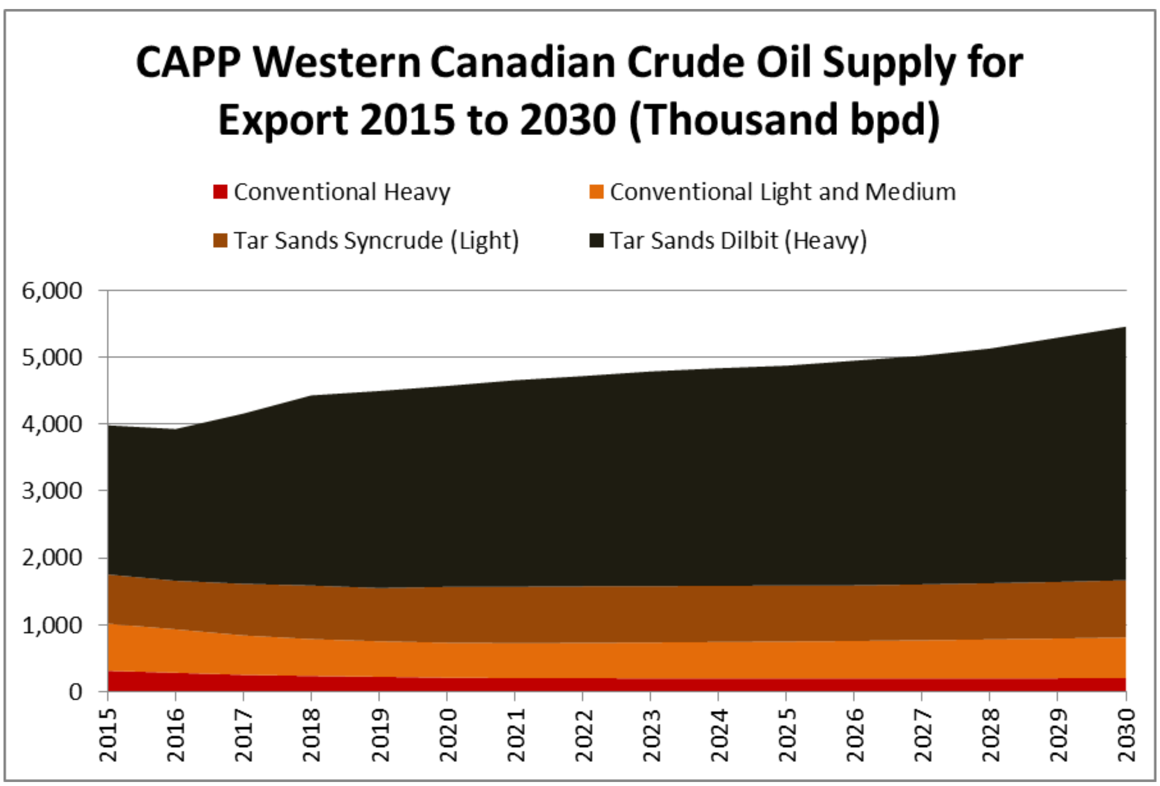
CAPP Western Canadian Crude Oil Supply for Export 2015 to 2030 (Thousand bpd)
Conventional Heavy
Conventional Light and Medium
Tar Sands Syncrude (Light)
Tar Sands Dilbit (Heavy)
6,000
5,000
4,000
3,000
2,000
1,000
0
2015
2016
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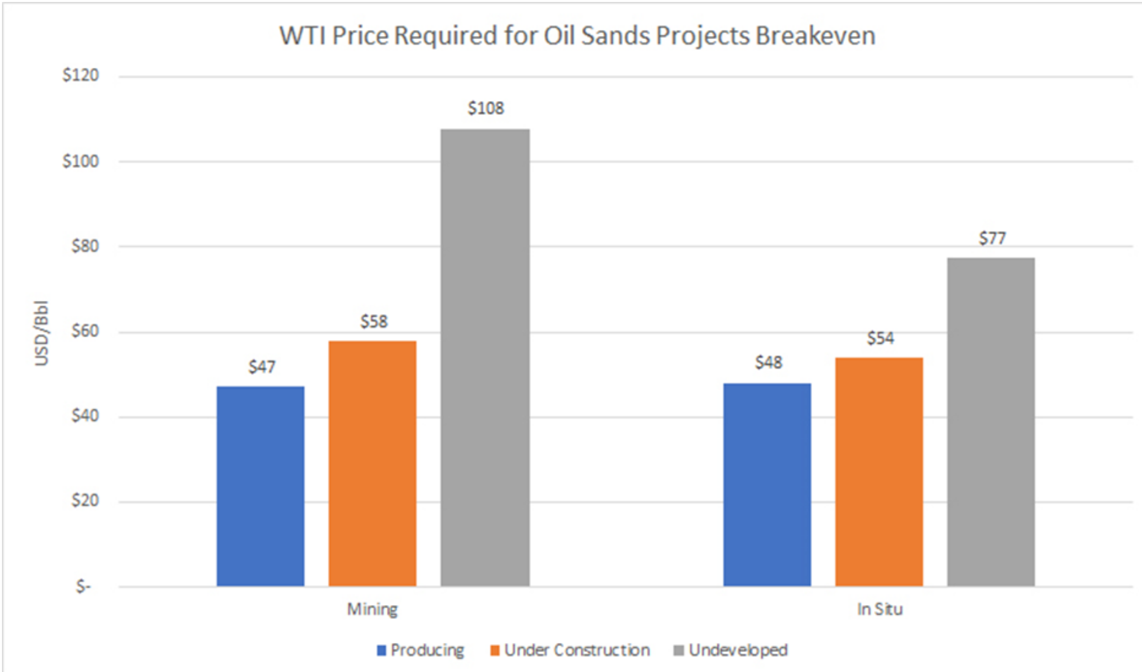
CAPP updates this report each June. CAPP is a trade association whose member companies produce about 85% of Canada's oil and natural gas. *Id.* In its forecasts, CAPP combines hydrofracked light crude oil with conventional light crude oil.

There is no bright line between conventional and unconventional crude oil, but conventional oil is that which can be extracted using traditional vertical oil wells with limited need for more exotic technologies. In comparison, unconventional oil is that which requires significant commitments of technology, money, and energy to extract. Extraction of oil from the tar sands region requires either open pit mining combined with partial refining (upgrading) of the extracted bitumen, or the use of paired horizontal steam injection and extraction wells. Both mining/upgrading and steam extraction are expensive and energy and labor intensive.

Once the bitumen is extracted there is still much that needs to be done to process it into the petroleum products the market requires, primarily gasoline and diesel. Bitumen is too viscous to transport through pipelines, such that it must either be semi-refined (upgraded) into a product called syncrude, or it must be diluted with lighter hydrocarbons, similar to solvents that essentially liquefy the bitumen to create dilbit.

Syncrude production requires that oil companies invest in and construct upgraders, which are expensive and require substantial time to construct. As a general rule, most syncrude is derived from open pit mining, because the mining process itself does not separate the raw bitumen from the sand, clay, and water with which it is mixed in the ground. Instead, the raw bitumen is separated from these other materials by upgraders that also partially refine it into syncrude, which is classified as a light sweet (low sulfur) crude oil. The equipment needed to perform this upgrading is expensive.

The chart below of data provided by Rystad Energy, an independent commercial provider of global energy data, shows that future oil sands mining projects will need a U.S. (WTI equivalent) oil price of $108 per barrel – just to breakeven. Attachment LS-5. This chart is based on the latest May 2017 data from Rystad Energy and already accounts for the cost savings realized in the sector as a result of the slowdown in activity and consolidation since the oil price crash. *Id.*



Production of dilbit is also expensive. Dilbit is produced using bitumen extracted by *in situ* production technology. The most common *in situ* technology is called 'steam assisted gravity drainage' or 'SAGD' production. Steam generation requires large amounts of natural gas, which must be transported to the SAGD fields and combusted in steam generators. The produced steam is then forced underground at high pressure to gradually heat the bitumen to the point that it liquefies and flows into an extraction well. The resources needed to extract bitumen by the SAGD method also increase the cost of extracting bitumen to well above the cost of conventional oil production. The chart above shows that future *in situ* projects have a breakeven price of $77 per barrel (WTI equivalent), well below the current price of crude oil. *Id.*

The USEIA's WTI spot price data shows that the price of this oil has averaged $51 since the beginning of the year. Attachment LS-6. At this price level, western Canadian oil extraction projects under development today are likely to begin production making a loss, and currently producing projects are operating at little to no profit. The future of oil prices is of course hard to predict but at the time of writing WTI Futures out to December 2025 are trading within a range of $40 to $65, which indicates that oil market professionals do not anticipate a rapid increase in oil price.

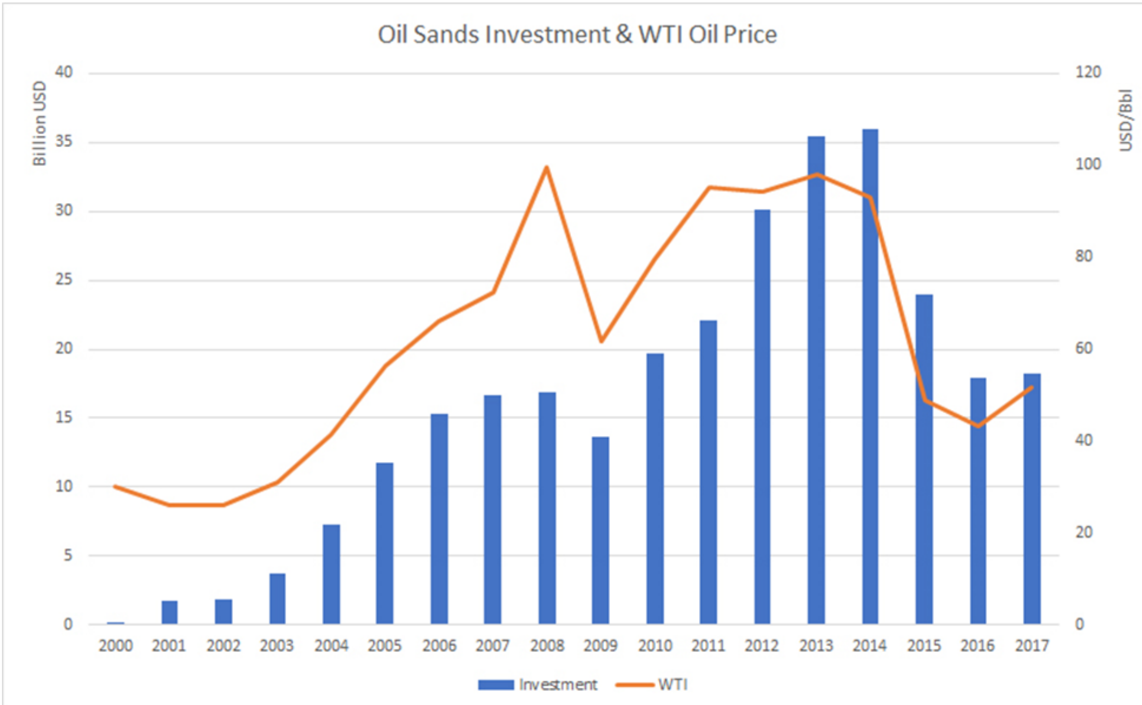
In addition to the foregoing costs of extraction, transporting bitumen to market is expensive because Canadian oil companies must blend the bitumen with diluent to make dilbit. Attachment LS-7. On average only 72% of a barrel of dilbit transported in a pipeline is bitumen. *Id.* This means that Canadian oil companies must buy 0.28 barrels of diluent for each 0.72 barrels of bitumen. *Id.* To get a full barrel of bitumen to market, the oil companies must ship 1.43 barrels of dilbit. *Id.* Making dilbit requires that Canadian oil companies purchase diluent, transport the dilute to the production site via pipeline, and blend the diluent and bitumen in mixers. *Id.* This process also increases the cost of producing dilbit relative to the cost of conventional crude oil.

Once a barrel of dilbit arrives at a refinery it requires several additional steps to convert it to useful products, such that only complex refineries can handle it. *Id.* These refineries super-heat the bitumen in expensive refining equipment called "cokers," add hydrogen to liquefy it, and intensively treat the bitumen to remove the high levels of sulfur, heavy metals and other contaminants that cannot be carried through to the finished petroleum products. *Id.* The intensive and expensive processing required to refine bitumen means that refinery companies will pay less for bitumen than they will for lighter and cleaner sources of feedstock that are less expensive to refine. Thus, dilbit is not only more expensive to produce than other crude oils, but it is also a lower value product that is worth less per barrel than other types of crude oil.

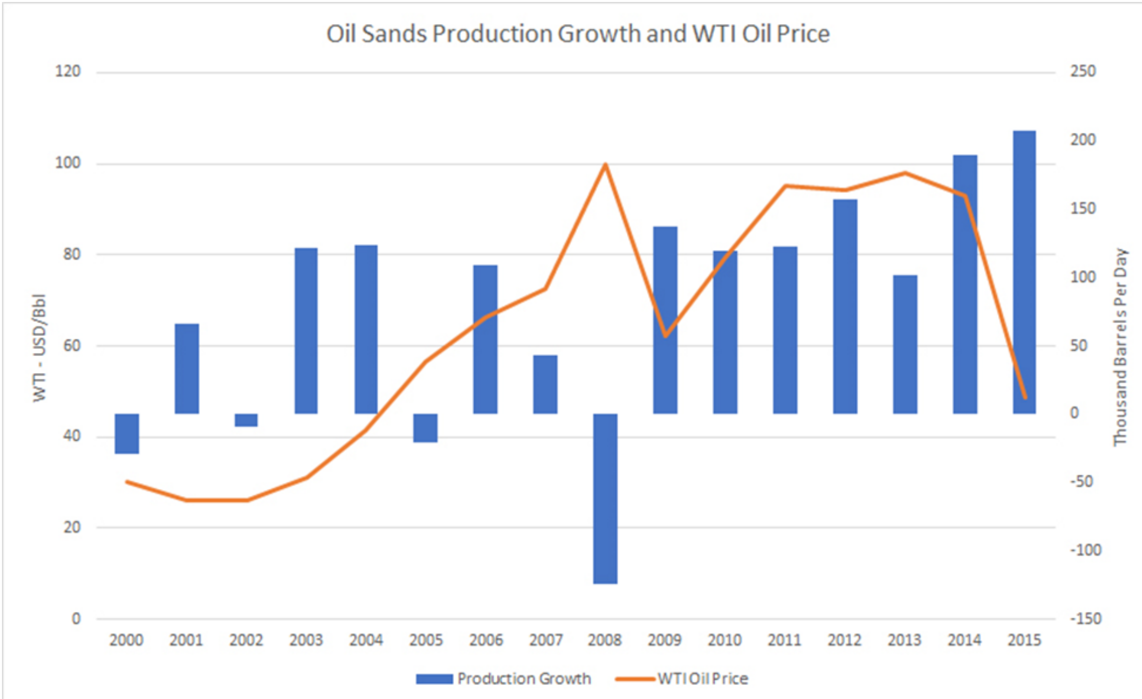
In addition, dilbit is produced only in remote northern Alberta. This means it must be transported very long distances by pipeline or rail to U.S. refineries. The current FERC-approved international joint tariff for transporting dilbit on the Keystone Pipeline from Hardisty, Alberta, to Houston, Texas, is $7.730 per barrel, though not all shippers are eligible to ship at this discounted price. Attachment LS-8. Similarly, the lowest current FERC tariffs to transport dilbit on Enbridge pipelines (Enbridge Mainline System to Flanagan South to Seaway) between Hardisty and Houston is $6.7042 per barrel. *Id.* In comparison, the cost of shipping crude oil from west Texas to refineries on the U.S. Gulf Coast is typically about $2 per barrel or less, depending on the distance (*e.g.,* Magellan Crude Oil Pipeline, L.P., tariff). *Id.* Since refineries base oil purchases on the as-delivered cost of crude oil, U.S. Gulf Coast refineries will buy Canadian crude oil only if its price is discounted so that it can complete with closer crude oil suppliers.

Dilbit's expensive extraction and processing methods, the distance it travels to market, and the lower price it fetches, all mean that global oil prices must be relatively high to make its extraction profitable. As noted above, the current breakeven price is estimated to be $108 per barrel. In the past, the boom in Canadian tar sands development was caused by historically high oil prices. The relationship between rising oil prices in the first 14 years of this century and investment in oil sands production is very clearly shown chart below of Rystad Energy data showing oil sands investments as of May 2017. Investment amounts include exploration capital expenditures (expex), capital expenditures (capex) and operational expenditures (opex). The WTI price data is from

USEIA. (Attachment LS-9).

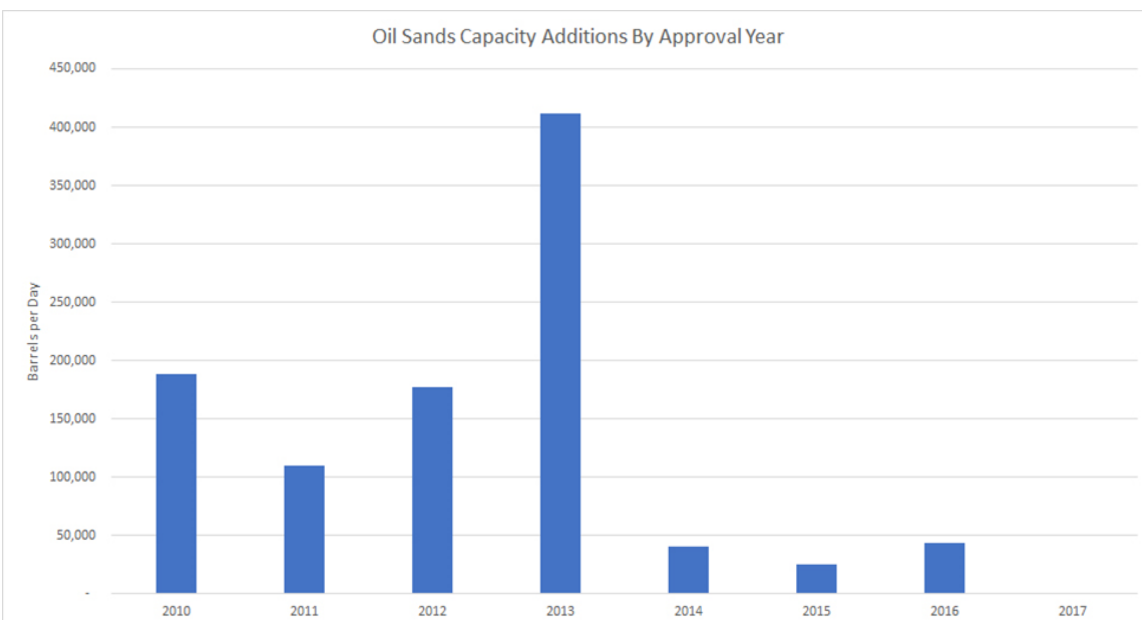


The chart of Rystad Energy data below shows oil sands production growing the most between 2010 and 2015 during the steadiest period of high oil prices, although the lag between investment and production and the economic crash in 2009 make for some anomalies over the long term back to 2000. *Id.* As discussed below, in 2016, growth in oil sands supply available for export was minimal.



10Q Have low oil prices actually impacted oil industry investments in western Canada?

A. The oil price slump has slowed the development of new oil sands production to a trickle and has thrown into question the future of the sector. The chart below of Rystad Energy data shows the total capacity of all new oil extraction projects sanctioned by the oil industry in western Canada. Attachment LS-10.

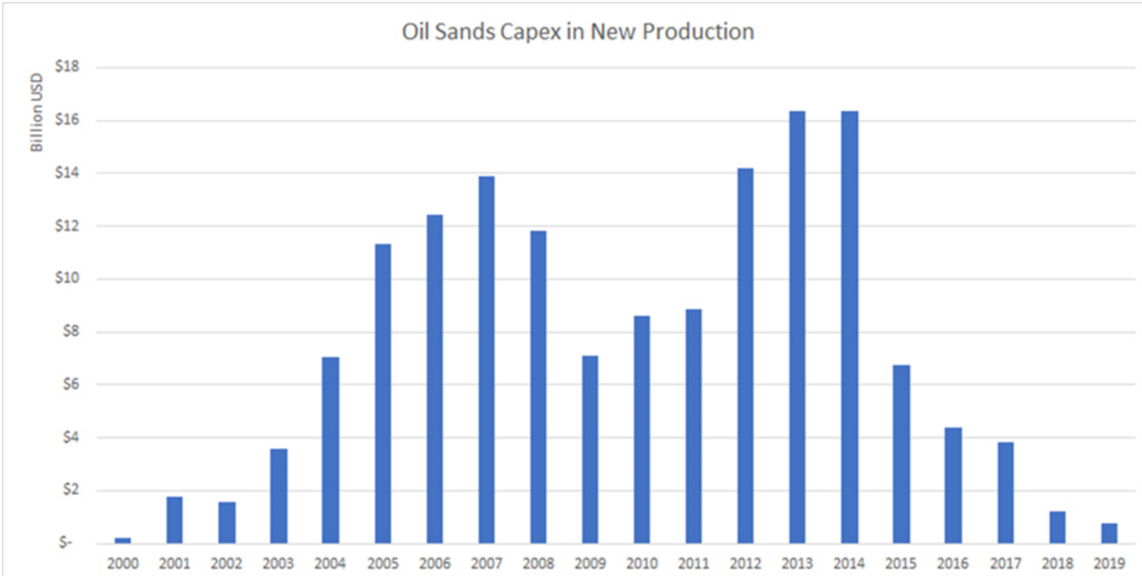


Projects sanctioned before the oil price slump in late 2014 continue to move forward, but since the beginning of 2015 only three minor capacity additions have been sanctioned (a final investment decision by a company). Unless more projects are sanctioned, extraction project construction will peter out before 2020. It is unlikely that new extraction projects will be sanctioned in the foreseeable future.

To understand the state of play with oil sands production growth, one must understand the investment cycle in the sector. Most expansion projects require lengthy construction periods spanning several years. This investment momentum is the key reason production capacity has continued to grow since the oil price collapse. The projects that have come online since late 2014, and those that are still under construction today, were primarily sanctioned before the oil price collapse. The three expansions that have been sanctioned since then are relatively modest incremental expansions of existing projects.

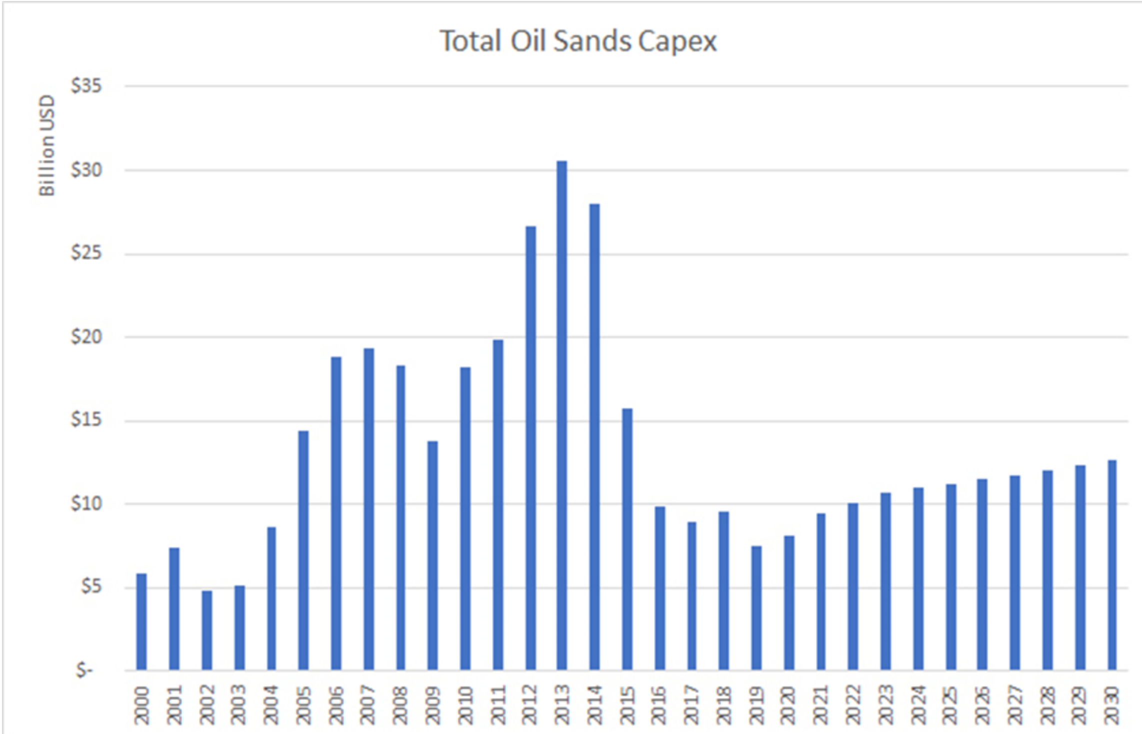
New projects will likely continue to come online through 2020 as remaining under-construction projects are completed, but the exact timing of their production ramp-up is uncertain. Moreover, the net increase in crude oil available for export from western Canada is uncertain, because the output of these new projects will be offset by declining production from older oil fields. Whether any further significant capacity is added after these currently sanctioned projects come online depends on oil prices rising enough to support new development. That currently appears a long way off. While development costs have been cut from the highs of the pre-2015 boom, nonetheless, the U.S. price of oil must be sustained above approximately $77 per barrel to justify new SAGD projects, and above approximately $108 per barrel to justify new surface mining projects. At present, oil market supply and demand fundamentals do not justify such high crude oil prices.

The disparity between the oil price needed to financially justify new oil sands projects on the one hand, and the prevailing oil price and prospects for price recovery on the other, has caused a dearth in investment in the oil sands sector that is today lower than it has been in over a decade. By 2019, investment in new projects in the oil sands is expected to drop to nominal levels. The Rystad Energy data in the chart below shows the annual capital expenditure (capex) spent on developing new oil sands production capacity since 2000, as well as a forecast of expenditures through 2019. Attachment LS-11.



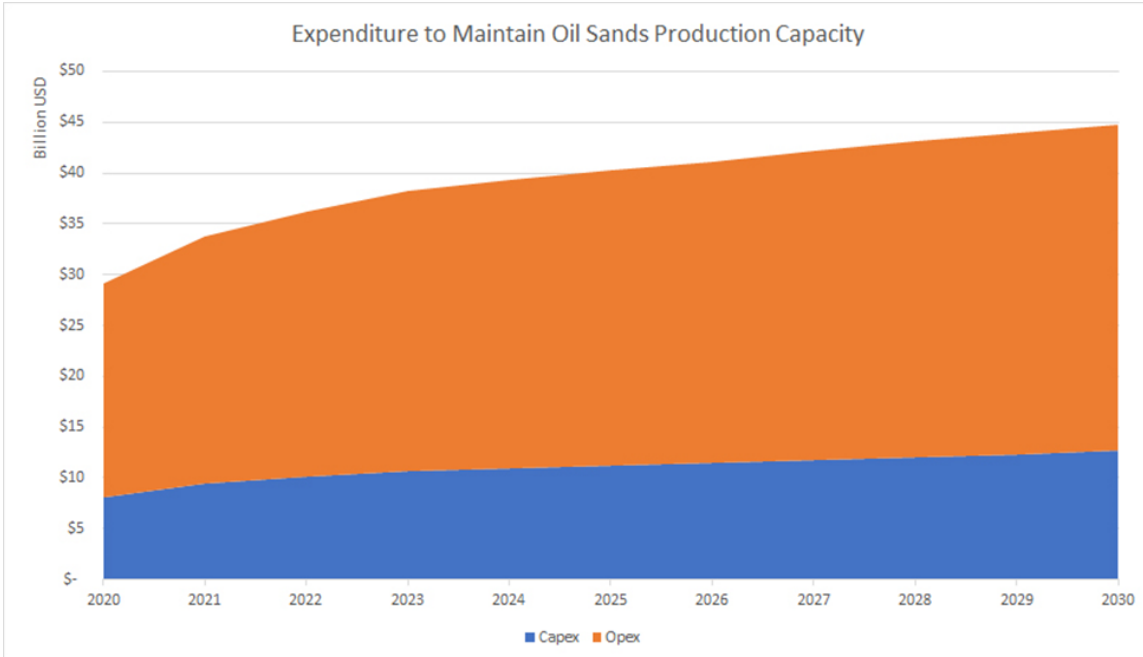
The projected capex shown in this figure beyond 2016 includes only investments in projects that have already been sanctioned. Thus, the Rystad data shows that capex in new extraction projects will end in 2019, indicating that no oil company has committed to build or expand a SAGD facility or surface mine beyond 2019.

This does not mean capex in the sector ceases completely. The chart below of Rystad Energy data shows the total capex spent in the oil sands including capex spent on maintaining production at ongoing projects. Attachment LS-12. This maintenance capex may be spent on, for example, drilling new wells at *in situ* projects within existing project boundaries (infill) in order to replace spent wells and maintain production. The capex shown after 2019 in this figure therefore would all be spent simply to maintain production levels at already producing projects. Therefore, despite projected capex rising from $8.2 billion in 2020 to $12.7 billion in 2030, no new production capacity will result from this level of capex.

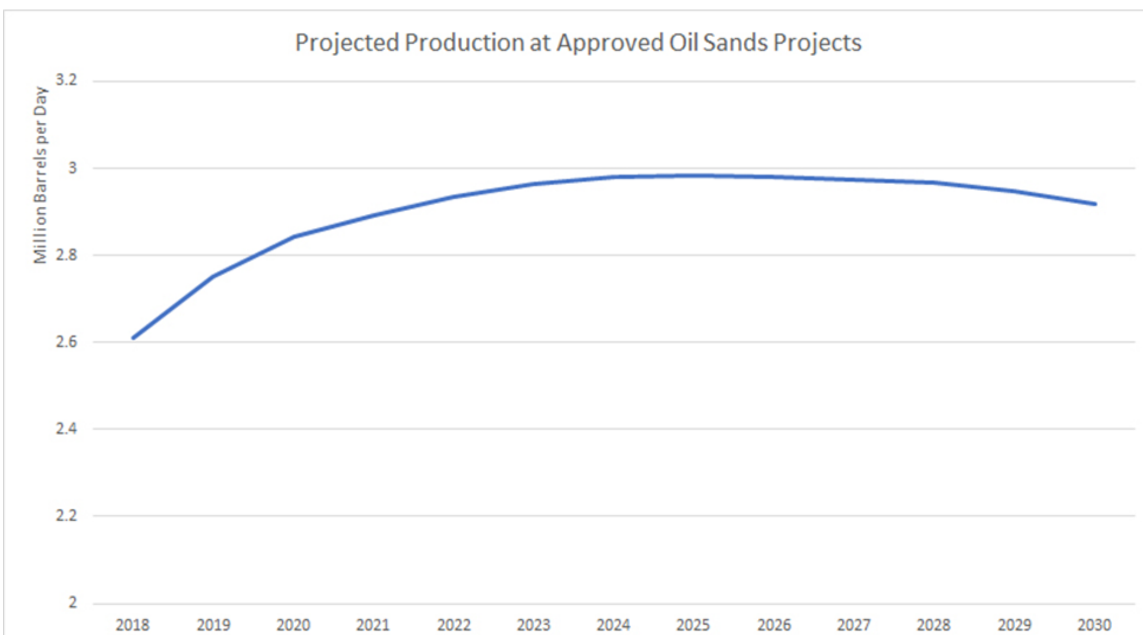


But the capex needed to maintain production is, of course, not the only expenditure required to keep production going. Operational expenditure (opex), which pays salaries, fuel and other supplies, processing, maintenance, and transport costs, is the main expense of continued production.

The chart of Rystad Energy data below shows that opex is projected to rise from $21 billion to $31.6 billion between 2020 and 2030. Attachment LS-13. This figure also shows that the total cost of maintaining the currently operational and sanctioned production capacity will rise to $44.8 billion by 2030.



Further, as the chart of Rystad Energy data below shows, despite this investment, production at the currently approved projects will start to decline from the mid-2020s as reserves deplete. Attachment LS-14.



During this same period, conventional oil fields are projected to decline from 933,000 bpd in 2016 to 811,000 bpd in 2030. CAPP 2016 Report, Attachment LS-4. Therefore, for western Canadian crude oil production to grow, new capacity additions in the Tar Sands Region will need to more than make up for depletion at existing conventional and unconventional projects, even as billions are spent to squeeze more oil out of these projects.

The lack of profit in oil sands project development has also resulted in major oil company pull-outs from western Canada. The table below shows that in the past year, five U.S. and European oil companies have sold their oil sands assets, while two more are thought to be considering sales. The source material for this table is provided in Attachment LS-15.

Date Announced	**Seller**	**Buyer**	**Reserves (million Bbls)**	**Production (Capacity Kbpd)**	**Sale Net Value (Million USD)**
Dec. 2016	Statoil	Athabasca	291	24	443
Apr. 2016	Murphy	Suncor	113	15.6	739
Mar. 2017	Shell	Canadian Natural	3,616	160	7,300
Mar. 2017	Conoco	Cenovus	5,465	280	13,300
Mar. 2017	Marathon	Shell/ Canadian Natural	1,214	50	2,500
Apr. 2017	BP	?	1,026	30	?
Apr. 2017	Chevron	?	1,071	50	?
Total			12,796	610	24,282

Since April 2016, over $24 billion has changed hands as Statoil ASA (Norway), Murphy Oil Corporation (U.S.), Royal Dutch Shell (Netherlands), ConocoPhillips (U.S.) and Marathon Oil Company (U.S.), sold their oil sands assets. *Id.* Shell, at one time a leading oil sands producer, sold all its oil sands assets but then bought a 50% stake in the assets sold by Marathon. *Id.* This left Shell as a 10% owner of the Albian Sands Project, in which it once owned a 60% stake. *Id.* Also, Shell retained an interest in Canadian Natural (CNRL) by receiving about 98 million CNRL shares in exchange for its direct ownership interests in oil sands projects, but it was reported in late May that Shell was looking to offload these shares in what could become the largest equity sale in Canadian history. *Id.* CNRL shares dipped on the announcement. *Id.* Any further decline in value at CNRL could also serve to limit that company's ability to make further investments.

ConocoPhillips was also one of the biggest players in the oil sands but sold its entire oil sands business along with other Canadian oil and gas assets to its oil sands project partner Cenovus. *Id.* Cenovus investors were not impressed and its stock fell 13% on the announcement. *Id.* This being said, it has recently been reported that ConocoPhillips is also looking to sell the Cenovus shares it received as part of this sale. *Id.*

Reports in April stated that both BP Global (U.K.) and Chevron Corporation (U.S.) were also considering sales, although these are yet to be officially announced. *Id.* There was some speculation about whether these companies may have missed the boat as the pool of capital available for such sales may have already dried up. *Id.*

The buyers listed above have essentially bought existing production at a discount, which is a less risky way to grow production at those companies compared to sinking capital into new projects. The sales have therefore reduced the pool of capital available for new projects as the number of companies involved in the sector is reduced and those remaining have spent capital on buying the assets of fleeing companies.

Additionally, the CEO of the largest oil sands company, Suncor Energy, recently told investors that his company had no plans for growth beyond that to which it was already committed. Attachment LS-16. CEO Steve Williams told investors at Suncor's end of year results conference in February 2017 that oil sands mining projects "are coming to an end, not just for Suncor but for the industry", that Suncor has "no plans to be going ahead with major capital investment in either mining or *in situ* in the foreseeable future" and that "(w)e have nothing of any materiality in the pipeline around mergers and acquisitions". In other words, the world's leading oil sands company has no plans for production growth in the foreseeable future. This is one of the clearest indicators that the future of oil sands production is highly uncertain and cannot constitute a source of oil supply that the United States can rely on.

11Q What conclusions do you draw about the future need for oil transportation capacity based on the foregoing information?

A. Unless oil prices rise modestly, many western Canadian oil production facilities will continue to lose money and the oil industry will struggle to make the new investments that are necessary just to maintain production. Absent a dramatic increase in oil price, development of new oil projects in Western Canada has ended, eliminating the need for any major increase in new crude oil pipeline export capacity from Canada.

III. WESTERN CANADIAN HISTORICAL PRODUCTION AND FORECASTS INDICATE THAT FUTURE INCREASES IN OIL SUPPLY FOR EXPORT WILL BE LIMITED

12Q. Please describe your review of data and forecasts related to crude oil production and supply in western Canada.

A. I have reviewed both the historical and forecasts of crude oil production and supply in the Western Canadian Sedimentary Basin (WCSB), including forecasts by the CAPP and the NEB. Production is defined as the total volume of crude oil produced in the WCSB. Supply is defined as the amount of this crude oil that is available to sell to distant customers, after taking account of refinery demand in the WCSB.

With regard to the CAPP data and forecasts, I have reviewed the data and forecasts for 2016. Attachment LS-4. This data includes both historical data of actual production and supply and forecasts of production and supply. Section 1.1 of the 2016 CAPP report states that its supply forecasts are based on a survey of its members and describes this survey as follows:

> The oil sands component of the forecast is based on CAPP's 2016 survey of all oil sands producers for the following data:

a) expected production for each project;

b) upgraded light crude oil production; and

c) volumes of upgraded crude oil and condensate used as diluent required to move the volumes to market.

This means that the CAPP forecasts are essentially based on the production plans of CAPP's member companies. The survey encompasses conventional crude oil production, bitumen and synthetic crude oil production, and fracked oil production from the Canadian Bakken Formation.

According to the CAPP reports, "supply" is calculated by first estimating total western Canadian production, which is the gross volume of petroleum produced by mines and wells, and then subtracting western Canadian refinery demand for this oil. Thus, the term "supply" is defined as the amount of petroleum available for transport from producing areas in western Canada to customers outside of this region. It does not necessarily mean the volume of crude oil exported to the U.S. or the volume of Canadian crude oil that is actually refined into finished petroleum products in the U.S.

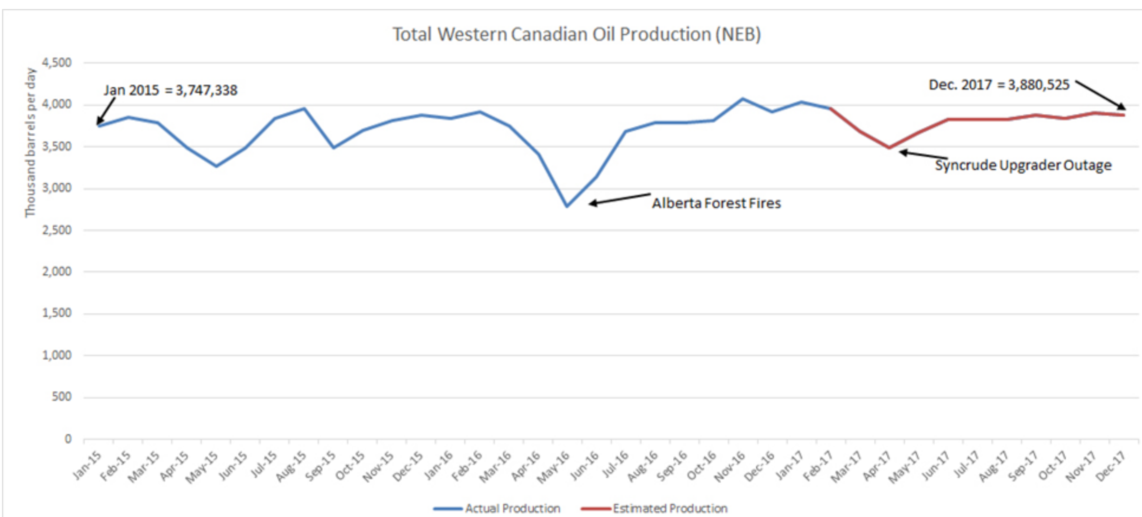
13Q. What conclusions do you draw from your review of the CAPP supply forecasts?

A. CAPP makes predictions every year concerning the number of barrels that it believes will be available as supply in subsequent years. The most recent report at the time that my testimony is due is the 2016 CAPP Report. The 2017 CAPP Report will be released in June 2017, such that I reserve the right to update my testimony on direct examination. The 2016 CAPP Report estimates that supply will increase from 3,981,000 barrels per day (bpd) in 2015 to 4,569,000 bpd by 2020, which is an increase of 588,000 bpd, and to 4,872,000 bpd by 2025, which is an increase of 891,000 bpd.

Since the CAPP June 2016 forecasts are based on its member companies' production forecasts from the beginning of 2016, which assumed rising oil prices through 2017, the accuracy of the CAPP 2016 forecasts fail to take into account continued low oil prices and are subject to the systemic bias inherent in these member forecasts. It seems likely that the CAPP member forecasts are biased by a variety of factors, including their need to satisfy shareholders and attract potential investors. Thus, the CAPP member forecasts are likely biased towards an optimistic assessment of future production. CAPP is a trade association formed to advance the interests of its members. Therefore, it is reasonable to expect that its forecasts of crude oil supply in western Canada would tend toward optimism and would generally be biased toward supporting a need for rapid pipeline development.

14Q. What conclusions do you draw from your review of the National Energy Board of Canada production and supply forecast?

A. The National Energy Board of Canada ("NEB") data shows that average western Canadian crude oil production in 2016 averaged 34,199 bpd less than in 2015, due in part to the fires in Alberta. Attachment LS-17. The NEB forecasts that average production in 2017 will be 160,344 bpd higher in 2017 than in 2016, on the expectation that there will be no significant disruption in supply, such as the fires. *Id.* This being said, peak production in 2017 is forecast to be less than the peak in 2016. *Id.* In fact, production in December 2017 is projected to be about the same as during the summer of 2015. *Id.*



Even though the industry expects new production capacity to come online in 2017, the NEB nonetheless forecasts an overall net decline in production during 2017, from 4.04 million bpd in January to 3.88 million bpd in December. Since the NEB's forecast cannot assume that major unexpected disruptions will occur, such as the 2016 wildfires and outage of the Syncrude upgrader, the forecast must instead assume that some other causes, such as operational issues and/or production depletion at existing projects, will reduce oil production in western Canada. The disparity between the industry's plans for new project capacity relative to the NEB's forecast of falling total western Canadian production suggests that maintaining production in Canada may require more investment than currently planned.

IV. CURRENT AND PROPOSED CANADA TO U.S. IMPORT PIPELINE CAPACITY AND UTILIZATION

15Q. Please describe your review of data related to the current pipeline capacity available to Canadian petroleum producers to export crude oil from western Canada.

A. I have reviewed data on current export pipeline capacity and utilization provided by pipeline companies either online or in filings to the Federal Energy Regulatory Commission ("FERC"). According to Enbridge's 2016 Pipeline System Configuration sheet (Attachment LS-18), the Enbridge Mainline System comprises the following six separate pipelines that cross the border from Canada into the US:

- Enbridge Line 1 236,500 bpd
- Enbridge Line 2a/b 442,200 bpd
- Enbridge Line 3 390,000 bpd
- Enbridge Line 4 795,700 bpd
- Enbridge Line 65 185,600 bpd
- Enbridge Line 67 800,000 bpd

Thus, the total current import capacity of the Mainline System is 2,850,000 bpd. These capacities are the annual nominal capacities of these pipelines, which is the average sustainable transportation rate over a year.

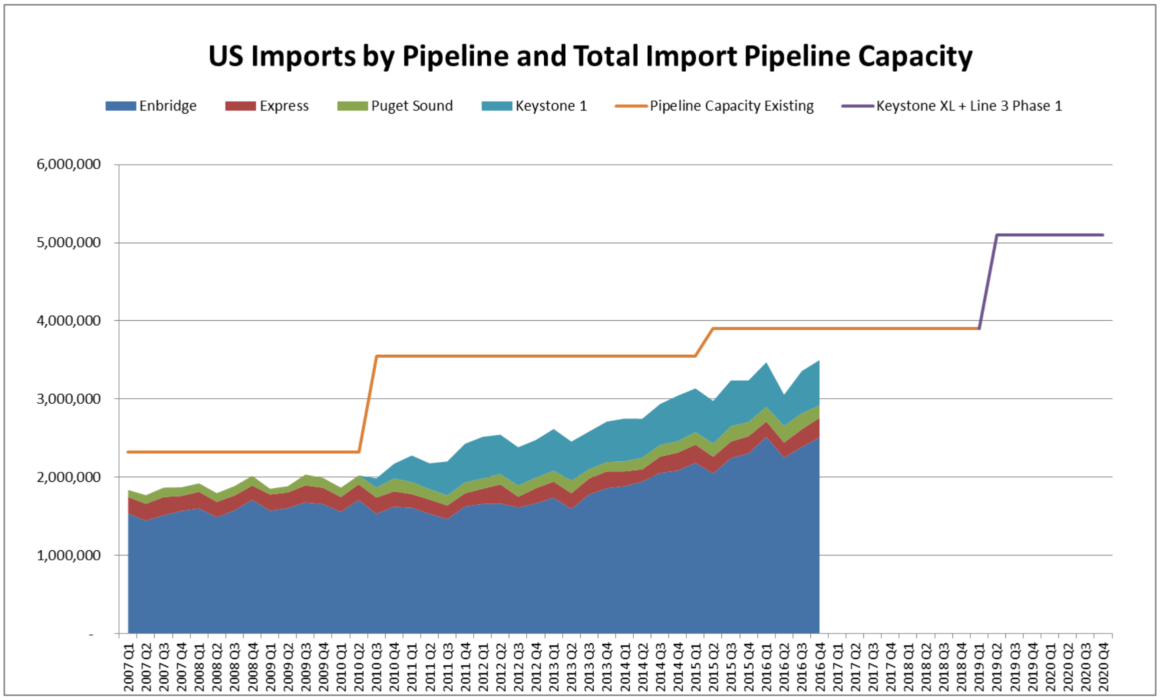
A number of other major pipelines also export crude oil from Canada to the U.S., including:

- Spectra Energy's Express-Platte Pipeline - 280,000 bpd into Montana; approximately 145,000 bpd into Wood River, Illinois, on the Platte Pipeline
- Kinder Morgan's Trans Mountain Pipeline - 300,000 bpd total, with a connection to the 180,000 bpd Puget Sound Pipeline into Washington State and the balance continuing on to Vancouver; and
- TransCanada's Keystone Pipeline - 591,000 bpd.

Id. Thus total pipeline capacity from producing areas in western Canada to the U.S. and British Columbia is 4,021,000 bpd, and of this total volume, pipelines can deliver 3,586,000 bpd into the upper Midwest, from where a number of pipelines provide transportation services to Oklahoma and the Gulf Coast. In addition, it is possible that a relatively small amount of crude oil is or could be imported to the U.S. on smaller pipelines from Canada into Montana, including an 85,000 bpd connection in Glacier County, Montana, between the Rangeland Pipeline and the Rocky Mountain Pipeline System, both owned by Plains All American Pipeline, L.P., for import into PADD 4, comprised of one 12-inch and one 8-inch pipeline. *Id.*

16Q. Please describe your review of data related to the utilization of pipelines used to import oil from Canada to the U.S.

A. Actual imports of crude oil by pipeline into the U.S. are reported by pipeline companies to the FERC on quarterly Form 6 Reports. I have reviewed data from these reports from the first quarter of 2007 to the fourth quarter of 2016 (the most recent). FERC collects this data as part of the tariff setting process for these pipelines. Full Form 6 reports are available online at www.ferc.gov in the eLibrary. A spreadsheet that compiles this data for each pipeline is included as Attachment LS-19. The data in the spreadsheet is illustrated in the chart, below.



17Q. What conclusions do you draw from your review of data related to the utilization of existing pipelines that import oil from Canada to the U.S.?

A. As of the fourth quarter of 2016, existing export pipelines operated at 90% of capacity and had approximately 400,000 bpd of combined unused capacity. *Id.* The pipeline industry generally assumes that operation up to 95% of capacity is within normal operations. This suggests that up to about 200,000 bpd of possible future expansions of supply for export from Canada can be accommodated by existing pipelines. When determining the need for the Keystone XL Pipeline, this unused existing capacity should be taken into account.

18Q. Does underutilization of pipelines have adverse economic impacts?

A. Construction of excess utility infrastructure absolutely has adverse economic impacts. Costs incurred to permit, construct, and build a pipeline impact the costs of the transportation of the crude oil. These costs are typically included by FERC in crude oil pipeline tariffs.

Increased pipeline tariff costs impact the price of crude oil and refined products. While crude oil and refined product pricing is set by indices, these indices are actually established by surveys done of various sellers and buyers of the commodity on a monthly basis. These buyers and sellers are surveyed with regard to the price of their oil at various locations that are used as market centers, such as Cushing, Oklahoma. When purchases are negotiated, there are usually "differentials" taken into account that actually apply to the cost of transporting the oil to the nearest market center. These negotiated prices, with the cost of transportation taken into account, are the prices that are reflected in the surveys and ultimately included in the average price of oil for the month. A similar process exists for refined products. Therefore, an increase in transportation costs also increases the market price for crude oil and refined products, such that the oil industry's cost of doing business is passed on to consumers in the form of fuel price increases.

19Q. Have you reviewed data related to other proposed pipelines that, if built, could transport crude oil from western Canada to other markets?

A. Yes, I have reviewed information about the following competing pipeline projects:

- Kinder Morgan Trans Mountain Expansion Project from Alberta to Vancouver, British Columbia – net increase of 590,000 bpd;
- Enbridge Line 3 Replacement Project from Alberta to Wisconsin – net increase of 370,000 bpd, but up to 525,000 bpd with additional pumps;
- TransCanada Energy East Project from Alberta to St. John, Newfoundland – net increase of 1,100,000 bpd.

Attachment LS-20.

20Q. What conclusions do you make from your review of information related to these proposed pipelines?

A. Should any one of these competing projects be constructed, there would be excess capacity indefinitely, because it is unlikely that enough production growth would occur to fill any of these proposed pipelines. This means that construction of a second new pipeline, such as the Keystone XL Pipeline, would be entirely redundant.

21Q. Is the Keystone XL Pipeline more or less likely to be built than these other pipelines?

A. Statements made by TransCanada senior management in its May 5, 2017, Earnings Call (transcript attached as Attachment LS-21) indicate that TransCanada has put the Keystone XL Project on hold and that the shippers who originally contracted for capacity on the Project are waiting to see if other competing pipelines will be built.

Specifically, Russell Girling, the CEO of TransCanada stated: ""In addition, we are updating our shipping contracts for the project and we anticipate that the core contract shipper group will be modified somewhat and include the introduction of new shippers and the reductions in volume commitments by other shippers." *Id.* This statement indicates that TransCanada's shippers are no longer contractually bound to ship specific volumes of oil on the Project for specific durations in years.

Paul Miller, the Executive Vice-President of TransCanada and President of the Liquids Pipelines subsidiary of TransCanada, stated:

- "The key work streams I guess, there's two primary work streams that being securing the commercial support for Keystone XL and the Nebraska Public Service Commission approval for the route through that state. In regard to the shipping contracts, we're making progress with our existing shipping group, as well as new entrants, as they work through their analysis and the documentation. A lot has changed since we were first denied the permits here in 2015 in regard to crude oil pricing and supply and various competitive alternatives, so they continue to work through that and I anticipate it will take a couple of months yet before we sum up our commercial support."
- "We will work through Nebraska. We will work through our commercial negotiations with the shippers, and once we have certainty on both, in early 2018 I would anticipate we would start staging the project as far as securing what material we still have to secure as well as the contractors, and that exercise will take upwards of six to nine months. So I would not see construction started until Q3 timeframe of 2018, and construction would take probably little over two years."
- "We do anticipate, ultimately, while we are targeting to secure the volume – contracted volume we had previously as we move – potentially move forward

with Keystone XL, I do anticipate some of the current shippers will increase their commitments. I also anticipate some of the current shippers may decrease their commitments as they look at their total transportation requirement. I would also anticipate that we will introduce new parties into the shipper group. So the net result of this is we do anticipate to have contractual support similar to what we enjoyed previously, albeit amongst the different shipper group.

- [90% of the capacity is] what we'll be targeting. Our goal is to fully contract XL, as you know, we have to set aside some capacity for the spot shippers and we'll certainly do that. And, our total will – our total remains competitive, notwithstanding the delay and we will with good CapEx, cost management, Russ talked about, we will keep our total in line."

Id. These statements suggest the following conclusions:

- That senior management admits that the Project shippers may reduce or transfer capacity commitments to potential new shippers indicates that the Project shippers have the option to terminate their contracts.
- That senior management does not expect to resolve its shipper commitments until "early 2018" indicates that its shippers are waiting to re-commit to the Project until after there is greater clarity on the future of the Kinder Morgan Trans Mountain Expansion Project and the Enbridge Line 3 Replacement Project. This timing will also allow the shippers to determine if oil prices will have risen as predicted by some industry analysts, to the degree needed to economically justify new investments in western Canadian oil extraction infrastructure.
- That senior management admits that the Project would not secure remaining material and contractors until early 2018, and would not finish this process until six to nine months later indicates that the construction contracts and remaining procurement contracts for the Project have been terminated.
- Mr. Miller's self-correction in the following statement is telling: "We do anticipate, ultimately, while we are targeting to secure the volume – contracted volume we had previously as we move – <u>potentially move forward</u> with Keystone XL . . . ." (emphasis added.) This correction clarifies that TransCanada is not

currently committed to construct the Project but rather this decision will be made in early 2018.

In sum, it appears from the foregoing statements that the Project is on hold until early 2018, by which time TransCanada and its shippers hope to have sufficient information to decide on whether to construct or terminate the Project. Should the construction of either the Trans Mountain Expansion Project or the Line 3 Replacement Project appear likely, there would be no need for the Keystone XL Pipeline. Thus, it appears that western Canadian crude oil shippers are treating the Keystone XL Project as a possible fallback option if other pipelines are not built, but only if market conditions improve enough to support investment in production growth.

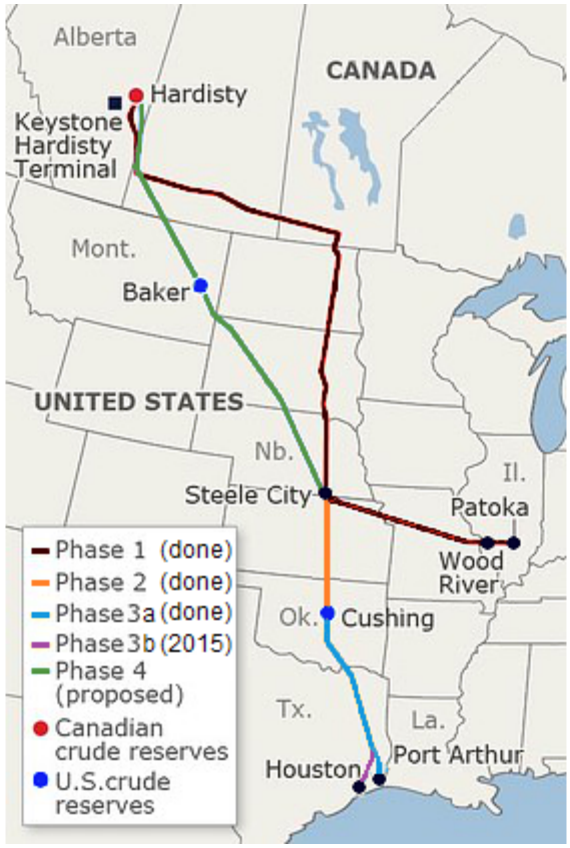
V. KEYSTONE XL WILL EXACERBATE AN ONGOING GLUT OF OIL IN CUSHING AND THE GULF COAST AND IS NOT NEEDED

22Q. Please describe your review of data related to crude oil in storage in Cushing, Oklahoma, and the US Gulf Coast.

A. I have reviewed: (a) crude oil storage data provided by the USEIA and (b) US crude oil production forecasts by Rystad. In combination, this data shows that oil supply in storage in the major crude oil trading hub of Cushing, Oklahoma, and in the U.S. Gulf Coast, is at record levels constituting a glut, why this has happened, and why constructing the Keystone XL Pipeline will exacerbate this situation.

23Q. Please describe your review of data related to pipeline capacity into and out of Cushing, Oklahoma, and any conclusions you might draw from this review.

A. There are currently 18 pipelines flowing crude oil into Cushing, with a total capacity of 3.6 million bpd. Attachment LS-22. There are however only 15 pipelines with a capacity of nearly 2.7 million bpd carrying crude out of the storage hub. *Id.* Therefore, the net inbound capacity is 841,000 bpd. *Id.* One of the inbound pipelines into Cushing is the existing “Keystone Extension Pipeline,” which is a 36” crude oil pipeline from Steele City, Nebraska, to Cushing, Oklahoma, with a maximum capacity of 830,000 bpd (identical to the Project). This pipeline is identified at “Phase 2” on the following map.



The Keystone Extension receives crude oil at Steele City only from TransCanada's existing 591,000 bpd Keystone Pipeline (Base Keystone Pipeline), which is identified as "Phase 1" on the above map. The Base Keystone Pipeline continues to Patoka, Illinois. TransCanada has firm contracts for 375,000 bpd of Base Keystone Pipeline capacity for delivery of crude oil to Illinois, 155,000 bpd of contracted capacity for delivery to Cushing, and the remaining 61,000 bpd of capacity is not contractually committed and instead is reserved for uncommitted shippers, such that it could be used for deliveries to either destination. Attachment LS-23. TransCanada's first open season sold 340,000 bpd of capacity to Wood River, Illinois. *Id.* Next, it announced that it had contracted another 35,000 bpd of capacity through negotiations. *Id.* Following an open season for the Keystone Expansion Project to Cushing, TransCanada announced that it had secured a total of 530,000 bpd of committed capacity on the Keystone System, such that shippers entered into contracts for an additional 155,000 bpd during this open season. *Id.* Therefore, assuming that shippers continue to seek delivery of oil to their original contracted destinations, the maximum amount of crude oil that could currently be transported to Cushing on the Keystone Extension is 215,000 bpd (155,000 bpd plus 61,000 bpd). *Id.*

Should the Project be constructed, TransCanada would operate the 30-inch diameter Base Keystone Pipeline separately from its 36-inch pipeline network that would include the Project, the Keystone Extension Pipeline, and its Gulf Coast Pipeline. This means that if the Project is built, TransCanada could deliver up to 830,000 bpd of crude oil into Cushing, a net increase of at least 615,000 bpd over the current available capacity. This means that, if the Project is built, total inbound pipeline capacity to Cushing would be approximately 4.2 million bpd, as compared to total outbound capacity of 2.7 million bpd, leaving a net inbound capacity of approximately 1.45 million bpd. Additional crude oil supply in this region would likely suppress oil prices further, resulting in suppression of petroleum development in the Tar Sands Region, as well as increased storage of unneeded crude oil in Oklahoma, which is discussed below.

24Q. Please describe your review of data related to pipeline capacity into and out of the US Gulf Coast region, and any conclusions you might draw from this review.

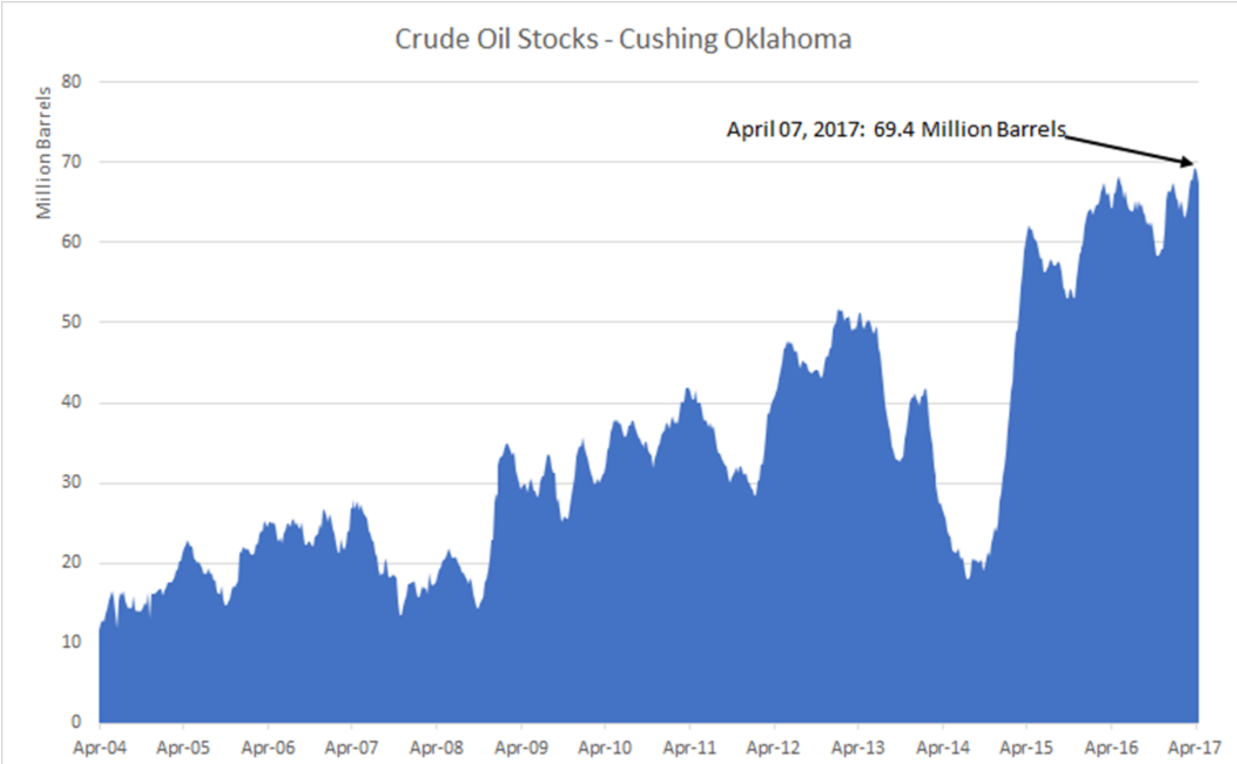
A. For many years the only major crude oil pipeline that transported crude oil from north to south was the Pegasus Pipeline. In recent years, a number of pipelines have been constructed that also transport crude oil to the south (Attachment LS-24), including:

- the Seaway and Seaway Twin Pipelines came online starting in 2012 with a maximum capacity of 850,000 bpd;
- the TransCanada Marketlink (Gulf Coast) Pipeline came online in 2014 with an initial capacity of 400,000 bpd and a maximum capacity of 500,000 bpd; and
- the recently completed Energy Transfer Crude Oil Pipeline (ETCO Pipeline) from the Patoka Terminal in southern Illinois to Nederland, Texas, which has a capacity that is expandable to 450,000 bpd, is expected to start commercial operations in June 2017.

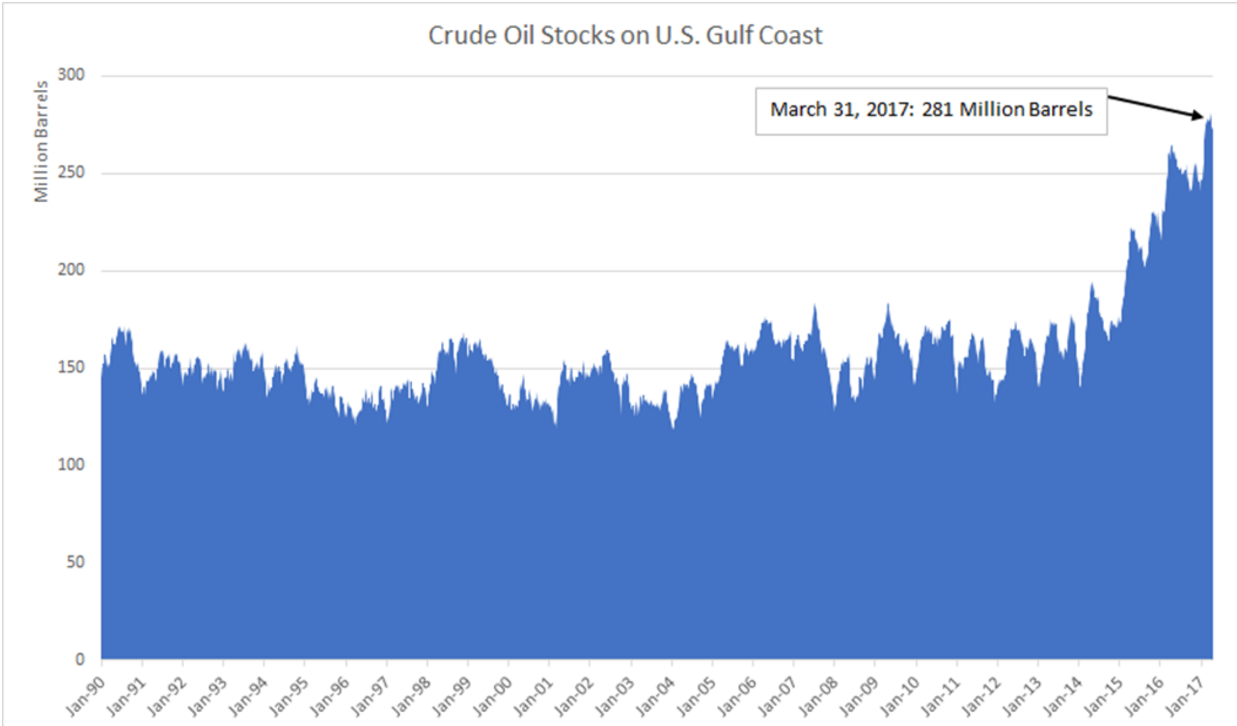
Thus, in the past five years, the crude oil pipeline industry has constructed at least 1.7 million bpd of new capacity from the Midwest to the Gulf Coast. In addition, a large number of pipelines transport oil from fields in Louisiana, New Mexico, Texas, and offshore oil locations to US Gulf Coast markets. Further, the US Gulf Coast has the capacity to import crude oil via supertanker from global markets. As a consequence, US Gulf Coast refineries do not need greater access to increased volumes of heavy Canadian crude oil.

25Q. Please describe your review of data related to crude oil storage in the Cushing and US Gulf Coast petroleum markets, and any conclusions you draw from this data?

A. I have reviewed USEIA data related to crude oil storage in the Cushing and Gulf Coast regions. Attachment LS-25. Crude oil in storage has been building steadily in Cushing and the Gulf Coast since 2015, and has consistently set new records. *Id.* At the beginning of April, Cushing and Gulf Coast crude oil storage combined was in excess of 350 million barrels. *Id.* These are historic highs far in excess of anything previously seen. The USEIA data tracks crude oil storage at Cushing back to 2004. Prior to 2009, there was only rarely more than 25 million barrels stored at the hub. Storage levels surpassed 30 million barrels for the first time in January 2009. From 2015 to date, storage levels have remained consistently over 50 million barrels and in recent months have reached record highs of over 65 million barrels. In the first week of April 2017, a new record was set at 69.42 million barrels. *Id.* At the end of April this had eased only slightly to 66.7 million barrels. *Id.*



On the Gulf Coast, where Keystone XL crude oil would primarily be delivered, storage levels are also at record levels. *Id.* EIA data going back to 1990 shows that until mid-2015, levels fluctuated between 100 and 180 million barrels. *Id.* The 200-million-barrel level was first surpassed in March 2015 and storage levels have remained above that ever since, reaching an all-time high of just under 281 million barrels on March 31, 2017. *Id.* The glut in the Gulf Coast has built even as exports of crude oil have hit record levels. See Section VII, *supra*.

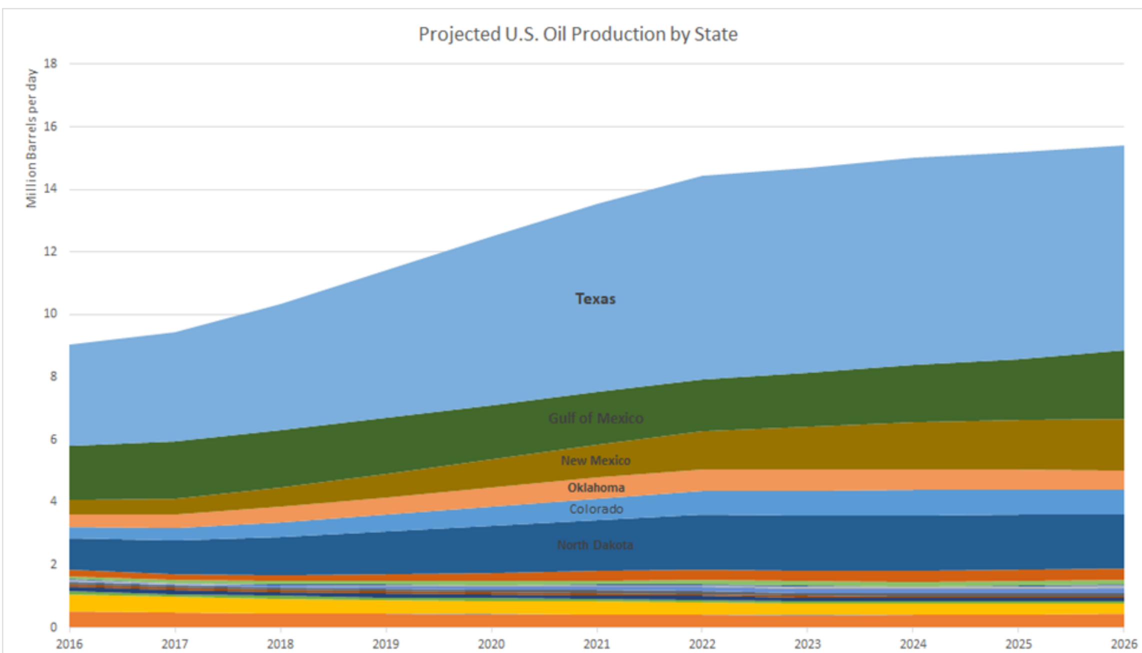


This crude oil storage data indicates that the Cushing and Gulf Coast markets are currently oversupplied with crude oil, such that there is no current need for additional inbound crude oil pipeline capacity into these markets.

26Q. What reasons exist for these record amounts of crude oil in storage, and what are the implications of this stored oil on whether or not additional crude oil supplies are likely to be needed in the Cushing and Gulf Coast markets?

A. The record amounts of oil in storage in the Cushing and Gulf Coast markets are an indicator of a lack of demand for new crude oil supply to this region. The amount of oil in storage has increased because global oil production has exceeded global oil demand. As a result, some of the world's oil has ended up in storage tanks. The fact that supply growth has exceeded demand growth is suppressing oil prices. It is possible that eventually lower oil prices will result in lower oil production and higher oil prices, but so far this has not happened to the degree necessary to increase oil price to a profitable level for Canadian tar sands producers. Instead, the recent marginal increase in oil price has resulted in increased U.S. production from fracked oil fields, which increased production has, in turn, continued the oil glut and kept oil prices too low for increased Canadian production. Since Canadian oil producers have some of the highest production costs in the world, increased production in Canada cannot happen until other lower cost oil producers are no longer able to increase their production to meet global oil demand. As long as lower cost producers can increase production to meet global demand, they will prevent new Canadian production from coming online.

The Gulf Coast refiners are well positioned to take advantage of oil supply from many of the world's suppliers and have no pressing requirement for additional access to Canadian supply. In fact, a look at projections for where production growth will likely come from in the coming decade suggests that the bulk of new supplies will come from producers in Texas, the Gulf of Mexico and other U.S. producers. Projections from Rystad Energy (Attachment LS-26) suggests that the U.S. will see substantial oil production growth in the coming decade.



The state with the most potential growth is Texas. Other leading areas include the Gulf of Mexico, the states of New Mexico, Oklahoma and Colorado, as well as North Dakota. The ongoing glut of oil in the Gulf Coast is only likely to continue as more U.S. supply dominates the market. Therefore, the potential for production growth from Canada is marginal and most at risk from lower oil prices.

This would indicate that Gulf Coast refiners have access to growing domestic sources of crude oil and that the ongoing glut of oil in this region is only likely to continue. While North Dakota is not a neighboring state, it is now directly connected to the Houston, Port Arthur markets via the Dakota Access and Energy Transfer Crude Oil Pipelines.

As long as the Gulf Coast market, the largest refining market in the U.S. and the world, remains well supplied with domestic and lower-cost overseas imported oil, the prospects of oil prices rising to support production growth in the Tar Sands Region are slim.

VI. THE KEYSTONE XL PIPELINE IS NOT NEEDED BECAUSE DOMESTIC DEMAND FOR CRUDE OIL AND PETROLEUM PRODUCTS HAS BEEN STABLE AND IS NOT LIKELY TO GROW AND DOMESTIC CRUDE OIL PRODUCTION HAS FAR EXCEEDED ANY DEMAND GROWTH

27Q. Please describe your review of data related to consumer demand for refined petroleum products.

A. I have reviewed USEIA data related to consumer demand in Nebraska, the Midwest (PADD 2), the Gulf Coast (PADD 3), and the U.S. as a whole for refined petroleum products. Specifically, I have reviewed both the EIA's "Prime Supplier Sales Volumes" monthly data and the USEIA "product supplied" data, both from January 1983 to March 2017. Attachment LS-27.

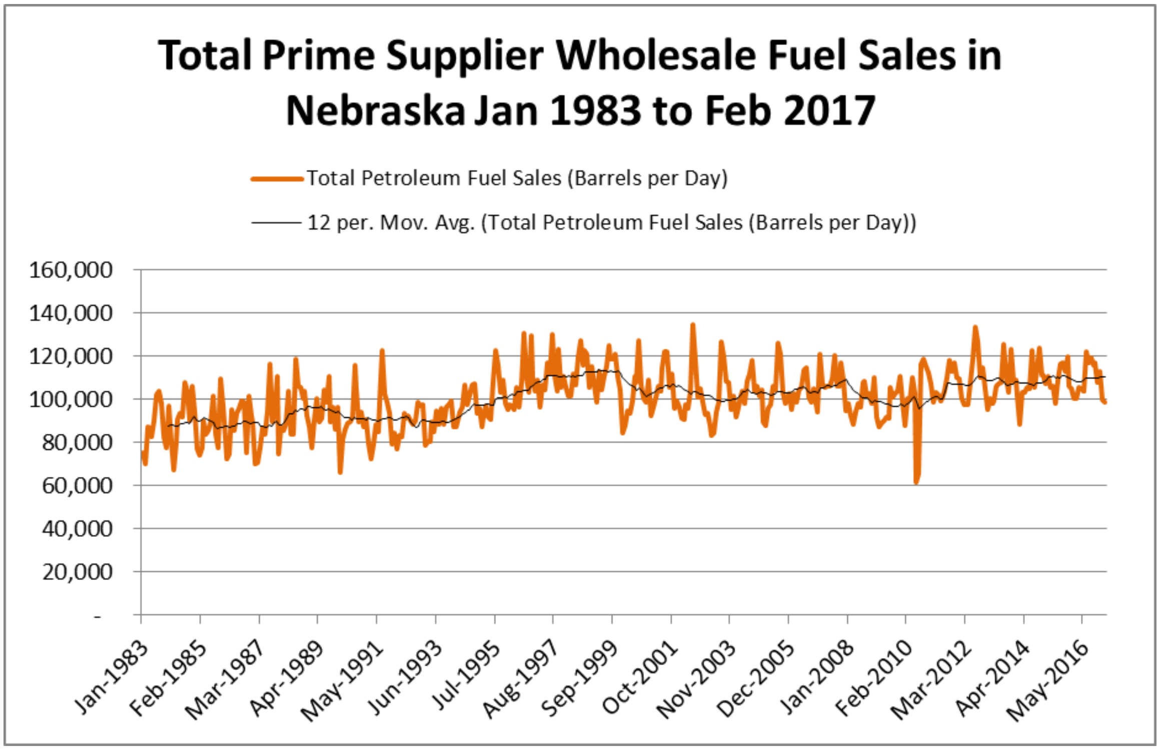
The prime supplier data shows wholesale sales of refined petroleum products into local markets. Spreadsheets of data for Nebraska, PADD 2, PADD 3, and the U.S. as a whole and their USEIA explanatory notes for its demand survey are also included in Attachment LS-27. *Id.* The types of products reported in the "prime supplier" data include motor gasoline, aviation gasoline, jet fuel, propane, distillate and kerosene (diesel fuel), and residual fuel oil. PADD 2 states include North Dakota, South Dakota, Minnesota, Nebraska, Kansas, Oklahoma, Missouri, Iowa, Wisconsin, Illinois, Indiana, Michigan, Ohio, Kentucky and Tennessee. PADD 3 includes the states of New Mexico, Texas, Arkansas, Louisiana, Mississippi and Alabama. In addition, I have reviewed the USEIA "product supplied" dataset, which shows total sales of both fuel and non-fuel petroleum products supplied to US markets. These reports are the basis of my research on recent consumer demand trends.

The EIA defines "prime supplier" as a "firm that produces, imports, or transports selected petroleum products across State boundaries and local marketing areas, and sells the product to local distributors, local retailers, or end users." According to the EIA "Definitions, Sources and Explanatory Notes" webpage for this data, the source for this data is EIA Form EIA-782<u>C</u> survey, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption." The Explanatory Notes for this data clarify that the "C" survey is intended to identify the sale of petroleum products <u>into local markets</u>. According to the EIA "Definitions, Sources and Explanatory Notes" website for the EIA's "product supplied" data, this data is also intended to report on all refinery output and not just sales for domestic consumption in specific regions. The "prime supplier" data focuses on consumer fuel sales and does not include specialty petroleum products, such as lubricants, and it also does not include natural gas liquids. In contrast, the USEIA product supplied data shows sales of all types of petroleum products, including those such as natural gas liquids that may be refined into fuels or used for other industrial processes.

The USEIA product supplied data shows the total volume of all types of petroleum products supplied to domestic buyers, including petroleum fuels, lubricants, waxes, petroleum coke, asphalt, and natural gas liquids. It is more comprehensive than the USEIA "prime supplier" data, but is not provided for individual states. I have reviewed the product supplied data for the US as a whole as well as data for PADDS 2 and 3. Although this data shows demand by domestic buyers, it is possible that some exported petrochemical products produced by U.S. petrochemical plants, such as materials used in plastics production, are included in this data.

28Q. What conclusions do you reach based on your review of data related to consumer demand in Nebraska for refined petroleum fuels?

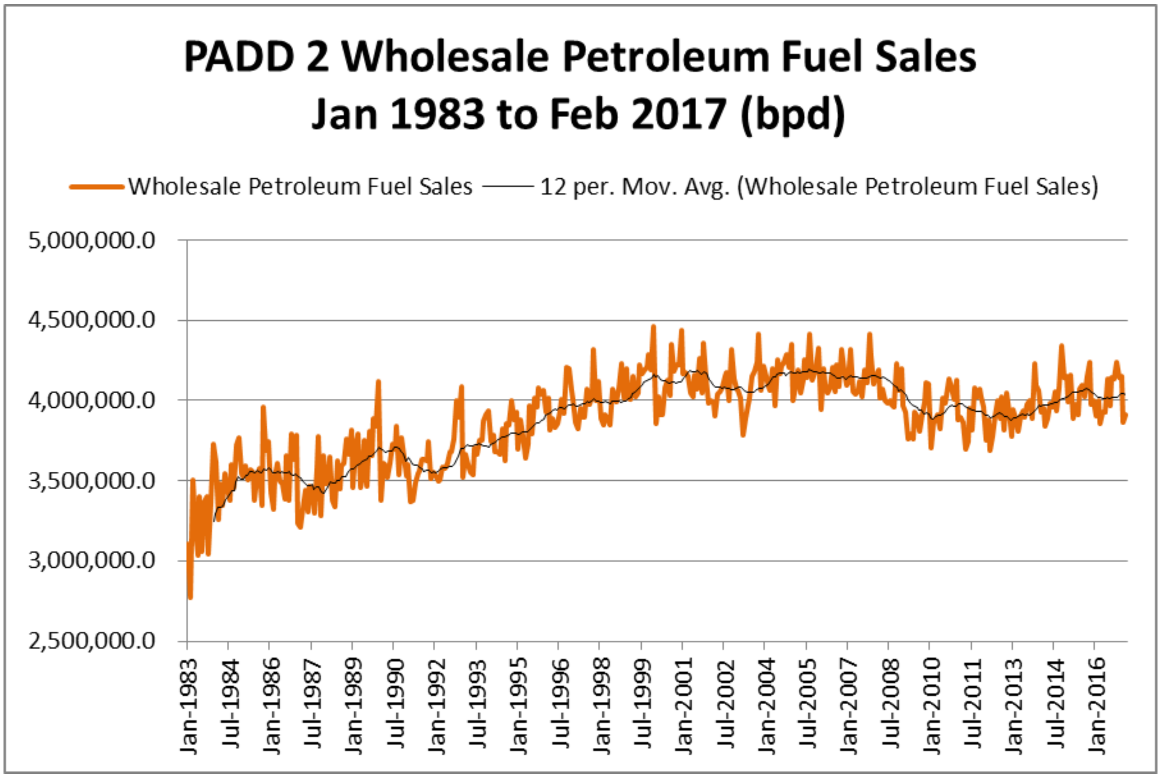
A. Focusing in on the state of Nebraska, EIA data shows that the year with the highest petroleum fuel demand was 1998 at 112,636.5 bpd. *Id.* After reaching the peak, there was a decline in total refined petroleum products consumed, and for the past five years petroleum fuel demand in Nebraska has been stable at just under the record set by the historical high. *Id.* The following chart illustrates historical Nebraska demand for refined petroleum products. *Id.*



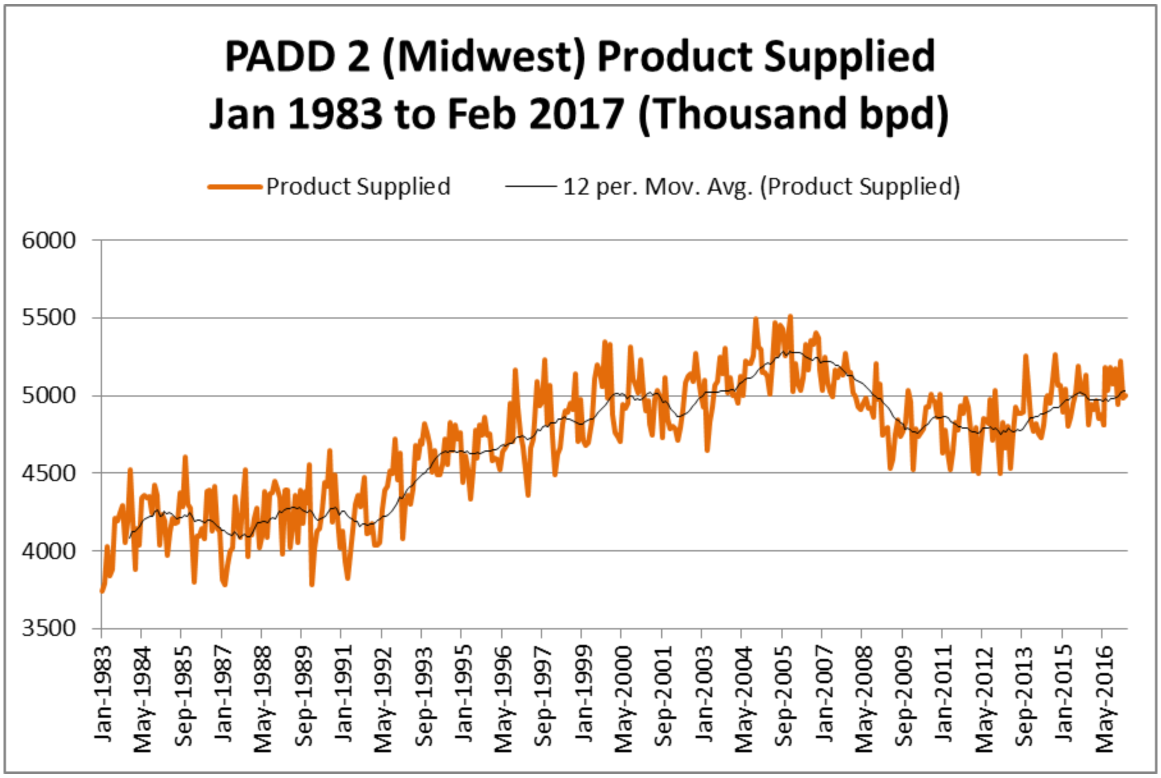
There is no indication that sales of petroleum products in Nebraska are currently increasing. Instead, sales of petroleum products to Nebraska consumers have been stable for the past five years and remain below record levels set almost 20 years ago.

29Q. What conclusions do you reach based on your review of data related to demand in PADD 2 for petroleum products?

A. Expanding the review of the prime supplier data to PADD 2, the average consumer demand for refined petroleum fuels in the entire region also peaked in 2004 at an annual average sales demand of 4,183,000 bpd. *Id.* Since then it dropped below 4 Mbpd and then rose slightly but has been stable for the past 3 years at approximately 4 Mbpd. *Id.* The total increase in demand in PADD 2 between 2012 and 2016 was about 170,000 bpd, but this increase occurred before 2014. *Id.* The following chart illustrates PADD 2 demand for refined petroleum products. *Id.*

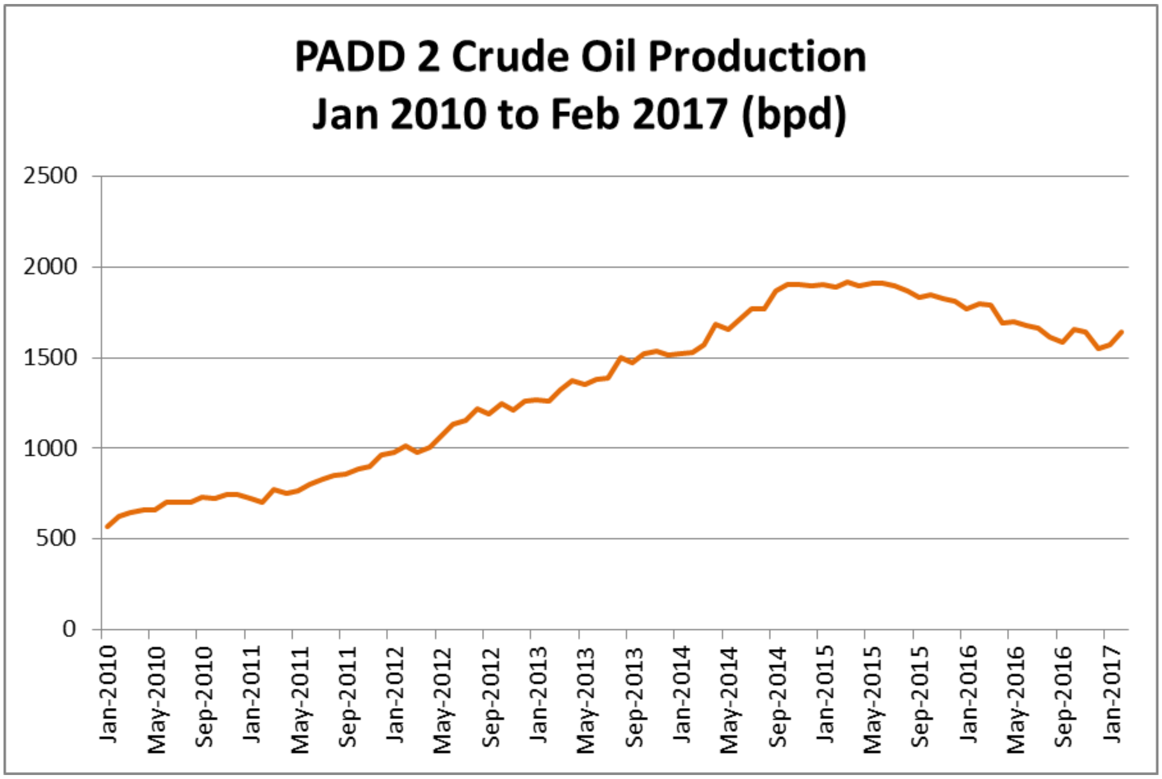


The USEIA product supplied data also shows that total petroleum products supplied in PADD 2 has been stable since 2014.



Thus, demand for petroleum fuels in PADD 2 is not growing and is well below historical peaks.

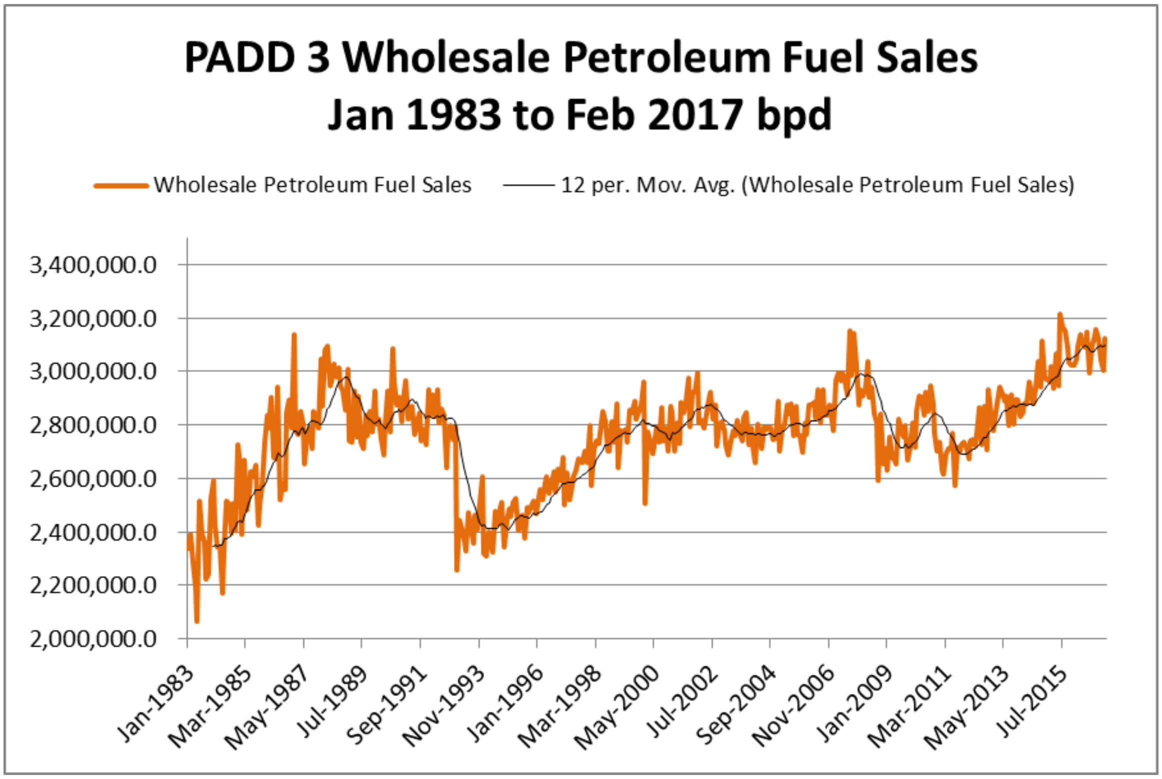
The modest 170,000 bpd increase in petroleum demand in PADD 2 since 2012 should be viewed in the context of crude oil production in this region during this same period (PADD 2 crude oil production data provided in Attachment LS-28. In 2012, average crude oil production in PADD 2 was 1,121,000 bpd, and in 2016 average crude oil production was 1,678,000 bpd, an increase of 557,000 bpd. *Id.* This being said, crude oil production since 2010 has increased by about 1 million bpd. *Id.* Thus, increased crude oil production in PADD has far outstripped the modest increase in demand since 2012.



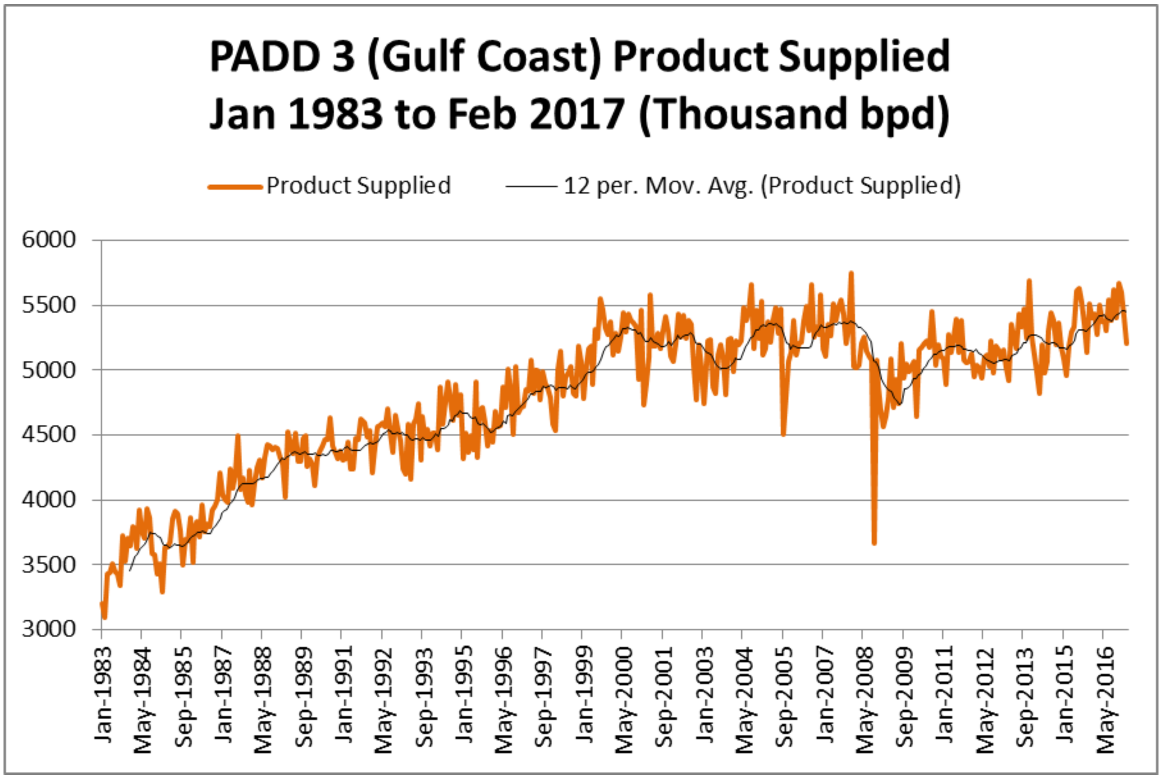
PADD 2 petroleum demand does not itself justify additional import pipeline capacity from Canada.

30Q. What conclusions do you reach based on your review of data related to demand in PADD 3 for petroleum products?

A. The USEIA prime supplier data shows that PADD 3 demand for petroleum fuel increased by about 300,000 bpd between 2012 and 2016. Attachment LS-27. This is an average growth rate during this period of just under 3% per year, but the rate dropped to 1.4% in 2016. *Id.*

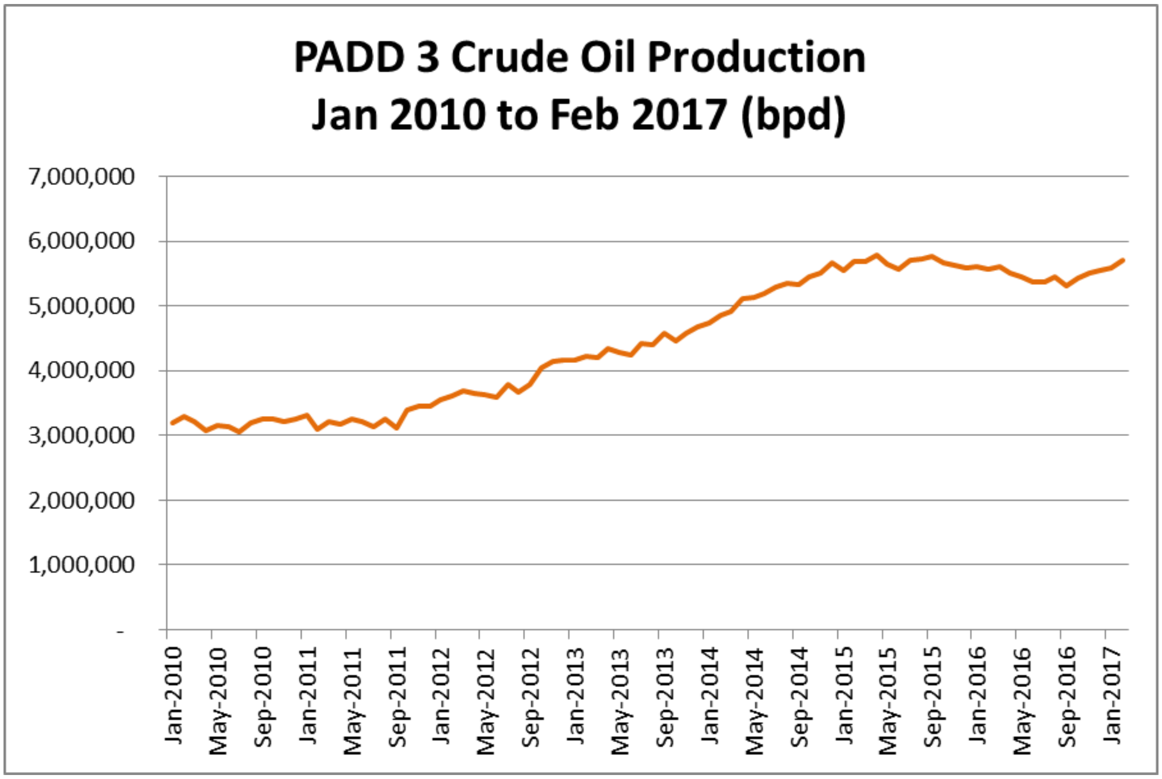


The USEIA product supplied data shows a similar trend with total product supplied increasing by about 387,000 bpd from 2012 to 2016, by an average of 1.9% per year, though the volume supplied has been stable since mid-2015. *Id.*



Likely, much of this increased demand is related to fuel demand by the fracking industry in PADD 3. Fracked wells require substantial amounts of fuel during both the fracking process and ongoing operations.

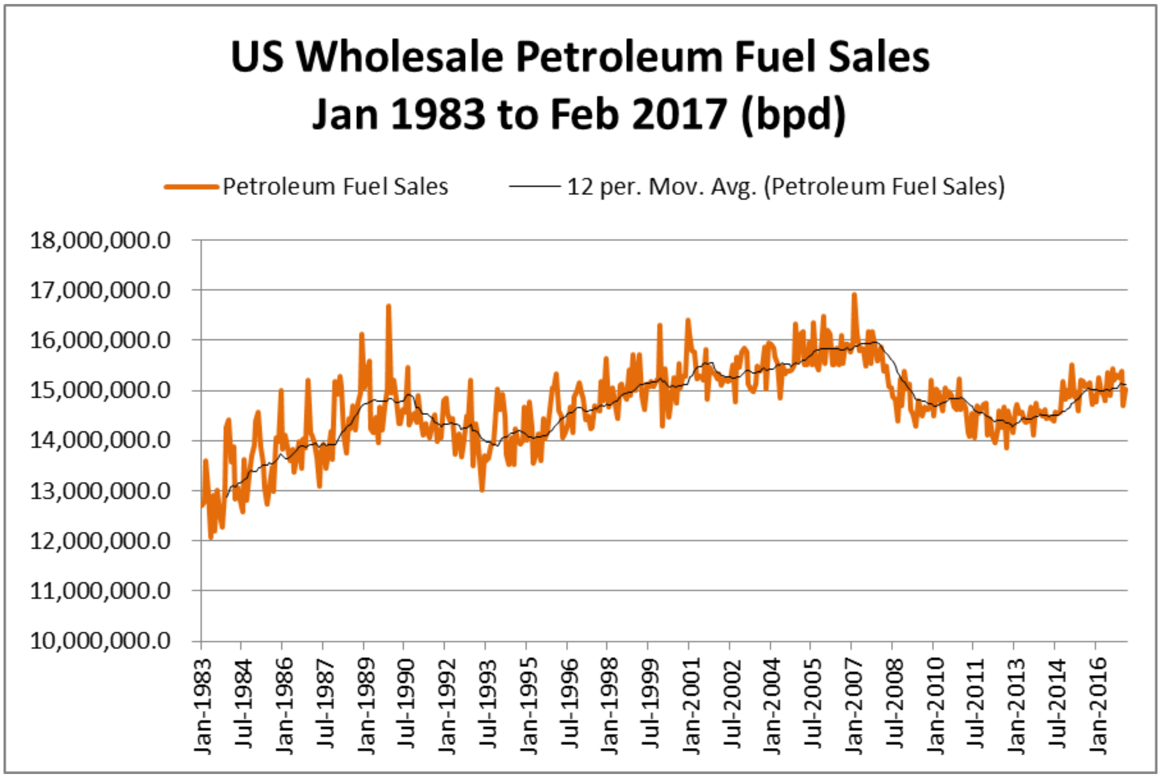
The increase in petroleum demand in PADD 3 should be viewed in the context of crude oil production during this period. In 2012, average crude oil production in PADD 3 was 3,775,917 bpd, and in 2016 average crude oil production was 5,472,500 bpd, an increase of 1,696,583 bpd. Attachment LS-28.



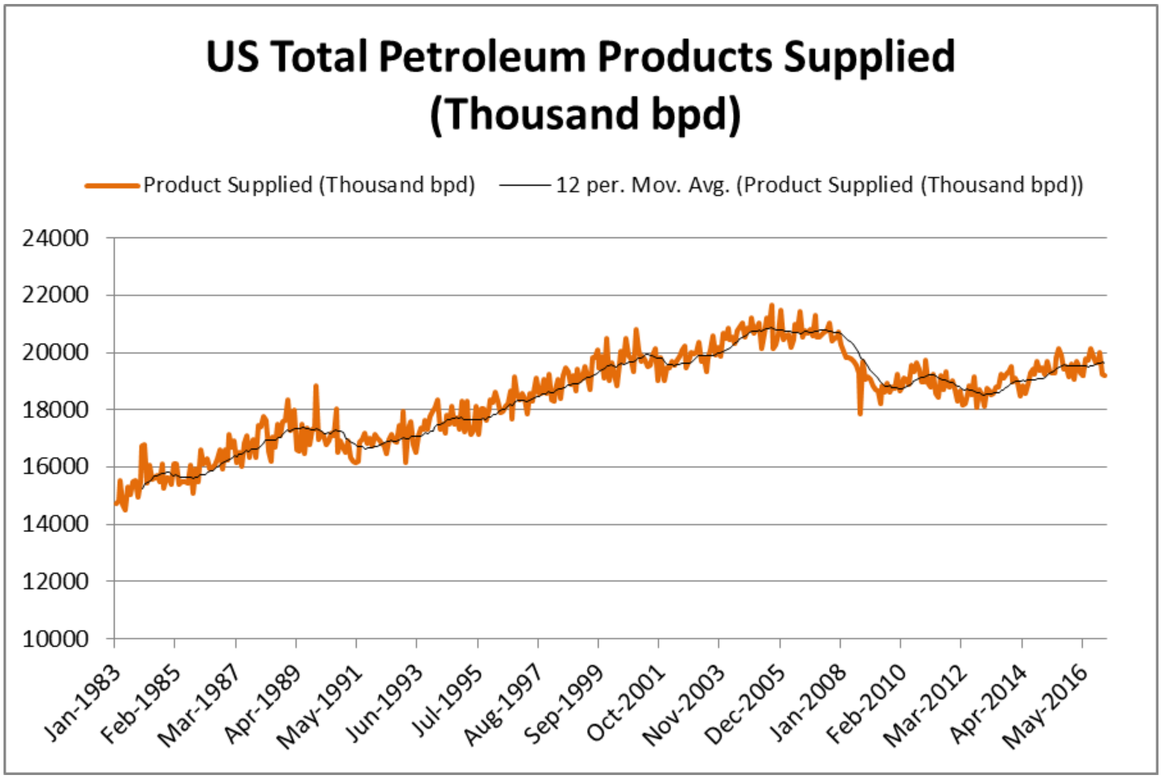
Thus, while PADD 3 refined petroleum fuel consumption increased by a bit over 300,000 bpd between 2012 and 2016, and total product supplied increased by 387,000 bpd during this same period, crude oil production increased by 1,700,000 bpd. It is clear that refineries in PADD 3 did not need Canadian crude oil to meet increased PADD 3 domestic fuel demand.

31Q. What conclusions do you reach based on your review of data related to consumer demand in the U.S. as a whole for refined petroleum products?

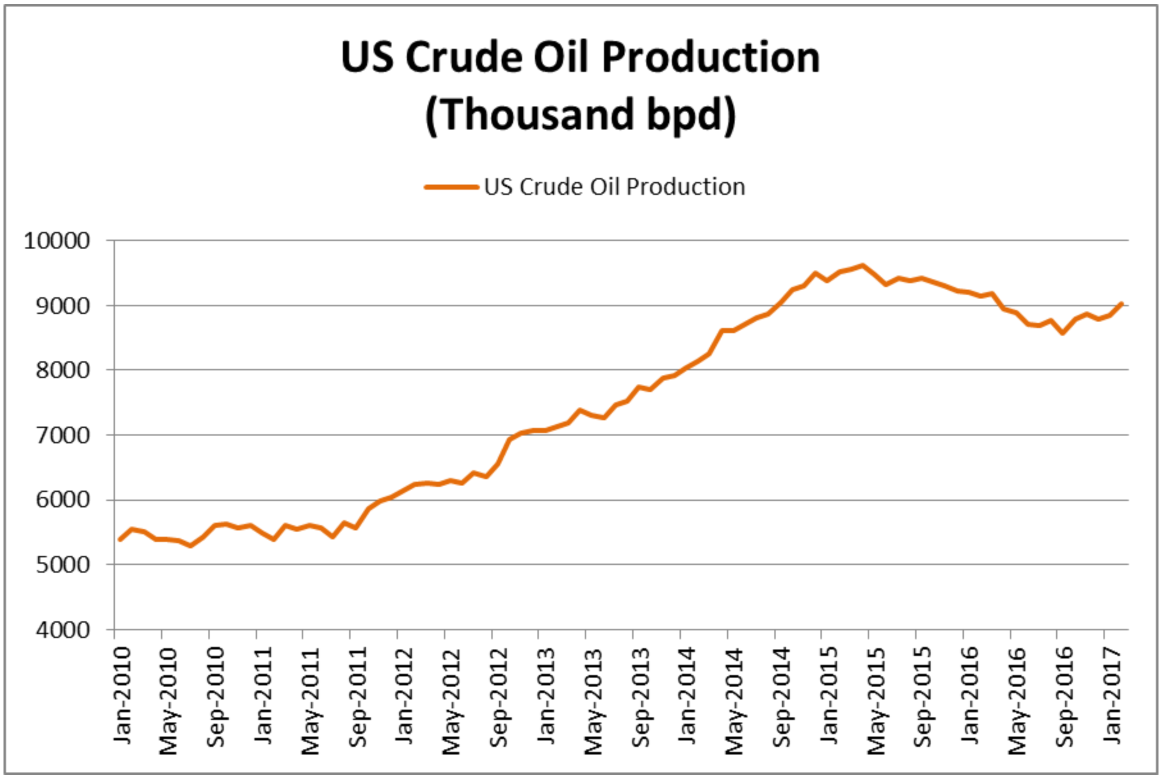
A. The EIA prime supplier data shows that 2007 was the peak year for average annual wholesale petroleum fuel sales in the U.S. as a whole, at 15,948,542 bpd. Attachment LS-27. In comparison, sales in 2016 averaged 15,137,539.7, which is 5.1% less than the record high. *Id.* Although the volume of petroleum fuel sales increased when oil prices started dropping in late 2014, they have been stable since late 2014. *Id.* Thus, this data shows that US consumer demand for petroleum fuels has not been increasing. The following chart illustrates total U.S. demand for refined petroleum products. *Id.*



The USEIA's "product supplied" data for the entire U.S. data shows that total U.S. demand for petroleum products peaked in 2005 at 20,799,300 bpd. *Id.* In 2016, US demand for petroleum products averaged 19,631,600 bpd, which is 5.6% below the peak year. *Id.* This data is similar to the trends shown in the prime supplier data. Total product supplied in the U.S. has been stable since mid-2015. Since 2012, total product supplied has increased by about 228,000 bpd, or on average about 60,000 bpd per year, representing an average growth rate of about 0.3%, but all of this increase happened before 2015. *Id.* Thus, total U.S. demand for petroleum products is not increasing.

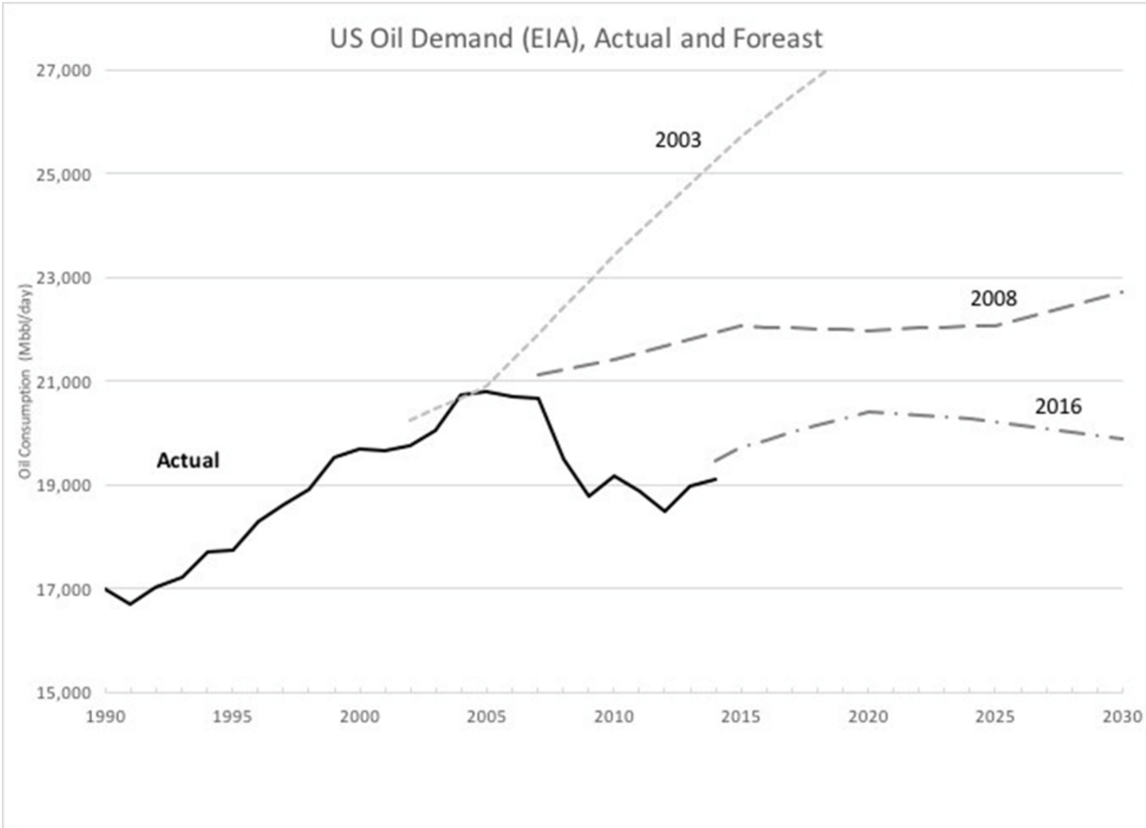


But, this increase in demand should be viewed in light of the net increase in US crude oil production during this time. The following chart of USEIA crude oil production data shows that total US crude oil production increased by an average of 478,000 bpd each year during this period – even accounting for the drop in production since 2015. Attachment LS-28. This is more than double the growth of total US petroleum product demand during this same time.

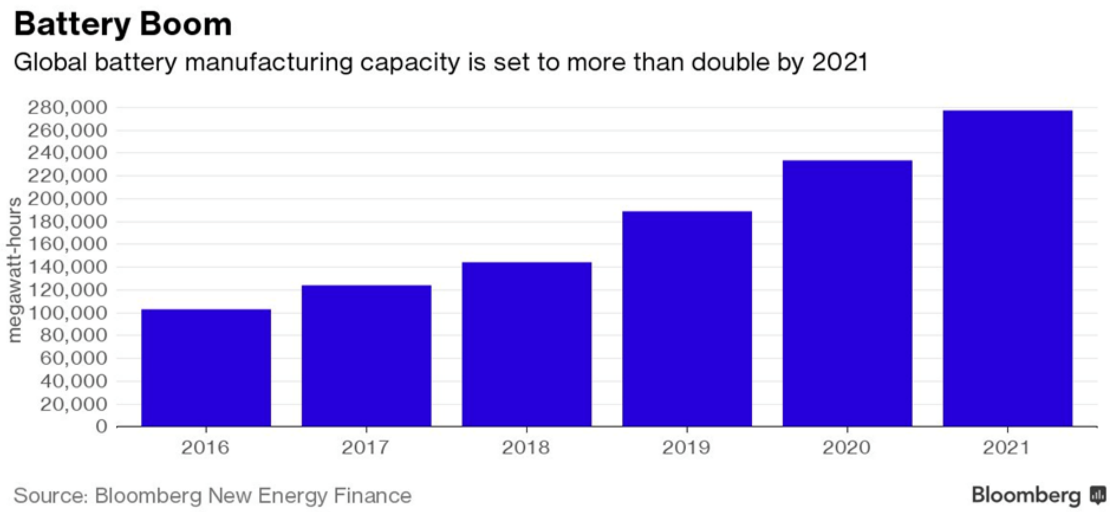


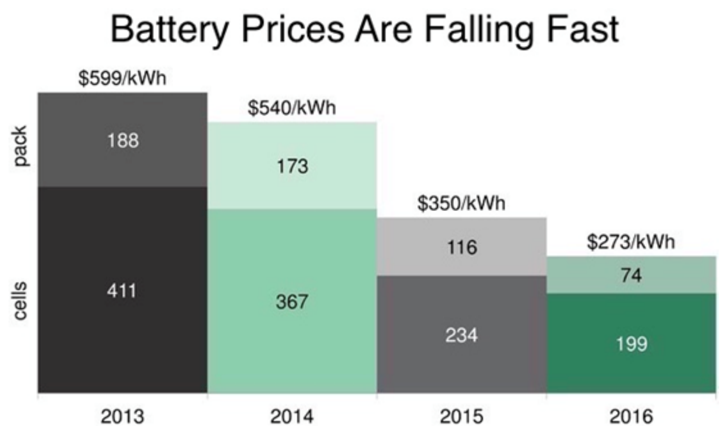
32Q. Have you reviewed any information related to future petroleum demand?

A. Yes, I am aware of growing evidence that U.S. oil demand will cease to grow in the near future. The following charts shows how USEIA petroleum demand forecasts have changed over the past 14 years. Attachment LS-29.



There is a growing convergence of expert opinion that a peak in global demand for oil is now in sight. An accelerating energy market disruption from electric vehicle technology, rapidly improving vehicle fuel efficiency, regulatory measures to address climate change, and the increased adoption of ridesharing and autonomous vehicle technology, are expected to contribute to a peak and decline in U.S. oil demand. Energy market and auto industry analysts are increasingly predicting a rapid, exponential increase in the uptake of Electric Vehicles (EVs), rather than slow linear growth. The expected pattern of sudden technological disruption has been seen in recent years in the sudden and widespread adoption of smart phones, and more recently in the dramatic fall in the cost of solar photovoltaic (PV) panels. There is now compelling evidence that EV adoption is following a similar pattern as a result of the rapid decline in the cost of batteries as manufacturing economies of scale are reached. The following charts show forecasts of battery manufacturing capacity and costs. Attachment LS-30.





A sudden transition in transportation could mean that EVs could overtake internal combustion engines rapidly. Investment Bank UBS predicts that EVs will reach price parity with standard internal combustion models next year, far earlier than had been previously assumed. Attachment LS-31. This is also the finding of a new report from Bloomberg New Energy Finance. *Id.*. Price parity is widely seen as the tipping point at which consumers rapidly shift towards buying EVs over traditional internal combustion engines. An analysis from Carbon Tracker Initiative and Imperial College modelled potential EV penetration using up-to-date cost estimates, with no regulatory change, and projected EVs would account for 55% of global passenger vehicles by 2040. *Id.*

After years of reluctance, vehicle manufacturers are now announcing aggressive plans for the electrification of their product lines. *Id.* Driven by growing competition from Tesla Motors, major U.S. carmakers Ford and GM have both announced new strategies embracing electrification of passenger vehicles. *Id.* VW plans to sell 1 million EVs by 2025, Volvo has said it will stop developing diesel engines and focus on electric drivetrains, and a number of new electric vehicle manufactures are competing for market share in China. *Id.* Tesla's Model S is already outselling all other luxury sedans in the U.S. and plans to sell 500,000 of its new Model 3 cars by the end of 2018. *Id.* Energy consultancy Wood McKenzie estimates that U.S. gasoline demand will reach a peak in 2018 as result of dramatic vehicle efficiency improvements, and continue to improve thereafter due to a shift to hybrid and electric drivetrains. *Id.* The USEIA Annual Energy Outlook 2017 predicts declining U.S. energy use from light-duty vehicles between 2018-2040. *Id.* Their model forecasts that gasoline consumption from light duty vehicles is expected to drop from 8.7 million barrels per day in 2017 to 7.5 over just the next 8 years. *Id.* Passenger cars in 2015 averaged 31 miles per gallon (on-road mpg), with improved fleet-wide standards already adopted by the industry, this number is expected to reach 45mpg by 2025. *Id.* Energy efficiency improvements in vehicles are expected to progress faster than the average increase in miles travelled each year. *Id.*

Emerging technological and social trends are facilitating rapid uptake of urban car sharing, ride sharing, and a shift towards vehicle automation. These interconnected changes have the potential to further reduce oil demand by reducing private car ownership, facilitating further design efficiency improvements, and improving driver fuel economy performance. These trends are expected to increase the average number of passengers per vehicle, allowing the average per person distance travelled to increase without increasing the absolute distance vehicle travel. Improving the efficiency of passenger vehicles to move people over time.

If oil prices rise to a level needed to re-start the boom in tar sands production ($77 per barrel for SAGD projects and $108 per barrel for mining projects), these prices would once again drive down fuel demand, in large part because poorer consumers could not afford to drive as much. Reduced consumer demand would, in turn, once again, force the price of crude oil down to affordable levels, which would be too low to support tar sands production.

Various energy industry players are debating the projected timing of peak oil demand, but many now acknowledge that it is a question of when, not if it will occur. The uncertainty around timing depends primarily around assumptions on the speed at which EVs replace internal combustion engine technology in vehicles, as well as the degree to which growth occurs in the non-transportation petrochemical industry. Major oil companies now acknowledge an impending end to growth in global oil demand. Royal Dutch Shell and Statoil have predicted that peak global oil demand could come within the next decade. Total SA has said that it now expects a peak in global oil demand by the 2030s, as a result of EVs accounting for a third of new-car sales by the end of the next decade.

As the rate of increase in petroleum demand slows and then falls, the need for new petroleum infrastructure, such as crude oil pipelines, is ending. Investment in the Keystone XL Pipeline is likely to be wasted.

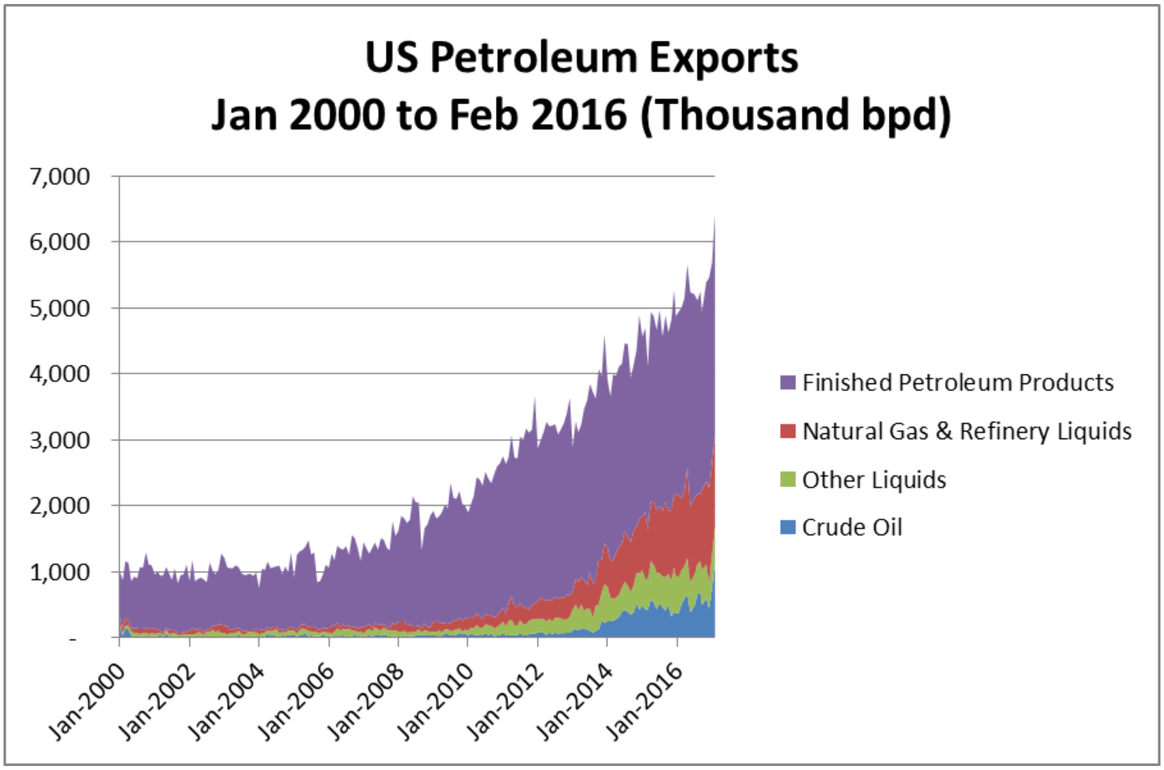
VII. THE KEYSTONE XL PIPELINE IS NOT NEEDED BY NEBRASKA OR THE U.S., BECAUSE IT WILL BE USED TO INCREASE EXPORTS TO FOREIGN MARKETS

33Q. Have you reviewed data related to U.S. exports of all types of petroleum?

A. I have reviewed the USEIA data related to exports of crude oil and petroleum products from the U.S. and PADD 3, and for specific ports on the Gulf Coast. Attachments LS-32 and 33.

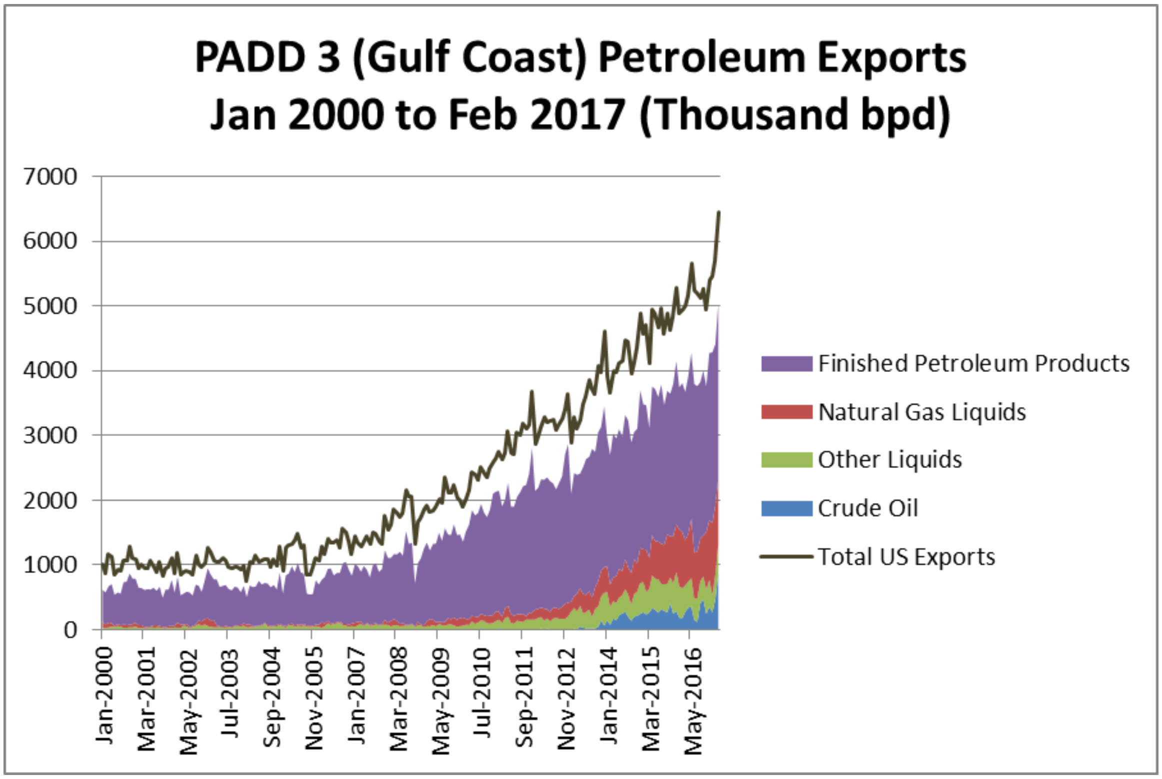
34Q. What does the USEIA data show?

A. Exports of crude oil and petroleum products from the U.S. have grown by over 5 million bpd since 2006, primarily in the form of finished petroleum products. Attachments LS-32. In February 2017, total exports spiked to 6,443,000 bpd, a month-over-month increase of 752,000 bpd over January 2017, and a year-over-year increase of 1.5 million bpd relative to February 2016. *Id.* About half of this increase was exports of crude oil and most of the rest was of refined petroleum products. *Id.*



Since crude oil is blended during refining, exported finished petroleum products and the "other liquids" category (partially refined products) are likely produced from a mix of domestic and imported oil. The exported crude oil and natural gas liquids are produced from wells in the U.S. and do not include exports of crude oil transshipped through the U.S. from Canada.

The USEIA divides the United States into five regions for analysis of petroleum industry data. These regions are called Petroleum Administration for Defense Districts or PADDs. PADD 3 comprises Gulf Coast states including Texas, Louisiana, Mississippi, Alabama, as well as Arkansas and New Mexico, and is generally considered as the Gulf Coast region. PADD 3 has the largest refining capacity of all the PADDs, primarily located in Texas and Louisiana, and is in fact one of the largest refining centers in the world, with over 8 % of global refining capacity. In February 2017, exports from the PADD 3 accounted for 78% of total exports from the U.S. *Id.* Of this, PADD 3 exports accounted for 80% of finished petroleum products, 78% of exported crude oil, 73% of exported natural gas liquids, and 79 % of other liquids. *Id.* In 2016, nearly 40 % of PADD 3 refining capacity was dedicated to product export. *Id.* With an annual average of 3.6 million barrels per day (BPD) of products exported in 2016, the PADD 3 region's exports have grown more than threefold since 2006. *Id.* The export spike in February 2017 is 730 % higher than average exports in 2006. The following chart shows PADD 3 petroleum exports relative to total petroleum exports from the U.S. *Id.*

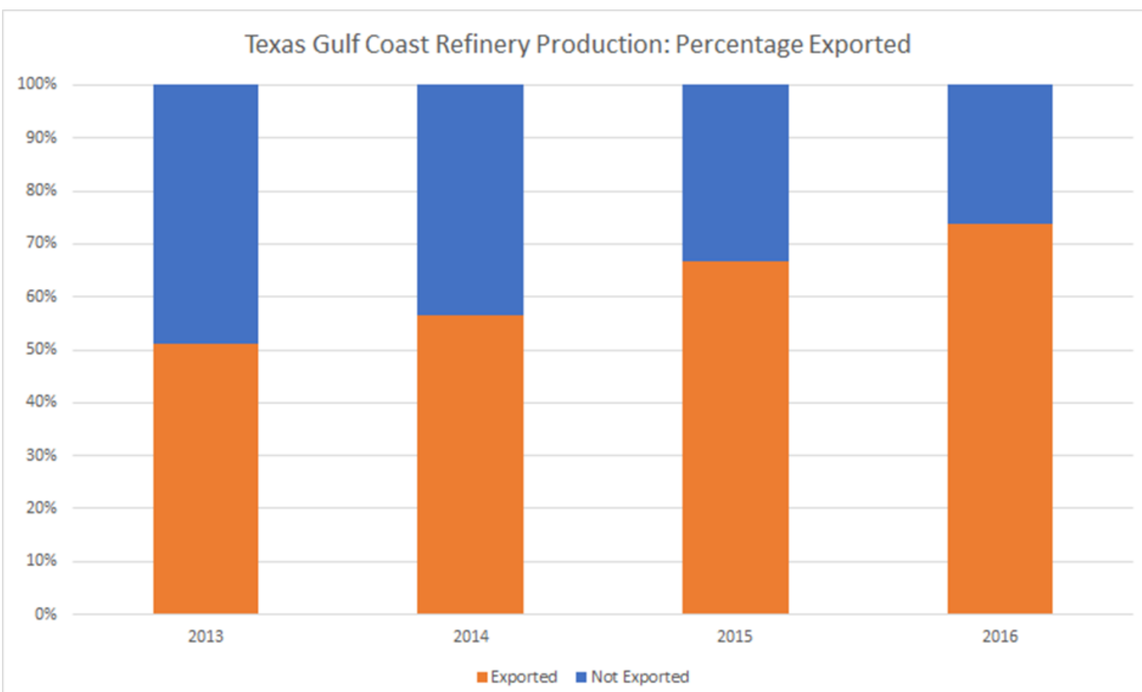


The data clearly shows that petroleum product exports from the wider Gulf Coast region have grown over 400 % since 2006, with 2016 average exports being 444 % higher than 2006 average exports. *Id.* The export spike in February 2017 is 730 % higher than average exports in 2006. *Id.*

However, breaking that data down to the Texas Gulf Coast sub-region reveals that the very region Keystone XL would serve is leading the export drive, with the majority of production exported. Data requested from EIA on exports by Gulf Coast port enables a correlation with EIA website data for refinery production by refinery sub-region. Attachment LS-33. This port-specific data provides a closer look at exports from the ports of Houston/Galveston and Port Arthur, those most relevant for Keystone XL.

Keystone XL would deliver crude oil to a terminal in Nederland, Texas. This terminal is located north of Port Arthur, where several large refineries are also located. Nederland is east of Houston, where several refineries are located on the eastern side of the city. TransCanada recently completed a pipeline linking the Nederland Terminal to Houston, with a view to accessing refineries in the Houston and Texas City area. I studied petroleum product export data from the ports of Port Arthur, Houston and Galveston. These last two are presented together in the EIA data and capture exports from Houston, Galveston and Texas City refineries. Petroleum product exports from these ports represent a much higher proportion of the sub-region's refinery production than in the wider PADD 3 region. *Id.*

The data indicates that many of the refineries in the Port Arthur, Houston, Texas City and Galveston area are exporting most of their production. *Id.* In 2016, exports from these ports accounted for 74 % of Texas Gulf Coast refinery production, up from 51% in 2013. *Id.*



In 2016, finished gasoline exports accounted for 87% of the finished gasoline produced in the region's refineries. *Id.* Including all gasoline additives and ethanol refined and blended in the region, exports account for 64% of gasoline related products. *Id.* Diesel exports account for 46% of the diesel produced in the region's refineries. *Id.*

Key Products (thousand BPD)	**Exports**	**Production**	**Percentage Exported**
Finished Gasoline	353	407	87%
Finished Gasoline + Blending Agents	491	762	64%
Diesel	578	1,260	46%

The high proportion of refinery product exports from this region indicate that Keystone XL would primarily serve a refining market that is focused on exports. These refineries are not serving U.S. energy needs, but rather global markets for petroleum products.

The State of Nebraska would bear the risks of hosting the pipeline without any clear benefit for the state or the nation. The project therefore serves the interests of the companies profiting from the extraction, transportation, refining and export of the crude carried by the project and not the wider American public.

VIII. THE PUBLIC INTEREST AND PUBLIC BENEFITS OF THE PROPOSED KEYSTONE XL PIPELINE

35Q. Based on your review of information about the Project, what conclusions do you draw about whether or not construction of the Keystone XL Pipeline in any route is in the public interest?

A. A pipeline that is not needed is not in the public interest, regardless of where it is built. The evidence shows that western Canadian oil economics does not currently support expansion of oil extraction facilities in Canada, and therefore also does not support construction of new crude oil pipeline export pipeline capacity from Canada. Moreover, trends in crude oil price and increasingly affordable transportation alternatives to internal combustion engines indicate that the long-term prospects for the oil industry are bleak, particularly for the Canadian tar sands industry because it is the high-cost producer in the global oil market. Even if there is a short-lived near-term need for increased export capacity from Canada that cannot be met via existing crude oil transportation capacity, there is a substantial risk that a different pipeline will be permitted to meet any limited demand and that such pipeline would not serve stagnant consumer demand in Nebraska or the U.S., but rather would be used to grow the oil industry's skyrocketing overseas exports. As such, there is no public benefit to imposing a route for the Keystone XL Pipeline on landowners in Nebraska, and the Keystone XL Pipeline is not in the public interest.

36Q. Does this conclude your testimony?

A. Yes, subject to updates to account for more recent data that should be available between the date of this testimony and the date of my testimony at the forthcoming Nebraska Public Service Commission hearing.

____
Lorne Stockman

Subscribed and Sworn to before me
this ____________ day of June, 2017.

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Notary Public

[Seal]