IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE, Plaintiff, and CHEYENNE RIVER SIOUX TRIBE, Plaintiff-Intervenor, v. U.S. ARMY CORPS OF ENGINEERS, Defendant-Cross Defendant, and DAKOTA ACCESS, LLC, Defendant-Intervenor-Cross Claimant.	Case No. 1:16-cv-1534-JEB (and Consolidated Case Nos. 16-cv-1796 and 17-cv-267)

DECLARATION OF MARIE FAGAN, PH.D

I. INTRODUCTION

1. My name is Dr. Marie Fagan. I currently serve as the Chief Economist at London Economics International, LLC, a consulting firm based in Boston. I have conducted research and consulted in energy economics for over 30 years with a particular focus on oil and gas, coal, and power markets, and have deep expertise in oil and gas production economics. I advise industry clients, financial clients, regulators, and public interest organizations. I have served as

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an expert witness in other cases involving crude oil pipelines. My full CV is attached as Exhibit 1 to this declaration.

2. I have been retained to offer testimony on behalf of several Tribes in this case regarding the potential closure of the Dakota Access pipeline ("DAPL"). I have prepared an expert report offering my opinion about the ramifications of closing DAPL for one to two years. That report is attached as Exhibit 2 to this declaration, and I hereby adopt it as my testimony in this matter. In preparing my report, I have reviewed the expert declarations filed by DAPL in support of their position that the pipeline should not be closed. I have also reviewed the previously filed declaration of Ian Goodman and generally believe it to be credible, given the time frame during which it was prepared. Finally, I have reviewed a number of additional sources and materials, which are catalogued in my report. In this declaration, I summarize the conclusions of the report for the convenience of the court.

II. SUMMARY OF EXPERT REPORT

3. The global oil market is currently undergoing an unprecedented and rapid period of change, brought about by the collapse in oil demand caused by the COVID-19 health crisis but also other factors. Even before the impacts of the coronavirus economic crisis, oil producers were facing headwinds from the capital markets upon whom they have depended for cash to sustain and grow production. Crude oil production in the United States has declined sharply in recent months as prices have fallen to unprecedented lows.

4. This trend is affecting North Dakota as it has other states. Preliminary data indicates that 6,000 of the state's 16,000 wells have already been "shut-in," i.e., temporarily or permanently closed. Production levels in the state have dropped from around 1.4 million barrels/day to around 900,000 barrels/day; additional reductions are possible. For several

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reasons, it is highly unlikely the North Dakota production will increase significantly in the next 18-24 months.

5. For this reason, it is my opinion that closing down DAPL would have limited if any impacts on oil production, transportation, prices, or availability. Any impacts that could occur would be so minor as to be lost in the noise of the other factors affecting the market. Because North Dakota production has fallen by roughly the same amount as DAPL's capacity (570,000 barrels a day), it is possible that there would be no additional need to transport crude by rail or other means, compared to the volumes transported by those means during 2019. Even if some of the volume carried by DAPL shifted to other modes of transportation, namely rail, it would be relatively easy to accommodate in light of the recent availability of additional rail cars and low utilization of the U.S. rail system.

6. The expert declarations filed by DAPL do not offer credible predictions because they fail to acknowledge the unprecedented situation in the oil market globally and North Dakota. They describe a world that no longer exists, and will not exist for years. All of them are based on either the false premise that the entire volume (or a very large portion of it) currently carried by DAPL would shift to rail, or the false premise that closure of DAPL would cause the entire volume (or a very large portion of it) currently being carried on it to stop production. Even without the current drop in North Dakota production, neither of those things would be true. Producers produce and sell oil when it is in their commercial interests to do so. Even if transportation costs for North Dakota producers were marginally higher, it simply means that some projects will continue to be profitable, and some will not.

7. Even if some North Dakota production becomes unprofitable and ceases because DAPL is not available, which is not likely at any noticeable level, it simply means production

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someplace else will fill that demand. North Dakota is at a competitive disadvantage to other major U.S. oil plays (such as the Permian basin in Texas) because it is distant from export terminals and refineries. If some marginal production in North Dakota falls off because of increased transportation costs, someone else in another state will benefit. Similarly, if DAPL is not available, other entities (like railroads or other pipeline companies) would benefit. In other words, at worst, closure of DAPL will simply redistribute benefits and burdens within the oil market—it will not disrupt the market as a whole.

8. Because closure of DAPL will have marginal or no effect on oil production or transportation in North Dakota, other impacts described in DAPL's expert declarations are also not credible. For example, because oil train traffic will not overwhelm the rail system, the adverse impacts on agriculture that are projected by other witnesses are substantially overstated. Moreover, while significant numbers of rail cars will not be needed to respond to DAPL's closure, the drop in oil production has rendered many rail cars unexpectedly available, and cheaper as well. Similarly, because production will not necessarily decrease as a result of DAPL's closure, it will likely have little effect on state tax revenues.

9. The claim that closure of DAPL will diminish our national security is misguided. The United States in recent years has emerged as one of the major global exporters of both crude oil and refined products like gasoline. The US is a net oil exporter. In light of excess production and low demand nationally, there is little chance that this will change in the next few years.

10. North Dakota oil production is not poised to recovery quickly from its current low levels. This is because of the confluence of several factors: uncertainties around the overall recovery of the economy; uncertainties about the levels of consumption of refined products like gasoline and jet fuel even when the economy recovers; and the reduced generosity of the capital

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markets on which the oil and gas sector rely for funding. The Corps has represented that an environmental impact statement ("EIS") would be done in 13 months. Even if that schedule were to double, in my opinion conditions will remain depressed in the basin relative to the early 2020 highs, limiting any adverse impacts of shutting down the pipeline during the time needed to prepare an EIS.

11. In short, it is my expert opinion that the claims of significant adverse impacts to oil production, taxes, and agriculture presented by DAPL in its expert declarations are not supportable. To the contrary, it is my opinion that the impacts of shutting down the pipeline (leaving aside DAPL's own profits) will be marginal and readily managed.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed on this 19th day of May, 2020.

Marie Fagan

Marie Fagan, Ph.D

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EXHIBIT 1

TO DECLARATION OF MARIE FAGAN, PH.D

Curriculum Vitae

Marie N. Fagan, PhD

Chief Economist, London Economics International, LLC

KEY QUALIFICATIONS:

Marie Fagan is the Chief Economist at London Economics International, LLC, based in Boston, Massachusetts. With over 30 years of experience in research and consulting for the energy sector, Marie's career has spanned international upstream and downstream oil and gas, global coal, North American gas markets, and North American power markets. She has advised C-suite industry clients, buy-side and sell-side financial clients, as well as legislators and regulators; she has served as an expert witness.

At LEI, Marie's expertise across electricity markets and fuels provides integrated perspectives and supports sound strategic advice for clients. She has experience as a project manager for complex, multi-year engagements, include a two-year project for the Maine Public Utilities Commission in 2014-2016, and a two-year project for the Mississippi Public Service Commission in 2017-2019. She has deep experience in econometric analysis.

Marie leads LEI's engagements related to oil and natural gas market analysis. She directs gas pipeline modeling efforts based on a sophisticated network model, supporting outlooks for natural gas prices and basis, and analysis of flows on North American interstate pipelines. She provides in-depth expert testimony on issues such as basis differentials, pipeline capacity and utilization in key regions, and LNG import and export supply and demand. Projects have included serving as independent market expert for the Maine Public Utilities Commission, in the evaluation of the costs and benefits of new natural gas pipelines into New England, and independent market expert for the Minnesota Department of Commerce in the matter of the CN application of Enbridge Energy for the Enbridge Line 3 expansion.

Marie directs LEI's research of the Electric Reliability Council of Texas ("ERCOT") electric power market. Recent projects have included examination of the political, legislative, and economic drivers the led to creation of ERCOT's Competitive Renewable Energy Zones ("CREZ"), and assessment of the potential for state-level support for further expansion of CREZ transmission lines.

From 1996-2014, she was with Cambridge Energy Research Associates ("CERA," now part of IHS Markit). She served as an Associate, then Associate Director for CERA's Global Oil research practice, as Director for the North American Gas research practice; she founded the CERAView Institutional Investor Service and co-founded CERA's Global Steam Coal service; she served as Senior Director for CERA's North American Electric Power service and of IHS CERA's Upstream Strategy service. Before joining CERA, Marie served as an economist with the United States Energy Information Administration ("EIA"), conducting analysis and modeling supporting the Annual Energy Outlook ("AEO"), and conducting analysis of energy company financial performance.

Marie is the author of original research with publications in academic and industry journals. She holds a PhD in Economics from the American University in Washington, DC. She is a member of the Energy Bar Association, the American Economic Association, International Association for Energy Economics, New England Women in Energy and Environment, and the Boston Economic Club. She is Vice President of Business for the US Association for Energy Economics.

EDUCATION:

Institution	American University, Washington DC
Date:	1995
Degree(s) or Diploma(s) obtained:	PhD in Economics. Dissertation: "Measuring Cost and Efficiency in US Crude Oil Resource Development, 1977-1990: A Frontier Translog Cost Function Approach"

Institution	University of Connecticut
Date:	1984
Degree(s) or Diploma(s) obtained:	Bachelor of Science, Business Administration (Finance)

EMPLOYMENT RECORD:

Date:	2014-present
Location:	Boston, MA
Company:	**London Economics International LLC ("LEI")**
Position:	Chief Economist (2020-present); Managing Consultant and Lead Economist (2016-2019); Managing Consultant (2014-2015)

Date:	2003-2014
Location:	Cambridge, MA
Company:	**IHS Markit (formerly Cambridge Energy Research Associates ("CERA"))**

Position:	Senior director, Upstream Strategy Advisory service (2012-2014). • Responsible for the re-vamp of research services and development of new research services focused on the needs of oil and gas exploration and production companies. Defined product architecture, defined deliverables, and generated research, as well as managed the delivery of research. Responsible for marketing plans and focus, conducting presentations to Board of Directors meetings and other C-suite client groups. Keynote speaker at IHS CERA events such as CERAWeek and other industry events and conferences Senior director, North American Gas, Power, and Renewables group (2007-2011). • Responsible for thought leadership, development, and delivery of research for IHS CERA's North American Electric Power Advisory Service and North American Gas and Power Scenarios Service. Led client engagements, as well as wrote and published research. Provided oversight and direction of the launch of a new research service, the IHS CERA Global Steam Coal Advisory Service Director/Senior director, CERAView Institutional Investor Service (2004-2007) • Created, launched and directed IHS CERA's first research service encompassing the oil, gas, and power sectors to serve a targeted client community. Developed a new IHS CERA research publication, *Investors' Energy Monthly*, and served as publication's executive editor. In this role, won the IHS Circle of Excellence Award in 2005 Director, North American Gas Advisory service (2003-2004) • Responsible for rapid re-construction and turnaround of one of CERA's largest research advisory services. Contributed to and helped define the research agenda, and was responsible for the editorial content and publication of major research and analytical reports related to gas infrastructure and markets in North America. Advised senior executive clients, including leading discussions of sensitive client-related issues.

Date:	2001-2002
Location:	Boston, MA
Company:	**International Human Resources Development Corporation ("IHRDC")**
Position:	Director, International Gas Program • Developed and implemented management training programs for middle and senior energy company managers, designed interactive presentations and teaching materials, and served as instructor. Taught principles of project development and financial analysis of energy company operations.

Date:	1996-2001
Location:	Cambridge, MA
Company:	**CERA**
Position:	Associate director, Global Oil advisory service (1999-2001) • Authored original research reports, responsible for client presentations and the management, execution, and delivery of consulting projects. Associate, Global Oil advisory service (1996-1998) • Developed and maintained IHS CERA's expertise in exploration and production costs, technology, and financial factors affecting the upstream oil and gas industry.

Date:	1994-1996
Location:	Washington, DC
Company:	**US Department of Energy, Energy Information Administration**
Position:	Economist • Conducted financial analysis of upstream and integrated oil and gas companies; evaluated and implemented conceptual approaches to analysis of energy markets and market incentives, and wrote and published original research reports.

Date:	1989-1994
Location:	Vienna, Virginia
Company:	Decision Analysis Corporation of Virginia (DAC)
Position:	Research associate/Associate • Performed economic and econometric analysis, modeling, and forecasting to support the Energy Information Administration energy end-use models. Designed the National Energy Modeling System's Commercial Energy Demand Model; conducted financial analysis of energy companies.

Date:	1988
Location:	Washington DC
Company:	US Department of Energy, Office of Policy, Planning and Analysis

Position:	Intern • Researched waste-to-energy potential in the United States; constructed a database, developed econometric models, analyzed results and produced written reports.

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RECENT PROJECT EXPERIENCE:

Date:	November 2019
Location:	Japan
Organization:	Private equity investor
Description:	**Long-term outlook for Japan electricity sector** LEI was engaged to prepare a brief, fact-based report that would help support a view of wholesale electricity prices in Japan after 2040. Marie authored the report, which covered i) the structure of Japanese electric power industry, and ii) the status of de-regulation and environmental policy. Based on this, Marie developed two reasonable scenarios for wholesale prices based on two different paths for energy supply to 2040 and beyond.

Date:	October 2019 – November 2019
Location:	ERCOT
Organization:	European investor-owned utility
Description:	**Investment environment for transmission in ERCOT** LEI was engaged by a European utility to examine the investment environment for transmission in ERCOT. Marie's team provided a detailed report covering agents and institutions, the regulatory and legal framework, remuneration of investment, and transmission planning.

Date:	July 2019 - August 2019
Location:	Alberta, British Columbia
Organization:	Counsel for natural gas producer
Description:	**Analysis of Western Canadian natural gas costs and production** LEI was retained by counsel to provide support in the matter of NOVA Gas Transmission Limited ("NGTL")'s application to the National Energy Board ("NEB"). LEI reviewed evidence and prepared testimony. Marie led analysis of the natural gas and natural gas liquids ("NGLs") market in Alberta and British Columbia, and the impact of a pipeline surcharge on producers of natural gas.

Date:	May 2019 – May 2020
Location:	United States, New England
Organization:	Investor-owned gas distribution utility
Description:	**Econometric benchmarking analysis of utility performance** LEI was engaged by an investor-owned local gas distribution company to support its rate filing for performance-based ratemaking. Marie led an econometric benchmarking

	analysis of utility performance and served as a testifying witness. The econometric analysis used a transcendental logarithmic cost function (a tried-and-tested methodology for providing empirical evidence in utility benchmarking cases) to help set expectations for further efficiency improvement. The benchmarking report was used by counsel to develop the company's strategy for the rate filing.

Date:	October 2018 – April 2018
Location:	United States, ISO-NE
Company:	Massachusetts Office of the Attorney General
Description:	**Winter fuel reliability/electric power market design** The MA Attorney General's Office of Ratepayer Advocacy ("AGO") engaged LEI to examine ISO-New England's proposals to address potential winter fuel security issues facing the electric power sector. Marie led the project, including developing an independent definition of the problem to be solved; developing solutions, identifying potential allies in the NEPOOL stakeholder community; analyzing other stakeholders' proposals; and working with the AGO in the stakeholder process. LEI developed an alternative proposal, a forward auction for stored energy reserves based on the financial concept of an American call option with a two-dimensional bid (the option premium and strike price).

Date:	February 2018 – December 2018
Location:	Global
Company:	Columbia University School of International and Public Affairs, Center on Global Energy Policy
Description:	**Econometric analysis of crude oil price and income elasticities of demand** LEI was engaged by the Columbia University, Center for Global Energy Policy ("CGEP") to conduct econometric analysis of global oil demand. Marie directed and managed the project, the foundation of which was a detailed econometric analysis of price and income elasticities of oil demand. Marie employed a variety of specifications of econometric models (including static and dynamic models, and symmetric and asymmetric models) and estimated separate models for crude oil, gasoline, and diesel demand. She used country-level data covering 40 years (1977-2016), aggregated into panel (pooled cross-section and time series) data sets for OECD, non-OECD, and oil-producing countries. Marie examined and reported the results of econometric tests covering time-series properties of the data (tests for integration and cointegration), performance of the log linear model specification as compared to an intrinsically non-linear specification, and the pool-ability of cross-sectional data. LEI's results were provided in a comprehensive report titled "Oil demand: Up the down staircase," which underwent academic review outside of CGEP.

Date:	September 2018-December 2018
Location:	United States, ISO-NE
Company:	Maine Public Utilities Commission
Description:	**Avoided energy supply costs** LEI was engaged to perform a critical review of the methodology and assumptions which underpinned other consultants' analysis of avoided energy supply costs ("AESC"). Marie led the gas market forecast, and the critical review of the other consultants' gas price forecast. She also led a careful examination of the economic theory and econometric techniques used by the other consultants to estimate demand-induced price reduction effects ("DRIPE"). Owing to miss-specified models and/or unwarranted assumptions (such as a perfectly inelastic demand curve for natural gas in the long term) the other consultants' DRIPE estimates were generally too high.

Date:	June 2018-December 2018
Location:	United States, PJM
Company:	Ohio Public Utilities Commission
Description:	**Management performance and financial audit of large utility** LEI was engaged to perform a management performance and financial audit of AEP Ohio's Alternative Energy Rider ("AER"). Marie led the project which required examining the terms of power purchase agreements ("PPAs") for wind and solar power, the cost of renewable energy credits ("RECs"); energy and capacity market prices; inventory strategies, and the accuracy of AEP Ohio's load forecasts. Marie recruited a local Ohio accounting firm to perform the financial portion of the audit; she provided guidance (as the firm had not previously audited a utility) and oversight of their work as well as the work of the LEI in-house team.

Date:	March - September 2018
Location:	United States, MISO, Michigan
Company:	NGO
Description:	**The role of Enbridge Line 5 in NGLs and crude oil transport in Michigan** For a non-governmental organization ("NGO") Marie produced three white papers examining the current and future role of Enbridge Line 5 in Michigan related to three issues: propane supply in Michigan, transportation for crude oil producers in Michigan, and supply of crude oil to Michigan-area refineries. Marie's analysis of the propane market included a comparative static econometric analysis of the supply and demand from propane in Michigan, explained in non-technical language. The white papers were used by the client in discussions with the Governor of Michigan and other stakeholders

Date:	July 2017-June 2018

Location:	United States, MISO, Minnesota
Company:	Minnesota Department of Commerce
Description:	**Role of Enbridge Line 3 in heavy and light crude oil supplies** Marie served as independent market expert assisting the Minnesota Department of Commerce in evaluating the application of Enbridge Energy for a Certificate of Need for its Line 3 oil pipeline expansion project (Docket No. PL-9/CN-14-916, OAH Docket No. 65-2500-32764). Marie's analysis covered global and local trends in refined product demand and crude oil supply, refinery utilization rates and utilization of high-conversion refinery capacity in Petroleum Administration for Defense District ("PADD") 2 and in the local Minnesota region. Her analysis required detailed examination of the assumptions and methodology of an oil pipeline linear programming-based model, in order to assess another witness's testimony which relied on the model. Marie provided written testimony; responded to interrogatory requests, provided written surrebuttal, and oral testimony.

Date:	June 2017-December 2018
Location:	United States, MISO, Mississippi
Company:	Mississippi Public Service Commission
Description:	**Management audit of large vertically integrated utility** Marie led a management audit of the fuel (gas, coal, and nuclear) and energy procurement activities of Entergy Mississippi. Marie's team assessed fuel and energy contract terms, and reviewed the prudency of coal and nuclear fuel procurement and inventory practices. Marie's team also assessed management, organization, controls, strategies, and outcomes for the company's hourly MISO offers. The team investigated the operations of a nuclear power plant, and the financial implications of the utility's power purchase agreement for nuclear power. Marie appeared before the Commission to present and defend findings.

Date:	November 2018 – February 2018
Location:	WECC
Company:	PacifiCorp
Description:	**Independent evaluator ("IE") for energy procurement** LEI was retained as an IE by PacifiCorp for its system-wide 2017 Solar RFP. Marie led the project, which included a review of PacifiCorp's Solar RFP, the facilitation and monitoring of communications between PacifiCorp and bidders, performing a review of the initial shortlist evaluation and scoring, and the filing of status reports and the final IE closing report.

Date:	April, May 2017
Location:	United States and Canada
Company:	Private client
Description:	**Review of investable energy sectors** For a private equity client, Marie led an extensive project reviewing a wide range of investable energy sectors in the United States and Canada. The sectors included: electricity generation (natural gas, wind, solar, hydro), AMI, distributed resources, demand response, retail energy, gas LDCs, gas storage, gas pipeline transportation, LNG-related infrastructure, vertically-integrated utilities, electric distribution utilities, and water utilities. LEI assessed the investment potential of each sector for the next five years, and proposed a methodology to screen and identify investment opportunities and execute on these opportunities.

Date:	March 2017

Location:	Alberta, Canada
Company:	Private client
Description:	**Analysis of capacity markets** LEI was engaged to provide global perspectives on the detailed mechanisms that make up capacity markets, so that eventual capacity market design in Alberta will be workable and efficient, with minimal unintended consequences. Marie led research and delivered a detailed report on market power mitigation mechanisms and their potential impacts on capacity market performance.

Date:	February 2017
Location:	North America
Company:	Provider of services to vehicle fleet industry
Description:	**Outlook for electrification of transportation** Marie developed scenario outlooks for electric vehicle ("EV") market penetration in the United States; examined the role of electric utilities (and their emerging EV-related business models) as potential partners versus competitors to the downstream transportation industry; identified activities and strategic positioning of upstream and downstream industry participants; led discussion of implications of "electrification of transportation" for fleet service companies, convenience stores, and other downstream industry participants. Presented material to company's partner advisory board.

Date:	December 2016
Location:	Alberta, Canada
Company:	Private client
Description:	**Analysis of capacity markets** To support Board-level understanding of the implications of potential capacity market designs in Alberta, Marie prepared a detailed review and comparison of capacity markets across international and North American jurisdictions. Report concluded "the devil is in the details" of capacity market design. Market design details with potentially large impacts on the client were resource eligibility definitions, price setting mechanism, demand curve design, performance requirements, and market power mitigation rules.

Date:	September 2016
Location:	Northeast United States
Company:	Private client
Description:	**Examination of solar business models** For a client performing due diligence related to a potential investment in business-to-business behind-the-meter solar in the Northeast United States, Marie led a project examining US federal and state incentives for solar adoption, and assessing business models used for targeting commercial, institutional, and industrial sectors. For each business model, LEI assessed the competitive environment—who is operating in the sector, what is their go-to-market strategy, and in general how these models have been performing. Marie's team also provided a 10-year outlook for solar renewable energy credits ("SRECs") for certain jurisdictions. Finally, LEI developed key questions the client should ask as part of its evaluation of potential transactions in the behind-the-meter solar sector.

Date:	October 2016-November 2016
Location:	California, Kansas
Company:	Law firm
Description:	**Support for counsel in contested matter** Marie prepared an expert report in support of litigation in Case 15CV-04225 in the District Court of Johnson County, Kansas. LEI was retained by counsel to examine the value of the green attributes of landfill gas (“LFG”) produced by a project in Kansas City and sold under long-term contract to the Sacramento Municipal Utility District ("SMUD"). Marie’s report demonstrated several flaws in the opposing counsel's expert's methodology. Marie proposed an alternative, more accurate methodology for valuing the green attributes of LFG, based on market fundamentals driven by the California RPS requirements.

Date:	August 2016-October 2016
Location:	Maine
Company:	Maine Public Utilities Commission
Description:	**Macroeconomic impact of biomass generation** Marie led an engagement to estimate the macroeconomic impact of biomass generation within the state of Maine (Maine PUC Docket No. 2016-00084). This included direct, indirect, and induced impacts on: permanent direct jobs, payments to municipalities, payments for fuel harvested in the State, payments for in-state resource access, in-state purchases of goods and services, and construction-related jobs and purchases. Marie used the macroeconomic model known as IMPLAN to capture the economic impacts on industries including logging, sawmills, and other forestry-related industries and well as on state and local taxes.

Date:	May 2016
Location:	ERCOT/Texas
Company:	Private client
Description:	**Examination of ancillary services** Marie conducted a case study assessing the current ancillary services (“CAS”) market in ERCOT, outlining the structure of ERCOT’s proposed Future Ancillary Services Nodal Protocol Revision Request (“FAS-NPRR”), and examining the implications of ERCOT’s experience so far for the Alberta electricity market. Findings included the following: While it was widely expected that the addition of large amounts of wind (and other non-synchronous generation) on the ERCOT system would significantly increase the need for ancillary services, by 2015, ERCOT’s procurement of CAS products had not increased compared with 2011. However, the need for synchronous inertial response (“SIR”) which is not part of CAS did increase somewhat over the time period, though ERCOT did not include SIR in its FAS-NPRR.

Date:	April 2016-May 2016
Location:	ERCOT/Texas
Company:	Renewable power investor
Description:	**Due diligence in ERCOT** LEI was hired to perform due diligence for an investor interested in wind assets in ERCOT. Marie examined the political, legislative, and economic drivers of ERCOT's Competitive Renewable Energy Zones ("CREZ") and provided an assessment of state-level support for further expansion of CREZ transmission lines. She also provided assessment of and outlook for ERCOT's and the Public Utility Commission of Texas's views of the "system cost" of wind (the potential increased need for ancillary services and firm capacity on the system).

Date:	June 2014-April 2016
Location:	Maine
Company:	Maine Public Utilities Commission
Description:	**Project manager and testifying expert** Marie served as project manager, independent market expert, and expert witness for the Maine Public Utilities Commission, in the evaluation of the costs and benefits of alternatives for expansion of natural gas supply into Maine pursuant to the Maine Energy Cost Reduction Act (MPUC Docket #2015-00071). Marie reviewed and evaluated proposals for firm natural gas transportation service by pipeline developers. These evaluations included LEI's review of commercial terms include in the pipeline Precedent Agreements that underpin capacity expansion projects; review of contract provisions for Firm Transportation Agreements and Negotiated Rate Agreements; and evaluation of the status of the FERC and state-level permitting process for each pipeline proposal. Marie provided expertise in upstream natural gas (exploration and production), midstream natural gas (interstate pipelines) and global energy markets including oil and LNG markets, to provide a solid grounding for LEI's long-term outlook for New England natural gas prices. Marie directed the natural gas network modeling (using GPCM, an industry-standard network model of the North American natural gas system) and power simulation modeling (using LEI's proprietary POOLMod model) to arrive at a quantitative cost-benefit analysis of proposals. She authored reports provided to the Commission; responded to discovery from other parties; prepared discovery questions and cross-examined witnesses; reviewed testimony by other parties and provided assessments of the issues presented; and she served as an expert witness in the proceedings.

Date:	November 2015-December 2015
Location:	US Northeast
Company:	Renewable power developer
Description:	**Due diligence for assets in ISO-NE (Maine)**

	LEI was hired by a wind developer to provide a quantitative assessment, based on an economic dispatch model, of congestion/curtailment risk for a wind asset in Maine. LEI used its proprietary dispatch model, PoolMod, to provide an outlook from 2016 through 2020 of hourly LMPs, as well as the components of LMP (energy, losses, and congestion). We incorporated information from the interconnection impact study to examine system limits for the plants in question. LEI also provided an assessment of risk of outages based on NERC outage data for NPCC. Marie led the project

Date:	October 2015-November 2015
Location:	ERCOT/ Texas
Company:	Private equity company
Description:	**Due diligence for assets in ERCOT** LEI was hired to forecast the potential energy revenues of two wind farms in Texas, using its proprietary dispatch model, PoolMod. Marie led the project, and also examined the implications of the PPA related to the two wind farms.

Date:	July 2015
Location:	North America/United Kingdom
Company:	UK Department of Energy and Climate Change
Description:	**Examination of design of auctions** Marie participated in a review of auction design for the UK DECC. The UK market regulator was interested in whether US power markets evaluate generation bids based on criteria other than the price bid, specifically, if the length of contract had a role in the auctions. LEI reviewed capacity market rules for PJM, ISO-New England and the New York ISO. Marie examined whether and for how long a "lock-in" option for the first year capacity price is offered to new generation assets bidding into the auctions. She also reviewed international spectrum auctions, North American gas transmission open season rules, and international auctions for toll roads to examine whether and how duration or length of contract is incorporated into bidding.

Date:	May 2015
Location:	Connecticut; Virginia
Company:	Private equity company
Description:	**Review of gas transportation contracts** Marie evaluated contracts for firm gas transportation capacity for gas-fired plants in Virginia and Connecticut.

Date:	April 2015
Location:	Connecticut; New Jersey

Company:	Private equity company
Description:	**Outlook for natural gas prices** LEI was retained to forecast delivered gas prices in New England (Connecticut) and PJM (New Jersey) and locational marginal prices as well as retail electricity prices in Connecticut. Marie led the gas market analysis.

Date:	August 2014 - January 2015
Location:	North America
Company:	Private client
Description:	**Monthly energy market reports** LEI was engaged to support an energy company's Regulatory Group in its administering of the company's compliance program. The purpose of the engagement was to ensure that client's transactional and business groups were made aware of market rules and regulatory risks. This involved creating and delivering a monthly report covering developments by regional market and traded products which included: energy, capacity, long-term transmission service, FTR auctions, ancillary services, diesel oil, PRB coal, natural gas commodity, transmission, and storage, RECS, and CO_2. Marie served as project manager and executive editor of the monthly report and monthly conference call, and provided the research and insight on US gas, oil, and coal markets, and FERC activities.

Date:	October 2014
Location:	New England
Company:	Private equity company
Description:	**Assessment of ancillary service market** To support potential acquisition of hydropower assets, Marie provided analysis of ISO-New England's Locational Forward Reserves Market ("LFRM").

Date:	April-June 2014
Location:	US Midwest
Company:	Private equity company
Description:	**Due diligence for asset in PJM** For due diligence related to a district cooling system in the Midwest, Marie reviewed contracts and developed a model for projecting revenues and gross margins for the asset. Marie provided insight by identifying the potential for lower customer contract prices at renewal (in contrast to the seller's assumptions) and other areas of revenue risk.

Date:	June 2014
Location:	North America
Company:	Law firm
Description:	**Examination of FERC policies and practices** LEI was engaged by a law firm on behalf of a Canadian energy company to provide market advisory for an investigation related to the timing of outage scheduling under

	PPAs. Marie provided research and expertise covering FERC practices related to monitoring, enforcement, and definition and prosecution of alleged market manipulation.

Date:	April-May 2014
Location:	Nova Scotia
Company:	Government of Nova Scotia
Description:	**Organization of energy system** Marie provided a detailed overview of the Nova Scotia gas and power sectors, including governing institutions, the legal and regulatory framework, recent developments and challenges, and SWOT analysis.

PUBLICATIONS:

Technical/Academic

Fagan, Marie. "Up the Down Staircase: What History Teaches Us about Oil Demand after a Crisis" (posted May 4, 2020). USAEE Working Paper No. 20-440. Available at SSRN: https://ssrn.com/abstract=3592443

Kleinberg, Robert and Fagan, Marie, "Business Cycles and Innovation Cycles in the U.S. Upstream Oil & Gas Industry." (December 1, 2019). USAEE Working Paper No. 19-423. Available at SSRN: https://ssrn.com/abstract=3508466 or http://dx.doi.org/10.2139/ssrn.3508466

"New England Oil, Gas, and Power Markets" guest lecture, University of Massachusetts, Boston, MA, October 2005, with Lawrence Makovich.

"The Disappearing Middle Class: Economies of Scale in Exploration and Development," presented at the International Association for Energy Economics, 26th annual conference, Aberdeen, June 2002.

"The Key Role of Technology in Reducing Offshore Finding and Development Costs," *Fundamentals of the Global Offshore Industry,* The Petroleum Economist Ltd., London, September 2001.

"The US Oil and Gas Supply Situation: How Did We Get Here?" guest lecture, Clark University, Worcester, MA, October 2000.

"The Technology Revolution and Upstream Costs," *The Leading Edge* (Journal of the Society of Exploration Geophysicists), June 2000.

Review of *Exploration, Development, and Production – Texas Oil and Gas 1970-1995,* for the *Journal of Economic Literature,* 1999.

"Resource Depletion and Technical Change: Effects on US Crude Oil Finding Costs from 1977 to 1994," *The Energy Journal,* 1997.

"Inter-jurisdictional Competition, Resource Rents, Tax Exporting, and Oil and Gas Severance Taxes," *The Journal of Energy Finance and Development,* 1997, with Kevin Forbes.

"Fiscal Illusion and Fiscal Sclerosis: The Case of Oil and Gas Severance Taxes," presented at the US Association for Energy Economics/International Association for Energy Economics conference, Boston, MA October 1996.

"Prices, Depletion, and Technical Change 1977-1990: The Declining Cost of Crude Oil," presented at the Allied Social Science Association Annual Meeting, American Economic Association/International Association for Energy Economics session, San Francisco, CA, January 1996.

"Technical Change and Scale Economies in US Onshore Oil and Gas Exploration 1977-1990," presented at the Southern Economic Association meeting, New Orleans, LA, November 1993.

US Department of Energy

State Energy Severance Taxes, DOE/EIA-TR/0599, Washington, DC, 1995.

Oil and Gas Development in the United States in the Early 1990s: An Expanded Role for Independent Producers, DOE/EIA-0600, Washington, DC, 1995, with Jon Rasmussen.

"Trash to Energy: A Burning Issue," *1988 Selected Papers and Presentations by DOE's Policy Integration Staff*, US Department of Energy, Office of Policy, Planning and Analysis, Office of Policy Integration, Washington, DC, December 1988, with Peggy Podolak.

IHS/CERA Publications

Global Prospects for Shale Gas: Assessing Above-ground Risks and Enablers IHS CERA Private Report 2013

The Impact of Technology on US Offshore Finding and Development Costs IHS CERA Private Report 2013

The Next E&P Hotspots: What are the Leading Indicators? IHS CERA Decision Brief 2012

Taking the Shale Gale International: Lessons from North America IHS CERA Decision Brief 2012

Prospects for Shale Gas in Europe: Insights from CERAWeek IHS CERA Insight 2012

Envisioning a Long-term Future for Coal IHS CERA Insight 2011

North American Power Industry Landscape 2011 IHS CERA Decision Brief 2011

Common Ground? CERAWeek Perspectives on US Electric Power Transmission IHS CERA Insight 2010

North American Power Industry Landscape 2010 IHS CERA Decision Brief 2010

Mexico's Road to Renewable Power: The Cost of a Range of Targets and Options IHS CERA Decision Brief 2009

Competitive Bidding: A Key Tool for Capital Formation in the US Power Sector IHS CERA Decision Brief 2009

Financing the Global Power Business: Insights from CERAWeek IHS CERA Insight 2009

Concentrating Solar Power: US Demand Heats Up IHS CERA Decision Brief 2008

US CO2 Policy Quandary: Near-term Reductions Imply a High Carbon Price IHS CERA Private Report 2008

The US Energy Act of 2007: Addressing the Demand Side of Electric Power IHS CERA Insight 2008

Investors' Energy Monthly December 2004 – November 2007

Some Sail, Some Fail: Utility M&A after PUHCA IHS CERA Decision Brief 2006

Another Decade of Rising Upstream Costs? IHS CERA Decision Brief 2006

Merchant Power's Recovery: Four Dimensions of Value IHS CERA Private Report 2006

PUHCA Repeal and Utility M&A: One Big Obstacle Down, Many Remain IHS CERA Decision Brief 2005

North American Gas Monthly Briefing January 2003 - June 2004

Costs are Up for North American Natural Gas IHS CERA Decision Brief 2004

Bottom Line: A New Long-term Floor for North American Gas Prices IHS CERA Private Report 2004

Upstream Gas Costs and North American E&P Strategy: Avoiding the Edge IHS CERA Decision Brief 2004

Can We Drill Our Way Out of the (Natural Gas) Supply Shortage? IHS CERA Decision Brief 2003

Cost-effective Deepwater Development: Seeing the Forest from the "Trees" IHS CERA Private Report 2001

Optimization and the Role of R&D IHS CERA Decision Brief 2001

Upstream Spending Plans: Inflation in the Pipeline IHS CERA Alert 2001

Upstream Technology on the Horizon IHS CERA Decision Brief 2000

Upstream Costs--Why the Gap will widen IHS CERA Decision Brief 1999

The Impact of Falling Oil Prices on Upstream Operations IHS CERA Decision Brief 1998

The Technology Revolution and Upstream Costs IHS CERA Private Report 1998

Managing the Rig Shortage IHS CERA Decision Brief 1997

SPEAKING ENGAGEMENTS:

News Media

"Upstream oil costs on the rise" (excerpts from *Another Decade of Rising Upstream Costs?* IHS CERA Decision Brief 2006), *The Wall Street Journal Morning Brief,* June 28, 2006.

"Unnatural Gas Prices," live television interview for CNN-FN, December 23, 2003.

IHS/CERA CERAWeek Roles

Chairman, Coal Plenary *Envisioning a Long-term Role for Coal,* March 10, 2011

Chairman, Strategy Session *Financing the Power Future*, March 10, 2011

Chairman, Expert Dialog *North American Gas and Power Scenarios Wildcards*, March 9, 2011

Chairman, Strategy Session *Financing a North American Power Sector in Transition*, March 12, 2010

Panelist, CERA Insights *Global Power Outlook*, March 12, 2010

Chairman, Strategy Session *US Electric Power Transmission: the Battle of the Jurisdictions*, March 11, 2010

Chairman, Critical Issue Forum, *Financing the Power Sector in a Turbulent Economy*, February 12, 2009

Chairman, Critical Issue Forum *Power Sector Investment: Global Capital, Local Strategies* February 15, 2008

Panelist, Leadership Circle *Global Power Outlook* February 14, 2008

Chairman, Critical Issue Forum *Rising Costs and the Outlook for North American Gas*, February 14, 2007

Host and Commentator, *Reception for Institutional Investors* February 13, 2007

Panelist, Critical Issue Forum *Oil Sector Finance: the Cliff behind the Clouds?* February 13, 2007

Host and Commentator, *Reception for Institutional Investors* February 7, 2006

Chairman, Critical Issue Forum *Financing the Oil Future: A Three-Trillion Dollar Dilemma* February 7, 2006

Host and Commentator, *Reception for Institutional Investors* February 15, 2005

Chairman, Critical Issue Forum *North American Natural Gas: E&P in a Mature Region* February 11, 2004

Chairman, Expert Briefing *North American Gas E&P Strategy: Getting off the Treadmill?* February 12, 2003

Panelist, Expert Briefing *Bracing for a Wild Ride: North American Gas Market Outlook* February 11, 2003

EXHIBIT 2

TO DECLARATION OF MARIE FAGAN, PH.D

Impacts of a temporary shutdown of Dakota Access Pipeline

prepared for Earthjustice by London Economics International LLC

May 19, 2020

London Economics International was engaged by Earthjustice on behalf of the plaintiff tribes to provide an independent view of the impact of a temporary shutdown of the Dakota Access pipeline ("DAPL") while the US Army Corps of Engineers conducts the Environmental Impact Statement ("EIS"). The timeframe of LEI's analysis is 2020-2022.

DAPL transports crude oil produced in North Dakota. North Dakota oil production is, in turn, part of a globally interwoven system of oil production, demand, and transportation. Oil producers such as those in North Dakota were facing a challenging business environment, even before the economic crisis triggered by global and US efforts to contain the spread of COVID-19. For the reasons discussed in this report, LEI believes relatively low oil demand and low oil prices (and, with it, low demand for oil transportation out of North Dakota) will last through 2021-2022.

LEI is not offering an opinion on whether DAPL should be shut down. LEI's analysis shows, however, that the rail transport system could easily manage the incremental need for oil transportation with little impact on rail congestion; that concerns over the impacts on the agricultural sector and energy security are misplaced; and other witnesses' estimates of losses are overstated based on unrealistic assumptions for oil prices and volumes of stranded oil.

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Table of contents

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Table of figures

1 Executive summary

The decision whether to shut down DAPL for 13 months or longer is coming during a "bust" phase in the notoriously boom-bust oil industry. In 2018 and 2019 indicators such as the level of investor interest in oil and gas companies, the struggles of OPEC to manage production and support oil prices, and international concerns leading to policies to reduce the use of fossil fuels to slow climate change were some of the headwinds faced by oil producers in North Dakota and elsewhere.

In addition to the oil price weakness in place by the end of 2019, the novel coronavirus and its impact on the global economy and oil demand have been unprecedented. Policies to contain the COVID-19 pandemic have created economic burdens for companies (be they oil producing companies, pipeline companies, hotel owners, or restauranteurs) and personal hardships for individuals (be they laid-off oilfield workers or other citizens relying on services such as unemployment compensation provided by state budgets).

As of mid-May 2020, oil production in North Dakota was 550,000 barrels per day ("b/d") lower than in February 2020. It is likely that oil production in North Dakota and other locations will recover from currently low levels, but this recovery depends not only on the price of oil, but on expectations of investors; and it could take two years or more. Investors, and their expectations, will ultimately determine when and how far oil US production will eventually recover. LEI discusses this in detail in Section 3. In the interim, the next two years are likely to be years in which oil production from North Dakota will be substantially below the level of early 2020; oil demand in the United States and abroad will be unusually low; and global oil prices will recover only gradually. If one had to choose a time in which to shut down a pipeline temporarily, now would be it.

The current environment is probably not permanent but could persist for one or two years; and the shut-down of DAPL is intended to be temporary. Low demand and low oil prices mean that the impact of shutting down DAPL will be much smaller than if oil demand and oil supply were surging and oil prices were high, and much smaller than claimed by the various other litigation filings. LEI summarizes the reasons for this below and supports its conclusions in the body of the declaration.

1.1 Prospects for North Dakota oil production growth were weakening before the coronavirus crisis

The Director of North Dakota's Department of Mineral resources reported that total oil production curtailed in North Dakota as of May 14, 2020 amounted to 550,000 b/d.[1] This

[1] MacPherson, James. Associated Press. *North Dakota aims to use COVID-19 aid to plug oil wells*. May 14, 2020. https://billingsgazette.com/news/state-and-regional/north-dakota-aims-to-use-covid-19-aid-to-plug-oil-wells/article_eadee456-3b1f-5b04-8d75-a0280fcb72ea.html

reduction represents 38% of recent North Dakota oil production, which had reached 1,434,500 b/d by February 2020.[2]

The reductions as of May 2020 are approaching the current 570,000 b/d capacity on DAPL. Assuming no further production cuts (which is unlikely, as discussed in Section 3.3), this leaves only about 20,000 b/d of transport capacity to make up for if DAPL were to close temporarily. Many of the Declarations filed in this matter assume that either 1) the entire 570,000 b/d, or a large portion of it must be shipped by rail if DAPL closes; or, 2) the entire 570,000 b/d of production, or a large portion of it, is stranded. For the next two years, neither of these extreme assumptions is warranted. Specifically, LEI discusses in detail why these assumptions are unrealistic in Section 5, Section 6, and Section 7.

1.2 Rail operations could take up the slack if DAPL were temporarily closed

Oil production from the Williston Basin is more-or-less synonymous with North Dakota production, and the Bakken geological formation is part of the Willison Basin.[3] In this report, as in much data from the State of North Dakota and other sources, the terms "Williston Basin," "Bakken region," and "North Dakota" oil production are used more or less interchangeably. The State of North Dakota tracks shipments of crude oil by rail from the Williston basin: as of February, 2020, these were estimated at 330,000 b/d.[4]

In general, it is mistaken to assume a one-for-one relationship—not every barrel that would have been shipped on DAPL will necessarily be transported by rail, or by any other means. Depending on the operating cost to produce the oil (which LEI discusses in detail in Section 3.3), some barrels will not be economic to produce or to ship by any means, whether on DAPL, on other pipelines, by rail, or by truck. But others will, and each producer will make such decisions based on their own operating costs, the cost of their transport options, and the price a buyer is willing to pay for the oil.

Some of the Declarations filed in this matter assume this one-to-one relationship holds. They assume that the entire 570,000 b/d capacity of DAPL, if it were closed, would have to be made up by rail, otherwise the production would be stranded completely. Concerns raised by witness Elaine Kub reflect worries over a re-play of 2014, in which rail congestion negatively impacted farmers. As LEI discusses in Section 6, the recent collapse in rail traffic (not just traffic related to

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[2] North Dakota Pipeline Authority. 2020. *Williston basin oil production*. Accessed May 2020.

[3] US Geological Survey. https://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf

[4] North Dakota Pipeline Authority. 2020. *NDPA Website data*. Accessed April 2020. https://northdakotapipelines.com/datastatistics/ North Dakota Pipeline Authority. Oil Transportation Table.

crude oil shipments) makes such congestion a feature of 2014 that is highly unlikely to recur in the next two years.

1.3 Economic losses are overstated by other witnesses

As LEI discusses in detail in Section 7, the annual economic losses to North Dakota producers and to the state and royalty owners estimated by Dr. Jeff Makholm are overstated owing to his flawed assumption that between 320,000 b/d and 570,000 b/d would be stranded, and his implausible assumptions for the price of oil in North Dakota in 2020 and 2021. Ms. Kub's estimates of losses to the agricultural sector are overstated, based on the assumptions for demand for substantial rail transport (for North Dakota crude oil as well as rail transport in general).

1.4 Energy security impact would be negligible

Energy security issues, which loomed over geopolitics when the United States was a large net importer of oil (and when oil prices were high), do not apply in the same way in a world awash in oil. Energy security, as traditionally thought of in the United States context, was centered on worries over access to, and the price of, oil supplies located in distant and potentially unfriendly countries. Under the current circumstances of oversupply and low oil prices, a temporary shutdown of DAPL would be a non-issue in terms of energy security.

1.5 The right time for temporary closure of a pipeline is when its impact would be smallest

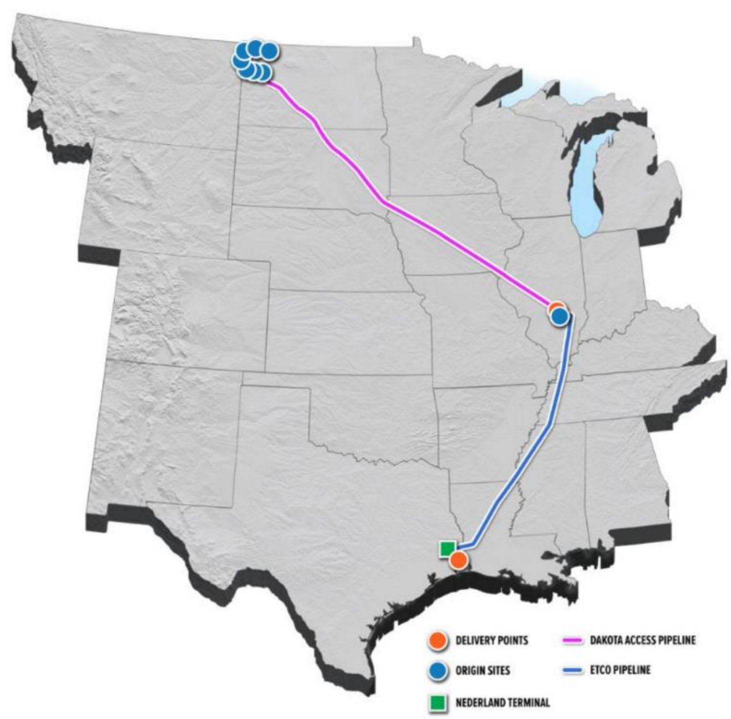
As discussed in Section 3, oil producers in North Dakota and other locations have been facing headwinds and financial challenges. In 2020, the economic impact of measures to contain the COVID-19 pandemic exacerbated these challenges. Oil prices and oil demand in North Dakota, the United States, and globally are currently far below recent historical levels. The North American oil pipeline system, which has been optimized to transport crude to US markets and more recently for bringing oil to ships for export, will be underutilized for at least a year or two. LEI's opinion is related to the economic impacts of closure, not other considerations. The low oil price and low oil demand conditions provide a window in which economic impacts would be minimized.

2 Introduction

2.1 The purpose of the Dakota Access Pipeline

Dakota Access and Energy Transfer's ETCO Project ("ETCOP") are collectively referred to as the "Bakken Pipeline."[5] The Bakken Pipeline is a 30-inch diameter, 1,916 mile pipeline with a capacity of 570,000 b/d, transporting crude oil from North Dakota to a storage and terminal hub near Patoka, Illinois, and on to US Gulf Coast connections including Nederland, Texas (see Figure 1).[6] The Bakken Pipeline is owned by Energy Transfer (36.3681%), Enbridge Inc. (27.5625%), PSXP (25%), MPLX (9.1875%), and ExxonMobil (1.8819%).[7]

Figure 1. The Bakken Pipeline



Source: https://daplpipelinefacts.com/About.html

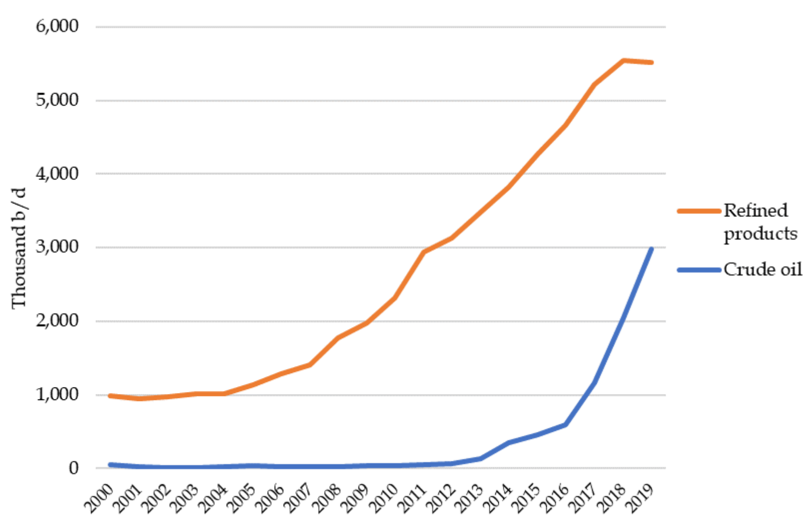
[5] Energy Transfer LP. 2019. *Annual Report on Form 10*-K. http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_ETP_2019.pdf

[6] Energy Transfer LP. 2020. *Business Overviews: Crude Oil, Energy Transfer*.

[7] Ibid.

The ETCOP portion of the Bakken Pipeline is a former natural gas pipeline which was converted to oil service.[8] The ETCOP portion allows crude oil to reach the US Gulf Coast. This is crucial for oil companies who want to increase production, because oil demand growth in the United States has been much slower than oil supply growth. Beginning in December 2015, the US Congress lifted the ban on US crude oil exports, and crude oil exports began to surge in 2016 (see Figure 2). The purpose of recent and ongoing pipeline projects such as the Bakken Pipeline, and TransCanada's ("TC") Keystone and Keystone XL pipelines is to give US and Canadian oil access to export markets.

Figure 2. US exports of crude oil and refined products



Source: EIA. US Exports of Crude Oil and Petroleum Products
http://www.eia.gov/dnav/pet/pet_move_exp_dc_nus-z00_mbblpd_a.htm

In February 2020, the North Dakota Public Service Commission approved Energy Transfer Partners' plan to increase DAPL's capacity by up to 500,000 b/d by 2021, to reach up to 1.1 million barrels per day ("mbd").[9]

2.2 LEI's role and task

LEI was engaged by Earthjustice on behalf of the plaintiff tribes to provide an independent view of the impact of a temporary shutdown of DAPL while the Army Corps of Engineers ("the Corps") conducts the EIS. The Corps said it expects the EIS process to take about 13 months but

[8] Energy Transfer LP. 2020. *Business Overviews: Crude Oil, Energy Transfer*.

[9] North Dakota Pipeline Authority. 2020. *Oil Transportation Table*. Accessed April 2020.

cautioned that the timeline is "subject to revision."[10] Therefore, LEI's analysis is focused on 24 months (from the current time through mid-2022).

LEI's task included reviewing certain filings in the case. LEI examined:

- Declaration of Ian Goodman: Case No. 1:16-cv-1534-JEB, 3154 (272-5) Dec of Goodman
- Declaration of William Rennicke: Case No. 1:16-cv-1534-JEB, 509-6 Ex. D - Rennicke Declaration and Exhibit
- Declaration of Guy Caruso: Case No. 1:16-cv-1534-JEB, 509-7 Ex. E - Caruso Declaration and Exhibit
- Declaration of Elaine Kub: Case No. 1:16-cv-1534-JEB, 509-8 Ex. F - Kub Declaration and Exhibits
- Declaration of Glen Emery: Case No. 1:16-cv-1534-JEB, 509-9 Ex. G - Emery Declaration and Exhibits_printable
- Declaration of Laura Olive: Case No. 1:16-cv-1534-JEB, 509-10 Ex. H - Olive Declaration and Exhibits
- Declaration of Jeff Makholm: Case No. 1:16-cv-1534-JEB, 509-11 Ex. I - Makholm Declaration and Exhibits
- Declaration of Marathon: Case No. 1:16-cv-1534-JEB, 509-12 Ex. J - Marathon_ Declaration

Declaration of Enerplus: Case No. 1:16-cv-1534-JEB, 509-13 Ex. K - Enerplus_Declaration

LEI's report refers to several of the Declarations.

LEI was not asked to opine on the desirability of, or need to, shut down the pipeline. There are many factors to consider in that decision, and many are outside the expertise of LEI. LEI's expertise lies in a deep understanding of oil and gas upstream (drilling and production, and financial) cost structures, the drivers of oil supply and demand, and the infrastructure which connects supply and demand. This expertise provides a solid foundation for examining the impact of a temporary shut-down of DAPL.

2.3 LEI's methodology

The need for a pipeline or any other form of transportation for crude oil depends on trends in oil supply and demand. Therefore, this report focuses first on these trends, and their direction for the next two years. Following the examination of supply and demand, the report turns to

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[10] United States Army Corps. 2020. *United States Army Corps Brief Regarding Remedy: United States District Court. Case 1:16-cv-01534-JEB Document 507 Filed 04/29/20.* Page 5. https://earthjustice.org/sites/default/files/files/corps_remedy_brief.pdf

examination of oil transportation options—namely crude-by-rail—which might be needed if DAPL is shut down.

LEI's analysis is based on data from government agencies such as the US Energy Information Administration ("EIA"), Statistics Canada, and several North Dakota agencies. Data from other independent sources are also utilized. In addition to sources such as these, at various points in the report, LEI refers to articles in news and trade publications. This is necessary because official data sources often have substantial lags in data collection and publication. The impacts on the oil industry of the COVID-19 crisis have been swift and dramatic; in some cases, the official data lags conditions on the ground. LEI's analysis is nevertheless based on quantitative analysis and data, not on isolated anecdotes.

2.4 Summary of qualifications of Marie Fagan

Dr. Marie Fagan is the Chief Economist at London Economics International, LLC. Based in Boston, Massachusetts, Dr. Fagan has conducted research and consulted in energy economics for over 30 years. Her work has spanned international upstream (exploration, development, and production) midstream (transportation) and downstream (refining) oil and gas, global coal, North American gas markets, and North American power markets. Dr. Fagan has worked on a broad range of issues, including pipeline economics, rail transport analysis, and oil supply and demand. She has deep expertise in oil and gas production economics. She has advised C-suite industry clients, buy-side and sell-side financial clients, as well as regulators; she serves as an expert witness in litigation and regulatory matters.

- ***Served as independent market expert assisting the Minnesota Department of Commerce***: Dr. Fagan evaluated the application of Enbridge Energy for a Certificate of Need for its Line 3 oil pipeline expansion project (Docket No. PL-9/CN-14-916, OAH Docket No. 65-2500-32764). Dr. Fagan's analysis covered global and local trends in refined product demand and crude oil supply, refinery utilization rates and utilization of high-conversion refinery capacity in Petroleum Administration for Defense District ("PADD") 2 and in the local Minnesota region. Her analysis required detailed examination of the assumptions and methodology of an oil pipeline linear programming-based model, in order to assess another witness's testimony which relied on the model. Dr. Fagan provided written testimony; responded to interrogatory requests, provided written surrebuttal, and oral testimony.
- ***Developed independent research on the role of Enbridge Line 5 in natural gas liquids ("NGLs") and crude oil transport in Michigan:*** For a non-governmental organization ("NGO") Dr. Fagan produced three white papers examining the current and future role of Enbridge Line 5 in Michigan related to three issues: propane supply in Michigan, transportation for crude oil producers in Michigan, and supply of crude oil to Michigan-area refineries. Dr. Fagan's analysis of the propane market included an econometric analysis of the supply and demand for propane in Michigan, explained in non-technical

language. The white papers were used by the client in discussions with the Governor of Michigan and other stakeholders.

- ***Analyzed the costs and benefits of expansion of natural gas pipelines into New England, for the Maine Public Utilities Commission***: Dr. Fagan led analysis of the costs and benefits of a number of contracts for firm transportation ("FT") service on proposed natural gas pipelines (MPUC Docket #2015-00071). She reviewed pipeline precedent agreements and rate agreements and provided a qualitative analysis and comparison of contracts offered. She led the quantitative analysis of the impacts of pipelines on gas and power prices, which was underpinned by LEI's proprietary simulation model of the New England power system, combined with a widely-used industry standard model of the gas pipeline system. Dr. Fagan provided insight and direction of research in gas price basis differentials, pipeline capacity and utilization in key regions, and LNG import and export supply and demand. She authored reports provided to the Commission; responded to discovery from other parties; prepared discovery questions and cross-examined witnesses; reviewed testimony by other parties and provided assessments of the issues presented; and provided oral and written testimony.

- ***Assessed impact of a pipeline surcharge on Western Canadian natural gas producers***: LEI was retained by counsel to provide support in the matter of NOVA Gas Transmission Limited ("NGTL")'s application to the National Energy Board ("NEB"). Dr. Fagan led analysis of the natural gas and NGLs market in Alberta and British Columbia, and the impact of a pipeline surcharge on producers of natural gas.

- ***Conducted detailed research of the relationship of oil demand to economic activity***: For the Columbia University Center for Global Energy Policy ("CGEP") Dr. Fagan directed and managed a detailed econometric analysis of price and income elasticities of global oil demand over four decades. The research is publicly available (USAEE Working Paper No. 20-440. Available at SSRN: https://ssrn.com/abstract=3592443).

- ***Analysis of oil and gas upstream costs and capital spending:*** Dr. Fagan's PhD thesis was a detailed examination of the cost structure of oil supply in the United States, including examining the impact of technology and input costs on the full-cycle cost to produce oil and gas. This researched was published *The Energy Journal* in 1997; in addition, she has published research examining the costs and prospects for shale development, upstream spending, oil and gas capital spending, and R&D spending.

3 Oil production in North Dakota, and its two-year prospects

The time frame for the proposed shut down of DAPL is 13 months, or potentially somewhat longer. This section focuses on the supply and demand dynamics that are impacting oil production from North Dakota currently and for the next two years. It outlines the drivers that are likely to keep North Dakota oil production substantially below previous highs of 1,434,500 b/d for the next two years at least.

3.1 The market environment for North Dakota crude oil

The oil market is global, not local (see Appendix A). Events and trends that impact supply and demand in one part of the world can move oil prices faced by consumers and producers in distant locations.

3.1.1 Oil prices are volatile

Like other commodity industries, oil prices cycle through booms and busts, with substantial volatility. An examination of the trends behind this volatility shows that events have evolved to create a price and investment environment in which North Dakota producers were already challenged—even before the impacts of the COVID-19 pandemic (see Appendix A). For example, Saudi Arabia (and to a much lesser extent, other producers) resorted to cutting back production to support prices in 2017. It is reported that Saudi Arabia requires an oil price of at least $60-$70 per barrel ("bbl") to maintain its government budget.[11] But during 2019, the average price had fallen to $57/bbl in spite of efforts by Saudi Arabia and other OPEC and non-OPEC producers to support prices.

The mild winter in 2019/20 further weakened demand. At a March 2020 meeting of "OPEC+" (OPEC members and other oil producing countries such as Russia), with the potential for even weaker demand owing to the COVID-19 pandemic already on the horizon, Saudi Arabia asked non-OPEC Russia to participate in further cuts in supply. Russia refused. This triggered a month-long price war in which Saudi Arabia offered deep discounts to customers, intending to add 2 mbd to its output (total global oil demand was about 100 mbd in 2019). Russia fired back by stating its intention to boost output by 200,000 to 300,000 b/d.[12] The price war began unfolding

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[11] Noha H. A. Razek, Nyakundi M. Michieka, and Emilson Silva. OPEC+'s 'Reasonable Oil Price Level' Notion and the External Breakeven in Saudi Arabia, Russia and Canada: Accounting for Economic Cycles and Pipeline Politics (November 21, 2019). USAEE Working Paper No. 19-420. Available at SSRN: https://ssrn.com/abstract=3491212 or http://dx.doi.org/10.2139/ssrn.3491212SSRN

[12] Ng, Abigale. "5 charts that explain the Saudi Arabia-Russia oil price war so far. April 1, 2020. https://www.cnbc.com/2020/04/01/5-charts-that-explain-the-saudi-arabia-russia-oil-price-war-so-far.html; and Blas, Javier, et al. "Saudi Arabia and Russia end their oil-price war with output cut agreement." *World Oil.* April 9, 2020. https://www.worldoil.com/news/2020/4/9/saudi-arabia-and-russia-end-their-oil-price-war-with-output-cut-agreement

just as the impact of the coronavirus was taking hold of the global economy. The collapse in oil demand resulted in an unprecedented crash in oil prices (discussed below). However, as noted above and discussed in Appendix A, even without the coronavirus and its impact on global oil demand, the OPEC+ agreement that was supporting prices in the $50-$60/bbl range in 2019 was fraying.

3.1.2 Capital markets turned off the taps in 2018 and 2019

At oil prices of $50-$60/bbl, US-based oil companies seemed to be attractive investments because they could increase production at those prices. But many were relying on debt financing; they were not earning enough from operating cash flow and were relying on high-yield debt (junk bonds) to support growth. In 2018 and 2019, capital markets became less willing to fund the oil sector. Bond and equity financing fell to $22 billion in 2018 compared to $60 billion in 2017, for the lowest level of financing in the sector since 2007.[13] The Federal Reserve Bank of Dallas reported in 2019 that banks had already cut leverage limits for oil and gas companies to 2.5 - 3 times EBITDA, down from 3.5 - 4 times EBITDA.[14] The implications of reduced access to capital for future production is discussed in more detail in Section 3.3.2. Note that the tightening of capital availability occurred prior to the 2020 oil price collapse.

3.2 The global oil price collapse of 2020

Beginning in the first quarter of 2020, the world-wide reaction to the COVID-19 pandemic destroyed oil demand at an unprecedented level. The International Energy Agency ("IEA") expects a never-before-seen 8.6 mbd annual decline in demand for 2020, compared to 2019.[15] The requirement for social distancing and bans on travel impact oil demand disproportionately compared to much of the rest of the economy, since the majority of petroleum products (gasoline, diesel fuel, and jet fuel) are used for travel. A portion of this demand may be lost forever, as working from home and other cultural changes adopted in effort to control the pandemic may take root in the economy.

Before the crisis and social lockdown, oil prices as measured by West Texas Intermediate ("WTI"), a global benchmark crude, were in the range of $50-$60/bbl, as noted previously. Prices fell off a cliff in April 2020, with the WTI benchmark ending the month at an average of about $17/bbl.

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[13] Energize Weekly. 2019. *Debt load to squeeze shale drillers cash flow and pinch dividends, analysis says.* Accessed May 2020. https://www.euci.com/debt-load-to-squeeze-shale-drillers-cash-flow-and-pinch-dividends-analysis-says/

[14] Meyer, Gregory, and Joe Rennison. 2019. *Investors starve US shale drillers of capital.* Financial Times. Accessed May 2020. https://www.ft.com/content/187f8176-f4f4-11e9-b018-3ef8794b17c6

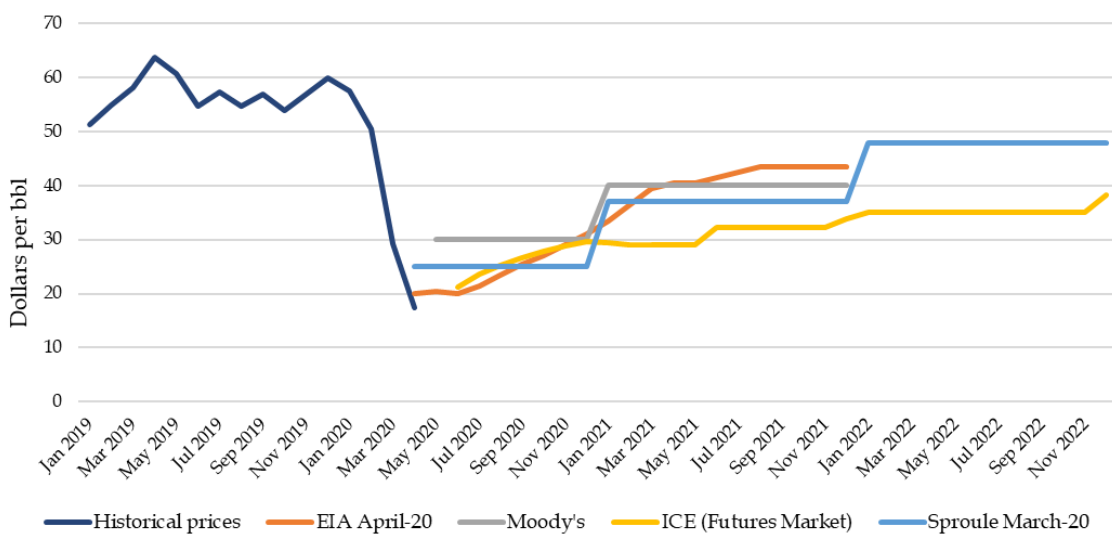
[15] International Energy Agency ("IEA"). 2020. *Oil Market Report - May 2020.* Accessed May 2020. https://www.iea.org/reports/oil-market-report-may-2020

During the month of May prices recovered to about $30/bbl, based on large cutbacks in production from Saudi Arabia and other producers.

3.2.1 Oil prices are not expected to recover to 2019 levels, even by 2022

Publicly available outlooks and the traded futures markets put the oil price recovery by 2022 to below $50/bbl (see Figure 3). As discussed later in Section 3.3, only a portion of North Dakota oil production will be viable at such prices, and a lower price outlook also translates to less capital flowing to oil producers. These will both drag down future North Dakota oil production as discussed in Section 3.4.

Figure 3. Outlooks for WTI oil prices to 2022



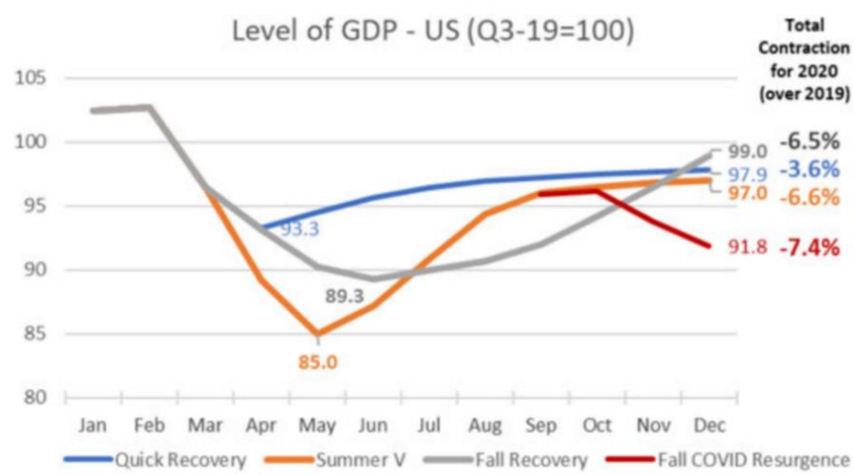
Sources: Moody's: S&P Global Market Intelligence. Gas Week. May 4, 2020;
Sproule, https://sproule.com/price-forecast/;
US Energy Information Administration, Short-term Energy Outlook ("STEO")
https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M;
Intercontinental Exchange ("ICE") https://www.theice.com/products/213/WTI-Crude-Futures/data?marketId=463544&span=1

3.2.2 Potential for slow economic recovery

Owing to social distancing and the lockdown of the US and global economies, the US economy has suffered devastating job losses, with 20.5 million workers unemployed in April 2020, and an unemployment rate of 14.7%, the highest in the post-World War Two era.[16] Real gross domestic product ("GDP"), a measure of economic activity, fell 4.8 percent in the first quarter of 2020 compared with the fourth quarter of December 2019.[17]

The pace of economic recovery is uncertain. The Conference Board, a well-established independent organization of business executives, projects GDP for 2020 using a scenario approach. The use of a scenario approach, rather than a single point estimate, reflects the wide uncertainties about the near future. In the Conference Board's best-case scenario ("Quick Economic Recovery" shown below in Figure 4), US economic growth would decline 3.6% for 2020. However, health officials are concerned about the possibility of a second wave of COVID-19 infections when economies emerge from lockdown, and/or during the wintertime flu season.[18] Apart from the cost in terms of peoples' health and well-being, this could keep people out of work, and stall recovery in economic activity. In the case of a COVID-19 resurgence in the fall, the total economic contraction projected by the Conference Board for 2020 would be 7.4%.

Figure 4. Conference Board's scenarios for US economic recovery



Source: Conference Board. April 9, 2020. https://www.conference-board.org/data/usforecast.cfm

[16] United States Department of Labor, Bureau of Labor Statistics. 2020. *Economic News Release: Employment Situation Summary.* Accessed April 2020. https://www.bls.gov/news.release/empsit.nr0.htm

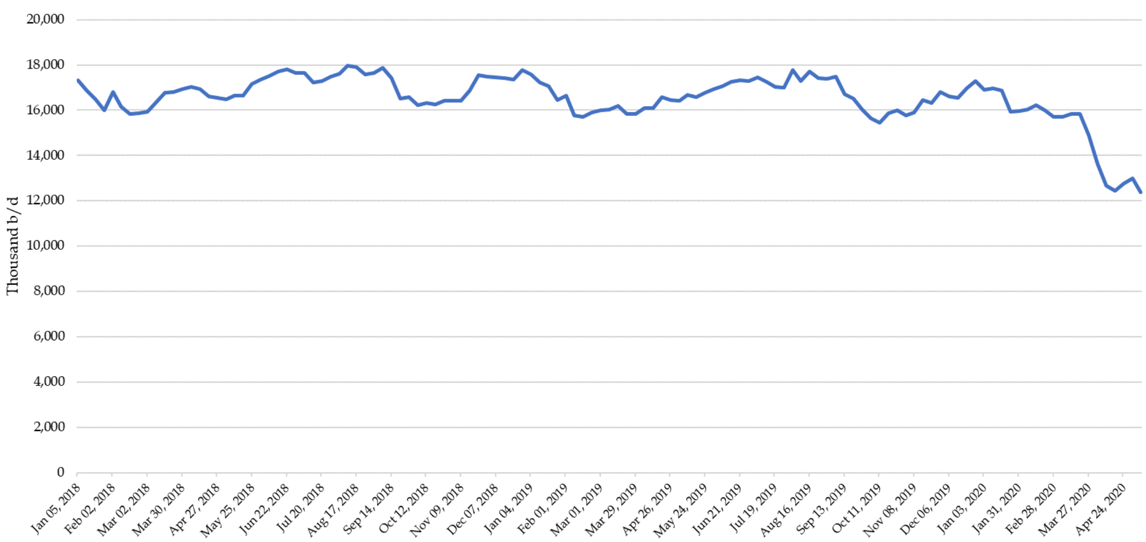
[17] US Department of Commerce, Bureau of Economic Analysis. 2020. *Gross Domestic Product, 1st Quarter 2020 (Advance Estimate).* Accessed April 2020. https://www.bea.gov/data/gdp/gross-domestic-product.

[18] Sun, Lena. 2020. *CDC director warns second wave of coronavirus is likely to be even more devastating.* Washington Post. Accessed 2020. https://www.washingtonpost.com/health/2020/04/21/coronavirus-secondwave-cdcdirector/

3.2.3 Low demand for refined products leads to less need for crude oil production

Owing to the COVID-19-related lockdowns, US demand for refined products (gasoline, diesel fuel, jet fuel, and other products) collapsed in the second quarter of 2020 (see Figure 5). By May 13, 2020, US refinery runs were more than 3 mbd lower than in March 2020. Crude oil supplies not needed by refineries began to back up into the supply chain. This first showed up as higher-than-average storage levels; eventually, once storage is full, it will translate into the need to reduce oil production. Even if such oil production were economic to produce, there would be nowhere to put it.

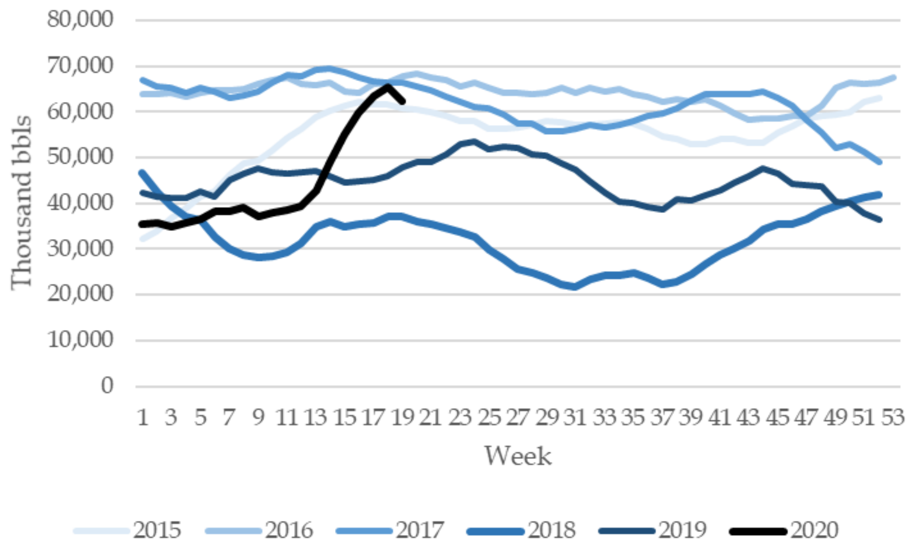
Figure 5. US refinery net inputs of crude oil



Source: EIA. "US weekly supply estimates." http://www.eia.gov/dnav/pet/pet_sum_sndw_dcus_nus_w.htmData 2: Refiner Inputs and Utilization

The decline in refinery runs translated into a swift build-up of crude oil stocks, as evidenced by weekly storage inventories at Cushing, Oklahoma (see Figure 6). Crude oil inventories quickly reach near-record levels.

Figure 6. Weekly Cushing, OK crude oil stocks excluding Strategic Petroleum Reserve ("SPR")



Source: EIA.
http://tonto.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPC0_SAX_YCUOK_MBBL&f=W

Cushing, OK, is located in US PADD 2, as is Patoka, IL, the terminus of DAPL (see Appendix A for a map of US PADDs). PADDs do not represent physically separate regions. They are interconnected via crude oil and product pipelines (see Appendix A for a map of PADDs and pipelines). PADDs are simply a convenient way to track oil supply, demand, and transportation activities in the United States.

3.2.4 Potential for incomplete recovery of oil demand

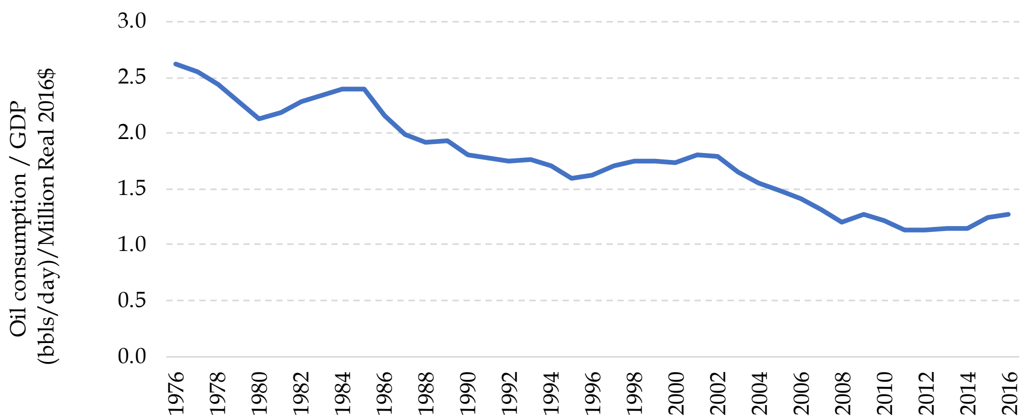
Even when the economy eventually recovers, oil demand might not reach previous levels relative to economic activity. For example, despite the lifting of government stay-at-home orders, potential travelers might wait for a vaccine to be sure of safety during air travel or non-essential trips like long-distance driving vacations. During March 2020, a medical researcher reported that a vaccine available to the public could be 12 months away.[19] Without a vaccine, widespread unemployment may stubbornly persist in service sectors such as hospitality, reducing travel to and from work and reducing the discretionary income that funds travel and leisure. Even when workers can begin to return to offices and other locations outside the home, demand for gasoline may not recover fully. A 2017 US government survey reported that vehicle miles travelled

[19] LaFave, Sarah. 2020. *What will it take to develop a vaccine for covid-19?*. Johns Hopkins University. Accessed May, 2020. https://hub.jhu.edu/2020/03/26/covid-19-vaccine-development-ruth-karron/

("VMT") that are work-related are only 21% of total VMT.[20] Other vehicle travel such as for social and recreational purposes, shopping and errands, and other home-based trips may be more subject to discretion, and slower to recover.

The experience of many decades of global oil demand and economic activity shows that once economic activity becomes less oil-intensive, oil demand per unit of GDP does not recover to previous levels.[21] In 1976, every million dollars of global GDP (in 2016 dollars) was associated with 2.6 b/d of oil consumption (see Figure 7). Over the decades, improvements in energy efficiency and the shift of economies from energy-intensive manufacturing to less energy-intensive services reduced global oil intensity to about 1.3 b/d per million dollars of global GDP.

Figure 7. Oil intensity of the global economy



Source: BP Statistical Review of World Energy 2017 and World Bank

The reason that oil intensity with respect to GDP is important on a global level is that the oil market is global, not local (see Appendix A). Events and trends in one part of the world can impact oil prices across the globe.

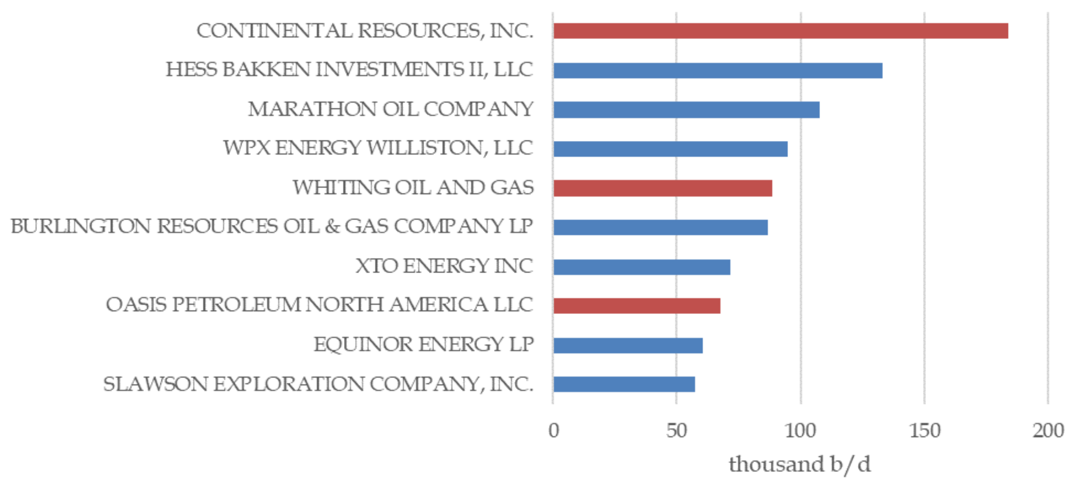
[20] US Department of Transportation, Federal Highway Administration, 2017 National Household Travel Survey. http://nhts.ornl.gov.

[21] Fagan, Marie. 2020. *Up the Down Staircase: What History Teaches Us about Oil Demand after a Crisis*. USAEE Working Paper No. 20-440. Posted May 4, 2020. Available at SSRN: https://ssrn.com/abstract=3592443

3.3 Many North Dakota producers, including large ones, are in financial distress and/or shutting in production

About 130 oil producing companies operate in the Bakken shale region in North Dakota.[22] Many of them are small, with production less than 1,000 b/d. The ten largest companies had production levels ranging from 184,000 b/d down to about 60,000 b/d before the oil price collapse (see Figure 8). The impacts of lower oil prices have not been limited to the small producers, who usually have less financial backing and more limited and less attractive acreage positions, and therefore higher costs, than the larger companies. Some of the largest companies have shut in production and/or filed for Chapter 11 bankruptcy protection.

Figure 8. The ten largest oil Bakken shale oil producers, based on February 2020 production*



*Red bars indicate Chapter 11 or substantial shut-in of production as verified by public sources. This is not a comprehensive list of companies in distress, because other producers may have taken similar actions, though public information is not available.

Source: February 2020 production, North Dakota Department of Mineral Resources. https://www.dmr.nd.gov/oilgas/mprindex.asp

- **Continental Resources, Inc** had shut in most of its production as of April 24, 2020. The company told at least one refinery that it was declaring force majeure and would not supply crude despite its contractual obligation.[23] Continental recently referred to its operating costs of $25-$28/bbl (across all regions, not just the Bakken) as “low,” but such

[22] North Dakota Department of Mineral Resources. *Monthly Production Report Index*. Official Portal for North Dakota State Government. Accessed May 2020. https://www.dmr.nd.gov/oilgas/mprindex.asp

[23] S&P Global Market Intelligence. 2020. *Continental calls force majeure to avoid Bakken oil deliveries – Reuters*. Accessed April 2020.

costs are still higher than recent oil prices, and they do not include the cost of debt repayment.[24] Continental is facing $1.1 billion of debt maturing in September 2022.[25] Continental's production was not hedged, which means it was instantly exposed to low spot prices for oil.[26]

- **Hess** cut its Bakken drilling program to one active rig for 2020, compared to the six rigs originally planned.[27] CEO John Hess said the company will remain at one rig until WTI oil prices stabilize around $50/bbl; and if prices stay low into 2021, the company will reduce its rig count to zero.[28]

- **Whiting Petroleum** filed for Chapter 11 bankruptcy protection on April 2, 2020.[29] It has about $1 billion of debt coming due over the next year.[30] It had recently reported operating costs at $37/bbl, including interest payments on debt.[31]

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24 Continental Resources. 2020. *Investor Update: Presentations*. Accessed May 2020.

http://investors.clr.com/presentations. Accessed May 8, 2020.

25 S&P Global Market Intelligence. 2020. *S&P drops shale driller Continental Resources' rating below investment grade.* Accessed April 2020. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/s-p-drops-shale-driller-continental-resources-rating-below-investment-grade-57796845

26 Reuters. 2020. *Continental Resources Halts Bakken Shale Output, Seeks to Cancel Sales.* Accessed April

2020. https://pgjonline.com/news/2020/04-april/continental-resources-halts-bakken-shale-output-seeks-to-cancel-sales

27 S&P Global Market Intelligence. Luhavalja, Amanda. *Hess slices 2020 capital spending to $1.9B, to cut Bakken shale rig count to 1.* Gas Week May 11, 2020. https://ofccolo.snl.com/Cache/5C1E4D2C6D403926997.PDF?CachePath=%5c%5cdmzdoc2%5cwebcache%24%5c&T=&O=PDF&Y=&D=

28 Ibid.

29 Whiting Petroleum. 2020. *Investor Relations*. Accessed April 2020.

30 Phillips, Matt, and Clifford Krauss. 2020. *American Oil Drillers Were Hanging on by a Thread. Then Came the Virus*. New

York Times. March 20, 2020. https://www.nytimes.com/2020/03/20/business/energy-environment/coronavirus-oil-companies-debt.html

31 Whiting Petroleum. 2020. *Fourth Quarter and Full Year Operations and Financial Update.* Accessed April 2020.

https://whitingpetroleumcorp.gcs-web.com/static-files/3622fc13-0b34-42e4-b44b-88c7f80cbb58

- **Oasis** began to shut down drilling in the Bakken shale on April 28, 2020.[32] It had hedged its production to support cash flow, but this was apparently not sufficient.[33] The company must service debt of over $2.7 billion.

This is not a comprehensive list of Bakken producers in distress or shutting in, as not all companies provide public information as to their finances and activities. Some companies which may wish to file for Chapter 11 (which affords protection from creditors and provides breathing room to access financing) may be unable to do so and be forced to liquidate instead. Analysts point out that, unlike in the 2014-2016 oil price crash, some oil companies may not survive in any corporate form.[34]

3.3.1 Supply costs explain part of why production will remain low

To understand why oil production in North Dakota is likely to remain low for the next two years (or perhaps longer) and therefore the demand for pipeline export capacity out of the Bakken region will be weak, one must understand the drivers of production. The cost of oil supply relative to oil prices is one important driver, and the other is access to capital from investors.

3.3.1.1 Oil prices must be higher than full-cycle costs to maintain and increase production

Full-cycle costs include the capital cost of investing in new shale wells—drilling, fracking, and other new-well costs including expected investor returns—in addition to the operating cost of existing wells. The relationship between full-cycle costs and the price of oil indicates whether a producing region can expect to attract investment and increase production in the future. The expected oil price received in a given region must be at least as high as the full-cycle cost; otherwise investors will not expect to make a positive return on their investment, and they will not provide capital.

In the Bakken region, a recent survey by the Federal Reserve Bank of Dallas indicated full-cycle costs averaged $51/bbl, with a range of a little below $40/bbl to close to $60/bbl (see Figure 9).

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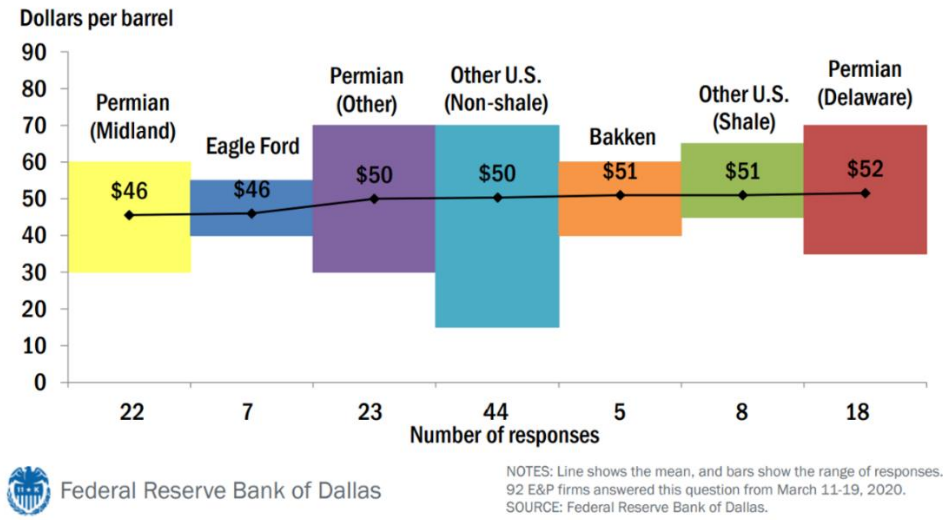
[32] Slav, Irina. 2020. *Another Big Shale Driller Stops Operations in The Bakken*. Accessed Apr 29, 2020. https://oilprice.com/Latest-Energy-News/World-News/Another-Big-Shale-Driller-Stops-Operations-In-The-Bakken.html

[33] Oasis Petroleum. 2020. *Investor Presentation*. Accessed May 2020. http://oasispetroleum.investorroom.com/events

[34] Cable News Network ("CNN"). 2020. *Oil prices turned negative. Hundreds of US oil companies could go bankrupt. Accessed May 2020. https://www.cnn.com/2020/04/20/business/oil-price-crash-bankruptcy/index.html*

Figure 9. WTI oil price needed to drill new wells (i.e., full-cycle cost)



Source: Survey by Federal Reserve Bank of Dallas April 6, 2020. https://www.dallasfed.org/-/media/Documents/research/energy/energycharts.pdf?la=en

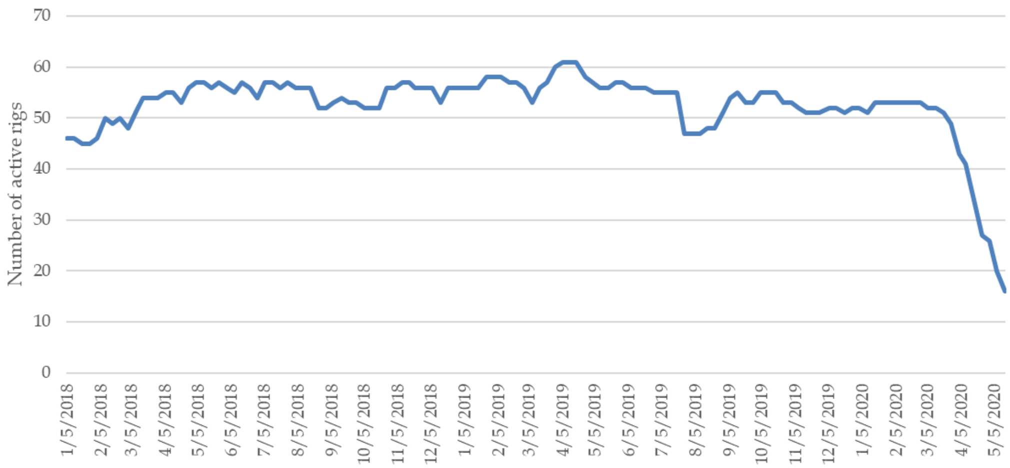
Other sources confirm the $40-$60 general range for Bakken region full-cycle costs. Individual Bakken producers note that long-term breakeven prices of about $45/bbl (WTI) constitute attractive drilling locations.[35] The remark cited earlier by CEO John Hess implies Hess's break-even point for a new Bakken well is $50/bbl (WTI). Thus, under recent operating conditions, it is reasonable to assume that it takes approximately $45/bbl to $50/bbl (WTI) to maintain and/or increase long-term production levels in the Bakken region.

Oil prices lower than $45-$50/bbl can cover operating costs for existing wells (discussed in more detail below), but do not provide enough earnings to drill new wells. This is evidenced by the collapse in drilling activity. The number of active oil-directed rigs working in the Williston Basin fell from about 50 before the oil price collapse, to 16 on May 15, 2020, according to the closely watched Baker-Hughes weekly rig count survey (see Figure 10). The state of North Dakota recently reported similar numbers, with only 13 active rigs.[36]

[35] Oasis Petroleum. 2020. *Investor Presentation*. Accessed May 2020. http://oasispetroleum.investorroom.com/events

[36] https://www.dmr.nd.gov/oilgas/riglist.asp.

Figure 10. Active oil-directed rigs in the Williston Basin



Source: Baker Hughes. https://rigcount.bakerhughes.com/na-rig-count

Without new wells, production will decline. This is because every oil well has a natural decline rate. The initial production ("IP") of oil from a Bakken shale well might be substantial, but this IP rate drops quickly during the first year of operation. After the first year, the IP rate will tend to decline more slowly. This implies that a slowdown in drilling could have a delayed reaction—it might not show up right away, but in the following year aggregate state-level production would reflect the lack of new wells.

3.3.1.2 Operating costs only cover the cost of keeping existing wells producing

In the near-term, even if oil prices are not high enough to support full-cycle costs, existing wells will keep producing as long as they can cover their out-of-pocket expenses (operating costs). In the Bakken region, the recent Federal Reserve Bank of Dallas survey indicated such costs averaged $28/bbl, with a range of $10/bbl to $45/bbl. This indicates that some, but not all, North Dakota production can continue even if oil prices stay low. This general cost structure is confirmed by other sources. The Director of the North Dakota Department of Mineral Resources noted that reopening the 750 wells idled as of May 1, 2020 makes economic sense at $25 a barrel.[37]

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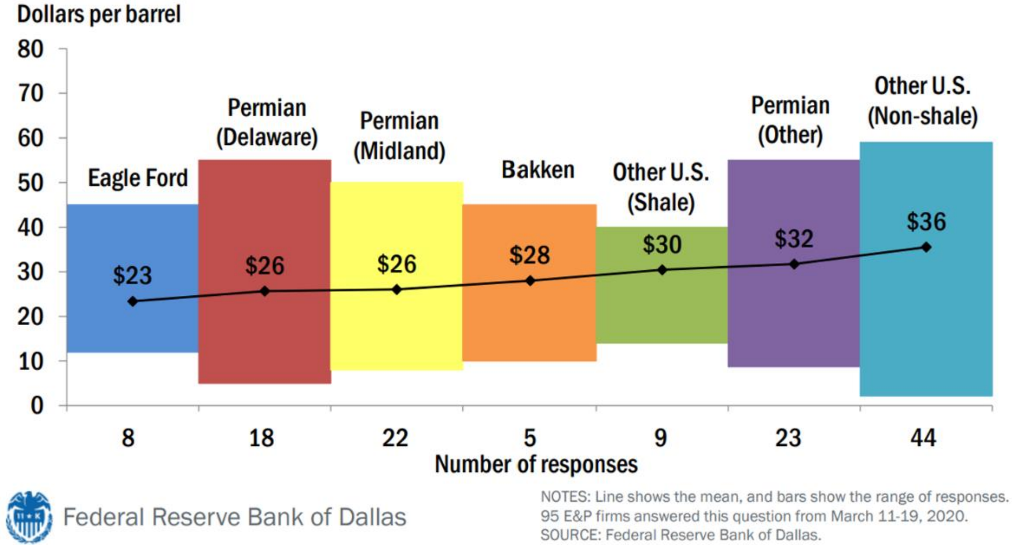
[37] Cooper, Renee. 2020. *Oil prices back to break-even, as the state looks at financial solutions*. Accessed May 2020. https://www.kxnet.com/news/local-news/oil-prices-back-to-break-even-as-the-state-looks-at-financial-solutions/

Figure 11. WTI oil price needed to cover the cost of producing from existing wells



Source: Survey by Federal Reserve Bank of Dallas April 6, 2020. https://www.dallasfed.org/-/media/Documents/research/energy/energycharts.pdf?la=en

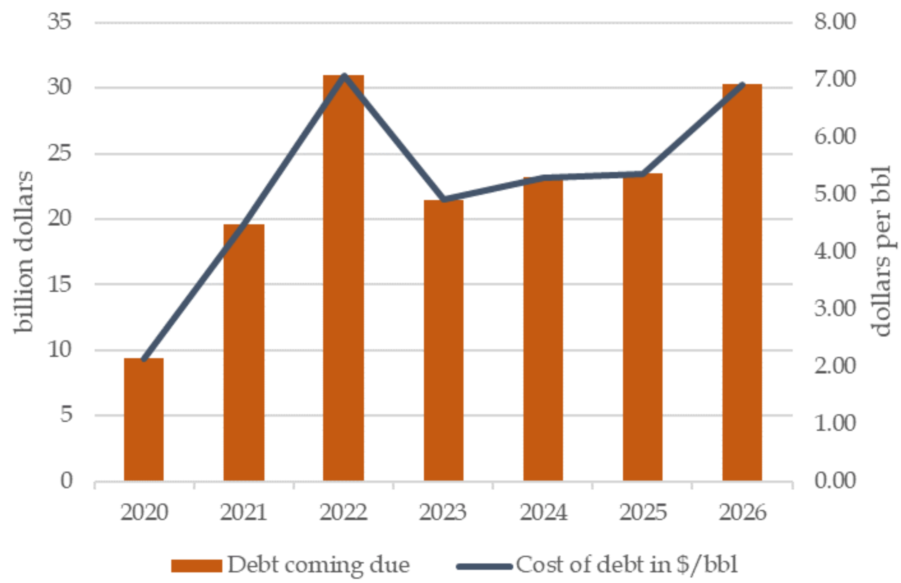
However, an oil price sufficient to cover operating cost does not guarantee that a company can stay in business. In a 2020 investor presentation, Continental reported operating costs of about $25-$28/bbl, as noted previously, but it nevertheless shut in its production.[38] The problem with just covering operating costs is it there may be no cash left for paying down debt; and oil producers are deeply in debt, as discussed next.

3.3.2 Less access to debt will contribute to low production

For the US oil and gas production sector, nearly $20 billion in debt financing will be due for repayment in 2021; and another $30 billion is due in 2022 (see Figure 12). If US oil producers could match 2019 levels of oil production of 12 mbd, about $4.50/bbl of the earnings of the oil and gas sector would be needed to pay debt coming due in 2021, and $7/bbl would be needed in 2022. This is a low estimate of the $/bbl needed because the estimated debt coming due is only for companies rated by S&P Global Ratings, while the production estimate includes all US producers.

[38] Continental Resources. 2020. *Investor Update: Presentations*. Accessed May 2020. http://investors.clr.com/presentations. Accessed May 8, 2020.

Figure 12. Oil and gas producers' bonds, bank loans, and credit facilities due each year



Notes: Total dollar amounts are based on debt for companies which are rated by S&P Global Ratings (not the whole oil and gas sector). Cost in dollars per barrel is based on assumed annual production of 12 mbd (the whole sector).

Source: S&P Global Ratings, reported in *Gas Week* S&P Global Market Intelligence. April 27, 2020.

Financing requirements for new wells and projects will become even more stringent, as the impact of near-term lower oil prices dampen expectations for future prices. This reduces financiers' expectations of future cash flows and returns. Expectations for lower oil prices and the ongoing reduction in capital provided to the oil sector means growth in oil production will be slower than before the COVID-19 pandemic, even if and when oil prices recover fully to 2019 levels.

3.3.3 Hedges to roll off for 2021, squeezing cash flow even more

Oil is a notoriously boom-bust industry, and the people who work in the business expect ups and downs. Many mid-sized oil companies therefore hedge their production forward to insulate cash flows from volatile oil prices. It is reported that many producers hedged up to 50% of their production through 2020.[39] This means that some may be able to keep producing despite very low spot prices, as rather than earning these low spot prices, they will earn the dollar value of their hedges. It has been reported that "Most of the oil producers in the Bakken region have hedged a significant portion of their 2020 sales, typically at $50 or $55 a barrel…That will defer

[39] S&P Global Market Intelligence. 2020. *Gas Week: May 4, 2020.* Accessed May 2020.

some of the pain until next year."[40] When the hedges roll off over the next year or two, more oil production will be exposed to market prices and more oil producers may be in financial distress.

3.4 Why won't Bakken production rebound quickly, as it has in the past?

In the wake of the oil price crash of 2015, North Dakota Williston Basin oil production bounced back quickly (see Figure 13). The drop in North Dakota first purchase prices from over $82.89/bbl in 2014 to $36.51/bbl in 2016 reduced production by less than 150,000 b/d This was a small decline in production, which was more than made up for when oil prices recovered to $60.27/bbl in 2018.

Production bounced back strongly based on two drivers. First, oil prices increased from 2016 to 2018 as Saudi Arabia cut back production. Second, North Dakota producers significantly reduced their drilling and completion costs and increased their wells' productivity. Production costs declined by approximately 25% after 2015, reflecting the improved design of wells, shorter drilling and completion times, and higher first-year production (initial production, or "IP") rates.[41] Overall, efficiency gains and technological innovation helped stimulate a near tripling of output per well in the Bakken region.[42] The impact of lower costs and higher efficiency led average break-even prices for the shale oil industry to fall from over $70/bbl in 2012 to less than $50/bbl in 2016–17.[43]

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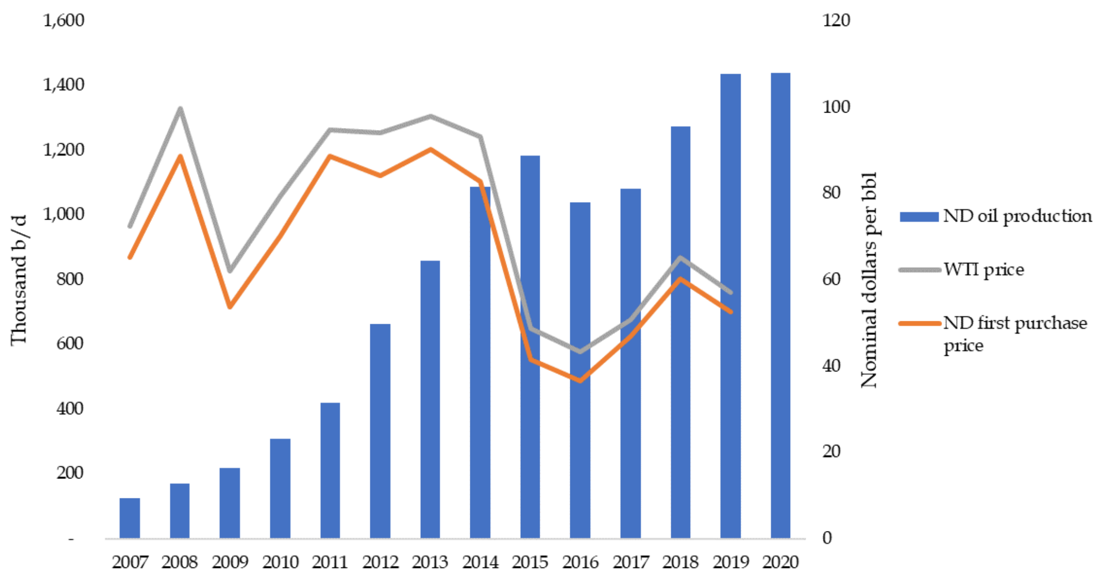
[40] Sun, Lena. 2020. *CDC director warns second wave of coronavirus is likely to be even more devastating.* Washington Post. Accessed 2020. https://www.washingtonpost.com/health/2020/04/21/coronavirus-secondwave-cdcdirector/

[41] Curtis, T. 2015. *U.S. Shale Oil Dynamics in a Low Price Environment*. Oxford Institute of Energy Studies, Oxford, United Kingdom.

[42] Curtis, T. 2016. *Unravelling the U.S. Shale Productivity Gains*. Oxford Institute for Energy Studies, Oxford, United Kingdom

[43] Rystad Energy. 2017. *Supply Data Services*. Rystad Energy, Oslo.

Figure 13. North Dakota Williston basin oil production and oil prices

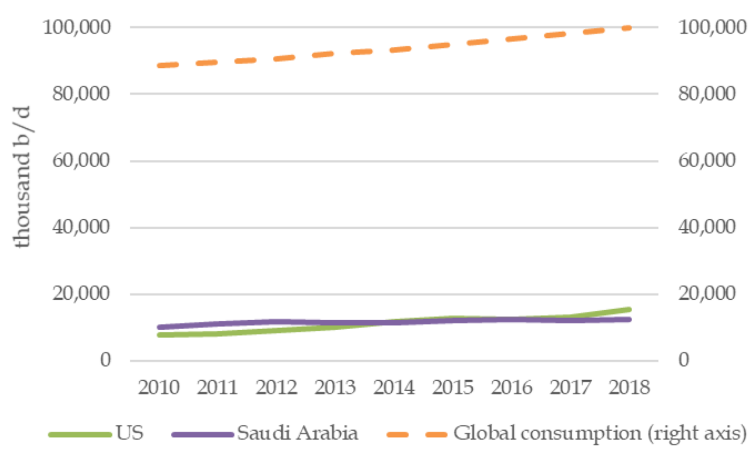


Source: North Dakota Pipeline Authority. *US Williston Basin Oil Production*. <https://northdakotapipelines.com/us-williston-basin-oil-production>; EIA. *Domestic crude oil first purchase prices by Area.* 2020; EIA. *Spot prices for crude oil and petroleum products*. 2020.

To understand why North Dakota oil production is not poised for a fast recovery this time around, it is necessary to understand the difference between the 2015 oil price collapse and the 2020 collapse. The 2015 price collapse was not triggered by a demand slump. It was triggered by a surge of supply from Saudi Arabia. Oil demand did not shrink. In fact, demand was growing. Prices recovered in 2018 not only because Saudi Arabia eventually backed down and reined in production, but also because global oil demand grew (see Figure 14).

This time it is different. Demand destruction, not surging supply, is driving the low oil price. Now, if oil prices are to recover to pre-crisis levels, producers must do all the work to balance supply and demand. This effort is taking several forms. OPEC and its associates have agreed to huge cuts in production (though the historical record shows that many such countries do not actually cut production as promised). Companies who cannot cover their costs at lower prices are declaring bankruptcy. Companies who are still solvent are cutting capital spending.

Figure 14. Saudi Arabia and US oil production, and global oil demand



Source: BP Statistical Review of World Energy 2019.

3.4.1 Bakken production will probably recover in the long term, but will grow more slowly

Eventually, economic activity will recover; the recovery is likely to happen faster if a COVID-19 vaccine is developed and can be administered to large portion of the world's population. And, eventually, oil production in the Bakken and other regions will begin to increase. The pace of this recovery will be impacted by the ongoing and future policies which may impact demand and supply (for example, policies based on producing and consuming less fossil fuel to address global climate concerns), as well as structural changes to how economies use oil, which may take hold in the wake of the coronavirus economic crisis.

More limited access to capital means production will likely grow at a slower rate than before, even given similar oil prices. As discussed above in Section 3.3.2, the capital markets helped support the recovery in oil production in 2016-2018. Improvements in technology and efficiency were created in the process of the ongoing drilling and completion activity which was financed by the capital markets. Following the 2015 oil price crash, in 2016 US oil and gas producers raised $56.6 billion in equity and debt; whereas in 2019 such financing was only $19.4 billion.[44] It will be lower still in 2020, because with less lending, companies will have to rely more on their own (severely reduced) cash flows to provide capital for new drilling. With oil prices just covering operating costs, producers may not be able to fund new drilling from sales of existing oil. Without new drilling, they will not be able to book new reserves. Without new reserves, they will not have collateral for borrowing, and their growth will be much slower.

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[44] Meyer, Gregory, and Joe Rennison. 2019. *Investors starve US shale drillers of capital. Financial Times.* Accessed May 2020. https://www.ft.com/content/187f8176-f4f4-11e9-b018-3ef8794b17c6

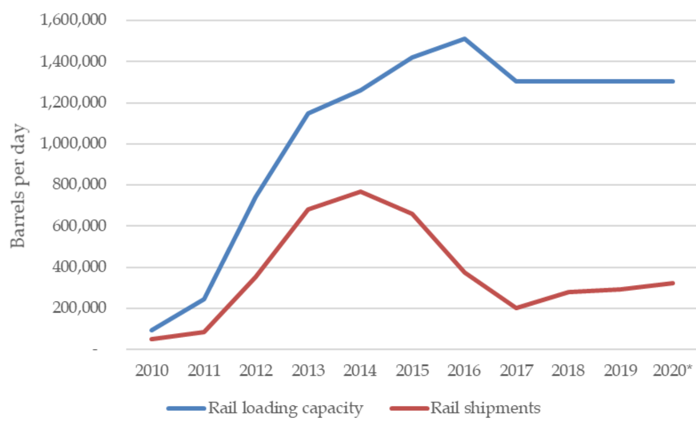
4 Temporary shutdown of Dakota Access will not strain the rest of the transport system

As demonstrated above, production in North Dakota has sharply declined already and is highly unlikely to recover in the next two years. If production of oil from North Dakota remains about 500,000 b/d lower than 2019 for the next 24 months, the pipeline/refining/rail system could handle the 1 mbd remaining, with modest and manageable increases to rail shipments, if any. This is detailed below.

4.1 Modest need, if any, to increase rail transport over recent levels

Approximately 16% of North Dakota's (Williston Basin) oil production in 2019 was transported by rail.[45] The state estimated that the quantity of oil transported by rail was between 260,000 b/d and 290,000 b/d in 2019, and reached 299,000 b/d to 329,000 bd in February 2020.[46] This is far lower than the nearly 800,000 b/d crude-by-rail shipments in 2014 (see Figure 15).

Figure 15. Williston Basin rail loading capacity and crude-by-rail shipments



Source: North Dakota Pipeline Authority. "NDPA Website data." https://northdakotapipelines.com/datastatistics/
*2020 capacity data is estimated; 2020 shipment data is as of February 2020.

[45] Bismarck State College. 2019. *Spotlight on North Dakota Energy, 2019*. Accessed May 2020. https://www.energynd.com/wp-content/uploads/2020/04/Spotlight_On_Energy_2019_Web.pdf

The vast majority of Williston Basin production North Dakota, and the majority of North Dakota production is in the Williston Basin, so official unofficial sources tend to use the terms, as well as "Bakken region" interchangeably.

[46] North Dakota Pipeline Authority. 2020. *NDPA Website data*. Accessed April 2020. https://northdakotapipelines.com/datastatistics/ North Dakota Pipeline Authority. *Oil Transportation Table*. Accessed April 2020.

As shown in Figure 15, North Dakota crude-by-rail transport has in the past few years used only a fraction of the over 1.2 mbd loading capacity the State estimates is currently in place.

If the loss of North Dakota crude oil production compared to 2019 levels is about 500,000 b/d for the next two years (and losses may well be greater than that, for the reasons we discussed in Section 3 above), then closing DAPL's 570,000 b/d would leave only 70,000 b/d requiring other export options (assuming that remaining 70,000 b/d is economic to produce and ship). If that option is rail, it amounts to a small increase in rail exports that would carry none of the severe impacts claimed in the DAPL litigation filings.

4.2 Rail cars are available and rail traffic is down, based on recent data

Even before the coronavirus economic crisis, demand for rail cars for transporting oil was reported to be weak, and lessors were hoping for an uptick in demand. In 2018, one observer noted that "Substantial fleet build-ups over the last few years due to low costs of capital and a booming fracking market have created a temporary oversupply of railcars since freight rates slowed in recent years."[47]

4.2.1 Demand for crude shipments by rail has collapsed

The economic crisis reduced demand for shipping crude oil and petroleum products by rail in the United States. Crude-by-rail traffic plummeted in March and April with low oil prices and low oil demand (see Figure 16). This steep decline means that many tank cars which had previously been busy are now available. For example, Western Canadian producer Cenovus Energy recently idled its 100,000 b/d crude-by-rail capacity, because the price of oil was too low to cover the cost of producing and getting its heavy oil to market.[48] Imperial Oil is cutting its Western Canadian heavy oil production by 100,000 b/d, and reducing rail shipments.[49] Heavy Canadian oil is a lower-value crude oil than the light shale oil from the Bakken region, and Alberta is further from US Gulf Coast ports (so rail transport costs are higher for Canadian producers than North Dakota producers). It is not surprising, then, that Canadian producers idled

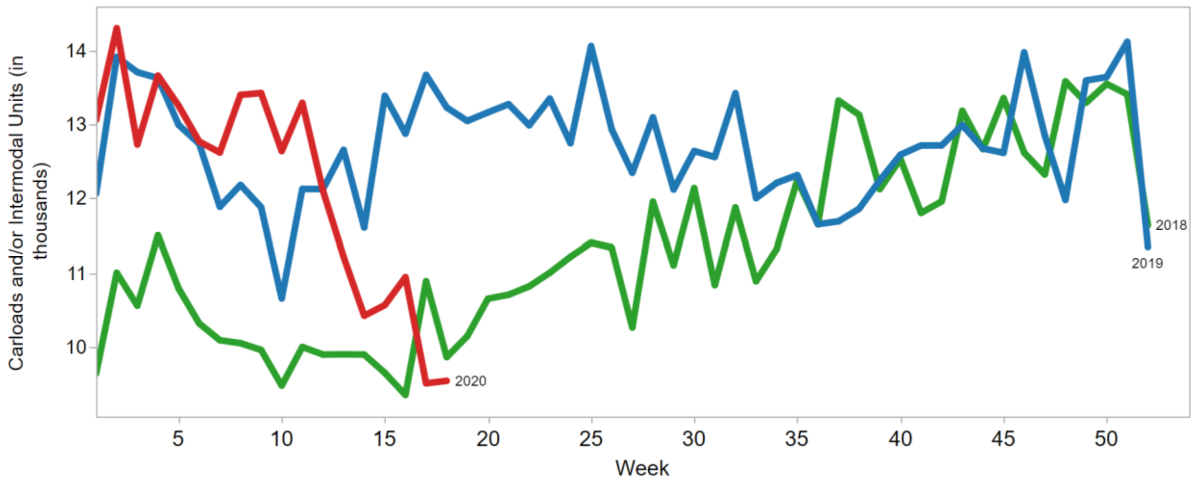
[47] Trinity Chemical Industries (TCIX Rail). 2020. *Future Demand for DOT117J Railcars*. Accessed May 2020. https://tcixrail.com/railcar-leasing/railcar-leasing-information

[48] Laverty, Gene. 2020. *Canadian oil sands producer uses creative solution to sidestep storage shortage.* Gas Week, S&P Global Market Intelligence. https://ofccolo.snl.com/Cache/5C1E4D2C6D403926997.PDF?CachePath=%5c%5cdmzdoc2%5cwebcache%24%5c&T=&O=PDF&Y=&D=

[49]Ibid.

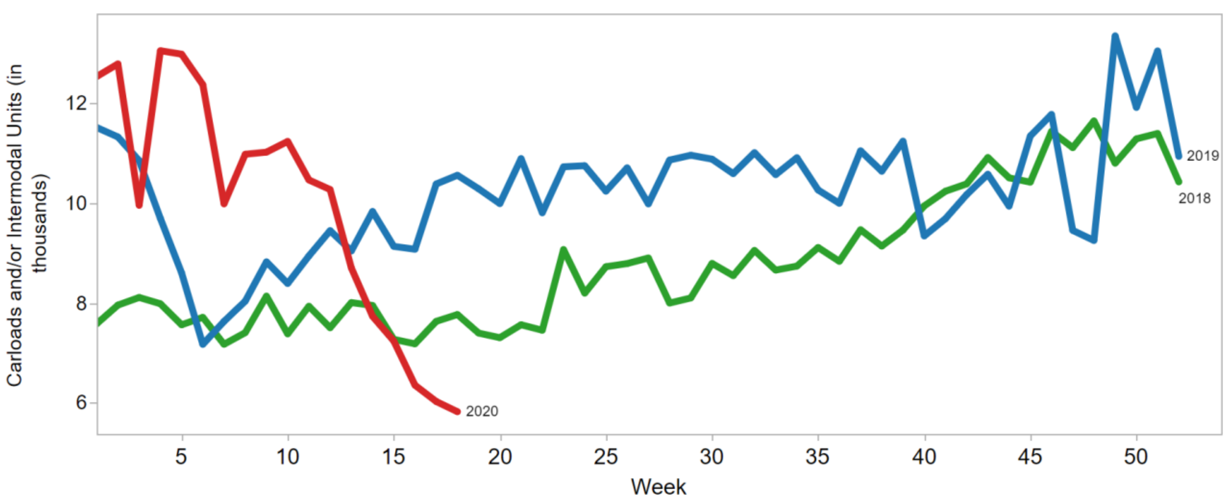
crude-by-rail operations. Oil-related rail traffic in Canada is down dramatically from January levels (see Figure 17).

Figure 16. Petroleum and petroleum products originated rail traffic (United States)



Source: Association of American Railroads. https://www.aar.org/data-center/rail-traffic-data/

Figure 17. Petroleum and petroleum products originated rail traffic (Canada)



Source: Association of American Railroads. https://www.aar.org/data-center/rail-traffic-data/

4.2.2 Demand for rail shipments in general is down

Owing to the economic crisis and the disruption of supply and distribution chains, overall railroad system traffic, not just oil-related traffic, is down. Rail shipments of all goods in the United States have fallen dramatically since February 2020 (see Figure 18). This decline in overall traffic implies that many routes are not as congested as they were in the past.

Figure 18. Total originated rail traffic (United States)

Source: Association of American Railroads. https://www.aar.org/data-center/rail-traffic-data/

4.2.3 With low demand, rail car costs are down

The cost to lease railcars is an important component of the cost of transporting crude by rail. With low demand for crude-by-rail, shippers are paying less for railcars. This cost was about $2,000+ per car per month in 2014 but fell dramatically through 2015 (see Figure 19). More recently, lease rates were reported to be about $800 per month before the oil price collapse and are now down to $500/month.[50]

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[50] Reuters. *U.S. railroads push against oil industry demands for storage in rail cars.* April 9, 2020. https://www.reuters.com/article/us-global-oil-rail-storage/u-s-railroads-push-against-oil-industry-demands-for-storage-in-rail-cars-idUSKCN21R2TO. Accessed May 15, 2020.

Figure 19. Crude railcar lease rates, 2013 to 2015

Source: Genscape[51] "30k" refers to 30,000 gallons, or about 715 barrels; "31.8k" refers to 31,800 gallons, or about 750 barrels; "29k" refers to 29,000 gallons, or about 690 barrels. Light crude oil, such as Bakken oil, does not require heated rail cars.

4.3 LEI's analysis shows that additional North Dakota crude oil on rail is not substantial

If DAPL is shut down temporarily, this would leave an estimated 518,000 b/d capacity on pipelines which can carry crude oil out of North Dakota (see Figure 20).

[51] Genscape. "Tank-Car Lease Rates Plummet on Weak Crude-By-Rail Demand, Low Crude Prices." November 11, 2015. <https://www.genscape.com/blog/tank-car-lease-rates-plummet-weak-crude-rail-demand-low-crude-prices>

Figure 20. Crude oil pipeline capacity from the Williston Basin for 2020

	Pipeline	2020 capacity	Export direction and interconnection
1	Butte Pipeline and Butte Expansion	160,000	southwest to Guernsey, WY; interconnects with pipelines to Cushing, OK
2	Enbridge Mainline North Dakota	210,000	east; internconnects with Enbridge Mainline in Clearbrook, MN
3	Enbridge Bakken Expansion	capacity to be idled in 2020	north, interconnects with Enbridge Mainline in Cromer, Manitoba
4	Plains All-American Bakken North	40,000	north; interconnects with Enbridge Mainline in Saskatchewan
5	Energy Transfer Partners Bakken Pipeline (DAPL)	570,000	southeast; to Patoka, IL
6	Bridger Expansion Project	not completed yet	southwest to Guernsey, WY; interconnection to Cushing, OK
7	Kinder Morgan Double H Pipeline	108,000	southwest to Guernsey, WY; interconnection to Cushing, OK
	Total pipeline capacity	**1,088,000**	
	Total pipeline capacity less DAPL	**518,000**	

Sources: NDPA https://northdakotapipelines.com/datastatistics/, and verified by company data

LEI does not assume that the whole of the 518,000 b/d capacity on the remaining export pipelines can be utilized. Pipeline utilization rates are typically below 100% because of various operational limitations. Thus, we assume that the remaining lines could be utilized at 90%, which would allow flows of 466,200 b/d. Assuming that North Dakota's production in the next 24 months is 500,000 b/d lower than in 2019 (which is conservative, it may well be much lower for the reasons discussed in Section 3), an additional 179,260 b/d would need to be shipped by rail (see Figure 21). LEI calculated this 179,260 b/d assuming no shipments by truck, and utilization of North Dakota's one operating refinery at 90%. This 179,260 b/d is the high end of LEI's calculation of the need for rail transport. At the low end, the need for additional rail transport could be as low as 70,000 b/d, which is the difference between the total capacity on Dakota Access of 570,000 b/d and LEI's projected decline in ongoing production of 500,000 b/d[52] The low-end estimate of 70,000 b/d on rail assumes that trucking volumes are the same as in 2019, that there is also no

[52]LEI's assumption that North Dakota production will be 500,000 b/d lower on an ongoing basis for two years is conservative, as it is somewhat lower than the loss of 550,000 /bd as of May 2020; it assumes a small amount of production (50,000 b/d) comes back relative to May 2020. However, actual lost production could be much greater.

change in crude runs to refineries, and the whole 70,000 b/d is economic to produce and ship by rail.

Figure 21. North Dakota crude oil transport options

	2019 actual	2020-2022 annual projection	difference
Total ND crude oil production, b/d	1,436,500	936,500	-500,000
of which:			
Pipeline	1,034,280	466,200	-568,080
Rail	229,840	409,100	179,260
Trucked	100,555	Assume 0	-100,555
Refined in state	71,825	61,200	-10,625

Sources: 2019 actual production, North Dakota Pipeline Authority. Williston basin oil production. Accessed April 2020 https://northdakotapipelines.com/us-williston-basin-oil-production; 2019 transportation, based on percentage provided in *Spotlight on North Dakota Energy*, 2019. Bismarck State College. https://www.energynd.com/wp-content/uploads/2020/04/Spotlight_On_Energy_2019_Web.pdf; 2020 and 2021 production, LEI estimate, high-case scenario for producers.

The additional 179,000 b/d which might, in a conservative (i.e., high-need) scenario, be shipped on rail could easily be accommodated by the existing rail system.

4.4 The cost of crude-by-rail versus pipeline transportation

It seems to be an unquestioned assumption by witnesses in the current matter that it costs $5-$10 more per barrel to transport oil by rail than by pipeline. Glen Emery of ETCOP claims that rail transport would be about $5/bbl higher than the cost to ship on the Bakken Pipeline, but does not provide evidence for this statement.[53] In 2014, the Congressional Research Service ("CRS") reported that "refiners found it profitable to utilize the North Dakota oil delivered by rail even though the rail transportation cost is perhaps $5 to $10 per barrel higher than pipeline costs."[54] However the CRS report did not specify the distance on pipeline versus rail. Because rail freight rates are quoted in dollars per ton-mile, it is necessary to know the distance travelled to be able to compare costs. Later research refers to the 2014 CRS report, without providing updated

[53] United States District Court for the District of Columbia. 2020. *Declaration of Glenn Emery in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB.

[54] Frittelli, John, et al. 2014. *U.S. Rail Transportation of Crude Oil: Background and Issues for Congress*. Congressional Research Service. https://fas.org/sgp/crs/misc/R43390.pdfFrittelli P. 4.

estimates of rail costs; and witness Jeff Makholm refers to this source.[55] There was no specific analysis in the Emery or Makholm Declarations with respect to this price difference.

4.4.1 LEI's estimate of the cost of crude-by-rail

LEI examined the assumption of a $5/bbl-$10/bbl premium for crude-by-rail by looking closely at the components of rail costs.

The largest component of the cost of transporting crude by rail is the railroad freight charge. Witness Elaine Kub reported that, as of 2018, railroads were earning revenues of over $70/ton for crude oil shipments, about $9.50/bbl.[56] Freight rates are charged based on a tons-per-mile rate. In 2018, the average freight revenue in the United States for Class I railroad was $0.0423 per ton-mile; this translate to $0.00577/bbl/mile for oil (assuming this average rate applied to oil).[57]

LEI calculated the cost to transport oil by rail 1,172 miles (the distance from the Bakken region to Patoka, IL). To perform these calculations, LEI assumed each rail car carries 700 barrels of crude oil; the railcar lease cost would be $500/month; the freight walk-up rate would be 0.0423 per ton-mile (equal to the walk-up tariff for all freight); and the transload cost (to load and unload each car) would be $700/rail car. LEI calculated the freight charge by multiplying the rate per barrel-mile by 1,172 miles. LEI computed the cost to lease railcars using cycle-time data from witness William Rennicke; LEI then added estimated transload costs per barrel. LEI arrived at an estimate of the cost of Bakken crude-by-rail of $8.00 per bbl, for a route of equivalent distance to Patoka (see Figure 22). Compared to the tariff rates on DAPL, the incremental cost of crude-by-rail ranges between $1.99/bbl to $2.65/bbl for such a route.

This $1.99/bbl to $2.65/bbl estimate is based on two conservative assumptions (i.e., assumptions which result in a higher-cost estimate for the cost of rail). First, rail rates are quoted as tariffs based on walk-up rates which apply to the equivalent of a last-minute transaction. However, many shippers do not pay walk-up rates. Instead, they pay a lower rate by providing their own equipment such as tank cars, and/or committing to shipping large or fixed volumes. LEI's assumption that the oil shipper pays the full walk-up rate ***in addition to*** providing their own leased railcar amounts to a conservative assumption. Second, the Association of American Railroads "Class 1 Railroad Statistics" for May 2016 (latest publicly available) shows that crude oil transport costs in 2015 in terms of $/ton-mile were lower than the weighted average for all

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[55] Strata. "*Pipelines, Rail & Trucks.*" 2017. https://www.strata.org/pdf/2017/pipelines.pdf; Declaration of Jeff D. Makholm, P. 9.

[56] United States District Court for the District of Columbia. 2020. *Declaration of Elaine Kub in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB. P. 16 (tons converted to barrels by LEI, at 7.33 barrels per ton).

[57] United States Department of Transportation. "Average Freight Revenue per Ton-Mile." Accessed on May 15, 2020. <https://www.bts.gov/content/average-freight-revenue-ton-mile>.

commodity groups. LEI's assumption that the oil shipper pays the average freight rail rate therefore amounts to another conservative assumption.

Figure 22. Estimate of cost for rail transport on DAPL

Assumptions			
Volume of oil per rail car		700	bbls
Railcar lease cost		500	$/month
Transload cost		700	$/car
Freight rate (walk-up)		0.0423	$/ton/mile
Barrel per ton		7.33	
Freight rate (walk-up)		0.00577	$/bbl/mile
Patoka cost estimate			
Miles from Bakken to Patoka		1,172	
Freight charge	$	6.76	$/bbl
Rail car lease cost	$	0.02	$/bbl/day
Rail car lease cost for 10 day cycle time	$	0.24	$/bbl for round trip
Transload cost	$	1.00	$/bbl
Total estimated cost for crude by rail	**$**	**8.00**	**$/bbl**
DAPL uncommitted cost	$	6.01	$/bbl
Difference	**$**	**1.99**	**$/bbl**
DAPL committed cost	$	5.36	$/bbl
Difference	**$**	**2.65**	**$/bbl**

Sources:
Freight rate, United States Department of Transportation. "Average Freight Revenue per Ton-Mile." Accessed on May 15, 2020. <https://www.bts.gov/content/average-freight-revenue-ton-mile>
Rail car lase costs, Reuters. *U.S. railroads push against oil industry demands for storage in rail cars*. April 9, 2020. https://www.reuters.com/article/us-global-oil-rail-storage/u-s-railroads-push-against-oil-industry-demands-for-storage-in-rail-cars-idUSKCN21R2TO. Accessed May 15, 2020;
Transload costs, Dynamic Risk. "*Final Report: Alternatives Analysis for the Straits Pipelines.*" Appendix J, P. J-2. Prepared for the State of Michigan. October 26, 2017;
Cycle time, Declaration of William Rennicke. p. 9;
Bakken Pipeline tariffs, Dakota Access Oil Pipeline Tariffs
https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14559293.

Witness William Rennicke noted that railroads sometimes charge $1,000 per car extra for shipping in a jacketed CPC1232 rail car.[58] This $1,000/car (for a 700-barrel car) translates into $1.43/bbl. Under the conditions of a collapse in demand for crude-by-rail services, it is logical to assume

[58] United States District Court for the District of Columbia. 2020. *Declaration of William J. Rennicke in support of Dakota Access, LCC's Brief on the Question of Remedy.* Case. No. 1:16-cv-1534-JEB.

that the "sometimes" noted by Mr. Rennicke would become "rarely," as railroads cut costs to keep customers.

Based on the analysis above, LEI does not believe the cost difference to transport oil on DAPL versus rail is \$5/bbl- \$10/bbl; it is likely to be \$2/bbl-\$3/bbl, or even lower.

5 Mr. Rennicke's conclusions about the impact on rail are based on an inaccurate premise and out-of-date information

Mr. Rennicke's report (Declaration of William J. Rennicke in support of Dakota Access, LCC's Brief on the Question of Remedy, Case No. 1:16-cv-1534-JEB) provides faulty conclusions, because they are based on an inaccurate premise and out-of-date information about railroad usage.

5.1 The need to replace all 570,000 b/d is an inaccurate premise

Mr. Rennicke's premise is that every barrel that would have been shipped on DAPL would have to be shipped by rail (or not shipped at all), ***in addition to*** any recent volumes of crude-by-rail. However, in the very likely case that oil production is weak in the next two years, the loss of 570,000 b/d of pipeline capacity will be more-or-less matched by the loss of production. There would be a small net impact on rail shipments. Also, as noted previously, some barrels may not be economic to produce, so not shipped via any means.

Mr. Rennicke noted that 3,700 specialized tank cars could quickly (from "day 1") be made available to transport extra volumes of crude oil from North Dakota, and he estimated they could accommodate 165,000-246,000 b/d (assuming his cycle times).[59] LEI notes that this incremental capacity would be more than enough to accommodate North Dakota production along with other pipelines in the next two years. If the actual number of cars is 1,500, as he notes may be the low-end number, they could transport 12% -18% of DAPL's capacity (or 68,000 b/d to 102,000 b/d, assuming the cycle times he used). This would be plenty, given current and expected levels of low oil prices and low production for the next two years.

5.2 Mr. Rennicke's data does not reflect the collapse in demand for crude-by-rail

Mr. Rennicke based his analysis of the need for more tank cars on data from January 2020 (Rennicke declaration, Exhibit 3, at p. 8). This Exhibit shows monthly crude oil carloads in the US of 20,251, and 28,380 in Canada. These numbers are the foundation of his estimate that there are 3,685 potential spare crude oil railcars that could be called upon for use in transporting the crude oil which would be otherwise stranded if DAPL were to shut down.

LEI reproduced Mr. Rennicke's exhibit using more recent information. Updating the EIA data series cited by Mr. Rennicke shows US crude oil shipments by rail down 30% in February 2020 (at 9,199 thousand bbls), compared to the most recent January 2020 number (13,151 thousand bbls) (see Figure 23). It is likely that when March and April data are available, the declines relative to January will be even steeper, as indicated by Figure 16 shown previously. Assuming the same

[59] United States District Court for the District of Columbia. 2020. *Declaration of William J. Rennicke in support of Dakota Access, LCC's Brief on the Question of Remedy.* Case. No. 1:16-cv-1534-JEB.

700 bbls per tanker car that Mr. Rennicke uses, crude oil carloads in the US would also show a 30% decline.

Figure 23. Rennicke Exh. 3, with updated information

Crude oil shipments by rail, converted to carloads	Rennicke Exh 3 (1)	Updated information (2)		Change from Jan to Feb
	Jan-20	**Jan-20**	**Feb-20**	
US: thousand bbls shipped by rail	14,176	13,151	9,199	-30%
assumed barrels per railcar	*700*	*700*	*700*	
Crude oil carloads, US	20,251	18,787	13,141	-30%
Canada: thousand tonnes shipped by rail	27,156	27,156	24,291	-11%
assumed tonnes per carload	*957*	*957*	*957*	
Crude oil carloads, Canada	28,380	28,380	25,386	-11%
Total carloads	**48,631**	**47,167**	**38,527**	**-18%**
Estimated crude oil tank car fleet	28,000	28,000	28,000	
Min fleet at 15-day cycle time	24,316	24,316	19,862	-18%
Potential spare cars	**3,685**	**3,684**	**8,138**	

Sources: (1) Rennicke Declaration, Exh. 3 at p. 8, and footnote 9. (2) Barrels shipped by rail, US, EIA pet_move_rail_a_epc0_rail_mbbl_m.xls, accessed May 7, 2020; Tonnes shipped by rail, Canada, Statistics Canada. Table 23-10-0216-01, "Railway car loadings statistics, by total tonnage transported, monthly" DOI: https://doi.org/10.25318/2310021601-eng, accessed May 7, 2020.

LEI used a similar process to update Mr. Rennicke's estimates of carloads used by Canadian crude-by-rail. Canadian data is reported in tonnes, not barrels; LEI used the same assumption for tonnes per carload that Mr. Rennicke used to arrive at an estimate of 25,386 carloads for February 2020, a decline of 18%. As in the United States, Canadian crude-by-rail shipments have fallen much further since February, as indicted by the trend shown in Figure 17 previously. For the US and Canada in total, assuming the same cycle times, the need for railcars fell 18% from January to February. If we assume that Mr. Rennicke's estimate of a crude oil tanker fleet of 28,000 cars is correct, the updated analysis shows that 8,138 cars would be available for service, which is much more than the 3,685 cars he estimated.

This wider availability also means that Mr. Rennicke's projections of the need to build more railcars is incorrect. First, it is based on his premise that every 570,000 b/d would need to be replaced by rail. This is inaccurate, because of the sharp decline and potential for a slow recovery in North Dakota oil production discussed in detail in Section 3.4. Second, it ignores the wider availability of tanker cars as of February 2020, as shown by EIA and Statistics Canada, and the huge decline in shipments shown in the Association of American Railroads ("AAR") data (shown in Figure 16 and Figure 17 previously), which imply there are by now many more idle cars than the February data indicate. His outlook is out of date: more tank cars will not be needed in the two-year window. As a major tank car leasing company noted, with respect to future demand for DOT117J railcars, "The most significant driver of DOT117J railcar leases is the price of oil."[60]

5.3 The focus on Patoka is misguided when demand is low

Mr. Emery of Energy Transfer Partners notes that Patoka is a highly desirable destination for crude oil because it is a refining center and an interconnection point to the US Gulf Coast.[61] DAPL provides a unique service to this location as it is the only direct line from the Bakken region to Patoka.

However, with oil storage filled nearly to the brim, refineries running at low capacity, and weak export markets, being tied to limited options for crude sales is less attractive. The greater speed and flexibility offered by rail could be helpful to producers who need to react quickly to opportunities to find buyers of oil in a variety of geographic locations.[62] Transporting crude by rail from North Dakota to the Gulf Coast or to refineries on the United States East Coast is reported to require 5 to 7 days, compared to about 40 days for oil by pipeline (see Figure 24).[63]

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[60] Trinity Chemical Industries (TCIX Rail). 2020. *Future Demand for DOT117J Railcars*. Accessed May 2020. https://tcixrail.com/railcar-leasing/railcar-leasing-information

[61] United States District Court for the District of Columbia. 2020. *Declaration of Glenn Emery in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB.

[62] Wallheimer, Brian. 2018. *Why transporting oil by rail is popular, despite the cost.* Chicago Booth Review. Accessed May 2020. https://review.chicagobooth.edu/economics/2018/article/why-transporting-oil-rail-popular-despite-cost

[63] Frittelli, John, et al. 2014. *U.S. Rail Transportation of Crude Oil: Background and Issues for Congress.* Congressional Research Service. https://fas.org/sgp/crs/misc/R43390.pdf

Figure 24. Oil transport time from North Dakota to US Gulf Coast

Source: https://www.strata.org/pdf/2017/pipelines.pdf

Rail also provides a supply link from the Bakken region to refineries on the East Coast which are not connected to pipelines.[64] These refineries are configured to run light crude oil such as Bakken crude. Before the growth of Bakken supplies these refineries ran light imported crude oil. Imported oil into PADD 1 (the US East Coast) declined dramatically from 2010 through 2014 as crude-by-rail from PADD 2 displaced imported oil.[65]

[64] Birn, Kevin, and Juan Osuna. "Railroad Oil Shipping is Here to Stay." March 2015. *American Oil and Gas Reporter*. https://www.aogr.com/web-exclusives/exclusive-story/railroad-oil-shipping-is-here-to-stay

[65] EIA. "Crude oil movements by rail between PAD Districts." http://www.eia.gov/dnav/pet/pet_move_rail_a_epc0_rail_mbbl_a.htm; and "Crude oil imports by area of entry." http://www.eia.gov/dnav/pet/pet_move_imp_a_epc0_im0_mbblpd_a.htm.

6 Ms. Kub's analysis of impacts on the agricultural sector depends on Mr. Rennicke's flawed assumptions and conclusions

Ms. Elaine Kub provided expert evidence relating to the impact of increased rail use (if DAPL is shut down) on agricultural markets.[66]

Mr. Rennicke's conclusions form the basis of Ms. Kub's analysis. She said "I defer to rail experts who conclude there are insufficient rail tanker cars capable of carrying the crude oil volumes currently transported on DAPL and that sufficient additional cars cannot be financed or built in the short term."[67] In addition, she notes. "Because rail lines on which DAPL volumes would need to flow are already constrained in places, even the modest amount of DAPL's crude oil capacity that could be accommodated by available rail tanker cars would constrain those lines further and divert substantial rail capacity away from agricultural and other commodities."[68] However, as LEI has noted previously and showed in Figure 18, overall rail traffic is down. This implies less congestion for 2020 than Ms. Kub assumes in her analysis.

She explains that her conclusions are based on data from 2014, before DAPL was in service.[69] As LEI showed previously in Figure 15, the year 2014 had the highest crude-by-rail shipments out of the Williston Basin, at nearly 800,000 b/d. In addition, although 2020 rail traffic from grain is still on par with historical levels, rail traffic from other farm products has declined (see Figure 25 and Figure 26).

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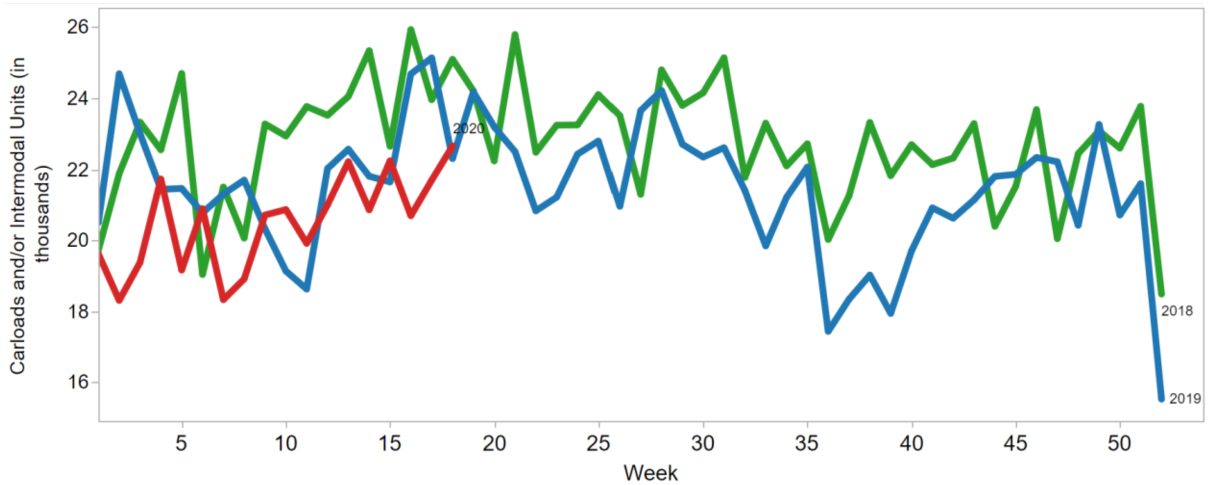
[66] United States District Court for the District of Columbia. 2020. *Declaration of Elaine Kub in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB.

[67] Ibid., P. 2.

[68] Ibid., P. 2.

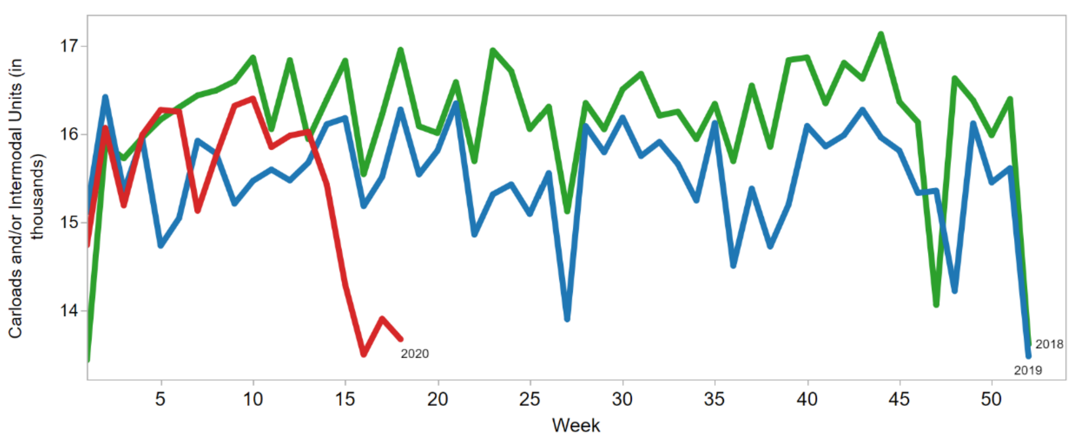
[69] Ibid., P. 3.

Figure 25. Grain, originated rail traffic (United States)



Source: Association of American Railroads. https://www.aar.org/data-center/rail-traffic-data/

Figure 26. Food and farm products excluding grain, originated rail traffic (United States)



Source: Association of American Railroads. https://www.aar.org/data-center/rail-traffic-data/

Low overall use of rail owing to the ongoing economic recession, combined with the much lower demand for crude by rail from North Dakota means the next two years will not be the replay of 2014 that Ms. Kub fears. Her estimates of the impact of closing DAPL on the agriculture sector depend on her assumption of "delays comparable to those experienced in 2014."[70] Such delays are unlikely to materialize based on the far lower usage of the US rail system.

[70] United States District Court for the District of Columbia. 2020. *Declaration of Elaine Kub in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB. P. 19.

7 Economic losses are overstated

The Declaration of Jeff D. Makholm Case No. 1:16-cv-1534-JEB provides estimates of economic losses from the shutdown of DAPL. These estimates provide the foundation for estimates of broader economic impacts discussed in the Declaration of Glen Emery. In this Section, LEI demonstrates that Dr. Makholm's estimates of economic losses are substantially overstated. He uses the flawed assumption about lack of available rail cars (repeating the mistake of Mr. Rennicke) and he relies upon an untenable outlook for North Dakota oil prices.

7.1 Dr. Makholm's estimate of harm is based on Mr. Rennicke's flawed analysis and economically untenable oil prices

Dr. Makholm estimated that North Dakota producers would lose $2.03 to $3.17 billion dollars in 2020 based on assumed loss of exports of between 320,000 b/d and 500,000 b/d if DAPL is shut down; and in 2021 would lose $3.18 to $5.95 billion based on the same range of assumed loss of exports. These losses are overstated by a substantial $2 billion - $5 billion, as demonstrated below.

7.1.1 Losses are exaggerated based on oil quantity assumptions

Dr. Makholm's premise that there are not enough tank cars to transport 570,000 b/d is based on Mr. Rennicke's analysis.[71] As LEI demonstrated in Section 3, Section 4, and Section 5, only a small fraction of the 570,000 b/d would end up on the rail system; and the rail system in any case is likely to have many more available tank cars than Mr. Rennicke assumed. The stranding of 320,000 b/d - 570,000 b/d and its impact on oil company and state revenues is a foundation of Dr. Makholm's analysis.

7.1.2 Losses are further exaggerated based on Dr. Makholm's oil price assumptions

The assumed outlook for crude oil prices is key to any estimate of losses. Dr. Makholm explained his assumptions for crude oil prices in footnotes 9 and 10 on page 10:

> [9]*"I estimate the historical earnings to oil and gas producers in North Dakota attributable to DAPL by multiplying barrels of oil shipped on DAPL by the price of crude oil for oil and gas taxed in North Dakota. For North Dakota crude prices, see Quarterly Update Detail – Forecast to Actual Comparison, N.D. Legislative Council (Sept, 2017), https://www.legis.nd.gov/files/fiscal/2015-17 /docs/17_9041_24000.pfd. North Dakota crude oil prices reflect the average of Flint Hills Resource prices and West Texas Intermediate prices."*

[71] United States District Court for the District of Columbia. 2020. *Declaration of Jeff D. Makholm, PhD in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB., p. 8.

> [10] *"I estimate expected earnings in 2020 and 2021 by multiplying barrels of oil shipped on DAPL in 2019 by historical North Dakota crude oil prices that are similar to expected prices in the latter half of 2020 and 2021. The U.S. Energy Information Administration expects West Texas Intermediate crude oil average prices to decline by 48 percent and 28 percent in 2020 and 2021, respectively, relative to the average price in 2019. See Short-Term Energy Outlook, U.S. Energy Info. Admin. (release date Apr. 7, 2020), https://www.eia.gov/outlooks/steo/marketreview/crude.php. I select two historical periods in which North Dakota crude oil prices reflect similar declines relative to 2019: August 1, 2015 to July 31, 2016 (in which the North Dakota crude oil average price was 41 percent lower than the average price in 2019) and April 1, 2016 to March 31, 2017 (in which the North Dakota crude oil average price was 28 percent lower than the average price in 2019). For those historical North Dakota crude oil prices, see Monthly Update Detail – Forecast to Actual Comparison, N.D. Legislative Council (Sept. 2017), https://www.legis.nd.gov/files/fiscal/2015-17/docs/17_9044_24000.pdf. I calculate the monthly ranges of loss to oil and gas producers by multiplying the expected quantity of barrels per day shipped on DAPL each month that could not be shipped via rail (the quantity of barrels stranded) by the price per barrel that month and the number of days in the month. I then sum this monthly loss for the remaining months in 2020 and all twelve months of 2021 to determine the 2020 and 2021 losses to oil and gas producers."*

To understand what exactly his price assumptions were (and therefore to understand their impact on his estimate of losses from closure of DAPL) it is necessary to carefully examine the information in Dr. Makholm's footnotes. He said he used average North Dakota oil prices (based on the average of WTI and Flint Hills Resource ("FHR") prices shown in the North Dakota Legislative Council Report) for the 12 months encompassing August 1, 2015 to July 31, 2016 and then April 1, 2016 to March 31, 2017 as his assumed prices for 2020 and 2021. Based on the North Dakota FHR data source he cited, these prices are $35.54/bbl (for 2020) and $42.26/bbl (for 2021).[72] Although Dr. Makholm does not provide the actual price he used, LEI believes that $35.54/bbl and $42.26/bbl are close estimates to his prices, based the description in his footnotes. These represent the annual averages of his monthly outlook prices for 2020 and 2021.

Relative to the WTI price outlook provided by the EIA Short-term Energy Outlook ("STEO") (upon which Dr. Makholm claims to base his outlook) his North Dakota oil outlook prices are wildly inconsistent with history and with economic logic. His 2020 assumption implies that North Dakota crude oil would sell for $6.20/bbl **more** than WTI in 2020; his 2021 price assumption assumes a premium of $1.14/bbl **more** than WTI (see Figure 27). However, in the time periods Dr. Makholm used in his analysis, North Dakota crude oil sold at between $5.68/bbl and $5.53/bbl **less** than WTI (see Figure 27).

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[72] North Dakota Legislative Council. 2019. *Oil and Gas Tax Revenue Collections and Allocations Quarterly Update Detail.* Accessed May 2020. https://www.legis.nd.gov/files/fiscal/2017-19/docs/19_9007_04000.pdf and previous annual updates.

Figure 27. Dr. Makholm's oil price assumptions

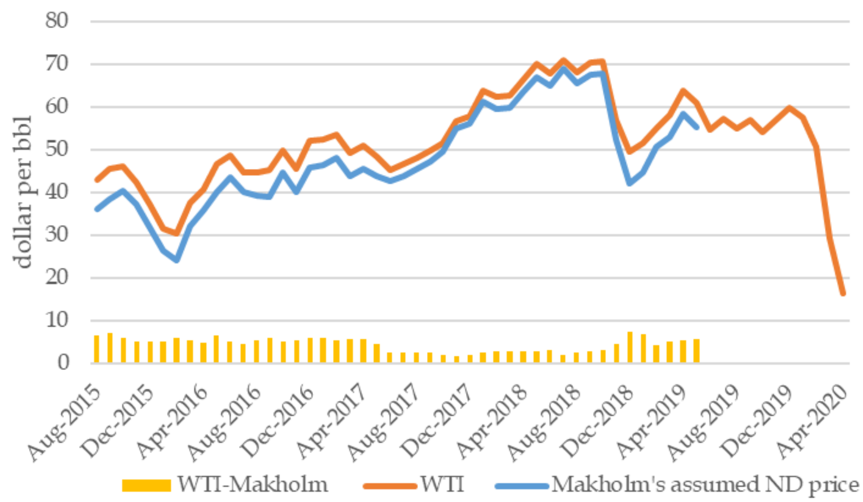
Dollars per bbl		Prices and differentials
WTI 2019	$	57.02
WTI outlook 2020 (STEO April 7)	$	29.34
WTI outlook 2021 (STEO April 7)	$	41.12
Makholm estimated ND oil price		
August 2015-July 2016	$	35.54
April 2016-March 2017	$	42.26
Price differential (WTI-ND) implied by Makholm assumption		
2020	$	(6.20)
2021	$	(1.14)
Actual WTI price		
August 2015-July 2016	$	41.22
April 2016-March 2017	$	47.79
Actual historical differential (WTI-ND)		
August 2015-July 2016	$	5.68
April 2016-March 2017	$	5.53

Source: ND prices, https://www.legis.nd.gov/files/fiscal/2015-17/docs/17_9044_24000.pdf; WTI prices http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm

The roughly $5.50/bbl differential was evident not only in the years which Dr. Makholm's data covered, but more recently, too (see Figure 28). The yellow bars in Figure 28 represent the difference between the WTI price (the orange line) and Dr. Makholm's ND price (the blue line). For only a short period (during 2017 and 2018) were price differentials narrower than about $5.00/bbl.

Dr. Makholm provided no reason why the price discount of North Dakota crude should suddenly reverse for the next two years. It defies economic logic. North Dakota oil is distant from the Cushing, OK market hub (the pricing point for WTI); Cushing has storage capacity and export pipelines to the US Gulf Coast; and it costs money to transport North Dakota crude to Cushing—it is not free. That is why North Dakota crude oil sells at a discount to WTI, and none of those reasons are set to change in the next two years.

Figure 28. Historical prices for WTI and FHR



Source: WTI, EIA http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm; FTR, North Dakota Legislative Council, https://www.legis.nd.gov/historical-oil-and-gas-tax-revenue-publications, "Oil and Gas Tax Revenue Collections and Allocations Quarterly Update Detail," https://www.legis.nd.gov/files/fiscal/2017-19/docs/19_9007_04000.pdf and previous annual updates.

If Dr. Makholm wanted to base his North Dakota price outlook on EIA's STEO projection of $29.34/bbl WTI in 2020, a more realistic and economically credible price outlook for North Dakota crude oil would be $23.84/bbl (i.e., $5.50/bbl lower than WTI, in line with previous differentials); and the STEO projection of $41.12/bbl in 2021 would imply an economically credible North Dakota prices of $35.62/bbl. However, though such an outlook for FHR prices is economically credible, it is probably on the high end—EIA's STEO outlook is substantially higher than the futures market (shown previously in Figure 3).

Finally, Dr. Makholm makes another error in logic. He forgets that losses to one party are often gains to another party. The losses to DAPL and the increased cost to transport by rail is a loss to oil producers, but a gain to railroads and railcar lease companies. The loss of tax and royalty revenues in North Dakota will result in gains in such revenues for other oil-producing states such as Texas, if Texas oil producers fill the gap left by lower North Dakota production.

7.2 Energy Transfer Partners' claims of harm depend on flawed analysis

The Declaration of Glen Emery, of Energy Transfer Partners (an owner in Dakota Access, LLC)[73] is based on the flawed analyses provided by Mr. Rennicke and Dr. Makholm.

Mr. Emery relies on Mr. Rennicke's analysis which, as LEI's analysis showed, underestimates the availability of rail cars and overestimates the need for rail cars. Mr. Emery's estimate of the additional $1 billion per year required to transport oil if DAPL was closed relies on the assumption that all the 570,000 b/d would be stranded if not shipped by rail.[74] Mr. Emery's concerns over the impact of greater use of rail on agricultural earnings is also misguided, as he relied on the agricultural analysis provided by Ms. Kub, which in turn is based on Mr. Rennicke's out-of-date information and flawed assumptions.

Mr. Emery notes "Landowner and royalty owners…would receive greatly reduced royalty payments."[75] Such payments would only decline to the extent that higher transport costs impact the cost basis for royalty payments. He, again, relies on the assumption that 570,000 b/d of oil is stranded, so supports no royalties or taxes. Without that assumption, the impact on royalties and taxes is much smaller. He makes the same error in logic as Dr. Makholm, ignoring the gains to other locations and businesses that are the other side of the losses to North Dakota oil producers.

Mr. Emery admits that "While Dakota Access foresees (sic) a temporary slowdown in demand for transportation due to the current COVID-19 pandemic, demand is fully expected to steadily increase as the economy recovers."[76] LEI does not disagree that an increase in economic activity would help oil demand increase. But Mr. Emery is not specific or concrete in his pronouncement, and the pace of recovery of economic activity is deeply uncertain, as the Conference Board outlooks illustrated (see Figure 4 previously). The economy may not fully recover until after the period that DAPL would be closed. Mr. Emery also ignores the headwinds facing the oil industry from less-generous investors, which imply lower production levels even with oil prices similar to 2019 levels. His very broad statement has no evidence to support it.

[73] United States District Court for the District of Columbia. 2020. *Declaration of Glenn Emery in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB.

[74] Ibid, P. 21.

[75] Ibid. P. 3.

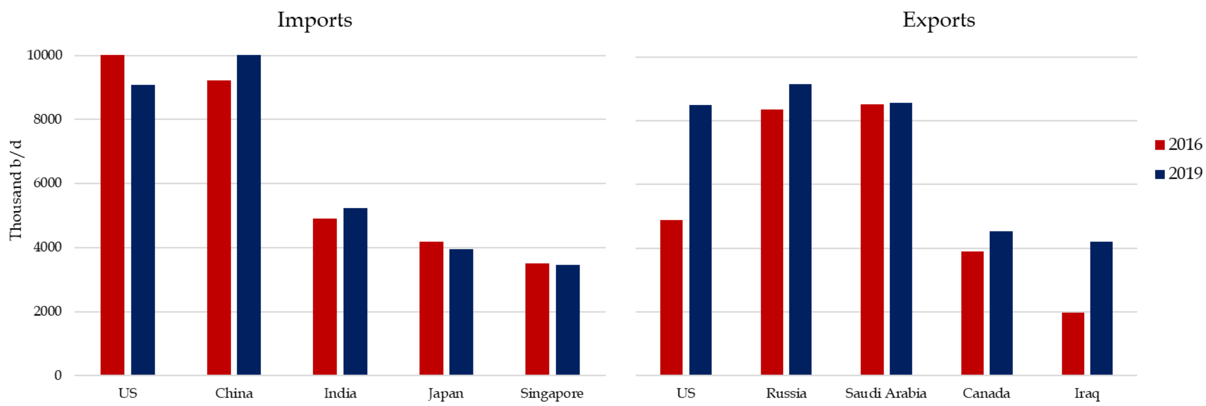
[76] Ibid. P. 11.

8 Traditional energy security issues are diluted when oil demand and prices are low

The Declaration of Mr. Guy Caruso notes that the strong oil and gas production of the United States, along with its extensive export infrastructure and thereby its access to the global oil market, has contributed to energy security in the United States.[77] As LEI understands him, Mr. Caruso is referring to traditional energy security issues—the worries over access to crude oil from potentially unfriendly and/or unstable regions of the world that loom large when a country is highly dependent on imported oil.

However, the United States is now less dependent on foreign crude oil. Surging shale oil production from the Bakken region and the Permian region, and the change to federal laws which allowed crude oil exports, transformed the United States from the world's largest importer of oil as recently as 2016, to one of the world's largest exporters in 2019 (see Figure 29).

Figure 29. The world's top five oil importing countries and top five oil exporting countries in 2016 and 2019



Source: BP Statistical Review of World Energy, 2019.

Traditional energy security issues, which haunted geopolitics when the United States was a large net importer of oil (and when oil prices were high), do not apply in the same way in a world awash in oil. Under the circumstances, a temporary shutdown of DAPL would be a non-issue for energy security.

[77] United States District Court for the District of Columbia. 2020. *Declaration of Guy F. Caruso in Support of Dakota Access, LLC's Brief on the Question of Remedy*. Case 1:16-cv-1534-JEB.

9 The best time to close a pipeline is when oil demand and prices are low

It might be unintuitive, but LEI's analysis detailed in this declaration shows that a temporary shut-down of an oil pipeline such as Dakota Access will have a relatively small impact in the current and near-term environment of low oil prices and low demand. LEI's analysis shows that the impact on North Dakota oil producers' earnings, government oil tax earnings and land and royalty owners would be billions of dollars less than claimed by other intervenors. Impacts on the rail system would be minor. Energy security impacts would also be minor compared with previous years and decades during which the United States was more dependent on oil imports.

10 Appendix A: DAPL in the context of the broader oil market

Oil produced from the Bakken region, and the transportation provided by DAPL, all take place in the context of a global oil market. Wholesale prices for oil are not a function of crude prices for the specific refineries supplying a specific market. Refined products instead follow crude prices in the broad global market. It helps to understand this global interconnectedness, as it underlies projections of oil demand, supply, and prices.

10.1 Crude oil markets are global

Crude oil is a global commodity. This is because oil is easy and inexpensive to transport by tanker ships. Even if shipped thousands of miles, imported crude oil remains economically competitive. This economic competitiveness is evident in the very high share of global trade in crude oil compared to oil consumption. In 2018, global trade in crude oil reached 45.4 mbd, or 2,263 million tonnes (see Figure 30). This global trade accounted for 45% of total global consumption of crude oil of 99.8 mbd in 2018.[78]

In December 2015, the US Congress lifted the ban on crude oil exports from the United States.[79] Crude oil exports began creeping up before the lifting of the ban, but these exports were mostly to Canada, which was excluded from the previous restrictions.[80] The lifting of the export ban at the end of 2015 boosted exports to countries other than Canada, and crude oil exports surged. This lifting of the ban allows access to a larger export market for US suppliers. It adds to global supplies, and thus could keep global crude oil prices lower than otherwise and make it harder for OPEC to support prices. The lifting of the ban provided impetus for more pipeline capacity to be built in North America to reach export locations such as the US Gulf Coast.

Because the oil market is integrated globally, events that impact supply or demand in one part of the world can impact crude oil prices all over the world.

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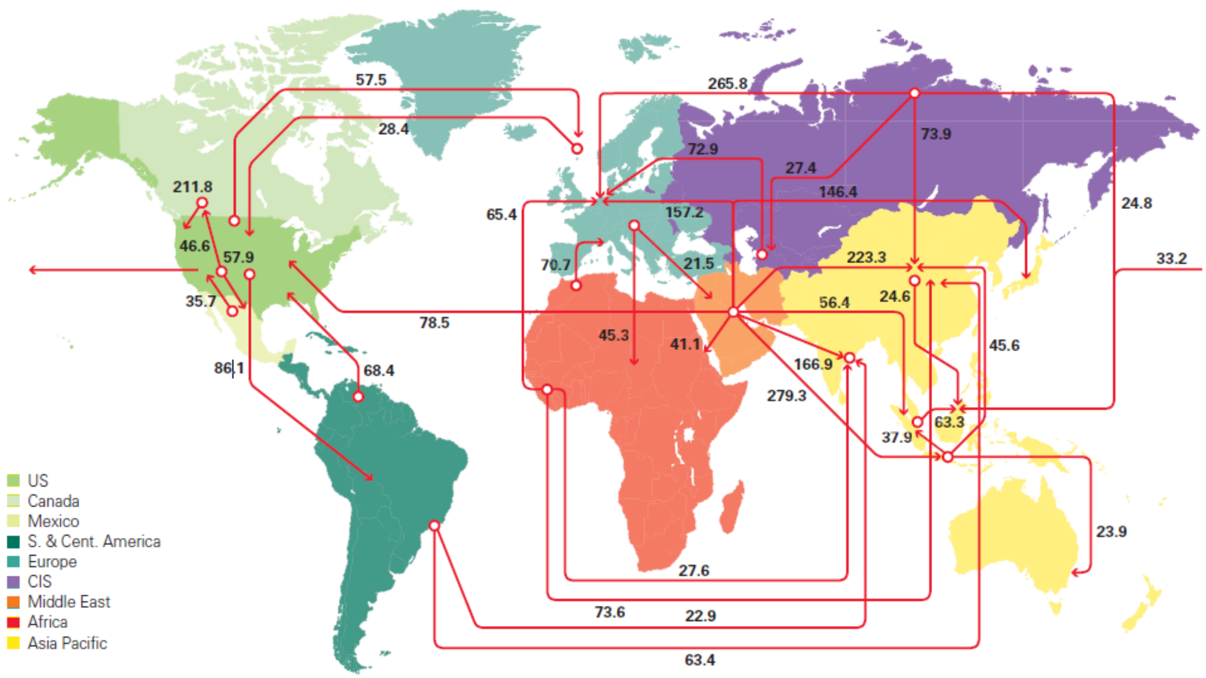
[78] British Petroleum. 2019. *Statistical Review of World Energy, 2019*. BP.

[79] The Wall Street Journal. "Congressional Leaders Agree to Lift 40-Year Ban on Oil Exports." December 16, 2015.

[80] EIA. "Today in Energy." August 16, 2016. https://www.eia.gov/todayinenergy/detail.php?id=27532

Figure 30. Major oil trade movements, 2019 (million tonnes)



Source: BP Statistical Review of World Energy 2019. "Oil Trade 2015 and 2016." <http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/oil/oil-trade-movements.html>
Note: One (metric) tonne is equal to about 7.33 barrels of oil.

10.1.1 Oil price are volatile and prone to booms and busts

An examination of oil prices for the past few decades illustrates the volatility of oil prices. Strong economic growth in the early 2000's and modest growth in oil production resulted in record-high oil prices above $120/bbl by July 2008. The price collapse to $40/bbl in 2008-09 reflected the slowdown in oil demand from the global financial crisis. Oil prices cycled upward again from 2009 to about 2011 as demand recovered but did not reach previous peaks (see Figure 31).

Figure 31. Monthly West Texas Intermediate ("WTI") spot prices

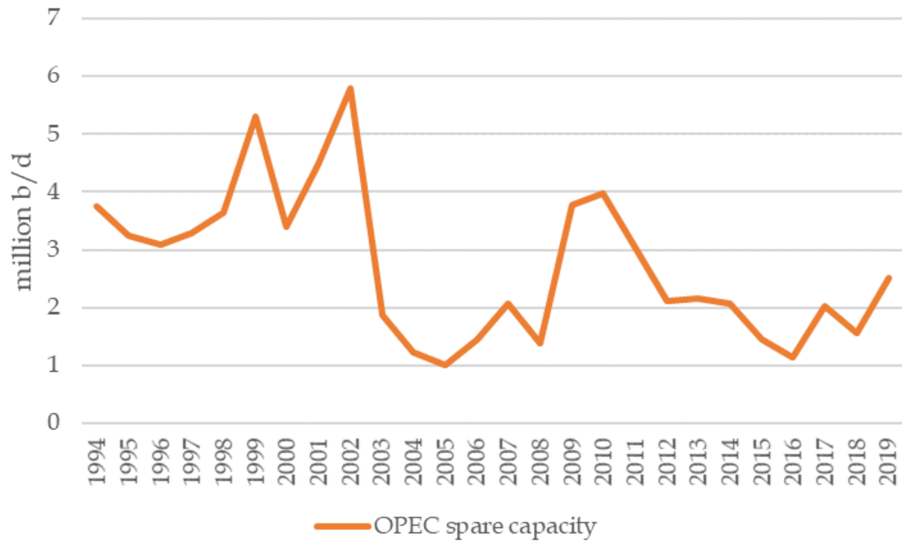
Source: Energy Information Administration ("EIA") http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm

The seeds of the next downturn in the cycle began at the end of 2014. Saudi Arabia and, to a lesser extent, several other OPEC producers typically hold spare capacity, which is oil they could produce, but choose not to. They hold this production off the market to maintain prices at a level that supports government budget requirements. Supporting prices was getting more and more difficult for Saudi Arabia because of the surge in production from the light oil (shale) plays in the United States—the Bakken shale in North Dakota, and the Permian Basin region in West Texas.

Thus, to keep prices near $100/bbl in 2010-2014, Saudi Arabia had to tolerate a smaller and smaller share of the oil market. It was essentially supporting global prices at the cost of its own production levels.

At the end of 2014, Saudi Arabia changed strategy. Rather than supporting global prices, the Kingdom began flooding the market with oil. It intended to induce a collapse in prices below the cost of production for its main rivals, the United States shale producers, and drive them out of business. To that end, Saudi Arabia increased its annual average production from 11.5 mbd in 2014 to 12.4 mbd in 2016. OPEC spare capacity declined by nearly 1 mbd from 2014 to 2016 (see Figure 32) as the idle capacity was brought into production.

Figure 32. OPEC spare crude oil capacity



Source: EIA https://www.eia.gov/opendata/qb.php?category=1039872&sdid=STEO.COPS_OPEC.A

Saudi Arabia and other OPEC members expected that the price collapse to below $60/bbl would wipe out a significant portion of US shale oil production, permanently. However, though production from these regions declined somewhat, the fall in price was too small to make a large impact on market share for OPEC. And in the meantime, oil at or below $60/bbl was not enough to support Saudi Arabia's budget, which is reported to need about $60-$65/bbl.[81]

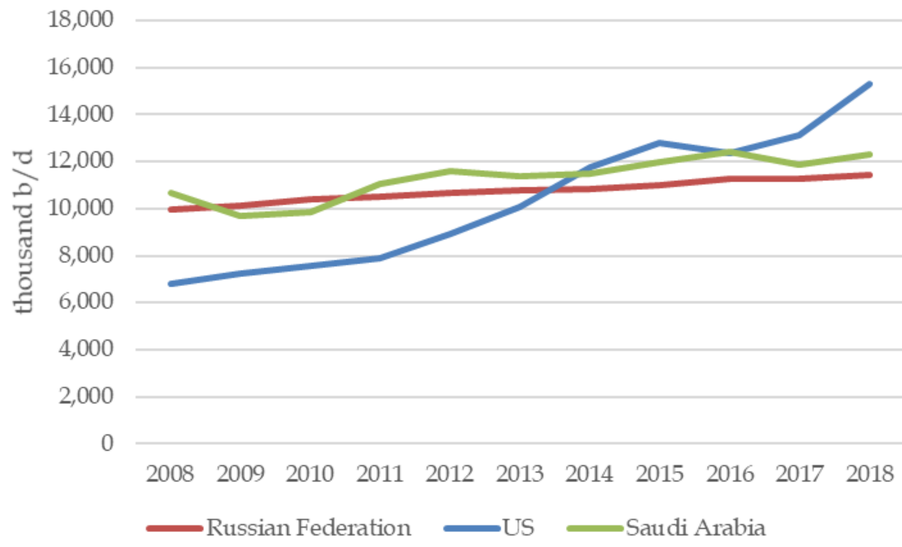
Though it was relatively easy for Saudi Arabia to increase production, cutting production is another matter. Cuts are difficult for OPEC to agree upon and to implement. The interests of each country are not aligned—for example, Iran was intent on ramping up to at least 4 mbd after the lifting of sanctions in January 2016 and refused to participate in any production cutbacks. The agreement of non-OPEC Russia, which produced nearly as much oil as Saudi Arabia, is crucial to an effective agreement. And, as for any cartel, each member has an incentive to "free ride"- to keep its production flat or to increase it while the other members cut production.

However, facing persistently low prices for two years, at its November 2016 meeting, Saudi Arabia led a producers' agreement to cut production and shore up oil prices—the first production cut agreed since 2008. Russia participated in this agreement, with relatively small cuts in

[81] Noha H. A. Razek, Nyakundi M. Michieka, and Emilson Silva OPEC+'s 'Reasonable Oil Price Level' Notion and the External Breakeven in Saudi Arabia, Russia and Canada: Accounting for Economic Cycles and Pipeline Politics (November 21, 2019). USAEE Working Paper No. 19-420. Available at SSRN: https://ssrn.com/abstract=3491212 or http://dx.doi.org/10.2139/ssrn.3491212SSRN

production (see Figure 33). Oil prices recovered to about $70/bbl by 2018. Meanwhile, US oil production resumed its increase, and based on this increase in supply and a weakening of global demand growth, oil prices again slipped below the $60/bbl level 2019.

Figure 33. Oil production from the United States, Russia, and Saudi Arabia

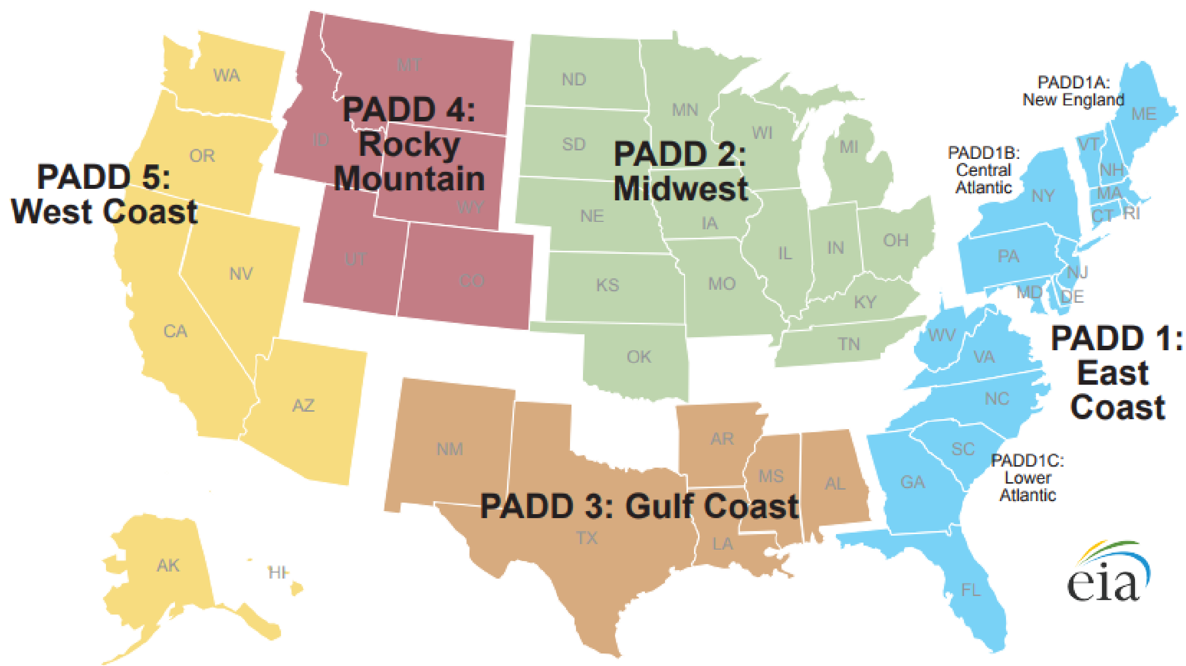


Source: BP Statistical review of World Energy 2019.

10.2 Refined product markets are well-integrated

The markets for refined products are well-integrated across North America. By integrated, LEI refers to the fact that, similar to crude oil, refined products can flow freely from one location to another in response to price signals. In the US, refined product regions which are commonly used are the "Petroleum Administration for Defense Districts" ("PADDs") (see Figure 34).

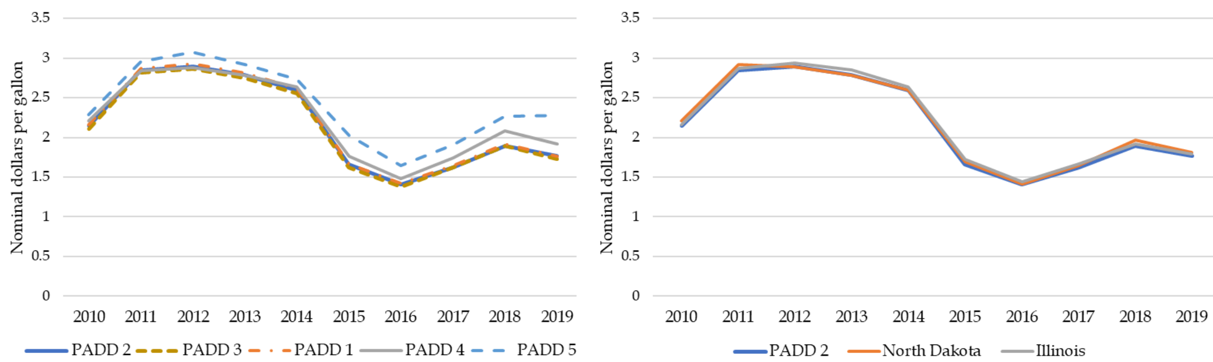
Figure 34. United States Petroleum Administration for Defense Districts (PADD)



Source: EIA

PADDs are an administrative concept, developed by the federal government during World War II to help manage fuel rationing. Thus, PADDs do not represent physical boundaries between markets, and the price data shows that, for the most part, the US is a single, integrated market for refined products such as gasoline and diesel fuel. This is evident in looking at the price of refined products across US PAD Districts. Wholesale gasoline prices in PADD 1, PADD 2, PADD 3, and PADD 4, track one another closely (see Figure 35). The exception is PADD 5, the West Coast region, which includes California which has specific rules for gasoline that make it more expensive than other markets.

Figure 35. Wholesale gasoline prices



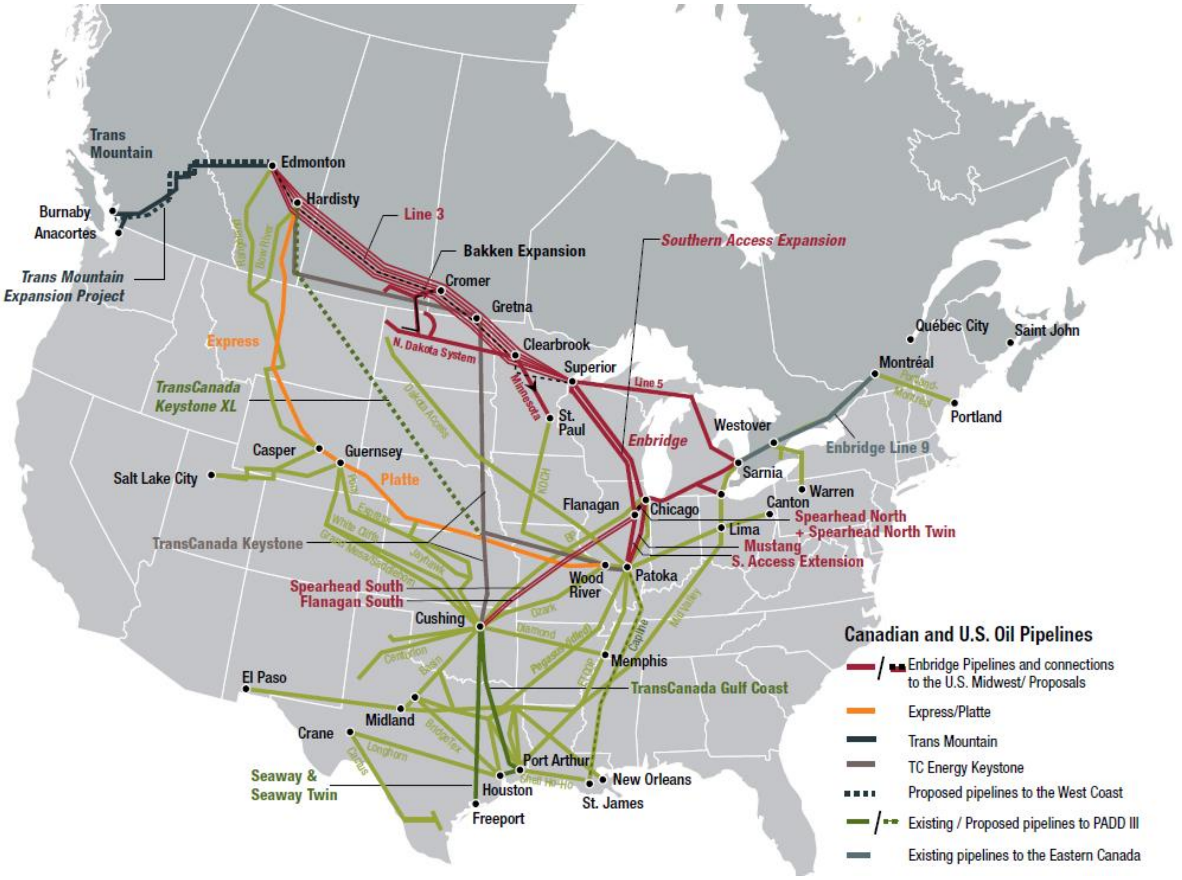
Source: EIA. *Total Gasoline Wholesale/Resale Price by Refiners*. 2020.

The path of DAPL lies entirely within PADD 2. The wholesale price of gasoline tracks closely within PADD 2, averaging only 4% lower in Minnesota than in Illinois (see Figure 35 above). This close tracking of prices indicates that PADD 2 is internally a single, integrated market. In such markets, when a local price spike occurs – for example, if a refinery or pipeline is unavailable — the spike will be short-lived because supplies can be brought in from alternative refineries or using other transportation modes.

10.3 Pipeline infrastructure connects oil supply and demand across the United States, and to international markets

The reason the refined product markets in the United States are so well-integrated is the dense network of crude oil and product pipelines which exists. Crude pipelines connect major supply regions such as Western Canada, North Dakota, and Texas to refining and export centers (see Figure 36). Patoka, IL, the terminus of DAPL, is a key hub in the North American pipeline system. North Dakota crude oil reaching Patoka has access to refining centers that serve the US Midwest. Crucially, it also has access to southbound transport to the US Gulf Coast, for refining and export. A well-developed network of pipelines which transport gasoline and other refined products add another layer of integration to the US oil market.

Figure 36. Major crude oil pipelines in North America, 2019



Source: Canadian Association of Petroleum Producers ("CAPP"). *2019 Crude Oil Forecast, Markets and Transportation*

10.4 US crude oil exports have increased dramatically

In December 2015, the US Congress passed a law allowing exports of crude oil to markets around the world. Previously, exports were permitted only to Canada. US oil production growth has run far ahead of demand, so crude oil for export grew strongly after lifting of the export ban. By 2019, US crude oil exports reached almost 3 million barrels per day (see Figure 2 shown in Section 2 previously). The export of refined products began to surge over a decade ago. Because crude oil exports were not allowed, refiners kept busy manufacturing products such as gasoline and distillates for foreign markets.

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE, Plaintiff, and CHEYENNE RIVER SIOUX TRIBE, Plaintiff-Intervenor, v. U.S. ARMY CORPS OF ENGINEERS, Defendant-Cross Defendant, and DAKOTA ACCESS, LLC, Defendant-Intervenor-Cross Claimant.	Case No. 1:16-cv-1534-JEB (and Consolidated Case Nos. 16-cv-1796 and 17-cv-267)

THIRD DECLARATION
OF DONALD HOLMSTROM

I, Donald Holmstrom, declare as follows:

1. I am an attorney, incident investigator, and process safety practitioner with many decades of experience with the oil industry and U.S. government. I worked for the U.S. Chemical Safety and Hazard Investigation Board (CSB), a non-regulatory scientific agency modeled after the National Transportation Safety Board for 17 years. At the CSB, I managed, led or participated in over 70 major chemical accident investigations serving as a Lead Investigator, Investigation Supervisor and head of the Recommendations Department. For nearly a decade, I

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directed the Western Regional Office of the CSB. I managed or led many of the largest and most significant chemical incident investigations in recent U.S. history, including the 2005 BP Texas City explosion, the 2010 Tesoro Anacortes oil refinery fire, the 2010 Deepwater Horizon offshore fire and explosion, and the 2012 Chevron Richmond, CA oil refinery fire. During my tenure, approximately two thirds of the Board's investigative staff worked for the Western Regional Office under my direction. I have published over 15 professional papers related to my expertise. My CV is attached as Exhibit 1 to this declaration.

2. I have extensive experience drafting root-cause investigation reports for releases of hazardous materials or chemical accidents in the oil and gas or chemical industries. I drafted reports that addressed the importance of effective management systems for incident investigation, corporate safety oversight, safety culture and risk management. In particular, two investigations I led and managed for the CSB — the 15 fatality 2005 BP Texas City refinery explosion[1] and the 11 fatality 2010 Deepwater Horizon blowout and explosion[2] both involved a history of repeat incidents, ineffective "lessons learned" systems, flawed safety culture, and a failure of corporate leadership and oversight. The CSB reports and recommendations on these incidents and others were highly regarded[3] and resulted in new safety standards and regulatory initiatives by the American Petroleum Institute (API), BSEE, EPA and OSHA.

3. Upon completion of the BP Texas City investigation, I had numerous meetings

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1 https://www.csb.gov/bp-america-refinery-explosion/

2 https://www.csb.gov/macondo-blowout-and-explosion/

3 The CSB "chemical industrial accident investigations and recommendations have been called the 'gold standard' in industrial accident prevention by Rep. George Miller (D-Calif.)." Chemical and Engineering News, Volume 86, Issue 35, September 2008 https://cen.acs.org/articles/86/i35/Bringing-Life-Deadly-Accidents.html. Congressional Record-House, Volume 154, Pt. 5, April 30, 2008, p.7343. https://www.govinfo.gov/content/pkg/CRECB-2008-pt5/pdf/CRECB-2008-pt5-Pg7331-4.pdf.

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and presentations to Congressional representatives and government agencies including the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA was concerned about these same issues and had specific concerns about BP pipeline spills in Alaska. As a result of our interaction, CSB staff participated at PHMSA's request on the API committee that developed Recommended Practice 1173, *Pipeline Safety Management Systems* (2015). CSB staff was part of the team that developed the applicable safety management standard.

4. That important pipeline safety standard was developed in response to a recommendation from the NTSB out of the 2010 Enbridge Marshal, MI crude pipeline disaster. Having reviewed recent serious pipeline incidents, the NTSB concluded that safety management systems "are needed to enhance the safety of pipeline operations," citing the CSB's BP Texas City Refinery Report as support for its position.[4] API 1173 incorporated many of the key lessons from the CSB BP Texas City Report including the importance of effective corporate safety leadership and oversight, root cause investigations, safety culture and the use of leading and lagging key performance indicators. In contrast, the minimum regulatory requirements of PHMSA are dated and have not kept up with modern pipeline standards[5] and responses to Congressional mandates and recommendations from government reports.

5. I also have personal experience recommending to companies handling highly hazardous material when to stand down their operations to address serious issues with chemical incidents and lack of effective integrity management. In investigations I led or managed, the CSB on occasion advised companies to shut down, or postpone restart operations, until serious

[4] *Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall Michigan, July 25, 2010*; National Transportation Safety Board Accident Report.

[5] For example, PHMSA has not incorporated a new API standard by reference into their regulatory scheme since 2013. 49 CFR § 195.3. API standards are typically updated on a 5-year schedule.

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systematic issues were addressed. At times companies were eager to restart operations before the causes of the incident had been determined or their safety systems and plants were safe to operate. While non-regulatory, the CSB had the authority to issue urgent recommendations to address these concerns. These interventions were generally successful. For example, I and the CSB Board Chair advised the CEO of an oil refinery in Salt Lake City, Utah that had a serious history of leaks, incidents and mechanical integrity deficiencies to shut down operations and address the problems. The refinery ceased operations for a number of months to upgrade their safety systems and the mechanical integrity of their piping and equipment.

6. I currently serve as a consultant to the Standing Rock Sioux Tribe and a member of the technical team advising the Tribe on technical matters relating to the risks imposed by the Dakota Access Pipeline ("DAPL"). I previously submitted two declarations in this action, one in support of the Tribe's motion relating to remedy, (ECF 272-4), which further discusses my expertise and qualifications relating to risk management and analysis of pipelines, and a second in support of the Tribe's motion for clarification (ECF 342-1).

7. As a member of the Tribe's technical team, I am also one of the contributors to the technical document submitted to the Army Corps as part of its remand review. That document provides additional detail on some of the topics discussed in this declaration. I also advise the Tribe on matters related to oil spill response planning and assisted the Tribe in drafting their Tribal Emergency Response Committee (TERC) Lake Oahe Pipeline Oil Spill Emergency Response Plan (March 2020).

8. To date, I have spent many hours involved in this work by reviewing documents and participating in meetings with Tribal agency heads, including the Departments of Emergency Management, Water Resources, and Environmental Regulation, the interdisciplinary

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technical team, and Tribal leaders. I have a high degree of familiarity with the environmental review documents prepared by the Corps and DAPL, as well as other technical declarations and documents filed by DAPL related to the issue of remedy (including declarations of Stamm, Aubele, and Godfrey). I served as an expert witness on behalf of the Tribe before the North Dakota Public Service Commission when it was considering a proposal to double the capacity of DAPL. I have also carefully reviewed and summarized recent data from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) related to hazardous liquid[6] pipeline spill incidents and operator safety information.

9. In its brief and supporting declarations, DAPL tries to yet again make the case that operation of the pipeline is safe and hence the Court should not vacate its permits. They even go so far as to proclaim DAPL the safest pipeline in the world. This hyperbole is not supported by the record or the facts. The very issues that they cite to buttress their claim of safety, for example, the worst case discharge calculation, ETP safety record, leak detection and shutdown systems, spill preparedness, and among others, are issues that the Tribe has been contesting since the very start of this process. In fact, many of them formed the basis of this Court's decision in favor of the Tribe. But DAPL simply repeats, or expands upon, the same contested claims that the Tribe has been debunking throughout the process. I disagree with the factual allegations made in DAPL's multiple expert and corporate declarations. These issues have been addressed in multiple submissions made by the Tribe. I will focus on some key assertions in my review. In my view, DAPL is an unusually unsafe pipeline, managed by a corporate entity with an unusually troubled safety record. In this declaration, I provide a detailed

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[6] PHMSA defines hazardous liquids as "petroleum, petroleum products, anhydrous ammonia and ethanol." 49 CFR 195.2 Definitions. Hazardous liquid "commodity released" categories for incident reporting include crude oil, highly volatile liquid (HVL) and refined products. PHMSA regulates these hazardous liquids under a common framework as they present similar hazards.

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look at ETP's misleading claim to have an ordinary or even impressive safety record, which it does not. I then briefly turn to other issues, including worst case discharge, leak detection, best practices, and the proposal to double DAPL's capacity.

10. In my view, given the gravity of the safety performance, pattern of hazardous liquid spills, and regulatory violations and enforcement history of Dakota Access Pipeline's (DAPL) operator Sunoco Logistics and corporate parent Energy Transfer LP remains of great concern. Since 2012, Energy Transfer and its subsidiary hazardous liquid pipelines have the worst safety record in terms of spill numbers, significance and volume in the PHMSA database compared to other corporate pipeline families with large numbers of spills. Their most recent spill and enforcement record since 2016 does not reflect improvement. It is clear that Energy Transfer's corporate oversight over safety and learning from incidents is broken — they are failing to meaningfully lessen the frequency and severity of their pipeline spills.

11. In addition, as revealed by PHMSA data and DAPL-related documentation, multiple other aspects of Energy Transfer's pipeline safety management systems are significantly flawed. These systems include the DAPL's risk management approach; failure to apply modern, more protective pipeline safety standards such as API RP 1173; integrity management plan; their operations, maintenance and emergency response procedures; leak detection; and breaches of the Corps' Lake Oahe Easement Conditions that impact safe operations. Allowing Energy Transfer's DAPL[7] to operate without a valid and approved assessment of its environmental impact in this context poses a serious threat to people, property, and the environment.

12. API RP 1173 is widely recognized as a critical standard for pipeline safety

[7] The Dakota Access Pipeline is a less than wholly owned subsidiary of Energy Transfer Operating, LP (ETO). ETO is a consolidated subsidiary of Energy Transfer LP (ET), 2019 United States Security and Exchange Commission Form 10-K, pp. iii, 1. https://ir.energytransfer.com/static-files/4ecb1de6-ace2-4da3-b708-e655eaef13c1. DAPL's operator is Sunoco, a subsidiary of Energy Transfer LP.

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performance improvement. Its stated goal is to provide a framework for operators to establish effective pipeline safety management systems that drive toward zero incidents and continuous improvement of safety performance.[8] The standard details safety management systems that are needed to achieve those goals including leadership and management commitment; incident investigation, evaluation and lessons learned; safety assurance including performance measurement and evaluation of the data; and management review and continuous improvement. API RP 1173 emphasizes that "commitment, leadership and oversight from top management are vital" for the success of the pipeline safety management systems.[9]

13. In order to evaluate the risk of the continued operation of the DAPL Lake Oahe crossing, it is important to review Energy Transfer's pipelines spill record and related data. The API Standard specifically addresses pipeline risk by focusing on the operators' performance data. The risk management approach of API RP 1173 first emphasizes data gathering specific to the pipeline system:

> *These data serve as the foundation of risk management and shall include available data over the pipeline life cycle and shall be updated based on work performed and as needed during the life of the pipeline. Incident data, including the cause of incidents, shall be included as appropriate. The pipeline operator shall conduct a regular review to identify data gaps and evaluate data quality as part of risk assessment, consistent with continuous improvement.*[10]

API RP 1173 emphasizes the key role such operator's own performance data plays in its continuous assessment and improvement approach called "Plan-Do-Check-Act." That approach focuses on the real risk measured by the corporation's own safety performance history, not by generic incident data compiled from other operators as DAPL and the Army Corps assert.

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[8] API RP 1173 *Pipeline Safety Management Systems* (2015) Introduction, p.vii.

[9] *Id.*

[10] *Id.* at 11.

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14. Energy Transfer is the corporate parent of a family of hazardous liquid pipelines regulated by PHMSA that are subsidiaries or controlled but less than wholly owned. PHMSA requires that hazardous liquid pipeline spills meeting specific criteria be reported to the agency[11] and assigns an Operator ID for each pipeline system identified in PHMSA submissions. PHMSA also requires that operators identify the safety program relationship between different operators and the primary operator for those pipelines. For purposes of reporting DAPL hazardous liquid incidents to PHMSA, Energy Transfer has grouped together DAPL and the connected Energy Transfer Crude Oil Company, LLC (DAPL-ETCO). For DAPL-ETCO, Energy Transfer is identified as the primary operator ID. In total, 14 different hazardous liquid[12] operator IDs have Energy Transfer LP (Operator ID 32099) as the designated primary operator indicating their common safety program relationship. These include Sunoco LP (18718), Mid-Valley Pipeline (12470), West Texas Gulf (22442), Energy Transfer (32099),[13] DAPL-ETCO Operations Management LLC (39205), Inland Corporation (32683), Permian Express Partners LLC (39596), Bayou Bridge Pipeline LLC (39462), and Harbor Pipeline Co. (7063). My review of Energy Transfer pipeline safety performance and incident data will focus on these 9 hazardous liquid pipelines.[14]

15. While some of the listed Energy Transfer hazardous liquid pipelines are recently

[11] 49 CFR §195.50. Reporting Accidents requires an accident report for hazardous liquid spills (with some exceptions) that result in spills over 5 gallons, explosion or fire, death of a person, personal injury requiring hospitalization, estimated property damage exceeding $50,000.

[12] I have limited the Energy Transfer review to hazardous liquid hydrocarbons, excluding CO2 and ammonia pipelines. I have also removed hazardous liquid terminals from review that have no or minimal associated pipelines.

[13] Note Energy Transfer LP (32099) is listed as both a primary operator and also with its own Operator ID for its own separately listed hazardous liquid pipeline assets.

[14] Other listed Energy Transfer operator IDs were not included in the incident and safety analysis due to inactive status, functioning primarily as a hazardous liquid terminal, and lack hazardous liquid pipeline mileage or no submitted data.

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constructed (DAPL-ETCO, Permian Express and Bayou Bridge), others have a lengthier corporate subsidiary relationship with Energy Transfer or its predecessor Energy Transfer Equity (ETE).[15] Energy Transfer Equity LP (ETE) merged with Energy Transfer Partners in 2018 to form Energy Transfer LP. In 2012, ETE's then subsidiary Energy Transfer Partners (ETP) had acquired Sunoco Inc. for 5.3 million dollars.[16] Sunoco Inc., Sunoco Logistics and ETP were listed as consolidated subsidiaries of the parent corporation ETE in its 2012 Annual Report.[17] At the time of the Sunoco acquisition by ETP, Kelcy L. Warren was both the Chairman of the Board of ETP's General Partner and the General Partner of ETE, LE GP LLC.[18]

16. My review of the safety record of the Energy Transfer's consolidated subsidiaries and controlled hazardous liquid pipelines focuses on incident and safety data since 2012 and examines performance since 2016 to assess any improvements. I will also look at performance of the pipelines since 2006 to provide historic context.

17. In the 2012 Sunoco acquisition, ETE became the corporate parent of what is now a significant portion of its hazardous liquid pipeline assets, including Sunoco LP, Mid-Valley Pipeline Co. and West Texas Gulf Pipeline Co.[19] These three pipelines, in addition to Energy

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[15] Energy Transfer Equity LP (ETE) merged with Energy Transfer Partners in 2018 to form Energy Transfer LP in a move that simplified its corporate structure – "Energy Transfer Equity now called Energy Transfer LP," *Energy Transfer Equity, L.P. And Energy Transfer Partners, L.P. Complete Merger, Simplify Structure*, Energy Transfer Press Release, October 19, 2018, https://ir.energytransfer.com/news-releases/news-release-details/energy-transfer-equity-lp-and-energy-transfer-partners-lp. Prior to the merger, Energy Transfer Partners had been a consolidated subsidiary of ETE, *Energy Transfer Equity 2012 Annual Report*, p.4, https://ir.energytransfer.com/static-files/6a687e75-d5fc-4a96-bc4d-b346e79ab250.

[16] *Energy Transfer Partners To Acquire Sunoco In $5.3 Billion Transaction*, Energy Transfer Partners Press Release, April 30, 2012, https://ir.energytransfer.com/news-releases/news-release-details/energy-transfer-partners-acquire-sunoco-53-billion-transaction.

[17] *Energy Transfer Equity 2012 Annual Report*, p.4, https://ir.energytransfer.com/static-files/6a687e75-d5fc-4a96-bc4d-b346e79ab250.

[18] *Id.* at 119 and 121. The 2012 Annual Report states that ETE as a limited partnership is managed by its General Partner. The report also states, "Our General Partner is majority owned by Kelcy Warren." Kelcy Warren is currently the CEO and Chairman of the Board of the General Partner of Energy Transfer LP.

[19] Sunoco purchased a controlling interest in West Texas Gulf pipeline in

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Transfer's separately listed pipelines, account for over 90% of hazardous liquid pipeline spills for Energy Transfer's family of pipelines since the 2012 acquisition.[20]

18. DAPL-ETCO has experienced 12 spills since the pipelines were operational in June of 2017. Over six thousand gallons (146 Bbls) of crude oil has been spilled with nearly $200,000 in property damage. One spill impacted a High Consequence Area (HCA) and another spill of five thousand gallons (119 Bbls) was categorized by PHMSA as significant.[21]

19. PHMSA pipeline safety regulations have developed the concept of an HCA, to identify specific locations where spills can have the most serious negative impact on critical resources such as drinking water sources, populated locations and "unusually sensitive" environmental areas. HCAs require additional regulatory programs such as Integrity Management Plans to prevent spills from impacting these highly sensitive areas. Lake Oahe has been determined to be an HCA due to its ecological characteristics. From my experience and review of the PHMSA incident data, this number and impact of spills for a pipeline only in operation for 3 years is highly unusual and very concerning.

20. The nine Energy Transfer pipelines tracked in my review from 2012 to present spilled hazardous liquid on 290 occasions or on average 2.9 spills per month. These spills were

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2002. https://www.bulktransporter.com/archive/sunoco-logistics-acquire-interest-west-texas-gulf-pipe-line. Sunoco bought the Mid-Valley pipeline in 2006. https://www.tulsaworld.com/archive/sunoco-closes-acquisition-of-mid-valley-pipeline/article_81444925-c157-5ae5-a95c-b7827f3933eb.html

[20] PHMSA provides pipeline safety source data in several formats. https://www.phmsa.dot.gov/data-and-statistics/pipeline/source-data. Operator hazardous liquid incident data and programmatic information can be found and searched on the Operator Information web page https://opsweb.phmsa.dot.gov/primis_pdm/pub_op_search.asp. Detailed hazardous liquid incident data spreadsheets derived from incident reports can be downloaded from the Annual Report Data web page https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. The most recent hazardous liquid annual file provides incident data from 2010 to present.

[21] PHMSA defines a significant spill as resulting in death or injury requiring inpatient hospitalization, $50,000 in total costs, non-HVL liquid such as crude oil of 50 barrels or more, releases resulting in fire or explosion or HVL releases of 5 barrels or more.

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not minor or lacking impact. 94 or 32% of those were significant incidents as defined by PHMSA. The spills resulted in over 2 million gallons (48,777 Bbls) of hazardous liquid released with over $90 million in property damage. Energy Transfer's separate operator ID pipelines alone spilled over 625,000 gallons (14,994 Bbls) of hazardous liquid with property damage of nearly $5 million.

21. Equally alarming is the record in HCAs. From 2012 to 2018[22] the Energy Transfer pipelines experienced 50 incidents defined as large spills by PHMSA.[23] Nearly 20% of all of the spills over this time period were large spills in high consequence areas like Lake Oahe.

22. Furthermore, Energy Transfer's pipelines required over 300 HCA "immediate condition repairs." These repairs are defined as serious enough to require immediate shutdown of the pipeline or a reduction in operating pressure to conduct the urgent repair and protect the highly sensitive areas.

23. Energy Transfer's spill and integrity management record since the year of its acquisition of Sunoco is extremely troubling. Their management leadership and corporate oversight has failed to improve the poor safety performance of these pipelines when compared to a longer time-frame prior to the Sunoco purchase.

24. Looking at the data from 2006 to present, the same nine pipeline operator IDs in my review experienced 490 spills or 2.9 per month. 148 or 30% of those incidents were categorized as significant. From 2004 to 2018 these pipelines had 107 large spills in HCAs and required over 900 HCA immediate condition repairs. The spill volume over 14 years totaled

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[22] PHMSA's integrity management performance data is available through 2018.

[23] To be classified as a large HCA spill by PHMSA the release must result in death or personal injury requiring hospitalization, property damage greater than $50,000, a release of more than 5 barrels, fire or explosion, or pollution of water.

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nearly 3 million gallons (71,172 Bbls) and resulted in $113 million in property damage.

25. It is important to note that the vast majority of property damage ($90 Million) occurred under Energy Transfer corporate leadership compared to the 14-year total of $113 million for the 9 operator IDs. The three pipelines operator IDs historically related to Sunoco – Mid-Valley, West Texas Gulf and Sunoco LP – account for over 90% of the PHMSA fines since the ETE acquisition in 2012.

26. Even more revealing of Energy Transfer's failure to make pipeline safety improvements during its corporate leadership tenure is its recent incident history. From the year of the construction of DAPL in 2016[24] to present, the nine Energy Transfer pipelines reviewed had 125 hazardous liquid spills or 2.4 per month. 43 or 34% of those spills were categorized by PHMSA as significant. Over 1 million gallons (25,597 Bbls) of hazardous liquid was spilled leading to $34,477,683 million in property damage. Energy Transfer pipelines experienced 21 HCA large spills and 116 HCA immediate repairs from just 2016 to 2018. This is not meaningful safety improvement.

27. Spills in the pipeline rights of way (ROW)[25] or releases of hazardous liquid that migrate off the operator's property occur in 31% of all Energy Transfer pipeline incidents. Energy Transfer has implied that since some spills have not migrated outside of the ROW, its spills have had minimal impact. To the contrary, Energy Transfer hazardous liquid spills have had very significant offsite impacts. Since 2012, 32% of the corporation's spills with offsite consequences have resulted in water system contamination including drinking, surface, ground

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[24] DAPL incident reports list the installation year the equipment involved in the incident – for all the DAPL incidents it was 2016. DAPL was put into operation in June of 2017.

[25] PHMSA defines rights of way as "the property, or easement, that pipeline operators secure to install and maintain transmission pipelines." https://primis.phmsa.dot.gov/comm/ROWBrief.htm?nocache=3133.

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and well water. The 71 incidents with offsite impacts have resulted in a total spill volume of 1,227,870 gallons (29,235 Bbls). These offsite hazardous liquid releases are in fact 60% of the total incident spill volume since 2012. Rather than a minimal impact, the majority of Energy Transfer's immense incident spill volume is impacting people, the public and private property, water systems and the environment away from the property controlled by the operator, resulting in serious impacts.

28. I compared the PHMSA record of the Energy Transfer family of pipelines to other major hazardous liquid pipeline corporations and their primary operator IDs from both 2012 and 2016 to present. Since 2012, Energy Transfer's family of pipelines had 291spills – the most of any other corporate family of pipelines. During that period, Energy Transfer had the most significant incidents and barrels spilled. Since 2016, Energy Transfer's 125 hazardous liquid spills was second worst (trailing only Enterprise with 231 spills). ET was second also in terms of property damage and barrels spilled. I examined hazardous liquid pipelines with the most number of spills since 2017 where the "item involved" in the spill was limited to newer installations[26] for pipeline operator IDs transporting primarily crude oil. Energy Transfer's family of pipelines experienced the 28 spills second only to Enterprise with 36. A single pipeline operator ID DAPL-ETCO was fourth with 12 spills. Looking at the most recent data, Energy Transfer had the second worst spill record overall and involving new installations. The DAPL-ETCO safety record was particularly concerning having the fourth most spills for a single pipeline operator ID for new installations compared to other pipeline families.

29. The Corps mischaracterizes the Tribe's position concerning more prevalent

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[26] New installations refer to new equipment, pipelines systems; and expansions, extensions, or replacements. The review focused on new installations since 2016, the year that DAPL's 12 spill incidents listed as the equipment involved in the spill as the "installation year."

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failures with newer pipelines such as DAPL. The Corps asserts that since DAPL has been in operation for nearly three years it is now no longer "new" and not subject to a generalized concern of spills and incidents. The Tribe, however, in its 2018 expert report submitted during the remand cited an analysis by the Pipeline Safety Trust that reviewed PHMSA data for the frequency of hazardous liquid incidents by decade.[27] That report noted, looking at incidents by decade installed since the 1920s, that "more dangerous still were the very newest pipelines – those installed since 2010."[28] The Trust had compared decades of performance, not "new" pipelines. The incidents since 2010 by pipeline mileage were more than double the previous decade of the 2000s and greater than pipelines built in the 1920s. More importantly, my review is not generalized – the DAPL-ETCO and Energy Transfer safety data and incident record underscores our corporate-specific concerns about the frequency and severity of their pipeline spills.

30. Equally concerning is Energy Transfer's history of regulatory violations and enforcement actions both in terms of cases initiated by PHMSA and penalties collected. Since ETE acquired Sunoco in 2012, Energy Transfer's family of pipelines have seen 59 PHMSA enforcement cases resulting in $3,411,800 in penalties collected and five Corrective Action Orders (CAOs).

31. CAOs are one of PHMSA most serious enforcement tools – one that is rarely employed.[29] CAOs require operators to take specific necessary actions to address conditions that

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[27] Standing Rock Sioux Tribe, *Impacts of an Oil Spill from the Dakota Access Pipeline on the Standing Rock Indian Reservation*, pp. 53-54 (2018).

[28] Pipeline Safety Trust, *Are Older Pipelines Really More Dangerous*, Pipeline Safety, Spring 2015, https://pstrust.org/wp-content/uploads/2013/03/Incidents-by-age-of-pipes-PST-spring2015-newsletter-excerpt.pdf , p.6.

[29] PHMSA has only issued 15 corrective action orders since 2016. https://primis.phmsa.dot.gov/comm/reports/enforce/CAO_opid_0.html#_TP_1_tab_1

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PHMSA finds to be hazardous to people, property or the environment.

32. In fact, most of the more serious enforcement actions have taken place more recently. From 2016 to present, PHMSA has initiated 37 enforcement cases and collected over $3.3 million in penalties. The $3.3 million in penalties collected over the most recent four-year period represents nearly all of the cumulative fines levied on the nine pipelines over the last 8-years indicating a deteriorating safety performance under Energy Transfer's corporate leadership.

33. Compared to other corporate families of pipelines and their primary operator IDs with the most spills since 2012, Energy Transfer had the most enforcement cases against them by PHMSA and the largest number of penalties collected. They had the most CAOs (5) compared to the next worst company (Colonial Pipeline) that had two. Applying these criteria since 2016, Energy Transfer had the most enforcement cases, most penalties collected and the largest number of CAOs. In that recent period, among the corporate pipeline families that had the most spills Energy Transfer had penalties collected ($3.3 million) that were over 6 times greater than Enterprise – the next most fined corporation.

34. A number of Energy Transfer's PHMSA enforcement actions include repeat citations with a history of failure to effectively report or investigate incidents; develop operations, maintenance and emergency response procedures; and implement integrity management and corrosion control plans. Energy Transfer has demonstrated that it tolerates systematic safety problems in its pipeline operations.

35. For example, in March, 2015, PHMSA issued a Corrective Action Order to ET's West Texas Gulf Pipeline Company as a result of a February crude oil spill. PHMSA discovered that a portion of the pipeline with 80% metal loss was "fixed" with a clamp, which the CAO

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rejected and required the section of pipeline be replaced. The original CAO was amended in September, 2015, as a result of multiple additional incidents that PHMSA described as causing "the expansion of PHMSA concerns regarding the safety of the West Texas Gulf System."[30] The events that led to the amended CAO include a prior failure to report a February 19, 2013 incident; additional incidents in April, 2015 of improper pipeline repairs; a second leak on June17, 2015 due to metal loss near the location of the original February spill; a June 19, 2015 "major release" of 138,600 gallons (3300 Bbls) of crude; two additional incidents on May 28, 2015 and June 23, 2015 on the Permian Express II managed by West Texas Gulf; and a November 10, 2015 spill that sent five workers to the hospital.

36. Most significantly, DAPL was ordered by PHMSA and later agreed in an October 3, 2016 Consent Agreement (attached as Exhibit 2) to create "a Safety Management System promoting a safety culture" based upon the elements of API RP 1173.[31] Those RP 1173 system elements listed included Management Commitment and Leadership, Risk Management, Incident Investigation, Safety Assurance and Continuous Improvement and Emergency Preparedness and Response.

37. As a result of the events related to the CAO, PHMSA pursued additional enforcement violations against West Texas Gulf. In a related November 2015 enforcement action for failure to report the February 19, 2013 spill incident that resulted in a fire and injuries to five workers, PHMSA fined West Texas Gulf $141,000.[32] The company was cited for failure

[30] Pipeline and Hazardous Materials Safety Administration Consent Agreement, CPF No. 4-2015-5005H, In the Matter of West Texas Gulf Company, October 2016, p. 1, https://primis.phmsa.dot.gov/comm/reports/enforce/documents/420155005H/420155005H_Consent%20Agreement_10032016.pdf.

[31] *Id.* at p.5.

[32] PHMSA Final Order, West Texas Gulf Pipeline Company, CPF No. 4-2015-5009, November 3, 2015, pp.2-3, https://primis.phmsa.dot.gov/comm/reports/enforce/documents/420155009/420155009_Final%20Order_11032015.p

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to provide timely notice of the incident or submit an incident report.

38. In a separate action, in a December 2019 Final Corrected Order to Energy Transfer LP CEO Kelsey Warren[33], PHMSA found numerous pipeline safety violations including several citations relating to flawed implementation of the requirements of 49 C.F.R 195.402, *Procedural Manual for Operations, Maintenance and Emergencies*. The citations stated that the company failed to follow its own incident investigation procedures, noted reoccurring similar incidents, and the lack of a root cause investigation report required by its own procedures. PHMSA collected a penalty of $1,019,200. A number of other recent Energy Transfer significant enforcement actions have addressed similar issues.[34] DAPL and its declarants ignore their own PHMSA violations and enforcement record and their recent history of large fines, CAOs, and repeat violations.

39. Energy Transfer's pipeline safety incidents have led to unprecedented regulatory actions related to the construction and operation of its pipelines, for many different violations on different pipelines throughout the United States. Pipeline safety performance deficiencies that

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[33] PHMSA Final Corrected Order, West Texas Gulf Pipeline Company, CPF No. 4-2016-5022, December 9, 2019, pp.3-9, https://primis.phmsa.dot.gov/comm/reports/enforce/documents/420165022/420165022_Corrected%20Final%20Order_12092019_text.pdf.

[34] PHMSA Corrective Action Order, Mid-Valley Pipeline, CPF No. 4-2014-5026H, arising upon a 4000 Bbls release on October 13, 2014 into Tete Bayou an HCA based upon environmental sensitivity and proximity to drinking water intakes. https://primis.phmsa.dot.gov/comm/reports/enforce/documents/420145026H/420145026H_Corrective%20Action%20Order_10172014.pdf. PHMSA found this was the second failure on the same pipeline - another spill of 364 Bbls occurred in a nature preserve seven months earlier that had led to its own corrective action order (CPF No. 3-2014-5002H). https://primis.phmsa.dot.gov/comm/reports/enforce/documents/320145002H/320145002H_Corrective%20Action%20Order_03252014.pdf. PHMSA in a Final Order dated June 15, 2018 found that Sunoco had failed to submit an incident report related to the release and ignition of crude oil in a Terminal that injured seven workers. Sunoco did not contest the violation. https://primis.phmsa.dot.gov/comm/reports/enforce/documents/420175011/420175011_Final%20Order_06152018.pdf.

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are reflected in a range of activities, locations, and phases of work can be evidence of broader systemic problems. That is the situation with Energy Transfer.

40. In 2017-2018, Sunoco was forced to suspend pipeline operations because of environmental contamination on four separate occasions across three states. Other examples include a 2018 explosion of the newly in-service Revolution Pipeline in Pennsylvania that destroyed a residential home resulted in a record $30 million fine.[35] In May 2020 it was revealed that the Pennsylvania Department of Environmental Protection (DEP) issued an additional 680 violations for stream pollution, erosion and pipeline route slip leading to slides and stability issues according to the DEP. It is reported that the Department of Justice is conducting a criminal investigation.[36] In June 2017, the Ohio EPA levied a $431,000 fine for 18 incidents of mud spills from drilling, and storm water pollution on the Rover Pipeline.[37]

41. Just the previous month, Rover had spilled over 2 million gallons of drilling mud in three incidents. The Ohio EPA Director stated "All told, our frustration is really high. "We don't think they're taking Ohio seriously…Normally when we have…a series of events like this, companies respond with a whole lot of contrition and whole lot of commitment. We haven't seen that. It's pretty shocking."

42. Energy Transfer's Mariner East pipeline construction in Pennsylvania has been plagued with regulatory violations, construction stoppage orders, sinkholes and water system

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[35] State Impact Pennsylvania, *The Revolution Pipeline Explosion Resulted in A Huge Fine for Energy Transfer. Now, DEP Says It's Found Hundreds of New Violations*, May 7, 2020, https://stateimpact.npr.org/pennsylvania/2020/05/07/the-revolution-pipeline-explosion-resulted-in-a-huge-fine-for-energy-transfer-now-dep-says-its-found-hundreds-of-new-violations/.

[36] *Id.* Pittsburg Post Gazette, *DOJ is Building a Criminal Case Around Energy Transfer's Rover Pipeline Explosion*, February 26, 2020, https://www.post-gazette.com/business/powersource/2020/02/26/Energy-Transfer-pipeline-explosion-Revolution-criminal-investigation-DOJ/stories/202002260046

[37] Marcellus Drilling News, *EPA Slaps Rover Pipe with 431K Fine for Spills, other Issues, May 10, 2017,* https://marcellusdrilling.com/2017/05/ohio-epa-slaps-rover-pipe-431k-fine-for-spills-other-issues/

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contamination. The Pennsylvania DEP fined Sunoco $2 million in January 2020 for a spill during the construction of its Mariner East 2 of three million gallons of drilling fluid.[38] Those releases occurred over several months in 2017 and led to 208,000 gallons of drilling fluid settling on the bottom of a Pennsylvania lake.

43. In another incident, Sunoco was levied a $200,000 fine and agreed to oversight by an independent expert as part of a settlement over a 2017 release of flammable gases on their Mariner East 1 pipeline.[39] The Public Utilities Commission cited the company's lack of corrosion management and inspections as the cause of the leak.

44. An effective integrity management program focuses not just on the lessons learned from these significant incidents that Energy Transfer has experienced, but on lesser mechanical integrity failures as well. It is universally accepted that major incidents are low frequency/high consequence events.[40] It is an axiom of incident investigation that accidental chemical releases have multiple system causes and typically have precursor events. This makes investigating and learning from more numerous smaller releases key to preventing major incidents. Often the difference between a large event and a small one is a matter of fortuitous circumstances; a release is observed immediately by company personnel or a member of the public or flammable vapor drifts away from sources of ignition. The dismissing of the

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[38] Farm and Dairy News, *Sunoco Fined Nearly $2M for Pennsylvania Pipeline Violations,* January 16, 2020, https://www.farmanddairy.com/news/sunoco-fined-nearly-2m-for-pennsylvania-pipeline-violations/595368.html.

[39] State Impact Pennsylvania, *Sunoco To Pay $200,000 Fine, Must Increase Oversight Following Investigation of Aging Mariner East 1 Pipeline*, March 2, 2020, https://stateimpact.npr.org/pennsylvania/2020/02/27/sunoco-to-pay-200000-fine-must-increase-oversight-following-investigation-of-aging-mariner-east-1-pipeline/.

[40] DAPL and its declarants inappropriately refer to "low risk, high consequence" in their analysis ignoring that high consequence is an element of the risk equation. When examining major accident potential, modern more rigorous risk assessment approaches place less emphasis on claims of low frequency and focus more effective preventative measures when the consequences of a spill are high. Note Lake Oahe is a high consequence area. Both the Deepwater Horizon explosion and spill and the BP Texas City refinery incident were preceded by assertions that an incident was very unlikely to occur.

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significance of smaller releases by DAPL and its experts is revealing of the lack of rigor of their approach and safety management systems to address mechanical integrity deficiencies and prevent hazardous liquid releases.

45. The dismissal by DAPL and its experts of the significance of smaller oil spills reveals a cavalier attitude toward safety management systems, in contravention of the standards established by API in RP 1173. It is this lackadaisical approach that puts the Standing Rock Sioux Tribe at significant risk from DAPL, and justifies shutdown of the pipeline pending preparation of an environmental impact statement by the Corps of Engineers.

46. The spill record and regulatory violations point to a failure of corporate leadership in addressing the serious history of hazardous liquid spills, lack of effective incident investigation and prevention systems, and a corporate safety culture that that has normalized spills. DAPL touts its "exceptional" spill record and cites data based upon spills-per-mile that is "about equal" to the industry average for just one year – 2019. My review of Energy Transfer's safety record and enforcement history tells a completely different story. Not all pipeline miles would result in the same environmental consequences – Energy Transfer's record since 2012 of serious spill impacts to water systems and HCAs like Lake Oahe undermine DAPL's claims. This is especially the case concerning recent spills and violations. It must be noted as well that the goal of API RP 1173 is not to drive incidents to a claimed industry average. Hazardous liquid spills are unacceptable. Energy Transfer has failed in effectively working toward the goal of API RP 1173 – zero incidents and meaningful continuous improvement.

47. Applying modern, more protective pipeline safety standards to reduce risk and prevent incidents is one of the most important elements for safe operation. As a result of lessons learned from recent major incidents, Congressional mandates, NTSB recommendations and

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Government Accountability Office (GAO) reports, standard-setting bodies have recently issued a number of more rigorous pipeline safety standards. API RP 1173 on *Pipeline Safety Management Systems* has been recognized as a key advance for the pipeline risk management and the prevention of incidents. PHMSA has supported the adoption of the API RP 1173 management system approach, concluding it will result in pipeline safety improvements.[41] It is applicable to pipeline design, construction, operations, maintenance and emergency planning.

48. There is no evidence that Energy Transfer has applied API RP 1173 to the Dakota Access Pipeline. It was not listed among standards adopted in the Corps' Environmental Assessment, the Corps' Remand Report or anywhere else in the Remand Administrative Record despite the fact that the Standing Rock Sioux Tribe's reports and correspondence asked numerous times for its application and documentation of its use. While DAPL now claims in recent filings after 3 years of DAPL operation to have adopted RP 1173, their longstanding lack of candor about the use of RP 1173 makes that assertion unconvincing. DAPL's failure to discuss API RP 1173 goals, specific elements, tools, or metrics required by the standard underscore that it is not being applied. Their lack of progress in reducing spills in their impact reinforces that conclusion.

49. Equally important for the evaluation of the safe operation and risk of DAPL are the use of effective operations, maintenance and emergency procedures. PHMSA requires a manual of such pipeline procedures to be developed prior to operation.[42] The manual must be

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[41] PHMSA, Safety Management Systems; API RP 1173; Energy Pipeline Management Summit; Slides 25 and 46, May 23, 2016; https://www.slideshare.net/MarcusEvansEnergy/emphasizing-the-importance-of-pipeline-safety-management-systemsbill-lowry-phmsa.

[42] 49 C.F.R. 195. 402(a), Procedural Manual for Operations, Maintenance and Emergencies.

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specific "for each pipeline system."[43] It is key that the manual be pipeline system specific as it must address such system specific procedure details such as operating and maintaining existing equipment, minimizing hazards unique to the pipeline system, and identifying pipeline facilities located in areas that would require an immediate response to protect people or the environment. These details are required by PHMSA as well.[44] The procedures should also include what system specific actions to take with safety critical equipment to mitigate a spill such as an Emergency Flow Restriction Device (EFRD) that fails to close and the specific location and how to close the EFRD manually if needed.[45] Energy Transfer, however, did not have a DAPL specific, PHMSA compliant set of operation, maintenance and emergency procedures prepared at the time the pipeline was put into service or during the Corps remand process. To the best of my knowledge, it still does not exist.

50. Energy Transfer acknowledged there was no DAPL specific operations and maintenance procedures.[46] Sunoco as the DAPL operator had used instead a generic set of maintenance procedures that contain no DAPL specific information: "prior to issuing the easement conditions for the Lake Oahe crossing, this Liquids Pipeline Operations and Maintenance Manual was not fully developed to include this new DAPL system."[47] The Sunoco manual only referenced the name DAPL-ETCO once in the manual in a list of Sunoco operated

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[43] *Id.*

[44] 49 C.F.R. 195. 402(c)

[45] Note that PHMSA has cited Energy Transfer LP in a case where 49 C.F.R. 195. 402 was violated where Sunoco failed in their operations, maintenance and emergencies manual to include procedures for a specific valve that failed in the incident. Sunoco argued in the hearing that a procedure should not be required for a specific valve. PHMSA disagreed and the citation was upheld determining a procedure was needed to safely operate, maintain and repair the specific valve. A citation of $251,800 was levied in the case.

[46] Email string between Army Corps' Brent Cossette and Energy Transfer's Tom Siguaw, *DAPL – Lake Oahe – Operations Manual ****Submittal to USCOE****,* April 10, 2018, RAR004499.

[47] *Id.* at RAR004499-4500.

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pipelines.[48] Energy Transfer stated that they planned an update at some unspecified time in the future to include the DAPL.[49] In fact, the attached *Sunoco Pipeline L.P. (SPLP) & Affiliates DOT 195 Maintenance Manual* contained no procedures related to operations or emergencies at all. This was not the first time the Corps had requested this manual. The production of the manual was specifically required by the Corps' Environmental Assessment (EA) and the Lake Oahe easement conditions.[50] Energy Transfer has been in breach of these requirements as evidenced by the record in this matter.

51. It is significant that flawed operations, maintenance and emergency procedures were the most cited Energy Transfer pipeline violations by PHMSA. An operations manual is not a paperwork exercise. The fact that Sunoco personnel have no DAPL-specific maintenance procedures and are completely lacking operations and emergency procedures – as required by regulation – places the continued operation of DAPL at high risk and is untenable.

52. Similarly, DAPL failed to produce a PHMSA-compliant Integrity Management Plan to the Corps also required by the EA and the easement conditions. As with the requisite operations procedures manual, Energy Transfer told the Corps they lacked a DAPL-specific plan and would produce one some unspecified time in the future.[51]

53. PHMSA requires Integrity Management Plans (IMPs) specifically for high consequence areas. IMPs are essential for preventing releases into sensitive areas like Lake

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[48] *Id.* at RAR004507.

[49] *Id.* at RAR004500.

[50] U.S. Army Corps of Engineers – Omaha District, Environmental Assessment: Dakota Access Pipeline Project Crossings of Flowage Easements and Federal Land, July 2016, p. 3-4.

[51] Email string between Army Corps' Brent Cossette and Energy Transfer's Tom Siguaw, *FW: (Non-DOD Source) DAPL – Lake Oahe – Risk Assessment (Pipeline Integrity Management Plan)****Submittal to COE*****, April 10, 2018, RAR004721-22.

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Oahe. The IMPs must be developed for "each segment of pipeline" and include a requirement of an initial baseline assessment of that specific pipeline.[52] The Sunoco Logistics *Pipeline Integrity Management Plan* (2017) like the procedures manual is not DAPL-specific and only makes reference to DAPL in the list of Sunoco operated pipelines and location of their offices.[53] PHMSA regulations require that a written IMP be produced for a pipeline installed after 2001 within one year of operation. The Energy Transfer letter dated in April was just prior to the one-year date of operation. However, no DAPL-specific IMP was provided to the Corps subsequent to this communication that is evident in the record. The available evidence is that none was ever drafted or provided to the Corps as part of this litigation.

54. The 2019 edition of API RP 1160 *Managing System Integrity for Hazardous Liquid Pipelines* has incorporated many of the management system elements and focus on data and performance metrics from API RP 1173 to promote continuous integrity management improvement. There is no evidence in the EA's list of standards or remand record that DAPL has adopted API RP 1160 (either the 2013 or 2019 editions). Integrity Management Plans and the prevention of spills in HCAs is a critical component of safe operation and protection of sensitive areas like Lake Oahe. The fact that no PHMSA-compliant IMP is evidenced in the record reflects seriously flawed corporate management system performance and helps explain the number of DAPL-ETCO spills and overall Energy Transfer safety performance.

55. Preventing incidents is key to protecting people and the environment, but if a spill occurs effective leak detection is vital to mitigating the impact of a release of hazardous liquid.

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[52] 49 C.F.R. 195.452(a)(2) and (3) Pipeline Integrity Management in High Consequence Areas.

[53] Email string between Army Corps' Brent Cossette and Energy Transfer's Tom Siguaw, *FW: (Non-DOD Source) DAPL – Lake Oahe – Risk Assessment (Pipeline Integrity Management Plan)****Submittal to COE*****, April 10, 2018, RAR004830 and 4832.

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Energy Transfer has asserted that its computational pipeline monitoring (CPM) leak detection software is state-of-the-art and will detect all spills at or below 1%. However, a comprehensive PHMSA study looking at incident data found that CPM only had a successful detection rate of 20% for hazardous liquid spills.[54]

56. In my review of PHMSA data I examined Energy Transfer's effectiveness of using CPM to detect leaks. I used similar criteria as PHMSA in examining the data limiting the review to spills in the rights-of-way (ROW) where CPM was functional. PHMSA requires tracking of the "accident identifier" in the incident reports submittals such as notification from the public, CPM and SCADA systems or local operating personnel. Looking at the data from 2012, CPM was functional in only 25 of the 92 spills that also met the ROW criteria. Of those 25 spills, only 5 or 20% were detected by CPM or SCADA systems, similar to the identified serious weaknesses in operator performance in the PHMSA leak detection study. Random notification from members of the public were twice as likely to detect Energy Transfer spills than CPM or SCADA. Ground patrols – also touted by Energy Transfer as an effective safeguard – detected zero spills.

57. The American Petroleum Institute developed a standard to assist operators to assess and improve leak detection performance, API RP 1175, *Pipeline Leak Detection Management* (2015). RP 1175 explains that the standard has been promulgated in response to mandates and recommendations from Congress and the NTSB to improve identified weaknesses in pipeline leak detection.[55] The recently adopted API RP 1175 includes guidance on the selection of leak detection systems and establishing performance criteria and the use of metrics

[54] Pipeline and Hazardous Materials Safety Administration, Final Report 12-173, Leak Detection Study, at 2-11

[55] API RP 1175, Pipeline Leak Detection Program Management, p. 4 (2015).

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for system improvement. However, there is no evidence in the EA that DAPL has adopted RP 1175 or used performance metrics to improve its own troubled leak detection record. This is another example of Energy Transfer failing to adopt a more modern protective safety standard that was developed to improve identified deficiencies in industry performance.

58. Another standard, API RP 1130 on *Computational Pipeline Monitoring for Liquids* (2007), has been incorporated by reference into the PHMSA regulatory scheme. RP 1130 provides for testing of leak detection systems through actual or simulated withdrawal of the pipeline hazardous liquid. There is no evidence in the remand record of any actual CPM performance testing or results. Energy Transfer's actual historic CPM performance indicates these standards are not being adopted or are applied ineffectively.

59. Energy Transfer's largest recent incident is illustrative of their actual troubled CPM performance. The newly in-service 2016 Permian Express II spilled 361,000 gallons (8600 Bbls) from a pinhole leak that led to $4 million in property damage. According to ET's incident report operators initial observed "line imbalance indications" which were stated not to exceed "established normal operating tolerances."[56] The pipeline was not shut down for 12 days until the leak was eventually discovered. DAPL and its experts imply CPM was not involved in the incident, but the incident reports states that CPM was operational but not "functional." That can indicate a variety of operational and maintenance deficiencies including a lack of effective initial performance testing, as required by API RP 1130. DAPL states the leak was detected by the SCADA system but fails to explain why the leak was not shut down immediately, as the company purports to be its practice.

[56] PHMSA Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data, Hazardous Liquid Accident Data – January 2010 to Present, Incident Report Number 2016035. The description of the incident comes from the report data and narrative.

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60. Leak detection systems do not typically automatically initiate pipeline shutdown and isolation. Shut-downs typically require human and organizational decision-making. The likely answer is that a discovered leak that is allowed to persist for 12 days is very likely being hindered by ineffective control center human and organizational factors. API RP 1130 recognizes that leak detection requires evaluation and decision-making by a pipeline controller when detection systems indicate a possible release. Those organizational and human factors issues addressed in RP 1130 were not effectively managed by Energy Transfer in the Permian Express II incident. The attempt to minimize the significance of a 361,000-gallon crude spill also reflects the lack of prioritization by Energy Transfer to identify system weaknesses and improve performance.

61. The determination of worst case discharge (WCD) is also directly related to the risk of DAPL's continued operation. The greater the WCD, the greater the potential consequence and risk. The WCD impacts risk assessment, potential harm to people and the environment, and emergency preparedness.

62. DAPL and its experts' primary disagreement is with the minimum legal requirements of PHMSA and its WCD formula, which they argue is unrealistic and overly protective. Yet PHMSA's definition and calculation formula reflects what is required for determination of worst case consequences, not the likely case as imagined by DAPL. PHMSA also requires that the worst case definition be applied to each element of the calculation. That is a prudent approach, because major accidents typically occur when there are multiple system failures.

63. DAPL has failed to rebut the fact that the Lake Oahe WCD calculation is grossly understated, and leaves out key components of the required WCD formula. DAPL would like

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only to look at the best case of partial equipment shutdown. The DAPL calculation only uses the 9-minutes it takes to shut down the pump station. However, the PHMSA formula requires consideration of detection time, valve closure, and the effects of adverse weather conditions which was not incorporated into the DAPL calculation, even though legally required. DAPL and its declarants provide misleading information that their WCD calculation was based upon 12.9 minutes and talk about the 3.9 minutes it takes to shut the EFRDs, however that additional time was not included in their calculations. The only time period used by DAPL in WCD volume calculations was 9 minutes for the shutdown of a pump station – "The Total Volume of Oil Released = The volume of oil that leaves the pipeline under pressure before the pumps are shut down + the volume of oil remaining in the pipeline between the next nearest valves." No detection time was included in the 9-minutes – "Given: the pump stations are designed to shutdown in 9-minutes."[57] Even though lacking PHMSA required elements, the Corps makes clear in their final Remand Report that this calculation is the basis for the DAPL WCD.[58]

64. DAPL and its declarants inaccurately state that the Lake Oahe WCD calculation has been reviewed by the regulator. PHMSA did review and approve the DAPL Facility Response Plan and the WCD calculation for a North Dakota storage tank and a segment of pipeline in South Dakota. The South Dakota pipeline WCD unlike Lake Oahe did use a 12.9 minute shutdown time in the calculation.[59] However, the Lake Oahe WCD was shown in the

[57] Dakota Access Pipeline Project, North Dakota, Lake Oahe Crossing, Spill Model Discussion Document Number DAPL-WGM-GN000-PPL-STY-0019, Wood Group Mustang, May 2016, RAR014985.

[58] Analysis of the Issues Remanded by the US District Court for the District of Columbia Related to the Dakota Access Pipeline Crossing at Lake Oahe; Department of Army, Corps of Engineers; August, 2018; p.19.

[59] Facility Response Plan (FRP), Dakota Access Pipeline North Response Zone, February 2019, p.51. The 12.9 minutes is still a best case of equipment operation and leaves out key components of the WCD such as detection time and the impacts of adverse weather conditions.

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FRP only as the total volume and lacks any methodology or calculations.[60] This information could not have been reviewed by PHMSA as it was not provided even though the methodology and calculations were required by regulation.[61] The Lake Oahe WCD volume lacking calculations gave the misleading appearance of using the same methodology as the South Dakota pipeline WCD where the calculations were provided. Any claim that PHMSA reviewed the FRP and approved the methodology and calculation of the Lake Oahe WCD is inaccurate.

65. Moreover, the impacts of adverse weather conditions are more than subfreezing temperatures, as DAPL argues. The Lake Oahe EFRDs do not have backup power to close the valves in the advent of a power failure, not an uncommon event in rural North Dakota. The Corps' Lake Oahe Easement Conditions require EFRDs to be capable of closure at all times. If power is unavailable and if manual closure is required it could take up to a number of hours for personnel to reach the valves in harsh North Dakota winter conditions. If a pipeline leak in Lake Oahe occurs in under ice conditions and CPM and SCADA are not effective, it could take days to discover. These credible WCD scenarios need to be considered using the required PHMSA formula. Also, a pinhole leak under the 1% detection limit (up to 6000 bpd) could result in a much larger WCD either under ice or given the fact that overflights can be delayed as long as three weeks as described in the EA. The proposed near doubling of DAPL's capacity would significantly increase a true DAPL WCD and amplify the DAPL spill risk, potential impact to the Tribe and the sensitive Lake Oahe environment, and lack of preparedness of responders.[62]

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[60] *Id.*

[61] 49 C.F.R 194.105, Worst Case Discharge, (a) Each operator shall determine the worst case discharge for each of its response zones and provide the methodology, including calculations, used to arrive at the volume.

[62] DAPL's claims to preparation based upon a larger WCD storage tank spill are inopposite. A emergency response action to a storage tank spill on land with secondary containment would be significantly different than a spill in Lake Oahe that is larger than the grossly understated DAPL volume in terms of equipment, hazards, training and difficulty.

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66. Energy Transfer's DAPL has breached the Corp's Lake Oahe easement conditions, seriously impacting safe operations. As noted, the Corps' Special Conditions in the Lake Oahe Easement require the "Documentation Conditions" of the production and submittal of the Operations and Maintenance Manual and the Risk Assessment (Integrity Management Plan).[63] DAPL-specific plans as required by PHMSA are not evident in the remand record. The Easement under "Pipeline Safety Conditions" requires that the Lake Oahe EFRDs be fully available for closure – "Mainline valves must be capable of closure at all times."[64] We know from a review of the Lake Oahe EFRD technical drawings that there is no backup power to remotely close the valve actuators in the event of a power failure – a well-known important risk assessment scenario. While there is backup power to the communication system for Lake Oahe EFRDs, there is no backup electrical power to remotely close the valves – they are not capable of closure "at all times."

67. These are serious breaches of the Corps' Lake Oahe DAPL easement conditions that impact the safe operation of the pipeline. Safety critical equipment that may not be capable of closure, lack of essential procedures that are necessary to operate and maintain the pipeline, lack of plans that prevent mechanical integrity failures all are necessary for the prevention of spills into the Lake Oahe high consequence area.

68. As noted, I served as an expert witness on behalf of the Tribe to the ND Public Service Commission when it was considering DAPL's application to double the capacity of the pipeline from 570,000 barrel/day capacity to 1.1 million. In my view, and in the testimony I presented to the Commission, doubling of the capacity of the pipeline would significantly

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[63] Department of the Army Easement for Fuel Carrying Pipeline Right-of-Way Located on Lake Oahe Project Morton and Emmons Counties, North Dakota; February 8, 2017, USACE_ESMT000037.

[64] *Id.* at USACE_ESMT000039.

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increase the risks of an incident, and make the potential consequences more severe should one occur. More saliently, the proposal to double capacity renders a significant part of the NEPA analysis, and work done on remand, pointless. For example, the Corps would need to identify a new WCD based on the increased maximum flow rate. That corrected WCD would then inform the spill model, downstream receptor analysis, Facility Response Plan, Geographic Response Plan and DAPL risk assessment—all of which rely on the existing (already flawed) WCD. DAPL has falsely asserted that the WCD would not change if the capacity was doubled. However, in the PHMSA regulation the WCD would significantly increase – it is directly correlated to the "maximum flow rate expressed in barrels per hour."[65] The claim made by DAPL that they have already done all of the work required for an EIS is wrong in any event, but is completely unsupportable in light of the expansion proposal.

69. The safety record and spill history of the Energy Transfer family of pipelines, including DAPL, is very troubling. Actual performance represents the real risk of continued operation. One of API RP 1173's basic principles is the necessity of up-to-date standards to reduce risk: "Pipeline operators conform to applicable industry codes and consensus standards with the goal of reducing risk, preventing releases, and minimizing the occurrence of abnormal operations."[66] API RP 1173 also identifies that "meeting and exceeding minimum standards" is

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[65] 49 CFR 194.105(b)(1), Worst Case Discharge. PHMSA uses the formula $WCD\ (bbls)=[(RT+ST)\times FR]+DDV$ where RT=response time, ST=shutdown time and DDV=drain down volume. While the "largest line drainage volume after shutdown" would remain the same, the "maximum flow rate expressed in barrels per hour" is multiplied by the sum of response time plus shutdown time. Increasing the maximum flow rate to 1.1 million bpd would seriously impact the WCD and greatly increase the safety risk of DAPL. For purposes of illustration, with a 1.1 million bpd maximum flow rate (45,833 barrels per hour), a one hour time to respond and shutdown the pipeline and a hypothetical drain down volume of 10,000 Bbls, the WCD would be 55,833 Bbls. With the same assumptions, at a 600,000 bpd maximum flow rate (25,000 barrels per hour) the WCD would be 35,000 Bbls.

[66] API RP 1173 Pipeline Safety Management Systems (2015), p.vii.

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evidence of a positive safety culture.[67] Despite their claim in the EA to do just that,[68] the failure of Energy Transfer to effectively apply more protective standards to DAPL such as API RP 1173, 1160, 1175, 1130 and other recent standards indicates an unwillingness to continuously improve.[69] This also helps explain Energy Transfer's ongoing poor spill performance and record of regulatory violations and enforcement.

70. Many of Energy Transfer's regulatory violations relate to their observed spill prevention deficiencies, and the failure to report incidents, conduct effective incident investigations and effectively address corrosion control and integrity management. It is particularly concerning that the corporation and top management have not implemented more rigorous safety practices that were promulgated by the leading oil industry trade association to address the need for companies to improve their safety performance – companies such as Energy Transfer. This approach is antithetical to a key provision of API RP 1173, the importance of corporate oversight and leadership commitment to drive toward zero incidents and continuous improvement.

71. In sum, it is my expert opinion that continued operation of DAPL, while an EIS is being prepared, presents untenable risks to the Standing Rock Sioux Tribe and others who rely on Lake Oahe. It is respectfully recommended that this court shut down the Dakota Access Pipeline in light of DAPL's violation of its easement conditions, insufficient management plans, absence of backup power, inadequate response capabilities, and lax safety culture.

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[67] *Id.* at xi.

[68] U.S. Army Corps of Engineers – Omaha District, Environmental Assessment: Dakota Access Pipeline Project Crossings of Flowage Easements and Federal Land, p. 48, 88 (July 2016).

[69] These standards are not referenced in the Environmental Assessment as applicable to DAPL where the EA provided the list of standards applicable to the project, Id. at 4 and 39. Note API RP 1130 and 1160 appear in the text but not in the context of their stated utilization in the construction, operation and maintenance of the Dakota Access pipeline.

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I declare that the foregoing is true and correct under penalty of perjury.

Executed on this 20 day of May, 2020.

Donald D. Holmstrom

Donald Holmstrom

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EXHIBIT 1

TO DECLARATION OF DONALD HOLMSTROM

DONALD S. HOLMSTROM

6200 Gale Drive Boulder, CO 80303
Ph. 303-990-1487(m)
Donho2@comcast.net

Key Qualifications

Over 35 years of experience conducting chemical incident investigations for the oil industry and US government. Seventeen years of experience managing and leading chemical incident investigation and recommendations activities at the US Chemical Safety Board (CSB), a non-regulatory, scientific agency modeled after the National Transportation Safety Board (NTSB). Nineteen years of industry experience in oil industry operations, process safety systems and extensive involvement with incident investigation in process plants, pipelines and exploration and production. Recognized leadership in process safety problem solving. Broad knowledge of safety practices, standards and regulations. Demonstrated ability as a writer and public speaker.

Work Experience

US Chemical Safety and Hazard Investigation Board (1999-2016, retired 11-1-16)

Director, Western Regional Office (WRO) (2008-2016)

- Managed and/or led over 70 major accident investigations - many of the largest and most significant chemical incident investigations in recent US history including the 2005 BP Texas City explosion, the 2010 Tesoro Anacortes oil refinery fire, the 2010 Deepwater Horizon offshore fire and explosion, the 2012 Chevron Richmond, CA oil refinery fire and the field investigation of the 2013 West, Texas ammonium nitrate explosion.
- Developed and successfully advocated the implementation of important technical, safety standard and regulatory recommendations that were addressed to parties such as the National Fire Protection Association (NFPA), the American Petroleum Institute (API), National Association of Corrosion Engineers (NACE), the Occupational Safety and Health Administration (OSHA) and the Environmental Protection Agency (EPA).
- Responsibilities included managing multi-disciplinary teams of chemical and mechanical engineers, chemists, human factors specialists, and lawyers – approximately two thirds of the agency investigators reported to the WRO.

Total Petroleum Inc./Ultramar Diamond Shamrock/Asamera Oil (1981-1999)

Operations and Process Safety (1981-1999)

- Participated in and led numerous chemical accident investigations. Implemented the first root cause analysis and process hazard analysis activities at Total Petroleum Inc. in response to serious process safety issues. These activities led to establishing new procedures for incident investigation, the elimination of unsafe refinery equipment, process winterization, decommissioning process equipment, establishment of more rigorous mechanical integrity protocols, asbestos handling protocols for insulation removal, and safe lighting of fired heaters.

Additional Experience

- Numerous technical certifications and/or training related to fire and explosion investigation, hazardous materials, mechanical integrity, root cause determination, process safety systems, human factors analysis, chemical testing, and emergency response.
- Speaker on CSB investigation reports and recommendations to such organizations as American Petroleum Institute (API), the American Industrial Hygienist Association (AIHA), the Center for Chemical Process Safety (CCPS), the United Steelworkers (USW), the Department of Energy (DOE), the Pipeline and Hazardous Materials Safety Administration (PHMSA), the American Chemistry Council (ACC), the International Association of Drilling Contractors (IADC), the Texas Chemical Council, Exxon Mobil, Chevron, Covestro, Chlorine Institute, and the Society of Petroleum Engineers (SPE).
- Author or co-author of numerous articles on incident investigation and process safety in publications such as Chemical Engineering Progress, Loss Prevention Bulletin, Process Safety Progress, Journal of Hazardous Materials and the NFPA Journal.
- Colorado Governor's Panel of Health Advisors, 1993-94.
- Served on the 2014 Technical Panel for the project "Separation Distances in NFPA Codes and Standards" undertaken by The Fire Protection Research Foundation, an affiliate of NFPA.
- Presented the CSB's final two Macondo incident investigation reports on the day of release at the SPE International Conference on Health, Safety, Security Environment and Social Responsibility, "Macondo: Lessons Still to be Learned," Stavanger, Norway April 2016.
- Served as a member of the 2019 National Academy of Science, Engineering and Medicine (NASEM) Gulf Research Program's Safer Offshore Energy Systems Grants Review.

Education

Stanford University, Bachelor of Arts (Human Biology and English), 1974

University of Colorado School of Law, Juris Doctor, 1978

Publications

“The Hazards of On-line Maintenance: A Case Study of a Multiple Fatality Incident at the Tosco Avon Refinery in Martinez,” California; D.S. Holmstrom; International Symposium Proceedings, Mary Kay O’Conner Process Safety Center, Texas A&M University, October 2000.

“A Multiple Fatality Incident at the Tosco Avon Refinery, Martinez, California; Donald Holmstrom, Stephen Selk, Stephen Wallace, and Isadore Rosenthal;” Loss Prevention Bulletin, Issue 167, Institution of Chemical Engineers (IChemE), October 2002.

“Chemical Hazards Management: A CSB Perspective,” Don Holmstrom, Joint EFCOG/Department of Energy (DOE) Chemical Management 2002 Workshop Presentation/Paper, November 2002.

“Improving Reactive Hazard Management, the Implementation of Recommendations,” John F. Murphy and Don Holmstrom, 18th Annual Center for Chemical Process Safety (CCPS) Paper, Managing Chemical Reactivity Hazards & High Energy Release Events, September 2003.

“Understanding Reactive Chemical Incidents,” John Murphy and Don Holmstrom, Chemical Engineering Progress (CEP), American Institute of Chemical Engineers, March 2004.

“CSB Investigation of the Explosions and Fire at the BP Texas City Refinery on March 23, 2005,” Don Holmstrom, Francisco Altamirano, Johnnie Banks, Giby Joseph, Mark Kaszniak, Cheryle MacKenzie, Reepa Shroff, Hillary Cohen and Stephen Wallace, Process Safety Progress, American Institute of Chemical Engineers, Volume 25, Issue 4, September 2006.

“Buildup to Disaster,” Mark Kaszniak, Don Holmstrom, and Cheryl MacKenzie; National Fire Protection Association (NFPA) Journal, July/August 2007.

“Human Factors Analysis of the BP Texas City Refinery Explosion,” Cheryl MacKenzie, Donald Holmstrom, and Mark Kaszniak; Proceedings of the Human Factors and Ergonomics Society Annual Meeting, Vol. 51, Issue 20, October 2007.

“Investigating Beyond the Human Machinery: A Closer Look at Accident Causation in High Hazard Industries, Cheryl MacKenzie and Don Holmstrom, Process Safety Progress, American Institute of Chemical Engineers, Volume 28, Issue 1, December 2008.”

“Trailer Siting Issues: BP Texas City,” Mark Kaszniak and Donald Holmstrom, Journal of Hazardous Materials, Elsevier, Vol. 159, Issue 1, November 2009.

“Static Electric Discharge during Solvent Handling and Storage, Randy McClure, Donald Holmstrom, Laurence Britton and Mark Kaszniak; American Society of Safety Engineers (ASSE), 48th Annual ASSE Professional Development Conference Paper, July 2009.”

“Valero-McKee Refinery Propane Release and Fire; Donald Holmstrom, Johnnie Banks, James Lay, Cheryl MacKenzie, and Vidisha Parasram;” Process Safety Progress, American Institute of Chemical Engineers, Volume 29, Issue 4, November 2010.

“Inadequacy of the Contractor Selection Process and its Impact on Worker Health and Safety: The US Chemical Safety Board Xcel Cabin Creek Hydroelectric Plant Investigation;” Don Holmstrom, Cheryl MacKenzie, Mark Kaszniak, Randy McClure, and Vidisha Parasram; 138th American Public Health Association (APHA) Meeting and Exposition Conference Paper, November 2010.

“The Human Factors of Process Safety and Worker Empowerment in the Offshore Industry Workshop Presentation,” The CSB Macondo Report: Barriers to Worker Participation, National Academies Gulf Research Program, January 2018; presentation summarized in “The Human Factors of Process Safety and Worker Empowerment in the Offshore Industry, Proceeding of a Workshop,” Steve Olson and Heather Kreidler, Rapporteurs, the National Academies Press, 2018.

“California’s 2017 Process Safety Regulations for Oil Refineries - the Future of U.S. PSM Regulations?” Mike Wilson, Don Holmstrom and Bill Hoyle; 2018 Global Conference on Process Safety Paper, April 2018.

“Protecting Workers from Chemical Catastrophes: California’s 2017 Process Safety Management Regulations for Petroleum Refineries;” Mike Wilson, Don Holmstrom and Bill Hoyle; requested and submitted to the Office of the High Commissioner for Human Rights, United Nations, UN Special Rapporteur regarding Human Rights and Worker Exposures to Toxic Substances, 2018.

Interests

River running, hunting and fishing in the Rocky Mountains

EXHIBIT 2

TO DECLARATION OF DONALD HOLMSTROM

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
West Texas Gulf Pipe Line Company,	)	**CPF No. 4-2015-5005H**
Respondent.	)	

CONSENT AGREEMENT

On March 12, 2015, under the authority of 49 U.S.C. § 60112, the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration (PHMSA), issued a Corrective Action Order (Original CAO) to West Texas Gulf Pipe Line Company (West Texas Gulf or Respondent), owned and operated by Sunoco Pipeline L.P. (SPLP), to take the necessary corrective actions to protect the public, property, and the environment from potential hazards associated with Respondent's West Texas Gulf Pipeline. PHMSA issued the Original CAO in response to a failure that occurred on February 25, 2015, on the West Texas Gulf Pipeline System #1, Unit 8514, at mile post (MP) 257 on the Blum-to-Wortham Segment, which resulted in the release of approximately 30 barrels of crude oil (Failure).

Since that time, there have been additional accidents on the West Texas Gulf Pipeline that have caused the expansion of PHMSA's concerns regarding the safety of the West Texas Gulf System. The following events have occurred:

- On April 8, 2015, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty and Compliance Order 4-2015-5009 (NOPV1) to Respondent for failure to report a serious accident that occurred on February 19, 2013, at its Wortham, Texas Facility (2013 Failure). Respondent has complied with the terms of the proposed Compliance Order and paid the proposed penalty, so PHMSA issued a Final Order and closed the case on November 3, 2015.

- On April 27, 2015, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty 4-2015-5012 (NOPV2) to Respondent for certain violations arising out of the Failure, alleging improper pipeline repair methods and the failure to correct a metal-loss condition that was known by Respondent to exist prior to the Failure. Respondent paid a portion of the proposed penalty in that case and is awaiting the issuance of a Final Order.

- On June 7, 2015, West Texas Gulf experienced a second leak on the Affected Segment involving external metal loss due to corrosion was reported to PHMSA by the Respondent at a location approximately seven miles downstream from the original leak and nine and one-half miles upstream of the Wortham, Texas Facility for which the Original CAO was issued.

- On June 19, 2015, a major release of crude oil occurred at Respondent's Wortham Facility, where an estimated 3,300 barrels of crude oil leaked from a failed flanged connection on piping that was installed in 2013 and associated with the construction/modification project in which the February 19, 2013 accident occurred.

- On May 28, 2015 and June 23, 2015, two reportable accidents occurred at the SPLP Corsicana facility as part of the Permian Express II construction project. This project was managed by the same West Texas Gulf department responsible for projects upon which the West Texas Gulf February 19, 2013 accident and the June 19, 2015 accidents occurred.

- On November 10, 2015, a failure of a relief valve and release of crude oil occurred while piping associated with the June 19, 2015 release was being replaced. Five people were transported to the hospital for treatment of crude oil exposure to the face and eyes as well as bruises and contusions after a relief valve failed when it was improperly disconnected while under pressure. The accident was a result of improper isolation and failure to follow instructions for safely de-energizing the valve before its removal.

- Taken together, the accidents described above raised serious concerns to PHMSA about the overall safety of the West Texas Gulf Pipeline System, the processes by which West Texas Gulf makes decisions about safety, how different parts of the company discuss and learn from past mistakes, and whether there are sufficient measures in place for the company to have an effective safety culture.

- On September 4, 2015, PHMSA issued an Amendment to the Original CAO (Amended CAO), with preliminary findings describing the events that had occurred since the Original CAO was issued in February 2015, and ordering West Texas Gulf to prepare a comprehensive written plan to improve the safety performance of the Affected Segment, to hire an independent third party to review and oversee implementation of the plan, and other corrective actions.
.
- West Texas Gulf has filed the required monthly reports regarding the actions taken to address the issues in the CAO. The most recent report, dated April 15, 2016, indicates the pipeline has returned to service and is limited to the 80% operating pressure based on approvals provided by PHMSA.

The West Texas Gulf Pipe Line System is approximately 580 miles in length and transports crude oil from Colorado City, Texas, to terminals in Longview and Nederland, Texas.

Respondent requested a hearing, but PHMSA and Respondent agreed that settlement of this proceeding will avoid further administrative proceedings or litigation of this Notice and that entry into this Consent Agreement is the most appropriate means of resolving issues raised in the Amended CAO and in the public interest. Therefore, pursuant to 49 C.F.R. Part 190, without adjudication of any issue of fact or law, and upon consent and agreement of Respondent and the PHMSA (the Parties), the Parties agree as follows:

I. <u>General Provisions</u>

1. Respondent acknowledges that its pipeline system is subject to the jurisdiction of the Federal pipeline safety laws, 49 U.S.C. § 60101, et seq., and the regulations and administrative orders issued thereunder. For purposes of this Consent Agreement, Respondent acknowledges that it received proper notice of PHMSA's action in this proceeding and that the Amended CAO states claims upon which relief may be granted pursuant to 49 U.S.C. 60101, et seq., and the regulations and orders issued thereunder.

2. Respondent agrees to take the actions specified in Section II of this Agreement (Corrective Measures) and to abide by the terms of this Consent Agreement. These actions, including any work plans and schedules, shall automatically be incorporated into this Consent Agreement. This Consent Agreement does not constitute a finding of violation of any Federal law or regulation and may not be used in any civil or administrative proceeding of any kind as evidence or proof of any fact, fault or liability, or as evidence of the violation of any law, rule, regulation or requirement, except in a proceeding to enforce the provisions of this Consent Agreement.

3. After Respondent returns this signed Agreement, the PHMSA's representative will present it to the Associate Administrator for Pipeline Safety recommending that the Associate Administrator adopt the terms of this Agreement and Order. The terms of this Agreement and Order constitute an offer of settlement until accepted by the Associate Administrator.

4. Respondent consents to the issuance of a Consent Agreement and Order, and hereby waives any further procedural requirements with respect to its issuance. Respondent waives all rights to contest the adequacy of notice, or the validity of the Consent Agreement and Order, including all rights to administrative or judicial hearings or appeals. Upon issuance of a Consent Agreement and Order for this matter, Respondent's Request for Hearing will be deemed withdrawn. The Original CAO will continue in full force and effect according to its terms, and the Amended CAO will be deemed withdrawn upon issuance of a Consent Agreement and Order.

5. This Consent Agreement and Order shall apply to and be binding upon the PHMSA, and upon Respondent, its officers, directors, and employees, and its successors, assigns, or other entities or persons otherwise bound by law. Respondent agrees to provide a copy of this Consent Agreement and Order and any incorporated work plans and schedules to all of Respondent's officers, employees, and agents whose duties might reasonably include compliance with this Consent Agreement and Order.

6. For all transfers of ownership or operating responsibility of Respondent's pipeline, Respondent shall provide a copy of this Consent Agreement and Order to the prospective transferee at least 30 days prior to such transfer and simultaneously provide written

notice of the prospective transfer to the PHMSA Region Director (Director) who issued the Notice.

7. This Consent Agreement and Order constitutes the final, complete and exclusive agreement and understanding between the Parties with respect to the settlement embodied in this Consent Agreement. The Parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Agreement and Order, except that the terms of this Consent Agreement and Order may be construed by reference to the original Corrective Action Order.

8. Nothing in this Consent Agreement and Order affects or relieves Respondent of its responsibility to comply with all applicable requirements of the Federal pipeline safety laws, 49 U.S.C. § 60101, *et seq.*, and the regulations and orders issued thereunder. Nothing in this Consent Agreement and Order alters the PHMSA's right of access, entry, inspection, and information gathering or the PHMSA's authority to bring enforcement actions against Respondent pursuant to the Federal pipeline safety laws, the regulations and orders issued thereunder, or any other provision of Federal or State law.

9. This Consent Agreement and Order does not waive or modify any Federal, State, or local laws or regulations that are applicable to Respondent's pipeline systems. This Consent Agreement and Order is not a permit, or a modification of any permit, under any Federal, State, or local laws or regulations. Respondent remains responsible for achieving and maintaining compliance with all applicable Federal, State, and local laws, regulations and permits.

10. This Consent Agreement and Order does not create rights in, or grant any cause of action to, any third party not party to this Consent Agreement and Order. The U.S. Department of Transportation is not liable for any injuries or damages to persons or property arising from acts or omissions of Respondent or its officers, employees, or agents carrying out the work required by this Consent Agreement and Order. Respondent agrees to hold harmless the U.S. Department of Transportation, its officers, employees, agents, and representatives from any and all causes of action arising from any acts or omissions of Respondent or its contractors in carrying out any work required by this Consent Agreement and Order.

II. <u>Corrective Measures</u>

11. Upon issuance of the Consent Agreement and Order, Respondent agrees to perform the Corrective Measures set forth below.

12. Regarding the entire West Texas Gulf Pipe Line System, its operation, and the Operating, Maintenance and Construction policies and procedures under which it operates, including all aspects for which the regulations in 49 C.F.R. §195 apply to the pipeline system and its operator, Respondent must:

(1) submit, for prior review and approval of the Director, a comprehensive written plan, including timelines for specific actions to improve the safety record of Respondent's West Texas Gulf Pipe Line System; and

(2) hire an independent third-party pipeline expert in safety management systems (SMS) to review and assess the written plan, which third-party expert must oversee the creation, execution and implementation of the actions identified in the plan, and must provide bi-monthly monitoring summaries to PHMSA and Respondent concurrently. The specific role of the third-party SMS consultant is to review the creation, execution and implementation of the SMS, by performing a gap analysis, recommending improvements, observing the phases of implementation, providing consultation, and communicating via written reports concurrently to PHMSA and Respondent.

13. Respondent must address any deficiencies or risks identified in the third party's assessment, including modifying repair procedures and implementing corrective actions related to safety culture and safety management processes. If PHMSA disapproves of Respondent's rationale for deferment, the agency must provide written notice to Respondent in accordance with Section III below. The plan must be sufficiently detailed with specific tasks, milestones and completion dates. At a minimum, the plan must address:

(1) Organizational issues, including creation of a Safety Management System promoting a safety culture that is equivalent to the elements considered essential in the American Petroleum Institute (API) Recommended Practice (RP) 1173, including:

i. Management Commitment and Leadership
ii. Risk Management
iii. Operational Controls
iv. Incident Investigation, Evaluation and Lessons Learned
v. Safety Assurance and Continuous Improvement
vi. Competence, Training, Qualification and Development
vii. Emergency Preparedness and Response
viii. Documentation and Record Keeping
ix. Stakeholder Engagement;

(2) Contractor oversight and inspection of construction activities while performing construction in existing or operating facilities, whether the facilities are owned or operated by Respondent or other pipeline operators transporting hazardous materials and subject to the requirements of 49 C.F.R. §195, and the commitment to ensure adequate resources are provided to maintain safety during construction activities. Specific attention shall be given to:

i. Adherence to Respondent's Operations and Maintenance procedures required by 49 C.F.R. 195 Subpart F,
ii. Operator Qualification regulations in 49 C.F.R.§ 195 Subpart G, and
iii. Drug and Alcohol Post Accident Testing regulations in 49 C.F.R.§199;

(3) Work planning process and requirements to define the appropriate level of preparation, review, and approval to ensure safe performance of activities if the scope of work is not in an existing O&M procedure;

(4) Any other task, issue, or item that is necessary to promote and sustain the safety of the West Texas Gulf Pipe Line System.

14. The actions required by this Consent Agreement are in addition to and do not waive any requirements that apply to Respondent's pipeline system under the Original CAO, and under 49 C.F.R. Parts 190, 194, 195 and 199, as applicable, or any other Order issued to Respondent under authority of 49 U.S.C. § 60101, *et seq.,* or under any other provision of Federal or State law.

15. Consent Order Documentation Report (CODR). Respondent must create and submit on a quarterly basis, a CODR. The intent is for the CODR to summarize all activities and documentation associated with the Consent Order and to identify any activities or documentation for the period reflected in previous report activities so the status of each item in the Consent Order is reflected in each report. When the Respondent has concluded all of the required items in the Consent Order, it will submit a final CODR to the Director. This will allow the Director to complete a thorough review of all actions taken by the Respondent with regards to the Consent Order prior to approving the closure of the Consent Order.

16. It is requested that Respondent maintain documentation of the costs associated with implementation of this Agreement, and include in each report submitted pursuant to Item 15, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

17. The Director may grant an extension of time for compliance with any of the terms of the Consent Order upon a written request, timely submitted, demonstrating good cause for an extension.

18. For all submissions based upon this Consent Agreement that requires the approval of the Director, the Director may (a) approve the submission in whole or in part; (b) impose specific conditions; (c) modify the submission to cure any deficiencies; (d) reject the submission in whole or in part; or (e) any combination of the above.

19. Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator are final.

III. Review and Approval Process

20. With respect to any submission under Section II of this Consent Agreement that requires the approval of the Director, the Director may: (a) approve, in whole or in part, the submission, (b) approve the submission on specified conditions, (c) disapprove, in whole or in part, the submission, or (d) any combination of the foregoing. If the Director approves, approves in part, or approves with conditions, Respondent will take all action as approved by the Director, subject to Respondent's right to invoke the dispute resolution procedures in Section IV with respect to any conditions the Director identifies. If the Director disapproves all or any portion of the submission, the Director will provide Respondent with a written notice of the deficiencies. Respondent will correct all deficiencies within the time specified by the Director and resubmit it for approval.

IV. <u>Dispute Resolution</u>

21. The Director and Respondent will informally attempt to resolve any disputes arising under this Consent Agreement. If Respondent and the Director are unable to informally resolve the dispute within 15 days, Respondent may request in writing, within 10 days, a written determination resolving the dispute from the Associate Administrator for Pipeline Safety providing all information that Respondent believes is relevant to the dispute. If the request is submitted as provided herein, the Associate Administrator will issue a final determination in writing. The existence of a dispute and the PHMSA's consideration of matters placed in dispute will not excuse, toll, or suspend any term or timeframe for completion of any work to be performed under this Agreement during the pendency of the dispute resolution process except as agreed by the Director or the Associate Administrator in writing.

V. <u>Enforcement</u>

22. This Consent Agreement and Order is subject to all enforcement authorities available to the PHMSA under 49 U.S.C. § 60101, *et seq.*, and 49 C.F.R. Part 190. All work plans and associated schedules set forth or referenced in Section II will be automatically incorporated into this Consent Agreement and are enforceable in the same manner.

VI. <u>Recordkeeping and Information Disclosure</u>

23. Unless otherwise required in this Consent Agreement, Respondent agrees to maintain records demonstrating compliance with all requirements of this Consent Agreement for a period of at least five years following completion of all work to be performed. For any reports, plans, or other deliverables required to be submitted to the PHMSA pursuant to this Consent Agreement, Respondent may assert a claim of business confidentiality or other protections applicable to the release of information by the PHMSA, covering part or all of the information required to be submitted to the PHMSA pursuant to this agreement in accordance with 49 C.F.R. Part 7. Respondent must mark the claim of confidentiality in writing on each page, and include a statement specifying the grounds for each claim of confidentially. The PHMSA determines release of any information submitted pursuant to this Consent Agreement in accordance with 49 C.F.R. Part 7, the Freedom of Information Act, 5 U.S.C. § 552, DOT and/or the PHMSA policies, and other applicable regulations and Executive Orders.

VII. <u>Effective Date</u>

24. The "Effective Date" as used herein is the date on which the Consent Order is issued by the Associate Administrator incorporating the terms of this Agreement. Unless specified to the contrary, all deadlines for actions required by this Consent Agreement run from the Effective Date of the Consent Order.

VIII. <u>Modification</u>

25. The terms of this Consent Agreement may be modified by mutual agreement of the Parties. Such modifications must be in writing and signed by both parties.

IX. Termination

26. This Consent Agreement terminates upon completion of all terms set forth in Section II (Corrective Measures) as determined by the Director, Southwest Region. Respondent may request written confirmation from the PHMSA when this Consent Agreement is terminated. To the extent ongoing monitoring is required, PHMSA may terminate this Consent Agreement with respect to all other requirements with the exception of such monitoring. Nothing in this Consent Agreement prevents Respondent from completing any of the obligations earlier than the deadlines provided for in this Agreement.

X. Ratification

27. The Parties' undersigned representatives certify that they are fully authorized to enter into the terms and conditions of this Consent Agreement and to execute and legally bind such party to this document.

28. The Parties hereby agree to all conditions and terms of this Consent Agreement:

[SIGNATURES ON NEXT PAGE]

For Respondent, West Texas Gulf Pipe Line Company:

Mike Prince

By: Mike Prince, President
3801 West Chester Pike, Newtown Square, PA 19073

9-29-16
Date

For PHMSA:

Rodrick Seeley
Director, Office of Pipeline Safety
PHMSA Southwest Region
U.S. Department of Transportation

10/3/16
Date

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE,

Plaintiff,

and

CHEYENNE RIVER SIOUX TRIBE,

Plaintiff-Intervenor,

v.

U.S. ARMY CORPS OF ENGINEERS,

Defendant-Cross Defendant,

and

DAKOTA ACCESS, LLC,

Defendant-Intervenor-Cross Claimant.

Case No. 1:16-cv-1534-JEB
(and Consolidated Case Nos. 16-cv-1796 and 17-cv-267)

DECLARATION OF PATRICK S. FLANDERS, P.E.

I, Patrick S. Flanders, declare as follows:

1. I am a Professional Engineer, licensed in the State of South Dakota with many years of oil and gas experience internationally and within the USA. I began consulting in 2017, upon retiring after 35 years of process safety engineering with major oil and gas industry and petrochemical companies. I now consult with oil and gas producers, suppliers of safety critical components and design contractors, on automation technology and integrated safety systems for production facilities and pipelines. My expertise relates to the instrumentation and control systems that make up pipeline safety systems, including overpressure systems, in order to reduce

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the risk of crude oil releases into the environment. In this capacity, I have since January 2017 provided technical consulting services to the Standing Rock Sioux Tribe on pipeline safety concerns with the Dakota Access Pipeline.

2. I earned Bachelors' of Science degrees in Mining Engineering (1982) and in Electrical Engineering (1988) from the South Dakota School of Mines and Technology. In addition to my license as a registered Professional Engineer in the state of South Dakota, I am a Fellow within the International Society of Automation (ISA) and a recognized international expert in the area of Safety Instrumented Systems. I served as a voting member on the standards committee for the 8th Edition of the American Petroleum Institute RP 14C Committee, which provides the generally accepted industry practice for upstream oil and gas safety systems, entitled, *Analysis, Design, Installation and Testing of Safety Systems for Offshore Production* (2017). Previously, while with Saudi Aramco, I was appointed as the Process Automation Professional Body Leader on the Saudi Aramco Board of Engineers and Chairman of the High Integrity Pressure Protection System Committee. As the lead process automation Subject Matter Expert (SME), I served on the World Economic Forum Oil and Gas Sector team, for the development of uniform worldwide standards for the oil and gas industry and contributed to a Joint Industry Practice team to develop a safety system communications protocol for use within the process industries (Foundation Fieldbus for Safety Instrumented Systems). I have numerous publications and am a well-known presenter and trainer, providing continuing education training sessions to oil and gas engineers within the USA and internationally on integrated pipeline safety systems.

3. I possess over 35 years of experience in the energy industry, including operations, process safety management and facility safety audits (Quantitative Risk Assessment studies and

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Loss Prevention Compliance Reviews). I specialize in Instrumentation and Automated Safety Control Systems. I am a career oil and gas industry engineer, having designed and supervised construction and reviews of safety and spill prevention systems for hazardous liquid pipelines and upstream and downstream oil and gas facilities within the United States and Saudi Arabia.

4. I have developed, patented and commercialized innovative technologies for safety critical operations in the oil industry, with over 50 patents issued in my name. I pioneered the "Smart ZV" concept for the use of smart valve positioners globally to improve final element diagnostics and functional testing methods, for verification of hazardous liquid pipeline automated safety systems. I developed, patented, prototyped and successfully deployed High Integrity Pressure Protection Systems on oil and gas pipelines offshore and onshore to reduce the risk of overpressure within the highest risk applications in the industry. In addition, I developed and implemented technologies for integrated safety systems that have saved my employers and clients, and their insurers, significant sums, by reducing spills and environmental damage through proper risk assessment, safety system design and installation, and functional testing and performance verification.

5. Through my work with the Standing Rock Sioux Tribe, I am very familiar with the technical documents prepared by DAPL, the Army Corps of Engineers, and their engineering contractors related to DAPL. I have reviewed the Army Corps of Engineers, Omaha District, *Final Environmental Assessment, Dakota Access Pipeline Project, Crossings of Flowage Easements and Federal Lands* (2016); Fluid Flow Consultants, *DAPL Gathering System, DAPL Mainline and ETCOP Oil Pipeline Surge Analysis* (June 2017); Process Performance Improvement Consultants, *Independent Assessment of Dakota Access Pipeline (*April 2017); *Surge Protection Study for the Dakota Access Pipeline*, U.S. Army Corps of Engineers, *Analysis*

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of the Issues Remanded By the U.S. District Court Related to the Dakota Access Pipeline Crossing at Lake Oahe (2019); RPS, *Lake Oahe Spill Model* (Feb. 2018). I have also reviewed the declaration being simultaneously filed by Don Holmstrom, with whom I have worked closely on the Standing Rock Sioux Tribe Technical Team, and agree with the conclusions he draws.

6. Although there are many safety system deficiencies that were identified previously by the Standing Rock Sioux Tribe that require detailed analysis during the upcoming EIS, I focus here on one issue: the documented inadequacies in the pipeline surge prevention and overpressure protection systems provided for the High Consequence Area pipeline river crossings, most notably, Lake Oahe. The lack of adequate pipeline surge relief at the river crossings is contrary to regulatory requirements, industry best practices, and in my view constitutes a non-compliant (nonexistent) safety layer that warrants suspension of operations until these systems can be fully evaluated, deployed, and the risks mitigated. The Lake Oahe crossing of the Dakota Access Pipeline is defined as an "unusually sensitive area" (as defined by PHMSA in 49 CFR §195.6) and a "high consequence area" (as defined by PHMSA in 49 CFR §195.450). A high consequence area is a pipeline crossing that could affect drinking water systems or sensitive environmental receptors, such as the Missouri River, bald eagle nests along the river, and Native American cultural resources, all of which are impacted by the Lake Oahe crossing of the Dakota Access Pipeline. A pipeline crossing in a high consequence area triggers enhanced integrity management planning requirements and deployment of "Best Available Technology" to meet the associated higher than normal, risk reduction targets for critical safety devices.

7. As a Senior Engineering Consultant that supervised the planning, design and operation of many pipeline safety systems in high consequence areas (offshore, onshore, crude

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oil, and gas applications), I am well situated to provide an opinion on the design requirements to adequately protect the high consequence area at the Lake Oahe crossing, and whether DAPL in fact complies with these requirements. My intention is to place emphasis on the automated protection schemes installed to prevent a spill from occurring and to mitigate the environmental damage that would result from a spill.

8. The Dakota Access Pipeline should not be operating at present, due to the failure to properly design and operate the system in a manner that complies with the PHMSA integrity management and overpressure protection requirements for the Lake Oahe crossing.

9. Reliable operations and process safety risk reduction requires fault tolerant design, functional testing, and performance verification of critical safety devices and systems. In my view, the critical safety protective systems including Surge Relief Valves for overpressure protection, Integrity of Controls used for Surge Prevention and Emergency Shutdown, external monitoring along the HDD river crossing segment for crude oil accumulation, leak detection and worst case discharge crude inventory control are all deficient. The emphasis of my analysis in this document is inadequate pressure surge relief. Nevertheless, all of these deficiencies result in unacceptable risk to Lake Oahe and the Standing Rock Sioux Tribe.

10. With respect to Surge Relief, all crude oil pipelines are vulnerable to over-pressurization that can result from surge events when flow is suddenly interrupted by pumps starting and stopping, valves opening and closing, etc. Over-pressurization of a crude oil pipeline due to surge is a serious concern for safety system engineers because it could result in a catastrophic spill, or an explosion. Consequently, surge prevention controls and surge protection equipment must be carefully designed and properly installed. The use of transient flow analysis and proven, off-the-shelf, surge relief valves is well known in the industry and surge relief valves

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are applied routinely as a separate independent protection layer to protect crude oil pipelines from overpressure due to surge.

11. For example, PHMSA regulations at 49 CFR §195.406(b) provide that: "No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110% of the operating pressure limit … Each operator must provide adequate controls and protection equipment to control pressure within this limit." To ensure compliance with these industry regulations, major oil companies typically maintain internal standards that prescribe minimum mandatory requirements for sizing, selection, installation, periodic test and inspection of liquid surge relief valves and surge relief systems on crude oil pipelines. Guidance is provided by experts consulting with associations such as the American Petroleum Institute (API) and the International Society of Automation's International Electrotechnical Commission (ISA/IEC). The ISA/IEC develops consensus standards for Safety Critical Devices, such as main line valves, surge relief valves and valve actuators.

12. According to accepted industry practice, "adequate over-pressure controls" refer to maintained Safety Critical Devices that are properly designed, installed and inspected. Safety Critical Devices are the components of an overall integrated safety system. The system must be designed so that a single point failure will be mitigated by other Safety Critical Devices in an integrated system, to prevent a spill or other accident.

13. The surge prevention and control equipment for DAPL is described in the report prepared by Fluid Flow Consultants, entitled *DAPL Gathering System, DAPL Mainline and ETCOP Oil Pipeline Surge Analysis.* (RAR 17286). It is made up of a controlled pipeline shutdown via a programmable logic controller (PLC) that shuts down all pump stations no later

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than 8 seconds after a Main Line Valve (MLV) or station suction Motor Operated Valve (MOV) start to close.

14. No supporting documentation was provided in the Fluid Flow Consultants' report to support that the DAPL surge prevention system (valve position monitoring devices, communications, programmable logic, and pump controls) are maintained as Safety Critical Devices or that the integrated control system meets even the minimum requirements for design, component selection, and functional testing procedures of an IEC 61511/ISA S84 compliant Safety Instrumented System. Ultimately, in my view, the report fails to demonstrate compliance with the requirement for "adequate controls" of pressure surge prescribed in 49 CFR §195.406(b).

15. The overpressure protection equipment requirement refers to separate and independent Surge Relief Valves (SRV) specifically sized and installed to prevent overpressure spikes in pipelines that result when the "controls" fail to prevent surge from occurring. The Fluid Flow Consultants report, *DAPL Gathering System, DAPL Mainline and ETCOP Oil Pipeline Surge Analysis*, identified potential surge initiators – pump station inlet valve closures, main line valve closures, or pump station shutdowns – that would cause excessive pressures greater than the 110% of maximum operating pressure limit. The report correctly recommended that Surge Relief Valves be installed to protect against overpressure due to surge should the PLC based pump shutdown system fail to function. However, the report limited the scope of the required Surge Relief Valves to only the pump station inlets, leaving the pipeline High Consequence Area river crossing HDD pipeline segments without protection. In other words, the surge protection system is designed to protect *the pump stations* along the pipeline from damage caused by pressure surge, but *not* the segments of the pipeline at the Lake Oahe crossing

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or other river crossings. Considering the risk associated with the HHD river crossings (High Consequence Areas), proper overpressure protection design requirements include SRVs at these locations, but they do not exist.

16. The Fluid Flow Consultants DAPL surge report further identified 11 HDD river crossings at risk of overpressure including the Lake Oahe HDD at MP 167 (ref. Table 15, page 36). The report identified a serious deficiency in the pipeline surge protection systems deployed on DAPL river crossings and non-compliance with American Society of Mechanical Engineering (ASME) standard B31.4 and 49 CFR §195.406 mandatory safety requirements. The report stated in paragraph 4 on page 26: "Table 15 shows the results for selected (what we deemed to be the worst in terms of highest surge pressures) … The reader can see that in most cases, the surge pressures greatly exceed 110% of MOP. This is unacceptable." (RAR 17310). The lack of surge protection at the high consequence areas leaves the river crossing HDD pipeline segments without protection from overpressure due to surge and arguably violates the integrity management planning requirements of 49 CFR §195.452.

17. The DAPL surge report, finding number 4, acknowledged that as designed and operated, DAPL lacks sufficient surge relief protection for compliance with the 110 percent over-pressurization prohibition of 49 CFR §195.406(b), for the HDD pipeline segments. Finding number 4 stated: "If the closing of a MLV is the surge initiator and the PLC does not shutdown the pumps, the surge pressures greatly exceed 110% of the MOP even if the station suction SRVs are in place. The station suction SRVs do NOT protect the lines against MLV closure." RAR 17289 (emphasis in original). As stated above, Finding 4 failed to recommend surge "protection" (Surge Relief Valves) for the environmentally sensitive High Consequence Area HDD river crossings. Although this deficiency was documented in DAPL's own materials, to

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the best of my knowledge no action was ever taken to remedy the problem and the Oahe river crossing remains unprotected against this significant overpressure risk.

18. Pressure surge can be caused by failure of the main line valves. The automated operational system can fail and result in an unplanned, spurious closure of valves that are located at various segments of the pipeline. Surge relief is required to ensure that a mistaken closure of mainline valves, such as the Emergency Flow Restriction Devices (EFRDs) on both sides of Lake Oahe, does not cause a dangerous pressure surge in the pipeline. If one of the Lake Oahe EFRDs were to be subject to a spurious closure, there would no surge protection available for this high consequence area.

19. With respect to pipeline operations, 49 CFR §195.402, and the Corps of Engineers easement for the DAPL Lake Oahe crossing, require a DAPL-specific operations plan. The *Independent Assessment of Dakota Access Pipeline* describes the operator's failure to comply with this requirement – no such plan has been prepared as required. The regulation requires the operations plan to address the "unintended closure of valves or shutdown." 49 CFR §195.402(d)(1)(i). Thus, the DAPL surge report indicates that the pipeline design fails to include proper surge relief from over-pressurization in violation of 49 CFR §195.406(b), and the administrative record lacks a DAPL operations plan that includes requisite mitigation to an unintended valve closure (which, as described above, causes pressure surge) in violation of 49 CFR §195.402(d)(1)(i).

20 Based upon the foregoing, it is my expert opinion that, as currently designed and operated, the Dakota Access Pipeline poses an unacceptable risk to the Standing Rock Sioux Tribe as it fails to meet important PHMSA safety regulations, its safety systems lack installed performance verification required to demonstrate compliance with industry best practice for

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Safety Instrumented System risk reduction, and DAPL fails to provide adequate overpressure protection (Surge Relief Valves) at the environmentally sensitive pipeline HDD river crossings. These risks justify that the pipeline should be shut down pending preparation of an environmental impact statement by the Army Corps of Engineers.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on this 15th day of May, 2020.

Patrick S. Flanders

Patrick S. Flanders, P.E.

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UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE, et al., Plaintiffs, v. U.S. Army Corps of Engineers, et al. Defendants.	)	Civil Action No. 16-1534 (JEB)

SECOND DECLARATION OF ELLIOT WARD

1. I serve as the Standing Rock Sioux Tribe of North Dakota's Emergency Response Manager. I have been in this position for nearly 10 years and I have been involved in Disaster Declarations throughout those ten years. The Tribe has an emergency response management team and a Tribal Emergency Response Commission that works together on emergency response matters that impact our Reservation. I am the Tribal government official responsible for the timely and effective first response to a disaster on our Reservation.

2. In March, 2015, I received a copy of a highly redacted Facility Response Plan and Geographic Response Plan for the Lake Oahe crossing of the Dakota Access Pipeline. Although the emergency response zone is nearly exclusively within our Reservation, that was the first time that I had seen these documents. I was never contacted or consulted by Energy Transfer for advice or input into the plan. I signed the Confidentiality Agreement required by the Protective Order in the above-captioned matter, and received unredacted copies of these documents.

3. I have objected to these plans for several reasons. The first collection point was shown to be just east of the community of Cannonball ND just below the Cannonball Elementary School and half a mile from the community of Cannonball ND. The plans at that time if a spill should occur would be to move all of the oil into a small inlet adjacent to the Cannonball community and to bring in frac trucks, oil skimmers, frac tanks, and other heavy equipment to attempt to retrieve the oil off of the river, thereby causing a major disruption and danger to the elementary school and to the local community. The second extraction point was located just east of the Standing Rock Sioux Tribe' Prairie Knights Casino, which provides over 400 jobs for the local residents of Sioux County and surrounding counties in North Dakota. The extraction point was located just north of the Prairie Knights Marina which provides recreational/sport fishing and swimming areas along with an RV park. There was not a passable road to get to the proposed extraction point and noted especially in the severe winter weather of the Dakota's at times there are six feet of snow and ice and roads are impassable for weeks at a time. This was not considered in the plans that I reviewed at that time. The third extraction point was just north of Fort Yates North Dakota which is the hub of the reservation and houses the Standing Rock Sioux Tribal headquarters, the Bureau of Indian Affairs Agency, the Indian Health Services hospital and other tribal programs and at that time the Tribe's primary water treatment plant that provided clean drinkable water to the Tribe's 9,000 residents and others. The plans was to extract oil from what is known as the Porcupine creek area which lies two miles north of Fort Yates ND water intake/treatment plant. All of these extraction points had been planned by DAPL with the Corps of Engineers knowledge. The Standing Rock Sioux Tribe had no input into any of these plans. I

submitted my declaration to your court and within several days I was presented with an alternative plan that indicated that any oil spill from the DAPL pipe line would be directed toward the eastern bank of the Missouri River into Emmons County, North Dakota.

4. The Standing Rock Sioux Tribe has never been involved in DAPL's Spill response planning, nor have they provided a copy of the Spill Response Plans or Emergency Plans to my office, or to the Tribal Chairman or any other Tribal official. Our position is that the Tribe must be fully involved to make sure that our waters and our communities are properly protected in the event of a spill. My office has developed a Lake Oahe Emergency Oil Spill Response Plan over the past four years to protect our lands and waters from a Worst Case Discharge of oil from the DAPL pipeline. We have also hired Technical Experts who have had many years of experience in working in the oil field and oil industry to assist in the development of this plan. We have contacted a locally owned Oil Spill Recovery Operator (OSRO) to assist the Tribe in cleaning and mitigating an oil spill if necessary.

5. The Tribe has also been working closely with the Environmental Protection Agency Region VIII of Denver, Colorado, to have our Lake Oahe Oil Spill plan recognized by their offices and to be included in their updates to the federal Upper Mid Missouri River Sub-Area Contingency Plan.

6. Many aspects of Energy Transfer's FRP and GRP make my job more difficult. A spill could be a worst case discharge (WCD). The FRP's WCD for Lake Oahe is currently grossly understated and violates PHMSA's minimum requirements for calculating the WCD – lacking detection time, EFRD valve closure time and

consideration of adverse weather conditions. The Energy Transfer proposal to double the flow of DAPL renders the GRP and FRP even more unsuitable for spill mitigation and clean-up activities. The plan now and in the future places the emergency responders at risk.

7. In order to properly prepare for emergency response, it is extremely helpful to have access to information on the chemicals that first responders and oil spill clean-up workers will be exposed to. However, Energy Transfer and the Corps of Engineers have refused to provide any information to my office relating to the volatility, flammability or chemical composition of the Bakken crude and the chemical additives currently flowing in the Dakota Access Pipeline. The FRP only references generic crude hazards that are contradicted by the Bakken crude oil ConocoPhillips Safety Data Sheet (SDS) that is appended but not referenced in the body of the FRP.

8. For example, for flammability, Table 6.1 in the FRP lists the crude oil as a fire hazard of 3 (on a 0-4 scale with 4 as most hazardous) based upon a flash point of under 100 degrees F. The SDS states that Bakken crude is "extremely flammable" and has a flash point under -20 degrees F with a GHS rating of "1," the highest hazard for flammable liquids. This inconsistent information, and the overall lack of cooperation by ET and the Corps of Engineers, puts Tribal First Responders at risk.

9. The hazardous chemicals of concern such as benzene, toluene, ethylbenzene, and xylene are typically in significantly elevated concentrations in Bakken crude and can accumulate in the ambient air to unsafe levels in work areas. Hydrogen sulfide, which is also toxic, may also be present. The appended GRP air monitoring plan lacks effective monitoring for these toxins and references inadequate action levels for

workers and communities. There is no guidance on sheltering in place or criteria for evacuation, due to potential unsafe levels of toxins in the air or water.

10. The crude oil containment and recovery strategies are based upon the faulty assumption that spilled oil will be floating on the lake's surface for the duration of the containment and recovery. This is contrary other documents in the record. Oil in the water column is very difficult to remediate and may require special methods and equipment that are not readily available. The GRP lacks any reference to cleaning up oil contained in the water column or equipment that could be used to capture oil under this scenario.

11. The GRP also lacks any reference to a site-specific Health and Safety Plan (HASP) required by OSHA's Hazwoper for clean-up operations conducted under the standard. The FRP includes a "site" safety plan acknowledged as "generic" (2017 FRP p.74), that lacks any specificity to DAPL and the specific hazards of Bakken crude.

12. One major area of concern would be the effects of an oil spill on the Standing Rock Sioux Tribe's Ceremonial and Cultural sites and medicinal sites along the Missouri River and its tributaries. The people of Standing Rock have used these sacred sites for thousands of years and destruction of these sites by an oil spill would be devastating to the entire culture and spiritual connections we have as a Tribe to the earth and the water which is our first medicine. The Tribe could provide thousands of stories and spiritual reasons why an oil spill would decimate our culture.

13. Tribal communities and others residing on the Standing Rock Sioux reservation rely heavily on the water from the Missouri River to furnish clean and safe drinking water to our local communities and to farmers and ranchers who live on the

reservation. These communities and residents will suffer the most if an oil spill takes place. Tribal participation is necessary to make sure that any response plans properly address the interests of the Tribe. That has not occurred.

14. For the safety of our First Responders in the event of an oil spill, and of our Tribal community, DAPL should not be operating pending the preparation of an environmental impact statement by the Army Corps of Engineers,

I declare, under penalty of perjury, that the foregoing is true and correct.

Elliott Ward

Elliot Ward

STATE OF NORTH DAKOTA)
:
COUNTY OF SIOIX)

SUBSCRIBED and SWORN to before me
this 20th day of May, 2020

Notary Public

My Commission Expires 5·30·20

SHEENA ELK
Notary Public
State of North Dakota
My Commission Expires May 30, 2020

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE; YANKTON SIOUX TRIBE; ROBERT FLYING HAWK; OGLALA SIOUX TRIBE, Plaintiffs, and CHEYENNE RIVER SIOUX TRIBE, ET AL. Intervenor-Plaintiffs, v. U.S. ARMY CORPS OF ENGINEERS, Defendant. and DAKOTA ACCESS, LLP, Intervenor-Defendant.	Case No. 1:16-cv-1534-JEB (and Consolidated Case Nos. 16-cv-1796 and 17-cv-267)

DECLARATION OF TRIBAL HISTORICAL PRESERVATION OFFICER STEVE VANCE IN SUPPORT OF THE CONSOLIDATED BRIEF OF STANDING ROCK SIOUX TRIBE, CHEYENNE RIVER SIOUX TRIBE, OGLALA SIOUX TRIBE, AND YANKTON SIOUX TRIBE REGARDING REMEDY

1. The information contained herein is based on my personal knowledge, and I am competent to testify to the contents contained herein if I am called to do so in any proceeding.

2. My name is Steve Vance. I am an enrolled member of the Cheyenne River Sioux Tribe, and am the duly appointed Tribal Historic Preservation Officer ("THPO"). In addition to my years of previous service to the Tribe, I have served as the THPO for the last ten years. I have significant knowledge of the Cheyenne River Sioux Tribe's oral history, cultural and spiritual laws,

and historic documentation.

3. When appointed by the Tribe, I was honored to serve as the Tribe's THPO because it is critical for the Cheyenne River Sioux Tribe to participate in its own preservation and protection. Tribal Historical Preservation Officers are regulatory officers who manage and protect cultural resources, sacred sites, and other historical sites within the exterior boundaries of the Cheyenne River Reservation. Historical preservation is essential to telling our own story and maintaining our cultural identity.

4. This job is also fulfilling because it helps me protect the traditional Lakota lifestyle that I practice alongside many others on our Reservation. I have spent the vast majority of my life speaking Lakota, and being immersed in Lakota cultural practices and knowledge.

5. The Cheyenne River Sioux Tribe and its people have been present on the land currently known as the Cheyenne River Reservation since before the creation of the United States of America and their presence spans into time immemorial.

6. Prior to the American Government forcing us to take reservations, the Lakota bands of the Cheyenne River Sioux Tribe had no boundary to their territory. The bands were hunters that traveled over their ancestral homelands.

7. The Ft. Laramie Treaty of 1851 between the United States and the Great Sioux Nation reserved a portion of the Sioux historic homelands for the Tribes to keep, and the Cheyenne River Reservation is included in that area. Montana, Wyoming, Nebraska, North and South Dakota are also within the bounds of the 1851 Treaty.

8. The Ft. Laramie Treaty of 1868 explicitly reserved certain rights such as hunting and fishing, along with other rights. One of those rights is the Federal Government's obligation to arrest "bad men" among the non-Indians who commit harms on our reservation.

9. The Sioux Agreement Act of 1889 set the current reservation boundary lines within the borders of South Dakota.

10. The Flood Control Act of 1944 granted the Army Corps of Engineers the authority to dam the Missouri River, and gave them control over of the resulting federally-owned reservoir, Lake Oahe. The Oahe Taking Act authorized the Corps to seize over 100,000 acres of tribal lands along the Missouri near the proposed location of the Oahe Dam for the Oahe Reservoir (also known as Lake Oahe). The Tribe suffered greatly in the building of the Oahe Dam. The Dam destroyed more Indian land than any other single public works project in the history of the United States. The Cheyenne River Sioux Tribe lost 104,420 acres, including unfathomable numbers of historical, archeological, and religious sites.

11. Adding to this long history of loss, the DAPL Project is not the first time that one of our rivers has been harmed by American industry. In the 1800s, gold mining contaminated the Cheyenne River, which is the southernmost boundary of the Reservation. As a result of the Homestake Gold Mine, the Cheyenne River is still contaminated with arsenic today.

12. Since time immemorial, the Sioux People—the Lakota, Dakota, and Nakota—have associated the Missouri River with a "blood line." The Cheyenne River Sioux Tribe is no exception; the Tribe has relied upon the Missouri River to serve as a highway from its headwaters in Montana down to where it flows into the Mississippi. Oral tradition discusses the Missouri River as a location for bartering and trade, ceremonies, and communication. Likewise, the Missouri River bottomlands have provided game, timber, and shelter.

13. As a "blood line" of the Lakota people, the waters of the Missouri River itself are sacred and essential to us and our Lakota way of life. Clean, pure water is necessary for the rites and sacraments that comprise our religion. Water is a part of who we are. The waters of *Mni*

Sose—the Missouri River—have always been necessary to our existence as Lakotas and for our spiritual practices. We chose to live by *Mni Sose* because of its importance to our existence. Similarly, *Mni Sose* is essential to all of the plant and animal life that relies on *Mni Sose* for water. All of that life is also essential to Lakota life ways because those plants and animals are an important source of our foods and medicines. *Mni Sose* is even more important today because the other bodies of water important in our culture were removed from our access, such as the waters in the Black Hills. *Mni Sose* is the blood line and the life line of the people. Just as all of our drinking and municipal use water comes from Lake Oahe, all of the water we use for our religious practices comes from Lake Oahe, and we cannot practice our religion without it. We cannot survive without it.

14. As long as the Dakota Access Pipeline continues to pump oil underneath our blood line river, the Missouri, we are in constant fear that the river, the plants, the animals, and the earth around it will be polluted.

15. Long ago our prophets told of the coming of a Black Snake that would be coiled in our homeland and which would harm us. In the prophecy, the Black Snake devoured the people. We would as children go out in the dark with this monster in the back of our heads. There was this black dark figure, and it was a huge snake that was going to devour the people, so the people became scared and ran back inside. This pipeline, like the snake in this story, is black, it is slippery, and it moves. We Lakota people believe that the crude oil that is proposed to flow through the Dakota Access pipeline is the Black Snake. We believe that the very act of pumping this black crude oil under our sacred *Mni Sose*, the very existence of the crude oil pipeline pollutes the pure, natural water of Lake Oahe and cause a critical imbalance that will contaminate the water. The existence of this crude oil pipeline under the Lake Oahe Reservoir poses a special

threat to the way we practice our religion. It is this location and area where we travel to the river to draw our pure water for our religious uses. As long as the pipeline is under the riverbed it is harming the spiritual energy of the water and it poses an incessant threat to our religious practices.

16. The use of unnatural waters is not a substitute that adherents to our religious principles, including myself, can accept. Bottled water, for example, is not a natural source of water. It is surrounded by the chemicals used in plastic. When we conduct ceremony, we do not wear jewelry or man-made items. We use wooden buckets to carry the water because wood is from nature.

17. A leak in the Dakota Access Pipeline would contaminate our only source of drinking water, municipal use water, and sacred water. The pipeline's ongoing presence, and the looming threat of seepage, leak, and rupture that necessarily accompanies it, inflicts ceaseless anxiety upon us that will not end until the pipeline is removed.

I declare under the penalty of perjury that the foregoing is true and accurate to the best of my knowledge.

Dated May 18, 2020

Steve Vance

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

STANDING ROCK SIOUX TRIBE,

Plaintiff,

and

CHEYENNE RIVER SIOUX TRIBE,

Plaintiff-Intervenor,

v.

U.S. ARMY CORPS OF ENGINEERS,

Defendant-Cross Defendant,

and

DAKOTA ACCESS, LLC,

Defendant-Intervenor-Cross Claimant.

Case No. 1:16-cv-1534-JEB
(and Consolidated Case Nos. 16-cv-1796 and 17-cv-267)

DECLARATION OF ALBERT TWO BEARS

1. This is my statement regarding the Dakota Access Pipeline that runs across the Missouri River on the ancestral lands of the Dakota, Lakota, and Nakota.

2. My name is Albert Two Bears, age 78. I was born, raised and lived in Cannon Ball, North Dakota all my life. My Great Grandfather was Chief Two Bears who was forced to move with other clan leaders and their families from Minnesota back in the 1800's, and many were massacred at White Stone Hill. My Grandfather was known as Chief Basil Two Bears; he and other leaders settled on the northern fringes of the established Standing Rock Reservation

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and was a leader of his people and made trips to Washington, D.C. to meet with BIA officials for the benefit of the people of Standing Rock. I am considered a hereditary chief and have served the people of Standing Rock as a Tribal Council member for 16 years. During my tenure on Tribal Council for the district of Cannon Ball, we were the first district to have a water line that was extended from Fort Yates, North Dakota. Also, as a Tribal Council member, we pushed and succeeded to establish a tribally-owned Casino. The Prairie Knights Casino now sits on land that I ran my cattle on. Many changes have taken place on the Standing Rock Reservation due to government regulations and oversight that have not been beneficial to the members of the Standing Rock Sioux Tribe.

3. I have been a rancher in the Cannon Ball area for 57 years and have the Missouri River to the East of my ranch. My livestock rely on the water from the Missouri River for survival. The land that I own and lease is along the river. Along with my livestock, there is wildlife that rely on the Missouri River for survival.

4. The damage done along the Missouri River first started with the flooding of bottom lands along the river from the construction of the Oahe Dam. My family, relatives, friends and others lost homes, livelihoods and a way of life that provided a living, not having to rely of the federal government for a mere existence. On celebrations days in Cannon Ball, I can remember my Grandfather Basil riding his horse early in the mornings announcing the day's happenings in Dakota language, while the campers had the lush bottom lands to enjoy the celebration. The ways of nature to provide a living were destroyed. Today the natural fruits and other foods that were needed and utilized are about non-existent. The whole circle of life was totally upset.

5. Now comes an oil pipeline that will completely destroy what remains in nature

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and the people of Standing Rock. The pipeline will leak! This has been proven time and time again around the world. There are no complete safeguards in place to assure anyone that an oil pipeline leak will not happen or, when this leak happens, what are the foolproof plans for remediation?

6. I speak for the present and future, for not only the residents of Cannon Ball, North Dakota, and Standing Rock Reservation, but also my neighbors on the East side of the Missouri River that also utilize the Missouri River for their livelihood through farming and ranching.

7. The oil pipeline does not need to exist at the cost and way of life for many!

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 19 day of May, 2020.

Albert Two Bears

Albert Two Bears
Cannon Ball, North Dakota

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