ECONOMIC IMPACTS OF A DAKOTA ACCESS PIPELINE SHUTDOWN

September 1, 2020

EXECUTIVE SUMMARY

At the request of the American Petroleum Institute (API), ICF, supported by Hellerworx, LLC analyzed the economic impacts of shutting down the Dakota Access Pipeline (DAPL) on the Bakken Shale region, including impacts to producer revenues, state tax revenues, and employment. The scenario adopted in this report for when and how long DAPL might be shut down was created in consultation with API and does not reflect any specific analysis or opinion on the part of ICF on any legal, policy or technical issues related to the pipeline and its permits. The ICF analysis concerns the market and economic impacts of a certain shutdown scenario, not whether any shutdown is warranted.

ICF analyzed the economic impacts of shutting down the Dakota Access Pipeline (DAPL) on the Bakken Shale region, including impacts to producer revenues, state tax revenues, and employment. To analyze these impacts, ICF modeled Bakken rig activity, oil and gas production, oil disposition, and prices under two regulatory scenarios: one where DAPL remains in operation and one where DAPL is offline for a total of 16 months—13 months for the environmental impact study to be completed, one month for the court to review the study, and two months for the line to be refilled with oil prior to restart of commercial operations. ICF estimated job and other economic impacts for the 16-month shutdown period. In order to capture the lagged impact of reduced drilling and completion activity during the shutdown period, ICF analyzes the impacts on production, producer revenue, and taxes for an additional year after the pipeline restarts for a total analysis period of 28 months. This analysis uses the oil price forecast from the U.S. Energy Information Administration (EIA)'s August 2020 Short-Term Energy Outlook (STEO). **Exhibit 1** below compares the economic impacts of the two DAPL operation scenarios. The bullets following the table summarize the key findings of this analysis.

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Exhibit 1. Summary Economic Impacts of DAPL Shutdown

Time Period	Data Item	Unit	No DAPL Shutdown	DAPL Service Interrupted for 16 Months	Difference
16-month Shutdown Period (9/2020 to 12/2021)	Average WTI Crude Price	$/bbl.	44.22	44.22	none
	Average Bakken to WTI Differential	$/bbl.	(4.32)	(9.89)	(5.58)
	Average Bakken Wellhead Price	$/bbl.	39.90	34.32	(5.58)
	Average Rig Count	count	32.0	17.6	(14.3)
	Avg. Jobs in Upstream Sectors	count	12,885	9,907	(2,978)
	Avg. Jobs in All Upstream-related Direct and Indirect Sectors	count	21,041	16,178	(4,863)
	Avg. for All Direct, Indirect and Induced Jobs	count	31,899	24,526	(7,373)
28-month Analysis Period (9/2020 to 12/2022)	Cumulative New Wells Completed	count	2,687	2,059	(628)
	Cumulative Crude Oil Produced	MMB	1,057	942	(115)
	Cumulative Natural Gas Produced	Bcf	1,955	1,742	(213)
	Cumulative NGPL Produced	MMB	368	327	(40)
	Producer Revenues	$MM	57,582	48,044	(9,538)
	State Production Taxes	$MM	4,942	4,090	(852)
	State Income Taxes Attributable to O&G	$MM	416	347	(69)

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Key Findings

- **Oil Prices:** The loss of DAPL will likely force many North Dakota producers and crude buyers to shift up to 570,000 b/d of crude oil production from DAPL to alternative, higher cost transportation routes, including other pipeline systems (to the extent capacity is available) and rail. These higher-cost alternatives will result in lower producer netbacks[1]. Lower netbacks due to rail use, and a temporary price crash in the initial period after the DAPL shutdown, lower the Bakken wellhead price by an average of $5.58/bbl. over the DAPL 16-month out-of-service period versus the no-shutdown case.
- **Drilling Activity & Employment:** Lower wellhead values for Bakken crude without DAPL will depress drilling activity and other upstream and midstream investment, resulting in a corresponding loss of jobs. In the DAPL Shutdown scenario, the average number of operating rigs is reduced by 14.3 rigs over the 16-month shutdown period, resulting in an average loss of 3,000 direct upstream jobs. Job losses expand to 4,900 when including indirect job losses in sectors related to oil and gas production and 7,400 when counting all direct, indirect and induced job losses.
- **Oil Production:** Lower Bakken oil prices without DAPL reduce Bakken oil production by slowing drilling and well completion activity and by slowing the return of oil wells shut-in earlier this year due to demand losses from the COVID-19 pandemic and associated lockdowns. In addition, a small volume of additional production may be forced to shut-in in the initial period after the DAPL shutdown as shippers may require time to arrange alternative pipeline and rail logistics. In the DAPL Shutdown Scenario, approximately 115 million barrels of crude oil are not produced over the 28-month analysis period. In addition, there are corresponding output losses of associated-dissolved natural gas and natural gas liquids (NGLs).
- **Producer Revenues & State Receipts:** In the DAPL Shutdown Scenario, lower oil and gas production and lower wellhead oil prices result in lower revenues for Bakken producers of an estimated $9.5 billion over the 28-month analysis period. This in turn reduces oil and gas extraction and producer income taxes in North Dakota and Montana by a total of $921 million over the analysis period.

[1] Netbacks are market prices or imputed values of a commodity at location "A" computed as the reported prices at location "B" minus the cost of transporting that commodity from location "A" to location "B". Netback pricing is expected to be observed where location "B" represents a large, competitive market for that commodity, that commodity is being regularly transported in significant volumes from location "A" to "B", and incremental transportation service by one or more modes is available from "A" to "B".

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INTRODUCTION

Prior to the startup of DAPL in mid-2017, the Bakken Shale region experienced pipeline takeaway capacity constraints as the region's production growth outpaced investment in new pipeline infrastructure. As a result of these constraints, a large share of Bakken production—as much as 60%--was forced to move on higher-cost rail transportation routes. The higher costs of rail transportation caused wellhead prices in the Bakken region to fall to steep discounts to U.S. and international benchmarks, tempering revenue growth and incentives for new drilling for Bakken producers.

The startup of DAPL in 2017 was a major boost to Bakken producers, providing an efficient and low-cost transportation route to major refining centers in the Midwest and Gulf Coast regions. With DAPL in place, Bakken-Williston production grew rapidly, rising from about 1.07 million b/d in the first quarter of 2017 to 1.51 million b/d by first quarter of 2020. In second quarter of 2020, COVID-19 lockdowns and a Saudi-Russian price war led to a collapse in world oil prices, leading to the short-term shut-in of a significant portion of Bakken area oil production and a sharp reduction in drilling activity. This led to a fall in producer revenues and a corresponding collapse of North Dakota state tax revenues; according to a report from the North Dakota Legislative Council, oil and gas extraction tax revenue fell by $160 million (81%) below forecast in June 2020.[2] World oil prices have recovered from the second quarter, with WTI prices averaging more than $40 per barrel in recent months, and Bakken producers have already begun to restore production shut-in earlier in the year.

The potential court-ordered shutdown of DAPL puts this recovery at risk. Even at depressed production levels, at least some disrupted DAPL pipeline volumes would be forced on to higher cost rail routes, again widening the differential between Bakken wellhead prices and WTI, slowing the return of drilling activity needed to maintain production. This slower recovery will have major impacts for Bakken producer revenues, state tax revenues, and jobs. The analysis contained in this report is intended to estimate the magnitude of those impacts. This analysis involves several pieces:

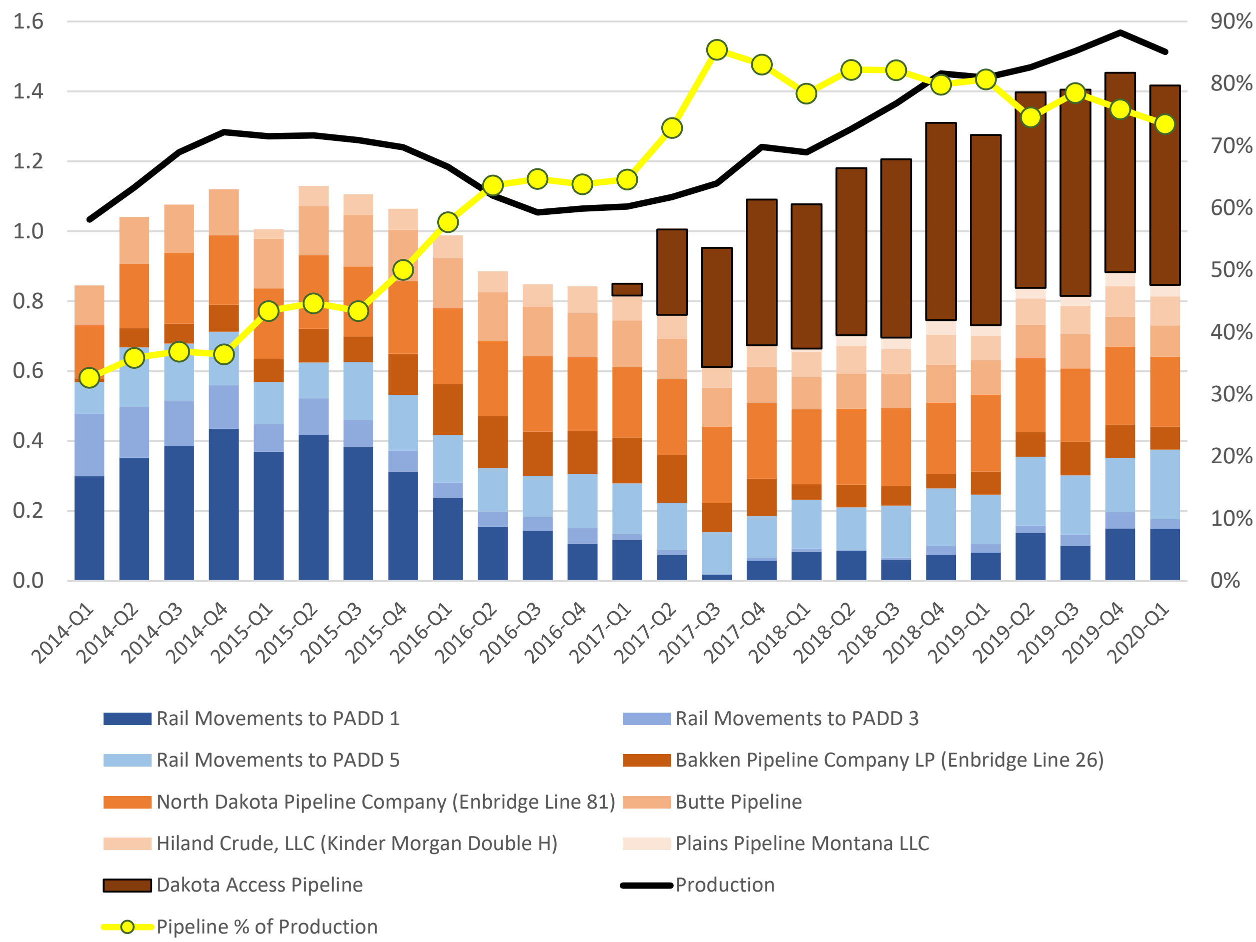
1) A review of historical Bakken oil output and disposition
2) An assessment of alternate pipeline capacity
3) An assessment of available rail loading and transportation capacity
4) A comparison of non-DAPL transportation costs
5) An analysis of the economic impacts of a potential DAPL shutdown

[2] June 2020 tax revenues are based on April 2020 producer revenues https://www.legis.nd.gov/files/resource/committee-memorandum/21.9005.11000.pdf

1. HISTORICAL BAKKEN PRODUCTION AND DISPOSITION

Exhibit 2 presents historical Bakken-Williston production and takeaway volumes from Q1 2014 through Q1 2020.[3] The takeaway volumes include pipeline and rail volumes but do not include movements to the North Dakota refiners, and net truck/rail movements to or from Canada.

Exhibit 2. Bakken Pipeline and Rail Takeaway Volumes Q1 2014- Q1 2020 (Million b/d)[4]



Source: ICF analysis of data from FERC, EIA, and NDPA

Exhibit 2 shows that Bakken crude disposition has shifted from primarily rail to primarily pipeline modes over the past six years, particularly following the Q2 2017 startup of DAPL, which provided producers and shippers access to Midwest and Gulf Coast markets at much lower prices than alternative means. The startup of DAPL, with its lower transportation costs, led to lower differentials between Bakken wellhead prices and U.S. and international benchmarks, spurring a

[3] Data are from FERC Form 6 and EIA rail movements.
[4] DAPL started interstate crude oil shipments on May 14, 2017. Some DAPL volumes shown in Q1 and Q2 2017 represent line fill injected into the pipeline prior to commercial startup.

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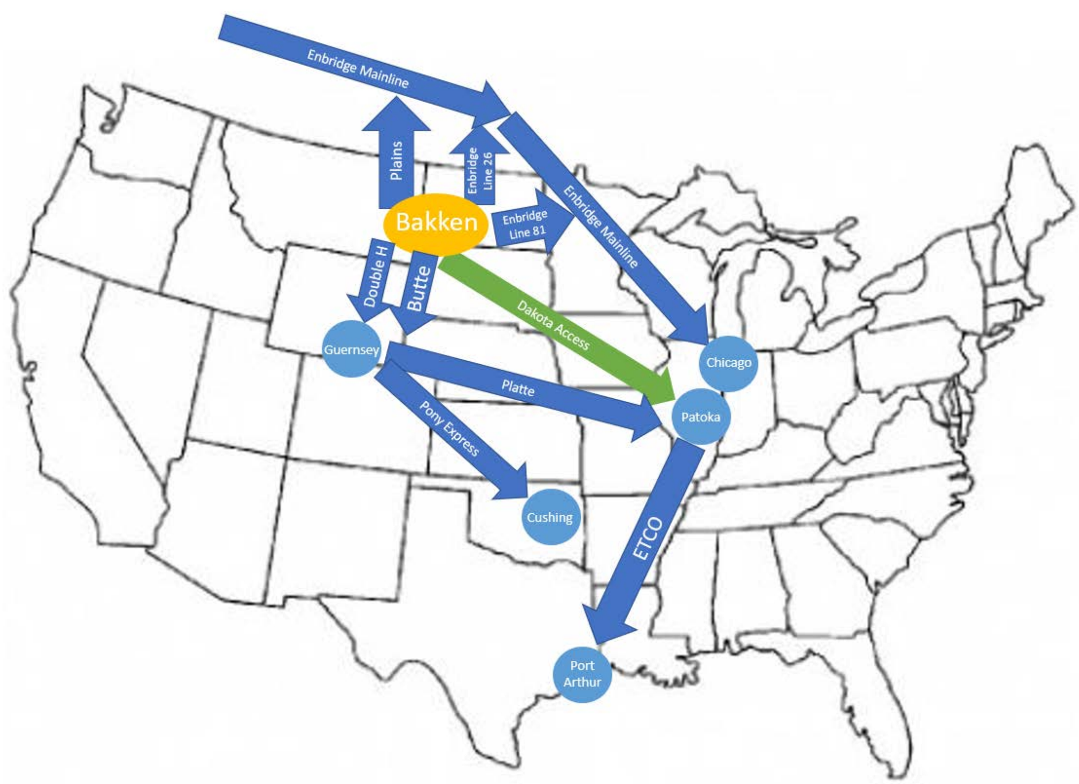
strong increase in drilling activity and new production in the Bakken region. From Q1 2017 to Q1 2020, Bakken-Williston oil production increased by more than 40% from 1.07 million b/d to 1.51 million b/d.

In Q1 2020, Bakken producers were highly dependent on pipelines for oil production takeaway with pipeline movements out of the Bakken averaging 1.04 million b/d, accounting for approximately 73% of total Bakken-Williston production volumes. Of this volume, 570,000 b/d (about 50%) was transported via DAPL, which is equal to the pipeline's full capacity. The remainder of Q1 2020 Bakken production was distributed by rail (375,000 b/d), primarily to refineries on the East Coast and in the Pacific Northwest; processed at the Mandan and Dickinson[5] refineries in North Dakota (87,000 b/d); or trucked to Enbridge pipeline receipt points in Canada (100,000 b/d).

2. ASSESSMENT OF ALTERNATE PIPELINE CAPACITY

How Bakken producers manage a potential DAPL shutdown will depend on how much effective capacity is available on alternate pipelines and rail. **Exhibit 3** presents a map of the six Bakken-Williston Basin oil takeaway pipelines and their downstream connections.

Exhibit 3. Bakken-Williston Basin Takeaway Pipelines and Their Downstream Connections



[5] The Dickinson refinery shutdown in May 2020 and is converting to biofuel in Q3 2020

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DAPL pipeline connects downstream to the Patoka, IL oil storage hub where crude volumes either flow south on the ETCO pipeline to the Gulf Coast or are shipped on crude lines from Patoka to Midwest refineries. Of the five non-DAPL takeaway pipelines, three lines (Enbridge Line 26, Enbridge Line 81, and Plains Pipeline Montana) connect downstream to the Enbridge Mainline system at interconnects in Canada or Minnesota (north and east of the Bakken). The other two takeaway pipelines (Butte and Kinder Morgan Double H) connect to the west and south to the oil logistics hub in Guernsey, MT, where they interconnect with the Platte or Pony Express pipeline systems.

Exhibit 4 lists six Bakken-Williston Basin oil takeaway pipelines, their nameplate capacities, Q1 2020 pipeline flows as reported to FERC, Q1 2020 spare capacity (calculated as nameplate capacity less flows), and Q1 2020 utilizations.

Exhibit 4. Bakken Takeaway Pipeline Capacity, Flows, and Spare Capacity (Q1 2020) (b/d)

Pipeline	Nameplate Capacity	Q1 2020 Flows	Q1 2020 Spare Capacity	Q1 2020 Utilization
Dakota Access Pipeline (DAPL)	**570,000**	**569,837**	**163**	**100%**
Connected to Enbridge Mainline				
Enbridge Line 26	145,000	65,693	79,307	45%
Enbridge Line 81	214,000	199,918	14,082	93%
Plains Pipeline Montana	40,000	33,776	6,224	84%
Connected to Platte Pipeline/Pony Express				
Butte Pipeline	260,000	89,696	170,304	34%
Kinder Morgan Double H Pipeline	84,000	82,270	1,730	98%
Total Non-DAPL Pipelines	**743,000**	**471,353**	**271,647**	**63%**

Source: ICF analysis of NDPA, pipeline company, and FERC data

Exhibit 4 indicates that in Q1 2020, total nameplate pipeline takeaway capacity was 743,000 b/d, of which approximately 272,000 b/d of spare capacity was technically available. DAPL was operating at capacity. Of the lines connecting downstream to the Enbridge Mainline, Enbridge Line 81 and Plains were operating at high utilizations, while Enbridge Line 26 was only about 45% utilized. Of the lines connecting south to Guernsey, Kinder Morgan Double H operated near capacity while the Butte pipeline operated at just one-third of capacity.

Despite the apparent spare capacity seen in **Exhibit 4**, it is estimated that only a small amount of this spare capacity could have been utilized in Q1 2020 due to downstream constraints on the Enbridge Mainline, Platte, and Pony Express systems, which primarily move production out of Western Canada. In Q1 2020, the Enbridge Mainline operated near capacity and could have only taken small additional volumes from Enbridge Lines 26 and 81, and Plains. Meanwhile, both pipelines out of Guernsey (Platte and Pony Express) were at max capacity in the Q1 2020 and could not have taken additional volumes from Butte or Double H. It should also be noted that

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quarterly flows on non-DAPL pipelines have never exceeded a combined 570,000 b/d (Q1 2016) and the highest flow since DAPL's startup was 533,000 b/d in Q4 2019.

In Q2 2020, the impacts of the COVID-19 pandemic led to shut-ins of crude oil production in Western Canada resulting in spare capacity opening up on the Enbridge, Platte, and Pony Express pipelines, increasing the ability of Bakken takeaway pipelines to increase utilization if needed. However, recent pipeline company investor calls indicate that pipeline utilizations have already been increasing in early Q3 2020 as Canadian producers restart shut-in oil sands production and conclude upgrader turnarounds. Furthermore, EIA's August 2020 STEO projects that Canadian liquids production will return to within 5% of pre-pandemic volumes by late 2020.

Given current trends, it is likely that the Enbridge, Platte, and Pony Express pipelines will have already returned to full or near full utilization by September 2020 as restored Canadian production first maximizes available pipeline capacity before turning to rail. Based on these constraints, ICF estimates total effective capacity on non-DAPL pipelines out of the Bakken to be only 500,000 b/d, well below nameplate capacity of 743,000 b/d.

3. ASSESSMENT OF RAIL TAKEAWAY CAPACITY

Effective crude-by-rail transportation capacity out of the Bakken region is a function of loading capacity at crude-by-rail terminals in the Bakken region, the receipt capacity of downstream crude oil receipt terminals, and the availability of tank cars permitted for crude oil transportation. Each of these components are discussed in the sections below. It should be noted that these factors provide a technical limit on rail takeaway capacity but may overstate the ability of producers to arrange logistics and find buyers willing to take Bakken crude via rail delivery.

Bakken Crude-by-Rail Loading Facilities

According to North Dakota Pipeline Authority (NDPA), total nameplate loading capacity at Bakken crude-by-rail terminals is approximately 1.3 million b/d. These facilities are dispersed across the Bakken region, roughly aligning with DAPL and other pipeline injection points connected to production wells and gathering systems. While Bakken-origin rail movements were as high as 714,000 b/d (ten unit train loadings/day) in 2014, volumes in Q1 2020 averaged about 375,000 b/d (approximately five unit trains/day) and were as low as 220,000 b/d (3-4 unit trains per day) in May 2020. A number of the rail loading facilities in the Bakken are not operating at this time but maintain skeleton crews. These facilities indicate that their assets are available and that it may take several weeks to a couple months to be ready to operate at capacity.[6] In order to reflect a reasonable utilization potential of these assets (due to possible rail delays, crude production variability, etc.), ICF estimates that the likely "calendar day" capacity of rail loading in the Bakken is

[6] There are a few facilities listed in various publications as being available for rail loading that we have eliminated these due to lack of response, or, in at least one case, the site tanks had been dismantled and it is now used for fracking sand.

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about 75% utilization of total nameplate capacity, or approximately 1.0 million b/d. We expect that capacity to be available within two months of a pipeline shutdown.

U.S. Crude-by-Rail Unloading Destinations

Crude-by-rail unloading capacity is primarily located in the East Coast (PADD 1), Gulf Coast (PADD 3), and West Coast (PADD 5) regions. Nameplate capability is adequate to receive approximately 1.8 million b/d by rail, far more than North Dakota could load, although many receipt terminals (especially in PADD 3) are target markets for deliveries of Canadian crude. Canadian rail deliveries to the U.S. were almost 400,000 b/d in January 2020. Recent volumes are much lower with Canadian pipelines having more capacity due to COVID-19 impacts.

Exhibit 5 shows the nameplate capacity of Bakken rail loading terminals and unloading terminals in PADDs 1, 3 and 5[7]. In addition, we show a more conservative capacity estimate based on "calendar day" capability to account for delays in rail cycle time, local logistics issues, and so on. We reflect 75% utilization for all locations except PADD 5, which has demonstrated sustained ability to receive up to 90% of listed capacity over time. The final two columns in the exhibit show average Q1 2020 rail volumes and estimated effective spare capacity over that period (subtracting Q1 2020 flows from estimated effective capacity).

Exhibit 5. Summary of Loading and Unloading Rail Capability

Location	Nameplate Capacity, TBD	Effective Capacity*, TBD	Q1 2020 Volumes, TBD	Q1 2020 Spare Capacity, TBD
Bakken Loading	**1,346**	**1,009**	**375**	**634**
PADD 1 Unloading	690	518	169	349
PADD 3 Unloading	910	682	234	448
PADD 5 Unloading (WA)	215	193	188	5
Total Unloading	**1,815**	**1,393**	**591**	**802**

*Assumed at 75% of Nameplate Capacity in PADDs 1 and 3; 90% in PADD 5
Source: ICF analysis of company websites and EIA crude-by-rail data

Exhibit 5 shows approximately 800,000 b/d of effective rail unloading spare capacity was available in Q1 2020. Therefore, in Q1 2020, U.S. crude-by-rail spare capacity plus actual Bakken crude-by-rail volumes totaled approximately 1,175,000 b/d, which is higher than the effective loading capacity in the Bakken. As a result, U.S. rail unloading capacity does not present a technical constraint on Bakken rail loadings.

PADD 1 nameplate unloading capability is reduced due to the closure of the PES refinery in Philadelphia in 2019, as well as the reduced permit for the Global rail receiving location in Albany, NY. Most PADD 1 unloading sites – other than PBF Delaware City and Phillips 66 Bayway– need

[7] For PADD 5, we are assuming that all sustainable railcar receipts are with the Puget Sound refineries in Washington State.

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the railed volume to be transloaded from rail into a tank, and then loaded on barge equipment to the refinery at an additional cost to the refinery gate.

PADD 5 unloading capability is all located at refineries in Washington State that can accept unit trains. Bakken volumes to PADD 5 peaked at 230,000 b/d in January 2020 but have declined to 100,000-150,000 b/d in April and May as refiners everywhere reduced runs. This means recent volumes could be increased up to 193,000 b/d and possibly higher.

PADD 3 nameplate unloading capability is greater than 900,000 b/d. What is important to note is that while the DAPL/ETCO pipeline system delivered 430,000 b/d to Port Arthur in the first quarter 2020, there is only about 100,000 b/d of rail receiving capability in that area, and it is already in use for receipts of Canadian Heavy and Bakken crude. The Houston area has about 200,000 b/d capacity, but the bulk of the rail would access the St. James to New Orleans corridor in Louisiana. Since up to half the Bakken shipped to Port Arthur has been exported, the specific destination of the cargoes may not matter, and with capability to get to the Clovelly terminal and LOOP, it is possible Bakken could be loaded on VLCC's with no reverse-lightering. In other words, the delivery diversity should enable Bakken crude to reach multiple refineries and export locations, even if direct delivery to Port Arthur via DAPL/ETCO is not available, albeit at a higher cost.

Railcar Availability

ICF worked with rail consultants at Hellerworx to assess the current U.S. rail system capacity to move increased volumes of Bakken crude-by-rail, including examining any constraints related to rail tank car availability, rail congestion, access to locomotives and rail crews. With respect to railcar availability, it is critical to note that most rail loading sites in the Bakken are on BNSF track and <u>BNSF does not allow crude oil railcar movements with DOT 117R (retrofitted) railcars</u>. They will only permit use of DOT 117J railcars, which have slightly thicker shells than the 117R railcars.

Exhibit 6. Summary of DOT 117J and DOT 117R Railcars in Service

Cars in Service	DOT 117J	DOT 117R
Crude Oil	12,509	7,071
Ethanol	9,980	12,359
Other Flammable Liquids	3,429	5,941
Total Railcars in Service	**25,918**	**25,371**

Source: Umler, American Association of Railroads (AAR) presentation, April 2020

With only three to four unit trains per day leaving the Bakken (likely 117J) in May 2020, and perhaps one to two Canadian sourced unit trains (likely 117R), it is likely there were spare 117J railcars available to move crude. The number of 117J railcars reportedly in crude service (12,509) would allow 11 unit trains per day to be loaded and transported on BNSF track in the Bakken and moved to the most remote location (St. James). Additional crude from Canada may be able to be transported on 117R railcars. While there are new 117J rail cars being built, ICF assumes those are dedicated to replacing the 117R rail cars carrying ethanol (since they will be prohibited after

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4/2023). The oil transport market did not anticipate a need to return to large scale crude-by-rail movements, so it is possible there could be conflict between ethanol and crude shippers for 117J railcar access.

Railroad Capacity

Hellerworx found that there should be no issues with additional unit train traffic for several reasons:

- Railroad volume has declined substantially in the past year – more than just the impact of COVID-19
- All Class 1 railroads have locomotives in storage. To load one 70,000-barrel unit train per day to Port Arthur would require 10 unit trains and 20 locomotives moving continuously (two locomotives are required per train). Per Hellerworx, there are sufficient locomotives in storage to cover at least 10 additional 70,000 b/d unit train deliveries (700,000 b/d and 200 locomotives)
- Railroads have furloughed train crews and other personnel and should be able to handle at least 100 unit train crew needs (i.e. up to 700,000 b/d delivery needs)
- Line capacity should be available in the rail systems that would be handling the crude oil unit trains.

4. ALTERNATE BAKKEN OIL TRANSPORTION COSTS

The Bakken wellhead oil price moves up and down with benchmark crude oil prices, such as WTI. The differential between the Bakken wellhead price and the WTI price is largely a function of transportation costs for the “last barrel” of crude oil moved out of the Bakken. The “last barrel” pricing concept draws on the “Law of One Price” in economics, which indicates that within the same competitive market, sellers cannot charge different prices for the same commodity (in this case a barrel of Bakken crude oil). If some Bakken producers are forced to discount wellhead sales prices to account for higher shipping costs, then all other producers in the competitive Bakken market must also equivalently discount prices due to the nature of competitive markets. This means that shifting the last barrel from DAPL to alternate pipelines will widen the Bakken-WTI differential by the difference in the cost of using DAPL and the cost of using the alternate route to reach the ultimate destination. Similarly shifting the last barrel from DAPL to rail will widen the differential by the difference between the DAPL cost and the rail transportation cost.

Rail Transport Costs

Hellerworx assessed the potential cost to move crude by rail from the Bakken region to representative destination markets, including Port Arthur, TX; St. James, LA; and Yorktown, VA. Costs to Washington State were not estimated, since this capacity is likely to be utilized first and it will not represent the last barrel of crude moved. The cost to Stroud, OK (near Cushing) was not evaluated due to information from the Stroud facility that they have a term contract to transload Canadian through 2024 and so not available to take Bakken crude.

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Exhibit 7. Estimated Rail Movement Costs from Epping, ND ($/bbl)

	Port Arthur, TX		St. James, LA		Amoco, VA	
Charge Categories	Low	High	Low	High	Low	High
Rail freight, incl. fuel surcharge	$6.67	$8.77	$6.63	$8.72	$6.67	$8.83
Railcars	$0.51	$0.51	$0.54	$0.54	$0.49	$0.49
Terminal load/unload	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
Total Charges	**$8.43**	**$10.53**	**$8.42**	**$10.51**	**$8.41**	**$10.57**

Source: Hellerworx analysis

Rail costs assume that current railcar lease fees (about $500/month) will increase to $1,000/month if DAPL is required to close. The "low" and "high" rail freight costs are based on actual costs in the high demand 2013-2015 period ("high"), and low demand 2016-2018 period ("low"). For locations which require destination transfers into refineries (PADDs 1 and 3), there may be an additional $1.00/bbl. fee.

Pipeline vs. Rail Cost Comparison

DAPL transported 570,000 b/d to Patoka, Illinois in the first quarter of 2020. From Patoka, 435,000 b/d was transported down the ETCO pipeline to Port Arthur, TX. The remaining 135,000 b/d was transported on other pipelines to Midwest refineries. A cost comparison of alternative options to move crude to Port Arthur is shown in **Exhibit 8**, including both pipeline and rail options (rail is shown both to Nederland, TX (Port Arthur) and St. James, LA). This comparison reflects a committed DAPL tariff to Port Arthur versus uncommitted pipeline tariffs to Port Arthur through alternative pipeline routes out of the Bakken, as well as estimated rail rates explained in the previous section. The use of an uncommitted tariffs is reasonable for this comparison given that the DAPL shutdown would be temporary, and shippers would not be able to get committed terms on alternate lines.

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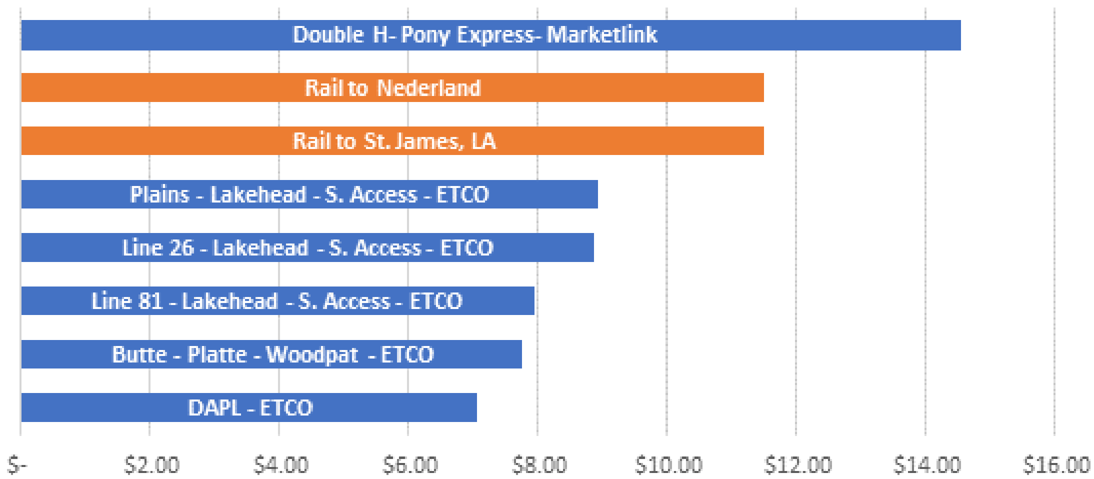
Exhibit 8. Bakken Oil Transport Costs to Port Arthur, TX Costs by Mode ($/bbl)



Source: Published pipeline tariffs, Hellerworx estimates (rail)

The rates presented in **Exhibit 8** simply present the cost differentials for shipping crude via various options. The chart does not presume that there is capacity available on the pipelines that would allow them to be utilized in the event of a DAPL shutdown.

5. ECONOMIC IMPACT ANALYSIS

To analyze the economic impacts of a DAPL shutdown, ICF modeled Bakken drilling activity, production, oil prices, producer revenues, taxes, and employment under two scenarios: one where DAPL remains in operation and one where DAPL is offline for a total of 16 months—13 months for the environmental impact study to be completed, one month for the court to review the study, and two months for the line to be refilled with oil prior to restart of commercial operations. In order to capture the longer run impacts of decisions made during the shutdown period, we analyze impacts for one additional year after the pipeline restarts for a total analysis period of 28 months.

Key Assumptions

Key assumptions of the model are described below:

- **Benchmark Oil Prices:** future oil prices from August 2020 through December 2021 are pulled from the U.S. Energy Information Administration (EIA)'s August 2020 Short-Term Energy Outlook (STEO). The STEO projects benchmark West Texas Intermediate (WTI) oil increasing from $40.50 per barrel in August 2020 to $48.00 per barrel in December 2021. Thereafter, ICF increases oil prices by an additional $0.50 per barrel per month through December 2022.

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- **Bakken Crude Oil Prices:** Bakken wellhead crude oil prices[8] follow a stepwise function:
    - For periods when DAPL is in operation, Bakken wellhead prices are set as WTI minus $4.32 per barrel (the 2019 average differential).
    - For periods when DAPL is shut down and disrupted barrels are shifted to higher cost rail transport, Bakken prices are discounted by an additional $4.49 per barrel, reflecting the difference between the DAPL/ETCO tariff to Port Arthur, TX and assessed rail costs to Gulf Coast delivery locations.
    - For periods when effective local refinery, pipeline and rail takeaway capacity are insufficient to handle produced volumes, producers are expected to discount prices to avoid shutting in production and Bakken wellhead prices are assumed to be discounted to the average cost of operating an existing Bakken well.[9] This "shut-in price floor" aligns with the "shutdown rule" in economics, which states that in the short run a firm will not continue to operate if prices fall below the average variable costs of production. In March 2020, the Dallas Fed assessed the average WTI oil price needed to cover Bakken well operating costs at $28 per barrel, which translates to approximately $23 per barrel at the Bakken wellhead given the average Bakken-WTI differential during the period of the survey.[10] ICF uses a $23 wellhead price assumption for periods when Bakken takeaway capacity is insufficient to handle produced volumes. It is possible prices could fall lower in the immediate term following the closing of DAPL depending on the operating costs for the marginal shut-in wells and producers' expectation for future prices. As shown in the sensitivity analysis in Appendix A, this would lead to larger adverse economic impacts.[11]
- **Bakken Oil and Gas Production:** Bakken oil production is modeled as a function of rig activity (driven by the historical relationship to the Bakken wellhead price), average new production volumes per rig, legacy well decline rates based on well age, and assumptions on when producers will restart output shut-in earlier in the year due to a price collapse related to demand impacts from the COVID-19 pandemic and lockdowns, and a price war between Saudi Arabia and Russia. Associated gas and NGL production are estimated based on oil output given historical ratios.
- **Effective Bakken Oil Takeaway Capacity:** ICF developed assessments of effective oil production takeaway capacity for transportation options other than DAPL, including

[8] North Dakota Crude Oil First Purchase Price from EIA. "First Purchase" is an equity (not custody) transaction involving an arms-length transfer of ownership of crude oil associated with the physical removal of the crude oil from a property (lease) for the first time. A first purchase normally occurs at the time and place of ownership transfer where the crude oil volume sold is measured and recorded on a run ticket or other similar physical evidence of purchase. The reported cost is the actual amount paid by the purchaser, allowing for any adjustments (deductions or premiums) passed on to the producer or royalty owner.
[9] This aligns with the "shutdown rule" in economics, which states that in the short-run firms will continue to produce so long as price exceeds average variable costs.
[10] Federal Reserve Bank of Dallas. Energy Slideshow (Slide 34). August 3, 2020.
[11] EIA reports that Bakken wellhead prices fell to $11.76/barrel in April of 2020. (see link in footnote 8)

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alternate pipelines, rail, and local refining. Effective alternate pipeline capacity is based on the pipeline capacity out of the Bakken that could reasonably be available given constraints on downstream pipeline systems. Although the nameplate capacity of oil pipelines (other than DAPL) out of the Bakken totals approximately 743,000 b/d, ICF estimates that only 500,000 b/d of this capacity could be effectively used to move crude oil. Effective rail capacity is assessed as the volume of crude oil that can reasonably shifted to rail given the rail loading capacity available in the Bakken and the time needed to arrange necessary logistics (ramp up operations at rail loading facilities, obtain required railcars, find buyers, etc.). Although total rail loading capacity in Bakken totals more than 1.3 million barrels per day, ICF estimates that only 420,000 b/d could be effectively loaded in the first month, ramping up to more than 900,000 b/d capacity by December 2020.

Production, Disposition, and Price Impacts

ICF's model compares forecast Bakken oil production (driven by the initial STEO price forecast) against effective takeaway capacity to estimate the disposition of crude oil to local refineries, pipelines, and rail under the two pipeline scenarios (Shutdown and No Shutdown). In the DAPL Shutdown Scenario, if volumes are forced to shut-in due to insufficient pipeline and rail takeaway capacity or are forced to rail due to insufficient pipeline takeaway capacity, the Bakken netback price is shifted downwards per the stepwise Bakken price assumptions. This in turn drives rig activity in the subsequent months and thus future oil production growth. For each month in the model, the total oil production is multiplied by the wellhead oil price to obtain a producer revenue stream, and similar calculations are performed to produce revenue streams for associated gas and NGL production. These revenue streams are then multiplied by the appropriate oil and gas extraction and income tax rates to estimate the impact on state tax revenues.

The production modeling and disposition results for the Shutdown Scenario are presented in **Exhibit 9** and the Bakken wellhead price forecasts for the Shutdown and No Shutdown Scenario are presented in **Exhibit 10.** The two scenarios are further discussed in sections below the exhibit. The exhibit shows that August 2020 production is estimated to be approximately 1.21 million b/d as producers bring back online much of the low cost, high yield production volumes that were shut-in due to the oil price collapse earlier in the year (primarily in April and May 2020). This is the starting baseline for the two DAPL scenarios.

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Exhibit 9. Modeled Bakken Oil Production and Disposition (Shutdown Scenario)

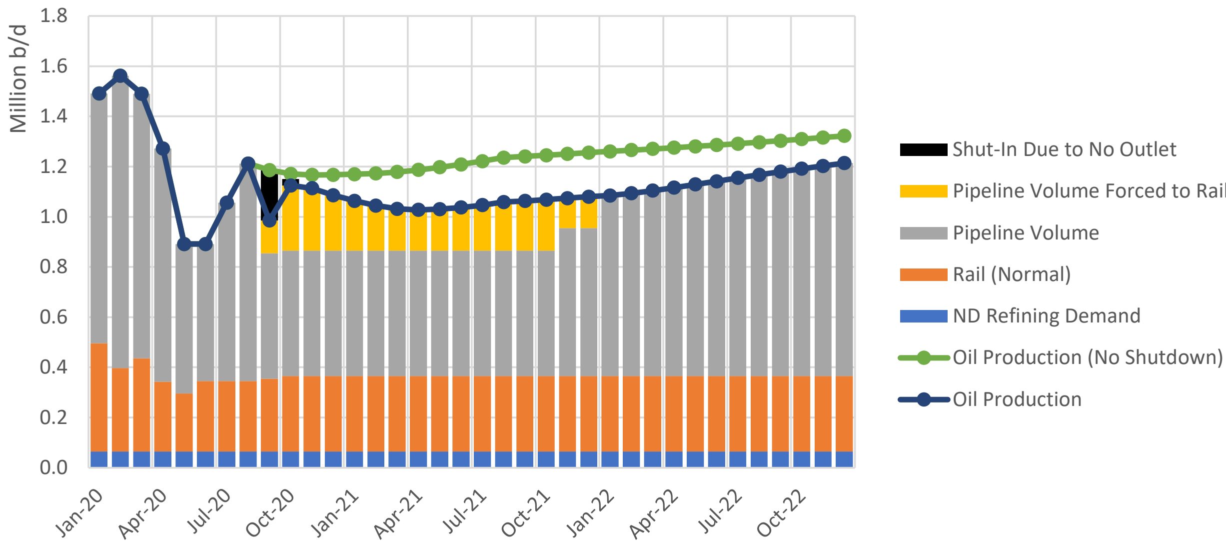
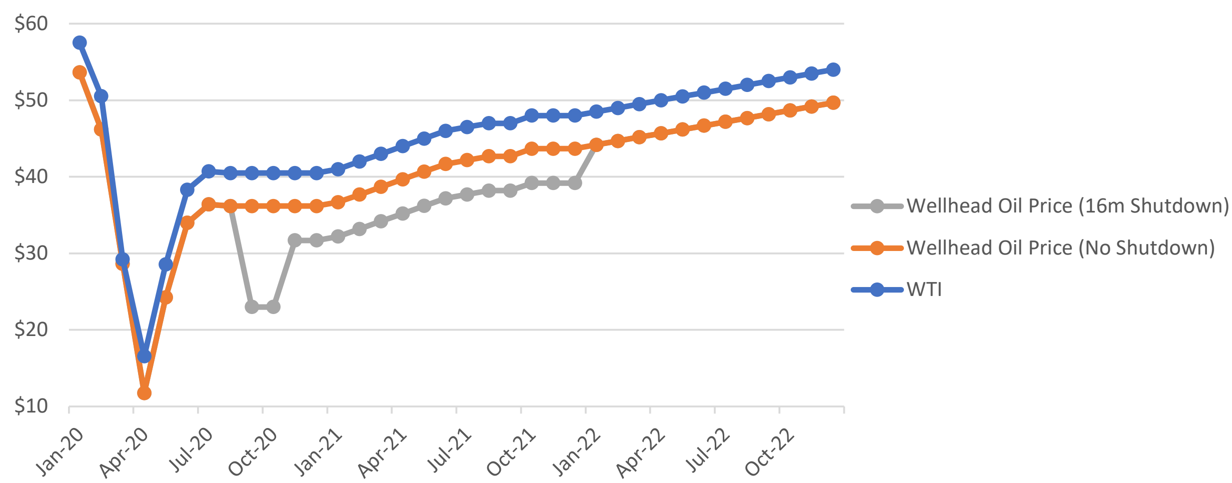


Exhibit 10. Modeled Bakken Oil Prices (Shutdown Scenario v. No Shutdown Scenario vs. WTI)



No Shutdown Scenario: If DAPL were to remain in operation, total Bakken takeaway capacity would exceed 1.415 million b/d, more than enough to handle expected production volumes in August 2020. As result, Bakken wellhead prices would follow the baseline forecast of WTI minus $4.32 per barrel. Under these prices, production would decrease slightly from August 2020 as natural declines from legacy wells exceed the restart of approximately 110,000 b/d of previously

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shut-in production and new production from newly completed wells.[12] Bakken production would bottom out at a low of approximately 1.67 million b/d in November 2020 and increases thereafter as higher prices incentivize more drilling and completion activity that exceeds the natural decline rates. Output continues to increase for the rest of the analysis period, reaching a high of approximately 1.32 million b/d at the end of the analysis period. This remains within the available takeaway capacity estimate.

Shutdown Scenario: If DAPL were to shut down for 16 months starting in September 2020, available Bakken takeaway capacity would be reduced to 0.985 million b/d (0.500 million b/d pipeline, 0.420 million b/d rail, and 0.065 million b/d local refining), which would be insufficient to handle September 2020 production volumes of 1.21 million b/d. This will initially leave an estimated 200,000 b/d of production with no outlet in September 2020, forcing an equivalent volume of production to be shut in. This will lead to a sharp reduction in the Bakken wellhead oil price as producers compete for limited takeaway capacity to avoid shutting in wells. ICF models this drop in oil prices to $23 per barrel—the assessed average shut-in price for existing Bakken wells. This price collapse would halt the return of previously shut-in production as well as any new drilling and well completions in the following months. In October 2020, production shut-ins due to takeaway constraints would be reduced to approximately 25,000 b/d as lower production (due to natural well declines and halted new production) and increased takeaway capacity (due to additional rail capacity becoming available as rail logistics and crude buyers are secured). Production and takeaway capacity will not rebalance until November 2020 when effective rail capacity becomes sufficient to handle all produced volumes. At this time, Bakken wellhead oil prices will be reset to a new equilibrium of WTI minus $8.81 per barrel, reflecting the higher cost of rail transport. This new price equilibrium will result in lower rig activity and thus lower production compared to the baseline case with DAPL in operation. In the DAPL shutdown scenario, production declines from 1.21 million b/d in August 2020 to 1.03 million b/d in April 2021 before gently rising as prices increase, reaching 1.08 million b/d by December 2021. In January 2022, DAPL restarts commercial operations thus eliminating “forced” rail volumes and eliminating the transport cost penalty. From January 2022 onwards, Bakken production growth follows the trend of the No Shutdown scenario but from a lower starting point resulting in a climb to 1.21 million b/d by the end of the year.

Revenue and Tax Impacts

Production volumes and prices presented in the preceding section are used to model impacts to producer revenues, state oil and gas extraction taxes, state income taxes, and employment. **Exhibit 11** shows the losses in oil and gas producer revenue when going from the No Shutdown to Shutdown Scenario. These impacts are broken out between losses caused by lower oil prices (during the 16-month shutdown period), losses caused by lower oil output (at the prevailing wellhead price), and losses caused by lower natural gas and NGL output.

[12] The 110,000 b/d of shut-in production is assumed to begin restarting when Bakken wellhead prices exceed $35/bbl. After the $35/bbl threshold is passed, production returns ratably over the next 12 months with 9,145 b/d of production being restored each month.

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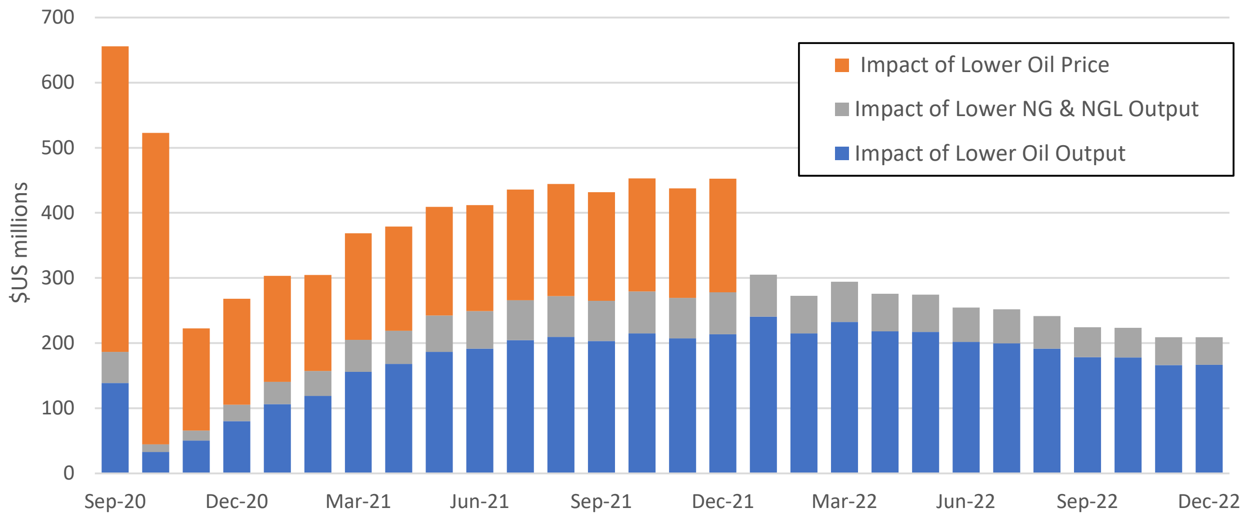
Exhibit 11. Monthly Oil and Gas Producer Revenue Losses (Shutdown Scenario vs. No Shutdown Scenario)



Revenue losses are greatest in September and October 2020 at $656 million and $523 million respectively. Revenue losses in this period are driven primarily by the lower oil price--a drop of about $13 per barrel between the No Shutdown and Shutdown scenarios---as a result of oil producers competing for limited takeaway capacity to avoid shutting in existing wells. After the constraints are alleviated in November 2020 in Shutdown Scenario, losses drop to $223 million as the market rebalances and a new price equilibrium is established at the rail transport cost differential vs. DAPL. Losses then increase during the remainder of the DAPL shutdown period as the production differential between the Shutdown and No Shutdown Scenario widens from approximately 53,000 b/d in November 2020 to 176,000 b/d by January 2022. After DAPL restarts in January 2022, losses are reduced as the price differential disappears, but remain significant due to the lasting effect of reduced drilling activity during the DAPL shutdown period. Overall, oil and gas producers are estimated to lose a total of $9.5 billion during the 28-month analysis period, including $6.5 billion during the 16-month shutdown and $3.0 during the following 12 months.

State tax revenue impacts are directly tied to oil and gas producer revenues both through taxes on oil, gas, and NGLs extracted and producer incomes. The vast majority of Bakken production (96%) takes place in North Dakota. ICF analyzed impacts on tax revenues using North Dakota's effective tax rates, including effective tax rates on oil production of 9.8%, on gas and NGL production of 4.1%, and on company incomes of 0.76% (after accounting for estimated deductions). North Dakota rates are also applied to the Montana portion of production for a full accounting of tax impacts. Over the 28-month analysis period, ICF estimates the DAPL Shutdown would result in total production tax losses of approximately $852 million and total income tax losses on oil and gas companies of $69 million in North Dakota and Montana, for a total of $921 million in tax losses. The magnitude and timing of these tax impacts would correlate with the revenue impacts presented in **Exhibit 11**, with production tax collection lagging revenue by two months.

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Employment Impacts

ICF reviewed historic upstream oil and gas production sector job counts in North Dakota from the Bureau of Labor Statistics.[13] From January 2018 through December 2019, upstream employment averaged approximately 19,000 jobs. Historic production sector employment levels are shown in **Exhibit 12**.

Exhibit 12. Historic North Dakota Upstream Oil and Gas Production Sector Jobs

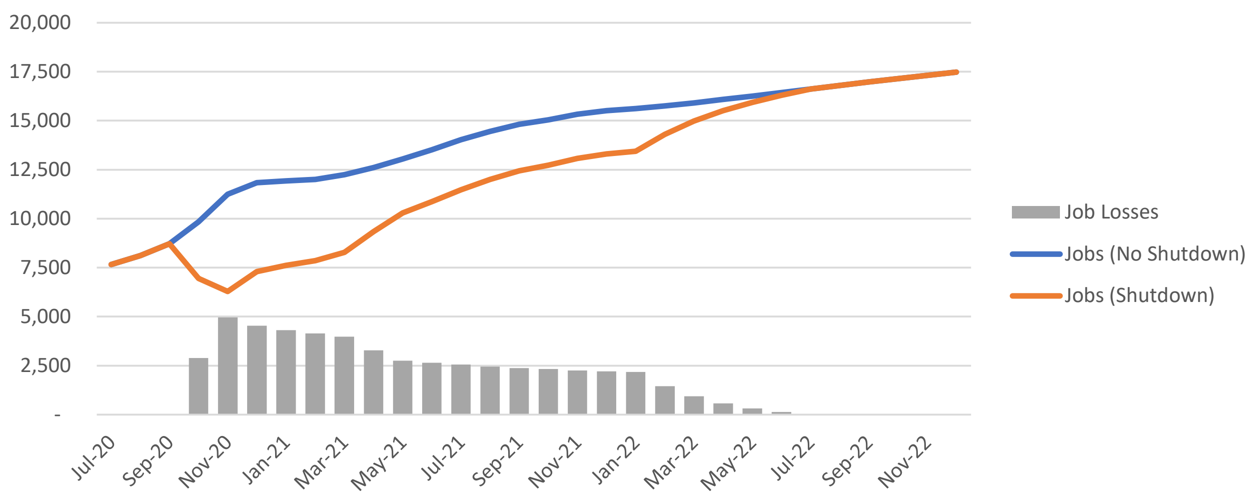
Source: Bureau of Labor Statistics

From this baseline, ICF modeled impacts on oil and gas production sector employment by correlating employment with drilling activity, which in turn is driven by the Bakken wellhead oil price. ICF assumes an observed floor of approximately 6,000 jobs in the Bakken region with minimal rigs in operation during the summer of 2020. From the employment floor, ICF increases employment ratably with drilling activity. Employment levels in the Shutdown and No Shutdown scenarios are presented in Exhibit 13. During the 16-month shutdown period, job losses in the Shutdown Scenario range from about 5,000 in the immediate aftermath of the DAPL shutdown to 2,200 in December 2021, just before DAPL restarts. After DAPL restarts in January 2022, employment gradually returns to the No Shutdown baseline as wellhead oil prices and rig activity converge under both scenarios. Over the 16-month shutdown period, direct job losses average approximately 3,000 in the oil and gas upstream sector. Reduced economic activity in the upstream sector also leads to second order effects in related (so called "indirect") sectors, such as trucking, construction, providers of onsite supporting equipment and materials. ICF estimates 1,900 indirect job losses in these sectors on average over the shutdown period and an additional 2,500 induced job losses as a result of reduced spending by direct and indirect employee

[13] Direct upstream employment is defined here using three NAICS codes: Crude Petroleum & Natural Gas Extraction (211111), Drilling Oil & Gas Wells (213111), and Support Activities for Oil & Gas Operations (213112)

purchasing consumer goods and services in their communities. In total direct, indirect, and induced job losses are estimated to average approximately 7,400 over the analysis period.

Exhibit 13. North Dakota Upstream Oil & Gas Sector Employment, Shutdown v. No Shutdown



Appendix A. Shut-in Price Floor Assumption Sensitivity Analysis

This appendix examines the impact of changing the "shut-in price floor" assumption in the model used to estimate economic impacts from a 16-month DAPL shutdown. The shut-in price floor refers to the point at which producers would shut-in production rather than continuing operating in the short-term. In theory, this will happen when wellhead prices fall below the average variable costs of production.[14] Variable costs in oil production include energy, water, transportation to point of sale, etc., but do not include certain fixed operating costs, such as full-time labor and fixed capacity costs on takeaway pipelines. In the economic model used in the DAPL shutdown analysis, the shut-in price floor is applied when Bakken takeaway capacity (from pipelines, rail terminals, and local refineries) is insufficient to handle produced volumes, forcing producers to discount prices as they compete for limited takeaway capacity. The shut-in price floor impacts the revenue calculation for Bakken producers in the months when it is applied. A lower shut-in price floor will have a proportional downward impact on revenues from crude oil sales in those months. Because future drilling decisions are based on a weighted average of the preceding month's prices, the lower shut-in price floor in the constrained months also drives lower drilling activity, particularly in the 6-month period after the shut-in price floor is applied.

In the economic analysis, ICF used a shut-in price floor assumption of $23 per barrel. This price was derived from a March 2020 Dallas Fed survey of five oil producers that assessed the average WTI oil price needed to cover Bakken well operating costs at $28 per barrel. To get the equivalent Bakken wellhead breakeven price, ICF subtracted the approximate Bakken-WTI differential during the period of the survey (about $5).[15] The $23/bbl shut-in price floor is a convenient and defensible assumption but obscures some of the complexity associated with producer-to-producer and well-to-well variance in operating costs. The Dallas Fed survey of five producers showed that in March 2020 operating cost breakevens ranged from as high has $45 WTI ($40 Bakken) to as low as $10 WTI ($5 Bakken) (See Exhibit 1).

In reality, the shut-in price floor/operating breakeven may not be a single fixed number but may move along a scale—as producers discount prices to compete for limited takeaway capacity, the highest cost producers begin shutting in wells first until a balance between output and available takeaway capacity is reached. Accordingly, the price that achieves this balance will fall as the difference between output and available takeaway capacity increases. Predicting exactly how far this price falls would require a well-by-well database of operating costs.

[14] This aligns with the "shutdown rule" in economics, which states that in the short-run firms will continue to produce so long as price exceeds average variable costs.
[15] Federal Reserve Bank of Dallas. Energy Slideshow (Slide 34). August 3, 2020.

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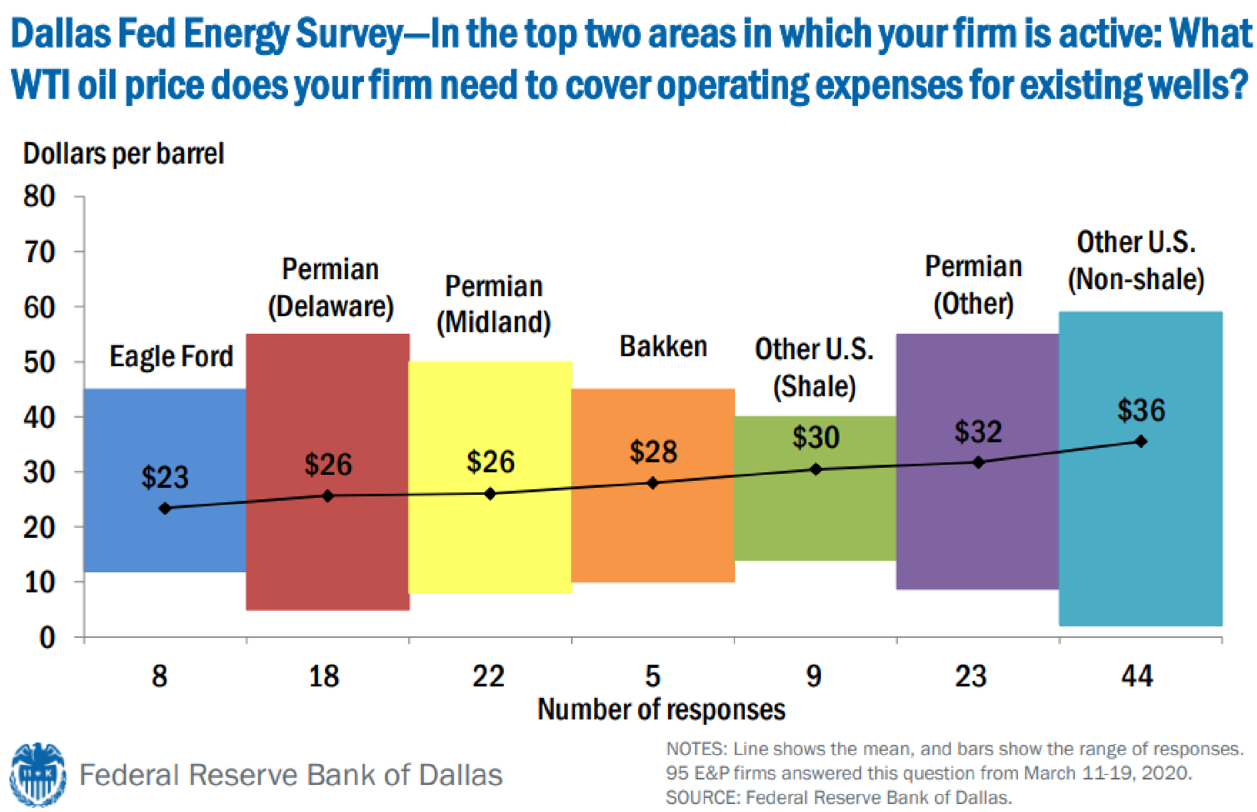
Exhibit 14. Shut-In Prices for Existing Wells Assessed by Dallas Fed



Source: Federal Reserve Bank of Dallas. Energy Slide Show. August 3, 2020.

In addition to the theoretical limitations mentioned, the shut-in price floor assumption may be complicated by a number of additional "real world" factors, including the cost of shutting-in and later restarting wells, the time it takes get contractors to safely shut-in wells, the impact of shutting-in wells on well pressure and the ultimate recoverable resource, whether producers are locked into term contracts, how long the price depression is expected to last, the time-value of money, etc. In the very short-term, it is possible that these "real world" issues temporarily force prices well below the theoretical shut-in price floor.

Given the inherent uncertainty in the shut-in price floor assumption, ICF ran a sensitivity analysis to understand how changes in the shut-in price floor impacted the modeled outcomes. For this analysis, ICF selected alternative Bakken wellhead shut-in price floor assumptions of $13, $18, and $28 per barrel. Results of this analysis are presented in Exhibit 2.

Exhibit 15. Sensitivity Analysis: Economic Impacts of DAPL Shutdown Using Various Shut-in Price Floor Assumptions

Time Period	Data Item	Unit	Impact of DAPL Shutdown vs No Shutdown Case @ Shut-in Price Floor of: $13	$18	$23	$28
16-month Shutdown Period (9/2020 to 12/2021)	Average Bakken to WTI Differential	$/bbl.	(6.83)	(6.20)	(5.58)	(4.95)
	Average Bakken Wellhead Price	$/bbl.	(6.83)	(6.20)	(5.58)	(4.95)
	Average Rig Count	count	(16.1)	(15.7)	(14.3)	(11.9)
	Avg. Jobs in Upstream Sectors	count	(3,992)	(3,472)	(2,978)	(2,511)
	Avg. Jobs in All Upstream-related Direct and Indirect Sectors	count	(6,519)	(5,669)	(4,863)	(4,101)
	Avg. for All Direct, Indirect and Induced Jobs	count	(9,883)	(8,595)	(7,373)	(6,217)
28-month Analysis Period (9/2020 to 12/2022)	Cumulative New Wells Completed	count	(701)	(682)	(628)	(529)
	Cumulative Crude Oil Produced	MMB	(130)	(126)	(115)	(94)
	Cumulative Natural Gas Produced	Bcf	(241)	(234)	(213)	(174)
	Cumulative NGPL Produced	MMB	(45)	(44)	(40)	(33)
	Producer Revenues	$MM	(10,954)	(10,436)	(9,538)	(8,169)
	State Production Taxes	$MM	(981)	(933)	(852)	(732)
	State Income Taxes Attributable to O&G Activity	$MM	(79)	(75)	(69)	(59)

Exhibit 2 shows that applying a lower shut-in price floor has a significant impact on total economic impacts, although the impacts are non-linear. Dropping the shut-in price floor by $5 (from $23 to $18) increases producer revenue losses by $1.1 billion over the 28-month analysis period. Dropping the shut-in price floor by another $5 (to $13) increases producer revenue loses by a further $0.5 billion. Impacts on rig activity over the 16-month DAPL shutdown period and cumulative oil production over the 28-month period show similar non-linear trends as the shut-in price floor falls.

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