Shut In? Assessing the Merits of Government Supply Intervention in the Alberta Oil Industry

- **Ongoing and acute takeaway capacity bottlenecks present the Western Canadian oil patch with an extraordinary challenge, potentially depriving Alberta's upstream industry of C$15-39 billion[1] in royalty-applicable earnings[2] and the provincial government of C$1.5–4.1 billion[1] (roughly C$350–950 per Albertan) in royalty revenue in 2019**, all else equal, when compared to a scenario with adequate pipeline capacity (chart 1).

- **While the impacts of these bottlenecks are large, the overhang of stranded barrels is relatively small**—roughly 140 kbpd or 3% of Western Canadian production—and there have been calls for the Alberta government to help address the discount situation by throttling back or "shutting in" provincial oil production. In theory, such a policy could facilitate a narrowing of benchmark discounts by reducing competition for increasingly scarce pipeline and rail capacity until new takeaway infrastructure enters service in late-2019.

- **The bar for the government to intervene directly into the energy sector should be a high one** and the policy option should only be considered in an effort to prevent extreme value destruction.

- **We estimate that a supply restraint policy option, if executed efficiently, could avoid C$3–27 billion of the C$15-39 billion[1] in foregone upstream royalty-applicable earnings[2] and allow the province to recuperate C$0.3–2.9 billion of the C$1.5–4.1[1] billion in lost royalty revenue (chart 1).**

- **If discounts fall back, as we expect, to a more moderate level in 2019, the pay-off of government intervention is likely to be too small to justify the policy action;** however, if discounts remain wide around current levels (chart 2), the action could be justified given the magnitude of potential upstream earnings and royalty revenue losses.

- This is part of our ongoing research on the impact of Canadian oil differentials and the focus of these estimates is royalty-applicable revenues[2] and the impact of reduced royalties on the Alberta government's fiscal position. **Our analysis does not consider the additional costs of similarly depressed synthetic crude oil (SCO) (chart 2)**, which is treated as processed product rather than a raw commodity in this estimation, nor does it consider the impact of lost corporate or individual income tax revenue; **our next note on the subject will tackle a fuller valuation of Western Canadian upstream earnings**, taking into account other potential hedges against spot discount movements.

[1] All opportunity cost calculations are relative to a "adequate pipeline capacity" scenario (WCS-WTI: -US$13/bbl, MSW-WTI: -US$3/bbl); the lower end of the stated range reflects our current base case outlook for Canadian oil benchmarks (WCS-WTI: -US$24/bbl, MSW-WTI: -US$8.50/bbl) while the upper end reflects a scenario where discounts remain distressed around current levels (WCS-WTI: -US$40/bbl, MSW-WTI: -US$30/bbl) for the duration of 2019; see chart 1.

[2] "Royalty-applicable earnings" only account for the value of extracted petroleum (i.e. raw bitumen, conventional crude), from which royalties are calculated, and does not consider the additional value derived from upgrading to products like synthetic crude, though such integrated capabilities do insulate some bitumen producers from spot discount movements; see discussion in following section for more details on this valuation methodology.

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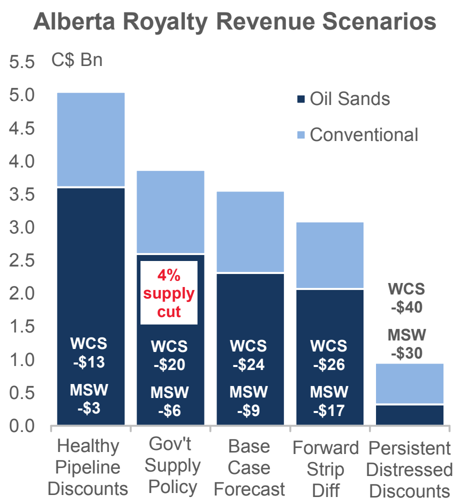
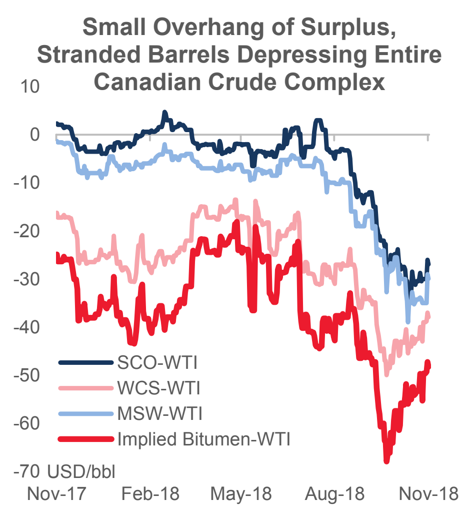
Chart 1



Note: Cal 2019, WTI US$60/bbl, CADUSD at 0.77; all discounts are in USD/bbl vs WTI; opportunity cost estimates are vs an "healthy pipeline " scenario, which we believe would see WCS discounts fall to $13/bbl; all other discount assumptions stated in chart.
Sources: Scotiabank Economics, Alberta Finance, Alberta Energy, NEB, AER, Bloomberg.

Chart 2



Sources: Scotiabank Economics, Bloomberg.

BACKGROUND AND CONTEXT: WHAT'S GOING ON AND HOW DID WE GET HERE?

The pipeline crisis facing the Western Canadian oil patch is by now a well-known story. (See our earlier work on the subject here and here.) **Put simply, there aren't enough pipelines to transport the crude from where it's produced in Western Canada to where it's consumed**, predominantly refineries in the US. This has widened the discount received for Canadian crude relative to US varieties—namely West Texas Intermediate (WTI), the primary North American light sweet crude benchmark—as Canadian barrels need to be marked down to account for the higher cost of marginal transportation. That additional cost necessitates that the Canadian crude discount, which is set by the last barrel clearing the market, needs to rise from an average of about US$13/bbl for Western Canadian Select (WCS, a heavy sour crude) in normal times to above US$20/bbl to account for the cost of pricier transportation like rail. But when production rises beyond the capacity of pipelines and rail combined, as Canada's oil patch is experiencing today, producers are forced to utilize even higher-cost transportation methods or to wait out the storm in provincial storage tanks already filled to the brim. The value of these stranded barrels plummets, dragging the regional benchmark down with them—most recently to an all-time high WCS discount of more than $50/bbl under WTI (chart 2). And while past discount blowouts have been mostly contained to heavy crude blends, even lighter crudes like Edmonton Mixed Sweet Blend (MSW) are trading at discounts of more than US$30/bbl despite being nearly equivalent grades of oil to WTI.

The good news is there is light at the end of the proverbial pipeline. Enbridge's Line 3 replacement is expected to come into service by late-2019, providing a cheap transportation outlet for 370 kbpd of currently-distressed crude. **The bad news is that Line 3 is still at least a year away**. Between now and next winter the Western Canadian oil market is at the mercy of rail schedulers and their attempts to mobilize more locomotives, tank cars, and trained crews—an effort that has thus far proved insufficient to clear the market.

ROYALTY REVENUE REGRET: POUR ONE OUT FOR THE STRANDED BARRELS

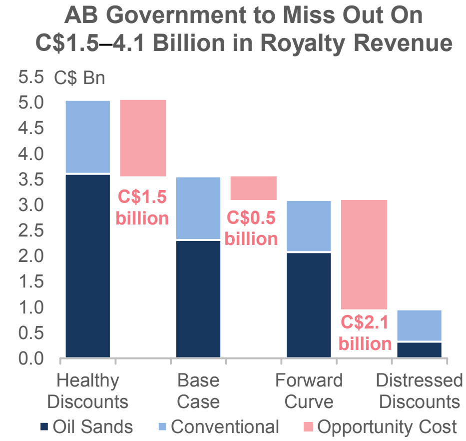
The high discounts currently plaguing barrels of Canadian crude destroy substantial value. In addition to the considerable toll that wider differentials are taking on the Canadian oil patch—where royalty-applicable revenues are set to underperform by C$15–39 bn—the Alberta government is on track to lose C$1.5–4.1 bn in royalty revenue in 2019 relative to a scenario where adequate pipeline capacity was available (chart 3). This loss of potential royalty revenue stemming from depressed provincial commodity pricing complicates the Alberta government's planned return to black ink, which already relies on robust economic growth and expenditure restraint.

Table 1: Oil Sands Royalty Guidelines

WTI Price	Pre-Payout	Post-Payout
≤ C$55/bbl	1% x Gross Revenue	25% x Net Revenue
C$55–120/bbl	{1% + [(8%/$65) x (C$ WTI - $55)]} x Gross Revenue	{25% + [(15%/$65) x (C$ WTI - $55)]} x Net Revenue
≥ C$120	9% x Gross Revenue	40% x Net Revenue

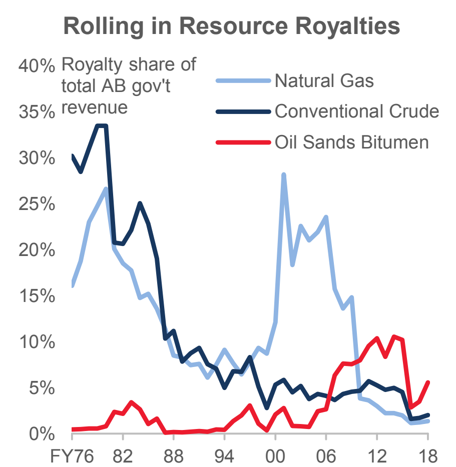
Source: Alberta Energy, full guideline document here, see chart 5 for pre/post-payout oil sands production volumes.

Chart 3



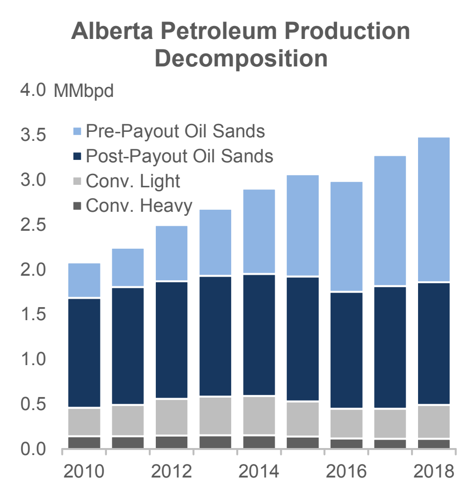
Note: Cal 2019, WTI US$60/bbl, CADUSD 0.77.
Sources: Scotiabank Economics, Alberta Energy, Alberta Finance, AER, NEB, Bloomberg.

Chart 4



Sources: Scotiabank Economics, Alberta Finance, Alberta Energy, Bloomberg.

Chart 5



Source: Scotiabank Economics, Alberta Energy, NEB, AER, Bloomberg.

Royalties are fees charged to resource developers by the owners of the resource under development. In Alberta, the provincial government owns more than 80% of mineral rights and applies a specific royalty rate to each unique oil well, gas well and oil sands project. **Given the province's energy-intensive economic base and status as a significant player in global oil and gas markets, royalty receipts have historically accounted for a substantial share of provincial government revenues (chart 4) and therefore constitute a key plank of fiscal planning**. In the Alberta government's last fiscal update, oil-related royalty revenues were forecast to come in around C$3.6 bn and make up 7.4% of total government receipts in FY19, assuming average WTI prices of US$61/bbl and a WCS discount of US$24/bbl.

Oil sector royalties received by the provincial government are a function of three factors: revenue generated from extractive operations, a project's payout status (chart 5), and the Canadian dollar price of WTI (Table 1). Another important consideration is that oil sands revenues are only collected on the value of the underlying bitumen a company extracts, rather than the value of the end-product that a company blends and ultimately sells to the market—for instance, bitumen that is upgraded to the status of more valuable synthetic crude (SCO). Royalty-applicable revenue[3] from Alberta's oil patch totalled an estimated C$44 bn in 2017: C$35.4 bn from oil sands operations and C$8.6 bn from conventional wells (chart 6). These industry revenues translated to an estimated C$3.4 bn in royalty receipts for calendar year 2017 (C$2.5 bn oil sands, C$0.9 bn conventional, chart 7).

REGULATORY RESCUE REDUX: SHOULD THE PROVINCIAL GOVERNMENT STEP IN TO SAVE THE PATCH?

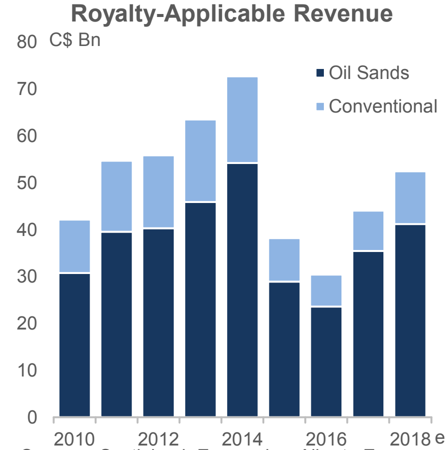
Given the lack of pipeline progress and sluggish oil-by-rail pick-up, the only real control rests on the supply side of the regional ledger. A handful of companies have already reduced output in the face of poor pricing and some have suggested that the provincial government needs to step in to organize a larger collective pullback to save Western Canadian producers from their collective action problem. **However, the bar for the government to intervene directly into the energy sector should be a high one**—top-down policy intervention is likely to be relatively inefficient as a means of controlling supply and should only be conducted if the action materially increases aggregate sector earnings and significantly raises provincial royalties.

In the market-only solution, producers can individually throttle back production, which has the effect of reducing competition for scarce pipeline and rail capacity, thereby lifting prices currently depressed by a mild overhang of surplus, stranded barrels. Some producers have done this already, voluntarily tightening the spigot on less economically productive assets in early-2018 until differentials improved through the spring. Companies have publicly communicated that a combined 140 kbpd of production will also be cut back through this winter as differentials remain wide.

Unfortunately, current curtailment plans are insufficient to completely clear the market and companies that pursue this strategy alone are enduring a first-mover disadvantage as some producers benefit from others' restraint without enduring any of the pain of cutting. This free-rider dilemma is further complicated by the fact that any efforts to negotiate some kind of regional production alliance or supply restraint pledge would likely run afoul of competition laws—under normal circumstances a group of producers collectively agreeing to reduce supply to inflate the value of their products would be viewed as anti-competitive behaviour.

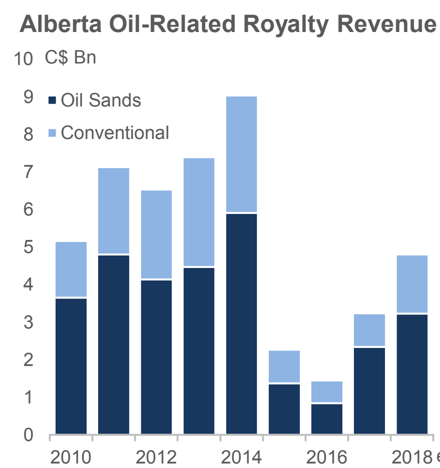
But these are not normal times and producers are experiencing a collective action problem that only an authority outside the industry can more completely address. This is where the Alberta government could potentially help. Section 85(1) of the Alberta Mines and Minerals Act gives the provincial government the power to "make regulations fixing the

Chart 6



Sources: Scotiabank Economics, Alberta Energy, Bloomberg, NEB.

Chart 7



Sources: Scotiabank Economics, Alberta Energy, Bloomberg, NEB.

[3] The value of a barrel of bitumen can be derived by backing out the cost of the higher-priced diluent (typically condensate, which trades nearer the price of WTI) from the WCS benchmark price. While royalty-applicable revenues don't reflect the uplift of upgraded products, integrated producers do have an effective hedge for the purposes of bitumen valuation: roughly 1.1 MMbpd of bitumen production, or just more than one-third of total oil sands output, enjoys some kind of hedge—typically reflecting an integrated refining asset or contracted firm pipeline capacity out of Western Canada—effectively insulating those barrels from movements in the spot market discount. For the purposes of this analysis, those barrels are treated as trading at a steady "healthy" bitumen discount (WCS-WTI: -US$13/bbl) regardless of how acutely the WCS differential has widened.

maximum amount of petroleum that may be produced under Crown agreements”, if such a regulation was found to be in the public interest. Such a policy could compel producers in Alberta to reduce output by some proportional volume across the board, taking 100–200 kbpd off the market and bringing regional production comfortably back in line with the capacity of pipeline and oil-by-rail services. We believe that a production cut of 140 kbpd—4% of Albertan conventional and oil sands output—from our baseline (chart 8) would be enough to draw down bloated inventories and facilitate a narrowing of the Canadian heavy oil discount from its current inflated level of almost $40/bbl under WTI to nearer $20/bbl.

We estimate that a supply curtailment policy, if executed efficiently, could avoid C$3–27 bn of the C$15-39 bn in foregone upstream royalty-applicable earnings and allow the province to recuperate C$0.3–2.9 bn of the C$1.5–4.1 bn in lost royalty revenue (chart 9). If discounts fall back in line with our forecast to a more moderate level in 2019 ($24/bbl WCS, $8.50/bbl MSW), the pay-off of government intervention ($20/bbl WCS, $6/bbl MSW) is likely to be too small to justify the policy action; however, if discounts remain exceptionally and persistently wide around current levels ($40/bbl WCS, $30/bbl MSW), the action could be justified in the interests of avoiding considerable value destruction. **The window of immediate need for such a policy action is expected to close later next year when additional pipeline capacity enters service**—we currently expect Enbridge’s Line 3 to begin operations in November 2019 (chart 10).

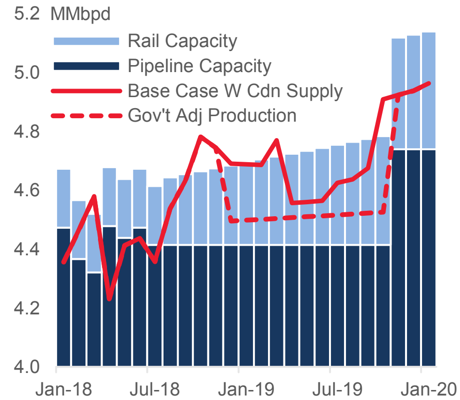
In addition to potentially preventing considerable value destruction, this policy option could bolster the government’s flexibility in responding to other sudden disruptive events like the Keystone pipeline outage in late-2017 that kick-started the early-2018 differential blowout. The flexibility to respond to unforeseen events and keep the industry on steady footing would also signal to the market that the distressed discount situation is under some degree of control, helping mitigate some of the uncertainty currently dragging on both energy sector capital investment and foreign investments into the Canadian energy space.

That the provincial government could step in to manage production has become an understandably controversial policy option, with the Alberta oil patch split between integrated producers—who have outlets for their discounted crude and thus aren’t feeling same degree of spot differential pain—and those facing serious headwinds given heavy spot market exposure and a lack of integrated downstream assets. The integrated opponents of the proposal blame those who have ramped up production without a plan to get their product to market, while proponents claim that pipeline delays are a political challenge that requires a policy solution. **That we are even discussing such a policy option is far from ideal—the least expensive, cleanest, and safest solution to this challenge remains the construction of additional pipelines.** There has also been some speculation that 85(1) does not apply to oil sands production, but the use of “petroleum” in the statutory language allows for some wiggle room in its application, in our view; furthermore, any question on the interpretation of this statute could be settled by new legislation clarifying the powers of government in this area.

Today’s acute discounts are expected to narrow considerably when Line 3 replacement enters service in late-2019, but unexpected delays have become synonymous with pipeline construction and that timeline could easily slip back into early 2020. **Beyond Line 3, the Western Canada patch will still require another major pipeline—either the Trans Mountain Expansion Project (TMEP) or Keystone XL (KXL)—in the early 2020s**. Unfortunately, both of those midstream projects have run into renewed legal opposition that will add months or years to previously anticipated timelines. Without either TMEP or KXL, the Canadian oil patch is likely to find itself back where we are today in only a few years, having the same “what can be done?” conversations after enduring billions in lost revenue along the way.

Chart 8

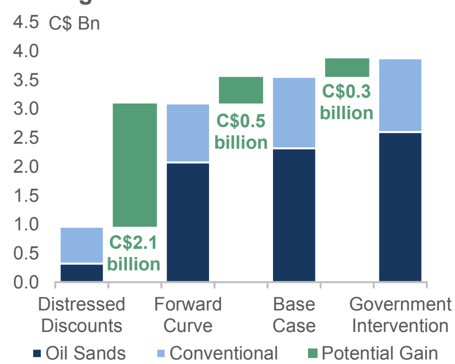
Invisible Hand Might Need Temporary Help from a Friend in Edmonton



Sources: Scotiabank Economics, Scotiabank GBM, CAPP, AER.

Chart 9

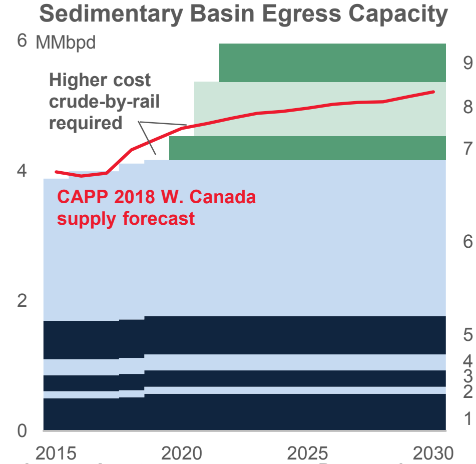
AB Government Could Raise Royalty Revenues by C$0.3–2.9 Billion with Legislated Production Restraint



Note: Cal 2019, WTI US$60/bbl, CADUSD 0.77.
Sources: Scotiabank Economics, Alberta Energy Department, AER, NEB, Bloomberg.

Chart 10

Pipeline Roulette: Western Canadian Sedimentary Basin Egress Capacity



Legacy Assets		Proposed
1. W. Cdn Refineries	4. Express	7. Line 3
2. R & Milk River	5. Keystone	8. KXL
3. Trans Mountain	6. Mainline	9. TMEP

Sources: Scotiabank Economics, CAPP.