Drained Away: Oil Lost from First Nations Reserves

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PRELIMINARY AND INCOMPLETE: PLEASE DO NOT CIRCULATE

Abstract

Inefficiencies in common pool resources are well-known, but in this paper we show how the common pool can also generate stark inequities. In Western Canada, many oil pools underlie land straddling the borders of First Nations reserves. We find that the shared resources were disproportionately extracted by wells drilled off reserves but in close proximity to reserve borders. Evidence suggests oil was drained from First Nations reserves, contributing to a large drop in production on reserve between 1985 and 2005. We explore the avenues through which First Nations could have been compensated for the lost production and find none were pursued. These results provide further evidence that the current regulatory environment of the oil industry does not adequately address the dual problem of equity and efficiency in the common pool.

JEL–Classification: Q32, Q48, J15

Keywords: resource equity, oil, Indigenous economics

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1 Introduction

Common pool resources have the well-known potential to lead to efficiency losses. Losses arise when private owners deviate from socially optimal decisions about extraction rates and capital investments. Less well-documented are the equity implications. In theory, efficiency gains can be had in a common pool where actors have heterogenous costs, by allocating more resources to the lower-cost party. This efficiency gain however, comes at the expense of equity.

In this paper, we present both a theoretical model and empirical evidence suggesting a case in which common pool resources have led to stark equity losses for many First Nations communities. We examine production from common pools of oil on and off First Nations reserves in Alberta and Saskatchewan, the provinces in Canada producing the majority of the oil in Canada. In the 1870s, federal legislation and treaties between First Nations and Canada recognized tracts of land known as reserves for the exclusive use of First Nations.[1] First Nations reserves introduce frictions in the form of higher transaction costs as well as restricted land and credit markets, although they also confer some protection of Native lands from further appropriation. But the creation of reserves certainly would not protect yet-to-be-uncovered oil from appropriation. In the following century, valuable minerals were found to span many of the borders, underlying land on and off First Nations reserves.

We find unequal production from common pools of oil spanning First Nations reserve borders in Alberta and Saskatchewan. In particular, we show compelling new evidence that wells drilled close to First Nations reserves were responsible for draining oil from the reserves, resulting in higher production off reserve. To the best of our knowledge, these patterns of drainage have not been previously documented. Our findings provide an important critique of the rule of capture, the rule widely adopted across oil- and gas-producing jurisdictions as

[1] Under Section 35 of the Constitution Act, First Nations are one of three broad categories of Indigenous Peoples in what is now known as Canada, the other two categories being Inuit and Métis. Treaties between First Nations and Canada known as historic numbered treaties and the Indian Act created the "Indian reservation system" for First Nations communities.

the method to assign ownership of the oil and gas produced. The rule states that ownership is determined when the oil is brought to the surface, regardless of where the oil originated in the subsurface. The adoption is so widespread that it is little questioned, and only more rules have been developed to reduce inefficiencies arising from the race to be the first to extract. Here we point out that the rule of capture, although applied equally, does not affect everyone equally.

We document a pattern in which production from wells within two kilometers of reserve borders coincided on and off reserve from the 1970s until the mid-1980s. Between 1985 and 2005, production from wells off reserve dominated production from wells on reserve. The history of events in the mid-1980s suggests many factors would have led to a price wedge between production from mineral leases that were federally managed on behalf of First Nations and production from mineral leases owned by the provincial Crown. Provincial policies disposed of federal taxes and price regulation, reduced royalty rates, and introduced tax incentives for production from provincial Crown mineral leases. One mechanism through which firms could capture resources at a lower cost would be to drain oil from First Nations leases, by extracting near the reserve but on provincially managed leases. We find that the drop in production from wells on First Nations reserves in the mid-1980s is at least partly driven by wells drilled close to reserve borders. We rely on a variety of methods, including distance-to-border fixed effects regressions, to show that much of the off-reserve production came from drainage of oil that originated on reserve. We also find evidence that firms paid more for the leases nearest First Nations reserve borders. This suggests premeditation: firms had the expectation that they would maximize production when they drilled close to a reserve.

The case studied in this paper is one of common pool extraction by agents with heterogeneous costs. Previous work on heterogeneity in the common pool has focused on characterizing who wins or loses when free access of the common pool is restricted (Weitzman et al., 1974; De Meza and Gould, 1987). Knowing who wins or loses is important to know the likelihood of reaching a coordination agreement to efficiently extract (Ostrom, 1990). The literature has shown that heterogeneity in efficiency losses from free access depends on the degree of heterogeneity across extractors (Johnson and Libecap, 1982; Dayton-Johnson and Bardhan, 2002), type of heterogeneity (Libecap and Wiggins, 1984; Baland and Platteau, 1998; Grainger and Costello, 2016), or type of resource (Lueck, 1995), with the benefits of addressing inefficiencies depending on the type of regulatory instrument used (Ambec and Sebi, 2011). This literature on heterogeneity has focused on determining efficiency and equity implications from restricting free access, focusing on static gains and losses.

We examine a case in which free access is already being restricted at a level that is common across oil and gas jurisdictions: in place are well-spacing limits, maximum rate limits, albeit non-binding, and unitization, albeit minimal. And, yet, we find still large inequities arise. As one might expect, a higher-cost extractor will get a smaller share of the resource, but we quantify the extent to which this happens and find large differences in production within the same pool.

Then by also examining dynamic implications of heterogeneity, we reveal how inequities can be further exacerbated by dynamic inefficiencies, previously undocumented. We adapt a dynamic model of common pool extraction to the case of heterogenous extractors, and show a higher-cost extractor not only produces less but also extracts faster, deviating more from the Hotelling-optimal extraction rate. In our context, we assume the First Nation is the higher-cost extractor on the basis of higher costs associated with exploration, obtaining rights to drill, and production. In this context, inequitable production away from First Nations also presents an exacerbation of already unequal economic conditions. Quoting Blaine Favel, former chief of the Poundmaker Cree Nation, "This is a finite resource that has been drained, and it has been drained from the poorest people in Canada" (Galloway, 2016).

A key question is whether First Nations were compensated for the excess production off reserve. Although the rule of capture states that this excess production is legal, regulations are in place to limit or compensate losses from drainage that occurs across different ownership types. When an off-reserve well is draining from a First Nations reserve, the federal regulator is legally required to intervene to ensure "equitable production."[2] The policy tool that regulators use to address drainage is an offset notice. When a well is drilled close to the border, the regulator can issue a notice for the leaseholder of the adjoining tract, requiring the leaseholder to drill a well to prevent drainage, present evidence of joint production, pay royalties commensurate with the drainage, or relinquish the lease. Offset notices are an example of a regulator-induced inefficiency, that more wells are drilled than socially necessary, however, given the rule of capture, offset notices are the only tool regulators have to prevent royalties being lost to the other jurisdiction. Examining the history of offset notices issued by the federal government on behalf of First Nations, which we obtained through two Access to Information and Privacy Act requests, we see that offset notices were rarely used, with an uptick in use only in 2019, when the Indian Oil and Gas Act was modernized.

This research may have important implications for First Nations with oil resources, in part because missing production suggests missing income. Missing production also raises questions about the role of the regulator. Energy systems on First Nations land currently exist within a regulatory environment developed and controlled by the federal government. Looking ahead, federal oversight of energy projects will continue to be relevant, as First Nations begin to pursue economic autonomy and energy sovereignty through energy transitions (Powell, 2015; Stefanelli et al., 2019).[3] Our findings relate to several themes of importance to First Nations—including natural resource management, sustainability, economic development, and sovereignty—so we approached this research with the deliberate engagement of Indigenous guides, rights holders, and stakeholders to minimize harm.

The rest of this paper proceeds as follows. Section 2 provides background information in

[2]Similarly, when a well on a First Nations reserve is draining provincial Crown minerals, the provincial regulator is responsible for stepping in. We discuss the regulatory environment in more detail in Section 2.1.

[3]Energy sovereignty centers the rights of communities to make their own decisions about energy sources and to control environmental, economic, and social externalities associated with energy production. Principles of energy sovereignty imply that the laws, policies, rules, and regulations governing energy systems on First Nations land must be formulated by the communities themselves (Schelly et al., 2020).

three parts: Section 2.1 describes the oil and gas industry in Western Canada, Section 2.2 discusses the rule of capture and the problem of drainage, and Section 2.3 contrasts some of the fixed and variable costs associated with operating on First Nations reserves with the costs of operating off reserve. In Section 3, we explain our methodological approach to the research, which has been grounded in Indigenous engagement. Section 4 discusses the data we use. Section 5 uses the data to present evidence of missing First Nations oil and to connect the missing oil to drainage. In Section 6, we explain how drainage relates to equity and efficiency. As part of that explanation, we present a simple model of dynamic inefficiencies that arise in the presence of agents with heterogeneous costs (Section 6.1), test the model with our data (Section 6.2), and discuss whether First Nations received compensation for inequitable production (Section 6.3). Section 7 concludes.

2 Background

2.1 The Oil and Gas Industry in Western Canada

The oil and gas industry has been a major contributor to the economy of Western Canada. At present, oil and gas is responsible for more than 20% of the GDP of Alberta and 16% of the GDP of Saskatchewan (Statistics Canada, 2018). The industry has played an important role in developing the economies of many communities throughout these two provinces, including First Nations communities. Figure 1 plots all the oil and gas wells that have been drilled in Alberta and Saskatchewan and demarcates the boundaries of First Nations reserves. As of August 2022, 7,140 wells have been drilled on 162 First Nations reserves across the two provinces.[4] According to our estimates, the 24 reserves in Alberta and Saskatchewan with active wells between June 2020 and June 2021 produced enough crude oil in that year to generate approximately $285 million CAD in revenue.[5]

[4]This includes 72 communities in Alberta and 90 in Saskatchewan.

[5]Estimate uses geoSCOUT monthly oil production data and the monthly oil par prices used for calculating provincial royalties. Of the 24 reserves still actively producing, 7 are located in Alberta.

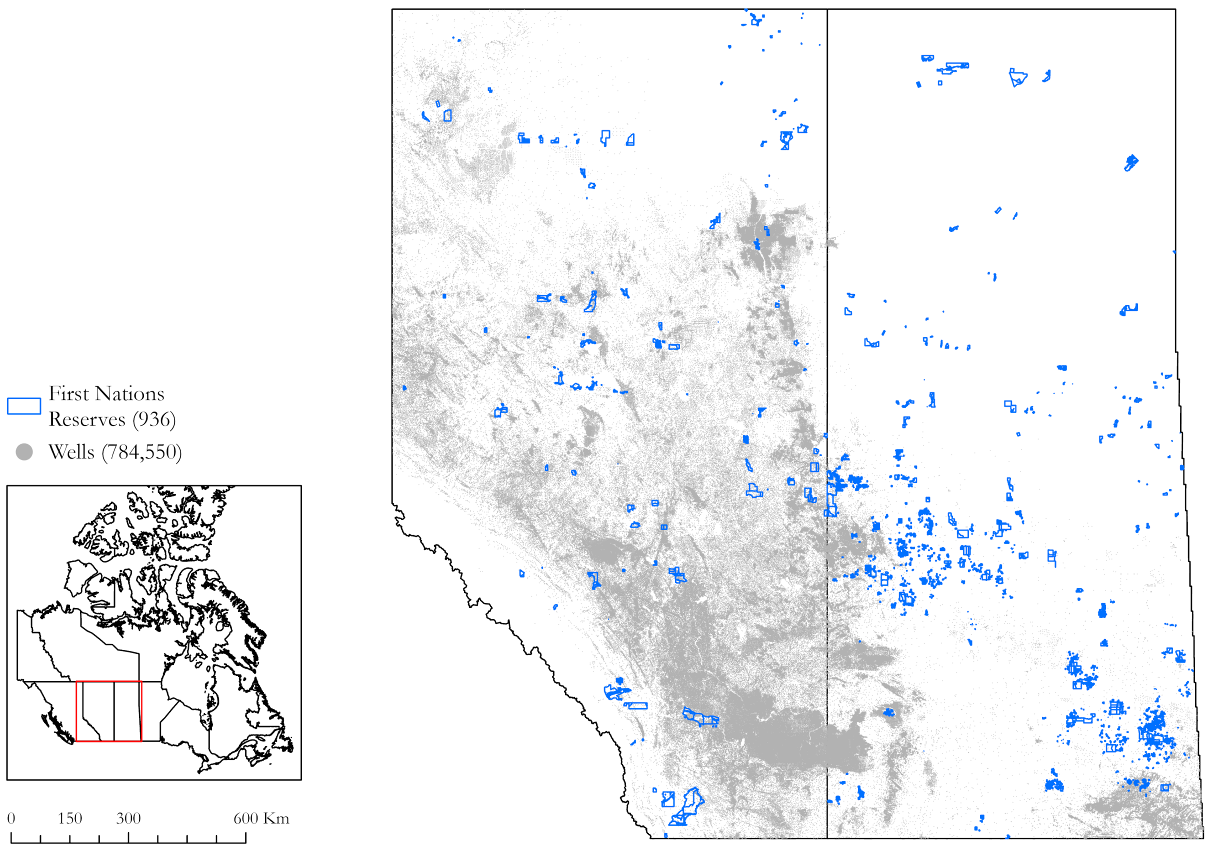
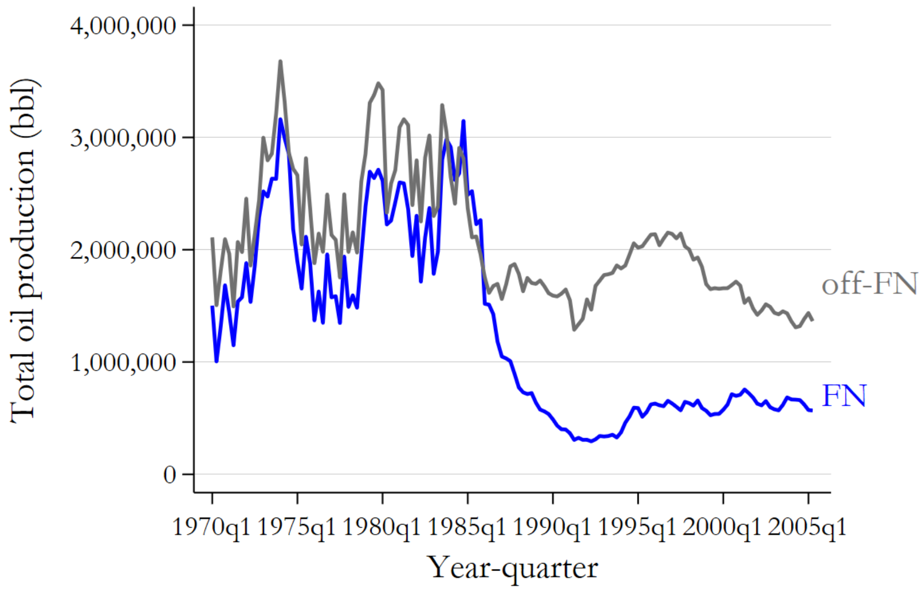


Figure 1: Wells and First Nations reserves in Alberta and Saskatchewan

Total oil production from wells on First Nations reserves pales in comparison to total production elsewhere in Western Canada; however, as the map depicts, First Nations reserves represent a small share of the overall land area in these provinces. Figure 2 shows that when off-reserve oil production is limited to a two-kilometer radius around the borders of First Nations reserves, production levels and trends are comparable on and off reserve, at least until 1985.[6] In Section 2.3 and Appendix B, we document several major policy changes coincident with this period that introduced incentives that would have driven production off reserve. Our paper focuses on the period of 1985–2005 because this is not only when we see a divergence in production but also before the advent of unconventional extraction, using horizontal wells and high pressures to fracture tight rock holding oil in place (for a discussion

[6]We break out Figure 2 by different distance intervals from the border in Appendix Figure A1. The drop in production on reserve in 1985 is partly driven by wells drilled up to 1.2 km from the border.

Figure 2: Quarterly oil production within two kilometers of First Nations reserves



Note: Quarterly barrels of oil production for Alberta and Saskatchewan combined. The off-reserve sample is restricted to wells within two kilometers of the First Nations reserve borders.

of the post-2005 period, see Section A.3).

Production around the borders of First Nations reserves, just like production elsewhere, is a function of the exogenously determined location of oil pools. Many subsurface accumulations of hydrocarbons in Canada underlie both First Nations land and provincially governed land, leading to patterns of production that span the borders. As an example, Figure 3 shows where production took place between 1965 and 2021 on and near one First Nations reserve that sits on a highly productive oil field with multiple oil pools.

Geological conditions do not vary systematically with the location of the First Nations reserve borders. The historic treaties that established First Nations reserves in the prairie provinces of Western Canada were signed in the 1870s, whereas the first oil well in Western Canada was drilled in 1902 (Government of Canada, 2017). Approximately 20% of First Nations reserve land was re-appropriated by the Crown between 1896 and 1911 with the objective of opening up lands for westward expansion, national parks, and World War I veterans. Ceteris paribus, the Crown would have been more likely to target mineral-rich land. And indeed, in correspondence, it is clear that these attempts were made, e.g., a 1925 letter from the Premier of Saskatchewan requesting geological surveys before "throwing mineralized sections of our northern country into Indian Reserves" (Bartlett, 1985). The surprise of oil on reserve came up in a 1938 Parliament debate: "It was not expected that developments of minerals or coal or of oil so far as Alberta is concerned would take place on Indian reserves, located as they were mostly in the northern part of the province" (Parliament of Canada, 1938). However, the reserve borders have largely remained the same after the 1920s and the majority of the large oil pools in Western Canada were discovered in the 1950s, after the delineation of most of today's reserve boundaries.

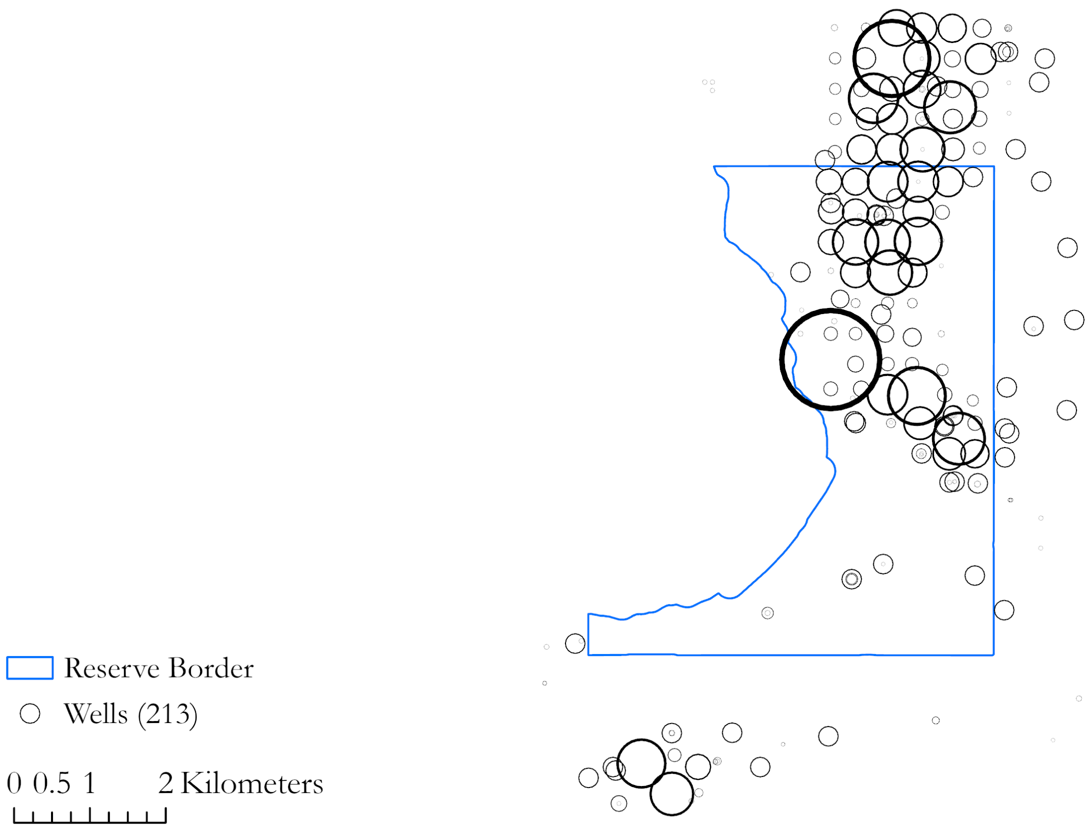


Figure 3: Production on and near a First Nations reserve

Note: Wells drilled between 1965 and 2021 on and within two kilometers of a First Nations reserve in Alberta. Size of bubble corresponds to cumulative production. This map is presented to illustrate the way in which pools may span First Nations reserve borders. Name of reserve is intentionally suppressed.

2.2 Drainage and the Rule of Capture

Oil and gas extraction across Western Canada follows the rule of capture, in which ownership of oil and gas is established when it is brought to the surface, regardless of its subsurface origins. The production of the 1980s, 1990s, and early 2000s was mostly from "conventional" technology. In conventional production, oil is extracted from isolated pockets underground in which the oil can flow through connected pores and natural fractures in the rock. One feature of conventional wells is that they are capable of draining common pool resources that originate relatively far away from the well.

Officially, drainage occurs when a well captures oil or natural gas that has migrated from a different tract of land. The rule of capture acknowledges that it is impossible to identify the origin of the oil or gas brought to the surface and allows for ownership, irrespective of whether drainage had occurred. Neither the well's operator nor the owners of the adjacent tracts of land are able to prevent a well from draining from the common pool. The only way to prevent drainage is to extract the resources first. The rule of capture therefore incentivizes excessive capital investments and rapid extraction of resources—the incentives put in place by the rule of capture can lead to "extractive anarchy" (Libecap and Smith, 2002), which can be ameliorated with regulations on well spacing or contractual agreements by firms (Libecap and Wiggins, 1984).

In Western Canada, mandatory spacing units were introduced to prevent the inefficient drilling of many wells in an area where one is capable of extracting all the resources. These rules apply to the vertical wells in conventional pools of our study.[7] The spacing unit is the area allotted to a well by law and includes the vertical subsurface area under the land. Spacing units are one-quarter section for oil wells, which is land area covering a square of a quarter mile by quarter mile, or approximately 400 meters by 400 meters. Although drainage depends on the geological formation and the parameters of the well, the spacing unit can

[7] With the move to drill multiple horizontal wells from the same well pad, these spacing rules became less applicable and were removed in 2021.

be used as a rough approximation for how far a conventional well is able to drain resources under typical conditions.

Different regulatory regimes are responsible for overseeing exploration and production on and off reserve. The federal government is responsible for overseeing exploration and production on First Nations reserves, and Indian Oil and Gas Canada (IOGC) is the federal legislative authority. In contrast, the provincial government is responsible for exploration and production on most land off reserve. In Alberta and Saskatchewan, the provincial Crown owns most of the mineral rights in the province.[8] For the majority of land, the minerals are owned and regulated by the provincial Crown, irrespective of who holds title to the land. As explained in more detail in Section C, federal regulations governing the oil and gas industry on First Nations lands remained largely unchanged from 1974 until the eventual modernization of the legislation in 2019. Official IOGC documents suggest that the modernization of the legislation was driven, in large part, by concerns that the old regulations provided insufficient protection from drainage (Indian Oil and Gas Canada, 2019b).

2.3 Cost Differences

Differences in the regulatory regimes governing the oil and gas industry have contributed to important differences in both fixed and variable operating costs. Before drilling a well, a firm obtains a surface contract for exploration and development rights as well as a subsurface contract for production rights. Firms must navigate more red tape on First Nations land for both contract types. We elaborate on differences in a variety of transaction costs in Section C.2.

The higher fixed costs of operating on First Nations reserves alone cannot explain the production divergence starting around 1985. But the 1980s bore witness to several major policy changes in Western Canada's oil and gas industry, changes that would have had differential effects on production on and off First Nations reserves, further increasing the

[8]A small fraction of mineral rights are owned privately by individuals or corporations in Alberta, larger in Saskatchewan, typically as a holdover from Homesteading policies in the 1800s.

wedge between profits.[9]

In 1980, the federal government became more involved in the oil industry through the National Energy Program (NEP), which, amongst a suite of actions, levied new taxes (Helliwell et al., 1986). The provincial governments were opposed and, by March 29, 1985, had signed the Western Accord, disposing of federal taxes and price regulation. When prices were deregulated in 1985, they fell with the world oil price (Figure A12). The lower prices would be expected to have a greater impact on drilling on reserve, where transaction costs are higher than off reserve.

Soon after, Alberta announced a more generous royalty holiday, provincial corporate income tax provisions, and a phased reduction in the royalty rate. The Albertan royalty and tax incentives would have only applied to production of provincial Crown minerals, representing a new gap between provincial and federal oil production. Royalty rates off reserve were lower than on reserve, with on-reserve rates as high as 50%.[10] By comparison, royalty rates on Alberta Crown minerals averaged approximately 12–20%.

In this time period, Saskatchewan produced less oil than Alberta (15% of Canada's oil production compared to 80% from Alberta). Nevertheless, Saskatchewan also made changes to incentivize producing Crown minerals. Saskatchewan introduced both a price-sensitive oil and gas royalty regime, reducing royalties during periods of low prices, and an enhanced oil recovery relief.

During this time of well-documented major changes to royalty rates on provincial lands, little is reported in official documentation on changes on reserve lands. For example, the annual report of Indigenous and Northern Affairs Canada only mentions the sum receipts

[9] Although tribal casinos began to dominate the economic landscape on federal reservations in the United States from the late 1980s (see, e.g., Wheeler, 2024), First Nations-owned casinos are relatively rare and are unlikely to have played a major role in the timeline of changing costs for First Nations communities in Western Canada around this period of time.

[10] Comprehensive data on royalty rates for production on reserve would require approval from every First Nation; however, we are able to observe some of the agreed-upon royalty rates through records of leases we obtained using the Indian Land Registry System (ILRS). As an example, one of those leases indicates that royalties from all oil on one First Nations reserve would be 35% of production for the first two years and 50% of production thereafter.

of royalties (Indian and Northern Affairs Canada, 1986).[11] Informal reports suggest that royalty rates remained high on reserve lands in the 1980s and 90s. In 1993, the Tribal Chiefs Association of North Eastern Alberta reported to the Royal Commission on Aboriginal Peoples that "the Provincial government is using royalty rights as a means to stimulate oil and gas activity. This is adversely affecting resource activity on reserves" (Tribal Chiefs Association of North Eastern Alberta, 1985). The report pointed to a newspaper article that stated, "the Blood Reserve has some current production, but the 1986 oil price crash killed interest in exploring Indian [sic] lands across Western Canada. Another deterrent was the standard Indian [sic] royalty rate of about 60 percent, which is far above the Alberta government's rate of about 20 percent...but all royalty rates are negotiable on reserve lands, and bands wanting development are ready to deal" (Boras, 1993).

The royalty rate gap was not permanent, though. As of the most recent provincial royalty rate changes, most royalty rates on reserve are now similar to provincial rates: "estimates [suggest] that about 70 percent of the royalties on First Nations lands in Alberta are based on Alberta's royalty structures. The other 30 percent are a mix of different types of royalty structures that are not based on the provincial regime" (Indian Oil and Gas Canada, 2008).

3 Indigenous Engagement

Academic research has a history of inflicting harm on Indigenous communities. These research abuses have ranged from the extractive to the downright unethical.[12] Our methodological approach stems from a commitment to conducting responsible research involving Indigenous peoples. Toward that end, we draw on the guidance from Canada's federal research funding agency on how to conduct responsible research involving First Nations, Inuit, and Métis Peoples in Canada (Tri-Council Policy Statement, 2018). We strive to minimize harm and produce outcomes perceived to be valuable by the Indigenous communities po-

[11] Note that INAC was known as *Indian* and Northern Affairs Canada at the time.

[12] As an example of unethical research in the nutrition field, physicians in Canada studied the effects of malnutrition by experimenting on First Nations children in residential schools (MacDonald et al., 2014).

tentially impacted by our work, all while maintaining a position of neutrality. We have also developed our approach in the spirit of the Ownership, Control, Access, and Possession (OCAP) Principles, a set of Indigenous data governance standards put forward by the First Nations Information Governance Centre (The First Nations Information Governance Centre, 2024).[13] We are unable to adhere strictly to all OCAP principles because our data are proprietary and cover all First Nations in Canada with oil or gas wells, thus precluding a return of the data back to First Nations possession and control. Instead, we have endeavored to provide First Nations that may have a stake in our research with as much access as possible, and that includes making this research paper open access.

We have worked on this research with three Indigenous consultants possessing more than 40 years of combined experience in oil and gas. Our Indigenous guides have supported our research since its inception, beginning with a pipe ceremony in Maskwacis, a First Nations community in central Alberta, to start the research in a good way.[14] Throughout the research project, our Indigenous guides not only shared their own insights but also facilitated informational meetings with oil and gas stakeholders. In the final stages of the research project, they arranged for us to discuss our results in conference with several chiefs and council members of Treaty 6. One important lesson we learned is that we cannot avoid all harm: our research will cause some parties harm, and it is our responsibility to understand the channels through which harm will occur and to assess the relevant tradeoffs.

Indigenous engagement has been instrumental in this research in two main ways. First, we cannot independently achieve our stated objective of mutual benefits and harm reduction, as we do not come from the communities impacted by the research and do not have the perspective to define what would be beneficial or harmful. Instead, we have relied on a slow and intentional process of developing deeply respectful relationships with the goal of

[13] Laurel Wheeler is OCAP certified.

[14] "In a good way" is an expression often used by Indigenous communities to refer to activities that are conducted in alignment with Indigenous Knowledge. The expression is typically used to emphasize the importance of building relationships with Indigenous partners and collaborators and elevating the voices of Indigenous peoples.

enhancing cultural safety.[15] Second, Indigenous engagement has helped to ensure the accuracy of our research design. From shaping research questions and guiding modeling decisions to interpreting results, an accurate understanding of the context is key.

To give one concrete example, an understanding of Seventh Generation thinking, an Indigenous philosophy based on the idea that our actions today will affect the balance of life for those in the seventh generation to come (Clarkson et al., 1992), could have implications for how one would model discount rates. An Indigenous-owned consulting company we contracted, SevGen Consulting, informed us of an additional reason discount rates might differ, driven by institutions. Efforts dating back to 1989 were made by members of their Nation to increase the rate of return earned on oil royalties held in trust by the federal government (Supreme Court of Canada, 2009), leading to 2005 legislation allowing the ability to opt out of oil and gas money management by the Federal government (Government of Canada, 2005).

4 Data

Our main analysis relies on monthly production quantities from oil wells drilled in Alberta and Saskatchewan between 1985 and 2005. Our primary source of data is geoLOGIC Systems, a company that collects and provides access to government records on the oil and gas industry. The dataset includes monthly oil and gas production from a panel of approximately 800,000 wells spanning 1965 to 2021. We observe a number of well characteristics, such as location, depth, age, and whether the well is in a unit agreement. In a unit agreement, different owners of a common pool agree to cooperate in production. For each well in our dataset, we know whether a well is in a unit and, if in a unit, the percent ownership and an identifier of the unit.[16] For leases off reserve, we have information on the price paid (bonus bid) for the lease. In addition to the well-level information, we also have data on more than

[15] Culturally safe research recognizes the political and historical context within which the research takes place and incorporates Indigenous Knowledge and methodologies (Brockie et al., 2022).

[16] For more, see Section 6.3.2.

40,000 unique oil and gas pools, including information such as discovery year and discovery well.[17] For a handful of wells we know the quantity of water that was injected into the well, to enhance oil recovery.

Table 1 provides summary statistics for key measures of wells, shown separately for wells located on First Nations reserves (FN) and wells located off First Nations reserves (Off-FN), both within two kilometers of a reserve border. We choose to focus on the two-kilometer radius around First Nations reserves because we want to examine well outcomes across comparable geographic areas. The median size of a reserve in our sample is 1.9 square kilometers. Of the wells drilled on First Nations reserves, we observe lower cumulative oil production, with the average well producing 20,741 barrels over its lifetime relative to the off-reserve average of 28,353 barrels. Production differences are not surprising given the various differences in operating costs (some of which are described in Section 2.3). The time to complete a well from the time drilling commences does not appear to be a source of cost differences on versus off reserve, as the average is eleven days, irrespective of the side of the border. We show evidence that wells on reserve are slightly more likely to be a part of a unit agreement but no more likely than off-reserve wells to be a part of a unit agreement that spans the border. We also report several characteristics of the oil pool, including recovery factor, rock volume, porosity, initial pressure, and oil density. The recovery factor, which reflects the amount of hydrocarbon that can be extracted from a pool, is the most comprehensive measure used in hydrocarbon reserve evaluation.[18] We only observe pool characteristics if a well is drilled and has non-zero production. Therefore, the differences in average pool characteristics on versus off reserve could reflect differences in the conditions that would be required for companies to drill a well in that area rather than actual differences in pool characteristics.

[17] An oil pool is a discrete subsurface accumulation of oil trapped in porous or fractured rock formations. Our data also identify the oil field, which can include one or more pools of oil in the subsurface.

[18] The recovery factor is a function of several other measures, some of which are in our data and some of which are not. Typically, the recovery factor is calculated using measures of reservoir permeability, water saturation, oil viscosity, reservoir porosity, and reservoir thickness.

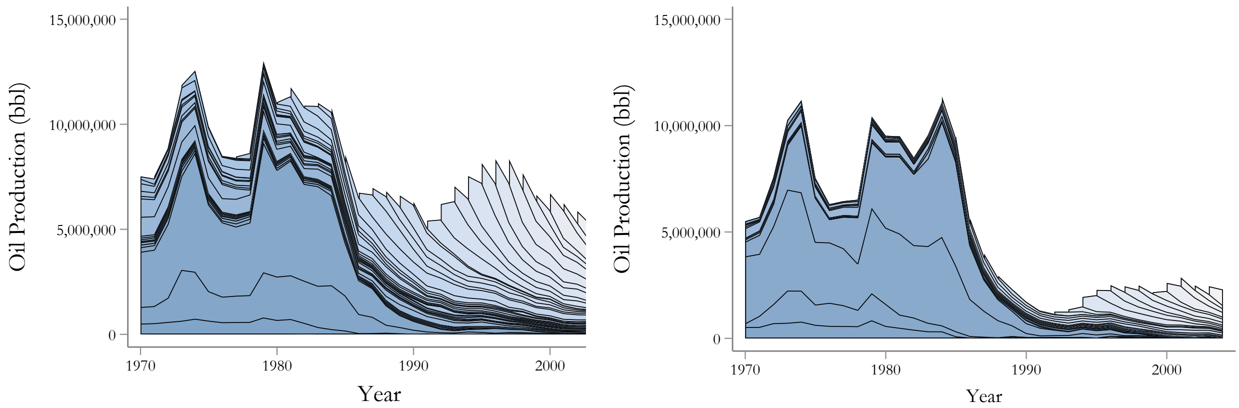
Table 1: Summary statistics

	FN		Off-FN		
	Mean (Std. Dev.)	N	Mean (Std. Dev.)	N	p-value
Cumulative oil production (bbl)	20,741	2,130	28,353	4,628	.00
	(63,291)		(96,862)		
Cumulative water injection (m^3)	1,506,245	41	2,401,054	96	.06
	(2,400,620)		(2,819,700)		
Recovery Factor (%)	14	484	16	1,167	.01
	(12)		(9.2)		
Rock volume (ha-m)	10,103	484	19,977	1,167	.00
	(21,762)		(65,522)		
Porosity (%)	15	484	18	1,167	.00
	(6.8)		(7.9)		
Initial pressure (kPa)	10,641	408	11,258	729	.00
	(3,603)		(2,987)		
Oil density (kg/m^3)	861	484	884	1,167	.00
	(37)		(53)		
Time to completion (days)	11	2,130	11	4,628	.89
	(100)		(104)		
1(Unitized)	.035	2,130	.027	4,628	.09
	(.18)		(.16)		
1(Unitized across border)	.017	2,130	.017	4,628	.91
	(.13)		(.13)		

Notes: Summary statistics of wells drilled between 1985 and 2005, on First Nations reserves or within two kilometers of a reserve border. Recovery factor is the percent of hydrocarbons recoverable from a reservoir, calculated for primary extraction without enhanced methods. Gross rock volume is the volume of rock from the top to the base of the reservoir. Porosity is a measure of the pool's ability to hold a fluid, calculated as the percentage of the total rock that is comprised of pore space. Initial pressure is the reservoir pressure upon discovery, prior to production. Oil density is a measure of how heavy the oil is.

5 Evidence of Drainage

In this section, we link a dip in production from wells drilled on First Nations reserves between 1985 and 2005 (Section 5.1) to disproportionately high production from wells drilled in close proximity to reserve borders in that same period of time (Section 5.2). Our analysis focuses on production from oil wells located in Alberta and Saskatchewan on First Nations reserves or within two kilometers of a First Nations reserve border. We show patterns of high total cumulative production and high average monthly production from wells drilled within 600 meters of First Nations reserve borders (Figure 5, Table 2). We also show a discontinuous increase in the bonus bids paid for rights to drill by the border and in the use



(a) Off Reserve

(b) On Reserve

Figure 4: Production by well cohort

Note: Each shaded area represents the annual oil production from a cohort of wells, off reserve (Figure 4a) and on reserve (Figure 4b). Includes wells drilled within two kilometers of a border.

of secondary recovery methods. Border discontinuities are not driven by geological forces, as pool characteristics are not more favorable by reserve borders (Figure A3). Our evidence suggests that wells were intentionally drilled close enough to the borders of First Nations reserves that they would have been able to drain resources from the other side of the border and that this drainage was disproportionately occurring away from First Nations.

5.1 Missing Oil

First Nations reserves are characterized by a host of legal, jurisdictional, and institutional differences relative to the rest of the province.[19] Despite these time-invariant differences, production data from Alberta and Saskatchewan indicate that in the 1970s and early 1980s, total oil production from wells within a two-kilometer radius around the border matched on and off reserve (see Figure 2). In the mid-1980s, however, production from wells off reserve remained high while production from wells on reserve dropped precipitously and remained low until the early 2000s. Our research is interested in characterizing this divergence.

Missing oil from 1985-2005 could be due to production differences from existing wells

[19]See Section C.

drilled prior to this period of time or due to production differences from new wells. The decline curves plotted in Figure 4 support the latter explanation. Graphs of annual oil production like these show a curved pattern known as a decline curve. Production tends to be highest when the well is initially drilled, and then the primary production rate declines over time. In Figure 4, different shades of blue correspond to different well cohorts, or cohorts of wells drilled in different years, with the most productive cohorts being from wells drilled in the 1950s.[20] A comparison of Figures 4a and 4b reveals similar production levels and trends for wells drilled off and on reserve, respectively, in the 1970s and early 1980s. The striking difference between the two figures is seen in levels of production from wells drilled in the mid-1980s until the mid-2000s. Although off-reserve well cohorts had lower initial production in this period of time than in earlier decades, they still produced more than 5 million barrels of oil annually. In contrast, production from on-reserve well cohorts in this period of time was so low that it appears to be missing.

5.2 Drainage of Oil

Here, we present evidence that some fraction of the missing oil from the 1985-2005 well cohorts was drained away. Figure 5 presents binned scatter plots of well-level data on total cumulative production (Figure 5a), average monthly production (Figure 5b), water injection (Figure 5c), and bonus bids for leases (Figure 5d) by distance to the border of First Nations reserves. The vertical line at zero represents the reserve border: everything to the left of the vertical line is based on data from wells drilled on reserve, and everything to the right of the vertical line is based on data from wells drilled off reserve. Distance to the border increases with the absolute value of the x-axis. Distance bins are optimally chosen by minimizing the integrated mean squared error (Cattaneo et al., 2023). The binscatter also allows us to control for local conditions through nearest reserve fixed effects.[21]

[20] Whereas Figure 2 plots total quarterly production from all active wells in a quarter, Figure 4 plots total production in a year, disaggregated by well cohort, effectively controlling for age of the well.

[21] We plot the raw data on select well outcomes in Figure A2.

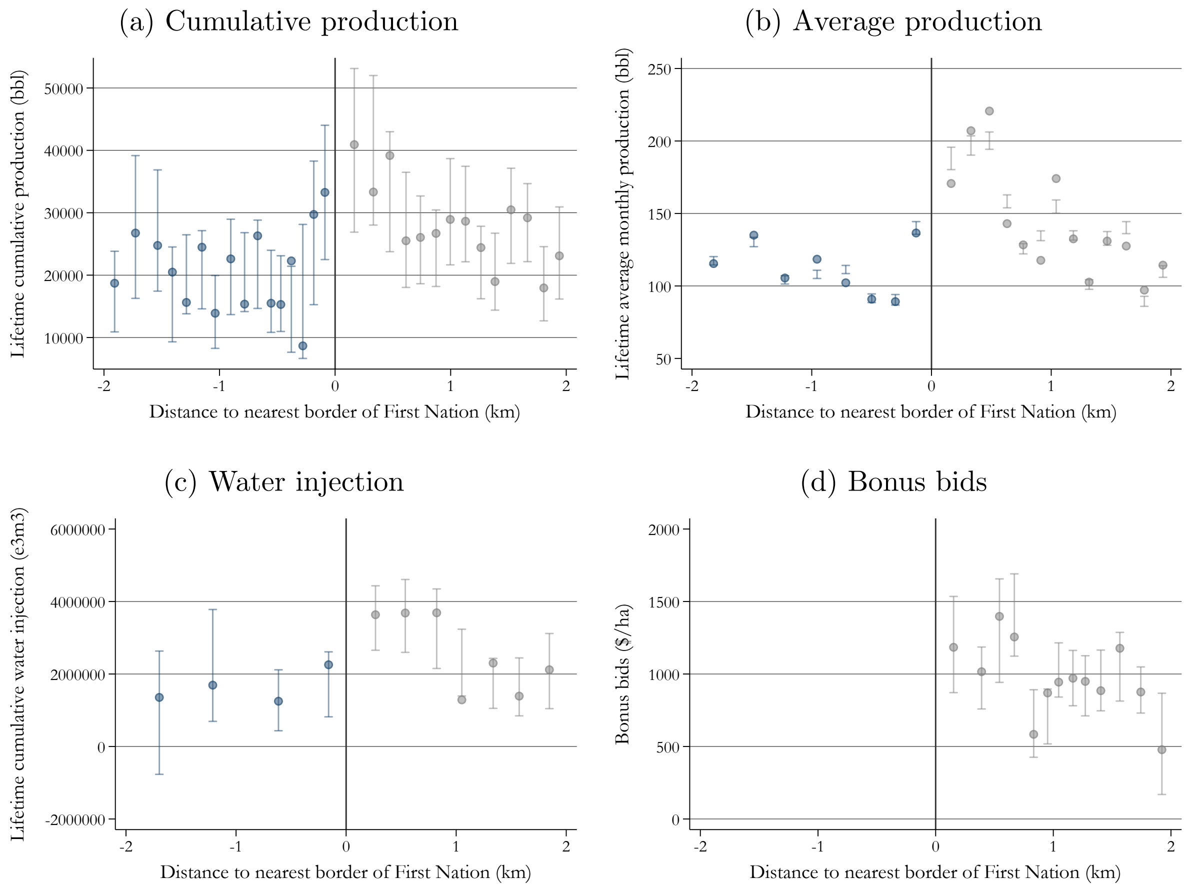


Figure 5: Well outcomes by border distance

Note: Binscatters of wells drilled between 1985-2005 either on a First Nations reserve (blue) or within two kilometers of a First Nations reserve (grey). 95% confidence intervals are shown. Cumulative production controls for nearest reserve fixed effects and year spudded; average monthly production controls for age of well, nearest reserve, and production year fixed effects; water injection controls for nearest reserve and year drilled fixed effects; and bonus bids control for nearest reserve and lease commence year. Figure A6 plots the same figures for the sample of wells drilled before 1985.

Each of the subfigures in Figure 5 shows an increase within 600 meters of the border. Among wells drilled between 1985 and 2005, the highest levels of total cumulative oil production within a two-kilometer radius of First Nations reserve borders come from wells drilled off reserve but within 600 meters of the border (Figure 5a). Wells drilled at this distance are capable of draining oil from under the reserve and, in fact, cannot be prevented from doing so (see Section 2.2). Although not all of the production from wells at the border is due to drainage, some portion comes from hydrocarbons that originated beneath First Nations reserves.

Not only do the off-reserve wells adjacent to the border have more total production over their lifetimes, but they also produce more each month (Figure 5b).[22] Higher productivity of wells by the border may be due to secondary methods of extraction, such as water flooding.[23] Conventional wells rely on pressure to extract oil, and pumping in water increases the pressure, maximizing the amount extracted. Although our data on water injection are incomplete, we find suggestive evidence of an increase by the border (Figure 5c). We also show that firms pay more for leases by the border: bonus bids, or the amounts paid for the rights to drill in a certain location, are higher by the border (Figure 5d).[24] Because of the uncertainty that precedes drilling, bonus bids reflect ex-ante firm expectations about productivity.

Discontinuous increases in activity at the borders cannot be explained by naturally occurring phenomena. Figure 6 plots the pool recovery factor by border distance.[25] If the spike in production at reserve borders were driven by differences in geology, we would expect to see a similar spike in the recovery factor at the border. Again, our data only describe pool characteristics when there is non-zero production in that location, so this is an imperfect test of the exogeneity of pool characteristics to border location. Nonetheless, our data do not indicate that the land near reserve borders is naturally more productive.

We estimate the effect of border distance on well outcomes through a distance-to-border fixed effects regression that takes the following form:

$$\mathrm{Y}_{ij} \;=\; \alpha_j + \sum_{k=-1}^{2} \gamma_k \, \mathbf{1}(\mathrm{Distance}_{ij}^{600(k-1),600k}) + \epsilon_{ij} \tag{1}$$

[22]Figure A2d suggests that the discontinuous increase in production by the border is not due to more wells being drilled adjacent to the reserve but rather more productivity from wells drilled there. We even see in the 200m bin from the border fewer wells drilled on both sides. This could be due to reserve borders being delineated by waterbodies or roads, but also that the mandatory Drilling Spacing Units require 100 meter distance from the side of the spacing unit.

[23]Other ways to enhance well productivity include adding pumps during completion, replacing rod strings, acidizing, or dewaxing wells. We do not have data on these methods.

[24]Note that we do not have data on leases for wells on reserve.

[25]Figure A3 recreates this figure for other pool characteristics.

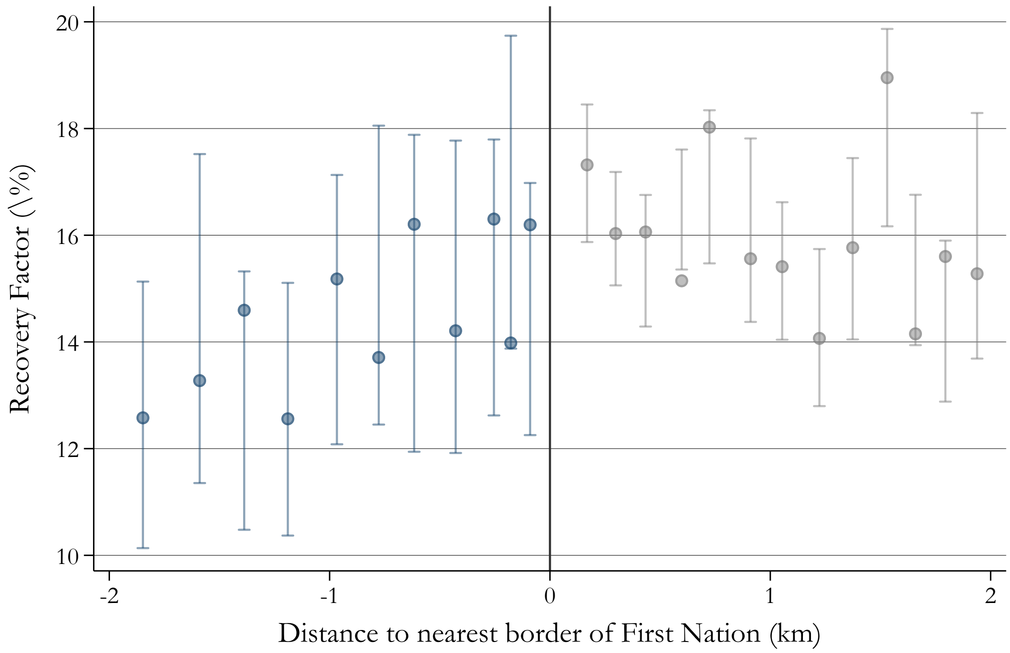


Figure 6: Pool recovery factor

Note: Binscatters of pool recovery factor for the 1985-2005 cohort of wells and 95% confidence intervals. Included are fixed effects for year drilled. Recovery factor is the percent of hydrocarbons recoverable from a reservoir, calculated for primary extraction without enhanced methods.

where Y is cumulative oil production, i indexes wells, j indexes the nearest reserve, and α_j is a nearest-reserve fixed effect. Distance-to-border fixed effects are captured by D_{ij} in 600-meter distance bins, k. Distance bins take negative values if wells are located on reserve and take positive values if wells are located off reserve. For instance, $D_{ij}^{0,600}$ is equal to one if well i is located off reserve and within 0-600 meters of the nearest First Nations reserve border and is equal to zero otherwise. $D_{ij}^{-600,0}$ is equal to one if well i is located on reserve and within 0-600 meters of the border.

In our analysis, we include all oil wells located on a First Nations reserve or within two kilometers of a First Nations reserve border in Alberta and Saskatchewan. We use 1.2 to 2 kilometers on either side of the border as the reference distance. The coefficients γ_k would be interpreted as the difference in total cumulative production specifically attributed to being within the k distance bin, as compared to wells farther than 1.2 kilometers from any First

Table 2: Well outcomes by border distance

	(1) Lifetime Prod. (bbl)	(2) Wells (drilled/month)	(3) Monthly Prod. (bbl/month)	(4) Water Inj. (million tons)	(5) Bonus bid ($/ha)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	-1,464	-.0009	-1.4	.57	
	(3,098)	(.00085)	(17)	(.5)	
$\mathbf{1}(\text{Distance}^{-600,0})$	207	-.0048***	-6.9	-.36	
	(4,029)	(.0017)	(23)	(.49)	
$\mathbf{1}(\text{Distance}^{0,600})$	10,711**	-.0052***	70**	.044	67*
	(4,559)	(.0013)	(30)	(.53)	(40)
$\mathbf{1}(\text{Distance}^{600,1200})$	2,722	-.00043	17	.23	-30
	(3,039)	(.0012)	(14)	(.62)	(50)
Nearest Reserve FE	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes
Area of bin	No	Yes	No	No	No
Age controls	No	No	Yes	No	No
Mean dep. var. if $\mathbf{1}(\text{Distance}^{\lvert 1200\rvert,\lvert 2000\rvert})$	22,370.22	.02	123.60	2.42	611.07
Obs.	6,640	450,576	1,216,546	125	1,171

Notes: Samples include wells drilled within two kilometers of a First Nations reserve. Samples include wells drilled between 1985 and 2005, but for Column (5) sample includes leases commencing between 1985 and 2005. Year fixed effects varies by specification: Column (1) is year well is drilled, Column (2) is year of observation of reserve-bin drilling count, Column (3) is year of production, Column (4) is year well is drilled, Column (5) is year lease commenced. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Nations border (on either side of the border). For example, a statistically significant γ_1 on the wells located 0 to 600 meters outside a First Nations border would indicate the effect on production due to being within 600 meters of the border compared to wells located between 1.2 and 2 kilometers from the border. Finding estimates of γ_k that are equally sized on either side of the border would suggest equitable production. This identification strategy relies on the quasi-exogeneity of borders to the location of oil. As explained in Section 2.2, the borders of First Nations reserves were drawn without regard for the location of oil pools.

Coefficient estimates are reported in Table 2. Examining the lifetime production of wells drilled between 1985 and 2005 (column 1), we see that the wells drilled within 600 meters outside First Nations borders have produced on average, 10,711 barrels more than wells in our reference category of outside 1.2 kilometers of the border. The average well in our reference category produces approximately 22,000 barrels during its lifetime. We see that the higher production comes from consistently larger average monthly production (column 3) rather than from more wells drilled in that distance bin (column 2). The combination of higher cumulative production and higher average monthly production is unexpected given that faster extraction is negatively associated with lifetime total production, suggesting that losses from too rapid extraction are offset by drainage. For only some of the wells are we able to match data on the bonus bids paid for leases off-reserve; for these wells, the amount paid for the lease per hectare of the lease area is larger at the border (column 5). We do not, however, find evidence that wells adjacent to First Nations reserves use more secondary recovery methods (column 4).[26] Of the wells that report injection of water, we see no significant association between water injection and distance to the border. That being said, we have relatively few observations for this measure, which could explain why we would not be able to detect actual differences.

We argue that some fraction of the excess production in the 0-600 meter distance bin is drainage from First Nations reserves. If this interpretation is correct, we would expect to see even more excess production at the border among wells drilled into pools with naturally greater capacity for drainage. In a separate analysis, we examine the relationship between lifetime cumulative oil production (column 1 of Table 2) and border distance, based on whether a well is drilled in an oil pool that is more or less conducive to drainage (Table 3).[27] We use the recovery factor of the pool to divide the sample into pools that have higher drainage potential versus not. We consider a pool to be "less favorable" to drainage if its recovery factor is below the median for all pools (column 1) and "more favorable" to drainage otherwise (column 2). We find that wells drilled in this period of time in pools with above median recovery factor have more overall lifetime cumulative production, with the average well in the reference category producing 97,219 bbl over its lifetime. We also find a very large effect on production associated with wells outside reserve borders, in both the 0-600 meter distance bin as well as the 600-1,200 meter bin, for wells in pools with above median drainage capacity, an effect that is not matched for wells drilled in pools with below median drainage capacity nor for wells drilled in other distance bins. We consider this to be further

[26]Secondary recovery methods involve injecting water or gas into a well to extend a field's productive life. This process can result in recovering 20 to 40 percent of the original oil in place.

[27]Note that our sample size is diminished relative to Table 2 because we do not observe pool characteristics for all wells.

Table 3: Production analysis by oil recoverability

	Below median	Above median
	(1)	(2)
	Lifetime Prod. (bbl)	Lifetime Prod. (bbl)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	-5,674	-20,312
	(5,636)	(18,246)
$\mathbf{1}(\text{Distance}^{-600,0})$	-8,440	1,137
	(8,623)	(21,679)
$\mathbf{1}(\text{Distance}^{0,600})$	-198	44,140*
	(7,611)	(25,525)
$\mathbf{1}(\text{Distance}^{600,1200})$	-8,879	27,471**
	(9,041)	(13,515)
Nearest Reserve FE	Yes	Yes
Year drilled FE	Yes	Yes
Mean dep. var. if $\mathbf{1}(\text{Distance}^{\lvert 1200\rvert,\lvert 2000\rvert})$	43,666	97,219
Obs.	553	1,067

Notes: Sample of wells drilled between 1985 and 2005 within 2km of a First Nations reserve. Outcome variable is the lifetime cumulative production from wells. Median recovery factor is determined by sample of pools within two kilometers of a First Nations reserve. Recovery factor is a percent that is recoverable, calculated for primary extraction, without enhanced methods. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

evidence of drainage.

6 What does Drainage Mean for Efficiency and Equity?

In a static setting, efficiency depends on the cost-effectiveness of extraction, with production from the lowest cost extractors increasing efficiency. The efficient allocation however, would have distributional consequences, if resource rents were all obtained by the lowest cost extractor. In the previous section we show that oil production from wells on and off First Nations reserves diverged dramatically in the mid-1980s until the mid-2000s, coincidentally with institutional factors that made costs higher on reserve (Figure 2). Inequities arise as the missing oil was driven by less production from on-reserve wells drilled in this period of time (Figure 4), both in terms of total lifetime production (Figure 5a; Table 2, column 1) and lower average monthly production (Figure 5b; Table 2, column 3). Taken together, this is suggestive evidence that First Nations oil was drained away by wells surrounding the reserves, drilled between 1985 and 2005, implying increased efficiency at the cost of increased inequity.

In this section, we show an additional inequity that is less obvious: an inequity that arises through a dynamic inefficiency. In a dynamic setting, efficiency also depends on the extraction rate. The optimal extraction rate would equate the value of the oil left in the ground to the rate of return that the oil sold would earn elsewhere Hotelling (1931). In oil production, extracting too quickly might also have an additional ramification of resulting in less ultimate recovery. In a theoretical model, we show that a lower-cost extractor will deviate more from a Hotelling optimal extraction rate, when competing against a high-cost extractor, and test the model with data on extraction rates on and off First Nations reserves.

6.1 Dynamic Inefficiencies that Exacerbate Inequity

Theoretical models of the efficiency losses from common-property had a start in fisheries (Gordon, 1954; Scott, 1955), progressing to include many analyses of renewable and non-renewable resources (see Heal, 2007 or for an overview).

Here we extend an existing model of a non-renewable common-pool resource (Khalatbari, 1977) to describe the case in which extractors have heterogenous costs. Many of the theoretical insights are derived from cases of symmetric equilibria, arising when all firms have the same cost structures (e.g., Lueck and Schenewerk,1996 or Benchekroun and Gaudet, 2003). An exception is Lueck (1995) who points out that the existence of heterogeneous extractors could reduce efficiency losses.

Khalatbari (1977) models a pool shared by $i = 1, 2..., n$ extractors, who start at time $t = 0$ with a known stock of resource under their lease, S_{i0}. Each period, resource owners face the risk that their stock is drained. Let α denote the share of i's stock S_{it} that is drained in each period by its $n-1$ rivals. Similarly, in each period the ith extractor drains a fraction, $\alpha/(n-1)$, of the total of its rivals' resources, $\sum_{i \neq j, j=1}^{n-1} S_{jt}$.

We start by making the same simplification to Khalatbari (1977) as Dasgupta and Heal

(1985), and focus on the case of two competitors, $j, i = 1, 2$ and $i \neq j$, which also better reflects the case of our paper, comparing extraction on and off reserve. We then adapt the two extractor case to characterize what might happen when the extractors have differential costs. In the models of Khalatbari (1977) and Dasgupta and Heal (1985), because extractors are homogeneous in costs, own and rival stocks evolve at the same rate, and insights can be derived without modeling the evolution of a rival's stock. In this paper, our optimization problem differs depending on the evolution of both own and rival's stocks, because with profit functions that are not equal, $\Pi_i \neq \Pi_j$, extraction rates and stocks progress differently over time ($\dot{S}_{it} \neq \dot{S}_{jt}$ using the dot notation to represent change over time).

Thus the illustrative optimization problem of the ith extractor is to choose the quantity to extract, R_{it}, that maximizes the stream of profits over time, discounted at rate r, subject to how own and rival's stocks change over time:

$$\max_{\mathrm{R_{it}}} \int_0^\infty \Pi_i \left(R_{it}\right) \mathrm{e}^{-rt} \ \mathrm{d}t$$

subject to

$$\dot{S}_{it} = -R_{it} - \alpha S_{it} + \alpha S_{jt}$$

$$\dot{S}_{jt} = -R_{jt} - \alpha S_{jt} + \alpha S_{it}$$

We derive the optimal extraction path from solving the current value Hamiltonian.[28]

$$\mathcal{H} = \Pi_i \left(R_{it}\right) + \mu_{it}(-R_{it} - \alpha S_{it} + \alpha S_{jt}) + \lambda_{it}(-R_{jt} - \alpha S_{jt} + \alpha S_{it})$$

The necessary conditions are:

$$\frac{\partial \mathcal{H}}{\partial S_{it}} = -\mu_{it}\alpha + \lambda_{it}\alpha = -\dot{\mu} + r\mu_{it} \tag{2}$$

[28]Note, we solve an open-loop Nash equilibrium, which assumes an extractor commits to their full extraction path at $t = 0$. A more complicated case is a closed-loop, feedback case, in which the extraction path is contingent on stock levels in the future. Closed-loop strategies are less studied, for reasons of being more complicated and that the number of equilibria are not guaranteed (Negri, 1989; Gaudet, 2007). We choose to demonstrate the simpler approach because it is sufficient for depicting the tradeoffs between equity and efficiency.

$$\frac{\partial \mathcal{H}}{\partial S_{jt}} = \mu_{it}\alpha - \lambda_{it}\alpha = -\dot{\lambda}_{it} + r\lambda_{it} \tag{3}$$

$$\frac{\partial \mathcal{H}}{\partial R_{it}} = \Pi_i'\left(R_{it}\right) - \mu_{it} = 0 \tag{4}$$

And transversality conditions that $\lim_{t\to\infty} \mu_{it} = 0$ and $\lim_{t\to\infty} \lambda_{it} = 0$, to ensure the resource is either fully exhausted or has zero value at the end of the extraction path.

The costate variable μ_{it} represents the in-situ value of the extractor's own resource, S_{it}, as a capital asset in the ground, referred to in the literature by many names, including scarcity rent, marginal user cost, opportunity cost of extraction, and shadow value of the extractor's own reserves. The co-state variable λ_{it} is the in-situ value of the rival's resource, from the perspective of the extractor.

From the first order conditions, we can obtain an equation for the optimal rate of extraction over time. From equation (4), the in-situ value of the extractor's own resource is equal to that period's marginal profit from extracting. Differentiating equation (4) with respect to time:

$$\Pi_i''\left(R_{it}\right)\dot{R}_{it} - \dot{\mu_{it}} = 0 \tag{5}$$

Substituting in equation (2) and (4) and isolating $\dot{R}_{it}$, we have the following Euler equation:

$$\dot{R}_{it} = \frac{r\Pi_i'\left(R_{it}\right) + \alpha\left(\Pi_i'\left(R_{it}\right) - \lambda_{it}\right)}{\Pi_i''\left(R_{it}\right)} \tag{6}$$

We have three implications that arise from this equation, that can be tested uisng the data.

Implication 1: Extraction is faster (decline is steeper) the higher the marginal profits, Π_i', and the higher the discount rate, r.

Proposition 1 is a theoretical result found in textbooks on natural resources, e.g., Perman, 2003. With positive profits, the profit function is increasing and concave in the quantity extracted, $\Pi_i'(R_{it}) > 0$ and $\Pi_i''(R_{it}) < 0$, and the optimal extraction follows a decline over time, $\dot{R}_{it} < 0$.

Helpful for understanding the drivers of decline, is to characterize the efficient path that arises without drainage. When there is no risk of drainage, $\alpha = 0$, extraction follows the efficient path according to the Hotelling (1931) benchmark:

$$\dot{R}_{it} = \frac{r\Pi'(R_{it})}{\Pi_i''(R_{it})} \tag{7}$$

From equation (7), $\dot{R}_{it}$, increases as $\Pi_i'(R_{it})$ or r increases.

Implication 2: Extraction is faster the higher the drainage potential, α.

Proposition 2 is the result presented in Khalatbari (1977) and Dasgupta and Heal (1985), which for homogenous costs describe the implications of introducing α. The revelation from their model is that the risk of one's resources being drained is likened to an increase in the discount rate, such that instead of extraction being dictated by r, it is dictated by $r + \alpha$:

$$\dot{R}_{it} = \frac{(r+\alpha)\Pi'(R_{it})}{\Pi_i''(R_{it})} \tag{8}$$

Equation (8) shows the dynamic inefficiency of drainage, that with drainage extraction departs from the Hotelling (1931) optimal extraction presented in equation (7).

Implication 3: Higher-cost extractors depart farther from optimal extraction in response to drainage potential than lower-cost extractors.

In our model, with heterogenous costs, the relative cost advantage of one's rival determines the extent to which drainage leads to deviation from the Hotelling optimal. The extraction rate depends on an additional term dependent on the difference in marginal profits of one's own resource and the in-situ value of the rival's reserves, $(\Pi_i'(R_{it}) - \lambda_{it})$. All else equal, when competing with a lower cost rival, i's value of their competitor's in-situ resources, S_{jt}, is lower than when competing with a high-cost rival, because with a low-cost rival, the oil is less likely to be still in the ground in the future. With a smaller λ_{it}, the term $(\Pi_i'(R_{it}) - \lambda_{it})$ is larger and faster the decline (Equation 6).[29] A lower λ_{it} will also lead to a lower growth rate of λ_{it}, as dictated by the the growth of λ_{it} and μ_{it}, Equations 3 and 2, i.e., $\dot{\lambda}_{it} = (r+\alpha)\lambda_{it} - \mu_{it}\alpha$ and $\dot{\mu}_{it} = (r+\alpha)\mu_{it} - \lambda_{it}\alpha$. This means that the lower λ_{it} from competing against a lower-cost rival holds over time. The co-state equations also mean that $\lambda_{it} \leq \mu_{it}$ (i.e., $\lambda_{it} \leq \Pi_i'(R_{it})$) holds over time.

Proposition 3 shows that there are not only inequities arising from the textbook case of Proposition 1, that a higher-cost extractor will extract slower, but also an inequity from the dynamic inefficiency of Proposition 2 being more severe for the higher-cost extractor. In the case of oil production, extracting too quickly could harm ultimate recovery. If oil is extracted too quickly, water can flow around oil pockets, "bypassing" the oil or the oil-water contact could create a "cone" also creating permanent damage to the well (Hyne et al., 2001).

6.2 Testing model predictions

Turning to the data, we first show decline curves the average monthly production by age of well, by land type and distance to border (Figures 7a and 7b). The speed of extraction

[29]The rival is making a similar optimization, and combining their version of equation (4) into the stock state equation, with the speed at which the rival's stock declines will depend on the rival's profit: $\dot{S}_{jt} = -\Pi_j'^{-1}(\mu_{jt}) - \alpha S_{jt} + \alpha S_{it}$, a lower-cost firm has higher $\Pi_j'^{-1}(\mu_{jt})$.

is given by the slope of the decline curve, which changes over the age of the well. Over short periods, oil decline can be approximated by an exponential decline, but over longer periods decline curves of conventional wells follow a hyperbolic decline [find cite]. We fit each subsample's average production, R_t over age, t, to a hyperbolic function to compute the implied slope at each age, to test the implications from the model. We estimate the parameters in a hyperbolic decline curve:

$$R_t = R_0 \left(1 + bDt\right)^{-1/b} \tag{9}$$

Where R_0 is the initial production rate—we use data only after the first year of production so, R_0 is production in month 12. To be estimated is D, the initial decline rate, and b, the decline exponent capturing how the decline rate changes over time. Using least squares we minimize the squared difference between the observed production and those predicted by the estimated hyperbolic function.

We calculate the steepness in the decline of the estimated hyperbolic function and plot these in Figures 7c and 7d. These show the derivative of the estimated hyperbolic functions:

$$\dot{R}_t = -R_0\hat{D}\left(1 + \hat{b}\hat{D}t\right)^{-1/\hat{b}-1} \tag{10}$$

We use our estimates of $\hat{b}$ and $\hat{D}$ to obtain the steepness of decline at each age.[30]

Testing prediction 1: Given the institutional differences during 1985–2005 we would expect that extraction off reserve was less costly, $\Pi'_{\text{off}}\left(R_{\text{off},t}\right) > \Pi'_{\text{on}}\left(R_{\text{on},t}\right)$, and we would expect a faster extraction rate off reserve than on reserve. Moreover, for reasons discussed in the Indigenous Engagement section, the discount rate could be lower if the oil company were Indigenous-owned, which would would also lead to a slower extraction rate on reserve. In comparing steepness on and off reserves, slopes are mostly steeper for wells off reserve,

[30] Parameter estiamtes for each subsample are found in Appendix Table A4. And fit with the actual data is shown in Appendix Figure A4.

with the exception that after the 200th month, the slope on reserve in the 0–600m bin has a steeper slope than the steepest slope off reserve. This bin is more likely to face drainage potential, so focusing on the bins farther than 600m from the border will give insights to extraction in the absence of drainage.

Testing prediction 2: From prediction 1 we determined that slopes off reserve are steeper than on reserve. To examine how extraction changes from introducing drainage potential, α, we compare slopes within a land type, varying just distance to the border, given that closer to the border α is higher. As the model predicts, nearer the border, where drainage potential is higher, slopes are steeper than farther from the border, holding for both wells on and off reserve.

Testing prediction 3: The model predicts that both extractors would deviate from the optimal extraction path as drainage potential increases, but the low-cost extractor will deviate more. To test this, we compare across land types, the deviation in slope when moving from farther to closer to the border. The estimated slopes suggest that the increase in steepness is larger for wells on reserve in the first part of a well's life. The percent difference in the slope in the 0–600m bin compared to the average slope in the farther bins is larger on reserve up until about the 100th month. The majority of production occurs in the first 100 months of a well's life, and so for the majority of production, the model predictions hold, that the high-cost producer deviates more when facing drainage potential.

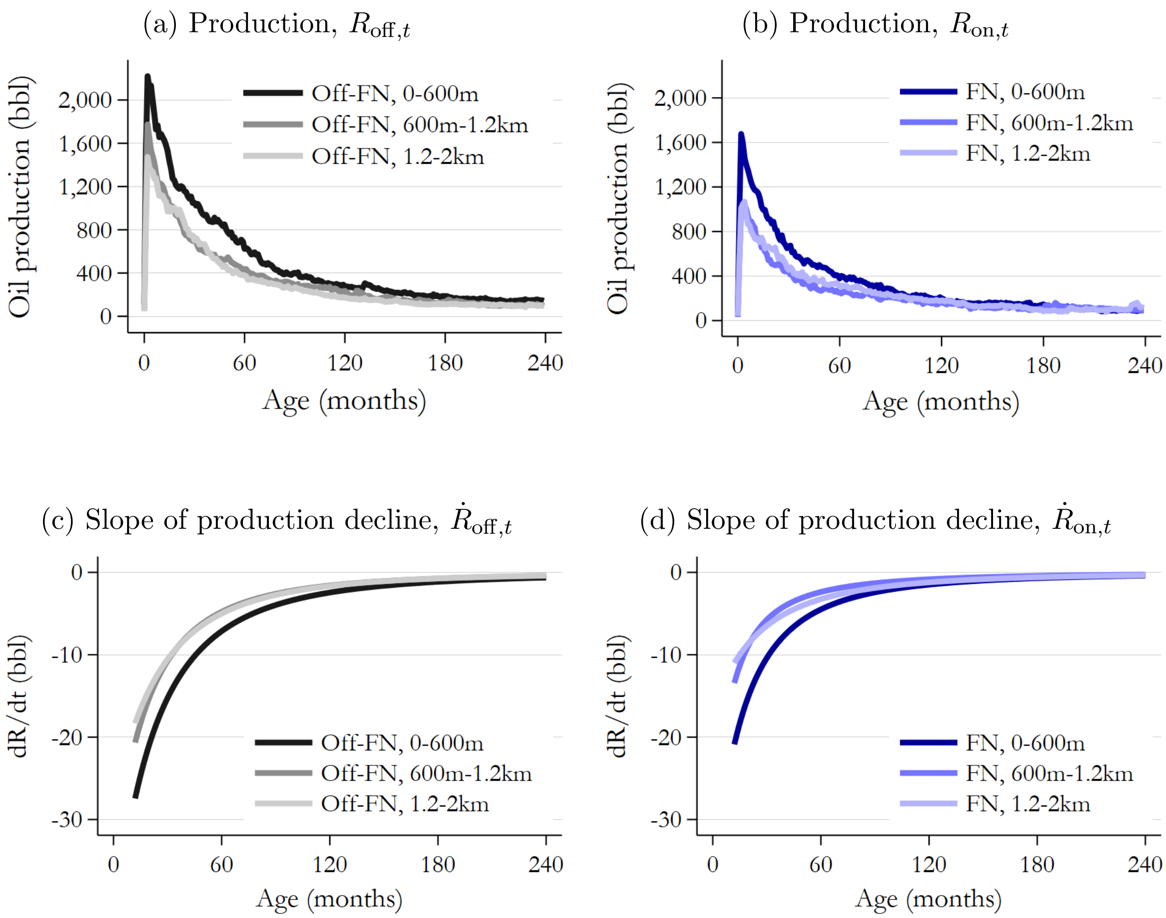


Figure 7: Production decline and speed of decline by distance to border

Note: Figures (a) and (b) depict average production by age of well, by subsamples of wells off and on First Nations reserves and distance bins from the border. Figures (c) and (d) depicts the slope of the decline curves at each month, as estimated from fitting a hyperbolic decline curve starting in month 12.

6.3 Compensation for Drainage

Inequitable production does not necessarily translate into welfare differences. Given the negative externalities of oil production and the limited land area of reserves, extracting more heavily off reserve with compensation for oil drained could be socially optimal. Drainage that is properly compensated would also represent efficiency gains if it prevents the inefficient drilling of multiple wells extracting resources that could have been extracted by one well. The important question is, therefore, whether First Nations were compensated for drainage. In this section, we examine the evidence on the two main mechanisms for the compensation of oil drained from First Nations reserves. We do not find evidence that First Nations have been adequately compensated for drainage.

6.3.1 Offset Notices

Drainage can occur anywhere there is a common pool of oil underlying different tracts of land. When drainage occurs between different jurisdictions, the regulator has a responsibility to address it. Many oil pools are shared between First Nations reserves and bordering Crown land. If a well located on First Nations land is draining provincial Crown minerals, this represents a loss of royalty for the province. To avoid royalty loss, the provincial regulator will issue a notice that requires the lessee of the Crown minerals to take one of three possible actions: drill a well to extract Crown minerals before they are drained away, pay royalties commensurate with the drainage, or join a unit agreement and jointly develop the pool (see Section 6.3.2).

In this paper, we focus on the case in which a well drilled on Crown land is draining resources from First Nations.[31] The IOGC is responsible for monitoring well licenses around First Nations reserves for external producing wells drilled in close proximity to the reserve border. When an oil or gas well, known as a triggering well, is drilled close enough to the reserve border that it could be draining resources from under the reserve, the First Nation is entitled to offset its losses. After the IOGC learns of the production taking place next to the border, it must take action by way of issuing an offset notice to each adjoining spacing unit on reserve that does not already have a producing well. This notice requires that the on-reserve contract holder either drill a well to offset the damage of drainage through production or pay royalties to the First Nation commensurate with the drainage.

Compensatory royalty is calculated based on the volume of oil that was produced by the triggering well (Indian Oil and Gas Canada, 2019a). Information about royalty payments to First Nations is confidential, so we cannot directly observe royalty payments issued in

[31] If drainage of Crown minerals were to occur from a well located on First Nations reserve land, the provincial regulator would be responsible for a series of actions parallel to those described here.

response to offset notices. However, we are able to observe offset notices issued. We acquired data on offset notices through two Access to Information and Privacy (ATIP) requests. For an example offset notice, refer to Figure A5. We found that the IOGC issued no offset notices prior to 1992 and only issued 53 notices during the 1985-2005 period of time (Figure 8). With the 2019 modernization of the Indian Oil and Gas Act (IOGA) (see Section C.1), offset notices became less costly to issue. The records we obtained indicate that 1,066 notices were issued between August 2019 and March 2022. However, drainage is not a problem of unconventional wells. The issuance of offset notices may have been more effective in the 1980s, 1990s, and early 2000s, when conventional wells were most common. We suspect that the offset notice provisions in the IOGA modernization may have been too little, too late.[32] In the period we study, royalty payments were not issued to First Nations as a direct response to offset notices.

[32]Figures A11 and A10 indicate that we don't see an increase in production or drilling on First Nations reserves after 2019.

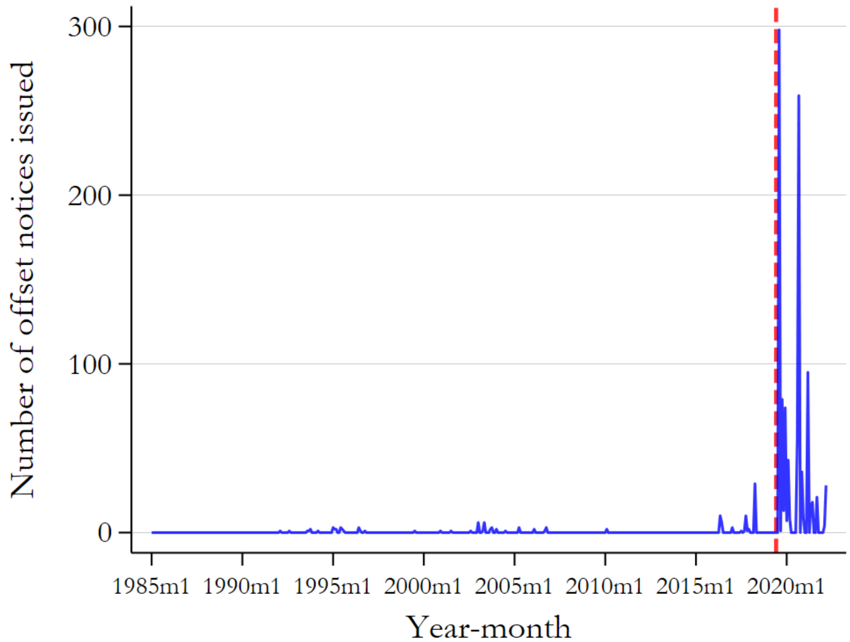


Figure 8: Offset notices issued for First Nations by Indian Oil and Gas Canada
Note: Data on offset notices were obtained by the authors through two Access to Information and Privacy Act requests. Unique observations are defined based on the combination of the date an offset letter was issued and the First Nations spacing unit to which the offset letter applied. In some cases, an offset notice applies to multiple First Nations spacing units. We count each of those as a separate offset notice. Dashed line indicates June 2019 when the modernization of the IOGA was announced.

6.3.2 Unitization

Royalty payments through unitization represent a second mechanism for compensation. A contract holder can enter into a unit agreement either spontaneously or in response to an offset notice. A unit agreement is a type of joint venture agreement, whereby different lease owners of the mineral rights jointly develop the pool as if the boundaries between the different ownership claims did not exist. In light of the rule of capture, unitization may be a more efficient way of extracting common pool resources than several parties independently developing the pool. With voluntary unitization, the unit is formed and different parties negotiate on the terms of how to allocate royalties. However, unit agreements are difficult to achieve because they involve estimates of pool productivity, which could be subject to error, before production rights are transferred (Libecap and Wiggins, 1984).

Our data on unitization indicate that oil units are rare, likely because the incentives to form a gas unit are stronger. In order to drill a gas well, firms need to obtain leases for the full section; to drill an oil well, firms only need the lease from the quarter section. We find only 4% of oil wells within 2 kilometers of a First Nations border are unitized and only 3% of wells are in units encompassing wells both on and off First Nations reserves. Among wells in units shared across borders, the average Crown-owned percent is 66%. In terms of total barrels, much of the production is coming from one unit that is unitized across both First Nations and Crown land, but the percent Crown-owned percent for this unit is 97.88.

6.3.3 Valuation of Lost Oil

What is the economic value of the oil drained from First Nations reserves? There are at least two reasons why this is a hard question to answer. First, as we explain in Section 2.2, total production at the border is not entirely due to drainage, as the specifications of the well (e.g., the use of secondary recovery methods) and the features of the geological formation (e.g., rock permeability) determine the drainage share of production within a given radius. We would require uniquely detailed engineering data on each well and geological data on each oil field and pool to precisely quantify drainage for a given well. Second, even if the drainage share of production were known, it would be difficult to conduct an economic valuation of it. Lost revenue is a function of prices and royalty rates, both of which are dynamic and endogenous.[33] Furthermore, the economic value of missing oil goes beyond lost revenue and could also include damages to the local health of the industry; damages to the economic environment; and losses in terms of investment value, earnings, and business values, all measures we do not have.

With appropriate caveats in mind, we use our estimates of the excess quantity of oil produced at the border to calculate a potential range of revenue lost due to drainage. Wells on either side of the borders of shared pools are capable of drainage, irrespective of which side

[33] We again note that royalty rates are not publicly available for First Nations reserves.

they are on (see Table 2), but the bump in production specifically attributed to being at the border is higher off reserve than on reserve. We define excess production due to drainage as the net production benefit associated with a well being drilled in close proximity (0-600 m) to the border. Summing the excess production across all wells, we estimate that approximately 11.5 million barrels of crude oil produced on land adjacent to First Nations reserves between 1985 and 2005 came from drainage. Put differently, First Nations lost approximately 11.5 million barrels of oil due to drainage.

In Table 4, we use our estimate of drainage (column 2) and we provide back-of-the-envelope estimates of revenue lost due to drainage (columns 5-6), based on different assumptions about prices (column 1) and the range of royalty rates applied to production (columns 3 and 4). We estimate that drainage could be responsible for \$66.6 - 332.8 million CAD in lost revenue. Importantly, our estimates are based on data from oil wells (not gas wells) in two provinces and do not comprise all related economic damages, only production revenues.

Table 4: Estimates of revenue lost due to drainage

		Royalty rate		**Revenue lost**	
(1)	(2)	(3)	(4)	(5)	(6)
Price	Excess quantity	Lower bound	Upper bound	Lower bound	Upper bound
\$48.08	11,536,247	12%	60%	$\$66,559,531$	$\$332,797,653$

Notes: Price (column 1) is the average price of a barrel of crude oil between 1985 and 2005, in 2021 dollars. Column (2) shows the excess quantity of oil produced, calculated as: $(\gamma_1 * N_1) - (\gamma_{-1} * N_{-1})$ where γ_k is the additional production of a well attributed to being drilled in the 0-600 meter distance bin off reserve (γ_1) or on reserve (γ_{-1}) and N_k is the number of wells drilled in those distance bins. Values of γ are provided by the coefficients in column (1) of Table 2. We interpret the excess quantity of oil as production due to drainage from First Nations. Lower and upper bounds on First Nations royalty rates are given in columns (4) and (5), respectively.

7 Concluding Discussion

Using production data from Canada's two most petroleum-rich provinces, Alberta and Saskatchewan, we find that, among oil wells drilled between 1985 and 2005, those located in close proximity to First Nations reserve borders had higher total production and more production per month than those drilled farther from the border. In this period of time, wells used conventional technology, meaning that they relied on pressure to extract oil from the subsurface. This pressure would have caused some oil to migrate through permeable rock from beneath the reserve, to be captured by the wells located at the border in a process known as drainage. We find evidence that firms were aware of the potential to maximize production through drainage: we show that bonus bids were higher for leases adjacent to the border, indicating that firms likely had the expectation of higher production by the border. We find no concomitant systematic differences in pool characteristics by the border, suggesting that the excess production would come through drainage rather than through naturally occurring geological features. Our results suggest that drainage contributed to inequitable production on either side of reserve borders from 1985 to 2005.

Drainage is a problem without a simple engineering solution. Instead, drainage is addressed through a combination of regulations, such as spacing units, and policy tools, such as offset notices. Our evidence indicates that the federal government did not use the policy tools at its disposal to address the drainage of First Nations oil and ensure equitable production across the border. Offset notices were rarely issued in the time period we study, which would have given many operators the opportunity to extract First Nations oil before a response could be coordinated. Although there are inefficiencies associated with various types of responses to offset notices, which we discuss in Section 6.3.1, the formation of a unit agreement as one response might be both efficiency-enhancing and welfare-improving when negotiations between parties are fair.

In addition to documenting inequitable production at the border, we provide theoretical and empirical motivation for a second source of inequity, one that arises through dynamic inefficiency. We show how differences in costs on and off reserve could contribute to an environment where operators extract oil more quickly than optimal on reserve, where costs are higher, and how this could contribute to less ultimate recovery.

The patterns of drainage that we document are problems arising from conventional extraction. With the increasing prevalence of unconventional technology, which involves horizontal drilling and hydraulic fracturing, the way in which operators can capture resources from others is changing. But the incentives and institutions underpinning the drainage of First Nations oil remain largely unchanged. The federal trusteeship, which was responsible for creating an environment of high transaction costs, continues to make costs higher on First Nations reserves, and will affect any new energy development on or near reserves.

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Appendix

A Additional Results

Figure A1 disaggregates the time-series of production quantities presented in Figure 2 into quarterly barrels of oil produced by wells located 0-600 meters from the border (a), 600-1200 meters from the border (b), and 1200-2000 meters from the border. The figure shows that the drop in production from on-reserve wells in the mid-1980s was mostly driven by wells drilled within 1.2 km from the border.

Figure A2 uses raw production data and plots outcomes for wells drilled between 1985 and 2005 by distance to the nearest First Nations reserve. Figure A2a shows a clear discontinuity in lifetime cumulative oil production at the border, where total production within 400 meters of the border is approximately 30 million barrels. The 200-400 meter distance bin contains 203 wells producing approximately 20 million barrels of crude oil over their lifetime.

Figure A2a understates the drainage away from First Nations reserves because it does not account for the land area contained within each of the distance bins. If drilling were equally likely everywhere and pool characteristics were held constant, we would see production increase with land area. Figure A2b shows how total land area in each distance bin changes with distance to the border of First Nations reserves. First Nations reserves have a limited land base, and we have several small reserves in our sample, so the total land area in each distance bin on reserve decreases as the distance to the border increases in absolute value.[34] Figure A2c shows how production varies with distance to the border when normalized by land area. The spike in total production off reserve but at the border is accompanied by a dip in total production on reserve, within one kilometer from the border. Although more wells were drilled off reserve than on reserve between 1985 and 2005, the number of wells drilled is relatively constant across all distance bins off reserve (Figure A2d).[35] This suggests that the wells in the 1985-2005 cohort that were drilled close to the border produced more than the wells drilled farther away from the border.)

Table A1 reports the estimates of border effects on eight other well outcomes. Looking at the time from spudding to completion, which has been used as an indicator for productivity (Kellogg, 2011), we see no difference by border distance (column 1). We also find no difference

[34]The average size of a reserve in our sample is 19.5 square kilometers, and the median is only 1.9 square kilometers. Area calculations are based on all reserves that have wells within 10 kilometers of the border.

[35]First Nations have a limited land base and might prefer not to drill wells on reserve land. Parker et al. (2024) document that other types of locally unwanted land use (LULU), solar and wind farms, are less likely to be hosted on Native lands than on comparable non-Native lands in the United States. However we find that wells are drilled, just not as heavily extracted from.

Table A1: Additional results

	(1) Time to complete	(2) Vertical depth (m)	(3) Surface casing (m)	(4) I(Discovery)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	-2.8	22	2.7	.011
	(2.9)	(20)	(5.7)	(.015)
$\mathbf{1}(\text{Distance}^{-600,0})$	4.6	-1.5	2.7	-.012
	(7.5)	(15)	(5.3)	(.016)
$\mathbf{1}(\text{Distance}^{0,600})$	-3.1	16	-3	-.0053
	(3.2)	(19)	(4.7)	(.015)
$\mathbf{1}(\text{Distance}^{600,1200})$	2.4	12	-1.4	-.0016
	(4)	(12)	(3.8)	(.012)
Nearest Reserve FE	Yes	Yes	Yes	Yes
Mean dep. if $\mathbf{1}(\text{Distance}^{\lvert 1200\rvert,\lvert 2000\rvert})$	10.24	1,008.53	186.21	.13
Obs.	6,726	6,722	6,365	6,726

	(5) I(Confidential)	(6) I(Unitized)	(7) I(Unitized both)	(8) I(Never produced)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	.043	.0046	.0046	.017
	(.032)	(.013)	(.0062)	(.02)
$\mathbf{1}(\text{Distance}^{-600,0})$	.0091	.0098	.0079*	-.0091
	(.026)	(.013)	(.0043)	(.021)
$\mathbf{1}(\text{Distance}^{0,600})$	-.0012	-.006	-.0033	.012
	(.05)	(.0081)	(.0055)	(.021)
$\mathbf{1}(\text{Distance}^{600,1200})$	.023	.0025	.0031	.025
	(.045)	(.0033)	(.0024)	(.017)
Nearest Reserve FE	Yes	Yes	Yes	Yes
Mean dep. if $\mathbf{1}(\text{Distance}^{\lvert 1200\rvert,\lvert 2000\rvert})$	.62	.03	.01	.37
Obs.	4,533	6,726	6,726	6,726

Notes: Sample of wells drilled between 1985 and 2005 within 2km of a First Nations reserve. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

in the depth of wells (column 2) or the surface casing depth (column 3) by border distance.[36] Looking at the likelihood that the well is a discovery well, defined by being the first well ever drilled in a pool, we don't see differences (column 4). We also don't find any effect associated with any of the distance bins for the probability of the well having confidential status (column 5), the probability that the well is unitized (column 6), and the probability that the well never produced (column 7). The number of observations decreases in column 5 because we don't have the confidential well status for Saskatchewan, only for Alberta. One of the only ways First Nations can recover drainage would be from unitization. Unitization, in general, is exceedingly rare, on average being in the 3% range. We do find a small but statistically significant positive effect of being within 600 meters of the border on reserve on the probability that the well is unitized across both on- and off-reserve wells (column 7). This tells us when there is production on First Nations reserves, it is more likely to be unitized with a firm extracting off reserve, but this is not the case for the production off the reserve, again suggesting FN are not receiving payment.

Table A2 reports heterogeneity in total cumulative production by the size of the reserve. These results indicate that patterns of drainage at the border are predominantly a phenomenon associated with large reserves, which we have defined as being larger than 75 square kilometers in area.

We use the same specification in Equation 1 and estimate border effects on an array of

[36] Surface casing depth protects water tables.

Table A2: Heterogeneity in cumulative production

	Large reserves	Small reserves	Tiny reserves
	(1)	(2)	(3)
	Prod. (bbl)	Prod. (bbl)	Prod. (bbl)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	2,063.66	-7,883.45*	
	(3,764.14)	(4,302.49)	
$\mathbf{1}(\text{Distance}^{-600,0})$	339.18	-1,896.54	
	(4,168.47)	(7,487.67)	
$\mathbf{1}(\text{Distance}^{0,600})$	11,871.54***	8,046.50	.00
	(3,542.44)	(7,947.47)	(.00)
$\mathbf{1}(\text{Distance}^{600,1200})$	6,392.74***	-1,711.23	-.00
	(2,297.73)	(4,910.03)	(.00)
Nearest Reserve FE	Yes	Yes	Yes
Year drilled FE	Yes	Yes	Yes
Mean dep. if $\mathbf{1}(\text{Distance}^{\|1200\|,\|2000\|})$	14,034.37	30,763.43	7.27
Obs.	3,333	3,307	30

Notes: Sample of wells drilled between 1985 and 2005 within 2km of a First Nations reserve. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level. Large reserves are at least 75 square km in surface area; small reserves are less than 75 sq km; tiny reserves are less than or equal to 0.05 square km.

Table A3: Pool characteristics by border distance

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Recovery Factor (%)	Water saturation (%)	Pay thickness (m)	Rock volume (ha-m)	Initial pressure (kPa)	Oil density (kg/m^3)	Porosity (%)	Discovery Year (year)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	-.75	.90	1.91	-6,232.59*	-478.90	-23.70***	-3.64**	7.70**
	(1.66)	(1.82)	(1.36)	(3,268.60)	(452.28)	(7.96)	(1.46)	(3.23)
$\mathbf{1}(\text{Distance}^{-600,0})$	.35	2.16	.92	-2,588.00	134.36	-22.53***	-4.00***	1.30
	(1.15)	(1.54)	(.80)	(2,187.04)	(813.99)	(8.10)	(1.21)	(3.46)
$\mathbf{1}(\text{Distance}^{0,600})$	1.02	1.51	.65	-878.86	-264.87	-5.87	-1.51	-.29
	(1.11)	(.99)	(.73)	(2,416.19)	(475.38)	(6.62)	(1.20)	(1.85)
$\mathbf{1}(\text{Distance}^{600,1200})$	.91	-1.02	.46	17,042.18	860.23**	-.09	-.36	-.64
	(.86)	(.73)	(.46)	(10,243.50)	(389.43)	(5.22)	(.92)	(1.37)
Year drilled FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Mean dep. if $\mathbf{1}(\|1200\|, \|2000\|)$	14.97	30.90	6.51	13,501.07	10,944.39	883.72	18.70	1,979.13
Obs.	1,637	1,637	1,637	1,637	1,133	1,637	1,637	1,604

Notes: Outcome variables are pool charactersitics for the sample of wells drilled between 1985 and 2005 within 2km of a First Nations reserve. Robust standard errors are clustered nearest reserve. No reserve fixed effects. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A4: Decline Curve Estimation

	b	D
	(1)	(2)
$\mathbf{1}(\text{Distance}^{1200,2000})$	0.659	0.023
	(0.023)	(0)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	1.195	0.045
	(0.022)	(0.001)
$\mathbf{1}(\text{Distance}^{-600,0})$	0.734	0.034
	(0.013)	(0)
$\mathbf{1}(\text{Distance}^{600,1200})$	0.607	0.027
	(0.017)	(0)
$\mathbf{1}(\text{Distance}^{600,1200})$	0.674	0.031
	(0.014)	(0)
$\mathbf{1}(\text{Distance}^{1200,2000})$	0.473	0.026
	(0.018)	(0)

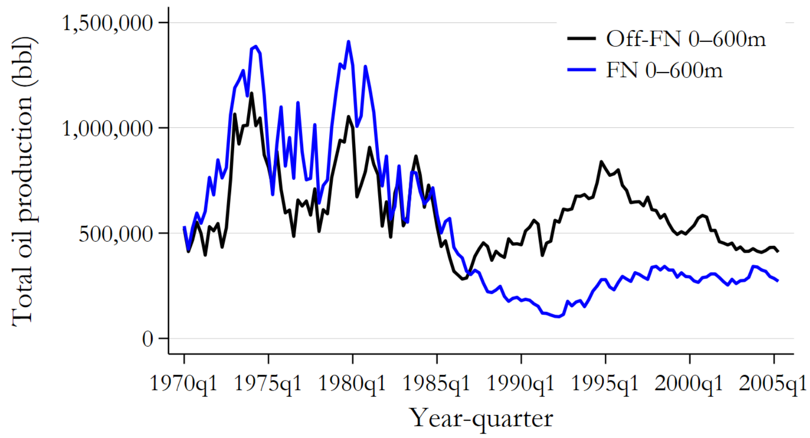
Notes: Estimates of the parameters of a hyperbolic decline curve. Standard error in parentheses. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

pool characteristics in Table A3 and Figure A3. Discontinuous increases in activity at the borders cannot be explained by naturally occurring phenomena. Figure A3 plots several of the most important geological determinants of oil pool productivity, including rock volume (Figure A3a), porosity (Figure A3b), initial pressure (Figure A3c), and oil density (Figure A3d). If the spike in production at reserve borders were driven by differences in geology, we would expect to see high levels of the four measures plotted in Figure A3 at the border, and we do not see these patterns.

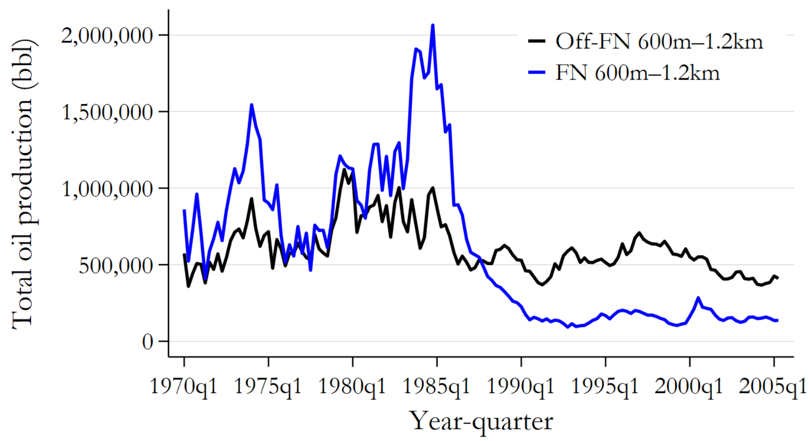
A.1 Decline Curve Estimation

Table A4 presents results from the estimation of the parameters in a hyperbolic decline curve, $R_t = R_0\left(1 + bDt\right)^{-1/b}$, for subsamples based on distance bins from the border. A larger D indicates a steeper decline in the initial period but a larger b indicates less steepness over time. With two numbers it is difficult to interpret slopes at any given age. Thus, it is these estimates that are used to calculate the slope of the decline curves at different ages, depicted in Figures 7 (b) and (c).

(a) Bin 0–600m from border



(b) Bin 600m–1.2km from border



(c) Bin 1.2–2km from border

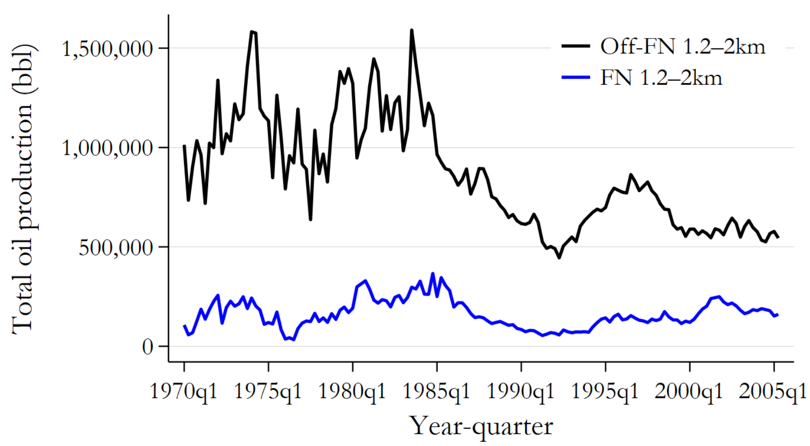
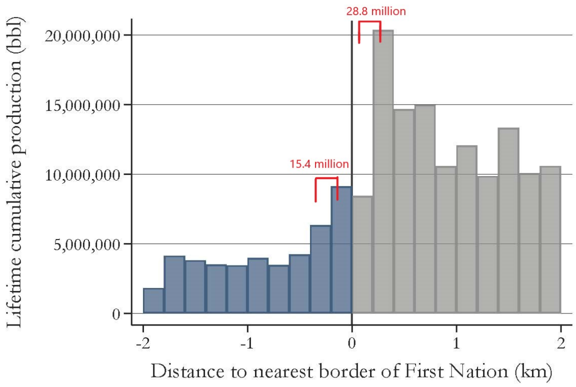
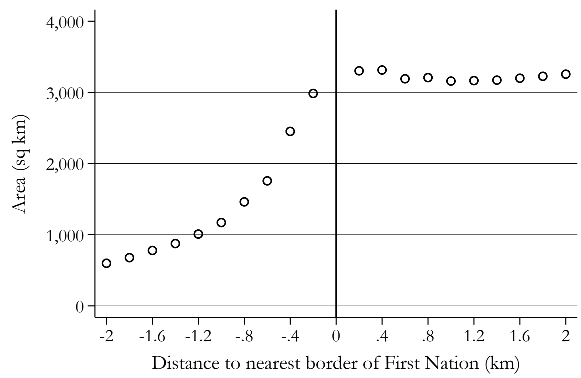


Figure A1: Quarterly Production by Distance Bins

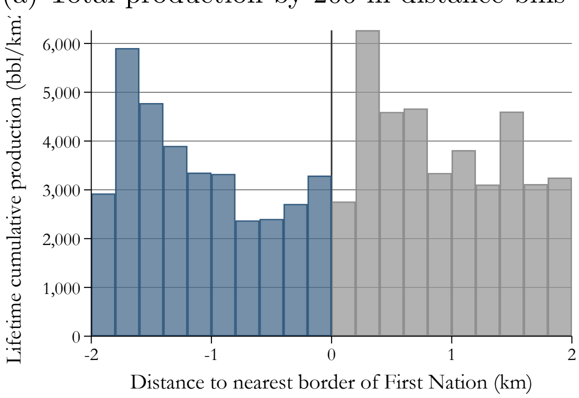
Note: Total production by wells in different distance bins from the border, on and off First Nations reserves, by quarter.



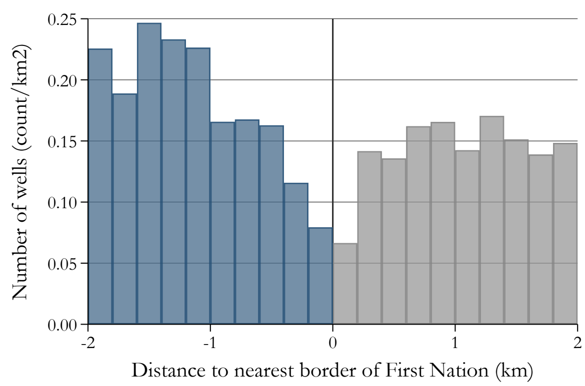
(a) Total production by 200-m-distance bins



(b) Land area by 200-m-distance bins



(c) Production, normalized by land area



(d) Wells drilled, normalized by land area

Figure A2: Well outcomes by border distance

Note: All figures are for wells drilled between 1985-2005. Total cumulative production, not normalized by land area. Total land area (in sq km) in each 200m distance bin. Total cumulative oil production, normalized by land area. Number of wells drilled by border distance, normalized by land area.

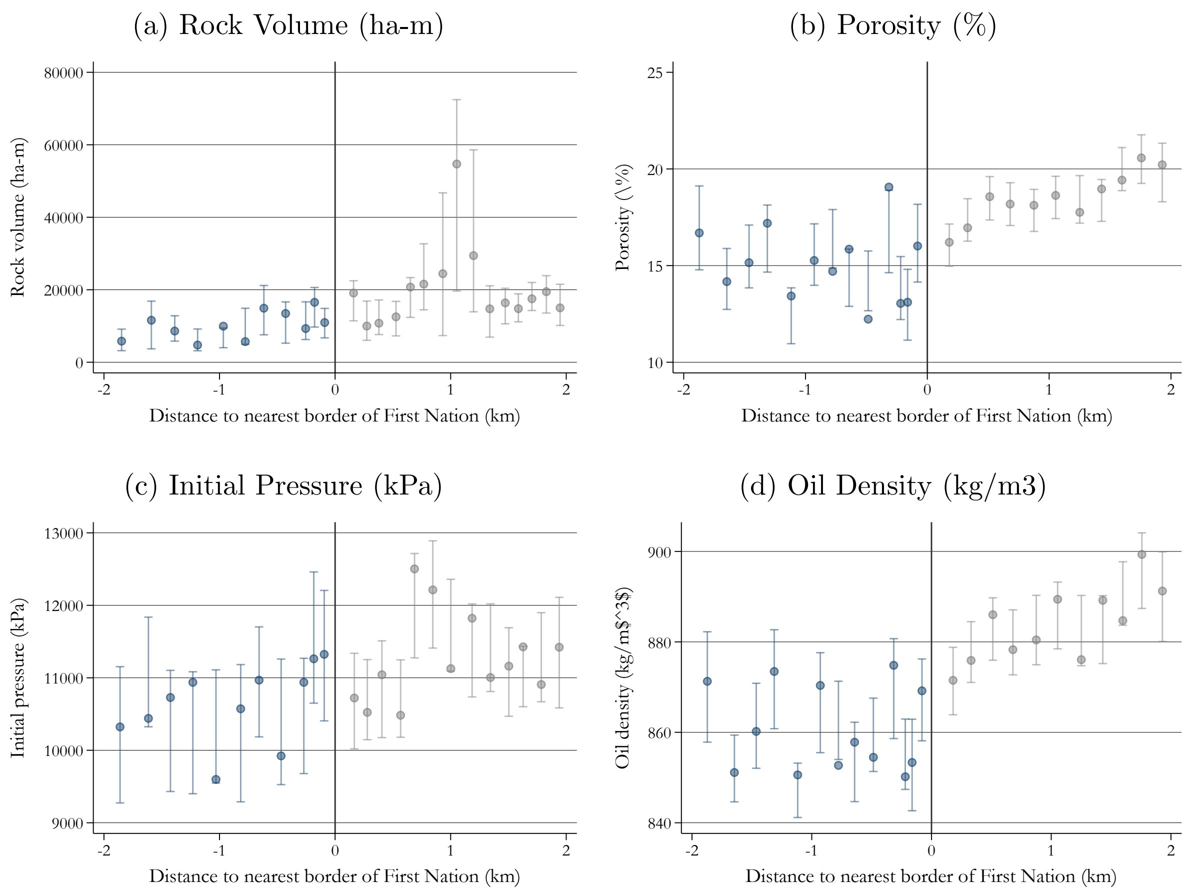


Figure A3: Pool characteristics, averaged over wells

Notes: Binscatters of pool characteristics from wells drilled between 1985 and 2005, on First Nations reserves or within two kilometers of a reserve border. We only observe pool characteristics when wells have non-zero production. Included are fixed effects for year drilled. Gross rock volume is the volume of rock from the top to the base of the reservoir. Porosity is a measure of the pool's ability to hold a fluid, calculated as the percentage of the total rock that is comprised of pore space. Initial pressure is the reservoir pressure upon discovery, prior to production. Oil density is a measure of how heavy the oil is.

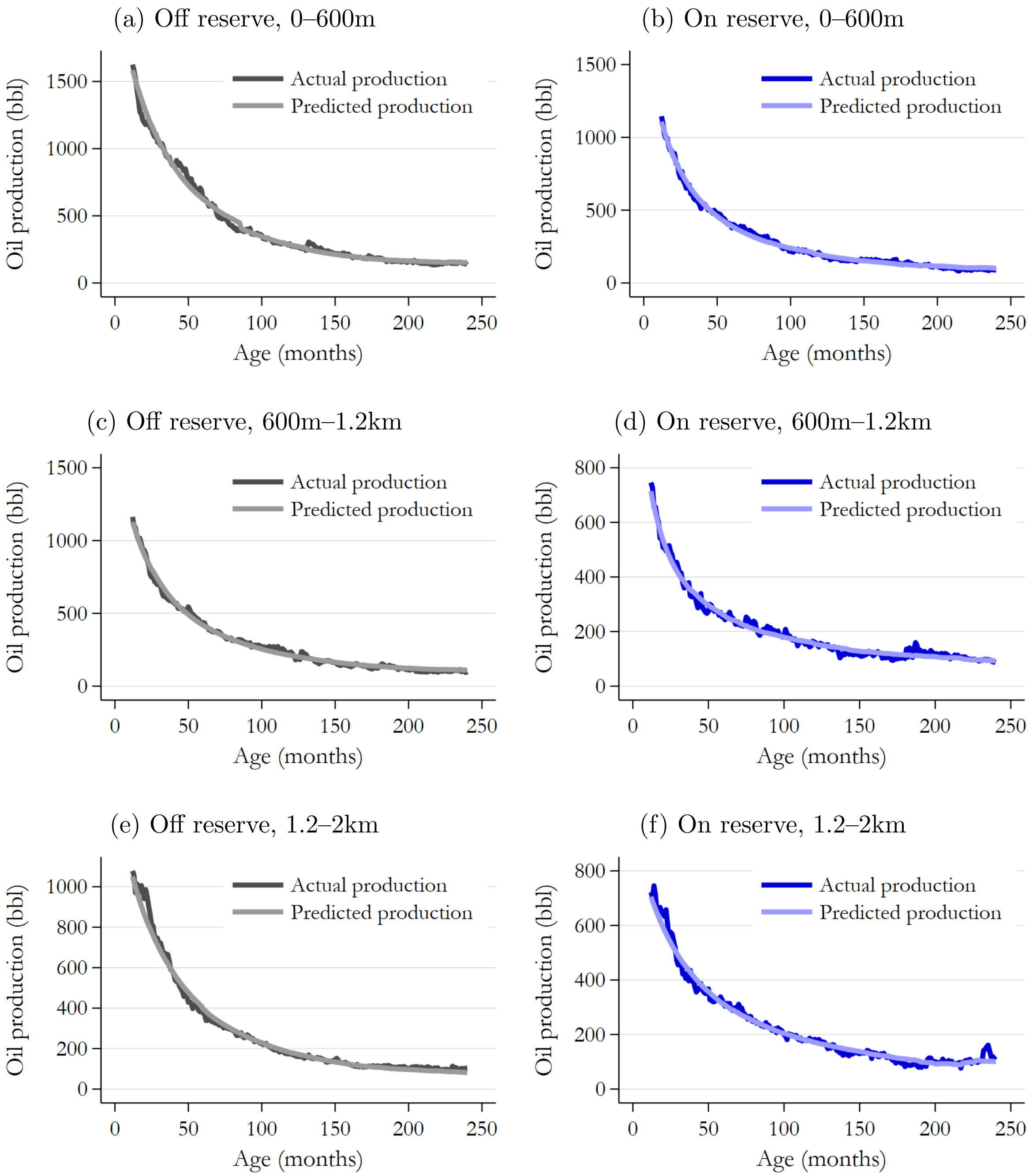


Figure A4: Actual versus predicted production decline using hyperbolic decline curve estimates

Note: Figure depicts comparison between average production and the predicted average production, using the estimates from hyperbolic decline.

18 June 1996

[redacted]
Seagull Energy Canada Ltd.
2900, 707 - 8th Avenue S.W.
P.O. Box 2870
Calgary, Alberta T2P 2M7

Dear [redacted]

Siksika Nation - Indian Reserve No. 146
Oil and Gas Lease No. OL-5461
Drainage Notice

A review of the wells in the Reserve area indicates that the gas well at 4-27-21-19W4M is producing from an undesignated zone. The Band Council and the Executive Director have jointly determined that there may be drainage of gas from section 22-21-19W4M by the well at 4-27-21-19W4M.

Pursuant to the Indian Oil and Gas Regulations (1995), hereafter called the "Regulations", you are hereby given ninety (90) days notice to:

(a) Commence drilling a well in section 22-21-19W4M down to the offending formation, as provided for in section 34(1) of the Regulations. The offending formation must be put on production; or

(b) Pay compensatory royalty as provided for in section 34(1)(b) of the Regulations; or

(c) Surrender, as provided for in section 35 of the Regulations, the Indian lands in section 22-21-19W4M.

Figure A5: Example offset notice

Note: An example of one of the offset notices received through one of the authors' Access to Information and Privacy (ATIP) requests.

A.2 Pre-1985 Cohorts

This subsection conducts analysis similar to that in Section 5 but for the period before 1985. Table A5 presents summary statistics of the wells drilled before 1985, separately based on whether the well was located on a First Nations reserve or off reserve but within two kilometers of a reserve. Table A6 uses the same outcomes as Table 2, but for wells drilled before 1985. Of the wells drilled before 1985, some of the monthly production occurred during the 1985-2005 timeframe. Breaking the monthly production outcomes into further subsamples shows that most of the excess production occurs from the 1985-2005 cohort (Table A7). Figure A6 replicates Figure 5 but for wells drilled prior to 1985.

Table A5: Summary statistics for wells drilled before 1985

	FN		**Off-FN**		
	Mean (Std. Dev.)	N	Mean (Std. Dev.)	N	p-value
Cumulative oil production (bbl)	184,341 (893,078)	1,113	110,984 (576,488)	2,379	.01
Cumulative water injection (m^3)	663,055 (1,953,692)	47	2,160,703 (3,968,885)	84	.00
Recovery Factor (%)	33 (25)	200	22 (18)	630	.00
Rock volume (ha-m)	59,388 (76,577)	200	36,192 (96,846)	630	.00
Porosity (%)	13 (4.8)	200	16 (8)	630	.00
Initial pressure (kPa)	12,465 (3,857)	192	11,629 (3,257)	478	.01
Oil density (kg/m^3)	840 (31)	200	872 (54)	630	.00
Time to completion (days)	33 (217)	1,113	53 (633)	2,379	.17
1(Unitized)	.11 (.31)	1,113	.065 (.25)	2,379	.00
1(Unitized across border)	.11 (.31)	1,113	.053 (.22)	2,379	.00

Notes: Summary statistics of wells drilled before 1985, within two kilometers of a reserve border.

Table A6: Pre-1985 cohort: Well outcomes by border distance

	(1) Lifetime Prod. (bbl)	(2) Wells (drilled/month)	(3) Monthly Prod. (bbl/month)	(4) Water Inj. (million tons)	(5) Bonus bid ($/ha)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	75,152	.00061	141	-1.2**	
	(62,360)	(.00046)	(89)	(.55)	
$\mathbf{1}(\text{Distance}^{-600,0})$	23,215	.00091	130	-.35	
	(22,431)	(.0015)	(81)	(.55)	
$\mathbf{1}(\text{Distance}^{0,600})$	23,149	-.0012**	187*	-.68	1,005
	(29,828)	(.00049)	(104)	(.81)	(831)
$\mathbf{1}(\text{Distance}^{600,1200})$	-30,839	.0021***	-143	-.18	651
	(46,213)	(.00062)	(168)	(.61)	(579)
Nearest Reserve FE	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes
Area of bin	No	Yes	No	No	No
Age controls	No	No	Yes	No	No
Mean dep. var. if $\mathbf{1}(\text{Distance}^{\|1200\|,\|2000\|})$	118,220.88	.01	475.68	1.26	568.81
Obs.	3,364	407,664	839,901	103	188

Notes: Parallel of Table 2, but using the sample of wells drilled before 1985. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

Table A7: Monthly production, by cohort and time period

	Cohort Drilled in 1985-2005		Cohort Drilled Pre-1985		
	(1) Prod. 1985-2005 (bbl/month)	(2) Prod. Post-2005 (bbl/month)	(3) Prod. Pre-1985 (bbl/month)	(4) Prod. 1985-2005 (bbl/month)	(5) Prod. Post-2005 (bbl/month)
$\mathbf{1}(\text{Distance}^{-1200,-600})$	-15	9.9	7.4	152	-4.8
	(31)	(11)	(133)	(139)	(3.2)
$\mathbf{1}(\text{Distance}^{-600,0})$	-11	-.81	274	-.48	6
	(54)	(12)	(257)	(40)	(9.5)
$\mathbf{1}(\text{Distance}^{0,600})$	153*	21***	498	16	16
	(80)	(7.5)	(326)	(30)	(13)
$\mathbf{1}(\text{Distance}^{600,1200})$	24	11	-421	-44	-2.8
	(40)	(7.3)	(458)	(57)	(7.9)
Nearest Reserve FE	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes
Age controls	Yes	Yes	Yes	Yes	Yes
Mean dep. var. if $\mathbf{1}(\text{Distance}^{\|1200\|,\|2000\|})$	268.30	49.37	1,178.29	206.07	28.73
Obs.	421,831	794,715	275,762	355,802	208,337

Notes: Subsamples of wells depending on when drilled and time of production. Sample of wells drilled within two kilometers of a First Nations reserve. Year fixed effects refers to year of production. Robust standard errors are clustered by nearest reserve. *** Statistically significant at the 1% level; ** 5% level; * 10% level.

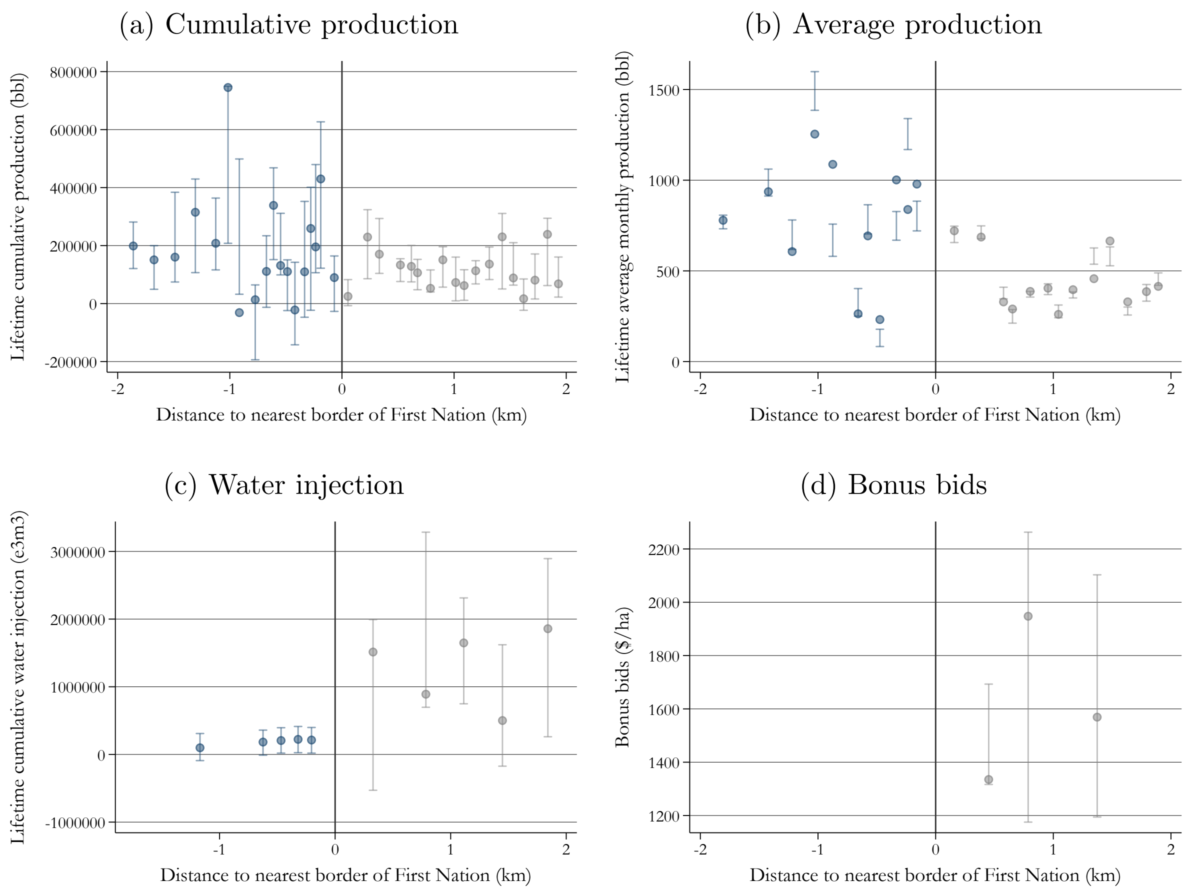


Figure A6: Well outcomes by border distance, pre-1985 cohort

Note: Binscatters of well outcomes from wells drilled before 1985 and 95% confidence intervals. Cumulative production controls for nearest reserve fixed effects and year spudded, average monthly production controls for age of well, nearest reserve, and production year fixed effects, water injection controls for nearest reserve and year drilled fixed effects, and bonus bids control for nearest reserve and lease commence year.

A.3 Post-2005

Figure A7 graphs the changes to the average distance that wells were drilled laterally over time, from 1975 to 2020. This figure demonstrates that horizontal drilling was rare in the period of time that we study (1985-2005) and would not have been a primary mechanism for drainage.

Figures A8 and A9 replicate Figure 2 and Figure 4, respectively, but show post-2005 outcomes. The increase in production after 2005 is driven by unconventional production, predominately from Saskatchewan, which shares the Bakken Formation with North Dakota, among other shale oil and tight oil formations. In unconventional production, the rock is less permeable for oil to flow through, because the pores in the rock are smaller and less connected, so oil is extracted using the combination of horizontal drilling and hydraulic fracturing. Most wells today are not simply vertical down, but rather have "lateral" portions going in different directions below the surface. In future work, we plan to explore the second divergence in production that occurred after 2005, when new types of technology associated with unconventional wells opened up new avenues for the drainage of oil.

Figures A10 and A11 use monthly data to examine whether the modernization of federal regulations, or the closing of the gap between provincial and federal regulations, closed the gap between production from wells on and off First Nations reserves. In each figure, the vertical line marks the month (July 2019) that the modernization of the Indian Oil and Gas Act (IOGA) took effect. We find no production discontinuity at that point (Figure A10). Because it may be difficult to affect production from existing wells, we also check whether the modernization of regulations was responsible for changes to the drilling of new wells. Figure A11 indicates that it was not. These results suggest that the modernization of the IOGA may have been either too little or too late to address missing oil production on First Nations reserves.

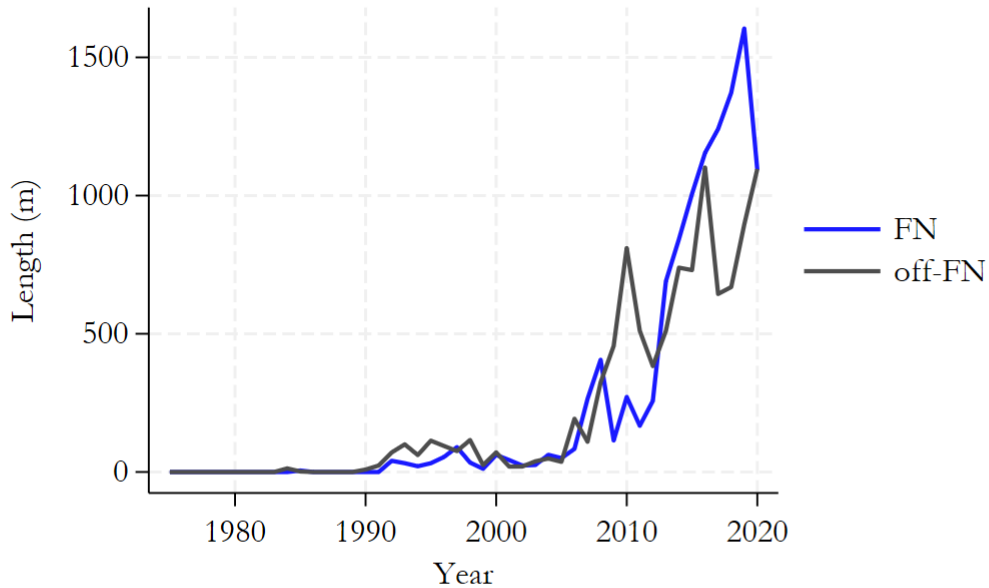
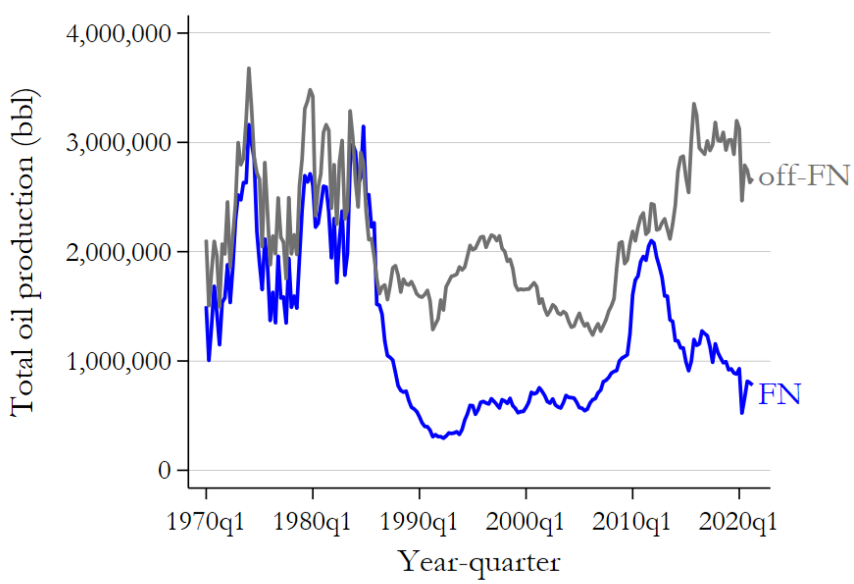


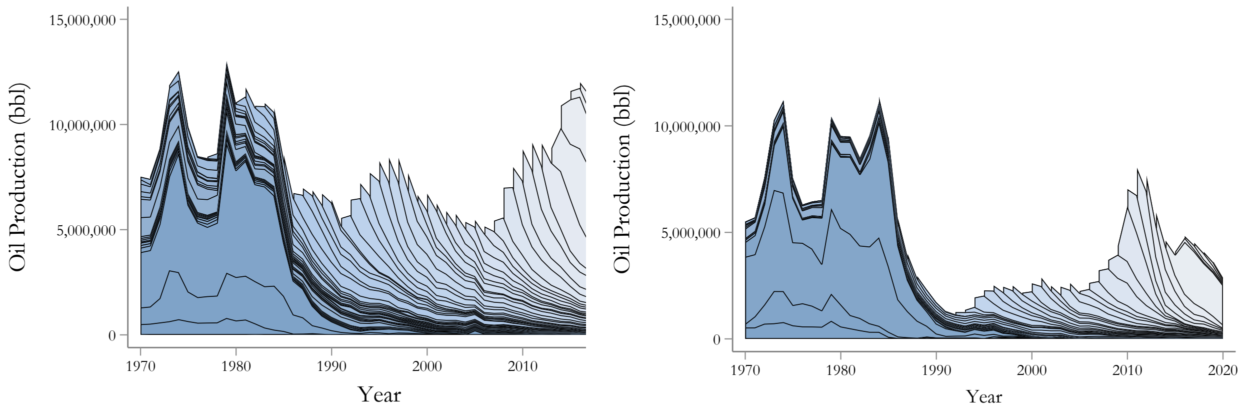
Figure A7: Average length of horizontal wells (1975–2020)

Note: Average distance that wells are drilled laterally by year within 2km of First Nations reserves.

Figure A8: Quarterly oil production within two kilometers of FN reserves, post-2005



Note: Quarterly barrels of oil production for Alberta and Saskatchewan combined. Sample is restricted to wells within two kilometers of the First Nations reserve borders.



(a) Off Reserve

(b) On Reserve

Figure A9: Production by well cohort, post-2005
Note: Annual oil production from well cohorts within 2km of a FN border. Off reserve (Figure A9a) and on reserve (Figure A9b).

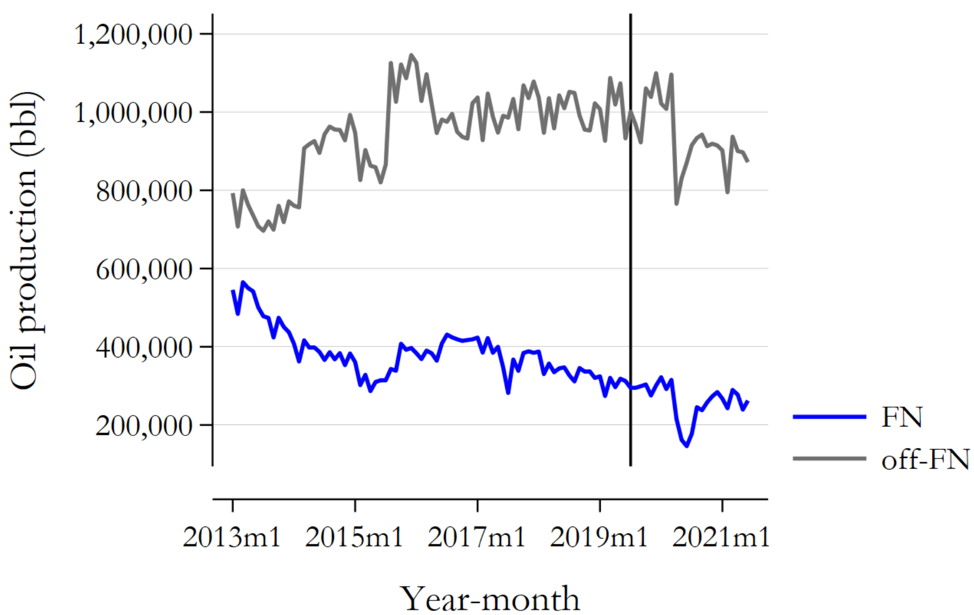


Figure A10: Production and the modernization of the IOGA
Note: Monthly barrels of oil production for Alberta and Saskatchewan combined. Sample is restricted to wells within two kilometers of First Nations reserve borders. The vertical line indicates the month that the modernization of the Indian Oil and Gas Act took effect.

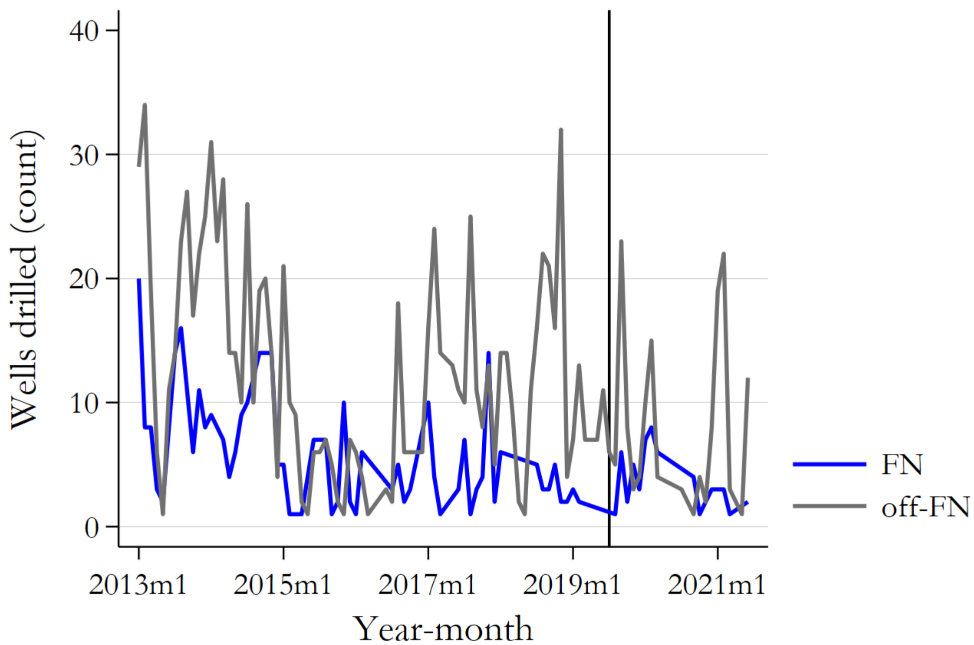


Figure A11: Well count and the modernization of the IOGA

Note: Count of wells per month for Alberta and Saskatchewan combined. Sample is restricted to wells within two kilometers of First Nations reserve borders. The vertical line indicates the month that the modernization of the Indian Oil and Gas Act took effect.

B Changes in 1985-1987

B.1 The Western Accord on Energy

In 1985, the Western Accord dismantled the National Energy Program and instigated a series of changes that fundamentally altered the development of Provincial Crown minerals across Western Canada.

First, the Western Accord deregulated crude oil prices on June 1, 1985 (Government of Canada, 1985). This change came at a time of falling global oil prices (see Section B.2). After 1985, oil could be purchased from Canadian or foreign sources without volume restrictions, as well as at prices freely negotiated between buyers and sellers (subject to certain clauses). Producing provinces retained their power to control production of crude oil.

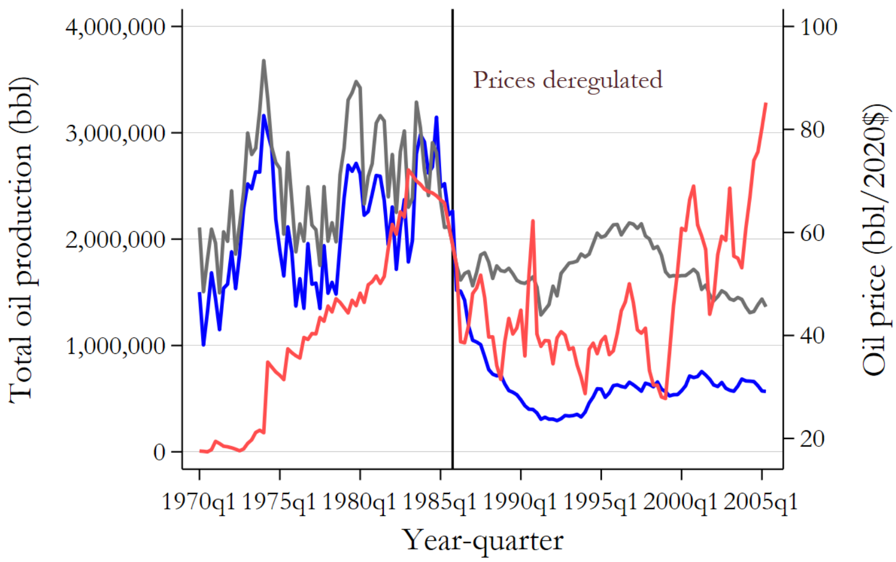
Second, the Western Accord required the Government of Canada to remove the following taxes and charges: the Natural Gas and Gas Liquids Tax (which includes the Natural Gas Export Levy), the Incremental Oil and Revenue Tax, the Canadian Ownership Special Charge, the Crude Oil Export Charge, and the Petroleum Compensation Charge (Government of Canada, 1985). In addition, the Petroleum and Gas Revenue Tax (PGRT) would not apply on new production of oil, natural gas, and gas liquids after April 1, 1985. This included production from new wells spudded on or after April 1, 1985, or incremental production from pools or portions of pools that were subject to enhanced recovery schemes that commenced operation on or after April 1, 1985. PGRT levied on prior production would be phased out beginning in January 1986. The Government of Canada also agreed that tax-based incentives designed to stimulate investment in Canada's oil and gas industry were to be of general application, without discrimination as to the location of the activities in question or as to ownership and control.

The Western Accord was signed by four parties: the Government of Canada, the Government of Alberta, the Government of Saskatchewan, and the Government of British Columbia. Immediately following the Western Accord, the Minister of Energy at the time, John Zaozirny, issued a statement covering the details of the Accord. In Government of Alberta (1985a), Zaozirny states that the Accord achieved three fundamental principles: (i) crude oil production would receive market value for the first time since 1973, (ii) the oil and gas industry would be taxed on its profits rather than its revenues, and (iii) any federal incentives to the oil and gas industry would apply across Canada. He also mentions that the producing industry was virtually unanimous in their support of dismantling the PGRT (Government of Alberta, 1985a).

B.2 Falling Global Oil Prices

Figure A12 shows average world oil prices overlaid onto the time series of production within two kilometers of a First Nations reserve. It was estimated that the dramatic decline in world oil prices (approximately 80% - see Figure A12) caused Canada's oil and gas industry to lose between $4.5 and $5.6 billion in cash flow in 1986 (David C. Hawkes, Bruce G. Pollard, 1987). In the West, there were only 71 rigs active in June 1986, compared to 320 at the same time the year before (June 1985). With the demise of the PGRT and the Canadian Ownership Special Charge, it was estimated that as much as $9 billion would be lost in federal revenues during the following four years.

Figure A12: Quarterly oil production and average oil prices



Note: Quarterly total barrels of oil production (on-reserve: blue; off-reserve: grey) and average oil prices (red). Sample is restricted to wells within two kilometers of the First Nations reserve borders.

B.3 Incentive Program Changes

Swiftly following the Western Accord, Alberta announced changes to oil and gas royalties, royalty tax credits, and incentive programs for production of Provincial Crown minerals (Government of Alberta, 1985b).

Beginning August 1, 1985, marginal royalty rates on old and new oil and natural gas were to be reduced in stages over a 24-month period, from 45% to 40% on old production and from 35% to 30% on new production. A royalty tax credit to small producers was to be increased effective April 1, 1986, from 50% of up to $2 million to 75% of up to $3 million in royalty obligations (Government of Alberta, 1985b). These new incentives coincided with the phasing out of cash grants under the Alberta Petroleum Incentive Program (APIP), the Exploratory Drilling Incentive System (EDIS) and the Geophysical Incentive System (GIS).

A new crude oil royalty holiday system would take effect June 1, 1985, applying to all new conventional crude oil wells drilled outside existing pool boundaries on or after June 1, 1985 (Government of Alberta, 1985b). So-called "off target" wells drilled on or adjacent to existing pool boundaries and wells drilled to produce crude bitumen from oil sands leases were not eligible for the benefits of the new program. The royalty holiday consisted of the greater of a 12-month royalty-free period for each eligible well to a maximum of $1 million per well or a royalty exemption defined as a volume of crude oil for each eligible well, calculated from a depth-related schedule. The program was in effect for a period of three years, from June 1, 1985, to May 31, 1988 (Government of Alberta, 1985b).

B.4 The Origin of Indian Oil and Gas Canada (the IOGC)

Pursuant to the Indian Act of 1876, the federal government is responsible for regulating the exploration and production of oil and gas on First Nations land (for more on this, see Section C.1). The organization developed to carry out that mandate, Indian Oil and Gas Canada (IOGC), was approved in 1986 and established in 1987, taking the place of Indian Minerals West. This timing coincided with the Western Accord and incentive program changes.

The IOGC's origin can be traced back to events in the early and mid-1970s. In late 1973 and early 1974, the price of oil and gas rose rapidly, and existing royalty rates became too low, prompting all provinces to pass statutes to increase rates (C.A. Webb, 1987). In order to increase royalty rates on reserve land to at least match the provincial rates, the Department of Indian Affairs and Northern Development (DIAND) amended existing regulations to allow the Minister to set rates from time to time by prescription, these rates would then apply immediately to all existing leases. Oil companies subsequently protested that the prescription was illegal, and they threatened litigation over the matter. In order to protect the option to enact this prescription and further regulations like it, the federal government removed the management of First Nations' oil and gas resources from the Indian Act and put it into a separate act, the Indian Oil and Gas Act.

The Indian Oil and Gas Act (IOGA), which went into effect on December 20, 1974, clarified surface rights, stating that the Band or the surface occupant has the right to adequate compensation; however, there was no arbitration board for the determination of this compensation on reserve land (C.A. Webb, 1987). The Indian Oil and Gas Regulations were amended, removed from the Indian Act, and put into the IOGA in 1977 (Indian and Northern Affairs Canada, 2009). One important feature of the amendments was an increase in the amount of information provided by the companies and increased reporting requirements to the Band council.

In April 1986, a workshop was held to determine whether to change the IOGA, and then a task force was created to study the issue and report back (C.A. Webb, 1987). The task force subsequently presented recommendations at a Chief's assembly held in Edmonton, Alberta, on March 5 and 6, 1987 (C.A. Webb, 1987). At the Chief's assembly, the IOGC was approved and the Indian Resource Council (IRC) was formed (C.A. Webb, 1987). The IRC is a First Nations-led advocacy organization that engages with the IOGC to ensure productive resource development opportunities for First Nations.

C Additional Institutional Context

For the past 40,000 years, hundreds of distinct communities of Indigenous peoples have inhabited the place now known as Canada, also known as "Turtle Island" by some Indigenous peoples (Dusault and Erasmus, 1996). By comparison, the history of European colonization is brief but transformative. Beginning in the late 1400s, trade in furs—primarily beaver pelts—drove European settlers to interact with Indigenous peoples through pre-existing trade networks as well as newly-established ones (Innis, 1999; Payne, 2004; Ray, 2015). Over time, these interactions changed Indigenous livelihoods, altered economic systems, and established new population centers. They also gave rise to the formation of political alliances and trading partnerships, relationships that would eventually be formalized through the process of treaty making.

The relationships between the Crown and Indigenous peoples have been complex and evolving. Section 35 of the *Constitution Act of 1982*, which recognizes and affirms the Crown as the fiduciary, or the trustee, of Aboriginal peoples in Canada, builds on the evolving legal and constitutional positions outlined in the *Royal Proclamation of 1763*, the *Constitution Act of 1867*, and the *Indian Act* (Hurley, 2000).[37] Among the many facets of the trustee relationship is the Crown's responsibility to manage and oversee First Nations lands, resources, and moneys. Most relevant to this paper is federal management of revenues from the use of First Nations reserve land and federal regulation of on-reserve oil and gas exploration and production.

[37] A "fiduciary relationship is one in which someone in a position of trust has "rights and power which he is bound to exercise for the benefit" of another" (p.1).

C.1 Regulatory Regimes

Different regulatory regimes govern oil and gas on and off First Nations reserves (see Table A8). There is a federal regime responsible for the disposition of oil and gas rights and the collection of rents on First Nations lands. The legislative authority is Indian Oil and Gas Canada, or the IOGC. The IOGC operates under the authority of the legislative instrument and the regulatory instrument that specifies how to execute the legislative instrument: the Indian Oil and Gas Act (IOGA) and the Indian Oil and Gas Regulations (IOGR), respectively. The IOGA remained largely unchanged from 1974, the time of its passage, until 2009, when it was eventually amended. During that period of time, the legislation was only 20 pages long. The changes to the IOGA didn't come into force until ten years later, in 2019, when the IOGR was amended.

Provincial regimes are responsible for overseeing oil and gas exploration and production off reserve. In Alberta, Crown land is regulated by the Alberta Energy Regulator (AER). The relevant legislative instrument is the Oil and Gas Conservation Act. In contrast to the federal legislation, the provincial legislation has been updated every two years to keep up with industry developments. The most recent version is currently 88 pages long, compared with the 20-page federal legislation for First Nations lands.

Table A8: Regulatory Regimes Governing Oil and Gas

	Federal	**Provincial**
Legislative authority	Indian Oil and Gas Canada (IOGC)	Alberta Energy Regulator (AER)
Legislative instrument	Indian Oil and Gas Act (IOGA) ·Unchanged 1974-2009	Oil and Gas Conservation Act ·Updated biannually
Regulatory instrument	Indian Oil and Gas Regulations (IOGR) ·Updated in 2019	Oil and Gas Conservation Rules

C.2 Cost Differences

A firm's decision about where to drill is a function of several relevant sources of transaction costs. These costs, which we can broadly characterize as operating costs, are often higher on First Nations reserves than the land surrounding the reserves.

The costs associated with *exploration* are, chronologically, among the first costs incurred by oil companies. Geophysical exploration programs ("seismic surveys") map the geological sub-surface structures, thereby serving as one of the most important tools of reducing production uncertainty prior to drilling. Companies can conduct seismic surveys and gather environmental field data after obtaining a license pursuant to the Mines and Minerals Act (Alberta Energy Regulator, 2024). This license would require the consent of the surface rights holders and occupants.[38] In the case of Provincial Crown minerals, seismic surveys would be considered proprietary, whereas on First Nations land, a copy of the seismic survey must be provided to the Nation as well as the IOGC by law (Government of Canada, 2019a). The requirement to share this information with First Nations represents an additional cost, or a loss of an intellectual property asset that has the potential to generate revenue.

The second set of costs arise as companies *obtain the rights to drill*: companies that wish to drill wells must acquire both the mineral rights and the surface rights to do so. The process for obtaining rights to extract Provincial Crown minerals is as follows. A company first requests that the province post them in a competitive first-price sealed-bid auction run by industry (Alberta Government, 2014).[39] A Petroleum and Natural Gas (PNG) agreement is issued to the highest bidder, providing them with the leasehold rights to drill (Alberta Government, 2016). Covert and Sweeney (forthcoming) show that auctioned oil leases are associated with more production and higher future lease values relative to leases that are privately negotiated. The company would be required to pay the landowner rental payments for the use of the land but, in practice, landowners are almost never able to withhold their consent to sign a surface lease with the PNG auction holder.[40]

On the other hand, the IOGC is responsible granting companies the rights to First Nations minerals (Government of Canada, 2022). The IOGC uses two processes to arrange subsurface contracts: either a public tender with competitive bonus bids, or a negotiation process. Negotiations determine the type of subsurface contract, the specific land areas covered in the lease, bonus amounts, and royalties. Obtaining surface rights to First Nations

[38] For Provincial Crown minerals, a surface owner only has recourse to delay consent for a time, because it is almost always approved if adjudicated.

[39] This is often called a "land sale," but this is an inaccurate description because the province retains the title.

[40] This is pursuant to the Surface Rights Act, following the mandate of the Land and Property Rights Tribunal.

lands then requires that land is designated through a process stipulated by the Indian Act.[41] Both the IOGC and the First Nation are involved in issuing subsurface and surface contracts. The IOGC grants and administers these rights, but the First Nation must provide approval in the form of a Band Council Resolution (BCR) (Government of Canada, 2019b, 2024). A BCR is a formal decision made by the governing body of an Indigenous band or First Nation. Approval of a BCR could take anywhere ranging from several weeks to several years.[42]

The next set of important operating costs arise as part of the *production* process. There are several reasons why production on reserve may be more costly than production off reserve. Operations that take place on reserve must be negotiated with Band Council. Oftentimes, these negotiations include stipulations such as the preferential hiring of First Nations workers. These hiring conditions may be levied irrespective of whether the First Nations workers have experience in the industry. Companies that are not owned and operated by First Nations may also incur an additional cost of familiarizing themselves with First Nations governance structures and IOGC regulations, which differ from provincial regulations. Finally, there may be relevant infrastructure considerations. Prior to the drilling the well, companies must prepare the above ground rig site, including constructing pads and access wells, in accordance with First Nations local laws and regulations. On reserve, the environmental guidelines are dictated both by the Canadian Environmental Quality Guidelines, which are also used by the province, and the First Nations Band Council. Furthermore, existing infrastructure on First Nations reserves is, on average, of poorer quality than infrastructure in nearby areas (The First Nations Financial Management Board, 2022). Other research has shown that high production costs negatively impact production (e.g. Leonard and Parker, 2021; Edwards et al., 2021).

In addition to costs associated with exploration, obtaining rights, and production, oil companies consider other relevant costs related to royalty rates and taxes. Royalty rates could vary by First Nation, but are not publicly available. The federal government had the authority to change royalty rates for production on First Nations reserves following the separation of oil and gas resources from the Indian Act into the Indian Oil and Gas Act in 1974 (C.A. Webb, 1987). Before 1985, royalties on First Nations reserves were considered

[41] In order to obtain surface rights to drill on reserve, companies must now also complete an environmental review form. Indigenous Services Canada (ISC) developed the Environmental Review Process (ERP) in 2013 to respond to the *Canadian Environmental Assessment Act* of 2012, which stipulates how to evaluate the environmental impacts of projects on federal land with the potential to have adverse environmental consequences (Government of Canada, 2023). This is federal legislation that does not apply to provincial land.

[42] The time it takes depends on a number of factors, such as the complexity of the proposed contract, the workload of the governing body, and any additional consultations required with community members or stakeholders. Obtaining a BCR often involves several stages such as community meetings, legal review, and formal resolution by Council.

too low, because they were calculated on a frozen domestic oil price (Rae, 2005). The lower royalty rates arise partly through the federal government having a well-documented conflict of interest: they have a fiduciary duty to First Nations but also weigh concerns over consumer prices. A 1984 case (*Guerin versus The Queen*) clarified the legal obligation that reserves are to be held for the use and benefit of the Bands.