UNIVERSITY OF CALGARY

THE SCHOOL OF PUBLIC POLICY
SPP Briefing Paper

Volume 10 • Issue 3 • February 2017

80,000 INACTIVE OIL WELLS: A BLESSING OR A CURSE?

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SUMMARY

For a century, oil and gas wells have been Alberta's economic pride. That there could be a hidden cost in maintaining these wells past their productive life is difficult to imagine, much less accept. The financial burden of abandoning a well officially is no doubt why Alberta producers delay doing so as long as possible. Turning a blind eye, they routinely keep non-producing wells in a state of "inactive" suspension and refuse to rule out the possibility that someday oil prices or technology, or both, will change significantly enough to make those wells profitable again. In most cases that will never happen, but the province plays along anyway: It enforces no limit on how long a well can be kept inactive before it must be reactivated or abandoned. While a convenience for well owners, there is no benefit to Albertans. They are exposed to the risk of thousands of inactive wells becoming a hazardous threat to public safety.

The longer a well is inactive, the higher the likelihood that its owner may no longer be around to arrange and pay for its official abandonment, a process whereby wells are permanently sealed using regulated methods that insure they cause no environmental damage. Oil and gas producers come and go. Periodic price shocks, like the one that recently ravaged the sector, drive companies into insolvency. When the owner of an inactive well is no longer around to pay for its abandonment costs, the well becomes orphaned. Alberta's permissive policies have led to a situation where there are now more than 80,000 inactive wells in the province. Some have been inactive for decades. If the possibility existed that they could eventually become economical, those wells might be considered a blessing. However, the simulations that model scenarios where prices are substantially higher or where production technology is significantly improved, clearly show that the vast majority of these wells will never be reactivated, no matter how dramatically conditions improve.

If oil prices rise 200 per cent, the modeling shows that just 12 per cent of oil wells become reactivated, and just seven per cent of gas wells. When the model tests to see what happens when a technological innovation improves so that the remaining oil or gas in a well that cannot be recovered is suddenly made recoverable (i.e., a 514 per cent increase in oil reserves), just 10 per cent of

inactive oil wells are reactivated, and just six per cent of gas wells. The most effective way to reduce the number of inactive wells, the model finds, is by reducing the cost of their abandonment. With a 25 per cent reduction in abandonment costs, the pool of inactive wells shrinks by 20 per cent for both oil and gas, while the number of abandoned wells increases by nearly 50 per cent for both oil and gas. In all cases, the amount of oil and gas production that would change one way or the other — either by a minimal level of reactivation or a significant wave of abandonment — is marginal and not of meaningful benefit to Albertans.

Creating an industry fund that takes responsibility for a well that has been orphaned has been Alberta's approach to managing all its orphan wells. The deemed liability of 80,000 inactive wells is so large presently that the fund would be insufficient to cover the costs. The only way to prevent the province's vast and growing number of inactive wells from remaining an ongoing risk to the public is by limiting the ability of owners to keep wells inactive as long as they like. Policies should recognize that most inactive wells will likely never produce oil or gas again.

INTRODUCTION

Recent news reports have raised alarm over the growing number of orphan oil and gas wells in Alberta and the Alberta Energy Regulator (AER) has recently put into place rules that it hopes will stem the rising number of orphan wells.[1, 2]

An orphan well is a well without a legally responsible party to pay for its final closure. The media have pointed to the sharp increase in the number of orphan wells as a cause for concern; in the last 24 months, the number of orphan wells awaiting cleanup has increased from 162 to 768.[3] However, this number is small when compared to the number of inactive wells in Alberta.[4] Inactive wells are wells that have not had any volumetric activity in a year or more but have not yet been permanently closed; these inactive wells, unlike orphan wells, still have a financially viable owner who is expected to pay for the final closure. As of Nov. 26, 2016, there were 81,602 reported inactive wells in Alberta.[5]

On one hand, these inactive wells could be a blessing if they are ever reactivated and brought back into production. On the other hand, given that they have not yet been permanently closed, they run the risk of imposing environmental costs or eventually becoming orphaned. Current policies in Alberta implicitly treat inactive wells as though they have future production potential by allowing operators to indefinitely suspend operations. If this assumption is wrong, and the inactive wells will not be reactivated in the future, these policies are masking a large potential accumulation of liability, as operators may claim bankruptcy and leave the wells orphaned. This briefing paper reports on the results of a previous paper that tries to disentangle whether "temporary" well suspensions in Alberta are effectively permanent.[6] While this does not speak to how many of the inactive wells will become orphaned, it is nonetheless informative with regards to future liability. Inactive wells that are not going to be reactivated are a liability, whether to their responsible party or to the Orphan Well Association.

Regulations in Alberta require that when the end of an oil or gas well's productive life has been reached, it must be "plugged and abandoned," which requires removing equipment and sealing groundwater formations with cement. The entire wellsite must also be "reclaimed," in other words the surrounding land is revegetated (or brought to a "new use" state).

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1 Kelly Cryderman, "'Orphan' wells left behind in oil slump," *The Globe and Mail*, March 18, 2016; Darcy Henton, "Alberta Says Industry Responsible for Reclaiming Oil Wells," Calgary Herald, February 10, 2016; Terry Reith and Briar Stewart, "Alberta faces growing backlog of abandoned oil and gas wells," CBC News, July 14, 2015.

2 Recent new rules to reduce risk can be found at the Alberta Energy Regulator website, https://aer.ca/rules-and-regulations/bulletins/bulletin-2016-16.

3 See the 2015/2016 annual report and 2013/2014 annual report of the Orphan Well Association at orphanwell.ca. Similarly, 2012 was a year noted for having a "large increase in the number of new orphan wells"; 50 new wells were added to the inventory of 14 orphan wells (Orphan Well Association's 2012/13 Annual Report).

4 Alberta's orphan-well count is also small when compared to the number of orphaned wells in the U.S. An estimated 149,371 orphaned wells are awaiting abandonment. See: Interstate Oil and Gas Compact Commission, "Protecting Our Country's Resources: The States' Case" (2008); and Jacqueline Ho et al., "Plugging the Gaps in Inactive Well Policy: Final Report," Resources for the Future Report (2016).

5 AER Inactive Well Licence List available at: https://www.aer.ca/rules-and-regulations/directives/directive-013.

6 Lucija Muehlenbachs, "A Dynamic Model of Cleanup: Estimating Sunk Costs in Oil And Gas Production," *International Economic Review* 56, 1 (2015): 155-185.

Plugging, abandoning, and reclaiming a wellsite can be an expensive endeavour, ranging in cost from $50,000 to several million dollars.[7] However, a well that has stopped producing need not be immediately plugged, abandoned, and reclaimed; it is possible to "suspend" production.[8] Current policies in Alberta do not put a time limit on how long a well can be suspended, allowing wells to be in a suspended state for an indefinite amount of time.[9] This is how we have 80,000 wells that have stopped production but have not been permanently cleaned up. Some of these wells have not produced for 60 years, yet according to the AER, their closure is only temporary.

There are requirements that a well owner must comply with in order to suspend a well. These measures reduce the risk to the environment and the public, but also allow for easier well reactivation, so that the productive life of the well is not cut unnecessarily short. Indeed, the AER views suspended wells as wells that are "not currently considered to be economically viable but could become so in the future."[10] However, in order to ensure the possibility that wells can be reactivated, regulators introduce the risk that these wells will become orphaned. Without requiring wells to be permanently closed, it is possible that a well with no hope of reactivation could be left suspended indefinitely. The true expectations of the well operators are unobserved by regulators and therefore it is difficult for regulators to know to what extent temporary closures are being used in lieu of permanent closures.

I describe here the results of a previous paper on the likelihood that inactive wells in Alberta will be reactivated.[11] The paper is the first attempt in the economics literature to decipher the true motivations behind well suspensions. This question can be addressed with a statistical method that uses historical decisions to estimate parameters of the model (such as the cost to permanently close a well or the cost to reactivate one), which can then be used in a model to predict future decisions (whether to reactive an inactive well). The model attempts to evaluate whether the inactive wells are still assets by simulating a hypothetical ideal scenario — for example, of high prices and improved technology — to see how many of these inactive wells would be reactivated. The paper finds that only with a drastic, arguably implausible increase in prices and recovery rates will there be a significant increase in the number of reactivated oil and gas wells. This implies that wells are typically left suspended not because of the option to reactivate, but rather to avoid costly environmental obligations, coupled with the fact that there is no penalty for leaving wells suspended indefinitely. Thus, the regulatory requirement (or lack thereof) is introducing a high risk of potential future liability for both the industry and taxpayers as most of these suspended wells are not assets and the longer they are suspended, the longer the operator

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7 This is a range of costs taken from the popular press and an annual report from Alberta's Orphan Well Association. I am not aware of any dataset on the costs paid for cleaning up non-orphan wells, therefore this is a range, and not indicative of the average cost. See: Cryderman, "'Orphan'"; and Orphan Well Association, 2007/08 Annual Report (Alberta Oil and Gas Orphan Abandonment and Reclamation Association, 2008). In the U.S. the costs are much lower. Expenditures on orphan wells range from US$474 to US$575,945. See: Ho et al., "Plugging."

8 Alberta Energy Regulator, "Directive 013: Suspension Requirements for Wells," February 2016. In other jurisdictions, this state of operation is termed "temporarily abandoned."

9 ibid.; Alberta Agriculture and Forestry, "The Inactive Well Compliance Program," http://www1.agric.gov.ab.ca/$Department/deptdocs.nsf/all/ofa16066.

10 Alberta Energy Regulator website, "How are Wells Suspended," https://www.aer.ca/abandonment-and-reclamation/how-are-wells-suspended.

11 Muehlenbachs, "A Dynamic."

is exposed to economic fluctuations that could drive it into bankruptcy, leaving these unproductive suspended wells orphaned.

Provided that there is proper environmental management and monitoring, indefinite suspension could be a well-guided policy if the wells that are eventually reactivated end up producing large quantities of oil and gas. However, the estimation predicts that the quantity of oil and gas supplied from the wells that are reactivated is very small. These findings have far-reaching implications for the oil and gas industry. Assuming that permanent well abandonment poses a lower environmental risk than indefinite suspension, and that the land can be used for other productive purposes, if companies are not taking into account the costs of plugging, abandonment, and reclamation, the development of oil and gas reserves is at a rate above what is socially optimal and subsequent market prices are consequently too low. The policy implication would be to call for stronger mechanisms to ensure companies do not use temporary closure in lieu of permanent closure. The paper summarized here demonstrates that policies for plugging and abandoning oil and gas wells in Alberta are biased towards inexpensive potential restart rather than environmental protection or remediation.

POLICY IN ALBERTA

When a well stops producing, some jurisdictions will allow the well to remain in a temporarily abandoned state so that it need not be immediately plugged, abandoned, and reclaimed. The requirements needed to obtain temporary abandonment vary across jurisdictions, from no requirements at all to needing to cap and plug the wells and perform well-integrity tests.[12] In Alberta, if a well has not produced in six to 12 months, depending on type, then operators must follow specific requirements to temporarily abandon the well, or what Alberta terms "suspend" (a process that is one step from plug and abandon).[13] In the requirements necessary for temporary abandonment, Alberta is on the stringent end of this spectrum, requiring pressure tests every one to five years depending on risk-level, and requiring medium-risk wells to be plugged.[14]

With regards to the *length of time* a well may remain suspended, Alberta is one of the more lenient jurisdictions as it has no limit set on the length of time a well can remain suspended.[15] Alberta's regulator has the authority to order a wellsite to be plugged and abandoned if the suspended well is not in compliance with regulation; however, this is not a common occurrence and such an order is often rescinded or amended. For example, in 2007 there were only six well-abandonment orders and in 2006 there were 19 well-abandonment orders, but as of June 2009 only two of these wells had been abandoned.[16] Therefore, although it is required under the Environmental Protection and Enhancement Act, s. 137,

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12 Ho et al., "Plugging."

13 AER, "Directive 013."

14 ibid.

15 In the U.S., the time limit on suspension ranges from six to 300 months. Many states provide extensions that allow wells to remain temporarily abandoned for a longer time period. In about two-thirds of these states there is no limit to the number or duration of extensions. See: Ho et al., "Plugging."

16 Alberta Energy Regulator, "Abandonment and Closure Orders," June 2013.

that all wells in Alberta eventually be abandoned and reclaimed, it is effectively up to the operator to decide on the time frame.

One issue with allowing for indefinite suspension of inactive wells is that inactive wells are more likely to become orphaned. If, instead of reclaiming a well, an operator leaves it suspended, unpredictable swings in the price of oil like those we have experienced in recent years can drive many once-productive operators into bankruptcy. Productive wells are more likely to be sold, with the proceeds collected by creditors, and inactive wells are more likely to be orphaned. The longer the well is suspended, the more likely it will encounter a low oil price.

This problem has been magnified by the Alberta Court of Appeal's recent Redwater decision, where it ruled that creditors of a bankrupt operator have first rights on proceeds from the sale of the operator's wells.[17] Those proceeds are not required to go towards reclamation of the bankrupt debtor's inactive wells. This has the potential to leave even more wells orphaned than before.

In Alberta, orphan wells are managed by the Orphan Well Association (OWA), a not-for-profit association that receives money from the industry through the orphan fund levy. The orphan fund levy is administered and managed by the AER. Due to the increasing problem of orphan wells, in 2016/17 the AER increased this levy from $15 million to $30 million annually. However, this fund is inadequate to cover the growing problem of orphan wells. Even if industry kept up this yearly rate of spending, it would take approximately 177 years to pay for deemed liabilities now totalling $36 billion.[18]

Typically, jurisdictions require companies to post financial bonds as an assurance so the company is liable for part of the abandonment and reclamation costs should it become insolvent. The bond amounts also vary, with many jurisdictions offering blanket bonds, in which a fixed bond amount is charged for all of the company's wells.[19] Alberta has an atypical system: a financial bond is only required if a company's liabilities are greater than its assets. Assets are calculated from the quantity of oil and gas produced and liabilities are calculated from the counts of wells of different types.[20] The assets-to-liabilities ratio is recalculated for a producer every month. Therefore, it is possible for companies to drill wells without posting any financial assurance bonds as long as the company's current production is high enough to maintain an assets-to-liabilities ratio greater than one.

With bonds set lower than the actual cost of reclamation, leaving a well in a temporarily suspended state is much less expensive than plugging, abandoning and reclaiming it.[21] Final

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17 Redwater Energy Corporation v. Grant Thornton Limited and Alberta Energy Regulator (2016), ABQB 278 (Court of Queen's Bench of Alberta, 2016).

18 Hélène M.E. de Beer, "Alberta's end-of-life oil and gas liabilities" (thesis, University of Calgary School of Public Policy), http://prism.ucalgary.ca/bitstream/1880/51698/1/de%20Beer,%20Helena%20Maria%20Elisabeth.pdf.

19 Ho et al., "Plugging."

20 Alberta Energy Regulator, "Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process," February 2016.

21 For example, the annual payment for a wellsite is based on "loss of use" and "adverse effects" only (not on the land value or the entry fee, which is paid one time in the first year). Compensation must be paid until the mineral-rights owner has received a reclamation certificate. The annual payments range between $167 and $600 per acre for loss of land use and from $117 to $2,500 per acre for general disturbance (Alberta Agricultural and Rural Development, "Compensation For Surface Leases," 2010.)

cleanup is so costly because of the remediation of existing environmental damages and the implementation of measures to prevent ongoing or future damages. Therefore, by having the option to suspend a well, companies do not have strong incentives to internalize either the environmental risks or future potential liabilities they impose on industry should they go bankrupt.

This type of system works well during an oil boom but not so well during an oil bust, precisely the time when a financial bond is needed. The industry has stressed that should any wells become orphaned, the industry as a whole will cover the cleanup costs through the orphan levy fund.[22] However, even this arrangement is only sustainable as long as the proportion that each company pays is small. During an oil bust, more companies declare bankruptcy, resulting in more orphan wells and fewer companies to split the costs. However, increasing bonding requirements will likely lead to sharp resistance, particularly from small operators with capital constraints.[23]

MODELLING OPERATORS' DECISIONS

Investments that involve sunk (irreversible, unrecoverable) costs, such as the cost to plug, abandon, and reclaim a well, require special attention when being modelled. For example, if there is a chance that a non-producing well will be reactivated in the future, then there is value in temporarily suspending the well and postponing the investment to permanently close it. There is also value in having the option to wait until the well becomes economically viable again and this value must be incorporated into the decision for the well's operating state. Furthermore, because there is a sunk cost to reactivate a suspended well, even if the forces that were originally behind the suspension are reversed, the well might still not be reactivated. Making matters more complicated is the uncertainty in future oil and gas prices as well as the unknown prospect of future production with future technologies. This makes the estimate of future streams of profits uncertain. All of these features make the decision for the operating state of a well perfect for modelling in a real-options framework.

Real-options models extend the theory of financial options and apply it to real investments such as building a factory or drilling a well. These models incorporate the fact that there is value in being able to exercise options (e.g., there is value from waiting until next year to decide what to do with a well, in case prices increase). And as one might expect, as the value of the option to postpone decisions increases, the more uncertainty there is. For instance, the less one knows about oil prices next year, the more valuable it is to delay plugging and abandonment. Therefore, one can model the decision of what to do with an active well (keep producing, temporarily suspend, or permanently close) as well as the decision for what to do with a suspended well (keep it suspended, reactivate, or permanently close). The decision can be modelled such that it includes the payoff from each choice as well as the value of all of the available options. Thus, decisions today depend on

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22 See Alberta Energy Regulator, "Bulletin 2016-05: First 2016/17 Orphan Fund Levy," March 2016. Each company will pay a portion of the Orphan Well Association's budget, depending on how much of the industry's future deemed liabilities are attributed to it.

23 These concerns are voiced in: Jesse Snyder, "Alberta's New Abandoned-Well Program Makes Compliance Impossible for Some," *Alberta Oil*, October 27, 2015.

all future potential costs as a result of today's decision, such as the cost to reactivate a well, the operations and maintenance costs of a suspended well, the lifting cost per barrel of oil, as well as some estimate of risk. These costs are typically not known to researchers or regulators and therefore these must be estimated.

The real-options model used here includes the following features: The operating state is dynamic and can be changed now, or at some later date; there are unrecoverable sunk costs to changing operating states; and future prices and recovery are uncertain. The operator will choose the option that maximizes the discounted stream of future profits. Each choice and future value depends on the current state of nature (the age of the well, the wellhead price of oil or gas, the per-well remaining reserves, and the current operating state). The choice made affects the current operating state (active, inactive, or plugged) and the remaining reserves per well. The model assumes that the producer maximizes lifetime profits only by choosing the operating state, but not through how much to extract.[24] If the producer decides to extract, the per-period quantity recovered is a random draw from a distribution that depends on the remaining per-well reserves, the age of the well, and estimated parameters governing the probability of future production. The quantity of future production is uncertain; however, with data on past production, a distribution of the probability of future production can be calculated. This probability distribution depends on the estimate of the quantity of oil that is in the ground, which is publicly available for oil and gas pools in Alberta. Therefore, the paper calculates the expected production and the expected price of oil in the future using past well production, quantity of reserves in place, and price movements.

Using an estimation method specifically developed for decisions such as these (irreversible, uncertain, and repeated over time), the parameters of the model (i.e., the costs and operator beliefs about future prices) can be estimated using historical data.[25] The estimation strategy intuitively works as follows: The first step is to estimate the operator's subjective beliefs for how the state variables progress over time. For example, what is the probability distribution of next period's oil price, or next period's remaining reserves. The second step takes these beliefs as given and estimates the cost parameters that result in the highest likelihood of replicating the historical decisions. Once the parameters are estimated, then one has a model of the optimal decision given any state of nature. With a fully estimated model, hypothetical scenarios that we have not seen in the past can be examined.

DESCRIPTION OF THE DATA

To run this model, a dataset at the well level was created in order to observe the decisions of operators per well over time. To do this, five datasets of the Alberta oil and gas industry were combined. The first dataset is a record of historical production from the universe of oil and gas wells in Alberta and was obtained through IHS Inc., which distributes the records collected by the Alberta Energy Regulator. This dataset contains monthly oil and

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24 The assumption rests on the assertion that extraction is mainly driven by reserve size and geologic factors, which producers do not have full control over.

25 John Rust, "Optimal Replacement of GMC Bus Engines: An Empirical Model of Harold Zurcher," *Econometrica* (1987): 999-1033.

gas production information dating back to 1924, with complete records starting after 1961. The data include variables on a well's location (latitude and longitude, as well as the name of the field and pool it is on), depth, licence date, spud date (the day the drill hit the ground), on-production date, and the names of the current and original operators.[26]

The second dataset is a historical record of official reserve estimates of all non-confidential pools in Alberta from both the Alberta Energy Regulator and the National Energy Board of Canada.[27] The dataset spans 2000 to 2007 and contains 67,142 oil and gas pools, although not all pools are observed in every year. This dataset contains: (1) initial oil or gas in place; (2) recovery factor, which is the fraction of the oil or gas in place that can be extracted "under current technology and present and anticipated economic conditions"; (3) initial established reserves, equal to the initial oil or gas in place multiplied by the recovery factor; and (4) remaining established reserves, equal to the initial established reserves minus the cumulative production and surface loss.[28] The data also include characteristics of the pools and hydrocarbons in those pools, such as porosity, initial pressure, area, density, temperature, and water saturation. Each pool can be matched to a well. These data are key to the estimation of production potential because they provide insights into each well's current productivity as well as a way to estimate production uncertainty in the future (i.e., how changes in oil and gas prices will impact recovery rates over time).

The third dataset, from the Alberta Energy Regulator, identifies wells that were plugged and abandoned, along with the date of plugging, and the wells that received a reclamation certificate or wells that were deemed reclamation-exempt by Alberta's Environment ministry. A longitudinal dataset is thus created where each well is classified as active, inactive, or plugged for each year from when it was drilled until 2007. A well is classified as active if it produced any volume of oil or gas within that year; it is classified as suspended if it did not produce oil or gas in 12 months or more; and it is classified as abandoned if it appeared in the dataset of abandoned wells.

The fourth dataset, from the Petroleum Services Association of Canada (PSAC), consists of geographic information system (GIS) shape files that designate areas that have similar costs in production and drilling. The PSAC boundaries and well locations were entered into GIS to assign a PSAC area to each well.

The final dataset is the average wellhead price of crude oil and natural gas in Alberta, obtained from the Canadian Association of Petroleum Producers' Statistical Handbook for Canada's Upstream Petroleum Industry.[29]

Taking the full dataset of the universe of wells in Alberta, some wells are omitted that do not fit into the model created. First, coalbed methane, heavy oil, injection, and water wells are excluded, leaving 350,457 wells in the production dataset. Second, since the model shows that the decision to plug and abandon, stop production, or reactivate a well depends

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26 An oilfield is the geographical area where a well is drilled. A field can have multiple pools, but each pool is a distinct reservoir that is confined within impermeable rock or water.

27 All pools eventually lose their confidential status (usually after one year), so this dataset contains nearly all pools in Alberta.

28 Alberta Energy Regulator, "Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017," 2008.

29 Canadian Association of Petroleum Producers, "Statistical Handbook for Canada's Upstream Petroleum Industry," 2009.

on the remaining oil and gas reserves, the full sample is restricted to only those wells that have a reserve estimate. Of the 350,457 wells, 105,207 are in a pool that is listed in the reserves dataset.

The result of this second restriction is that the analysis corresponds to wells that are, or once were, deemed producible (not "dry holes"). Wells that are drilled but do not tap into an oil or gas pool are more likely to be decommissioned without being completed and they will also not show up in the subsample. More than 45 per cent of the wells that are decommissioned in Alberta are decommissioned immediately after being drilled. The results from an estimation using the subsample cannot be generalized to all wells in the full sample, but they could be generalized to wells in the full sample that at one time produced. Whether to complete a well for production is a separate decision from whether to produce from an already completed well. And indeed, it is more challenging to determine the future of wells that have, or once had, a potential for production, as opposed to those that definitely cannot produce.

Thirdly, the subsample is further reduced by deleting any wells that traverse both oil and gas pools, leaving 94,009 wells in the working subsample. This significantly reduces the computational complexity, because modelling the choice to produce oil or gas is avoided without losing much insight into the choice of operating state.

Lastly, wells are then divided into different types depending on: (1) whether the well is an oil or gas well; (2) whether the well is in a single-well pool or a multi-well pool; (3) the applicable royalty regime; and (4) its PSAC area. Then, within these groups, wells are further divided by (5) clusters based on time invariant characteristics (depth, initial pressure, density, water saturation, and temperature).

RESULTS

In order to confirm that the model is capable of making counterfactual predictions, the first check is to see if the model output can identify historical decisions. If so, the model can be adjusted to examine questions in the form of "how many wells would be reactivated if…?" The first thought experiment examined simulates the industry under some different scenarios that operators claim would prompt them to reactivate after they choose to suspend well operations: high prices, improved recovery rates, and reduced reactivation costs. Similarly, two additional scenarios of potential policy options are explored: reducing the costs to plug and abandon wells or increasing the costs of leaving a well suspended. The length of all these scenarios is set at 12 years and the outcomes after 12 years are compared to a business-as-usual, baseline scenario.

In the first scenario, each well type faces the costs estimated for its type, but each now receives a constant "high price" (of $197.72 per barrel for oil and $462.44 per thousand cubic metres for gas).[30] The results are summarized in Table 1 below. For oil reserves, the growth of reserves does not compensate for the increased production, so there are 24 per cent fewer oil reserves than in the baseline case. Comparatively, for gas reserves, the high

[30] These were chosen using the U.S. Energy Information Administration's Annual Energy Outlook of 2009, using the "high price" case in 2030 for oil, and 1.5 times the "high price" case for gas.

price results in more reserve growth showing that the expected returns from investments in exploration or enhanced recovery are greater for gas than for oil. It is fascinating that, despite the active wells being more productive, the increased reserves and higher prices are not sufficient to induce many inactive wells to be reactivated. This is particularly striking in the case of gas wells where, with 78 per cent increased productivity and 120 per cent increased remaining reserves, there are only seven per cent fewer inactive wells than in the baseline case.

TABLE 1 HIGH PRICES

	Price at End of 12 years	Increase in Remaining Reserves	Increase in Annual Production	Number of Active Wells	Number of Inactive Wells	Number of Abandoned Wells
Oil	320%	-24%	21% (21% cumulative)	19%	-12%	-7%
Gas	200%	120%	78% (31% cumulative)	6%	-7%	-3%

Note: Values represent the per cent difference between the counterfactual scenarios and the baseline scenario.

In a second scenario, a hypothetical technology change allows for all the oil or gas in place to be recovered. To date, according to the data, recovery rates range from 15 to 95 per cent for gas, with an average of 67 per cent, and from .01 to 90 per cent for oil, with an average of 12 per cent. In the hypothetical scenario, recovery rates are simulated to be 100 per cent of the oil and gas that is in place. The results are summarized in Table 2 below. For both oil and gas, the number of active wells increase with increase in recovery rates. However, this significant increase does not induce the reactivation of many inactive gas wells. A higher recovery rate alone has less of an effect on increasing the number of producing wells than a higher price of oil or gas, which not only improves profits, but also increases reserve growth.

TABLE 2 TECHNOLOGY CHANGE INCREASES RECOVERY RATE TO 100 PER CENT

	Increase in Remaining Reserves	Increase in Annual Production	Number of Active Wells	Number of Inactive Wells	Number of Abandoned Wells
Oil	514%	411% (164% cumulative)	17%	-10%	-7%
Gas	418%	387% (275% cumulative)	7%	-6%	-6%

Note: Values represent the per cent difference between the counterfactual scenarios and the baseline scenario.

However, technology might not only improve recovery factors, but might also decrease the cost to reactivate a well. Therefore, the third scenario simulates the reactivation costs for all well groups dropping by 25 per cent. The results are summarized in Table 3 below. Interestingly, for gas, the additional production from active wells is only marginal: there is only 14 per cent more production in the last year of the simulation (seven per cent more cumulative production). The reactivated oil wells are slightly more productive than gas wells: after 12 years there are 19 per cent more active wells, and 20 per cent more production (only nine per cent more cumulative production than in the baseline case). Corresponding with the increased cumulative production, there are fewer remaining reserves at the end of the 12-year period (a reduction of 11 to 13 per cent). And in the case of gas wells, the production by the end of the 12 years is less than in the baseline case. However due to lack of data on reactivation costs, it is more difficult to assess the probability of a reduction in reactivation costs than it is to assess the probability of an increase in prices or recovery rates.

TABLE 3 LOW REACTIVATION COSTS

	Increase in Remaining Reserves	Increase in Annual Production	Number of Active Wells	Number of Inactive Wells	Number of Abandoned Wells
Oil	-13%	20% (9% cumulative)	19%	-7%	-12%
Gas	-11%	14% (7% cumulative)	9%	-4%	-10%

Note: Values represent the per cent difference between the counterfactual scenarios and the baseline scenario.

It is also interesting to look how responsive the model is to changes in the cost of plugging, abandoning, and reclaiming the well. The fourth scenario simulates the 12-year forecast with plugging and reclamation costs being 25 per cent cheaper than in the baseline case and the results are reproduced in Table 4 below. The number of plugged wells is very elastic to plugging costs, as a 25 per cent reduction in cost results in 46 to 48 per cent more abandoned wells. Decreasing abandonment costs might be unappealing to a regulator because not only does the number of inactive wells decrease, but also, this scenario results in 20 per cent fewer active wells. However, production only decreases by two to five per cent, because these wells are not big producers.

TABLE 4 LOW ABANDONMENT COSTS (25 PER CENT CHEAPER)

	Increase in Remaining Reserves	Increase in Annual Production	Number of Active Wells	Number of Inactive Wells	Number of Abandoned Wells
Oil	14%	-17% (-5% cumulative)	-17%	-20%	48%
Gas	10%	6% (-2% cumulative)	-18%	-20%	46%

Note: Values represent the per cent difference between the counterfactual scenarios and the baseline scenario.

In contrast, a policy that increases the cost of suspending a well could increase the number of abandoned wells without decreasing the number of active wells. To examine how responsive the operating choice is to the cost of leaving a well inactive, the final scenario simulates a 12-year forecast of inactivity being 25 per cent more expensive per year. As long as the externalities associated with leaving a well inactive are accounted for, ad infinitum, then leaving a well inactive could be socially optimal. This simulation can be likened to a tax on inactive wells. Such a policy would be more appealing to a regulator that maximizes social welfare, which is a function of production, because under this scenario, the number of decommissioned wells increases (by three to five per cent) as does the number of active wells (by five to six per cent). As expected with the reactivation of wells, this scenario results in an increase in the cumulative oil and gas produced over the 12-year period. However, the increase in cumulative production is less than the increase in reactivated wells (cumulative production only increases by two per cent), indicating that the average reactivated well is considerably less productive.

TABLE 5 HIGH SUSPENSION COSTS

	Increase in Remaining Reserves	Increase in Annual Production	Number of Active Wells	Number of Inactive Wells	Number of Abandoned Wells
Oil	-4%	-5% (2% cumulative)	6%	-9%	5%
Gas	3%	11% (2% cumulative)	5%	-13%	3%

Note: Values represent the per cent difference between the counterfactual scenarios and the baseline scenario.

DISCUSSION AND CONCLUSION

The paper summarized in this briefing paper aims to determine the rationale for leaving oil and gas wells inactive. Inactive wells can either become an asset, if they eventually are reactivated and contribute to our energy supply, or they could become a liability if they are never reactivated, cause environmental degradation, and must undergo costly cleanup, sometimes at another's expense. These results indicate that inactive wells are indeed a liability, as their future potential as productive resources is limited.

The model finds that the cost of abandonment plays an important part in determining the number of abandoned wells, however a policy to decrease the cost of abandoning a well would result in not only fewer inactive wells, but also fewer active wells, making such a policy less appealing to a regulator that favours increased production. Conversely, a policy of increasing the cost of suspending a well would increase the number of active wells and decrease the number of inactive wells. However, the contribution to the oil and gas supply from the wells that are reactivated would be very small. This calls into question the rationale behind current policies that provide producers the option of deferring a suspended well's reactivation indefinitely, accumulating liability.

If optimistic conditions are not enough to induce well reactivation, this implies that wells are left inactive not because of the option to reactivate, but rather the high sunk costs of abandonment. Should externalities result from suspended wells, then this behaviour may not be socially optimal. Whether this is optimal will depend on the cost of the environmental damages that suspended wells cause. Resources for the Future surveyed the literature on potential damages and found that while the pathways are clearly defined (they include mechanical integrity failure, failed well casings, and cement failure), there is little empirical literature quantifying that damage. For example, there are no studies measuring differences in the rate that methane leaks from suspended wells versus plugged and abandoned wells. This briefing paper has assumed that abandoning wells is a worthwhile endeavour, however, further research into the costs of the environmental damages is warranted.[31]

[31] Determining the costs of suspended wells is difficult but doable. The externalities associated with these wells depend on the well location, such as if the well intersects the range of the woodland caribou or is near any houses, for instance. For example, see: "Leaky Calmar well forces demolition of homes," CBC News, December 6, 2010, http://www.cbc.ca/news/canada/edmonton/leaky-calmar-well-forces-demolition-of-homes-1.939167. Litigation for groundwater contamination provides insights into the cost of groundwater contamination in the worst cases, however it is difficult to value the environmental costs from a given inactive well. See: "Calgary judge hears $33M lawsuit over natural gas drilling," CBC News, January 18, 2013.

About the Author

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ISSN
1919-112x SPP Research Papers (Print)
1919-1138 SPP Research Papers (Online)

DATE OF ISSUE
February 2017

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