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All's Well that Ends Well: Addressing End-of-Life Liabilities for Oil and Gas Wells

Of the roughly 450,000 oil and gas wells registered in Alberta, approximately 155,000 are no longer producing but not yet fully remediated. These wells impose potential risks and costs not borne by those who benefited during the productive phase. In a stress test, we estimate the potential social cost of well liabilities to be as high as $8 billion.

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The Study In Brief

The recent downturn in energy prices has shone a spotlight on the issue of cleaning up inactive oil and gas wells. In Alberta, mounting insolvencies have caused the number of "orphaned" wells – i.e., without a financially accountable owner – to balloon from fewer than 100 to 3,200 in the past five years. With low energy prices, that list of wells risks growing longer.

Of the roughly 450,000 wells registered in the province, approximately 155,000 are no longer producing but not yet fully remediated. These wells impose potential risks and costs not borne by those who benefited during the productive phase. These include the opportunity cost of taking up land that can't be used for other purposes, risks to households from released gas and explosions, risks to the local environment from water and soil contamination, and broader risks due to leaking greenhouse gases. Moreover, the cost to clean up wells from no-longer-viable owners has the potential to spill over to surviving firms in the industry and, ultimately, citizens. In a stress test, we estimate the potential social cost of well liabilities to be as high as $8 billion.

Alberta, along with other energy producing provinces in Canada, has a system in place to manage the risk of end-of-life well liability. However, a system that worked in the past is now strained under the weight of low prices. In addition, a recent court decision placing financial creditors in higher priority than environmental liabilities has further degraded the efficacy of current policies. This speaks to the need for reform.

To its credit, the Alberta government is in the midst of consultations on reforming the province's well liability policies. In this *Commentary*, we propose a two-part solution of partial bonding and mandated insurance for existing and new wells.

First, we recommend the province introduce an upfront bonding requirement. However, this bonding requirement should be less than the full expected liability cost. This recognizes that society should accept some risk in exchange for greater economic activity, as well as aligning with the time profile of a well's net asset value. Second, once a well enters the inactive phase, the province should require companies to hold insurance to cover the cost of cleaning up the well. In comparison to a strict time limit on inactive wells, an insurance requirement would allow firms to weigh the increased cost of holding unproductive wells against the potential value of returning them to production.

We hope our recommendations are considered by the current Alberta review of end-of-life well policies, due to report by the end of 2017.

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"Only when the tide goes out, do you discover who's been swimming naked." – Warren Buffett

Low oil and gas prices in recent years have been the proverbial low tide for energy producers. As a result, such firms have seen their asset values decline and, consequently, a light has been shone on the growing issue of oil and gas wells' end-of-life liabilities.

In Alberta, mounting insolvencies have caused the number of "orphaned" wells – i.e., without a financially accountable owner – to balloon from fewer than 100 to 3,200 in the past five years.[1] Moreover, the number of wells not sufficiently sealed nor reclaimed now totals just less than 155,000, or about 34 percent of all provincial wells.

These no-longer-producing oil and gas wells pose a financial risk not borne by those who benefited during their productive stage. We estimate the cost to fully reclaim currently orphaned wells at between $129 million and $257 million. As well, absent reform to the existing liability system, wells that have not yet been orphaned but are currently inactive or suspended pose potential costs to be borne by the rest of industry or, if these costs become unsustainable for the industry, by taxpayers. In this *Commentary*, we produce a financial stress test for this potential exposure based on various ranges of future bankruptcy rates and well cleanup costs: our estimate for non-oil-sands wells ranges from $338 million (including all wells for firms that are currently insolvent) to $8.6 billion (when including wells from firms that are close to being insolvent). This large span highlights the significant increase in potential exposure should weaker firms be tipped into insolvency.

Effective well liability-management policies during steadier times are showing signs of stress as liabilities mount. In Alberta, the Orphan Well Levy – an amount collected from all firms based on their share of expected cleanup costs – does not reflect company-specific bankruptcy risks. Meanwhile, a recent court decision favouring creditors over environmental liabilities has put into question the efficacy of the provincial liability-management regime, which collects more security from firms with greater risk of bankruptcy.

Clearly, governments in Western Canada need to create a long-term solution to the challenges of post-productive wells. In the past, they have used one-time financing to address immediate problems, such as the recent $30 million in the 2017 federal budget to cover the interest cost of a $235 million Alberta loan to the industry for well cleanup.[2] However, this approach may worsen the situation if firms know that the government is likely to subsidize the cost of addressing the problem, rather than leaving firms responsible for the full cleanup costs. Governments should adhere as much as possible to the principle that polluters, not the public, pay for any environmental damage.

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1 Roughly half the increase has come as a result of a recent decision by the Alberta Energy Regulator to force Lexin Resources into receivership that resulted in approximately 1,400 wells being transferred to the Orphan Well Association.

2 This was not the first time that governments have supported industry cleanup efforts. In 2009, Alberta gave a $30 million one-time grant to the Orphan Well Association during the last major energy price downturn.

In this *Commentary*, we aim to raise awareness of the growing problem of well liabilities and the risk to taxpayers and industry as a whole. We provide estimates of the potential social costs – those borne by parties other than the original well owners – in a stress test based on companies' relative financial strength, and we recommend policies to ameliorate the situation. We hope our recommendations are considered by the current Alberta review of orphan well policies, due to report by the end of 2017.

In summary, we recommend a two-stage bonding and insurance requirement for existing and new wells. Regulators should increase their financial security requirements over the life of a well because the ratio of a well's liability risk to its asset value increases once it stops producing and has little asset value remaining. Our recommendations would achieve the following goals:

1. Ensure adequate financial resources for cleanup. We recommend a bonding requirement, in line with the Texas model, that requires firms to post security for a prescribed fraction of their future expected liabilities. The amount would be less than the total expected liabilities to recognize that, for efficiency reasons, some orphan wells would be acceptable as a trade-off for creating more economic value. To provide flexibility for firms with higher capital costs, we recommend that well owners have the option to purchase surety bonds from third parties.

2. Create a disincentive to leaving wells in indefinite suspended status. Rather than a prescribed time limit, we recommend an insurance requirement for wells beyond their active (producing) stage. This would allow firms to weigh the increased cost of maintaining suspended status against their expectations of the future economic value of the well returning to service. The effect would be both to hasten the transition to well plugging and reclamation and to increase production from late-stage wells by companies seeking to avoid the cost of suspended status. In conjunction with the above bonding recommendation, well owners would see progressively more stringent collateral requirements as both the value of the well diminishes and the risk of social well-liability costs increase.

3. Finance cleanup costs for legacy wells. Governments must find a way to finance the cleanup cost of already orphaned wells. There is a case for these costs to be paid with long-term industry and taxpayer financing, as they are the cleanup beneficiaries. However, such government funds should only be for wells orphaned before the announcement date of the bonding and insurance mandates.

Setting the Stage: The Good, the Bad and the Ugly of Wells

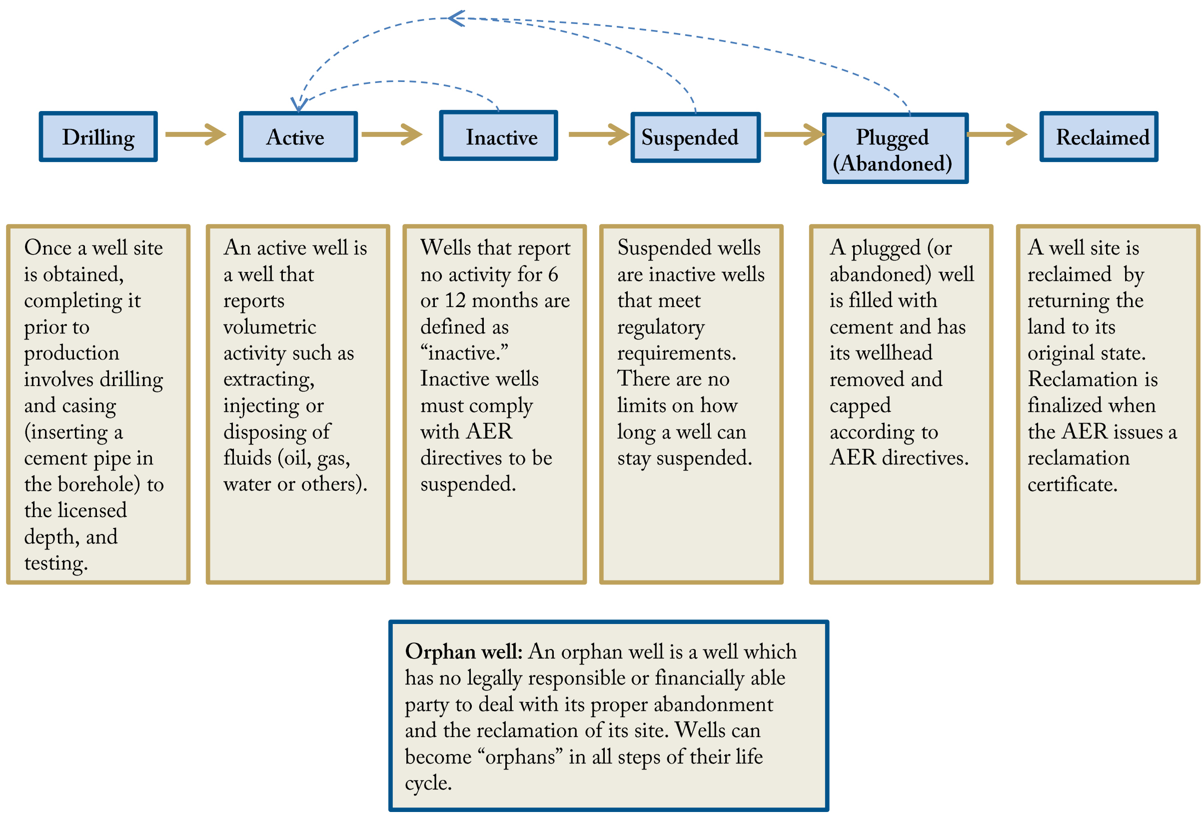
Oil and gas wells produce enormous wealth and economic value for the firms operating them, the people working in the energy sector, and provincial coffers during the time they bring energy to the surface. However, at the end of their lives, oil and gas wells are liabilities that can be costly to address.

Before we discuss the problem of well liabilities and the policies to manage them, let's start with some taxonomy. Figure 1 describes the various stages of a well's life.

The first stage, once an exploration company has found a suitable site, is drilling. During this time, a hole is drilled and the wellbore is cased (a cement pipe) to protect against groundwater contamination and to support the well's structural integrity. Once drilled, the well moves to the active stage, during which hydrocarbons are brought to the surface. A well can be active for decades, declining in productivity over time.

The first post-production stage is the inactive phase. In Alberta, the Alberta Energy Regulator (AER), responsible for safe and environmentally responsible resource development, deems as inactive wells that have not produced hydrocarbons for six months to a year. Once their wells are declared

Figure 1: Simplified Life Cycle and Taxonomy of Alberta Wells



inactive, producers have 12 months to undertake various precautionary measures, such as installing tubing plugs in the wellbore, after which the well transitions to the suspended stage. In Alberta, there is no time limit for how long a well can remain suspended. In the US, time limits for suspended wells range from six months to 25 years (Muehlenbachs 2017).

Once an operator deems that returning a suspended well to production has no value, a well moves to the abandonment stage. Contrary to what the word abandonment suggests, this is a rather involved process of an operator sealing the well to prevent any risk of groundwater or other environmental contamination. For clarity's sake, we use the term plugged throughout this *Commentary* rather than the common industry term of abandoned. The final reclaimed phase involves returning the surface area as close as possible to its natural state. Both these final periods involve significant costs borne by the operator. We include in this stage both reclamation and remediation.

As illustrated in Figure 1, it is possible for wells in the intermediate stages to switch from one phase to another. For example, in times of high oil prices, a firm could bring inactive wells back to production, or another firm that purchased a portfolio of existing wells could decide to re-drill a previously plugged one. However, as shown in Table A-1 in the Appendix, wells typically follow the path in Figure 1.

A separate classification is that of an orphan well. This occurs when the regulator declares that a well no longer has a financially viable and accountable owner, usually because of a bankruptcy. A well can be orphaned at any stage, but typically this occurs in the post-production period where it has little to negative value.

Why are Inactive and Suspended Wells a Problem?

Inactive and suspended wells have a number of potential environmental consequences, both locally and more broadly. Locally, there is the risk of surface water, groundwater and soil contamination. They can also be a safety hazard by posing a risk of explosion from released gas or by endangering health through toxic gas (Ho et al. 2016). Wells can also release methane, a potent greenhouse gas.

Lastly, suspended, inactive and plugged wells create an opportunity cost for those who own the land where the well is located. Indeed, oil and gas companies usually do not purchase the land on which they site their drilling facilities: instead, they enter into an agreement with the landowner that provides the drilling company certain surface rights. When the oil and gas company is no longer using the land to extract oil and gas and hasn't reclaimed the land, the landowner is not able to use the land for other uses, such as agriculture, residential or commercial development. While landowners receive lease payments for this imposition, it is possible they do not reflect the land's opportunity cost or the risk of producers going bankrupt prior to reclamation.

For these environmental-harm reasons, governments require firms to take several steps after the well has stopped producing. For policymakers, the key problems are inactive and suspended wells and, to a lesser extent, plugged wells that have undergone little or no reclamation work and are unlikely to return to production.

Limited liability structures, such as those used in the oil and gas extraction industry, can also exacerbate the problem of well liabilities. While such structures provide beneficial incentives for firms to operate, they also create perverse incentives that can lead to public health and environmental problems. As in many jurisdictions, firms in Alberta can avoid paying for damages through bankruptcy. Given such potential bankruptcy protection, firms may take riskier decisions. Furthermore, the ability to declare bankruptcy creates a perverse cost advantage for smaller firms, as they are more likely to experience damages exceeding their total value compared to larger firms with a portfolio of valuable projects. Research in the US has confirmed that small firms are overrepresented within hazardous industries because of the potential benefits of limited liability through bankruptcy (Davis 2015, Boomhower 2016).

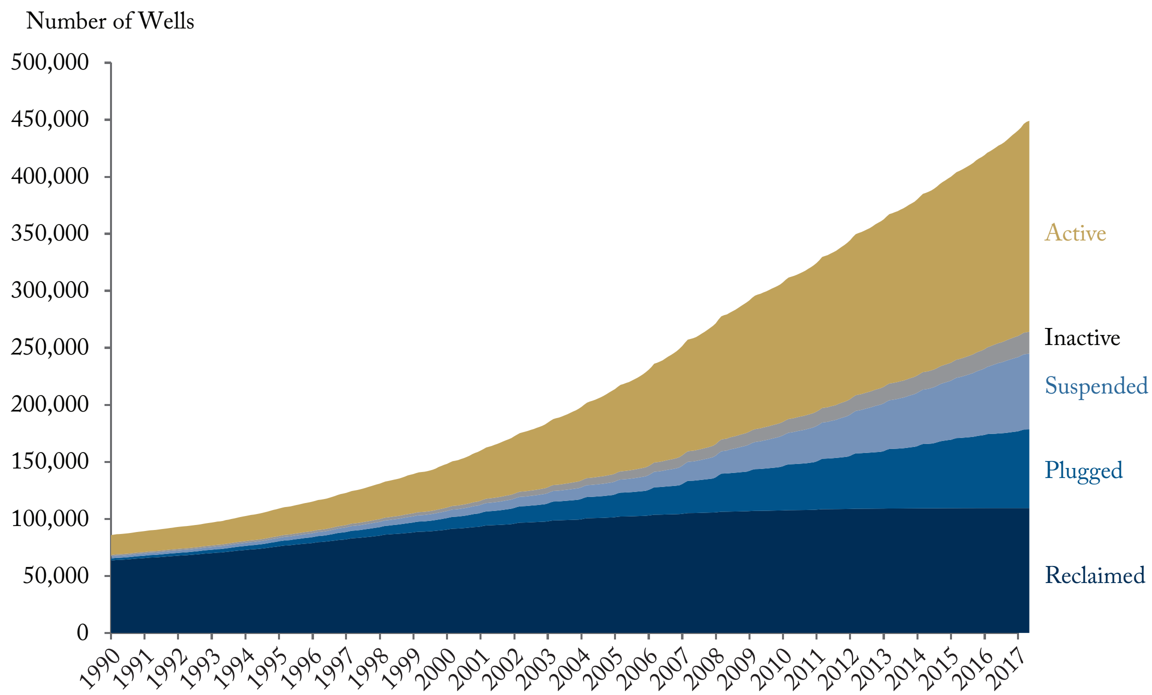
The State of Wells in Alberta

As of May 2017, there were some 450,000 Alberta wells at various stages of their life cycle. Of this total, 185,000 were active, while 155,000 were in various post-productive stages but not fully reclaimed. As Muehlenbachs (2015) shows, temporary closure is, in most cases, permanent closure. The average time that wells in Alberta remain in the suspended stage is eight years. Finally, 109,000 wells in Alberta have been fully reclaimed.

The province's largest licence holder, Canadian Natural Resources Limited (CNRL), holds permits for approximately 74,000 wells. Of these, roughly 20 percent are inactive or suspended, with a further 31 percent plugged or reclaimed. Table 1 lists wells by status for the province's top 10 licence holders, with CNRL and Cenovus Energy Inc. being the largest.

Over the past 25 years, Alberta oil and gas companies plugged an average of about 200 wells per month. When it comes to well reclamations, the AER tallies the numbers through its Reclamation Certificate Application Statistics. Between January 2016 and July 2017, about 250 wells per month have received AER reclamation certificates. However, January 2016 is the first month in which the AER reported a sizeable number of reclamation certificates issued, suggesting that few wells received

Figure 2: Wells by Status in Alberta (January 1990 to May 2017)



Source: Authors' calculations using AER data.

Table 1: Alberta Wells by Licence Status for the Top-10 Licensees (As of May 2017)

	Total Number of Wells	Share Active	Share Inactive or Suspended	Share Plugged or Reclaimed
	thousands		*percent*	
Canadian Natural Resources Limited	74	48	20	31
Cenovus Energy Inc.	35	76	9	15
Husky Oil Operations Limited	23	23	25	52
Imperial Oil Resources Limited	13	34	12	54
Ember Resources Inc.	11	88	6	5
Suncor Energy Inc.	11	10	4	87
ConocoPhillips Canada Resources Corp.	10	16	6	78
Penn West Petroleum Ltd.	9	31	36	33
Direct Energy Marketing Limited	9	78	11	11
Encana Corporation	8	69	4	27

Source: Authors' calculations using AER data.

reclamation certificates before this date.[3] This suggests that not all wells that companies have plugged proceeded to the next stage of restoring the land to its original use.

The growing inventory of orphaned wells, as well as inactive, suspended and plugged but not-yet-reclaimed wells, is a looming problem for other companies and taxpayers alike if the companies that own these wells go bankrupt, thus orphaning such wells. In the 2012/13 fiscal year, there were 74 orphan wells awaiting future reclamation work. That number increased to more than 1,500 in 2016/17 and 3,200 at the start of 2017/18. Few of these orphan wells are being reclaimed by the Orphan Well Association, discussed in more detail below. The association has fully reclaimed only 44 wells per year, on average, over the past nine years. Despite a recent surge to 122 reclamation certificates issued in 2016/17, that number is far less than the total increase in orphaned or plugged wells.

In theory, oil and gas companies are responsible for all costs related to their wells' end-of-life issues. However, when companies go bankrupt, there is no corporate body or shareholder that the AER can require to plug and reclaim a well. Indeed, a recent legal case, *Redwater Energy Corporation (Re)*, 2016 ABQB 278, confirmed that the federal *Bankruptcy and Insolvency Act* supersedes the provincial requirements that companies must clean up wells. In other words, bankrupt companies can avoid their liabilities and leave them as a public obligation (Buckingham, Gaston, and Paplawski 2016). The AER appealed the ruling, but the Alberta Court of Appeal upheld it in a split 2-1 decision. At the time of writing, the AER is seeking leave from the Supreme Court of Canada to appeal the judgment.[4]

Without changes to current policies, especially if the Supreme Court of Canada upholds or refuses to hear the appeal, the cost to plug and reclaim wells is increasingly threatening to be a social, rather than a private, one. In what follows, we estimate the potential cost of increasing well liabilities and suggest policies to ameliorate it. First, we discuss the root cause of the problem and current policies across Western Canada.

Policy Approaches

For firms to properly value end-of-life well costs, private costs must be aligned with social ones. While production value and associated expenses occur in the present, well-reclamation costs occur far into the future. In the event a firm ceases to exist, it may ultimately bear none of the costs. This presents a moral hazard challenge that provides incentives for imprudent risk-taking behaviour by oil and gas producers.

There are five main policy tools to remedy this problem: 1) direct regulation; 2) the tort system; 3) insurance; 4) bonding and 5) environmental-risk premiums. We discuss briefly the pros and cons of each, and relate them to Alberta' current liability-management system.[5]

Direct regulation ensures that during the drilling process firms take actions that reduce environmental risk and ultimate reclamation costs. An example is the AER's Directive 13 along with its Inactive Well Compliance Program, in which companies with inactive wells are required to take specific steps within a set timeline to suspend wells. The downside to regulation is its high administrative and monitoring costs.

3 See the AER's Reclamation Certificate Application Statistics Report available at https://www1.aer.ca/onestop.

4 For additional information on *Redwater* and subsequent rulings, see Bankes (2016, 2017) and Collins, Macleod and Kyriakakis (2017).

5 For a more fulsome discussion, see Davis (2015).

The **tort system** can be considered the backstop for well liability. In law, anyone who faces direct damages as a result of a firm's action, or inaction, can seek compensation in court. In the event of unpaid reclamation costs, a tort claim can be used to recover these costs. The tort system, however, may be of limited value in the event of bankruptcy and for broader environmental harms where there is no one with legal standing to launch an action. Meanwhile, bankruptcy laws dictate the order of recovery from a defunct firm and, as discussed earlier, the recent *Redwater* decision has significantly reduced the rights of those facing liability costs, including taxpayers, in relation to secured financial creditors.

Insurance, and specifically mandated insurance, protects those who would otherwise be burdened with unpaid reclamation costs from a firm avoiding its responsibility through bankruptcy. However, insurance does not resolve the moral-hazard problem of firms taking on excess risks because premium-paying firms would have little incentive to limit the risk and cost of environmental liabilities since a third-party insurer would cover the cleanup cost. This excess risk problem is particularly acute when there is an across-the-board standard premium cost that does not reflect firm- or well-specific risk factors. A free market for insurance also introduces an asymmetric information problem: only certain kinds of companies will know if they should seek out the protection. Companies with a high risk of bankruptcy – the precise firms that are a problem under the current system – will not take on the insurance, knowing they likely won't be around to claim it. Companies with good environmental records or low costs of plugging and reclamation will also not seek such insurance, as it will be more economical for them to reclaim themselves. That will leave only firms that do not plan to go bankrupt, but with a great risk of holding high-cost wells seeking the insurance, driving up the cost of insurance for all, which further discourages companies with low risk from taking on such protection. Well-designed insurance products, along with a mandate from the government that all operators have such insurance, can mitigate these problems.

Bonding involves firms handing over security – in the form of a letter of credit, a surety bond paid by a third party or other assets (see Ho et al. 2016) – to cover potential liabilities. Once reclamation is complete, the bond is returned to the firm. This method resolves the moral hazard problem – to the extent the bond is at least as great as the net-of-default, end-of-life costs, firms have a full incentive to incur the reclamation costs themselves. The downside, however, is the cost. Full bonding requires firms to set aside significant capital and forego the opportunity of a return on this outlay. For smaller firms, the cost of capital can be high, making bonding a significant burden. This risks lowering economic activity. Optimal bond requirements take this distortion into account. As a result, optimal bonding amounts are less than the expected nominal value of well liabilities.[6]

An **environmental-risk premium** would force oil and gas producers to internalize these costs and provide incentives for risk reduction by putting a price on a well's potential external damages. In an ideal system, governments would set the premium per firm or well at a level representing the overall risk to the broader public. However, it is likely difficult and costly to determine the proper level of risk. As well, safety behaviour is costly to monitor. Furthermore, unlike the damages from a tonne of greenhouse gases, the damages from specific wells are not equal. They depend on well-specific factors, such as proximity to surface water, groundwater and sensitive ecosystems, and also on the specific drilling techniques and inputs used, such as the pressure and chemicals injected.

6 A thorough discussion on optimal bonding requirements can be found in Gerard (2000).

Current Liability Regime in Alberta

Alberta uses a mix of the above approaches but, outside of the oil sands, generally relies on two policy tools to address well liability. The first is an orphan well levy collected from all well operators. This charge finances the plugging and reclamation costs of wells held by bankrupt companies. The AER, in conjunction with industry, sets the levy for each operator based on its share of total province-wide liabilities multiplied by the total amount it deems necessary to collect in a year to fund the Orphan Well Association (OWA), a not-for-profit that conducts the actual plugging and reclamation work.

The OWA system is a form of pooled insurance. It is a cost-effective way to manage idiosyncratic (company-specific) risk, but can get strained when faced with systemic industry risk, concentrating the burden onto surviving firms. In the long run, if demand for fossil fuels wanes or there are other long-term drops in energy prices, the financial strength of all oil and gas company balance sheets is likely to be strongly correlated. Since the OWA finances its cleanup expenses from producers' annual fees, a downturn in the oil and gas sector may result in firms being unable to pay these costs. This may place the ultimate burden of well liability on the taxpayer.

Also, by setting the levy as a proportion of firms' share of total liabilities, regardless of their specific financial strengths, the OWA does not differentiate between weak and strong producers and their corresponding differences in ability to pay their own plugging and reclamation costs. In effect, this results in financially strong firms subsidizing weaker ones and is not reflective of environmental risk.

The second Alberta well-liability management tool is the AER's Liability Management Regime (LMR), a form of contingent bonding. In contrast to the OWA, which does not consider the financial strength of companies, the LMR requires companies to provide a bond (or other security) if their financial strength falls below a set asset-to-liability threshold. Under the LMR, the AER first calculates a firm's liabilities based on its estimated cost of what would be necessary to fully plug and reclaim all its wells. Second, it estimates the potential asset value of wells based on the production from the company's active wells. The AER then calculates the ratio of the company's assets to liabilities. Companies with a ratio below one are required to provide the AER a bond to hold in trust sufficient to bring the ratio back to one.

The LMR system is meant to provide added protection for the OWA in the case of financially weak firms. It is based on the assumption that the combination of remaining asset value plus collected security to "top up" to the level of expected liabilities will be sufficient to cover a defaulting firm's cleanup obligations. This assumption is based on two further assumptions.

First, the asset-value calculation must reflect the true economic value of the well. However, due to changing energy prices, the AER's current fixed method of applying a notional netback to expected production does not do an adequate job of reflecting changing asset values.

Second, the AER must have access to the positively valued assets of a defaulting firm, properly estimated or not. The recent *Redwater* decision risks invalidating this second underlying assumption, putting the efficacy of the LMR into question. Since *Redwater* places creditors' claims before the fulfillment of reclamation obligations, any assets the AER had previously considered as available to pay for reclamation costs may no longer be practically available if the Supreme Court upholds or refuses to hear an appeal. Meanwhile, in response to the judgment, the AER has increased the requirement for firms wanting to acquire new wells to have an asset-to-liability ratio of at least two. This was an attempt to limit any increase in wells being held by weaker firms, without directly increasing the bonding requirement for other firms.

The Potential Looming Risk of Inactive and Suspended Wells in Alberta

The AER reports the LMR ratio for each licence holder. We have matched the number and status

Table 2: Licensee Wells and "Balance Sheets" by LMR Range

LMR Range	Number of Licensees	Active Wells	Inactive Wells	Suspended Wells	Total Assets (*$millions*)	Total Liabilities (*$millions*)	Asset to Liability Ratio
	May 2015						
0 - 0.99	350	1,674	1,377	535	$772	$1,072	0.72
1.00 -1.99	193	67,153	7,956	14,945	$12,713	$7,922	1.60
2.00 - 2.99	109	54,209	6,315	20,257	$24,025	$10,222	2.35
3.00 - 3.99	46	44,361	3,037	14,852	$24,517	$7,717	3.18
4+	153	24,660	4,240	8,154	$53,194	$5,503	9.67
Total	851	192,057	22,925	58,743	$115,222	$32,436	3.55
	May 2017						
LMR Range	**Number of Licensees**	**Active Wells**	**Inactive Wells**	**Suspended Wells**	**Total Assets (*$millions*)**	**Total Liabilities (*$millions*)**	**Asset to Liability Ratio**
0 - 0.99	337	1,701	2,069	1,067	$369	$828	0.45
1.00 -1.99	182	26,344	5,188	13,618	$11,530	$7,120	1.62
2.00 - 2.99	81	67,473	3,563	16,941	$13,422	$5,778	2.32
3.00 - 3.99	49	59,631	3,610	23,962	$33,560	$10,293	3.26
4+	108	26,748	2,805	9,716	$76,764	$6,186	12.41
Total	757	181,897	17,235	65,304	$135,645	$30,204	4.49

Note: See the appendix for additional details on methodology.

Source: Authors' calculations using Alberta Energy Regulator data.

of each Alberta well to operators in May 2015 (before many of the effects were felt from the decline in energy prices that began in late 2014)[7] and in May 2017, and we group companies by their LMR ratio (Table 2).

There are several things worth noting from this table. First, firms with an LMR ratio below one own a relatively small share of the total wells, although that amount has increased from 2015 to 2017 despite a drop in total wells. However, despite owning a small share of the wells in the province, the number of firms with assets less than liabilities is almost half the industry size by firm count. Second, while the number of active wells has fallen by 10,000 (or 5.3 percent), the number of inactive and suspended wells has increased by about 900 (or 1.1 percent).

But perhaps most importantly is how the ownership distribution has changed across the

7 May 2015 is also the first month in which the AER reported the license status used in this analysis.

different LMR ratio groups. Figure 3 shows the share of wells held by each LMR group, for active, inactive and suspended wells, in 2015 and 2017. Among inactive and suspended wells, the bulk of the increase has occurred among the financially strong firms with an LMR ratio of three to 3.99. The increase in the troublesome group below one is quite modest. Among active wells, we also see a shift in the distribution toward higher LMR ratios.

While there is an increase in the absolute number of inactive and suspended wells between 2015 and 2017, the average financial strength of well ownership appears to have increased. The average LMR ratio for inactive and suspended wells has increased from 3.4 to 4.0. Active wells see a similar increase, from 3.2 to 3.9. This is suggestive of strong firms acquiring wells from weaker ones.

The AER's recent move in response to *Redwater* to require firms acquiring wells to have an LMR ratio of two or higher is another step in the direction of improving well owners' average financial strength.

Liability Regimes in the Rest of Canada

BC's liability-management regime is similar to the current Alberta model. It calculates an LMR ratio in a comparable manner and also requires firms with a ratio below one to post a security. As of mid-2015, the median LMR ratio of BC producers was 1.54, and approximately 15 percent of them had ratios below one, with these firms holding $6.6 million in liabilities over and above their total assets and posted security (BC Oil and Gas Commission 2015).

Saskatchewan's model is also similar, but the potential scale of the well-liability issue is much larger than BC's. Firms pay a security and annual levy in a similar manner as in Alberta.[8] A detailed analysis of Saskatchewan wells (Saskatchewan Auditor General 2012) found that of 87,000 wells in the province, some 24,000 were not producing and 9,700 had been inactive for more than five years. The total looming estimated cleanup liability of all wells was $4.3 billion as of February 2017 (Saskatchewan 2017), up from $3.6 billion in 2012.

Quebec's recently created oil and gas regulatory regime requires companies to submit a site closure and reclamation plan, along with a financial guarantee covering the anticipated costs. The government retains the ability to set the financial guarantee amount through regulation. While this may work for the small number of wells in Quebec, it is likely not a model that would be workable in jurisdictions with a large number of oil and gas facilities as passing a regulation for every well would be a costly, uncertain and slow administrative burden.

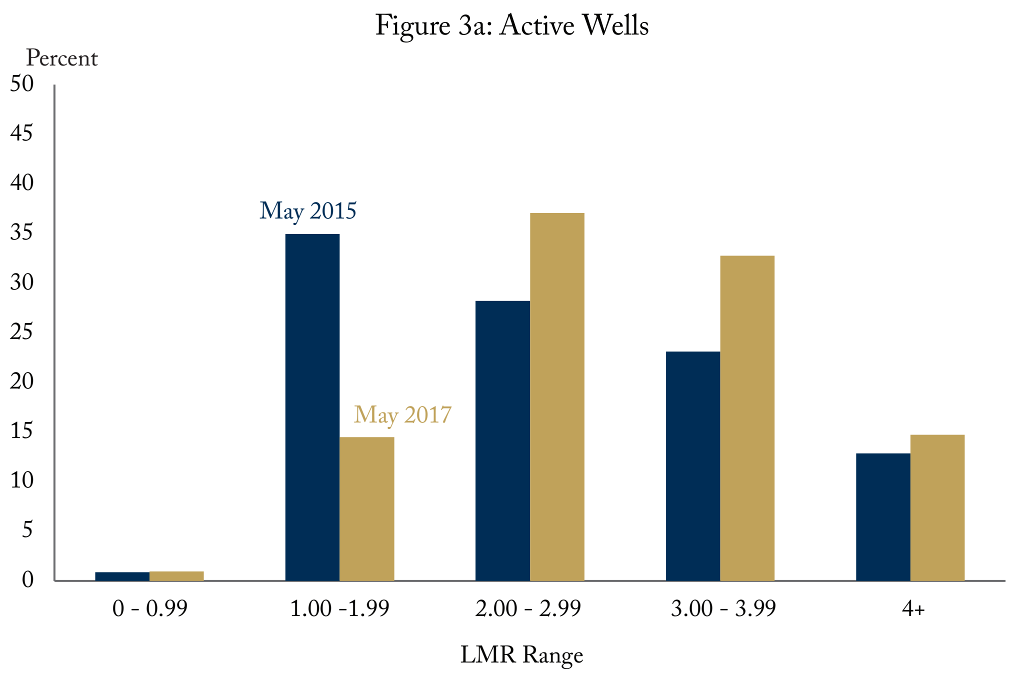
Regulation of the exploration and development of Canada's offshore oil and gas is part of an intergovernmental partnership among various federal entities and provincial governments.[9] Canada's offshore liability regime is determined federally and then managed by the regional regulators. The regime was updated in 2014 through the passing of the *Energy Safety and Security Act* (ESSA). These changes followed the Auditor General of Canada's 2012 recommendations to update the offshore oil and gas liability limits. Effective February 2016, the ESSA raised the "no-fault" liability limits for loss, damages and cleanup for offshore operators from $30 million (and $40 million in the Arctic) to $1 billion.[10] Furthermore,

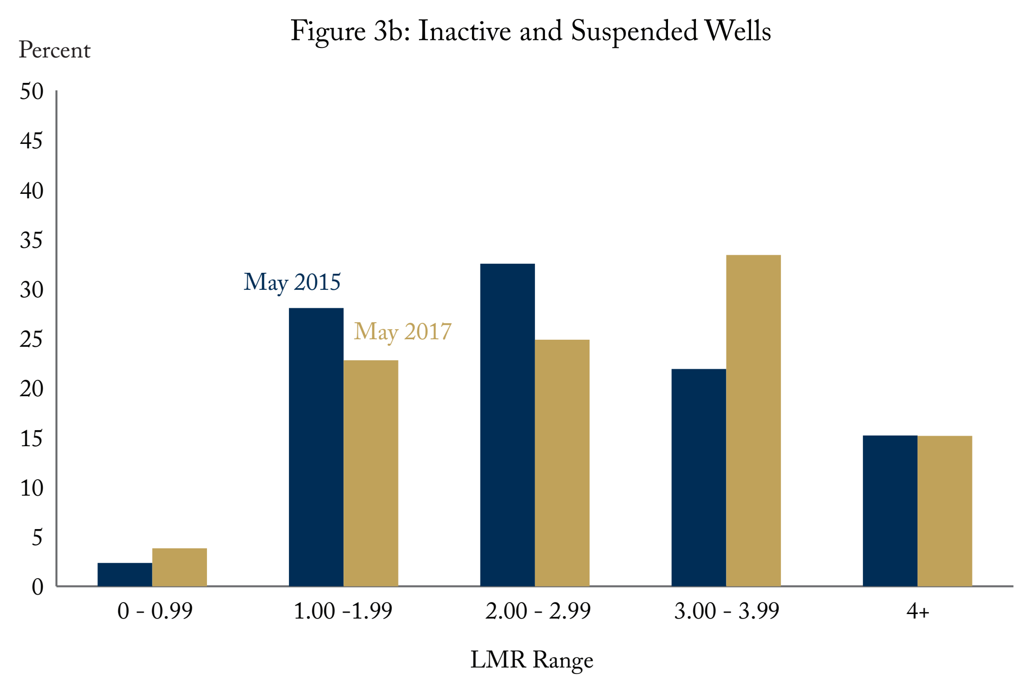
8 In 2016, Saskatchewan's largest single operator, Crescent Point Energy Corp., paid $328,321 in orphan fund levies to finance its share of the $2 million in total orphan well fund levies that year (Saskatchewan 2016).

9 In Atlantic Canada, this partnership takes the form of the Canada-Newfoundland and Labrador Offshore Petroleum Board and the Canada–Nova Scotia Offshore Petroleum Board.

10 If damages exceed the limit and participants are found guilty of fault or of being negligent, they are subject to unlimited liability.

Figure 3: Share of Wells by LMR Range and Status Year





Source: Authors' calculations using AER data.

operators are now required to provide regulators with access to $100 million in security per project or to an industry-managed pooled fund of at least $250 million (Government of Canada 2014).

Oil-Sands Mining

Alberta has in place a particular bonding regime for oil-sands mining facilities.[11] Under its Mine Financial Security Program (MFSP), which also covers coal-mining companies, the AER requires firms to hold security sufficient for carrying out suspension, remediation and surface reclamation work to the standards established by the province (Alberta Energy Regulator 2017). The required security amount is based on the circumstances of the mine and company. New oil-sands mines must hold at least $30 million ($60 million if the mine has an upgrader) as a base amount and then post additional financial security when there are fewer than 15 years of reserves. Firms must post a full security for all outstanding cleanup costs by the time there are fewer than six years of reserves. Firms must also post financial security to ensure their asset-to-liability ratio does not fall below three.

As of June 30, 2016, the total liability for oil-sands and coal mines was $23.2 billion, compared to $1.4 billion in total security held for both mine types. The approximately $1 billion in security held by oil-sands mines has not appreciably changed since 2010. However, coal mines have increased their total security posted from $214 million in December 2010 to almost $450 million by September 2016, with the increase in funding appropriately reflecting the recently increased probability that the coal sector will be unable to finance mine reclamation and remediation.[12]

US Regimes

When managing well liabilities, US states, which have jurisdiction for most oil and gas production, do not rely on assessing resource company assets and liabilities (see Ho et al. 2016 for a summary of US state policies). Instead, the bonding amounts the states set vary from a few thousand dollars to $250,000 per well in New York. For its part, Texas sets bond amounts higher than most states. A 2002 Texas policy change to require bonding of all oil and gas wells provides a useful case study for any Canadian reforms (See Box 1).

When operating on federal land, the minimum bond amount is $2,000 and has not been changed to account for inflation since the 1960s. US laws require that the bond payments companies provide transfer with the ownership of a well and that the owner receives the bond back only upon final reclamation of the site (Davis 2015).

The Looming Economic Cost of Well Cleanup in Alberta

What are the current and potential social costs of orphaned wells in Alberta? By social costs, we mean costs that would be borne beyond the firm imposing them. This may mean other industry participants or, potentially, taxpayers.

The costs to plug and reclaim a well can vary from a few thousand to several million dollars for sites with complex problems (Muehlenbachs

11 Oil-sands mining is different from in-situ oil-sands extraction. In an oil-sands mining facility, companies excavate bitumen along with the land surface above the resource. Oil-sands extraction requires facility operators to have large surface tailings ponds, which often contain toxic by-products. For their part, in-situ oil-sands facilities use surface wells to drain bitumen without large-scale surface disruption.

12 See https://www.aer.ca/documents/liability/AnnualMFSPSubmissions.pdf.

Box 1: The Impact of Bonding Requirements in the Texas Oil and Gas Extraction Industry

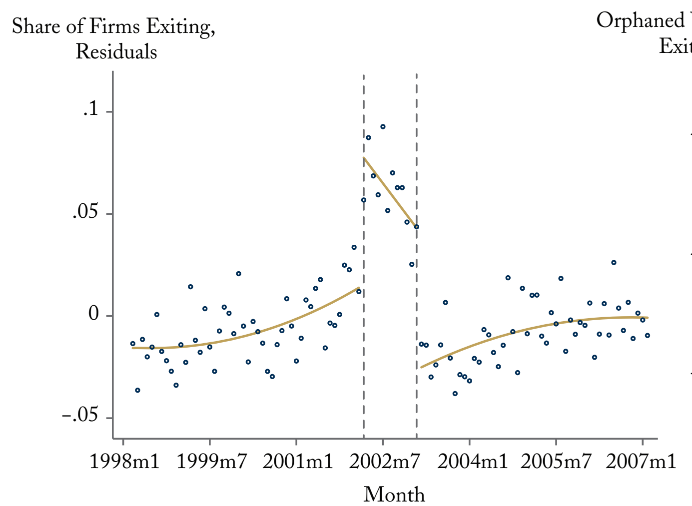
Similar to Alberta's current bonding system for oil and gas well projects, Texas used to require bonds only from firms with a poor compliance history. That changed in 2002 when bonding became a requirement for all producers. Texas set the new bond amount as US$2 per foot of well depth, with blanket bond options for producers with many wells. As a result, nearly all producers decided to purchase a surety bond from an insurer as opposed to posting their own assets. Depending on the perceived riskiness of an operator, premiums for the bonds ranged from 1 percent to 15 percent of the bond's face value.

Boomhower (2016) finds evidence that the Texas increase in bonding resulted in the number of firms exiting the industry increasing overall by six percentage points during the rollout's first year (Box Figure 1). This is a large increase because, controlling for other factors, Boomhower (2016) estimates that no firms would have exited the sector. For small firms, the rate at which firms chose to exit the market, rather than pay the cost of the bond premium, increased by 15 percent whereas it remained at no net exits for the larger firms. Afterwards, exit rates returned to pre-implementation levels for smaller firms.

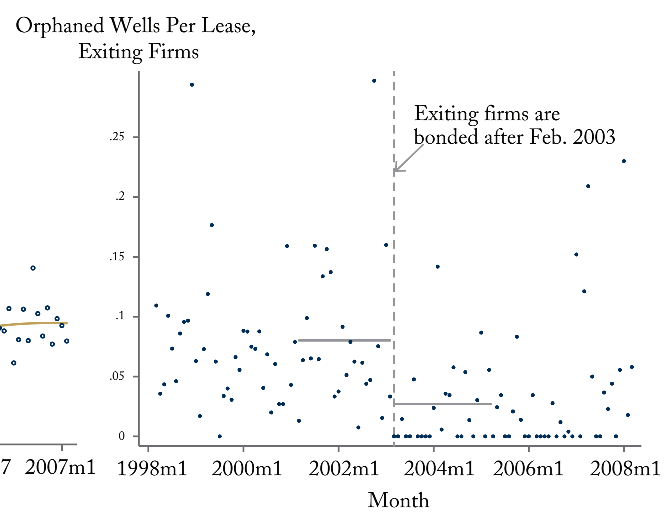
A similar story holds when it comes to production levels. Small firms reduced production by 4.7 percent, whereas the impact is near zero for large firms. More importantly, for the industry as a whole, production didn't fall as a consequence of the policy, but rather large producers acquired the assets of smaller firms.

The bonding requirement reduced the number of environmental violations and other harms, such as well blowouts. Exiting firms had 35 percent more environmental violations than the remaining firms. Furthermore, comparing exiting firms before and after the bonding requirements, the number of unplugged orphan wells left behind dropped by 75 percent (Box Figure 2).

Box Figure 1: The Effect of the Bond Requirement on Exit by Month



Box Figure 2: Average Rate of Well-Orphaning



Source: Boomhower (2016).

2017). The average cost to plug a well in 2015/16 was $61,000 (Orphan Well Association 2016). The average reclamation cost was approximately $20,000, although wells in the major reclamation category cost an average of $42,000 and nearly $120,000 in some cases.

With additional costs of inspection and monitoring, we consider the average cost of the full life cycle of decommissioning a well to be roughly $100,000. Using this value, we produce a stress test that estimates the potential social costs under different scenarios that could occur in the case of a widespread downturn in the oil and gas sector (Table 3). For each stress test, we create a low-and high-cost scenario. In the low-cost scenario, we assume that well plugging and reclamation costs are $80,000 and $20,000, respectively.[13] However, in consideration of the likelihood that OWA wells include especially complicated environmental risks, we include a high-cost scenario at double the amounts.

Our first of three stress-test estimates represents simply the cost of plugging and reclaiming wells currently in the OWA inventory. We estimate this liability to be between $129 million to $257 million (first row of Table 3). This estimate also underestimates OWA's exposure, as it assumes no new orphan wells. Recently, the shutdown of Lexin Resources by the AER increased by one-half the OWA well inventory, although these specific wells are likely to be sold rather than plugged.[14] This example highlights the risk of concentrating on the OWA's current liability. The OWA holds a relatively small amount of assets, $19 million as of March 31, 2017, to reclaim orphaned wells, which we ignore in our calculations.

In the second and third stress tests of Table 3, we calculate the plugging and reclamation costs of wells that are at risk of seeing the burden of their cleanup costs borne beyond their owners. These are the costs that the government can aim to reduce or eliminate through policy change. We start with wells of insolvent firms, defined as firms with a liability rating below one. Like in our earlier stress tests, we assume that in the low-cost scenario the costs of well plugging and reclamation are $80,000 and $20,000, respectively, and double those amounts for the high-cost scenario. The AER held $238 million in security under the LMR program as of July 2017, which we deduct from our stress test of social costs.

For our second stress test, we estimate the cost of cleaning up wells of firms with an LMR ratio below one – firms that are currently insolvent – ranges from $338 million to $903 million, in the low- and high-cost scenarios respectively. In the third stress test, we also include the wells of companies that are close to insolvency (those with LMR ratios between one and two). We include all non-reclaimed wells from these companies, not just inactive or suspended ones, because companies must eventually plug and reclaim all of their wells. This third, and most severe, stress test of the range of social costs increases from $4.2 billion to $8.6 billion. This dramatic potential social cost in the case of a

13 These estimates are near the average costs of well plugging and reclamation from the OWA 2015/16 annual report. Some wells can be much more expensive to reclaim. Indeed, the OWA in 2017 reported that a 1916 well cost $7.4 million to reclaim.

14 To estimate the OWA liability, we use the July 2017 "to be abandoned" and "to be reclaimed" lists and ignore the "to be suspended" list that included the Lexin Resources wells. This is because the shutting down of Lexin Resources and orphaning of its wells was an unusual occurrence. It is expected that Lexin will either regain custody of its wells, if the company becomes compliant, or the wells will be sold off (Southwick 2017). Therefore, we view our OWA liability estimate as an underestimate of the potential liability.

Table 3: Social Costs of Potential Well Orphanage in Alberta

Set of Wells Considered	Number of Wells		Social Costs ($millions)	
	To be Plugged	To be Reclaimed	Low Costs	High Costs
Orphan wells	1,438	683	$129	$257
Orphan wells, and wells of insolvent firms	4,837	2,468	$338	$903
Orphan wells, and wells of insolvent and close-to-insolvent firms	49,987	15,492	$4,211	$8,648

Notes: Insolvent firms are those whose liability rating is below one. Companies that are close to insolvency are firms with a liability rating between one and two. For these firms, the number of "to be abandoned wells" is equal to the total of their active, inactive and suspended wells. The number of "to be reclaimed" wells is equal to the amount of abandoned wells they hold. The low-cost scenario prices a well plugging and reclamation at, respectively, $80,000 and $20,000. These numbers come from the OWA 2015/16 annual report. We double these estimates in the high-cost scenario. Low-and high-cost scenarios also include the liability of currently orphaned wells. We do not include oil-sands mines in this analysis. We also assume that the entire LMR amount the AER has collected is from companies that are insolvent or close to insolvency. We subtract the $238 million in LMR the AER has collected as of July 2017 from the social cost for the second and third rows, as we assume it is available to address cleanup costs.

Source: Authors' calculation using Alberta Energy Regulator (AER) and Orphan Well Association (OWA) data. The number of orphan wells come respectively from the "to be abandoned" and "under reclamation" reports of the OWA.

systematic energy-sector failure provides a strong case for addressing the risk of these potentially large liabilities.

Policy Recommendations to Better Manage Well Liabilities

In reviewing the problem of well liabilities, notably in Alberta, the primary risks are:

1 Lack of adequate posted security in the event of bankruptcy, made worse as a result of the *Redwater* decision;

2 Lack of a disincentive for firms to maintain suspended well status indefinitely; and

3 Dealing with legacy well cleanup costs.

We present a suite of policy options to reduce the looming costs of well liabilities in a manner that is as economically efficient as possible by addressing environmental and bankruptcy risks. We propose a two-part solution to balance the need for adequate security without placing an excessive burden on productive and responsible well owners.

In the first part, we suggest the AER place a partial bonding requirement on all producers at the beginning of a well's productive life, along the lines of the Texas model. Firms would be required to post bonds of an amount determined by the regulator but less than the full expected cost of their liability. Firms with high capital costs could retain third parties to post surety bonds on their behalf, paying premiums to the provider instead. The government could also offer a competing bond system for small firms. Once cleanup is completed, the regulator would return the bonds to the owners.

In the second part of our policy proposal, firms with suspended wells would be required to hold insurance covering the full expected cost of abandonment and reclamation in the event they are unable to pay. They could also purchase this insurance from third parties, or the government could become a default insurer for small firms. Premiums would reflect the insurer's market-tested view of both the environmental risks (cleanup costs) and the company's financial strength. Firms with good environmental records would likely pay lower surety bond and insurance premiums and would reclaim wells to avoid future insurance premium increases (Davis 2015). Firms would no longer need to pay the orphan levy, which the AER currently calculates based on the scale of their operations.

The advantage of this two-part policy is twofold. Firstly, it does not deter otherwise economically viable projects from proceeding due to onerous bonding requirements. And, secondly, the regulator would collect adequate security through an insurance requirement late in a well's life when it is needed most – that is, when a well's asset value-to-liability ratio is at its lowest. Firms could avoid the insurance premium cost by advancing to the cleanup phase in a more timely fashion.

In contrast, a single – and higher – initial bonding requirement, rather than an additional insurance requirement at the end of a well's life, would impose higher costs on active wells. A high upfront bond requirement would result in a high likelihood of shutting low productive wells prematurely and discouraging drilling in the first place. As compared to the current system, companies at low risk of bankruptcy and average- or below-expected cleanup costs would likely see little increase, or perhaps a decrease, in their total costs if the government adopted a partial upfront bond and end-of-well-life insurance requirement.

Collecting Adequate Security for Well Liabilities

At the root of the problem of well liabilities spilling over to remaining industry and, potentially, the public, is inadequate security collection to cover future costs. As discussed above, Alberta's Orphan Well Levy does a good job of cost effectively managing occasional individual company failures, but is now strained under the weight of industry-wide weakness. However, the LMR, meant to serve as a bonding backstop against financially shaky companies, has been weakened significantly by the recent *Redwater* decision. Assets that were once included in the AER's financial-strength test have been effectively rendered unavailable to help cover cleanup costs post-bankruptcy. This calls for an overhaul of the current bonding system, or at least some major tweaks.

The optimal bonding amount is less than the full environmental liability due to the economic distortion created by the bond requirement (Garner 2000). A full bonding requirement creates a higher operating cost and, akin to a tax, reduces the incentive for companies to pursue socially beneficial resource development. In other words, the size of the bond requirement presents a tradeoff. Set too low, the public (and the rest of industry) risks bearing the cost of unfunded well liability. Set too high, resource development is discouraged to an inefficient level. Optimal bonding theory balances these two extremes by acknowledging that there is some amount of risk (i.e., unfunded well liability) that we would accept in exchange for higher economic activity. Our proposed policy recognizes this tradeoff by trying to match the profile of well-liability risk with the timing of security requirements, thus keeping initial bonding requirements low while increasing security in the latter stages of a well's life.

Third parties can compete to provide the most attractive financial terms to oil and gas firms while also reflecting the underlying project-specific environmental risk and firm-specific financial risk. Allowing companies to seek third-party surety bonding would also reduce the financial. reporting, and monitoring burden on the AER and the government. The AER could instead focus on laying out the standards of environmental outcomes – for example, the quality of reclamation remediation work – and leave oil and gas companies and bonding firms to determine the appropriate financial and operational risks to ensure they meet those standards.

Clearly, the bonding requirement would affect different-sized companies differently. This reflects the findings of Boomhower (2016), as discussed in Box 1, who found that bonding mandates have a particularly large effect on small firms. Private surety bond providers would likely charge higher prices to small firms, which have a higher risk of bankruptcy. If the government wishes to protect small firms taking on risks that private bond providers would not cover at affordable rates, it could offer a small-firm bonding program, effectively accepting and pooling the risk of collective small-firm defaults. The government may wish to put in place such a program on a limited basis to mitigate the potential for a large increase in the number of orphaned wells as a result of the move to a bonding mandate imposing higher costs. The option of participating in a pooled fund, akin to the OWA, or to opt out of the pooled system and instead hold company-specific surety bonds is a flexible solution for operators that has reduced compliance costs in other places, such as in Newfoundland and Labrador (Osler 2016).

Creating Disincentives to Avoid Indefinite Suspended Wells

Alberta and Saskatchewan have no time limits for suspended wells. This exacerbates both the potential environmental risks and the possibility of firm bankruptcy. Despite the fact that maintaining suspended status has the financial benefit of providing a low-cost possibility of returning a well to production, research by Muehlenbachs (2017) has shown this to be of low likelihood.

There are several methods to ensure timelier cleanup. The first is an explicit time limit. Such a limit could either be well-specific or based on the overall portfolio of a firm's wells, allowing producers to keep some wells inactive or suspended for a long time, but needing to plug and reclaim others. While we acknowledge the benefits of their administrative simplicity, time limits are likely to be an inefficient solution. Wells have different production profiles; some have greater longevity than others. Thus, time limits risk curtailing production from an economically viable (or potentially viable) well while being non-binding on others.

A better solution would provide operators with a price signal that reflects the marginal social cost of maintaining a suspended well. This would reflect both the potential environmental risks of deferred plugging, as well as the risk of the company ceasing to exist. Companies could then weigh that cost against the potential benefit – the option value – of maintaining a well in suspended status in either the hopes of bringing it back to production or incurring the time value of delaying cleanup costs.

A price solution would be less prescriptive than limits on the time that companies can hold wells suspended or inactive. Such an approach allows companies to make their own decisions about the merits of keeping a well suspended or inactive in hopes it can be reactivated relative to the social cost embodied in the insurance premium. A time limit makes the decision for them. The difference in approach is akin to the greenhouse gas emissions debate over the merits of a carbon price versus prescriptive government regulations to reduce emissions.

A price solution could be done in many ways. The first is a monthly per suspended well levy – a charge to remain in suspended well status. The issue with this route is it would be administratively difficult to assess the well- and company-specific risks. In all likelihood, a province-wide charge would be set, leading to an adverse selection problem.

Our preferred alternative is mandated insurance for inactive and suspended wells. The insurance premiums act as a financial deterrent to remaining in a post-production stage but firms retain the flexibility to choose whether to do so or not. Mandating insurance only at the post-productive stage has the benefit of increasing the stringency of security collection for at-risk wells, while not harming firms with producing wells or those that have a higher likelihood of returning to active status.

With an insurance policy, companies holding inactive or suspended wells would need to pay a monthly premium until they receive a reclamation certificate.[15] If the AER introduced such an insurance mandate, it would have a similar behavioural effect as an environmental risk premium. Firms would likely act in a way that would have numerous social benefits.

First, the insurance premiums on inactive or suspended wells directly address the social cost aspect of an environmental risk and reduce the incentive for companies to hold wells suspended or inactive indefinitely. Inactive and suspended wells are more likely to cause broader social harm than active wells due to their relative lack of value. That social harm is a reason for an insurance mandate focusing on suspended wells and not having all operators post the full bond value on active wells.

In her theoretical model, Muehlenbachs (2015, 2017) estimates that a 25 percent increase in the cost of keeping a well suspended or inactive, such as with an insurance premium, would reduce the number of inactive oil and gas wells by 9 percent and 13 percent, respectively.[16] A suspended and inactive well premium would also increase the incentive for companies to complete the cleanup of such wells by 3 percent to 5 percent.

Second, insurance premiums on suspended and inactive wells would increase production. Companies would have an incentive to continue producing from wells near the end of their life or return inactive wells to service to avoid paying a suspended or inactive well-insurance premium. According to Muehlenbachs (2017), a 25 percent hike in the cost of holding a well suspended or inactive would increase the amount of production over a 12-year period by 2 percent while increasing the number of active oil and gas wells by between 5 percent and 6 percent. Unlike other measures, such as reducing the cost of plugging wells (by, for example, provincial subsidies for well cleanup), an insurance premium levied only on suspended and inactive wells would not have the unintended consequence of companies cutting back on the number of active wells and production.

In contrast, a higher upfront bond requirement on all wells would reduce the incentive for companies to keep barely productive wells active, pushing many to prematurely curtail late-stage production in order to recover their bond earlier.

Financing Legacy Well Costs

A third well-liability issue relates to legacy orphan wells. The OWA must find a way to finance the plugging and reclamation work of the 3,200 wells currently in its inventory, plus any wells left to it by firms that go bankrupt before the AER can put in place a bonding requirement. Currently, the orphan well fund is the main method of financing the existing and looming orphaned well problem. The above approach of adding market-driven, but mandatory, bonding and insurance requirements would help address future liabilities on still-operating and future wells, but not on legacy wells.

Requiring the OWA to finance all existing liability costs for orphan wells would put the cost of decades of accumulated liabilities on the current generation of producers. Instead, creating a long-term fund that finances reclamation would spread out the cost of such liabilities. The revenue for such a fund could come from the broader tax base or from a tax on all existing oil and gas companies. Since the broader public, both today and in the

15 There would likely be a higher premium until the company plugs the well, then a lower premium until the firm receives a reclamation certificate.

16 All empirical estimates in this section are from Muehlenbachs 2015 and 2017.

future, is the end beneficiary of reclaiming existing orphaned wells, there is a case for some taxpayer financing of legacy well cleanups. However, such government funds should only be for wells orphaned before the announcement date of the bonding and insurance mandates.

Conclusion

Orphaned oil and gas wells are an increasingly large problem for Western Canadian provinces, and the potential looming liability of future wells is even larger. Our stress test of the future costs falling on the rest of the industry, and potentially the public, from orphaned wells yields a result as high as $8.6 billion. Recent court cases affirming the right of bankrupt companies to avoid their liabilities and leave them as a public obligation, as well as the rising risk of a sector-wide increase in bankruptcy means that governments should reform how they require firms to finance end-of-life well liabilities. Governments in Canada should replace antiquated orphan well levies with flexible requirements that all firms hold the appropriate insurance or bonding for end-of-life liabilities.

A combination of initial bonding and insurance on suspended wells can achieve the goals of cost effectively collecting adequate security from companies while creating the right incentives for companies not to take on risky behaviour or hold onto suspended and inactive wells indefinitely.

Appendix

The main dataset employed in the paper is the Alberta Energy Regulator's ST37. As a monthly report, the ST37 details the lists of all wells (past and present) by unique well identifier (UWI). For each UWI, the report includes information such as drill date, drill depth, fluid type and status.

A particularity of the UWI as an identifier is that a single wellhead can have multiple UWIs. Every time a new "drilling occurrence" or "event" is performed on a specific well, a new UWI is created and, therefore, a new row is added in the ST37. For example, the deepening of an existing well or the re-entering of a previously plugged well generates new UWIs for the same well. As such, if one wanted to determine the total number of wells in Alberta, simply summing the total UWIs in the ST37 would lead to double counting of certain wells. A more general well identifier contained in the ST37 is the licence number since each well has but one licence.[18]

For our analysis, we limit the ST37 dataset to one UWI per well licence and use wells of all fluid types. In order to do this, we keep the most recent drilling occurrence per well licence. For the May 2017 ST37, this reduces the total dataset from about 600,000 observations to 450,000.

As our analysis is interested in the share of different types of wells, we rely heavily on the licence status variable from the ST37. This variable was first introduced to the ST37 in May 2015 as part of the AER's Inactive Well Compliance Program. This is the reason why our analysis does not compare the May 2017 vintage to an earlier period.

The licence status reflects the administrative process of the well licence. Possible values from the ST37 are: Abandoned, Amended, Issued, Re-Entered, Reclamation Certified, Reclamation Exempted or Suspension. Because the licence status variable reported in the ST37 does not include the inactive category we add this status by merging the wells included in the AER's "Inactive Well Licence List." As such, we assume that wells on the inactive list are, indeed, inactive, meaning that we assume that other wells are active, unless they have a reclamation certificate or are exempted from being reclaimed, or the AER listed them as plugged or suspended. Also, because new licences are issued for previously plugged wells that are re-entered, we drop from the sample the old licences and keep the new licences for these wells.

Furthermore, we merge the May 2017 ST37 wells with the June 2017 inactive list. However, such a list is not currently available for May 2015 for comparison purposes. The closest version of the inactive list is from March 2016. As such, we use the March 2016 inactive list to create the inactive status for the May 2015 ST37. This choice of data is likely to lead to more conservative estimates of the share of inactive wells in 2015 as the compliance program began just at that time.

For Table 1 in the main text, we merge the ST37 data at each time period to the LMR ratios at the same period of the firms that hold the licence. Only 413,000 wells match to a firm with an LMR ratio, as opposed to the full 450,000 wells in the ST37. Table 1 in the main body of the paper is the LMR subset, and Table A-1 below represents the full sample.

Panel 1 of Table A-1 provides the comparisons of matched wells by status in May 2015 and May 2017. Reading our table from left to right, most wells maintain the same status in both years. For active wells, 90 percent that were active in May 2015 stayed active through May 2017. Of

18 In the event of a new firm or licensee re-entering a plugged well, a new licence is issued. As such, there is only one "active" well licence per well.

Table A1: Change in Alberta Well Status from May 2015 to May 2017

Panel 1: Matched Wells							
	Well Status (May 2017)						
	Active	Inactive	Suspended	Plugged	Reclaimed	Share of Wells	Total
Active	90%	3%	4%	2%	0%	43%	186,012
Inactive	7%	47%	38%	8%	0%	5%	23,697
Suspended	5%	3%	85%	7%	0%	13%	58,818
Abandoned	0%	0%	0%	92%	8%	15%	64,120
Reclaimed	0%	0%	0%	0%	100%	24%	103,841
Share of wells	40%	5%	14%	16%	25%		
Total	176,297	21,656	62,893	68,074	107,568		
Panel 2: Total Wells							
May 2015	194,121	23,796	59,163	64,155	103,865		445,100
May 2017	185,049	19,189	66,532	68,944	109,494		449,208

Note: Panel 1 of Table A-1 only includes wells that were reported by the AER in both May 2015 and May 2017.

Source: Authors' calculations using Alberta Energy Regulator data.

the remainder, 7 percent became either inactive or suspended and 2 percent were plugged. Interestingly, 38 percent of the inactive wells from May 2015 were suspended in May 2017. This significant suspension of inactive wells is a likely consequence of AER's Inactive Well Compliance Program that began in April 2015.

The majority of wells follow the above lifecycle, although 12 percent of the wells listed as inactive or suspended in May 2015 returned as active in May 2017. Panel 2 of Table A-1 provides the totals of wells in May 2015 and 2017 by status, regardless of whether the AER reports on them in both years, as we limit ourselves to in Panel 1.

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