cara CENTER for ASSET RETIREMENT ACCOUNTABILITY

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Submitted via email to rulescoordinator@rrc.texas.gov

Re: Item 477; Proposed amendments to 16 TAC §§ 3.15 and 3.58

Please accept these comments and attached exhibits regarding the Railroad Commission of Texas' proposed amendments to 16 TAC §§ 3.15 and 3.58 codifying exceptions to the plugging requirements for wells that have been inactive for at least 15 years and completed at least 25 years ago. These comments are prepared by and submitted on behalf of the Center for Asset Retirement Accountability (CARA), a non-profit organization dedicated to addressing the problem of aging fossil fuel infrastructure across the United States, including industry responsibility for decommissioning oil and gas wells and related infrastructure.

I. Introduction

In finalizing amendments to 16 Texas Administrative Code §§ 3.15 and 3.58, the Railroad Commission of Texas must give effect to Senate Bill 1150, but must do so with an understanding of the actual reality of inactive oil and gas wells in the state, including the fact that operators almost never return to service wells that have been inactive for 15 years.

The majority of the proposed rule focuses on the mechanics of giving effect to SB 1150's allowance for four categories of exceptions to the prohibition that an operator of a well that has been inactive for more than 15 years and was completed at least 25 years ago may not receive an extension to the deadline for plugging an inactive well. In other words, the proposed rule provides for four exceptions under which an operator of a well that has been inactive for more than 15 years may continue to maintain the well in inactive status.

The reality is that wells that have been inactive for more than 15 years are almost never returned to service under any circumstances. Accordingly, the effect of the proposed rule will be to increase the likelihood that the subject wells will remain unplugged, will continue to burden the surface of the land on which they're located, and that the operators of those wells will pass the plugging costs on to the public.

Although the Commission is constrained by the statutory language of SB 1150, it can and should nevertheless strengthen the amendments to 16 TAC §§ 3.15 and 3.58 beyond what is in the proposed rule.

The stark and unfortunate reality is that the majority of inactive wells are never returned to service, and the likelihood of a well being returned to service decreases the longer the well remains inactive. By the time a well has been inactive for 15 years the chances of it being returned to service are negligible. These patterns remain true regardless of increases in commodity prices or the development of new production technologies.

An analysis of approximately 84,000 oil and gas wells ranging in age from 1 year to more than 70 years determined that less than four percent were reactivated or decommissioned.[1] The study's author concluded that "[t]he proportion of inactive wells that are reactivated decreases with the age of the well."[2] The study found that over 90% of wells that are inactive and more than ten years old are neither plugged nor returned to service, and remain inactive.[3]

An analysis of Texas wells conducted by the Environmental Defense Fund for a September 2026 presentation to the Texas legislature analyzed inactive wells returned to production.[4] That analysis grouped the inactive wells into blocks based on the length of inactivity. For each group, ranging from 1 year to fifteen years inactive, the majority of inactive wells did not return to production.[5] By the time wells were inactive for five years, less than a quarter of those wells returned to production.[6] The EDF analysis also looked at which Texas wells were orphaned by their operator, and found that 75% of all wells that were orphaned by their operator were inactive between 1 year and 15 years.[7]

A similar analysis of wells in New Mexico also conducted by the Environmental Defense Fund found that most well reactivations occur within the first two years of a well being inactive, and that wells inactive for five years or more are highly unlikely to ever be reactivated.[8] Ninety

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[1] Muehlenbachs, "A Dynamic Model of Cleanup: Estimating Sunk Costs in Oil and Gas Production," Int'l Econ. Rev. Vol. 56, No. 1, p. 162, Table 2, February 2015. Attached as Exhibit 1.
[2] *Id*. at p. 162.
[3] *Id*. at p. 162, Table 2.
[4] Peltz, A., Environmental Defense Fund, "Orphan and Idle Wells in Texas and Beyond" presentation to the Texas House of Representatives Committee on Energy Resources, September 15, 2026, at slide 3. Available at https://capitol.texas.gov/tlodocs/89R/handouts/C2502026091511301/e19b6995-2db8-4ffd-a7d7-54277d895973.PDF
[5] *Id*.
[6] *Id*.
[7] *Id*. at slide 4.
[8] Peltz, A., Environmental Defense Fund, Direct Testimony before the New Mexico Oil Conservation Commission in Case No. 24683 at p. 57. Excerpt attached as Exhibit 2.

percent of wells in New Mexico that were ever reactivated were reactivated within 3.5 years.[9] Only 0.5% of wells that were reactivated were reactivated after 8 years.[10]

The data shows that operators are extremely unlikely to reactivate wells even when external factors would appear to support reactivation. Even a commodity price increase of 200 to 300% is only likely to increase reactivations by 12%.[11]

This leads to the unavoidable conclusion that wells are typically left inactive not in order to maintain a future option to reactivate, but simply to avoid the cost of decommissioning. Giving operators of long-term inactive wells even more time will not change this dynamic. These facts must inform the Commission's approach to amending sections 3.15 and 3.58.

II. Structure of comments

The Commission Staff's recommendation is organized to first address the application requirements for all four categories of exceptions, and then to discuss the criteria to be applied by the Commission in evaluating these applications.

In order to avoid repetition, these comments take a different approach, addressing each category of exception in turn and providing a discussion of both the application elements and evaluation criteria for each category. The discussion of each category then concludes with specific recommendations for amendments to the proposed rules.

III. Comments on the four categories of exceptions

[9] *Id.*
[10] *Id.*
[11] Muehlenbachs at p. 177, Table 5. Exhibit 1.

Both SB 1150 and the proposed rules provide for four categories of exceptions that would allow for additional extensions of the plugging requirement for wells that have been inactive for at least 15 years:

1. The operator's history of returning inactive wells to operation
2. The operator's financial hardship
3. The inactive well is included in a compliance plan
4. The operator files an individual performance bond

A. The operator's history of returning inactive wells to operation

1. Comments on the Proposed Rule's approach to establishing an exception based on an operator's history of returning inactive wells to operation

There are two fundamental flaws to the proposed rule's approach to setting forth the terms of an exception based on an operator's history of returning inactive wells to operation. First, the proposed rule fails to provide an adequate definition of what qualifies as a return to operation for these purposes. Second, the proposed rule fails to acknowledge or incorporate the profound difference between an operator returning a well to operation that has been inactive for a short period (e.g. 2 years or less) and a longer period (e.g. 8 years or more).

The rule must provide an adequate definition for "active operation"

SB 1150 refers to an "operator's demonstrated history of returning inactive wells to operation" (SB 1150, Sec. 1(c)(1)(A)), but does not provide any threshold or definition for the Commission to use in determining when a well has been returned to operation. The proposed rule similarly refers to an operator's "history of restoring inactive wells to active operation." "Active operation" is defined in the current rules, in the context of reactivation of an inactive well, as a

well that has "reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or until the well has reported production of at least one barrel of oil for oil wells or at least one Mcf of gas for gas wells each month for 12 consecutive months." 16 Tex. Admin. Code § 3.15(1).

The Commission should re-define "active operation" in section 3.15(a) to require demonstration of a longer period of higher production. Specifically, the Commission should eliminate any reference to a three month demonstration period, and replace the current definition with a requirement that, in order for an inactive well to be considered restored to active operation, the well must have "reported production of at least two barrels of oil for oil wells or at least ten Mcf of gas for gas wells each month for 12 consecutive months."

The Colorado oil and gas regulator recognized, during a rulemaking process, "the reality that some wells produce so little as to be functionally inactive," and stated that, "based on the Commission's experience and current and long-term oil prices, 1 BOE/d is well below the threshold at which a well can continue to be operated profitably."[12] Colorado regulations designate wells producing a daily average of less than two BOE or ten MCFE of gas over the previous twelve months as "low producing well[s]."[13] The New Mexico Legislative Finance Committee has also identified "two BOE per day" as an appropriate threshold for identifying

[12] Draft Statement of Basis, Specific Statutory Authority, and Purpose, New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 2 C.C.R. § 404-1, Cause No. 1R Docket No. 210600097, Financial Assurance Rulemaking at 12 (June 15, 2021), https://ecmc.state.co.us/documents/sb19181/Rulemaking/Financial%20Assurance/COGCC%20Draft%20Financial%20Assurance%20SBP%206-15-21.pdf.

[13] 2 Colo. Code Regs. § 404-1:100 (this definition also employs the industry-standard conversion ratio of 1 barrel of oil to 5.8 MCF gas).

uneconomic wells, including noting that the average well plugged in recent years in New Mexico produced approximately two BOE per day in the year prior to abandonment.[14]

This strengthened definition is needed to avoid a scenario where an operator ekes a small additional amount of production from an inactive well in order to qualify for the extension, but without actually restoring the well to a meaningful level of production. Such a well, even if it meets the current definition of producing 1 BOE/d or 1 MCF/d of gas for twelve months,[15] would not be economic and would remain at very high risk of dropping back into inactive status, or of being orphaned.

The rule must require applicant operators to demonstrate the ability to restore long-term inactive wells to operation

In evaluating an operator's history of restoring inactive wells to active operation in the context of considering whether to grant an exception for a well already inactive for more than 15 years, the Commission must consider the operator's experience with restoring long-term inactive wells to operation.

An operator's history of restoring to operation wells that have been inactive for only a short period does not tell the Commission anything about that operator's ability to restore wells that have been inactive for a longer period.

[14] Policy Spotlight: Orphaned Wells at 20, N.M. Legis. Fin. Comm. Pol'y Spotlight (June 24, 2025), https://www.nmlegis.gov/handouts/ALFC%20062425%20Item%204%20Policy%20Spotlight%20Orphaned%20Wells.pdf.

[15] 16 Tex. Admin. Code § 3.15(1).

As discussed above, it is well documented that the vast majority of inactive wells ever returned to service are reactivated within the first few years.[16] In neighboring New Mexico, only 0.5% of wells that were reactivated were reactivated after 8 years.[17] This means that there is a significant and material difference between an operator who has a demonstrated history of returning inactive wells to operation after 8 years, and an operator who has a demonstrated history of returning inactive wells to operation after 2 years. An operator who has returned an inactive well to operation after 2 years may still lack the knowledge, financial resources, or motivation to reactivate a well that has been inactive for more than 15 years. The Commission must account for this distinction in its rulemaking.

The proposed rule already takes the positive step of requiring applicants to specify, among other things, "the length of time of inactivity for each inactive well," and "when an active well was restored to active operation, if it was previously inactive."

In addition, the Commission should add three more questions to subsection (h)(4)(A):

- "for any well returned to active operation after being inactive, regardless of the current status of that well, the length of time the well was inactive before being returned to service"

- "for all inactive wells previously returned to active operation, an indication of whether that well subsequently returned to inactive status, including the date of each change of status from active to inactive or inactive to active, the length of each instance when the

[16] *See* Muehlenbachs, "A Dynamic Model of Cleanup: Estimating Sunk Costs in Oil and Gas Production," Int'l Econ. Rev. Vol. 56, No. 1, p. 162, Table 2, February 2015 (Exhibit 1); Peltz Testimony to NM OCC (Exhibit 2) at p. 57.
[17] Peltz Testimony to NM OCC (Exhibit 2) at p. 57.

well was active before returning to inactive status, and the length of time the well was inactive before being returned to active service"

- "all wells the operator returned to active operation after being inactive for a period of eight years or more, including the current status of each such well."

This information will allow the Commission to assess an operator's actually relevant experience pertaining to restoring wells inactive for more than 15 years to active operations.

The Commission should also amend the proposed rule to better refine the criteria the Commission will apply in assessing whether an operator's experience restoring inactive wells to active operation qualifies that operator for an exception. Specifically, the Commission should amend subsection (i)(1)(A) to read "the operator has a satisfactory history of restoring inactive wells to active operation if the application and additional documentation required under subsection (h) demonstrates that the operator has ever restored to active operation a well inactive for eight years or more, and demonstrates one of the following criteria:"

2. Suggested amendments to the proposed rule's approach to extensions based on an operator's history of returning inactive wells to operation

a. Amendments to definitions

Amend Section 3.15(a)(2) "Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, ~~until the well has reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or~~ until the well

has reported production of at least ~~one barrel~~ two barrels of oil for oil wells or at least ~~one~~ ten Mcf of gas for gas wells each month for 12 consecutive months."

b. Amendments to application requirements for extensions based on an operator's history of returning inactive wells to operation

Add Section 3.15(h)(4)(A)(vi) "for any well returned to active operation after being inactive, regardless of the current status of that well, the length of time the well was inactive before being returned to service"

Add Section 3.15(h)(4)(A)(vii) "for all inactive wells previously returned to active operation, an indication of whether that well subsequently returned to inactive status, including the date of each change of status from active to inactive or inactive to active, the length of each instance when the well was active before receiving inactive status, and the length of time the well was inactive before being returned to active service"

Add Section 3.15(h)(4)(A)(viii) "all wells the operator returned to active operation after being inactive for a period of eight years or more, including the current status of each such well."

c. Amendments to commission criteria for extensions based on an operator's history of returning inactive wells to operation

Section 3.15(i)(1)(A) "the operator has a satisfactory history of restoring inactive wells to active operation if the application and additional documentation required under subsection (h) demonstrates that the operator has ever restored to active operation a well inactive for eight years or more, and demonstrates one of the following criteria:"

B. The operator's financial hardship

1. Comments on the Proposed Rule's approach to establishing an exception based on an operator's financial hardship

This legislatively-directed exception for financial hardship must be understood for what it is: socialization of the costs of plugging. An operator with wells that have been inactive for more than fifteen years who currently lacks the funds to plug those wells is never going to plug or reactivate those wells, whether they receive an extension to the plugging requirement or not. This provision merely delays the inevitable, burdens landowners on whose property the wells are located, and ensures that Texas taxpayers will bear the costs.

Given that, the Commission's rule must be crafted to minimize the impact to Texas landowners and taxpayers, within the constraints provided by the legislature.

The final rule must ensure that the Commission treats an application for an extension based on financial hardship as an admission by the operator that it is insolvent and no longer able to satisfy its obligations under Texas' oil and gas program. Such an admission must carry consequences. At a minimum, the rule must provide that any operator who has applied for this exception is rendered ineligible to receive any new drilling permits or to receive transfer of operating authority for any existing well. This prohibition must extend not only to the operator, but also to any executive, officer, or owner, and to any other company associated with such individuals.

2. Suggested amendments to the proposed rule

a. Application requirements for an exception based on an operator's financial hardship

Add Section 3.15(h)(4)(B)(v) "an acknowledgment by the operator that by asserting financial hardship sufficient to warrant the plugging extension, the operator is admitting that it can no longer meet its obligations under Texas' oil and gas program and that it is therefore ineligible for

any future permits or permit transfers, and that the ineligibility extends to its owners, officers, and executives, and to any other companies associated with any owner, officer, or executive."

b. Commission criteria for an exception based on an operator's financial hardship

Add Section 3.15(i)(1)(B)(vi) "the operator's application includes an acknowledgment by the operator that by asserting financial hardship sufficient to warrant the plugging extension, the operator is admitting that it can no longer meet its obligations under Texas' oil and gas program and that it is therefore ineligible for any future permits or permit transfers, and that the prohibition and ineligibility extends to its owners, officers, and executives, and to any other companies associated with any owner, officer, or executive."

C. The inactive well is included in a compliance plan

1. Comments on the Proposed Rule's approach to establishing an exception based on inclusion of an inactive well in a compliance plan

The proposed rule's approach to implementing the exception for wells included in a compliance plan is inadequate in two ways. First, this section must define what is meant by "bringing the inactive well into production or operation as an injection well or other type of operation" in a manner that ensures actual operations, not merely a pretext to avoid plugging. Second, the Commission should impose additional limitations on operators who rely on the compliance plan approach in order to avoid additional future conditions that could imperil the success of the compliance plan, including a prohibition on the operator's receiving transfer of operating authority for any additional inactive wells.

As discussed above, the Commission must define what is meant by bringing an inactive well into production or operation in terms that prevent an operator from taking only minimal steps that

allow it to evade plugging but do not reach the level of restoring the well to actual service. The comments above on restoring inactive wells to active operations address the criteria needed for producing wells. The Commission should establish similar standards for wells restored to service as injection wells or for other types of operation. For such wells, the Commission should require the operator to file a plan certified by a petroleum engineer that identifies (1) the extent of reserves to be produced; (2) which wells accessing the reservoir will be used for injection or other purposes; and (3) which wells accessing the reservoir will be used for production. The petroleum engineer's certification must also include a determination that the proposed plan will actually result in production from each producing well of at least two barrels of oil for oil wells or at least ten Mcf of gas for gas wells each month for 12 consecutive months.

The Commission should also clarify that "other type of operation" is limited to uses related to fossil fuel production, and does not include alternative uses such as geothermal energy production or gravity energy storage. These uses are currently too speculative and are not appropriate for inclusion in this limited application for exceptions to the plugging requirement for wells that have been inactive for more than 15 years. Among other concerns, it has not been established that such older wells can actually be successfully converted to these new and largely speculative purposes.

Finally, the Commission should clarify that if an operator chooses to submit a compliance plan in order to secure an exception to the plugging requirement for wells that have been inactive for more than 15 years, the operator must focus on carrying out that compliance plan and therefore must not assume additional plugging liabilities. As a result, the Commission must prohibit operators with compliance plans from acquiring any additional inactive or low-producing wells while the compliance plan is in effect. Because an operator may have existing wells that become

inactive during the course of the compliance plan, the Commission must also require that any approved compliance plan must address not only currently inactive wells, but also all wells that produced less than two barrels of oil or ten Mcf of gas each month for the previous 12 consecutive months.

2. Suggested amendments to the proposed rule

a. Definitions

Amend Section 3.15(a)(2) "Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, ~~until the well has reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or~~ until the well has reported production of at least ~~one barrel~~ two barrels of oil for oil wells or at least ~~one~~ ten Mcf of gas for gas wells each month for 12 consecutive months."

b. Application requirements for an exception based on inclusion of an inactive in a compliance plan

Amend Section 3.15(h)(4)(C)(i)(II) "identify the operator's total amount of wells, including how many are active or inactive, and how many active wells produced less than two barrels of oil or ten Mcf of gas each month for the preceding 12 consecutive months."

Add Section 3.15(h)(4)(C)(i)(VII) "for any well to be returned to operation for a purpose other than production of oil or gas, include a plan certified by a petroleum engineer that identifies (1) the extent of reserves to be produced; (2) the production-related purpose, including injection, to

which all wells covered by the plan will be used (including but not limited to the well or wells that is the subject of the application); and (3) which wells accessing the reservoir will be used for production (including but not limited to the well or wells that is the subject of the application). The petroleum engineer's certification must also include a determination that the proposed plan will actually result in production from each producing well of at least two barrels of oil for oil wells or at least ten Mcf of gas for gas wells each month for 12 consecutive months."

Add Section 3.15(h)(4)(C)(i)(VIII) "contain an attestation that so long as the compliance plan remains in effect the operator will not participate in any application to receive transfer of operating authority for any additional inactive wells or any wells that produced less than two barrels of oil or ten Mcf of gas each month for the preceding 12 consecutive months."

Add Section 3.15(h)(4)(C)(iv) "If the Commission approves the compliance plan and grants the plugging extension, the operator shall be prohibited from receiving transfer of operating authority for any additional inactive wells, or any wells that produced less than two barrels of oil or ten Mcf of gas each month for the preceding 12 consecutive months, until all wells subject to the plugging extension have been plugged or brought into production or operation as an injection well or other type of operation."

c. Commission criteria for an exception based on inclusion of an inactive in a compliance plan

Add Section 3.15(i)(1)(C)(vi) "for any well to be returned to operation for a purpose other than production, the plan adequately demonstrates that the well will contribute to production exceeding two barrels of oil or at least ten Mcf of gas each month for 12 consecutive months."

Add Section 3.15(h)(4)(C)(vii) "includes an acknowledgment that if the Commission approves the compliance plan and grants the plugging extension, the operator shall be prohibited from receiving transfer of operating authority for any additional inactive wells, or any wells that produced less than two barrels of oil or ten Mcf of gas each month for the preceding 12 consecutive months, until all wells subject to the plugging extension have been plugged or brought into production or operation as an injection well or other type of operation."

D. The operator files an individual performance bond

1. Comments on the Proposed Rule's approach to establishing an exception based on an operator's filing an individual performance bond

The legislature, in SB 1150, and the Commission, in the proposed rule, allow an operator to secure an exception to the plugging requirement for wells inactive for more than 15 years by filing an individual performance bond. The language of the proposed rule echoes SB 1150 in requiring an operator, to be eligible for this extension, to provide "an individual performance bond that is in an amount that is not less than the full cost calculation for plugging the inactive well and runs with and covers the lifetime of the inactive well, regardless of a change in the operator." Proposed Rule at 15.

We applaud the recognition inherent in this proposal that existing Texas bonding requirements are woefully inadequate.

Under Texas law, oil and gas well operators have the option of either providing an individual per well bond, or a blanket bond. The individual bond is calculated as "an amount equal to $2 for each foot of well depth for each well." Tex. Nat. Res. Code § 91.1041. Blanket bonds range from $25,000 for ten or fewer wells, to a maximum of $250,000 for 100 or more wells. Tex. Nat. Res. Code § 91.1042. These amounts are far below actual plugging costs in Texas.

According to the Railroad Commission's most recent Monthly Report of State Managed Well Plugging Activities, the Commission spent $30,561,300.19 to plug 332 wells in August 2026, at an average cost of $92,052.11 per well.[18] For the year to date, the average cost was $62,138.21.[19] This is roughly consistent with the Commission's estimate of $65,143.32 per well, made in 2021 when it filed its Notice of Intent to apply for federal orphaned well plugging grants. In neighboring New Mexico, the average cost for the state to plug a well is $163,000.[20]

The average depth for wells plugged by the Commission, both in August and across 2026, is just over 3,000 feet.[21] Under current Texas financial assurance requirements, such wells would be covered by $2,500 or less per well, under blanket bonding, or at most $6,000 per well, under an individual bond. These amounts are a fraction of the state's acknowledged actual plugging costs. These figures also do not appear to include additional costs related to restoration of the surface.

To the extent the Commission intends to rely on the Cost Calculation Plugging Cost Estimates provided in compliance with HB 2259, the Commission must ensure that these estimates are complete and accurate. This includes ensuring that the "full cost calculation" reflects the most recent information on the costs to the Commission to plug orphaned wells, including as reflected in updated figures for the cost per foot of well depth, and is adequate to cover associated costs including surface restoration. The cost to plug an orphaned well is a good indicator of the cost to plug a well inactive for more than 15 years. As wells age, the costs to plug them increase.

[18] https://www.rrc.texas.gov/media/dnxifwtb/august-26-smp.pdf
[19] https://www.rrc.texas.gov/media/dnxifwtb/august-26-smp.pdf
[20] New Mexico Legislative Finance Committee Policy Spotlight, Orphaned Wells, https://www.nmlegis.gov/handouts/ALFC%20062425%20Item%204%20Policy%20Spotlight%20Orphaned%20Wells.pdf, at p. 13.
[21] https://www.rrc.texas.gov/media/dnxifwtb/august-26-smp.pdf

Casings and other components erode. Vegetation grows up around well pads and access roads. Access roads deteriorate and must be rebuilt in order to accommodate plugging rigs.

In addition to providing for complete and accurate cost calculations, the Commission should strengthen the proposed rule by amending the proposal in three ways.

First, the Commission should amend section 3.15(i)(1)(D)(iii) to include the additional phrase "...and listed on U.S. Treasury Department Circular 570." The U.S. Treasury Department maintains Circular 570[22] to provide a list of "companies holding certificates of authority as acceptable sureties on acceptable bonds and as acceptable reinsuring companies" who are therefore eligible to provide surety bonds for the benefit of the U.S. government. The criteria surety providers must satisfy in order to qualify to be listed on Circular 570 are specified in statute at 31 U.S.C. § 9305 and regulation at 31 C.F.R. Part 223. These criteria include consideration of the surety's solvency, profitability, and liquidity, including the amount and type of the surety's assets.[23] The regulations also impose a cap on the size of any individual bond a listed surety may issue, specifying that "no company holding a certificate of authority shall underwrite any single risk on any bond or policy on behalf of any individual, firm, association, or corporation, whether or not the United States is interested as a party thereto, the amount of which is greater than 10 percent of the paid-up capital and surplus of such company, as determined by Treasury."[24]

[22] U.S. Department of the Treasury, Department Circular 570: Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reinsuring Companies, July 1, 2024, https://www.fiscal.treasury.gov/surety-bonds/circular-570.html.
[23] 31 C.F.R. § 223.9.
[24] 31 C.F.R. § 223.10.

This additional requirement is necessary to ensure the reliability of the provider of the financial assurance. Even if the Commission sets the amount of the financial assurance at an appropriate level, the Commission remains at risk that the surety provider itself may ultimately default and not be able to pay out the full value of the bond provided. This risk is magnified when a single surety provides multiple bonds for multiple operators all subject to the same economic forces, including fluctuations in commodity prices. Should multiple operators fail at the same time, the surety may not be able to cover all of the bonds it must pay out.

The proposed rule partially addresses this concern by requiring that the financial assurance be "issued by and drawn on by a third-party bank authorized under state or federal law to do business in Texas." The additional proposed language provides additional protection, and would allow Texas to rely on the vetting and regulation of sureties already performed by the U.S. Treasury Department. If a surety operator does not qualify for listing on Circular 570, it should not be able to issue bonds to cover the risk of operator default in Texas.

Second, the Commission should amend section 3.15(i)(1)(D) by adding a fourth subsection: "(iv) it is not cancelable except by the Commission, and only after the Commission has determined that either the well has been fully and completely plugged in accordance with applicable Commission rules, or the Commission has accepted a replacement bond that meets all of the criteria of this section." Although proposed section (i)(1)(D)(ii) appropriately requires that the bond cover the lifetime of the well and remains in effect following a change of operator, the additional language is necessary to clarify the limited terms under which the bond may be canceled, and to clarify that the operator—or a transferee operator—may provide a replacement bond, but that the original bond will remain in place until the Commission determines that the replacement bond satisfies the criteria.

Finally, the Commission should provide for even more secure and reliable forms of financial assurance, such as a trust account or sinking trust account, as a form of authorized performance bond.

Under a trust account approach, the applicant would be required to deposit the required financial assurance amount in an account with a third-party bank that is authorized under state or federal law to do business in Texas, with the Commission named as the account's beneficiary such that the funds would not be considered part of the applicant's estate in the event of bankruptcy.

Under a sinking trust account approach, the applicant would initially be required to provide a surety bond or letter of credit for the required financial assurance amount, but would then make periodic deposits into a trust account. As the amount of funds in the trust account grow, the amount required to be maintained in the surety bond or letter of credit would decrease in a commensurate amount.

For example, under a six-year timeframe for a $150,000 estimated liability, at the time the Commission grants the extension, the financial assurance would be 100% surety bond with the trust account balance at $0. At year three, 50% of the assurance would be covered by a $75,000 bond, and the escrow account would contain $75,000. At year six, the surety bond would be released, and the escrow account would contain $150,000.

Such an approach avoids many of the risks associated with over-reliance on surety bond providers. Some surety providers have been allowed to accumulate an aggregate risk far beyond their ability to pay, by issuing multiple bonds for multiple wells. Because these operators and wells are subject to the same external economic factors, this means that multiple bonds could be forfeited at the same time, overwhelming the surety's ability to pay.

The sinking trust approach minimizes the risk by ensuring that actual dollars are available and verifiable in a bank account.

The trust approach (whether pre-funded, or under a sinking trust approach) also offers the benefit that the funds in the trust account can eventually be used by the operator to pay for the actual well plugging. When the well plugging obligation comes due, the Commission can authorize the operator to access the funds to pay for plugging. This is in sharp contrast to a surety bond, where the fees and premiums paid to the surety bond provider by the operator are purely for the benefit of the surety, who is only obligated to pay out funds to the Commission and only in the event a well becomes the responsibility of the state. In that case, the operator pays twice: first when it pays the fees and premiums to the surety provider, and again when it pays for the costs of plugging.

2. Suggested amendments to the proposed rule

a. Application requirements for an exception based on an operator's filing an individual performance bond

Amend section 3.15(h)(4)(D): "an individual performance bond or bankruptcy-remote trust account, alone or in combination, ~~that is~~ in an amount that is not less than the full cost calculation for plugging the inactive well, including associated surface restoration costs, ~~and~~ that runs with and covers the lifetime of the inactive well, regardless of a change in the operator. The bankruptcy-remote trust account may be structured as a sinking trust, with the amount required to be maintained in the performance bond reduced over time by an amount equal to the balance of the trust account."

b. Commission criteria for an exception based on an operator's filing an individual performance bond

Amend section 3.15(i)(1)(D)(iii): "it is issued by and drawn on by a third-party bank that is both authorized under state or federal law to do business in Texas and is listed on U.S. Treasury Department Circular 570 or, in the case of a trust account, is held by a third-party bank authorized under state or federal law to do business in Texas."

Add section 3.15(i)(1)(D)(iii)(iv) "it is not cancelable except by the Commission, and only after the Commission has determined that either the well has been fully and completely plugged in accordance with applicable Commission rules, or the Commission has accepted a replacement bond that meets all of the criteria of this section."

IV. Factors requiring mandatory denial

1. Comments on the Proposed Rule's factors requiring mandatory denial

We applaud the Commission's inclusion of factors requiring mandatory denial in the proposed rule. This approach is consistent with the legislature's decision to provide for only specific, limited exceptions to the plugging requirement for wells that have been inactive for more than 15 years. That said, the proposed rule would benefit from additional specificity in three areas.

First, regarding section 3.15(i)(2)(D), the Commission should provide examples of what constitutes financial hardship due to the operator's own fault or negligence. These examples should include an operator's failure to set aside funds adequate to cover the costs of plugging and remediating the well, during the well's production. This language is necessary to avoid creating an incentive for operators to avoid setting aside adequate funds in the knowledge that they will eventually be eligible for an extension based on financial hardship. The provided examples should also include an operator's agreement to acquire an inactive or low-producing (producing less than two barrels of oil or ten Mcf of gas each month for 12 consecutive months) well

without ensuring that it had adequate cash in hand to cover the cost of plugging that well. This language is necessary to avoid creating an incentive for operators to acquire wells without having adequate funds in hand, in the knowledge that they will eventually be eligible for an extension based on financial hardship. This language will also avoid an incentive for operators to transfer away wells to under-financed operators as a means to avoid the cost of well-plugging.

Second, regarding section 3.15(i)(2)(F), the Commission should clarify the fuzzy term "bad faith" by providing a more concrete requirement. Specifically, the Commission should provide that "bad faith" includes any deviation from the previous year's approved compliance plan that was not expressly approved by the Commission in advance. This requirement provides a disincentive for operators to treat their compliance plans as mere suggestions rather than binding requirements, including in the hopes that they can beg the Commission's forgiveness after the fact. This approach continues to provide for flexibility when unforeseen circumstances arise, but in a manner that remains under the Commission's control and discretion.

Third, regarding section 3.15(i)(2)(G), the Commission should insert the phrase "and listed on U.S. Treasury Department Circular 570" at the end of the existing language. This is consistent with the amendments discussed above regarding the exception based on provision of an individual performance bond.

2. Suggested amendments to the proposed rule's factors requiring mandatory denial

Amend Section 3.15(i)(2)(D) "the operator's financial hardship is due to the operator's fault or negligence. An operator will be determined to be at fault and negligent if it cannot establish that during the well's operation it had set aside funds sufficient to cover the typical costs to plug and remediate a well, or, if it acquired the well once it was inactive or producing less than two barrels

of oil or ten Mcf of gas each month for the prior 12 consecutive months, that it had failed to ensure that it had access to funds sufficient to cover the typical costs to plug and remediate a well;

Amend Section 3.15(i)(2)(F) "if renewing a compliance plan, the operator deviated from the previous year's approved compliance plan in bad faith, including if the operator did not secure express advance approval for the deviation from the Commission; or"

Amend Section 3.15(i)(2)(G) "the performance bond is not issued by and drawn on by a third-party bank that is both authorized under state or federal law to do business in Texas and listed on U.S. Treasury Department Circular 570."

Conclusion

CARA appreciates the opportunity to submit these comments. We urge you to carefully consider and adopt the proposed amendments.

Sincerely,



Peter Morgan
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Center for Asset Retirement Accountability (CARA)

Exhibit 1

Muehlenbachs, “A Dynamic Model of Cleanup: Estimating Sunk Costs in Oil and Gas Production,” Int’l Econ. Rev. Vol. 56, No. 1

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A DYNAMIC MODEL OF CLEANUP: ESTIMATING SUNK COSTS IN OIL AND GAS PRODUCTION*

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The environmental remediation required to permanently decommission most industrial projects is an expensive, irreversible investment. Real options literature shows that temporary closure has value under uncertainty. However, even if there is no intention to restart operations, there is an incentive to label a closure as "temporary" to avoid having to remediate ongoing or future environmental externalities. I estimate a dynamic discrete choice model of closure under price and quantity uncertainty to evaluate the likelihood of reactivation. The model reveals that the option to temporarily close is being widely used to avoid environmental remediation of oil and gas wells in Canada.

1. INTRODUCTION

Once an industrial project, such as a landfill, nuclear power plant, mine, or oil field has reached the end of its life, the costs associated with permanently decommissioning operations tend to be very high. Literature on real options has shown that inertia is optimal in dynamic decisions involving sunk costs in uncertain environments (Dixit, 1989, 1992; Dixit and Pindyck, 1994). If there is a chance that a project will be restarted in the future, there is value to temporarily closing it and postponing the investment needed to decommission it. However, once a project is temporarily closed it could remain in a state of hysteresis; there is a sunk cost to reactivate, so even if the forces behind the project's closure are reversed the project may still not be reactivated.

There are high sunk costs associated with decommissioning industrial projects because of the requirements to remediate existing environmental damages and implement measures to prevent ongoing or future damages. Therefore, by not decommissioning a project, a mothballed, or temporarily closed, state carries environmental risks that might not be internalized by the owner of the project. A difficulty, however, arises because regulators not wanting to cut the life of a viable project short will allow projects to be temporarily closed. It therefore could be the case that the value of the option to reactivate is zero or negative, but an owner "temporarily" closes a project as a way to avoid paying for decommissioning. Using a temporary closure in lieu of a permanent closure is facilitated by regulators not having perfect information on the costs or expectations of the operators.

In this article, I find evidence to help disentangle whether a temporary closure is indeed being used to avoid environmental cleanup. To the best of my knowledge, this is the first attempt to understand the true motivations behind temporary closures. To do so, I first build a dynamic programming model of the choice to temporarily close, decommission, or reactivate under uncertainty in prices and quantities. I then estimate the structural parameters in the model

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using data on historical operating decisions and changes in prices and productivity. Assuming prices and productivity are believed to follow the same path as in the past, I can use the fully specified model to predict how likely a reactivation is when presented with ideal operating conditions. In doing so, I demonstrate that data on closure decisions can be used to structurally estimate a real options model, which can be used to test the likelihood that a temporary closure is in actuality permanent.

I apply this framework to the oil and gas industry. Currently, there are hundreds of thousands of "temporarily abandoned" oil and gas wells scattered across North America, including over 3,700 temporarily abandoned wells in the Gulf of Mexico.[2] Permanent decommissioning of wells is required;[3] however, regulators, not wanting to impede production, make temporary closure an option despite the potential environmental externalities of not decommissioning.[4] Postponing permanent decommissioning also increases the risk that a firm will declare bankruptcy before undertaking the expense of the environmental cleanup. The inventory of "orphaned wells," or wells without a party responsible for plugging, is quite startling: New York for example has 44,600, Pennsylvania has over 100,000, and Texas has roughly 10,000.[5] Furthermore, the current boom in drilling for shale oil and gas makes it ever more important for policymakers to understand firms' incentives to environmentally remediate wells once they have reached the end of their productive life. Therefore, I use data on the decisions made for 84,000 conventional oil and gas wells in Alberta, Canada, to estimate the structural parameters of the dynamic programming-real options model of well-operating decisions. This article has two main contributions.

The first contribution is in testing the goodness-of-fit of a real options model to actual firm behavior. Real options models extend the Black and Scholes (1973) and Merton (1973) theory for financial options to that of irreversible real investments. Unlike the case of financial derivative models, empirical investigations testing the fit of real options models to data are rare. Gamba and Tesser (2009) note that this is due to two factors: The values of the state variables are often not observed and there is quantity uncertainty. In this article, I circumvent these two issues through the use of a data set on the reserve estimates of oil and gas pools over time. This is the first time these data have been used in the economics literature, and they provide annual estimates for the remaining reserves of over 42,000 oil and gas pools. These data provide me with information not used in previous studies: an estimate of a project's current productivity as well as a way to estimate uncertainty in its productivity in the future (i.e., technological advances in enhanced recovery methods that might increase recoverable reserves). This information is key in determining the likelihood that a well will be reactivated; without data on reserves, I would not be able to distinguish whether a well is inactive because the decommissioning costs are high or because the remaining reserves are significant enough to warrant reactivation in the future.

Much of the literature on real options relies on examples from the natural resource industry, and models of many different discrete decisions in the industry have been developed.[6] The empirical work on real options has relied on having data for the cost parameters instead of

[2] According to the Bureau of Ocean Energy Management's Borehole Dataset http://www.data.boem.gov/homepg/data_center/well/well.asp.

[3] In this article, decommissioning a well refers to what the oil and gas industry terms "plugging and abandoning," which involves equipment being removed and sealing groundwater formations with cement, as well as "reclamation," which involves revegetating the surrounding land (or bringing it to a "new use" state).

[4] Not permanently decommissioning an oil or gas well increases the risk of contamination of the atmosphere, drinking water, vegetation, and soil; lost productivity of other wells in the same pool; erosion; forest fragmentation; and even explosions (Kubichek et al., 1997; Williams et al., 2000; Mitchell and Casman, 2011).

[5] According to the Interstate Oil and Gas Compact Commission's (IOGCC) Orphaned Wells State's Progress http://groundwork.iogcc.org/topics-index/orphaned-wells/state-progress and Railroad Commission of Texas, (2006).

[6] Indeed, even the same three choices presented in this article (to activate, inactivate, or decommission a project) have been modeled by Brennan and Schwartz (1985), Castillo-Ramirez (1999), Cortazar and Casassus (1998), Cortazar et al. (2001), Stensland and Tjostheim (1989), Dixit and Pindyck (1994), and Gamba and Tesser (2009). However, these authors did not apply their models to real data and treated decommissioning costs as negligible.

structurally estimating these parameters, thereby restricting investigations to small sample sizes and results to a comparison of stylized facts from the predictions of real options to the data (e.g., Paddock et al., 1988; Hurn and Wright, 1994; Harchaoui and Lasserre, 2001; Slade, 2001; Moel and Tufano, 2002, examine irreversible investments in natural resource industries and all use data on fewer than 300 projects). Exceptions are from dynamic models of the decision to drill oil wells by Levitt (2009), focusing on the effect of learning, and Kellogg (2010), on the effect of price volatility. However, these papers also do not measure quantity uncertainty.

The second contribution is in presenting a framework to understand the relative importance of the value of investment flexibility and the perverse incentive to avoid cleanup costs. The extent to which permanent closures are being labeled as temporary has not been raised or investigated before. Throughout the real options literature, the permanent closure option is often downplayed. Decommissioning costs are treated as negligible or null (Brennan and Schwartz, 1985; Dixit and Pindyck, 1994), or the option of decommissioning is completely left out of the choice set (Paddock et al., 1988; Mason, 2001; Slade, 2001; Moel and Tufano, 2002). By assuming away decommissioning costs, the previous literature has overlooked the case of firms continuing to maintain the option to reactivate a project even when they have no intention, or there is no option value, to reactivate. When the costs from mothballing a project are small relative to the decommissioning costs, this behavior would be privately optimal, but when there are environmental externalities associated with mothballing, this behavior would not necessarily be socially optimal. If there is no potential or intention to reactivate a hazardous project, regulators have reason to implement policies to ensure that environmental obligations will be met.[7] The framework presented in this article is important because the effectiveness of any policy relies on the underlying reasons for the temporary closures at hand.

The estimated model suggests 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, implying that wells are typically left inactive not because of the option to reactivate but rather to avoid costly environmental obligations. This is a function of the expected value of a reactivated well being less than the expected value of an inactive well even when an operator is in an ideal state of nature. Considering that energy independence is frequently sought by policymakers, it is also important to consider the quantity of oil or gas that the reactivated wells might contribute to the energy supply. Under high oil and gas prices, the recoverable reserves increase (more so for gas than oil), but nonetheless, the number of reactivated wells remains minimal. Furthermore, the model predicts that the contribution to the oil and gas supply from these reactivated wells is only marginal. These findings have far-reaching implications for the oil and gas industry. If decommissioning costs are not being internalized, the development of oil and gas reserves would be at a rate above what is socially optimal. The policy implication would be to create stronger mechanisms to internalize the costs of decommissioning. One such mechanism is to increase bonding requirements, which are arguably too low at present.[8] This article demonstrates that in designing policies to decommission oil and gas wells, unnecessary weight has been placed on not jeopardizing production.

2. OIL AND GAS WELL BACKGROUND

This article focuses on Alberta, the main oil and gas producing province of Canada. Extensive record keeping in Alberta has resulted in comprehensive data on the industry. Also, there is

[7] One of the main reasons for a policy to induce prompt environmental cleanup is the risk that the firm will declare bankruptcy. The concern that oil and gas companies may walk away from their environmental obligations has been brought up by Boyd (2001), Parente et al. (2006), and Ferreira et al. (2003). While these authors discuss bonding mechanisms, the model here can be used to quantify the effect of a bond on production as well as the choice to undertake cleanup.

[8] For example, a blanket bond of $150,000 will cover all wells drilled on federal land in the United States. This bond amount was set in 1951 and does not reflect actual reclamation costs: between 1988 and 2009, BLM spent around $3.8 million to reclaim 295 orphaned wells (United States Government Accountability Office, 2010). And in the case of Alberta, there are no bonding requirements.

no limit to the length of time that a well can be left inactive in Alberta.[9] (In the United States, even when there is a time limit, permission for extended "temporary abandonment" is easily granted and the fine for leaving a well inactive without permission is usually small; for example, in Kansas the fine is only $100; State Corporation Commission of Kansas, 2010.) Because of the externalities associated with not decommissioning a well, it is required that wells be decommissioned, but it is up to the producer to decide the time frame. The economic life span of a well is uncertain, and, by allowing temporary closure, the option to reactivate remains, should prices or technology improve. Some wells have not produced any oil or gas in the last 60 years; nevertheless, this closure is still classified as temporary because the wells have not been permanently decommissioned. The cleanup costs associated with decommissioning in Alberta range from $20,000 to several million dollars per well (Orphan Well Association, 2008), whereas the cost that a producer must pay to keep a well inactive is usually only the payment to the owner of the surface rights.[10] The sheer volume of wells that have been drilled (over 2.5 million in the United States[11] and in Alberta over 225,000 that will eventually need to be decommissioned) make examining the factors influencing the decision to environmentally remediate a worthwhile endeavor.

An operator might incur losses to maintain an inactive well when it is not currently profitable to produce oil or gas in the hopes that prices or technology improve. According to the data on reserves used in this article, the percentage of hydrocarbon in place that is recoverable (i.e., the recovery rate) ranges from 0.01% to 90% for oil and from 15% to 95% for gas. However, once a well is inactive, because of the sunk cost to reactivate or decommission, even if recovery rates improve or diminish, the well may remain inactive. This hysteresis is directly modeled in this article, but there are other reasons for inactivity that are not explicitly modeled, but enter via an error term that compensates for unobservable states: (i) technical difficulties (e.g., blockage in the wellbore, a leak caused by corrosion or erosion, an external fire, or a temperature change causing mechanical failure), (ii) pipeline failure or pipeline capacity reached, (iii) gas plant capacity reached, or (iv) a mandated suspension for exceeding the maximum rate limit assigned to the well by the regulator.[12]

The development of enhanced recovery methods, including hydraulic fracturing and horizontal drilling, has brought wells back into production after many years of inactivity, and recoverable reserves have been seen to increase instead of decrease with time. Reserve growth was first examined by Arrington (1960) using his own company's reservoir data. And since then reserve growth has been studied using state or state subdivision estimates of initial established reserves (IER) from the American Petroleum Institute (Morehouse, 1997) or a small number of pools (Verma and Henry, 2004). This is the first time that such a large data set on reserves has been used to study reserve growth.

2.1. *Environmental Impacts.* The fact that technological advances can increase recoverable reserves over time increases the value of waiting to decommission a well. However, without proper decommissioning (and in some cases, even after proper decommissioning) a well poses

[9] The regulator does have the authority to order that a wellsite be decommissioned; however, this is not a common occurrence and the 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 (Alberta Energy Regulator, 2013a).

[10] The annual payment for a wellsite is based on "loss of use" and "adverse effects" only (not land value or 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 between $117 and $2,500 per acre for general disturbance (Alberta Agricultural and Rural Development, 2010).

[11] U.S. Energy Information Administration's U.S. Crude Oil, Natural Gas, and Dry Exploratory and Developmental Wells Drilled: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=E_ERTW0_XWC0_NUS_C&f=A

[12] Various wells must conform to maximum rate limitations set by the industry regulator. These limits are to ensure that the cumulative amount of oil or gas extracted is maximized. In this model, I do not truncate by the maximum rate limit because only about 10% of the wells have limits placed on them, and for only a portion of those wells is the rate limit binding.

a risk to vegetation, soil, surface water, and underground aquifers. Many wellbores extend thousands of meters underground, and it is often only a steel casing or cement that isolates the different formations. The casing might rust out or crack (especially when sand or salt water is lifted along with the hydrocarbons), and contaminants such as uranium, lead, salt, iron, selenium, sulfates, and radon may enter into formations that contain fresh water (Kubichek et al., 1997). The likelihood of this occurring increases when injection from disposal or enhanced recovery builds pressure (Canter et al., 1987). The most prevalent contaminant, methane, poses the risk of explosion if migration accumulates in adjacent buildings (for a list of explosions in Pennsylvania, some leading to fatalities, attributable to fugitive methane, see Pennsylvania Department of Environmental Protection, 2009). Decommissioning a well does not guarantee that there will not be any leaks, but the risk is much lower than that from active or inactive wells. Unplugged wellbores would also prevent the future use of a reservoir for carbon capture and storage (Watson and Bachu, 2009). Furthermore, by not reclaiming the land there is not only the opportunity cost of an alternative land use but unreclaimed well pads and related infrastructure can contribute to habitat fragmentation (Schneider et al., 2010). And finally, revegetating may also reduce turbidity in downstream rivers and streams caused by wellsites (Olmstead et al., 2013).

In Alberta, it is required that all wells eventually be decommissioned; however, it is, in effect, left up to the firm to decide when to decommission. Decommissioning a well entails plugging and abandoning and reclamation. Plugging and abandoning refers to leaving the wellbore in a permanently safe and stable condition so that it can be left indefinitely without damaging the environment. It is required that all nonsaline water formations be shut off with cement (Alberta Energy Regulator, 2010b). Reclamation includes removal of any structures, decontamination of land or water, and reconstruction of the land (Alberta Environment, 2000). Because the risk of environmental contamination is lower after plugging and abandoning, a company's liability is lower; however, it is not completely eliminated. Companies retain ongoing responsibility for wellbore integrity after plugging and abandoning a well (Province of Alberta, 2000).

The Alberta Energy Regulator estimates that abandonment costs range from $9,067 to $84,659 and land reclamation costs from $13,200 to $33,700 (Alberta Energy Regulator, 2013b); however, abandonment and reclamation costs can dramatically surpass these figures. For example, the Orphan Well Association spent over $2 million to reenter and repair one orphan well (Orphan Well Association, 2008) and has spent on average $23,000 per site in reclamation costs (Orphan Well Association, 2013). Although plugging and abandoning a well might prevent litigation or remediation costs associated with fluid or gas leakage (National Petroleum Council, 2011), it is difficult to quantify the cost of the ongoing environmental damages from unplugged, unreclaimed wells. The externalities associated with these wells depend on the well location (e.g., if the well intersects the range of the woodland caribou or is near any houses[13]), whether there is any groundwater contamination or fugitive emissions of methane (a potent greenhouse gas) to the atmosphere. However, methane leakage is poorly quantified (Alvarez et al., 2012) as are the existence values of threatened species. Litigation for groundwater contamination[14] provides insights into the cost of groundwater contamination in the worst cases; however, it is difficult to value the externalities from a given inactive well. Therefore, this article proceeds under the assumption that the regulation requiring decommissioning is in place because the averted environmental impacts outweigh the costs of decommissioning.

3. DATA

The data collected on the oil and gas industry in Alberta are unrivaled in their comprehensiveness and accessibility. Here, five data sets of the Albertan oil and gas industry are used. The first data set is a panel of production from the universe of oil and gas wells in Alberta. Obtained

[13] "Leaky Calmar well forces demolition of homes," CBC News, December 6, 2010.
[14] "Calgary judge hears $33M lawsuit over natural gas drilling," CBC News, January 18, 2013.

through IHS Incorporated, which distributes the records collected by the Alberta Energy Regulator, this data set contains monthly oil and gas production information dating back to 1924, with complete records starting after 1961. There is information on a well's location (latitude and longitude as well as the name of the field and pool it is on[15]), depth, license date, spud date (the day the drill hit the ground), and on-production date, plus the names of the current and original operators (unfortunately, there is no information on whether a well switched hands between these operators).

The second data set is a panel of official reserve estimates of all nonconfidential pools in Alberta from both the Alberta Energy Regulator and the National Energy Board of Canada.[16] The data set spans 2000–2007 and contains 67,142 oil and gas pools, although not observed in every year. The year that the estimate was last reviewed is listed, and therefore the data are extended to years prior to 2000 if the last review date of the pool was before 2000. This data set contains (i) initial oil or gas in place; (ii) 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" (Alberta Energy Regulator, 2008); (iii) IER, which is equal to the initial oil or gas in place multiplied by the recovery factor; and (iv) remaining established reserves, which is the IER minus the cumulative production and surface loss. Each pool contains information on characteristics of the pools and hydrocarbons in those pools, such as porosity, initial pressure, area, density, temperature, and water saturation.

The third data set is a list of all wells that were permanently decommissioned (plugged and abandoned and reclaimed). To decommission a well entails that the well has met abandonment standards set by the Alberta Energy Regulator (2010b) and reclamation standards set by Alberta Environment (1995) and received a reclamation certificate from Alberta Environment or Alberta Sustainable Resource Development or was exempted from certification. The data set contains both wells that were abandoned, along with the date of abandonment, and the wells that received a reclamation certificate or were reclamation exempt.

The fourth data set consists of GIS shape files that designate areas that, according to the Petroleum Services Association of Canada (PSAC), have similar costs in production and drilling (the areas are further described in the Appendix Figure A1 and Table A1). The PSAC boundaries and well locations were entered into ArcView GIS to assign a PSAC area to each well.

The final data set is the average wellhead price of crude oil and natural gas in Alberta, obtained from the Canadian Association of Petroleum Producers' Statistical Handbook (CAPP, 2009). The wellhead price is inflated to 2007 dollars using Statistics Canada's quarterly machinery and equipment price index for mining, quarries, and oil wells.

A panel is created where each well is classified as active, inactive, or decommissioned 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, classified as inactive if it did not produce oil or gas in 12 months or more, and classified as decommissioned if it appeared in the data set of decommissioned wells.

The full data set of the universe of wells in Alberta is pared down to a subsample that is used for the estimation. Excluding coalbed methane, heavy oil, injection, and water wells, there are 350,457 wells in the production data set. The decision to decommission, stop production, or reactivate a well depends on the remaining oil and gas reserves, and so 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 data set. The result of this restriction is that the analysis corresponds to wells that are, or once were, deemed producible, that is, 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% of the wells that are decommissioned in Alberta are decommissioned immediately after being drilled.

[15] An oil field 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.

[16] All pools eventually lose their confidential status (usually after one year), and so this data set contains nearly all pools in Alberta.

TABLE 1
SUMMARY STATISTICS

Variable	No. of Obs.	Mean	Std. Dev.	Min	Max	Unit
$\overline{Q}_{gas}$	118187	15.23	62.95	0	8800	E^6m^3
$\overline{Q}_{oil}$	54523	27.09	237.07	0	43871	E^3Barrels
Wellhead price$_{gas}$	37	111.90	64.76	25.89	293.91	2007C\$/E^3m^3
Wellhead price$_{oil}$	37	30.16	12.12	12.88	64.45	2007C\$/Barrel
Age$_{gas}$	61876	19.86	15.76	1	104	Years
Age$_{oil}$	31430	16.58	12.15	1	94	Years
Q_{gas}	118187	32.97	297.79	0	51271	E^6m^3
Q_{oil}	54523	135.64	1026.83	0	104866	E^3Barrels
No. of wells in pool$_{gas}$	118187	3.59	47.02	1	4117	Wells
No. of wells in pool$_{oil}$	54523	4.44	17.91	1	699	Wells
q_{gas}	322907	1.68	8.27	0.0001	568.39	E^6m^3
q_{oil}	155773	7.27	14.51	.001	822.95	E^3Barrels
Depth	93239	1197.53	690.36	90.9	6552	m
Porosity$_{gas}$	22452	.20	.08	0.01	0.4	Fraction
Porosity$_{oil}$	25894	.16	.07	0.01	0.36	Fraction
Density$_{gas}$	22452	.64	.08	0.54	2.03	kg/m^3
Density$_{oil}$	25894	868.64	48.01	708	999	kg/m^3
Initial Pressure$_{gas}$	22452	9038.08	7564.57	130	99625	kPa
Initial Pressure$_{oil}$	25894	12568.80	5688.37	1442	61097	kPa
Temperature$_{oil}$	25894	50.14	20.34	9	350	°C
Water Saturation$_{oil}$	25894	.31	.12	0.06	0.82	Fraction
Wells per Firm	1196	281.93	2015.26	1	44095	Wells
Pool Discovery Year$_{gas}$	22452	1989.67	13.90	1904	2007	Year
Pool Discovery Year$_{oil}$	25894	1988.31	12.40	1910	2006	Year
Area of Pool$_{gas}$	22452	854.43	9908.34	1	598512	Acres
Area of Pool$_{oil}$	25894	183.94	554.36	1	17890	Acres
Duration Inactive$_{oil}$	9556	8.39	8.33	0	73	Years
Duration Inactive$_{gas}$	12298	9.58	10.23	0	78	Years
Duration Active$_{oil}$	14472	10.11	9.11	0	46	Years
Duration Active$_{gas}$	34047	11.35	11.85	0	46	Years

NOTES: Statistics for wells in the subsample. Data on remaining reserves (Q) are listed for pools, 1993–2007. Extraction (q) is listed for wells, 1993–2007. The pool-specific variables—depth, porosity, density, initial pressure, temperature, water saturation, and discovery year—are time invariant in the data. Data on the age of the wells and duration active and inactive are a snapshot of 2007. Price data are the wellhead price from 1971 to 2007. $E^3 = 1000$.

The results from an estimation using the subsample cannot be generalized to all wells in the full sample, but could be generalized to wells in the full sample that at one time produced.[17] 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.

The subsample is further reduced by deleting wells that traverse both oil and gas pools. Doing so does not significantly reduce the size of the subsample (from 105,207 to 94,009); however, it does significantly reduce the computational complexity because modeling the choice to produce oil or gas is avoided without losing much insight into the choice of operating state.

The majority of the wells have small reserves, and only a few have large reserves, some being extremely large—for example, the largest gas reserve is 1,500 times larger than the mean gas reserve (Table 1). The pools with large reserves have more than one well—as many as 4,151 wells in a gas pool and 711 in an oil pool.

The production data set contains firm-reported volumes to which the accuracy is difficult to attest. The Alberta Energy Regulator identifies cases when there is *any* difference in the reported production of oil from a production company and a pipeline company. When the difference is 5% to 20% of reported gas volumes, the penalty is only a warning message.

[17] The similarity between age at decommissioning for wells in full sample that produced and all wells in the subsample is shown in the Appendix Figure A3.

TABLE 2
DISTRIBUTION OF OPERATING CHOICE FOR INACTIVE WELLS BY AGE

	Number of Observations		Proportion Reactivated		Proportion Stay Inactive		Proportion Decommissioned	
Age (in Years)	(Oil)	(Gas)	(Oil)	(Gas)	(Oil)	(Gas)	(Oil)	(Gas)
$1 \leq$ age < 10	18963	21091	0.110	0.194	0.874	0.790	0.016	0.015
$10 \leq$ age < 20	19892	14965	0.056	0.066	0.922	0.915	0.022	0.019
$20 \leq$ age < 30	7997	11234	0.057	0.075	0.914	0.897	0.029	0.028
$30 \leq$ age < 40	2340	4791	0.046	0.054	0.928	0.913	0.026	0.033
$40 \leq$ age < 50	2176	3135	0.030	0.042	0.945	0.929	0.025	0.030
$50 \leq$ age < 60	704	1461	0.024	0.027	0.953	0.955	0.023	0.018
$60 \leq$ age < 70	131	503	0	0.010	1	0.990	0	0
age ≥ 70	50	157	0	0	1	0.987	0	0.013

NOTES: Data from 2000 to 2007 subsample.

Further misreporting results in a fee of $100 if a well does not report in a given month, and upon persistent noncompliance the firm might be subject to increased audits or inspections or partial or full suspension (Alberta Energy Regulator, 2010a). Nonetheless, to the best of my knowledge there is no other data set of this size or comprehensiveness of any natural resource industry. And, with these data the composition of active, inactive, and decommissioned wells can be replicated to match reality closely.

Table 2 shows the proportion of inactive oil and gas wells that have been reactivated, left inactive, or decommissioned by different age intervals. The table illustrates that the hysteresis of inactivity increases as wells age. The proportion of inactive wells that are reactivated decreases with the age of the well and the proportion of inactive wells that are decommissioned increases then decreases with age.

4. MODEL

In order to capture the value of leaving a well inactive, I construct a real options model that 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 producer's decision to extract, 1, temporarily stop extraction, 2, or permanently decommission and remediate environmental damages, 3, is modeled as an infinite time Markov Decision Process (Rust, 1994). It is assumed that the producer is rational and follows a decision rule, $d_t = \delta_t(s_t, \epsilon_t)_{t=0}^{\infty}$, that maximizes the expected discounted sum of profits, $V(s, \epsilon) = \max_{\delta} \mathrm{E}_{\delta}\left[\sum_{t=0}^{\infty} \beta^t \pi(s_t, d_t, \epsilon_t | s_0 = s, \epsilon_0 = \epsilon)\right]$, where V is the value function for the well when choosing the optimal choice, δ, and depends on observed state variables s, and an unobserved random "payoff shock," ϵ, different for each choice. The instantaneous profit, $\pi(\cdot)$, is discounted by discount factor β, $0 \leq \beta \leq 1$. The observed state variables, s, include the age of the well, A, the wellhead price of the hydrocarbon, P, the per-well remaining reserves, $\overline{Q}$, and the current operating state, o. The current operating state ($o =$ 1, active, 2, inactive, or 3, decommissioned) is endogenous to the decision, and the remaining reserves per well are endogenous (when the operator extracts oil or gas) and exogenous (upon technology change or if another well is in the same pool).

The model assumes that the producer maximizes lifetime profits only through the extensive decision for the operating state, but not through the intensive decision for how much to extract.[18]

[18] The implication of not simultaneously modeling the decision of whether to extract and the decision of how much to extract is that there will be a disconnect between the lifetime profit-maximized quantity and the expected quantity I estimate outside of the model, which in turn could bias the predicted duration in a given operating state. However, 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 (further discussed in Subsection 5.1.1).

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 parameters, α, estimated in a separate estimation outside the dynamic programming model (i.e., the expected production is $\mathrm{E}q = \int_0^{\overline{Q}} q f_q(y|\overline{Q}, A, \alpha)dy$). The profit (Equation 1) if the producer decides to produce is equal to the expected quantity recovered, $\mathrm{E}q$, times the price of the hydrocarbon, P, less the per-unit extracted royalty rate (or severance tax), R, and a per-unit lifting cost to extract, C.[19] The per-unit lifting costs also depend on age, per well-reserves, and parameters, θ, to be estimated, $C = C_g(\overline{Q}, A, \theta)$.[20] The royalty rate in Alberta adjusts according to price and quantity produced, $R = R(P, q)$. This profit is then reduced by the corporate income tax, τ, assumed flat for all wells. If the current state of the well is inactive, there is a switching cost to activate, $SC_{(2\to1)}$.

If the producer instead chooses that the well be inactive, the producer pays a annual inactivity cost, M, and if the current state of the well is active, a switching cost $SC_{(1\to2)}$.

To decommission a well is to enter an absorbing state for which the producer pays a one-time switching cost, $SC_{(1,2\to3)}$, assumed to be the same for active and inactive wells.[21] Leaving the well in its current state entails no switching costs, $SC_{(1\to1)} = 0$, $SC_{(2\to2)} = 0$, and $SC_{(3\to3)} = 0$. The expected profit from a single period is

$$(1)\ \pi(s, d, \epsilon) = \begin{cases} ((1-R)P - C)\,\mathrm{E}q - \tau \max\{((1-R)P - C)\,\mathrm{E}q, 0\} - SC_{(o\to1)} + \epsilon_1 & \text{if } d{=}1 \\ -M - SC_{(o\to2)} + \epsilon_2 & \text{if } d{=}2 \\ -SC_{(o\to3)} + \epsilon_3 & \text{if } d{=}3 \end{cases}.$$

The expected present discounted value of the well can be expressed as the unique solution to the Bellman equation[22]:

$$V(s, \epsilon) = \max_d \left[\pi(s, d, \epsilon) + \beta \int_{s'} \int_{\epsilon'} V(s', \epsilon') h(s', \epsilon'|s, \epsilon, d) \mathrm{d}\epsilon' \mathrm{d}s' \right].$$

The state transition probability density function, $h(s', \epsilon'|s, \epsilon, d)$, is assumed to be a Markov process. The Conditional Independence assumption, as per Rust (1987, 1988), is adopted, allowing for the factorization, $h(s', \epsilon'|s, \epsilon, d) = f(s'|s, d)\rho(\epsilon'|s')$. Specifically in the case of this model, the state transition probability density function can be written as

$$h(\overline{Q}', P', A', \epsilon'|\overline{Q}, P, A, \epsilon, d) = f_q(\overline{Q} - \overline{Q}'|\overline{Q}, A, d) f_{\overline{Q}}(\overline{Q}'|\overline{Q}, P) f_P(P'|P) f_A(A'|A) \rho(\epsilon'|\overline{Q}', P').$$

Price is assumed to follow the exogenous process $f_P(P'|P, \varsigma)$, characterized by parameters ς. Recoverable reserves decrease from extraction but also increase or decrease from new

[19] Note that I do not include a fixed cost of extraction. When I include a fixed extraction cost, the estimated parameters converge to the lower and upper bounds specified for the parameters. Presumably this is because fixed costs are difficult to identify (as further discussed in Subsection 5.2).

[20] Chermak and Patrick (1995) and Foss et al. (2002) show how the lifting cost of natural gas depends on quantity extracted and remaining reserves. Chermak and Patrick (1995) use data from 29 gas wells in Wyoming and Texas from 1988 to 1990, and Foss et al. (2002) use data from 22 gas wells in Alberta for roughly three years. They both find that operating costs increase with quantity extracted and decrease with remaining reserves. It is expected that extraction costs rise as reserves are depleted; however, Livernois and Uhler (1987) explain that the discovery of new reserves can increase the reserves by more than what is extracted, but these new reserves are more costly to extract. This is how Livernois and Uhler (1987) explain a positive relationship between extraction costs and reserves using aggregate data from the Albertan oil industry. However, upon disaggregation, they find the typical results of extraction costs increasing with reserve depletion and quantity extracted.

[21] It is not necessary to make decommissioning an absorbing state, but in the sample there are only 261 observations of a switch from decommissioned to active, whereas there were 22,308 observed deactivations, 15,369 reactivations of inactive wells, 1,917 active wells decommissioned, and 3,664 inactive wells decommissioned

[22] Following Blackwell's theorem (outlined in Rust, 1994, Theorem 2.3).

discoveries, revisions, or technological change and follow $f_{\overline{Q}}(\overline{Q}'|\overline{Q}, P, \phi)$. The quantity extracted, q, is modeled as a random draw from the density, $f_q(q|\overline{Q}, A, \alpha)$. The payoff shocks follow the transition probability $\rho(\epsilon'|s')$, but I assume that $\rho(\epsilon'|s')$ is independent of s, so the payoff shocks are assumed to be independent and identically distributed (i.i.d.) across choices, state variables, and time. They capture unobserved, current period events that make a choice more or less expensive for the operator. For example, the shocks would capture a blowout that forces the operator to shut down an active well or capture an unexpected surplus of available workover rigs that make it cheaper to reactivate or decommission a well. Although it is possible to allow serial dependence in the process $\{\epsilon\}$ (see Norets, 2009), it is computationally burdensome, and as a first approximation, the main dependencies are captured by the serial dependence in the observed state variables.

This article abstracts away from modeling the decision to decommission as a function of the strategic interaction between agents competing for the same oil. The common pool resource problem would arise if more than one company competes for a migratory hydrocarbon (Libecap and Wiggins, 1984, 1985). However, each oil and gas pool in the sample is a distinct reservoir that is confined within impermeable rock or water, and so only within pools would we expect to see behavior influenced by the common pool. For the majority of the pools in this article only one firm has access to the pool and the number of wells in a pool is small (Table 1). The average number of wells in a gas pool is 3.5 (and 4.4 for oil pools), but the majority of the time there is only one well per pool (the median and mode are 1 for both oil and gas). This may be driven by the fact that 81% of the mineral rights in Alberta are owned by the Crown and then leased to companies, whereas in the United States, mineral rights are mainly determined by surface landownership, resulting in more fragmentation of mineral rights.[23] Nonetheless, observations of wells that are in pools that have no other wells are modeled and estimated separately from wells that are in pools with other wells. Wells in single-well pools and multiwell pools are modeled differently through their transition probability of recoverable reserves from extraction, f_q. For wells in single-well pools, only when the decision is to extract, $d = 1$, is the transition probability of reserves dependent on the probability of how much can be extracted, $f_q(\overline{Q} - \overline{Q}'|\overline{Q}, A, \alpha, d)$, whereas for wells in multiwell pools, reserves transition according to this probability whether the operator extracts or not, $f_q(\overline{Q} - \overline{Q}'|\overline{Q}, A, \alpha)$. Exogenous to whether the well is active or not, recoverable reserves also follow another process, $f_{\overline{Q}}(\overline{Q}'|\overline{Q}, P, \phi_g)$, that accounts for the probability of change from improved technology, discoveries, reassessment, and additions. The per-well reserves, $\overline{Q}$, also decrease whenever another well is drilled in the pool. It is assumed that the number of new wells drilled is an exogenously determined random shock.[24] The probability of a decrease in per-well reserves by another well being drilled is incorporated into the exogenous change dictated by the transition probability density $f_{\overline{Q}}$. Although there may be strategic interactions between different firms extracting from the same pool, modeling these in the probability of reserve decreases of multiwell pools is beyond the scope of this article. A justification for this simplification is that a large fraction of the multiwell pools are operated by a single firm,[25] alleviating much of the concern of strategic extraction driven by the common pool. However, it could still be the case that firms are making joint decisions for all the wells in the same pool, yet the model is treating these as separate decisions. Given that not all wells in the same pool have the same operating state, this is not a very large concern; however, if joint decisions were being made it would be because of increasing returns to scale, in which case, I would be underestimating the per-well costs.

[23] In Alberta, most leases are for one quarter section (160 acres). Only one oil well can be drilled on a quarter section, and only one gas well on one section (a company must obtain the mineral leases for all four quarters of the section).

[24] For a model of where to drill for oil and gas, see Levitt (2009).

[25] On average there are 1.8 (1.9) firms per oil (gas) pool but 54.1% (49.9%) of the oil (gas) pools only have one firm and pools that have more than one firm are larger (2.6 [4.2] times for oil [gas]).

Assuming that ϵ is drawn from the type I extreme value distribution, the Bellman equation becomes (Rust, 1988)

$$V_\theta(s, \epsilon) = \max_d [v_\theta(s, d) + b\epsilon(d)],$$

where θ are the parameters to be estimated for each well group (including the cost parameters in the profit equation and the parameters in the transition probability density functions) and v_θ is the fixed point of $v_\theta = \Gamma(v_\theta)$, where Γ_θ is a contraction mapping:

$$\Gamma_\theta(v)(s, d) = \pi(s, d, \theta) + \beta \int_{s'} b \log \sum_{d'=1}^{3} \left[\exp \left\{ \frac{v_\theta(s', d')}{b} \right\} \right] f(s'|s, d) \mathrm{d}s', \tag{2}$$

with location parameter of the extreme value distribution of ϵ normalized to zero and scale parameter, b, to be estimated.[26]

The assumption of the extreme value distribution[27] allows for a closed-form solution of the choice probabilities—that of the multinomial logit:

$$p(d|s, \theta) = \frac{\exp \frac{v_\theta(s,d)}{b}}{\sum_{d'} \exp \frac{v_\theta(s,d')}{b}}. \tag{3}$$

5. ESTIMATION

The estimation consists of three stages. First, I estimate the parameters of the producer's subjective belief for how the state variables progress over time as a standard parametric estimation. Second, the parameter estimates from the first stage are taken as given, and the remaining parameters in the Bellman equation, the costs in the profit function, are estimated via the Nested Fixed Point Algorithm (Rust, 1987). Nested within the algorithm to maximize the likelihood function of the choice probabilities (Equation 3), there is an inner algorithm to compute the fixed point, v_θ, of Equation (2). The outer loop of the algorithm, the maximization of the likelihood, was submitted to the solver KNITRO (Byrd et al., 2006). The inner loop, which solves the fixed point of Equation (2), consists of successive approximations followed by Newton–Kantorovich iterations. The third step is to obtain consistent standard errors from the full likelihood function. The parameter values from the first stage contain a measurement error, but they are treated as the true parameters in the second stage, and so the standard errors for the second stage parameters are inconsistent. To obtain consistent standard errors, the consistent parameter values from the first and second stages are used as starting points for one Gauss–Newton step of the full likelihood function (Rust, 1994).

Well-level heterogeneity is accounted for by estimating the dynamic programming model separately for different well types, g. All wells of the same type are treated as homogeneous, and wells of the same type that also have the same reserve size and the same age are assumed identical. The well types are determined by (i) whether the well is an oil or gas well, (ii) whether the well is in a single-well pool or a multiwell pool, (iii) the royalty regime applicable, (iv) PSAC area, and within these groups, and (v) clusters based on time-invariant characteristics (depth, initial pressure, density, water saturation, and temperature). The group is divided into clusters only if the likelihood ratio test confirms that clustering improves the fit over not clustering. This results in 88 different types of wells. The royalty regime depends on when the pool was

[26] A location parameter of zero means that ϵ has a mean zero; a scale parameter of one would mean ϵ has a variance of $\pi^2/6$. As b approaches zero, $V_\theta(s, \epsilon)$ converges to the ordinary Bellman equation.

[27] Dagsvik (1995) showed that the generalized extreme value class is dense; choice probabilities from any distribution can be approximated arbitrarily closely by choice probabilities from the generalized extreme value class.

discovered: There is an "old" category for oil from pools discovered before 1974, "new" for oil from pools discovered between 1974 and 1992, and "third tier" for oil from pools discovered after 1992. For gas wells, "old" refers to gas from pools discovered before 1974 and "new" to gas from pools discovered after 1974. Within each type, the royalty depends on price and the quantity extracted. The royalty regime remained the same from 1993 to 2009 (Province of Alberta, 2008), coinciding with the study period.

5.1. *First Stage Estimates.* The producer's beliefs about future prices and recoverable reserves are estimated in the first stage. These beliefs are unobservable and subjective, but here I assume that the producer's beliefs are recoverable from objective probability measures estimated from the data. I estimate the parameters, θ_{1st}, that maximize the first stage partial likelihood function:

$$L_1(\theta_{1st}) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} f\left(s_{t+1}^i | s_t^i, \theta_{1st}\right). \tag{4}$$

These parameters and their transition probability densities are described in the next three subsections.

5.1.1. *Transition in remaining reserves from extraction, f_q.* Reserve changes due to extraction are such that when the well is active, the quantity extracted is modeled as a random draw from a distribution that depends on the per-well remaining reserves, $\overline{Q}$, and age of the well. It implies that the producer only chooses whether to extract and does not have control over the quantity extracted. Although producers do have control over extraction rates, ultimately extraction is also driven by geological constraints that the producer does not have control over. In a regression of the annual quantity extracted on factors that the producer does not have control over, I find that the remaining reserves, porosity, temperature, depth, density, water saturation, and initial pressure are all statistically significant in determining extraction. Furthermore, these exogenous factors explain more of the variation in extraction quantities than the price of oil or gas.[28]

Therefore, the quantity extracted is modeled as a random draw from a distribution estimated using an equation that describes the production by well w in year t:

$$\log q_{wt} = \alpha_0 + \alpha_1 \log \overline{Q}_{wt} + \sigma \varepsilon_{wt} \tag{5}$$

assuming an i.i.d. $N(0, 1)$ error, ε. The regression is estimated separately for each well type–age group combination.[29] Extraction from a well is truncated to fall in the interval $[q^L, q^U]$ where the lower bound, q^L, is 10^{-8} (not zero because of the subsequent logarithm), and the upper bound, q^U, is equal to the well's per-well remaining reserves, $\overline{Q}$, multiplied by a factor, κ_m, which depends on whether the well is in a single-well pool, $m = 0$, or a multiwell pool, $m = 1$. In the data set there are a few observations where the amount produced in a year is greater than the per-well remaining reserves even for wells that are on their own pools (6% of the production data would be classified as such). Evidently the reserve size is sometimes an underestimate. Therefore, the factor κ_m is equal to the 99th percentile of the observed fractions

[28] The adjusted R^2 of a regression of the quantity extracted on a constant and price is much smaller than the adjusted R^2 of a regression that instead of price includes the remaining reserves (specifically, price results in 0.0068 for oil wells and 0.0002 for gas wells whereas remaining reserves result in 0.1275 for oil and 0.3635 for gas). Per-well remaining reserves also depend on price; however, the adjusted R^2 from a regression that includes the truly exogenous characteristics of porosity, temperature, depth, density, water saturation, and initial pressure is also larger than the adjusted R^2 when only including price (i.e., 0.0836 for oil and 0.2405 for gas).

[29] If there are less than 30 observations of production within a given type's age group, then observations from the age group without clustering were used.

TABLE 3
WEIGHTED AVERAGE PARAMETER ESTIMATES FROM THE FULL LIKELIHOOD

	Oil		Gas	
Parameters	Estimate	Std. Err.	Estimate	Std. Err.
Reserves Transition				
$\alpha_{0,1}$	0.312	(0.596)	3.333	(2.324)
$\alpha_{0,5}$	0.3	(0.581)	2.522	(1.797)
$\alpha_{0,15}$	0.07	(0.430)	2.454	(1.036)
$\alpha_{0,30}$	−0.103	(0.411)	2.288	(1.369)
$\alpha_{1,1}$	0.43	(0.163)	0.438	(0.263)
$\alpha_{1,5}$	0.274	(0.147)	0.47	(0.194)
$\alpha_{1,15}$	0.317	(0.128)	0.492	(0.115)
$\alpha_{1,30}$	0.404	(0.161)	0.51	(0.179)
σ_1	1.288	(0.178)	1.501	(0.100)
σ_5	1.267	(0.078)	1.52	(0.132)
σ_{15}	1.273	(0.077)	1.504	(0.231)
σ_{30}	1.171	(0.242)	1.344	(0.302)
$\phi_{0,U}$	0.373	(0.026)	0.268	(0.071)
$\phi_{1,U}$	2.00E-07	(3.81E-01)	571.55	(371.032)
$\phi_{0,D}$	0.69	(0.082)	0.432	(0.040)
$\phi_{1,D}$	1.00E-08	(3.13E-03)	6.56E-05	(7.56E-06)
Price Transition				
ϑ_L	0.427	(0.972)	0.707	(0.747)
ς_L	0.155	(0.477)	0.17	(0.357)
ϑ_H	0.603	(0.498)	0.594	(0.660)
ς_H	0.145	(0.206)	0.213	(0.378)
Lifting Cost (C)				
θ_1	0.032	(0.066)	1.64E-04	(7.76E-05)
θ_2	0.046	(0.202)	0.147	(0.286)
θ_3	1.588	(1.229)	3.775	(1.066)
Inactivity Cost (M)				
θ_4	0.26	(0.259)	0.386	(0.415)
Cost to Reactivate ($SC_{(2\to1)}$)				
θ_5	4.86	(1.131)	5.957	(2.629)
θ_6	0.087	(0.095)	0.024	(0.019)
Cost to Temporarily Deactivate ($SC_{(1\to2)}$)				
θ_7	1.774	(2.267)	2.594	(1.311)
Cost to Decommission ($SC_{(1,2\to3)}$)				
θ_8	7.923	(3.673)	9.703	(1.333)
Scale Parameter				
b	1.134	(0.376)	1.346	(0.300)
Not Estimated in Likelihood				
p_{HL}	0.272		0.062	
p_{LH}	0.160		0.100	
$\overline{P}$	0.031		1.143e-4	
μ_H	-3.203		-8.784	
μ_L	-3.772		-9.726	
β	.90		.90	

NOTES: These are the weighted averages of the estimates across 88 well groups. Using specification $C = \theta_1 + \theta_2/\overline{Q}^{\theta_3}$; $M = \theta_4$; $SC_{2\to1} = \theta_5(1+\theta_6)^A$; $SC_{1\to2} = \theta_7$; $SC_{1,2\to3} = \theta_8$. The standard errors are derived from the White (1982) misspecification consistent information matrix.

$q_w/\overline{Q}_w$ (different for single-well pools and multiwell pools).[30] The weighted average (across well types) of the coefficients in Equation (5) are displayed in Table 3. As expected, the older the well, the less production is expected from the well, for both oil and gas wells.

[30] The 99th percentile is used because there are a few outliers where q_w dramatically exceeds $\overline{Q}_w$. (That is, the 99th percentile of $q_w/\overline{Q}_w$ for gas wells in single-well pools, k_0, is 2.9 compared to a maximum of 66 and for gas wells in multiwell pools, k_1, is 25.2 compared to a maximum of 807.)

5.1.2. *Exogenous transition in reserves,* $f_{\overline{Q}}$. Apart from production, there are exogenous changes in reserves from, for example, more wells being drilled, reassessments, improved technology, or new discoveries. Changes in reserves from production are already accounted for by including f_q, so to estimate exogenous changes, $f_{\overline{Q}}$, the estimates of IER are used. A pool's IER is an estimate of the initial oil or gas in place multiplied by the recovery factor and does not include what has been extracted.

The current price of oil or gas might have different effects on the transition probability of remaining reserves. For example, under high prices, one would expect there to be more research and development into extraction technology, which would in turn increase the recoverable reserves. Once developed these technologies would remain available, even under low gas prices, and therefore, one would not expect there to be symmetrical decreases in reserves under low prices, but rather only smaller increases. On the other hand, higher prices would also result in the drilling of more wells, which would in turn reduce the per-well remaining reserves. I therefore estimate the distribution of the size of reserve increases separately from the distribution of the size of reserve decreases. As well as the likelihood of the size of a change, the transition probability, $f_{\overline{Q}}$, also includes the probability to increase, decrease, or remain the same. Depending on the type of pool (i.e., PSAC area, single- or multiwell, year discovered), 63% to 84% of the pool-year observations have no change in per-well IER.

The distribution of the natural logarithm of changes that did occur is depicted in Figure A5 in the Appendix and can be approximated by two exponential distributions spliced together. When there is an increase in reserves, the size of the increase, $\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})$, can be approximated by an exponential distribution, as when there is a decrease in reserves, and the size of the decrease, $-\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})$, can be approximated by a different exponential distribution. That is, when there is an increase (or decrease), $\Delta = \left|\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})\right|$ follows a distribution with density function

$$f_{\overline{Q}}(\Delta|\lambda) = \lambda \exp(-\lambda\Delta).$$

The current price is incorporated into the probability via λ, where

$$\lambda = \begin{cases} (\phi_{0U} + \phi_{1U}P)^{-1} & \text{when increase,} \\ (\phi_{0D} + \phi_{1D}/P)^{-1} & \text{when decrease.} \end{cases}$$

Therefore, using any observations of a reserve increase ($\overline{Q}_{it}^{IER} > \overline{Q}_{it-1}^{IER}$), I maximize the likelihood of the size of a increase as

$$L(\phi_{\mathbf{U}}) = \prod_i \prod_t \frac{1}{(\phi_{U0} + \phi_{U1}P_{t-1})} \exp\left(-\frac{\left|\ln\left(\overline{Q}_{it}^{IER}/\overline{Q}_{it-1}^{IER}\right)\right|}{(\phi_{U0} + \phi_{U1}P_{t-1})}\right).$$

And similarly, using any observations of a reserve decreases ($\overline{Q}_{it}^{IER} < \overline{Q}_{it-1}^{IER}$), I maximize the likelihood of the size of a decrease as

$$L(\phi_{\mathbf{D}}) = \prod_i \prod_t \frac{1}{(\phi_{D0} + \phi_{D1}/P_{t-1})} \exp\left(-\frac{\left|\ln\left(\overline{Q}_{it}^{IER}/\overline{Q}_{it-1}^{IER}\right)\right|}{(\phi_{D0} + \phi_{D1}/P_{t-1})}\right).$$

5.1.3. *Transition in price.* Analysis of the price of oil is a well-researched area, although there is little consensus for the best-fitting model. Models differ by allowing for mean reversion, nonstationary unit roots, underlying market fundamentals, unexpected jumps, or time-varying volatility, for example. To limit the number of states included in the model, I assume price

follows an exogenous first-order Markov process, which is an assumption for the formation of expectations for future prices: The producer bases its expectation on current prices. At the same time, producers have experienced periods of both low and high prices in the past. Therefore, I include a switching process between a high-price regime and a low-price regime in the Markov process. The regimes are determined depending on whether the price is above or below the average price observed from 1971 to 2007. Because we know which regime we are in simply by knowing whether the price is above or below the average price, there is no need to include "price regime" as a state variable in the model. That is, the final matrix of transition probability weights for price depends only on the current price. The transition probability of switching from regime H to L is simply the number of times that regime H was followed by regime L divided by the number of times the process was in regime H:

$$\hat{p}_{HL} = \frac{\sum_{t=1}^{T} I\{r_t = L, r_{t-1} = H\}}{\sum_{t=1}^{T} I\{r_{t-1} = H\}},$$

whereas, the opposite holds true for switching from L to H. For each regime, the parameters from a regression with deviations from the mean logarithm of price, $\wp_{t,r} = \log P_t - \mu_r$, are estimated:

$$\wp_{t,r} = \vartheta_r \wp_{t-1,r} + \varsigma_r \varepsilon_t, \tag{6}$$

where ε is i.i.d. $N(0, 1)$. The process is truncated so that price does not fall below $\underline{P} = 1\mathrm{E} - 6$ (and not zero because of the subsequent logarithm). The transition probability of price in regime r is

$$F_P(P_t|P_{t-1}, r) = \frac{\Phi\left(\left(\wp_{t,r} - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right) - \Phi\left(\left(\underline{\wp}_r - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right)}{1 - \Phi\left(\left(\underline{\wp}_r - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right)},$$

where Φ is the standard normal cumulative distribution function and $\underline{\wp}_r = \ln(\underline{P}) - \mu_r$.

The transition probability matrix is derived from a mixture of the distributions under high- and low-price regimes, including the transition probabilities between the two regimes:

$$F_P(P_t|P) = \begin{cases} p_{HH} F_P(P_t|P_{t-1}, r = H) + p_{HL} F_P(P_t|P_{t-1}, r = L) & \text{if } P > \overline{P}, \\ p_{LH} F_P(P_t|P_{t-1}, r = H) + p_{LL} F_P(P_t|P_{t-1}, r = L) & \text{if } P \leq \overline{P}. \end{cases}$$

.

5.1.4. *Transition in age.* To save computing time the age variable is discretized into the intervals $A = 1, 5, 15, 30$ for $1 \leq \text{age} < 5$, $5 \leq \text{age} < 15$, $15 \leq \text{age} < 30$, age ≥ 30, under the assumption that wells within these age intervals are similar. Oil and gas production over the life of a well typically follows an exponential decline, with the steepest decline within the first several years. Therefore, I make smaller intervals for younger wells, when the difference in age matters more.[31] These intervals also divide the sample into roughly four even groups (of 19%, 31%, 29%, and 18% of the observations in each age group, respectively). The transition probability of entering the next interval is $1/n_{years}$, where n_{years} is the number of years in the current interval.

[31] Also, when estimating production, q, from a well, the shorter intervals for younger wells helps capture this nonlinearity in production over the life of the well.

5.2. *Second Stage Estimation.* For each different well type, g, a different set of structural parameters, $\theta_{2^{nd}} = (C, M, SC_{(2\to1)}, SC_{(1,2\to3)})$, is estimated. The likelihood of observing the decisions d that were made for each well ($w = 1...W_g$) in the well group is maximized:

$$L(\theta_{2^{nd}}) = \prod_{t=1}^{T}\prod_{w=1}^{W_g} p(d_t^w | P_t, Q_t^w, A_t^w, \theta_{2^{nd}}, \hat{\theta}_{1^{st}}),$$

where p is the multinomial logit probability, given in Equation (3), that the choice for well w at time t is decision d. For each iteration of the likelihood there is a nested subroutine to find the fixed point to the Bellman equation (2). The model is in discrete time, and the producer chooses the operating mode on a yearly basis. In reality, this decision is in continuous time; however, a well is classified as an inactive well by the Alberta Energy Regulator if it has not reported any volumetric activity (production, injection, or disposal) within the last 12 months. Therefore, the data are assigned as follows: For a well in 2000, the current operating state, o, is the operating state in 1999, where the decision, d, is the operating state in 2000, given the average wellhead price of oil (or gas for gas wells) in 2000, the reserve size in 2000, and the age of the well in 2000.

The royalty rate is calculated using formulas specified by the Alberta Department of Energy (Alberta Energy, 2006). The rates range from 5% to 35% depending on the price of oil (or gas), when the reserve was discovered, and the volume of oil (or gas) produced. As this model is based on the expected production, and not the actual production, the royalty rate is the expected royalty rate.[32] The Alberta corporate income tax rate is 10% of taxable income whereas the federal corporate income tax rate is 22.12%. The combined federal and provincial tax rate on corporate income, τ, is set at 32.12% (Alberta Department of Energy, 2007).

Estimating the discount factor, β, along with the cost parameters is difficult. For example, both a high reactivation cost and a low discount factor will prolong reactivation. Therefore, for each well group, I estimate the cost parameters under seven candidate discount factors, ranging from 0.7 to 0.99. By examining the sum of the log-likelihoods across well groups for each candidate discount factor, a discount factor of 0.90 results in the highest total log-likelihood (illustrated in Appendix A.4).

The estimation requires specifying the functional form of the profit equation. I estimated the model under many different specifications that seemed reasonable and were flexible to incorporate features such as costs increasing as age increases and remaining reserves decrease. A parsimonious specification that led to timely convergence and high likelihood values is a specification where the lifting cost depends on the reserve size and age, $C = \theta_1 + \theta_2/\overline{Q}^{\theta_3}$; the fixed inactivity cost is a constant, $M = \theta_4$; the reactivation cost depends on age, $SC_{2\to1} = \theta_5(1+\theta_6)^A$; and deactivation and decommissioning costs are constant, $SC_{1\to2} = \theta_7$ and $SC_{1,2\to3} = \theta_8$. By construction of the multinomial logit (Equation (3)), identifying all fixed costs of the model is not possible. To identify the absolute costs, external information on actual well sale prices would be needed. The cost parameters are interpreted in million dollars, but also in relation to a normalized reactivation cost of zero for active wells (i.e., $SC_{(1\to1)} = 0$). Furthermore, the scale of the profit equation is already normalized because the coefficient on price is normalized (to one), which also means that I can estimate the scale parameter of the type I extreme value error term, ϵ.

5.3. *Third Stage Estimation: Maximizing the Full Likelihood.* The parameter estimates from the partial likelihood estimation are used as starting values in the maximization of the full likelihood function. I allow for one iteration of the maximization routine of the full likelihood function to determine a consistent estimate of the asymptotic covariance matrix for the estimates, which is used to determine consistent standard errors. The average estimates and standard errors of the 88 different well types, weighted by the number of observations, are displayed in Table 3.

[32] Formulas can be found in Alberta Energy (2006).

The coefficients were derived using price data scaled by one million dollars. The coefficient on price in the probability distribution for an exogenous increase in reserves, $\phi_{1,U}$, appears to be very different for oil and gas wells; however, because the prices are in millions of dollars, inverted, and taken to the negative power of Euler's number, the difference in the probability of an increase is not as large as these coefficients suggest. Nonetheless, gas reserve growth is more responsive to price changes than oil reserve growth, which is most likely because gas reserves are more difficult to estimate than oil reserves (Vanorsdale, 1987).[33]

It is important to note that the estimates in Table 3 do not represent the costs for switches that were actually made, but are the costs for a hypothetical well to switch to an arbitrary operating state (Kennan and Walker, 2011). Operators only choose to switch when the costs net of the payoff shocks are favorable, which would be less than the estimates in Table 3.

I find that on average the costs to decommission a well are higher than the costs to reactivate a well, and so one might expect that wells are more likely to be reactivated than decommissioned. However, the lifting costs increase as the remaining reserves decrease, and therefore, reactivating the well for a lower range of $\overline{Q}$ would result in paying more to extract than the price of gas or oil.

Firms could be postponing decommissioning because they intend to declare bankruptcy in the future; however, the number of orphan wells is relatively small in Alberta, implying that bankruptcy is not a very important option.[34] In other empirical contexts in which bankruptcy is an important option, the model would have to take the full portfolio of wells that a firm owns into consideration (e.g., a firm would not declare bankruptcy if it had many producing wells). In this case, to the extent that bankruptcy is an option, I am omitting an option that is available to active and inactive wells (i.e., the option to declare bankruptcy, at some cost, and avoid decommissioning costs), and by omitting this option, the estimated costs of an inactive or active well are biased downward and the decommissioning costs biased upward as compared to a model that incorporates this option. However, more important than interpreting the cost estimates is correctly simulating counterfactual scenarios, in which case the biased cost parameters to some extent account for the omitted bankruptcy option.

5.4. *Goodness-of-Fit Tests.* To test the dynamic programming model's ability to fit the data, the choice probabilities from the estimated dynamic programming model $p(d|s, \hat{\theta})$ are compared to the observed (nonparametric) estimates of the conditional choice probability function $\hat{p}(d|s)$. The nonparametric estimate $\hat{p}$ is the sample histogram of choices made in the subsample of wells with state s. Following Rust and Phelan (1997) and Rothwell and Rust (1997), by sample enumeration, if S is a collection of s cells, the nonparametric estimate of the choice probability is computed as

$$\begin{aligned}\hat{p}(d|S) &= \int_{s\in S} \hat{p}(d|s)\hat{F}(\mathrm{d}s|S) \\ &= \frac{1}{N_S}\sum_{i=1}^{N} I\{d_i = d, s_i \in S\},\end{aligned}$$

[33] Gas reserves are not only made up of "free" gas, but also the more difficult to measure "adsorbed" gas attached to the rock surface. There are other less probable reasons for differences in reserve-growth elasticities. For example, by construction of the model, newly drilled wells reduce per-well recoverable reserves, which combined with four times stricter well-spacing limits for gas wells (see Footnote 23) would reduce the probability of a reserve decrease for gas compared to oil. However, gas pools are on average four times larger than oil pools, so this is not likely to be the case. It is also not likely that the difference in reserve-growth elasticities is driven by a difference in the age of pools. Gas pools are slightly younger (84% of the gas pools were discovered after 1974 compared to 82% for oil), however not significantly.

[34] For example, in 2012, 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, 2013).

TABLE 4
ACTUAL VERSUS PREDICTED CHOICE PROBABILITIES

	Oil		Gas	
Current State	Observed	Expected	Observed	Expected
Active or Inactive				
Pr(Active)	0.6207	0.6205	0.6878	0.6822
Pr(Inactivate)	0.3683	0.3684	0.3026	0.3042
Pr(Decommission)	0.0110	0.0111	0.0096	0.0136
No. Obs.		150078		186274
χ^2		0.15		227.37
Marg. Sig.		0.93		0
Active				
Pr(Active)	0.9253	0.9256	0.9421	0.9330
Pr(Inactivate)	0.0691	0.0690	0.0534	0.0572
Pr(Decommission)	0.0056	0.0054	0.0046	0.0097
No. Obs.		96880		129322
χ^2		0.90		402.53
Marg. Sig.		0.64		0
Inactive				
Pr(Activate)	0.0660	0.0652	0.1105	0.1128
Pr(Inactive)	0.9132	0.9133	0.8685	0.8650
Pr(Decommission)	0.0209	0.0216	0.0210	0.0222
No. Obs.		53198		56952
χ^2		1.67		7.25
Marg. Sig.		0.44		0.03

NOTES: The chi-square test statistic was calculated as $\chi^2 = N\sum_{d=1}^{3}\{(\text{Obs}_{Pr(d)} - \text{Exp}_{Pr(d)})^2/\text{Exp}_{Pr(d)}\}$, where N is the number of observations.

where $\hat{F}(\mathrm{d}s|S)$ is the nonparametric estimate of the conditional probability distribution of s given S, equal to the number of observations in cell ds divided by the total number of observations in all cells that comprise S. This is compared to the estimates of the choice probability from the dynamic programming model:

$$p(d|S,\hat{\theta}) = \int_{s\in S} p(d|s,\hat{\theta})\hat{F}(\mathrm{d}s|S)$$
$$= \frac{1}{G}\sum_{g=1}^{G}\frac{1}{N_g}\sum_{i=1}^{N_g} p(d|s,\hat{\theta_g})I\{s_{ig}\in S\},$$

where $p(d|s,\hat{\theta_g})$ is the probability given by Equation (3) and $\hat{\theta_g}$ are the estimates of the structural parameters for group g.

Table 4 shows the observed choice probabilities alongside the expected choice probabilities from the dynamic programming model for oil and gas wells. The three panels in Table 4 show the cases that S is a collection of all possible s cells, that S is a collection of wells that are active, and that S is a collection of wells that are inactive. The dynamic programming model does a very good job at predicting the overall observed choice probabilities. In predicting the operating state all wells, the chi-squared test cannot reject the dynamic programming model at the 93% significance level for oil wells and at the 70% significance level for gas wells. In the case of gas, as well as when the sample is separated by current operating state, the chi-squared test rejects the dynamic programming model; however, the observed and expected probabilities do not differ by more than 0.01.

5.5 *Comparing Actual and Simulated Data Over Time.* The estimated model performs extremely well in replicating the period-by-period decisions. However it is also important to show

that the model can predict decisions over time and not just predict a onetime snapshot. Simulating the composition of wells over time is a more difficult task because any deviations from the real data will accumulate after each period, particularly when there is hysteresis. Using the state of the industry in 2000 as a starting point, I simulate the progression of wells, quantity extracted, and remaining reserves over seven years (Figure 1). Each well's path is simulated individually by a series of pseudo-random draws from its type-specific probability density of the state transitions and its subsequent type-specific probability density of operating-state choice.[35]

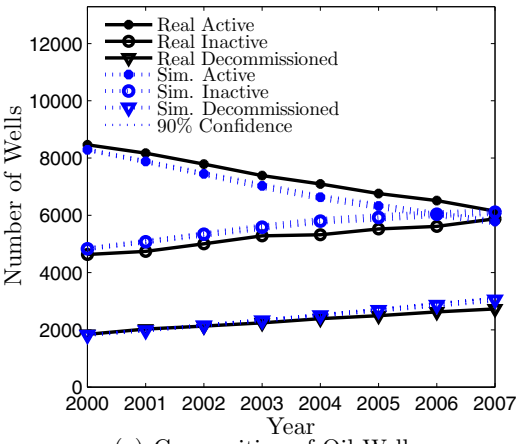
The dynamic programming model is able to match the data closely for the first year of the simulation for both oil and gas wells, but over time slightly overpredicts the number of inactive oil wells and underpredicts the number of inactive gas wells. The greatest discrepancy between the observed and predicted data, although still modest, is found in the underprediction of total oil production and overprediction of total remaining gas reserves (Figures 1 c and f). The difference in total oil production can be partially explained by the accumulated underprediction of the number of active oil wells. However, it is more likely driven by the fact that the sample used to estimate the parameters is different from the sample used in this simulation. In order to make a comparison between simulated and real data over time, I must restrict the sample used to estimate the parameters to a smaller subsample. First, because I am not modeling the decision to drill new wells, I restrict the sample to wells that were already drilled as of the year 2000, and therefore the simulation sample is composed of older wells on average. Second, because some of the pools in the estimation sample are missing reserve estimates in some years, I restrict the sample to only wells that have reserve estimates available for every year from 2000 to 2007.[36] The well-average of the ratio of log oil production to log oil reserves is 5.6% larger in the simulation sample than in the estimation sample, which would explain why the simulated production is underpredicted (i.e., the parameters governing production are set to be too small for this subsample). The difference between the estimation sample and the simulation sample also appears to be driving the discrepancy in the remaining gas reserves. The well-average change in the remaining gas reserves from year to year is 5% larger in the estimation sample than in the simulation sample, which would explain why at the end of the simulation the simulated reserves are higher. This exercise illustrates that the model is more reliable in predicting the extensive margin over the intensive margin.

5.6 *Policy Application of the Model.* If the option to mothball a well did not exist, then there would be a state of nature, L, of low enough prices, remaining reserves, and expectations for their increase that the value of operating the well, $V_L(1)$, would be less than the value of decommissioning, $V_L(3)$, and the well would be decommissioned. When the option to mothball exists, then such a well (with $V_L(1) < V_L(3)$) would not necessarily be decommissioned because leaving it inactive could be more valuable (less costly) than decommissioning, $V_L(1) < V_L(3) < V_L(2)$. However, the values of course depend on the current state of nature, and it could be the case that when prices or recovery rates become high enough, H, and these same wells would be reactivated in a high state, $V_H(3) < V_H(2) < V_H(1)$. However, there is a problem when there are wells for which even in a high state it is preferable to decommission them, but even more preferable to leave them inactive, $V_{L,H}(1) < V_{L,H}(3) < V_{L,H}(2)$.

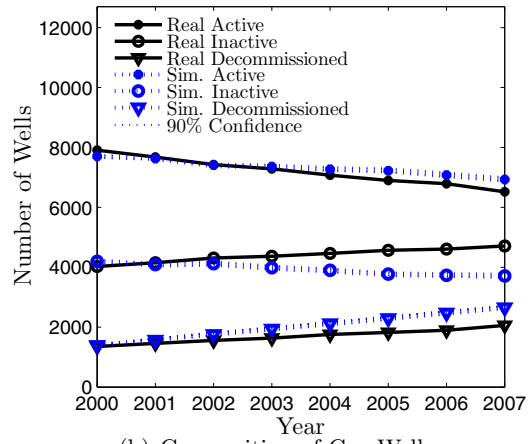
It could be the case that if the externalities associated with mothballing are internalized, then the option to decommission would become preferred and wells that would not be reactivated would be decommissioned, $V_{L,H}(1) < V_{L,H}(2 \text{ \& internalized costs}) < V_{L,H}(3)$. There are various policies that a regulator could try that would persuade the inactive wells, $V_H(1) < V_H(3) < V_H(2)$, to be decommissioned, $V_H(1) < V_H(2) < V_H(3)$, such as by increasing inactivity costs or subsidizing decommissioning costs. But without knowing the social cost of an inactive well, policies might be too bold and result in too many wells being prematurely decommissioned. Specifically, the worry of regulators is that these policies might encourage

[35] Each well path is simulated 30 times to obtain a 90% confidence interval around the average simulation.

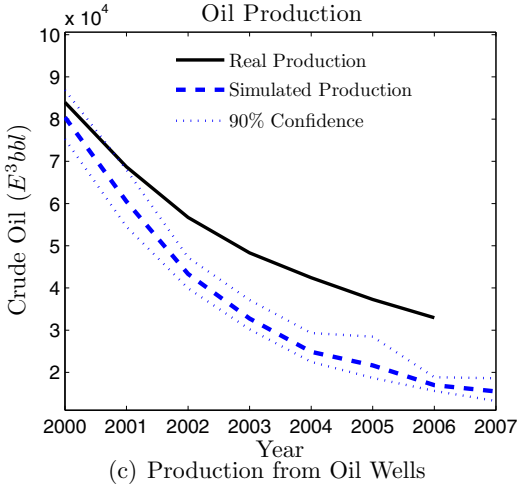
[36] Otherwise, there would be artificial drops in total reserves in years when data on reserves are missing.



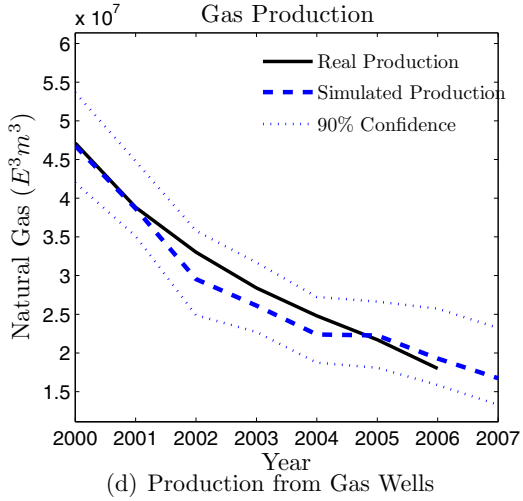
(a) Composition of Oil Wells



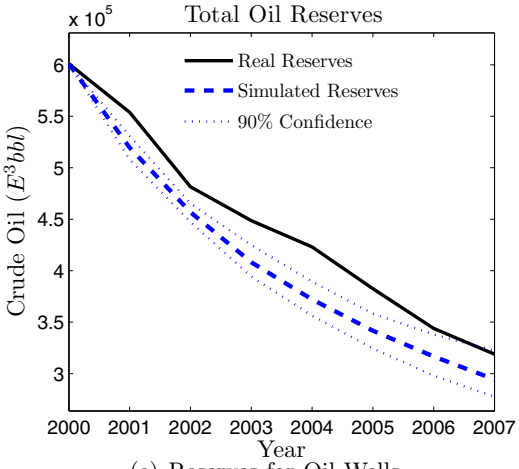
(b) Composition of Gas Wells



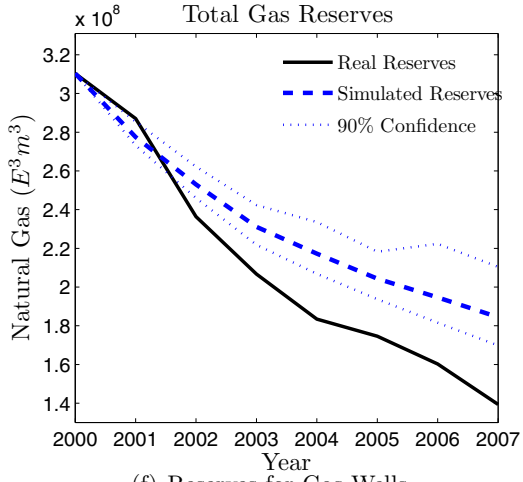
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells



(f) Reserves for Gas Wells

FIGURE 1

COMPARISON OF ACTUAL DATA AND SIMULATED DATA

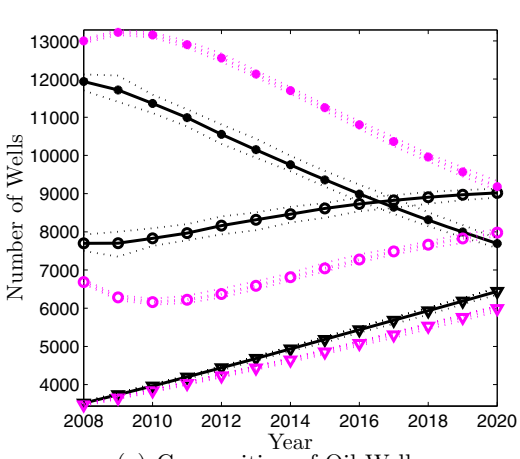
wells that would otherwise be producing, $V_H(3) < V_H(2) < V_H(1)$, to be decommissioned, $V_H(2) < V_H(1) < V_H(3)$. This might occur because the value of an active well depends on the option to mothball, so when the option to mothball becomes more expensive, the value of an active well also decreases. Moreover, wells that would have otherwise been temporarily deactivated in a low state might be decommissioned and then not able to reactivate in a high state. Premature decommissioning is an undesirable outcome especially when the regulator places a large value on domestic production.

To evaluate a policy based on its ability to encourage decommissioning without jeopardizing future production really depends on the well in question. Importantly, the value of a well in each of its operating states depends on the current state of nature as well as the payoff shock, ϵ. Because there is a wide distribution in the age of wells and the remaining reserves, one policy will affect each value differently. Therefore to evaluate a policy, it is important to look at the current distribution of wells in question and to look at how the policy affects the sum total of all wells. To do so, I simulate the choices for wells under different counterfactuals to determine the total effect on wells in the sample. If a significant proportion of the wells in the sample fall into the category of $V_{L,H}(1) < V_{L,H}(3) < V_{L,H}(2)$, then under a high state of nature, we would not see many reactivations. We can also see how changes to parameters in the model affect the operating choices, current production, and cumulative production overall. An important caveat is that these simulations are made under the assumption that the estimated transition probabilities reflect the actual transition probabilities of the operator. It could be the case, however, that an operator is more optimistic about reserves or prices and puts higher weight on future high states relative to those estimated in this article. Therefore the hypothesis that operator behavior can be explained by their waiting for better conditions is tested under the assumption that operators forecast the future using the same transition probabilities that are estimated in the article. The hypothesis that operator behavior can be explained by optimism about the future is not tested.

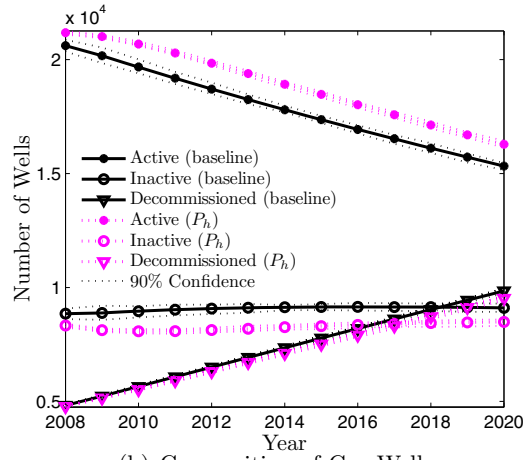
5.6.1 *Twelve-year forecasts of ideal scenarios.* The model is used to simulate the industry under different scenarios that operators claim to be waiting for: high prices, improved recovery rates, and reduced reactivation costs. These ideal scenarios are compared to a baseline scenario where prices, recovery factors, and the state of the industry are simulated to progress using only the estimated parameters.

In the first scenario, each well-type faces the costs estimated for the type, but they now receive a constant "high price" of \$197.72/bbl for oil and \$462.44/e^3m^3 for gas produced.[37] At the end of the 12-year forecast, averaged over 50 simulations, the high price for oil is 3.2 times the average forecasted price of the baseline. As illustrated in Figure 2 and listed in the first two rows of Table 5, the high price case results in 19% more oil wells that are active than the baseline prediction. The high price for gas wells is on average 2.0 times the average forecasted price of the baseline after 12 years, but only leads to 6% more wells that are active. The annual oil production by the 12th year is 21% higher, and there is 21% more cumulative oil production over the prior 12 years. In the case of oil, the growth in reserves does not compensate for the increased production, so that after 12 years there are 24% fewer oil reserves than in the baseline case. For gas reserves, the high price results in more reserve growth showing that the expected returns from investments in exploration or enhanced recovery are greater for gas than oil. At the end of the 12 years, there are 120% more gas reserves and 78% more production than in the baseline case. It is fascinating that in spite of the active wells being more productive, the increased reserves and higher prices are not sufficient to induce many inactive gas wells to be reactivated. This is particularly striking in the case of gas wells where, with 78% more productive wells and 120% increased remaining reserves, there are only 6% fewer inactive wells than in the baseline case.

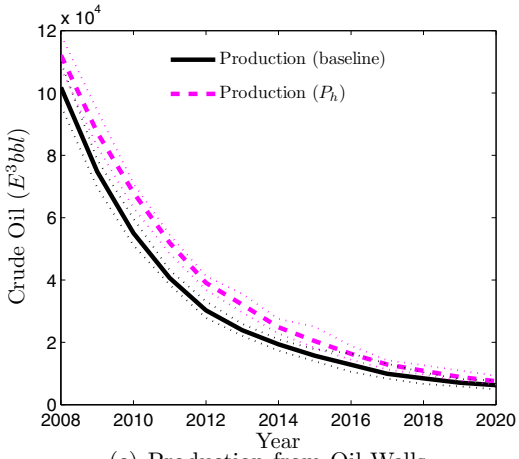
[37] This is equal to the U.S. Energy Information Administration's Annual Energy Outlook of 2009 "high price" case in 2030 for oil and 1.5 times the "high price" for gas.



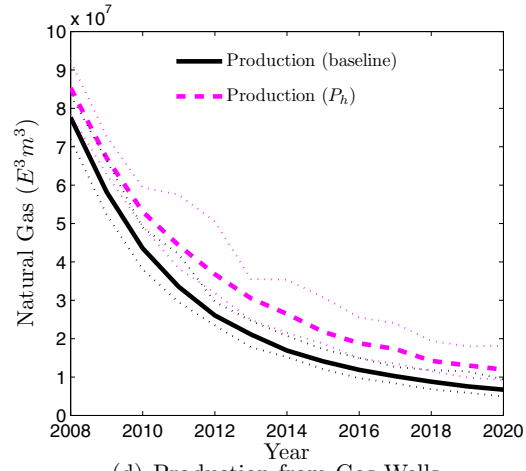
(a) Composition of Oil Wells



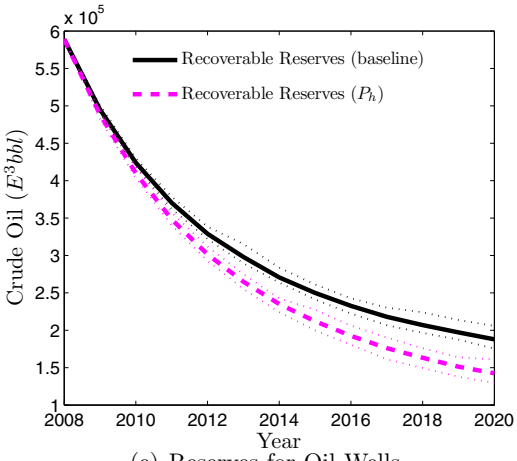
(b) Composition of Gas Wells



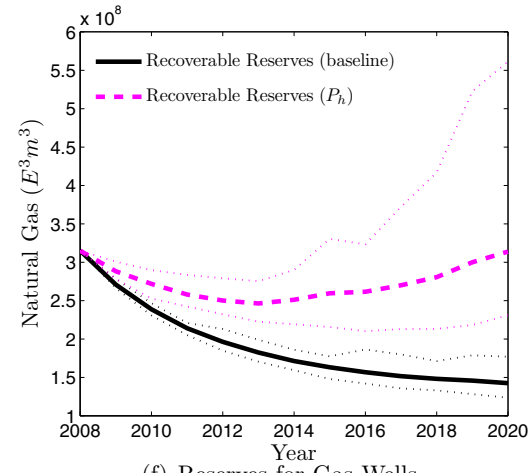
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells



(f) Reserves for Gas Wells

FIGURE 2

FORECAST UNDER BASELINE AND HIGH-PRICE SCENARIOS

TABLE 5
TWELVE-YEAR FORECAST OF COUNTERFACTUAL SCENARIOS (% △ FROM BASELINE)

Counterfactual Scenario	Well Type	No. Active	No. Inactive	No. Decomm.	Remaining Reserves	Annual Prod.	Cumulative Production
High prices (2.1−3.3×baseline P)	Oil	19%	−12%	−7%	−24%	21%	21%
	Gas	6%	−7%	−3%	120%	78%	31%
High recovery factors (100% recovery)	Oil	17%	−10%	−7%	514%	411%	164%
	Gas	7%	−6%	−6%	418%	387%	275%
Low reactivation ($.75\times SC_{(2\rightarrow 1)g}$)	Oil	19%	−7%	−12%	−13%	20%	9%
	Gas	9%	−4%	−10%	−11%	14%	7%
Low decommissioning ($.75\times SC_{(1,2\rightarrow 3)g}$)	Oil	−17%	−20%	48%	14%	−17%	−5%
	Gas	−18%	−20%	46%	10%	6%	−2%
Low annual inactivity ($1.25\times M$)	Oil	6%	−9%	5%	−4%	−5%	2%
	Gas	5%	−13%	3%	3%	11%	2%

NOTES: Values represent the percent difference between the counterfactual scenarios in the first column and the baseline scenario. Values are averages over 50 simulations. The columns of values represent the difference in the number of active wells in year 12, inactive wells, decommissioned wells, remaining reserves in year 12, annual production in year 12, and cumulative production over 12 years.

In a second scenario (Table 5, rows 3 and 4) a hypothetical technology change allows for all of the oil or gas-in-place to be recovered. To date, according to the data, recovery rates range from 15% to 95% with an average of 67% for gas and from 0.01% to 90% with an average of 12% for oil. In the hypothetical scenario, recovery rates are simulated to be 100% of the oil and gas that is in place. In the case of gas, increasing the recovery rate to 100% increases the remaining recoverable reserves by 418% and increases the annual production from producing wells by 387% (275% cumulative). But this significant increase does not induce the reactivation of many inactive gas wells (there are only 7% more active wells at the end of the period than in the baseline case). In the case of oil, the increased recovery rate increases remaining reserves by 514% and increases annual production by 411% (164% cumulative), but the number of active wells only increases by 17%. 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.

However, technology might not only improve recovery factors, but might also decrease the cost to reactivate a well. Therefore, I simulate the industry when the reactivation costs for all well groups are reduced by 25% (Table 5, rows 5 and 6). In the case of gas, after 12 years of lower reactivation costs, there are 9% more active wells, 4% fewer inactive wells, and 10% fewer decommissioned wells. Interestingly, the additional production from these wells is only marginal: there is only 14% more production in the last year of the simulation (7% more cumulative production). The reactivated oil wells are slightly more productive than gas wells: After 12 years there are 19% more active wells, and 20% more production (only 9% more cumulative production than in the baseline case). Corresponding with the increased cumulative production, there are less remaining reserves at the end of the 12-year period (a 11% to 13% reduction). 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 to assess the probability of an increase in prices or recovery rates.[38]

It is also interesting to see how responsive the model is to changes in the cost of decommissioning the well. I simulate the 12-year forecast with decommissioning costs being 25% cheaper than in the baseline case. I find that the number of decommissioned wells is very elastic to decommissioning costs, as a 25% reduction in cost results in 46% to 48% more decommissioned wells. Decreasing decommissioning costs might be unappealing to a regulator because not only

[38] Cost data are very hard to come by. For example, PSAC publishes average drilling and completion costs for 46 "typical" wells for $750 per year; however, these data would not shed light on the reactivation costs, which could vary widely depending on the well.

does the number of inactive wells decrease but also the number of active wells. This scenario results in 20% fewer active wells, and 2% to 5% less production.

Instead, increasing the costs of leaving a well inactive could increase the number of decommissioned wells without decreasing the number of active wells. To examine how responsive the operating choice is to the cost of leaving a well inactive, I simulate a 12-year forecast under a scenario where inactivity is 25% 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 in favor of maximizing production because, under this scenario, the number of decommissioned wells increases (by 3% to 5%) as does the number of active wells (by 5% to 6%). 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 2%), indicating that the average reactivated well is considerably less productive.

6 CONCLUSION

The decision that oil and gas producers make for the operating state of their wells can be categorized as a classic example of an irreversible investment under uncertainty. Restarting production or finally decommissioning a well is an expensive endeavor and is made with uncertainty in future recovery technology and prices. I show that this decision can be modeled by a real options formulation, and the structural parameters of the model can be estimated using data on operating decisions from oil and gas wells in Alberta. Indeed, the operating decisions made for 84,000 wells in Alberta can be replicated by modeling well operators as dynamic optimizers. Within-sample goodness-of-fit tests show that the model is able to closely predict actual operating choices.

The example of whether to activate, temporarily deactivate, or permanently decommission is used to demonstrate real options in textbooks and classrooms; however, the case of firms using temporary deactivation as a way to avoid paying for permanent decommissioning has been ignored. The motivation of this article was to determine the rational for leaving oil and gas wells inactive; either they could be a blessing, if they eventually are reactivated and contribute to our energy supply, or they could be a curse, if they are never reactivated, cause environmental degradation, and must undergo costly decommissioning. With the estimated structural parameters, I can predict how the operating choices might change under different conditions. I find that increased oil and gas prices and recovery rates might increase per-well annual production, but will not substantially increase the number of active wells. For example, doubling the gas price results in a 120% increase in recoverable reserves, but only a 6% increase in the number of inactive wells. On the other hand if it became cheaper for wells to be reactivated, we would have more active wells, but these wells would likely not be very productive, and total production would not increase as much. The cost of decommissioning plays an important part in determining the number of decommissioned wells; however, a policy to decrease the cost of decommissioning a well would result in not only fewer inactive wells, but also fewer active wells, making such a policy less appealing to a regulator in favor of production. Conversely, a policy of increasing the cost of mothballing a well would increase the number of active wells as well as decrease the number of inactive wells.

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 sunk cost of decommissioning is too high to warrant undertaking. Should there be externalities from idling the wells (such as continued contamination of groundwater) that are not accounted for in the decision, then this behavior may not be socially optimal. This article demonstrates that for the majority of inactive wells, temporary closure is, in effect, permanent closure. Advances in hydraulic fracturing and horizontal drilling have prompted a new surge in drilling for oil and gas, which has resulted in much debate and controversy, particularly in regards to the immediate environmental impacts.

Less attention has been given to concerns for the final cleanup and reclamation of these wells—unwarrantedly so given that in many of the areas where wells are being drilled, the financial bonds meant to ensure cleanup were set over half a century ago. The occurrence of firms not internalizing their decommissioning costs is likely generalizable to other industries that have high cleanup costs and are also allowed extended temporary closures.

APPENDIX

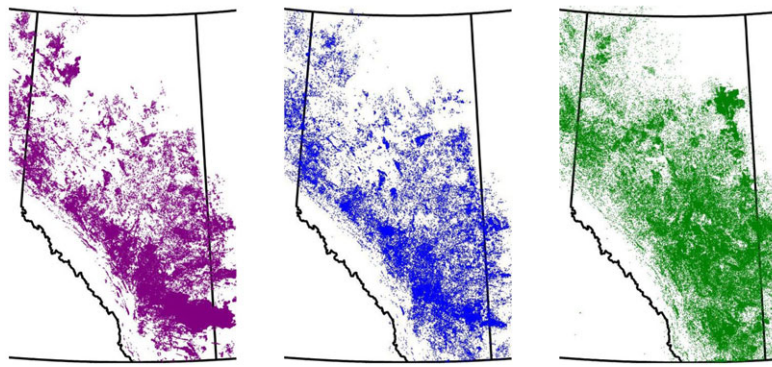
A.1. *PSAC Areas.* See Table A1 and Figure A1.

TABLE A1
CHARACTERISTICS OF PSAC AREAS

PSAC Area	Surface	Hydrocarbon	Characteristics
1	Rocky Mountains	Deep gas	Strict environmental regulations
2	Ranching, farming and forest	Oil and gas	Easily accessed
3	Agricultural prairie grassland	Gas and medium/heavy oil	Easily accessed
4	Prairie and woodland	Gas and heavy oil	Easily accessed
5	Agricultural	Oil and gas	Most densely populated area
6	Prairie and woodland	Shallow gas	Only winter drilling
7	Agricultural and logging	Oil and gas	Often no road access and winter drilling



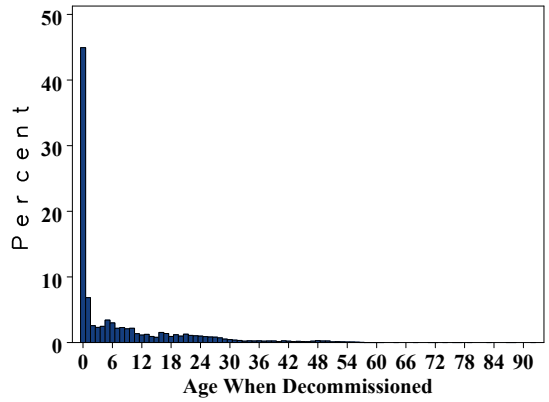
FIGURE A1
PSAC AREAS



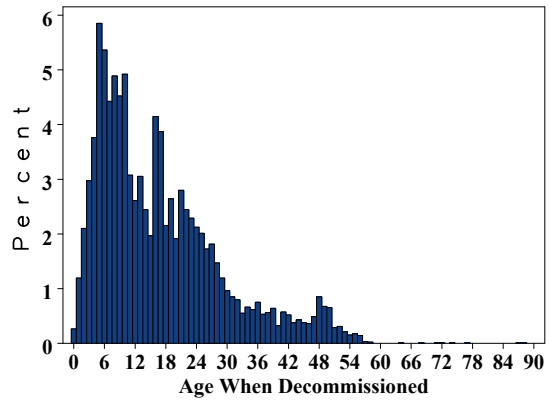
(a) Active Wells (150,997) (b) Inactive Wells (95,575) (c) Decommissioned Wells (103,885)

FIGURE A2
THE LOCATION OF OIL AND GAS WELLS IN ALBERTA IN 2007 BY OPERATING STATE

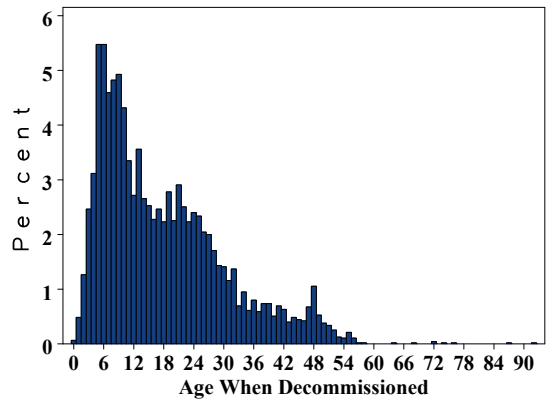
A.2. *Subsample as Compared to Full Sample.* See Figure A3.



(a) Full Sample



(b) Wells in Full Sample that Produced

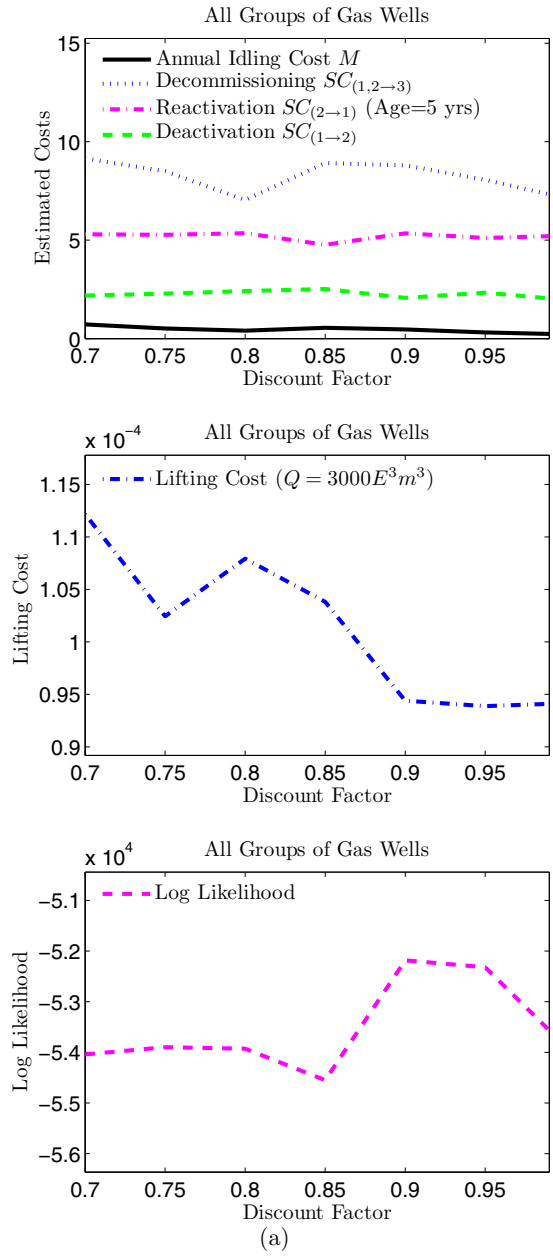


(c) Subsample

FIGURE A3

HISTOGRAM OF AGE WHEN DECOMMISSIONED

A.3. *Choice of Discount Factor.* The optimal discount factor varies by the different well groups, and no one discount factor would result in the highest likelihood for all groups separately. However, by summing the log likelihoods across the well groups by different fixed discount factors, a discount factor between 0.90 and 0.95 has the highest log likelihood.



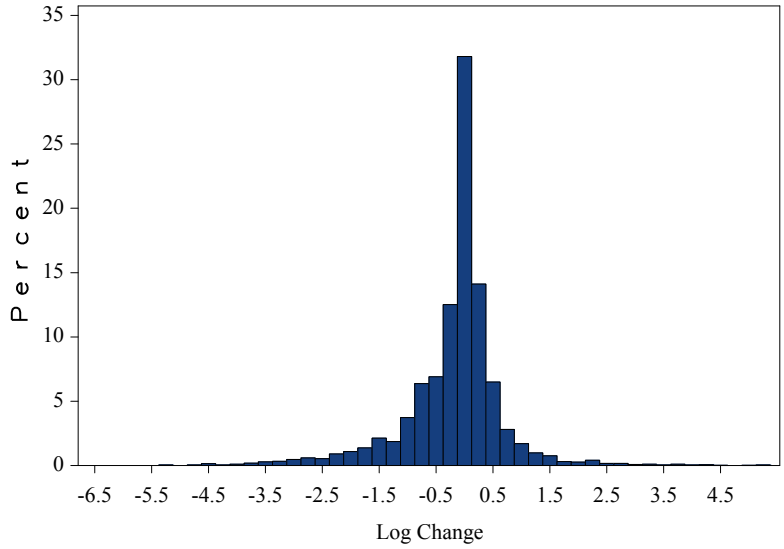
(a)

FIGURE A4

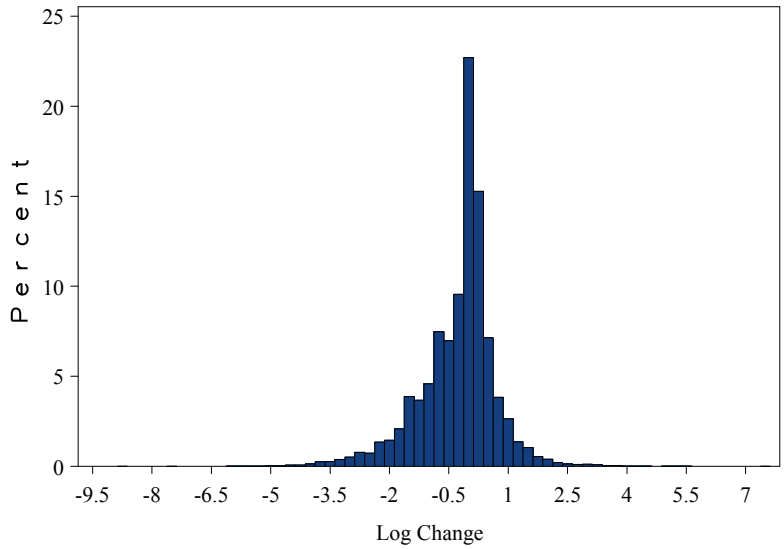
EFFECT OF USING DIFFERENT DISCOUNT FACTORS ON RESULTS FROM ALL GAS WELLS

Therefore, the estimation presented in this article uses a constant discount factor of 0.90 across all of the different well types. The summed log likelihoods by discount factor for all gas well groups are displayed in Figure A4. Also depicted are the average estimated costs across the well groups by discount factor. The reactivation costs are for inactive wells, five years of age, and the lifting costs are for wells with per-well reserves of 3 million m^3.

A.4 *Modeling the Probability of Transition of Recoverable Reserves.* See Figure A5.



(a) $\log\left(\frac{\overline{Q}^{IER'}}{\overline{Q}^{IER}}\right)$ for Oil Pools



(b) $\log\left(\frac{\overline{Q}^{IER'}}{\overline{Q}^{IER}}\right)$ for Gas Pools

FIGURE A5

HISTOGRAMS OF THE NATURAL LOGARITHM OF ANNUAL CHANGE IN INITIAL ESTABLISHED RESERVES (NOT INCLUDING OCCURRENCES OF NO CHANGE)

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Exhibit 2

Excerpt from Direct Testimony of Adam Peltz, Environmental Defense Fund, before the New Mexico Oil Conservation Commission in Case No. 24683

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC **CASE NO. 24683**

DIRECT TESTIMONY OF ADAM PELTZ

Table of Contents

BACKGROUND AND QUALIFICATIONS ……2

SUMMARY OF TESTIMONY AND OPINIONS ……4

OVERVIEW OF ORPHAN WELL PROBLEM ……..…7

19.15.2 NMAC—GENERAL PROVISIONS FOR OIL AND GAS OPERATORS ……..34

19.15.8 NMAC—FINANCIAL ASSURANCE ……..37

19.15.8.9.C NMAC – Active Wells ……37

19.15.8.9.D NMAC – Marginal Wells and Inactive Wells ……...……40

19.15.8.9.E NMAC – Inactive Wells and Wells in Approved and Temporarily Abandoned Status ……53

19.15.8.9.F & -G NMAC ……..60

19.15.9 NMAC—WELL OPERATOR PROVISIONS ……60

19.15.25 NMAC—PLUGGING AND ABANDONMENT OF WELLS ……..64

List of References ……75

19.15.8.9.E NMAC – Inactive Wells and Wells in Approved and Temporarily Abandoned Status

Q: Turning to Subsection E of 19.15.8.9 NMAC , changes are also proposed for "Inactive wells and wells in approved and temporarily abandoned status," what amendments do Applicants propose?

A: The proposed amendments shown in redline and strikeout:

19.15.8.9.E.~~D.~~ Inactive wells and wells in approved and expired temporarily abandoned status. An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years,~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC, in one of the following categories:

(1) a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E~~D~~ of 19.15.8.9 NMAC.~~:~~

~~**(a)** $150,000 for one to five wells;~~

~~**(b)** $300,000 for six to 10 wells;~~

~~**(c)** $500,000 for 11 to 25 wells; and~~

~~**(d)** $1,000,000 for more than 25 wells.~~

Q: What is the purpose of these modifications?

A: The proposed changes address wells that are inactive and wells in approved and expired temporary abandonment status – wells that are inherently more at risk of becoming orphaned, and therefore need increased financial assurance to protect the State from assuming the cost to sufficiently plug and abandon these wells.

There are non-substantive amendments in Subsection E. In the first paragraph, the amendments ensure that the section is covering all non-productive wells, i.e., inactive, approved TA and expired TA wells. In Paragraph (1), the term "one well plugging financial assurance" is

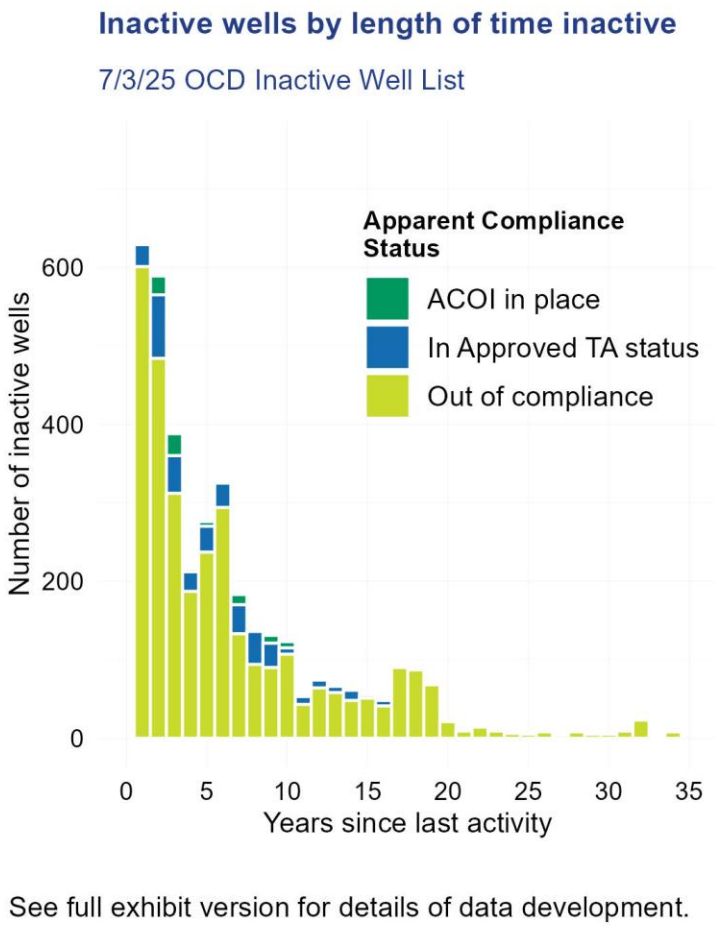
used for consistency with terminology in the Oil and Gas Act and within 19.15.8 NMAC.

The substantive changes in Paragraphs (1) and (2) are in amounts of financial assurance coverage. As elsewhere in the Revised Application, single well financial assurance is set at approximating OCD's average cost of plugging for all wells at $150,000. A blanket financial assurance option is included for administrative and cost efficiency, as above.

Subsection D establishes "categories of financial assurance" as the Commission is authorized to do under the Oil and Gas Act. Under the act, the Commission "shall" establish by rule "a blanket plugging financial assurance for temporarily abandoned status wells" "at amounts greater than fifty thousand dollars ($50,000)."[116] And the Commission "shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years . . . ."[117] The legislature, by setting a floor, not a ceiling, on bonds for TA wells has recognized the increased risk to the State these wells represent. And, by requiring a one well financial assurance for wells that have been in TA status for more than two years, the legislature has recognized that the longer a well is in TA status, the greater the risk.

While the legislature has recognized the increased risks that come from wells in **approved** TA status, the vast majority of wells on OCD's Inactive Well List are either in **expired TA status,** or (in far more cases) are just **inactive** with no apparent formal status or other agreed compliance order. Wells in expired TA status or that are just inactive are out of

[116] NMSA 1978, § 70-2-14(A).
[117] *Id.* At the election of the operator, the Commission may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status. *Id.*



Apps' Ex. 10

compliance with the Commission's rules and therefore are inherently riskier than wells in approved TA status where operators have followed the rules of the road. As discussed by Applicants' expert, Tom Alexander, approximately 3,200 wells out of the approximately 3,700 wells on the Inactive Well List are out of compliance, totaling *86%* of the wells in inactive status. Ninety-nine percent of the 350 operators with a well on this list have at least one inactive well out of compliance[118]. The data is shown again in the figure above (Apps' Ex. 10), and the

[118] These wells are out of compliance with 19.15.25 NMAC requirements to plug and abandon (even though some of the responsible operators may not be out of compliance for purposes of the compliance determination in 19.15.5.9.A(4) NMAC).

table below, which is Applicants' Exhibit 7.

OCD INACTIVE WELL LIST (15+ months inactive)
Listed wells and apparent compliance status
7/3/25

Well Subset	No. of wells	% of total inactive wells	No. of associated operators	%
Total well count (from Inactive Well search output – appears to represent wells other than Plugged & Released, Cancelled, and Never Drilled statuses)	**74,582**	n/a	n/a	n/a
Total inactive wells (15+ months)	**3,765**	**100%**	**350**	**100%**
Total approved TA wells* on Inactive Well Search list	419	11%	89	25%
Total expired TA wells* on Inactive Well Search list	155	4%	67	19%
Total wells under ACOI** on Inactive Well Search list	99	3%	3	1%
Wells on Inactive Well Search list with unusual status (Drilled, New, or Plugged) - *excluded from total below*	13	< 0.5%	11	3%
Total inactive wells apparently out of compliance (without ACOI or non-expired TA status)**	**3,234**	**86%**	**346**	**99%**

*The approved and expired TA status wells listed on OCD Inactive Well Search is only a subset of all wells labeled by OCD as having TA status, per OCD's Well History datafiles, and per a July 3rd search of OCD's Well Permitting Search for all TA wells.

** ACOI (Inactive Well Agreed Compliance Order) coverage was determined by the difference between wells included on 2 back-to-back queries of OCD's Inactive Well Search for wells 15+ months inactive— one set to include ACOI wells and one set to exclude them. Wells absent from the "Exclude ACOI" version of the list are presumed to have a compliance order in place.

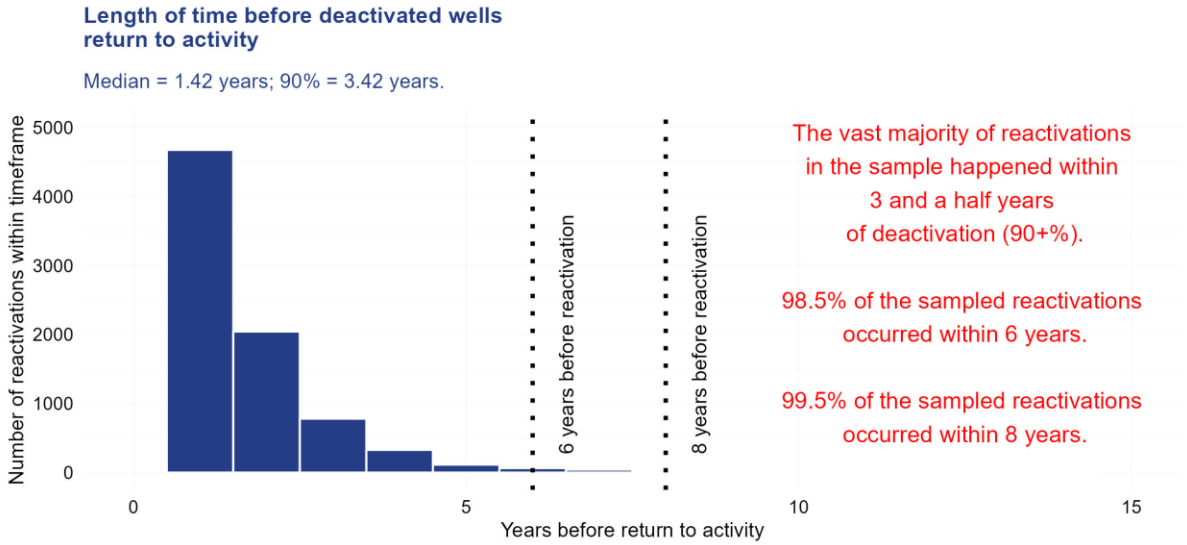
*** Some wells with an ACOI are also listed in expired TA status, so this total is slightly less than the sum of the preceding rows.

Apps' Ex. 7

It is these wells – wells in approved TA, expired TA, and inactive wells that have never gone into TA status – that by all measures are high risk and which should have full-cost financial assurance to protect the State. Requiring full-cost financial assurance for non-productive wells is increasingly common in major hydrocarbon-producing states. Wyoming generally requires full-cost financial assurance for idle wells.[119] North Dakota limits to seven the number of idle wells on blanket bonds.[120] The recently passed legislation in Texas, SB 1150, requires the TRRC to undertake rulemakings on idle wells generally and, in particular, on transfer, including considerations of financial assurance.[121]

[119] Wyo. Code R. § 055-0001.3 §4 (2020).
[120] N.D. Admin. Code 43-02-03-15(2) (2024).
[121] S.B. 1150, 89th Legis., 2025 Sess. (Tex. 2025).

Idled wells are at significantly increased risk for orphaning, since they do not produce any revenue at all. An EDF analysis of idled wells in New Mexico (*see* Applicants' Exhibit 13) found that most wells, if they are reactivated, the operators do so within 2 years, and after 5 years it is highly unlikely the well will produce again. The analysis found that for wells that were idled *and then later reactivated* between 2010 and 2024, over 90% reactivated within 3.5 years. Reactivations dropped off exponentially after only 2 years of inactivity.

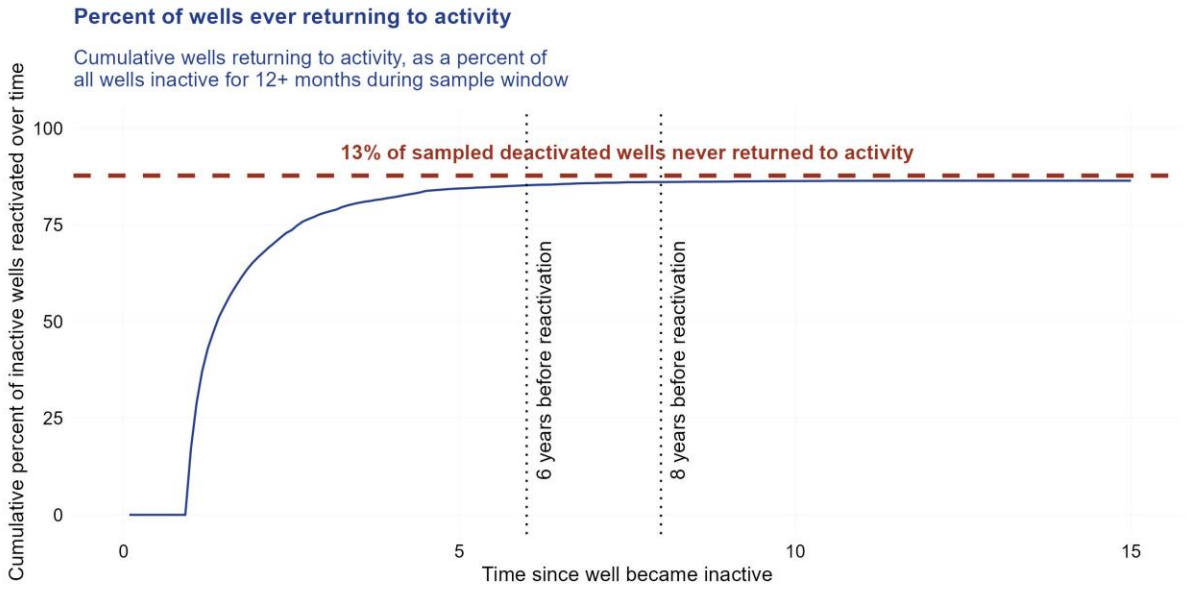


Histogram of length of time inactive prior to return to activity, across sample of wells that reactivated following 12+ months of no production.

Based on analysis of production data from 2010-2024, for wells spudded prior to 2017.

Apps' Ex. 13

Looking at all instances of wells becoming inactive for 12+ months after January 2010 (those spudded prior to 2017), 13% of the sampled wells *never* returned to activity. Of those that did reactivate, the vast majority did so within 3.5 years (90+%). Moreover, for purposes of Applicants' proposal requiring wells to be plugged after 8 eight years of inactivity, the analysis shows that functionally all of the wells that reactivated (99.5%) did so within 8 years of last activity.



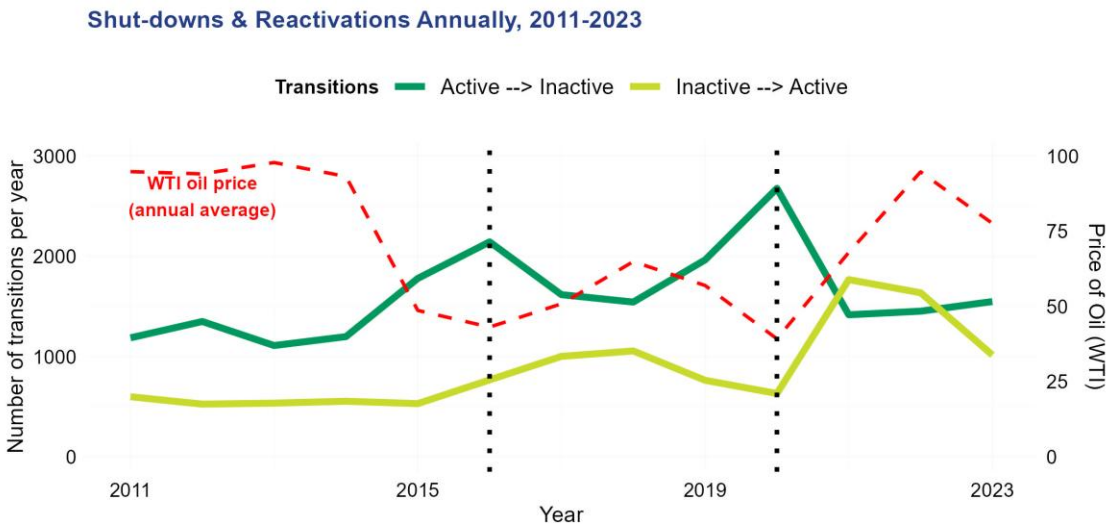
Apps' Ex. 13

The New Mexico analysis is consistent with previous EDF analysis in Texas[122] and Louisiana[123] that also found that after five years, the chance of an idle well ever returning to service is under 15%, and that post-idling production is usually only a tiny fraction of total lifetime production.

[122] Colin Leyden & Adam Peltz, *Don't Mess With Texas: Bill Begins to Tackle the Clean Up Challenge of Inactive Oil and Gas Wells,* EDF (May 29, 2025), https://blogs.edf.org/energyexchange/2025/05/29/texas-takes-a-step-forward-senate-bill-1150-begins-to-tackle-the-inactive-well-challenge/.

[123] Aaron Wolfe, Margaret Coleman, Maureen Lackner, Adam Peltz & Lauren Beatty, EDF, Louisiana's Inactive Wells: Steps Toward Improved Management (2024), http://dx.doi.org/10.2139/ssrn.5044308.

It is also worth noting that oil prices correlate with deactivations and reactivations of well production as tracked in this analysis. EDF also tracked transitions for all New Mexico oil and gas wells included in GO-TECH's County Production Volumes data (which is compiled from OCD production data), looking for all instances of wells becoming inactive for 12+ months, or returning to producing after such a 12+ month pause. *See* Apps' Ex. 69 below. When these transitions are plotted with West Texas Intermediate prices over time, price declines in 2016 (global oil supply glut, OPEC announcements, and geopolitics) and 2020 (COVID-related disruptions) correlate strongly with more wells transitioning to inactivity (green line).



Black lines drawn at 2016 (Shale bust) and 2020 (COVID-19). Increased numbers of deactivations are seen in the year of each event, with a smaller increase in reactivations lagging after (correlated to rising prices.)

Apps' Ex. 69

After each of these declines, as prices rose again, reactivations (yellow line) also increased – though fewer total wells reactivated after each price event than the number that deactivated by the low point of the price decline. Given that reduced prices represent a more significant impact for operators of low-producing wells with a higher expected ratio of costs to revenues, the wells that fail to reactivate after a sharp price decline are likely those low-

producing wells already at most risk of orphaning.

19.15.8.9.F & -G NMAC

Q: What are the proposed changes to Subsection F of 19.15.8.9 NMAC?

A: There are proposed changes under Subsection F concerning blanket plugging financial assurance.

The proposed amendments shown in redline and strikeout are:

> **19.15.8.9.F.** Operators who have on file with the division a blanket plugging financial assurance that does not cover additional wells shall file additional one ~~single~~ well plugging ~~bond~~ financial assurance for any wells not covered by the existing blanket plugging financial assurance ~~bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978. ~~or, in the alternative, may file a replacement blanket bond.~~

Q: What is the purpose of these modifications?

A: The terms "blanket plugging financial assurance" and "one well plugging financial assurance" are used for consistency with terminology in the Oil and Gas Act and within 19.15.8 NMAC. And the latter amendments recognize that financial assurance amounts in Commission rule must be consistent with any limitations in the Oil and Gas Act at Section 70-2-14.

19.15.9 NMAC—WELL OPERATOR PROVISIONS

Q: Mr. Peltz, Applicants propose changes to 19.15.9 NMAC—Well Operator Provisions—and specifically recommend additional requirements to 19.15.9.9 NMAC governing the "Change of Operator." What amendments to Applicants propose?

A: Applicants proposed the following amendments shown in redline:

> **19.15.9.9.B.** The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an officer, director, or partner of the new operator

request two more years of TA status in accordance with 19.15.25.13.B NMAC.

Paragraph (3) allows for wells with expired TA status to re-enter compliance upon application, though for a maximum of two years before either returning to service of plugging. This is a generous proposal for wells that are out of compliance and may have been out of compliance for many years.

Q: Finally, Mr. Peltz, what amendments do Applicants propose to 19.15.25.14 NMAC?

A: The proposed amendments shown in redline:

> **19.15.25.14.B.** The division shall not approve a permit for approved temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:
> **(1)** damage to the producing zone;
> **(2)** noncontainment of well bore fluids to the atmosphere or migration of hydrocarbons or water;
> **(3)** the contamination of fresh water or other natural resources; and
> **(4)** the leakage of a substance at the surface.

Q: What is the purpose of this amendment?

A: This provision adds a requirement to the showing an operator must make when it places a well in TA status to ensure that the well is not releasing methane or other constituents to the atmosphere. This provision prevents waste and protects human health and the environment. Generally, proper isolation of flow zones and the corrosive zones in the geology should prevent fluid migration of any kind outside of their intended zones.

Q: Mr. Peltz, does this conclude your testimony?

A: Yes.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Adam Peltz — August 7, 2025
Name — Date

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