Costs, Market Conditions, and Inventories Impact on Uncompleted Oil Wells

Dipanwita Barai[1], Thomas L. Marsh[2]

Abstract

This study examines uncompleted oil wells in the United States, focusing on seven key oil-producing regions to understand the impact of inventories, costs, and economic factors on uncompleted oil wells' growth. The research's primary contribution lies in integrating costs both theoretically and empirically. First, a theoretical model is developed to analyze uncompleted oil wells' growth, incorporating exploration and development costs. Second, Autoregressive Distributed Lag and Nonlinear Autoregressive Distributed Lag models are employed to empirically validate the theoratical model using monthly data from 2013 to 2019, capturing the dynamic and exogenous nature of economic factors. Third, the heterogeneous effects of inventories, costs, and other economic variables on uncompleted oil wells' growth are identified across regions. The analysis reveals that uncompleted oil wells' growth is positively influenced by the previous year's levels, both nationally and regionally. Exploration costs are found to increase uncompleted oil wells' growth, while completion costs have a negative impact. The study also highlights the heterogeneous effects of oil prices, refiner acquisition costs, reserves, rig count, pipeline capacity, and exports on uncompleted oil wells' growth in the short and long run. This study also examines the effects of the 2016 repeal of the U.S. crude oil export ban, indicating its significant impact on uncompleted well growth at the national level and in the Haynesville region

[1]Correspoding author: 315 Hulbert, School of Economic Sciences, Washington State University (WSU); email: dipanwita.barai@wsu.edu

[2]School of Economic Sciences, Washington State University

Acknowledgement: I would like to express my gratitude to my Ph.D. committee for the suggestions and guidance. SES Endowment for Sustainable Development (ESD), WSU

1 Introduction

In the United States (U.S.), drilled but uncompleted oil wells (uncompleted oil wells) play a pivotal role in the production, stocks, and pricing of petroleum products, including natural gas and oil, as uncompleted oil wells are the oil wells that have been drilled but not completed enough to start production (LLP, 2022). These petroleum products are integral to electricity generation and overall economic development in the country (Arora and Lieskovsky, 2014; Hamilton, 2012; Mugabe et al., 2021). Primarily driven by technological advancements often referred to as the "Shale Revolution," which combines hydraulic fracturing and horizontal drilling, the U.S. has experienced a substantial surge in oil and natural gas production since 2008 (Center, 2024). This surge in oil production has resulted in a significant decline in oil prices over recent years. Increased demand, partially due to the lifting of the oil export ban in 2016, has further incentivized production. This, combined with technological advances, has stimulated exploration and drilling activities[3]. Technological advances have reduced production costs and made exploration and drilling feasible even at lower price points. Many producers also employ an inventory strategy, completing high-yield wells while delaying the completion of others, thereby increasing the number of uncompleted oil wells. This approach allows flexibility to quickly scale up production if oil prices rise, providing a buffer stock that can be accessed when profitable. From 2013 to 2019, the U.S. saw a staggering 203.7% increase in uncompleted oil wells (EIA, 2023b).

The growth in uncompleted oil wells demands serious attention for several compelling reasons. First, uncompleted oil wells do not contribute to economic development as actively producing wells do, and they absorb significant economic rents (Boyce and Nøstbakken, 2011). Second, uncompleted oil wells pose severe negative environmental externalities through methane gas leakages, resulting in green house gas and health hazards, groundwater and

[3] In August 2016, the WTI oil price was $44.72 per barrel, with 604 drilled and 752 completed oil wells. By 2019, the WTI oil price had risen by only 27% ($56.95) per barrel, while the number of drilled wells increased by 96% (1,184) and the number of completed wells grew by 43% (1,080) (U.S. Energy Information Administration, 2024a).

soil contamination, and even geological explosions (Hill and Ma, 2017; Hill, 2018; Meng and Ashby, 2014). Lastly, when producers halt drilling activities, unemployment rates tend to rise. Overall, uncompleted oil wells adversely affect welfare, hinder sustainable economic development by increasing unemployment in oil sector as well as other oil related sectors (Wang, 2020), jeopardize human health and the environment, and lead to inefficient investments (Boyce and Nøstbakken, 2011). Although uncompleted oil wells are essential for oil and natural gas production, which contribute to local and state economic development through investments, labor, and income generation, maintaining a balance between the number of uncompleted oil wells and societal well-being is crucial for sustainable economic development.

Despite the critical role of uncompleted oil wells in the U.S. energy landscape, a limited literature exists on their growth. Previous studies, such as Mugabe et al. (2021), have explored U.S. uncompleted oil wells, considering factors like previous period uncompleted oil wells, pipeline capacity, rig count, and oil and natural gas prices. Meanwhile, Boyce and Nøstbakken (2011) have identified the significant influence of oil and natural gas reserves, production, and costs, in addition to prices, on development wells. However, none of these studies have conducted a comprehensive analysis of the extensive impact of changing economic factors, including future oil and natural gas prices, rig counts, reserves, production, and the previous states of uncompleted oil wells, pipeline capacity, and various cost components on uncompleted oil wells.

To shed light on the issue of uncompleted oil wells in the U.S., this study addresses these gaps by examining the impact of various determinants on the growth of uncompleted oil wells in the U.S. and seven distinct U.S. oil-producing regions: Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko. We develop a theoretical model that analyzes the dynamics of uncompleted oil wells' growth, incorporating exploration and development costs alongside several economic factors. The main contribution of this research lies in the incorporation of exploration and completion costs, both theoretically and empirically. We then employ Autoregressive Distributed Lag (ARDL) and Nonlinear ARDL (NARDL) models for time series analysis, using monthly data from 2013 to 2019 to validate the model's findings and account for the dynamic and exogenous nature of economic factors. The study also identifies the heterogeneous effects of inventories, costs, and other economic factors (future oil and natural gas prices, rig counts, reserves, production, pipeline capacity, and crude oil exports) on the growth of uncompleted oil wells at the regional level and analyzes the dynamics of uncompleted oil wells' growth in both the short and long term.

The results reveal several noteworthy findings. In our exploration and development model, we identify a formula that explains the equilibrium number of drilled and uncompleted oil wells, taking into account exploration, completion, and drilling costs. The equilibrium number of uncompleted oil wells grow as exploration costs increase, whereas higher completion costs reduce uncompleted oil wells growth. These dynamics are confirmed through empirical analysis. The results show that the previous year's status of uncompleted oil wells positively influences their growth at both national and regional levels. At the regional level, exploration costs increase the number of uncompleted oil wells' growth, while completion costs increment decrease the number of uncompleted oil wells' growth. Moreover, the findings indicate heterogeneous impacts of refiner acquisition costs, oil and natural gas prices, reserves, rig count, and pipeline capacity on regional uncompleted oil wells' growth. For instance, an increase in the future oil price in the previous period reduces the growth of uncompleted oil wells in the Appalachia region, while the Niobrara region experiences the opposite effect. Furthermore, an increase in the future natural gas price reduces the growth of uncompleted oil wells only in the Appalachia region. Refiner acquisition costs also play a pivotal role in regional uncompleted oil wells' growth, with higher refiner acquisition costs increasing uncompleted oil wells' growth in the Appalachia region. Conversely, in the Niobrara region, an increase in refiner acquisition costs in the previous year leads to reduced growth of uncompleted oil wells in the current year. The primary drivers of these regional asymmetries include geological and reservoir complexity, well depths, regulatory environments, infrastructure availability, land acquisition costs, and production focus. Lastly, the 2016 repeal of the U.S. crude oil export ban is shown to have significant influenced on the uncompleted oil wells' growth at the national level and in the Haynesville region.

Furthermore, our cointegration analysis indicates that inventory, costs and other economic variables (refiner acquisition costs, oil and natural gas prices, reserves, rig count, and pipeline capacity) have distinct long-run and short-run impacts on uncompleted oil wells' growth at the regional level. ARDL and NARDL models with error correction indicate that growth in the previous period and rising development costs reduce uncompleted oil wells' growth, while exploration costs increase uncompleted oil wells' growth in the long run. Additionally, the heterogeneous effects of costs, oil prices, reserves, rig count, and pipeline capacity on regional uncompleted oil wells' growth persist in both the long run and short run.

This study makes several contributions to the literature: 1) It presents a testable model, that is validated empirically using monthly data from 2013 to 2019. 2) This study focuses on the U.S. as well as its' seven oil and natural gas producing regions separately, estimating the impact of inventories, costs, and other economic factors on uncompleted oil wells. Each region exhibits different uncompleted oil well quantities, reserve deposits, and production focus, highlighting the need for region-specific analysis. For example, the Permian region has a significantly higher number of uncompleted oil wells than other areas, while the Appalachia region primarily focuses on natural gas and Natural Gas Liquids (NGLs) production (U.S. Department of Energy, 2017). The Bakken region boasts over 4.3 billion barrels of proven underground oil (U.S. Geological Survey, 2013). The paper also conducts a performance analysis of the estimated model through out-of-sample forecasting.

Besides the contribution to the literature, this study holds significance in policy debates. Identifying and understanding the determinants of uncompleted oil well production—such as inventories, costs, and economic factors—is crucial for determining an optimal level of uncompleted oil wells that balances societal benefits with environmental and economic costs.

This research provides valuable insights for policymakers aiming to minimize negative externalities like environmental degradation, while ensuring efficient resource management. By considering the regional differences in reserves, production patterns, and infrastructure, policymakers can craft tailored strategies that align economic goals with sustainability. For industry stakeholders, these findings can guide decisions on investment, production, and well completion strategies, helping to enhance profitability and operational efficiency.

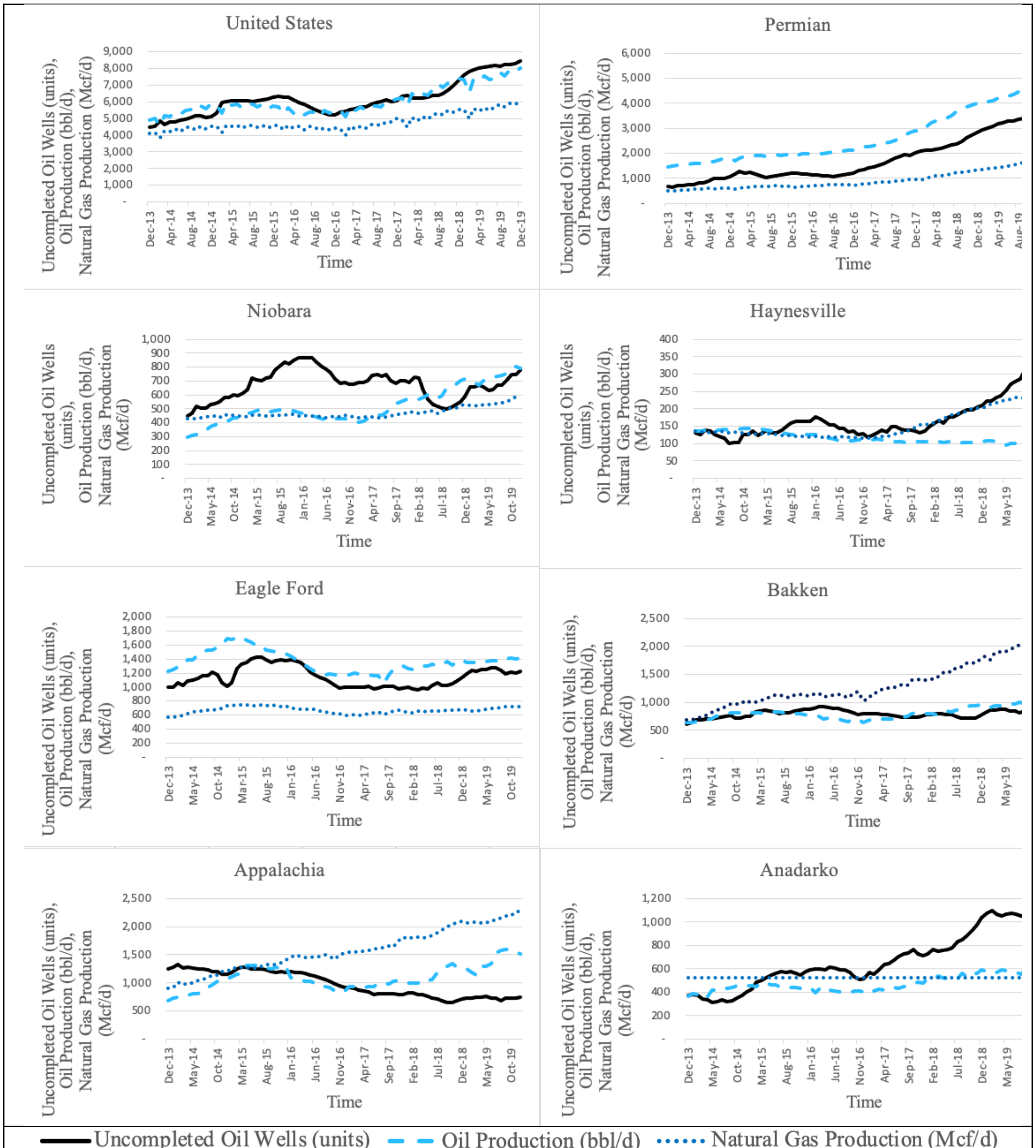
The structure of the study is as follows: 1) Section 2 provides an overview of previous research strategies and outcomes; 2) Sections 3 and 4 outline the theoretical model and empirical methodology, respectively; 3) Section 5 details the variables, including their names, units, sources, and descriptive statistics; and 4) Sections 6, 7, and 8 present the results, discussion, and conclusion, respectively.

2 Literature Review

The U.S. is the largest oil producer in the world, a position it has achieved through the rapid expansion of oil and natural gas production driven by remarkable technological advancements. Previous literature has noted that the rapid expansion of oil and natural gas production in the U.S. which has given rise to a surge in uncompleted oil wells (Kang et al., 2016; Peach and Adkisson, 2017). This transformative phenomenon, often referred to as the "shale oil revolution" since the 1920s, hinges on horizontal drilling and hydraulic fracturing techniques (Peach and Adkisson, 2017). The U.S. has witnessed a remarkable uptick in crude oil production, soaring by over 100% from 2000 to 2020 (EIA, 2023a). To visualize this surge in production, Figure 1 illustrates the upward trajectory of oil and natural gas production in the U.S. and most of its' seven major oil and natural gas producing regions. Notably, the surge in production has coincided with a significant increase in uncompleted oil wells from 2013 to 2019, particularly in the Permian Basin, which accounted for nearly 25% of all rigs in the U.S. (Apergis et al., 2016) and approximately 40% of the total uncompleted oil wells. Figure 1 provides a graphical representation of trends in uncompleted oil wells, revealing that the U.S., Permian, Haynesville, and Anadarko regions have experienced consistent growth in uncompleted oil wells, indicating more drilling activity relative to well completions. Specifically, the Anadarko region holds about 12% of the uncompleted oil wells, and the Haynesville region has around 4%. Conversely, the Appalachia region, primarily focused on natural gas, has seen a decline in uncompleted oil wells, accounting for about 9% of the total, as producers prioritize completing existing wells to reduce production costs. The Eagle Ford, Niobrara, and Bakken regions exhibit fluctuating trends, likely due to a mix of completing existing wells and drilling new ones in response to changing production dynamics, with these regions collectively representing about 35% of the uncompleted oil wells.

A substantial body of research has unveiled a significant interplay among oil and natural gas production prices, rig activity, and uncompleted oil wells. For instance, Shakya et al. (2022) identified a significant relationship between oil and natural gas prices and rig activity since the shale revolution. Likewise, Apergis et al. (2016) claimed that U.S. crude oil production has exhibited a strong positive relationship with crude oil prices and rig activity. Apergis et al. (2021) observed a symmetric pattern in oil prices and rigs drilling in the long run, regardless of drilling procedures (vertical, directional, and horizontal). However, they noted that an asymmetric relationship in oil production and rigs drilling, attributed to the high-cost investment required for drilling new wells. Furthermore, they also found that both oil price and production showed asymmetry in the short run due to producers' responses to economic fluctuations, with greater price and production differences during economic booms than in recessions. Apergis et al. (2021) further explained that the oil exploration process, which is the initial stage of oil wells, is also influenced by economic factors, as oil companies seek to optimize their operations and enhance financial value. Using linear fixed effects regressions as their empirical strategy, Mugabe et al. (2021) identified the vital roles of pipeline capacity, active well type and depth, rigs activity, and oil and natural gas prices on U.S. uncompleted oil wells.

Figure 1: U.S. and Seven uncompleted Oil Wells Regions: uncompleted oil wells, Oil Production, and Natural Gas Production Trends



Source: Energy Information Agency (EIA) https://www.eia.gov/petroleum/drilling

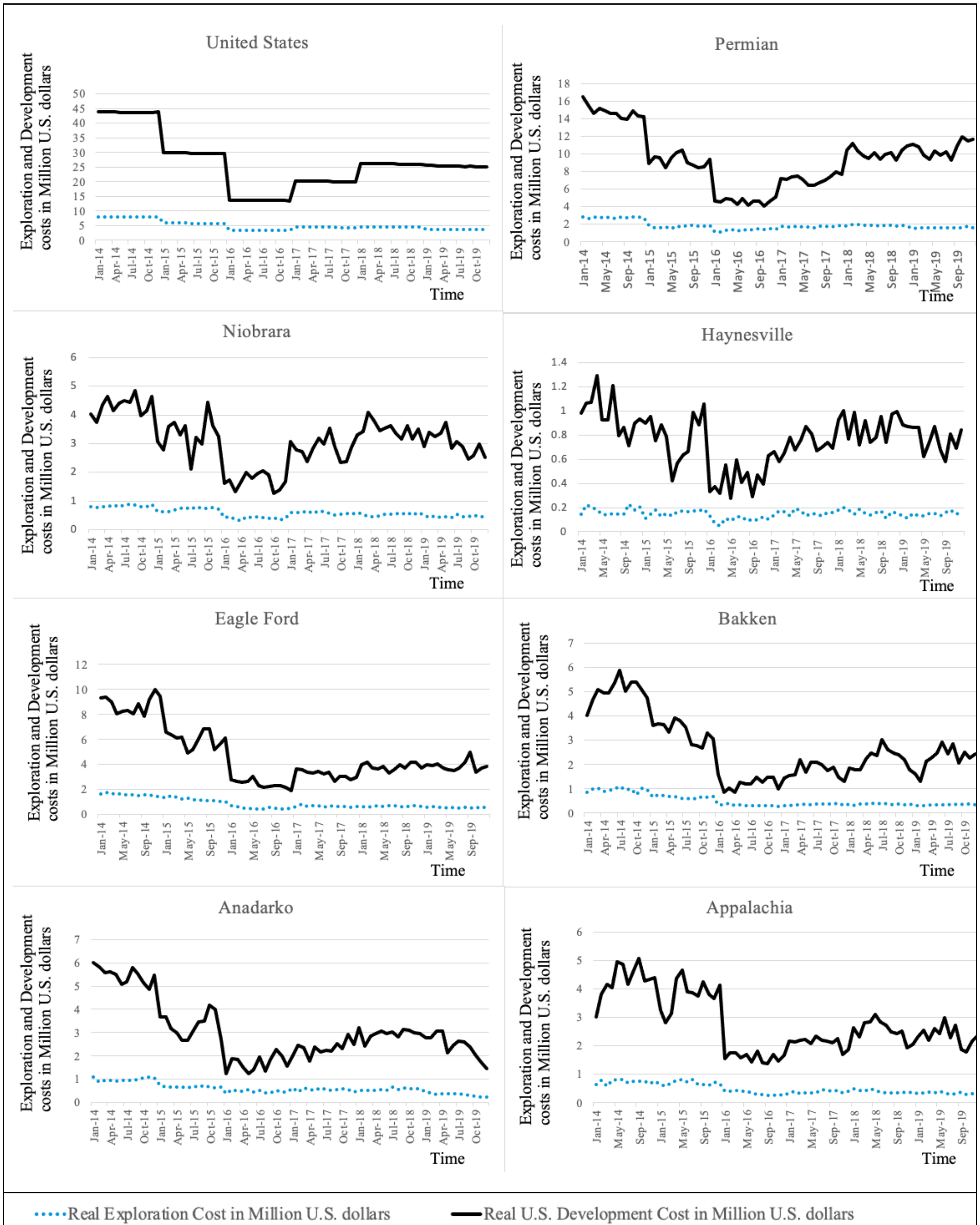
Note: bbl/d is Barrel of crude oil per day; Mcf/d=a thousand cubic feet per day

Cost is another important factor that can influence the production of uncompleted oil wells. According to the EIA (2016), cost plays a significant role in oil drilling and completion, with each well averaging \$9.09 million, including substantial completion costs of approximately \$5.7 million in onshore areas. U.S. oil and natural gas costs encompass exploration and development costs: rig and drilling fluid, casing and cement, frac pumps, and proppant expenses, completion fluids, flow back and other totaling around \$6.64 million in capital expenditures on average from 2013 to 2019 (EIA, 2016; Statista, 2024). Moreover, development costs, which are notably more expensive and time-consuming, exceeded \$5.5 million on average during the same period (Statista, 2024). The wells, referred to as uncompleted oil wells, are drilled but not yet completed or hydraulically fractured insufficiently for production. Figure 2 illustrates the total exploration costs of the drilled wells and development costs of the completed oil wells in the U.S. and seven U.S. oil-producing regions. This figure demonstrates that exploration and development costs fluctuate over time and vary from region to region. The variance of the total exploration and development costs can be attributed to differences in region size, total drilled, and completed oil wells. For instance, the Permian region significantly surpasses the Eagle Ford or Niobrara regions in both size and the number of drilled and completed oil wells. Boyce and Nøstbakken (2011) found that drilling costs significantly and negatively impact the total number of drilled and development wells per new field by using feasible generalized least squares (FGLS) as their methodology. They also found producing wells (rigs count) and reserves had a positive effect on the number of development wells per new field. Other studies such as Williams-Derry (2021) highlighted the influence of previous years' uncompleted oil wells, rig counts, production levels, infrastructure, and decision-making on uncompleted oil wells' growth. According to Levitt (2016), a significant effects of information spillovers on firms' exploration decisions and outcomes. By analyzing data from onshore oil and gas exploration activities, Levitt (2016) finds that firms can substantially benefit from information generated by nearby drilling operations. This shared information reduces exploration costs and increases the probability of successful drilling, thus enhancing overall industry performance (Levitt, 2016). The increased exploration activities and technological advancements driven by the "Shale Revolution" have likely resulted in significant information spillovers, which may influence the growth and management of uncompleted oil wells. As firms gain access to valuable information from nearby operations, their strategies for completing and managing wells could be affected, potentially impacting the overall number of uncompleted oil wells.

The 2016 crude oil policy change that ended the 40-year-old prohibition on crude oil exports from the U.S. has been the subject of several studies, providing valuable context for understanding the status of uncompleted oil wells. For instance, research by Langer et al. (2016) and Bihani (2018) reveal that lifting the export ban led to a convergence of U.S. crude oil prices with global benchmarks, incentivizing increased domestic production, boosting global trade flows, and contributing to economic growth and job creation in the U.S. oil sector. This policy shift improved market equilibrium by enhancing resource allocation and alleviating infrastructure bottlenecks. In contrast, the U.S. Government Accountability Office (2021) finds that the repeal of the export ban did not significantly impact production and export levels. This limited effect is attributed to the high price of U.S. crude oil, which has diminished profit margins for U.S. refiners compared to the period when the export ban was in place. These findings suggest that while the policy change had broad economic implications, its direct impact on uncompleted oil wells might be constrained by prevailing market conditions.

Based on the above discussion, exploration and development costs and other economic variables such as price, rig counts, oil and natural gas reserves, economic conditions, and uncompleted oil wells from previous periods along with policies have been found to impact the growth of uncompleted oil wells in the U.S.. However, previous studies (e.g., Mugabe et al. (2021)) have not extensively analyzed the multifaceted influence of these economic factors across U.S. regions and nationally. Focusing on the U.S. and seven U.S. oil-producing regions—Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko—

Figure 2: Total exploration costs of the drilled wells and completion costs of the completed oil wells in the U.S. and seven U.S. oil-producing regions



Source: Statista (2024). U.S. gas and oil companies capex on exploration and development 2010-2022.

this study examines the impact of costs, other economic factors, and inventories on uncompleted oil wells, recognizing the unique characteristics, production emphases, and policies of each region. Additionally, we analyze the effects of the 2016 repeal of the U.S. crude oil export ban on the growth of uncompleted oil wells at both national and regional levels.

3 Theoretical Model

Our theoretical model explains the impact of exploration and completion costs on uncompleted oil wells growth within the framework of an oil and natural gas exploration and development model of Boyce and Nøstbakken (2011). In this model, there are three key agents: landowners, exploration, and development firms. Landowners hold mineral rights and receive rents from selling these rights to exploration and development firms. Exploration firms drill wells with the purpose of finding new reserves where development firms drills with the purpose of production (Boyce and Nøstbakken, 2011). Our theoratical model finds that mineral rights owners (landowners) exclusively contract with exploration firms when there is exploration well related fixed costs, which aligns with Boyce and Nøstbakken (2011) model. Additionally, our model reveals that an increase in exploration costs increases uncompleted oil wells growth, while completion costs have the opposite effect on uncompleted oil wells growth at the equilibrium, given specific initial values for exploration, completion, and drilling costs. The detailed derivation of the exploration and development model and its findings are discussed in the following sections.

Oil and natural gas production requires drilling at the first stage, and then completion in the following stage. Boyce and Nøstbakken (2011) model derives exploration and development of competitive oil and natural gas field focusing on landowners, exploation and development firms, and total wells, but does not consider uncompleted oil wells and completion costs. Uncompleted oil wells and completion costs play a vital role for a well to generate oil and natural gas (Oil and Gas, 2022), consequently profit for the firm. In this study, we develop a testable model to derive the dynamics of uncompleted oil wells by incorporating completion costs and uncompleted oil wells.

Our exploration and development model starts with defining the present value of a field rent, Π_t as follows,

$$\Pi_t \quad = \quad \int_t^T e^{-r(s-t)}[p^e(s)q(s|w_1(t)) - C_O w_1(t)]ds \;-\; C_W w(t) \;-\; C_D w_1(t) \tag{1}$$

Here, t is the time when the field is discovered, T is the time when the resouce is exhaused, and $r > 0$ is the discount rate. The drilling decision depends on the expectation of the future prices. The expected rate growth in price is g and price at period s is $p^e(s)$. So, the expected price at time s is $p^e(s) = p(t)e^{g(s-t)}$. Now, if $r > g$, then the firm produces at the present period. That is, the firm produces in the present period if the expected price at time s is, $p^e(s) = p(t)e^{r(s-t)}$.

The production at time $s \geq t$ is $q(s|w_1(t))$ and the number of drilled wells at time t is "$w(t)$" in each field. Here, $w(t) = w_1(t) + w_2(t)$ where $w(t)$ is the total drilled oil wells, $w_1(t)$ is the completed oil wells and $w_2(t)$ is the uncompleted oil wells. The time difference of period s to t is $s - t$. Let θ denotes the proportion of the drilled wells that are completed. As the production increases the reserve falls. Field production decreases at the rate $\frac{q'(s)}{q(s)} = -\theta w(t)$ where $q'(s) = \frac{dq(t)}{dt}$ (MacAvoy and Pindyck, 1973). In other words, $\frac{q'(s)}{q(s)} = -w_1(t)$, since $\theta w(t) = w_1(t)$. Here, C_O is the operating costs, C_D is the costs to complete the well (such as casing and cement, frac pumps, equipment, proppant, completion fluids, flowback, and other costs related to geology, location, and sources) not including drilling costs, and C_W is the drilling costs where $C_D > C_W > C_O$.

Using equation (1), the exploration and development model demonstrates that landowners (mineral rights owners) exclusively contract with exploration firms because no contracting equilibrium exists between exploration and development firms when fixed costs related to exploration wells are present. The development firm cannot form a contract without an exploration firm. As a result, only the exploration firm remains. The detailed derivation of this exploration and development model is provided in the Appendix. Therefore, the subsequent part of the model involves only the landowners and exploration firm.

The equilibrium number of drilled wells[4], w* satisfies the following equation (2), where the marginal quasi-rent equals the marginal costs of the drilled wells,

$$\alpha V'(w_1*)\frac{\partial w_1^*}{\partial w^*} \quad = \quad C_w^\tau + C_D^\tau \frac{\partial w_1^*}{\partial w*} \tag{2}$$

Here, α is the proportion of recoverable reserves at the available technology at period t, $V(w_1) \approx \int_t^\infty e^{-r(s-t)}[p^e(s)q(s|w_1(t)) - C_O w(t)]ds$, $V(w_1*)$= is the quasi-rents stream from the equilibrium number of completed oil wells, $\alpha V(w_1^*)$ is the quasi-rents from the equilibrium number of completed oil wells (w_1^*), C_w^τ = drilling costs with available technology, and C_D^τ = after drilling to complete costs available technology.

Now, if N is the exploration firms' contact with the mineral rights owner, $\varnothing_x$ is the payments to the mineral rights owner for each lease, ρ is the probability that oil and natural gas is discovered in the land, $\alpha V(w_1^*)$ is the quasi-rents from the equilibrium number of completed oil wells (w_1^*), then, the landowner receive from the exploration firms at the equilibrium:

$$N\varnothing_x \quad = \quad N\rho[\alpha V(w_1^*) - C_w^\tau w^* - C_D^\tau w_1^*)] - C_x^\tau \tag{3}$$

Here, $N\varnothing_x$ = total payments to the mineral rights owners, C_w^τ = drilling costs with available technology, w^* is the total equilibrium number of drilled oil wells, w_1 is the completed oil wells and w_2 is the uncompleted oil wells, C_D^τ = after drilling to complete costs available technology,

[4]The detail derivation is given in the Appendix.

and C_x^τ = exploration costs available technology. So, $\alpha V(w_1^*) - (C_w^\tau)(w_1^* + w_2^*) - C_D^\tau w_1^*$ is the equilibruim field rents for w_1^* completed oil wells on oil and natural gas discovered field. Equation (3) shows that, at equilibrium and under the condition of free entry in the exploratory market, the total payments to the landowner (mineral rights owner) are equal to the total field rents of the N contracts of the exploratory firms minus the total exploration costs given the available technology. The expected profits of the exploration firms are expressed as $E[\pi_x] = N(\rho\pi_x - \varnothing_x) - C_x^\tau$, where N is the exploration firms' contract with the mineral rights owner, ρ is the probability that oil is discovered in the land, C_x^τ is the fixed costs of the exploration well with available technology in a field.

Contractual failure can happen due to the market failure such as no free entry or private or asymmetric information (Hendricks and Porter, 1988; Kellogg, 2011). We have also derived the contractual failures' effect model incorporating uncompleted oil wells, exploration and completion costs. The detail derivation is given in the Appendix. We find that landowners rent decreases as the number of firms (n) increases in the contractual failure, which aligns with Boyce and Nøstbakken (2011) findings.

Testable Comparative Static

From equation (2), we get optimum number of completed oil wells, w_1^*,

$$w_1^* \quad = \quad \frac{\sqrt{-p(t)R(C_x + C_D)(g-r)} + (C_x + C_D)(g-r)}{C_x + C_D} \tag{4}$$

From equation (3), we can write the optimum number of uncompleted oil wells, w_2^* as follows:

$$w_2^* \quad = \quad \frac{N\rho\alpha V(w_1*) - N\rho C_w^\tau w_1^* - N\rho C_D^\tau w_1^* - C_x^\tau - N\varnothing_x}{N\rho C_w^\tau} \tag{5}$$

Here, R is reserves, $p(t)$ is prices, $r$is discout rate and $g$is price growth. From equation (2),

$\alpha V'(w_1*)\frac{\partial w_1^*}{\partial w^*} = C_x^\tau + C_D^\tau \frac{\partial w_1^*}{\partial w^*}$. At equilibrium, it is rational to assume that completed oil wells and the drilled wells have a positive relationship, as an increase in drilling activity leads to a corresponding increase in the number of completed oil wells. This implies that $(\partial w_1^*)/\partial w^* > 0$. Using equation (2) and the numerical method[5] similar to Boyce and Nøstbakken (2011), we can write w_1^* as follows,

$$w_1^* = \frac{20 - \sqrt{C_x + C_D}}{10\sqrt{C_x + C_D}}; w_1^* > 0 \tag{6}$$

From equation (6), we find that if exploration or completion costs increase, the equilibrium number of completed oil wells falls: $(dw_1^*)/(dC_x) < 0$ and $(\mathrm{d}w_1^*)/(dC_D) < 0$.

Substituting equation (6) into equation (5) and applying the numerical method [6] similar to Boyce and Nøstbakken (2011), we get w_2^* as follows,

$$\begin{aligned} w_2^* = {} & 1.6(\frac{40w_1^*}{0.1 + w_1^*}) - 1.6 \times C_w \times (\frac{20 - \sqrt{C_x + C_D}}{10\sqrt{C_x + C_D}}) - 1.6 \times \\ & C_D \times (\frac{20 - \sqrt{C_x + C_D}}{10\sqrt{C_x + C_D}}) - C_x - 16 * 1.7 \end{aligned} \tag{7}$$

We also find from equation (7) that an increase in exploration costs increases uncompleted oil wells growth $((dw_2^*)/(dC_x) > 0)$, while completion costs have the opposite effect on uncompleted oil wells growth $((dw_2^*)/(dC_D) < 0)$ at the equilibrium, given the exploration costs per drill and completion cost per completed oil wells are at the national level[7].

This analysis can be applied to analyse the uncompleted oil wells growth dynamics at the regional and national level.

[5]Detail derivation in the Appendix A.2 Comparative Static.
[6]Detail derivation in the Appendix A.2 Comparative Static.
[7]The detail derivation given in the Appendix A.2 Comparative Static.

4 Empirical Methodology

In this study, we control for several important issues in the empirical analysis that were absent in the theoretical model due to simplification. For example, oil fields experience pressure loss as they age (Boyce and Nøstbakken, 2011), necessitating measures like water or natural gas injection or drilling additional wells to sustain production. To account for field age, we include the oil reserve ratio (oil reserve divided by oil reserve plus cumulative production) and natural gas reserve ratio (gas reserve divided by natural gas reserve plus cumulative production). Moreover, we acknowledge the dynamic and exogenous nature of economic factors. To capture this complexity, this study uses the linear and non-linear Autoregressive distributive Lag (ARDL) model (Pesaran et al., 2001), which incorporates lagged variables to analyze their effects on uncompleted oil wells over time. Also, it is rational to assume that there is autocorrelation or serial correlation in uncompleted oil wells' growth over time because producers tend to explore new areas where profits are higher, leaving unfinished oil wells behind (Levitt, 2016). Consequently, the number of uncompleted oil wells accumulates each year. This implies that $d(Uncompleted\, oil\, wells)_t$ are serially correlated with $d(Uncompleted\, oil\, wells)_{(t-i)}$ where "$d(Uncompleted\, oil\, wells)$" is the uncompleted oil wells growth, "d" denotes the change between two consequtive time periods, "t" is a time subscript, and "i" is the index for lags. Furthermore, this study is consistent with the nature of the data, where changes in costs and other economic variables are cointegrated at either the I(0) or I(1) level. This indicates that these variables have different impacts on uncompleted oil wells' growth in the long run versus the short run. Our modeling approach allows us to explore these distinct long-term and short-term impacts, providing a more comprehensive understanding of how costs and other economic factors influence uncompleted oil wells' growth in the oil and natural gas industry.

ARDL model is characterized by a single-equation system[8] where the dependent variable

[8] It should be noted that single equation models, while consistent, are not necessarily efficient (Greene, 2018).

is explained by its own lags and the lags of other independent variables. Importantly, we observe that some of the variables exhibit stationarity at the I (1) level. In the context of stationarity, ARDL necessitates that variables demonstrate stationarity at either I(0) or I(1), whereas the vector autoregressive (VAR) model requires all variables to be stationary at I(0). Another key consideration is that we assume a unidirectional causality between independent variables and uncompleted oil wells. Specifically, we posit that independent variables have an impact on uncompleted oil wells, but uncompleted oil wells do not influence the independent variables. For example, current uncompleted oil wells are not expected to impact the contract price of oil and natural gas. However, an increase in the contract price of oil and natural gas might incentivize producers to resume previously paused projects, potentially leading to a decrease in uncompleted oil wells. Furthermore, our modeling approach involves simultaneous equations that incorporate the lag of the dependent variable and the independent variables. Given that drilling activities typically exhibit a time lag of 4 to 6 months in response to a price increment (Oil and Gas, 2022), we make the reasonable assumption that the lag of independent variables can also wield a significant influence on the uncompleted oil wells in the contemporaneous period. Consequently, our decision to utilize the ARDL model is well-justified in light of these considerations.

In our analysis, we estimate both the generalized ARDL and NARDL (non-linear Autoregressive Distributive Lag) models initially. If there is cointegration, we proceed to estimate the ARDL and NARDL error correction model. The bounds test is employed to confirm the existence of cointegration, comparing F-statistics to critical values (Pesaran et al., 1995; Pesaran et al., 2001). The presence of cointegration signifies that independent variables impact the dependent variable differently in the long run compared to the short run.

To determine the optimal number of lags in these models, we rely on the Bayesian Information Criterion (BIC) (Enders, 2008), a preferred method over the Akaike Information Criterion (AIC). BIC provides more consistent results and penalizes additional parameters effectively compared to AIC (Koehler and Murphree, 1988).

The generalized $ARDL(p, q)$ specification can be expressed as follows:

$$y_t = \alpha_0 + \sum_{i=1}^{p} \beta_i y_{t-i} + \sum_{i=0}^{q} \lambda_i x_{t-i} + u_{it}. \quad (8)$$

In equation (8), the coefficients β_i, λ_i reveals the relationship dynamics of the inventories and economic factors with uncompleted oil wells. t is the time, i is the lag index, p and q signify the optimal lag lengths for the dependent and independent variables, respectively, and u_{it} is the serially uncorrelated or independent error term. The variable y_t indicates the change of uncompleted oil wells from *t-1* and t because this study focuses on the impact of economic factors growth (which is denoted as x_t) on the growth of uncompleted oil wells over time. Similarly, x_t indicates the difference between the independent variables at t and $t - 1$.

To conduct our analysis, we employ eight ARDL models: one dedicated to the U.S. and seven others tailored to the Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko regions. Consequently, the generalized ARDL specification for uncompleted oil wells in the U.S. and these seven regions is

$$
\begin{aligned}
d(Uncompleted\, oil\, wells_{tj}) = \alpha_0 &+ \sum_{i=1}^{q} \alpha_1\, d(Ex.\, cost_j)_{t-i} + \sum_{i=1}^{q} \alpha_2\, d(Dev.\, cost_j)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_3\, d(Ref.\, acq.\, cost_j)_{t-i} + \sum_{i=1}^{q} \alpha_4\, d(p_{oil})_{t-i} + \sum_{i=1}^{q} \alpha_5\, d(p_{gas})_{t-i} + \\
&+ \sum_{i=1}^{q} \alpha_6\, d(Oil\, reserve_j)_{t-i} + \sum_{i=1}^{q} \alpha_7\, d(Gas\, reserve_j)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_8\, d(Oil\, reserve\, ratio_j)_{t-i} + \sum_{i=1}^{q} \alpha_9\, d(Gas\, reserve\, ratio_j) \\
&+ \sum_{i=1}^{q} \alpha_{10}\, d(Pipeline\, cap._j) + \sum_{i=1}^{q} \alpha_{11}\, d(Rig\, count_j) \\
&+ \sum_{i=1}^{q} \alpha_{12}\, d(Interest\, rate)_{t-i} + \sum_{i=1}^{q} \alpha_{13}\, d(Real\, GDP)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_{14}\, d(Export_j)_{t-i} + \sum_{i=1}^{p} \alpha_{15}\, d(Uncompleted\, oil\, wells_j)_{t-i} \\
&+ u_{jit}
\end{aligned}
\tag{9}
$$

Here, j = U.S., Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko, respectively. We estimate equation (9) individually for the U.S. and each region. Ex.cost refers to the exploration costs of drilled oil wells exploration costs for the U.S. and each region. Similarly, Dev.cost refers to the development costs of complete wells for the U.S. and each region. Ref.acq.cost refers to the refiner acquisition costs for the U.S. and each region. P_{Oil} and P_{Gas} are the future price of the oil and natural gas, respectively. Oil and natural gas (gas) reserve is the oil and natural gas reserve per new drill, Pipeline cap. is the pipeline capacity per drill, Rig count is the total active rigs, Export is the crude oil export.

Equation (9) capture equilibrium dynamics through ARDL specifications for the uncompleted oil wells' growth of the U.S., Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko, respectively. Equations (9) shows the growth of uncompleted oil wells (j) as a function of the growth of costs (exploration (j), development (j), refiner acquisition(j)), the growth of the future price (p) of oil and natural gas, growth of oil and natural gas reserve per new drill (j), growth of oil and natural gas reserve ratio (j), growth of pipeline capacity (j), growth of interest rate, growth of real GDP, growth of total oil export, growth of rigs count (j), change in uncompleted oil wells (j) in the previous year, and a stochastic error term (u_{jit}). The associated coefficients of the explanatory variables represent their impact on the growth of the uncompleted oil wells in the U.S. and seven oil and natural gas producing regions.

Additionally, we incorporate the NARDL model to account for the potential asymmetric impact of real GDP (Gross Domestic Product) on uncompleted oil wells' growth during economic recessions or booms in the U.S. and other regions. This asymmetric influence is captured using the NARDL approach, employing partial sum decomposition following as Shin et al. (2014). The partial sum decomposition for GDP, following Luckstead (2018), can be summarized as:

$$d(RealGDP)_t^k = d(RealGDP)_0^k + d(RealGDP)_t^{k+} + d(RealGDP)_t^{k-} \tag{10}$$

Here, GDP_0 denotes the initial value at t = 0.

$$d(GDP)_t^{k-} = \sum_{n=1}^{t} min(\triangle(d(RealGDP)_t^{k-}), 0) \tag{11}$$

$$GDP_t^{k+} = \sum_{n=1}^{t} max(\triangle(d(RealGDP)_t^{k+}), 0) \tag{12}$$

Similar to the ARDL, we apply eight distinct NARDL frameworks: one for the U.S. and seven tailored to the Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko regions. NARDL frameworks are

$$
\begin{aligned}
d(Uncompleted\,oil\,wells_{tj}) &= \alpha_0 + \sum_{i=1}^{q} \alpha_1\, d(Ex.\,cost)_{t-i} + \sum_{i=1}^{q} \alpha_2\, d(Dev.\,cost)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_3\, d(Ref.\,acq.\,cost_j)_{t-i} \sum_{i=1}^{q} \alpha_4\, d(p_{oil})_{t-i} + \sum_{i=1}^{q} \alpha_5\, d(p_{gas})_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_6\, d(Oil\,reserve_j)_{t-i} \sum_{i=1}^{q} \alpha_7\, d(Gas\,reserve_j)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_8\, d(Oil\,reserve\,ratio_j)_{t-i} + \sum_{i=1}^{q} \alpha_9\, d(Gas\,reserve\,ratio_j) \\
&+ \sum_{i=1}^{q} \alpha_{10}\, d(Pipeline\,cap._j) + \sum_{i=1}^{q} \alpha_{11}\, d(Rig\,count_j)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_{12}\, d(Interest\,rate)_{t-i} + \sum_{i=1}^{q} \alpha_{13}\, d(Real\,GDP+)_{t-i} \\
&+ \sum_{i=1}^{q} \alpha_{14}\, d(Real\,GDP-)_{t-i} \sum_{i=1}^{q} \alpha_{15}\, d(Export_j) \\
&+ \sum_{i=1}^{p} \alpha_{16}\, d(Uncompleted\,oil\,wells_j)_{t-i} + u_{jit}
\end{aligned} \tag{13}
$$

Equation (13) capture equilibrium dynamics through NARDL specifications for the uncompleted oil wells' growth of the U.S., Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko, respectively. As we can see that captures the NARDL model specification is similar to the ARDL model, with the key difference being that we consider both *Real GDP +* and *Real GDP-*, instead of *Real GDP*, as in the ARDL model (equation 9).

Now, the ARDL (NARDL) model with error correction framework (Pesaran et al., 1995; Shrestha and Bhatta, 2018) is as follows:

$$
\Delta y_t = \alpha_0 + \gamma_1\, y_{t-1} + \gamma_2\, x_{t-1} + \sum_{i=1}^{p} \beta_i \Delta y_{t-i} + \sum_{i=0}^{q} \lambda_i \Delta x_{t-i} + \varepsilon_t \tag{14}
$$

Equation (14) represents the ARDL (NARDL) model with error correction, integrating both long-run and short-run dynamics. The coefficients γ_1, γ_2 indicate the long run while β_i, λ_i reveal the short-run relationship dynamics of the inventory, costs, and other economic factors with uncompleted oil wells. Time is represented as t, i is the index for lags, p and q are the optimum number of lags of the dependent and independent variable, respectively. ε_t stands for the error term. y_{t-1} indicates the uncompleted oil wells' growth at $t-1$ period and Δy_t indicates the change in the growth of uncompleted oil wells.

A Priori expectations

In this study, generalized $ARDL(p, q)$ model (equation 9 and equation 13) captures the dynamics of uncompleted oil wells' growth in the U.S. and seven distinct oil and natural gas producing regions by considering several key factors. We discuss the prior prediction of each explanatory variables. First, we control for the costs associated with exploration, development, and refiner acquisition, in line with our theoretical model. The coefficient (α_1) associated with exploration costs can be positive or negative, as higher exploration costs may deter new exploration, prompting producers to drill wells in previously explored areas, potentially increasing the number of uncompleted oil wells if the drilled wells yield losses or other wells are expected to generate higher profits. Alternatively, higher exploration costs may discourage drilling activity altogether, leading to a reduction in uncompleted oil wells. Similarly, the coefficients for development and refiner acquisition costs (α_2, and α_3) can also be positive or negatve. Increased development costs and higher refiner acquisition costs may discourage producers from completing the drilled wells, thereby increasing the number of uncompleted oil wells. Conversely, these increased costs may also discourage producers from drilling new wells and encourage them to complete previously paused prospective wells, resulting in a reduction of uncompleted oil wells.

Second, we control for the future prices (p_{oil} is the change in future oil price and p_{gas} is the change in future natural gas price) rather than spot prices, as future prices are more relevant to the production of natural gas and growth of uncompleted oil wells (Chen and Linn, 2017; Mugabe et al., 2021). The associated coefficients of p_{oil} and p_{gas} , denoted α_4 and α_5, respectively, are ambiguous (Mugabe et al., 2021). While higher future prices may incentivize production, attract investors- crucial for completing the wells- and reduce uncompleted oil wells (Mugabe et al., 2021), they could also encourage more drilling, increasing uncompleted oil wells' growth (Chen and Linn, 2017).

Third, oil and gas reserves are included since they are one of the significant determinants of drilling activity. Boyce and Nøstbakken (2011) indicate that oil and natural gas reserve presence is a necessary condition for drilling activity. The coefficients α_6 and α_7 reflect the impact of oil and natural gas reserve per new drill, respectively, on uncompleted oil wells' growth. Larger reserves may encourage more drilling, increasing uncompleted oil wells, but they could also lead to completing previously paused wells, reducing uncompleted oil wells' growth.

Fourth, we also control for oil reserve ratio (the ratio of oil reserve and oil reserve plus cumulative oil and natural gas production) and natural gas reserve ratio (the ratio of natural gas reserve and the natural gas reserve plus cumulative oil and natural gas production) to account for the aging of extraction fields. The associated coefficients of oil and natural gas reserve ratio are α_8 and α_9, respectively, and can be positive or negative. An increase in reserve ratio could encourage producers to drill more wells or require them to drill additional wells to sustain production. This is because older fields often experience pressure loss (Boyce and Nøstbakken, 2011), making it necessary to inject water or natural gas or excavate new wells to maintain production levels. In this case, an increase in the reserve ratio would lead to a higher number of uncompleted oil wells. Conversely, an increase in the reserve ratio might discourage drilling new wells while prompting producers to resume previously paused projects. This could happen when the higher reserve ratio indicates that there is still a significant amount of recoverable resources in the existing wells, making additional drilling less attractive. In such a scenario, uncompleted oil wells' growth would decrease. Hence, the direction of the impact of α_8 and α_9 depends on the specific circumstances of each region and how they respond to changes in the reserve ratio.

Fifth, we control for pipeline capacity and active rig count as in Mugabe et al. (2021). The associated coefficient of the pipeline capacity per drill is α_{10} can be ambiguous. Higher pipeline capacity may attract producers to drill more due to improved infrastructure, increasing uncompleted oil wells. However, increased pipeline capacity may also lead producers to complete previously paused wells, decreasing uncompleted oil wells. The associated coefficient of the rigs count (active in production) is α_{11} and can also be positive or negative. Producers often drill more wells than they can immediately complete, opting to finish wells that offer higher production and profits. This can result in an increase in uncompleted oil wells during periods of high active rigs and production (Mugabe et al., 2021). However, producers may also complete previously paused wells alongside newly drilled wells during such periods, reducing uncompleted oil wells.

Sixth, interest rates are included based on the theoretical model and Boyce and Nøstbakken (2011). The coefficients for the interest rate, α_{12}, is expected to be negative. Higher interest rates discourage producers from investing in drilling new wells, which could lead to a decline in the growth of uncompleted oil wells if producers decide to complete previously paused wells.

Seventh, real GDP and crude oil exports are accounted for to capture overall economic conditions. The impact of real GDP (α_{13}) and crude oil exports (α_{14}) on the growth of uncompleted oil wells can be either positive or negative. Stronger economic conditions may either encourage more drilling or lead producers to complete paused wells to meet rising demand.

Lastly, the coefficient (α_{15}), representing the effect of uncompleted oil wells' growth from the previous year, can also be positive or negative. Producers may either continue exploring new areas without completing older wells (Levitt, 2016), increasing uncompleted oil wells, or shift towards completing existing wells, reducing their growth.

Additionally, for the model with partial sum decomposition equation, (13) we consider real GDP growth in booms and recessions, with the coefficients α_{13} and α_{14} capturing these effects. α_{13} and α_{14} could be ambiguous, as real GDP growth may either encourage more drilling or lead producers to complete paused wells to meet increased demand during both economic booms and recessions. A similar explanation goes for the other variables' coefficients of the generalized NARDL model (equation 13) as the generalized ARDL model (equation 8). The priori expectations of the explanatory variables are same in the long run and short run.

To ensure the suitability of the ARDL model, a Dickey-Fuller unit root test is conducted, aligning with the assumptions required for ARDL and NARDL analysis (Pesaran et al., 2001). Additionally, this study conducts 10 period out-of-sample forecasts to evaluate the performance of the estimated models.

Finally, to evaluate the effects of the 2016 repeal of the U.S. crude oil export ban, a dummy variable is interacted with the export variable in generalized ARDL (NARDL) model (equations 9 and 13). The interaction term's coefficient could be positive or negative, as increased exports might either lead to more drilling and uncompleted oil wells or incentivize producers to complete previously paused projects.

5 Data

This study uses monthly data from December 2013 to December 2019, sourced from the U.S. Energy Information Administration U.S. Energy Information Administration (2024a), Statista (2024), and Federal Reserve Bank of St. Louis (2023b) to examine the impact of inventory levels, costs, and economic factors (refiner acquisition costs, oil and natural gas prices, reserves, rig count, pipeline capacity, GDP, interest rate, and crude oil exports) on the growth of uncompleted oil wells in the U.S. and seven U.S. oil-producing regions empirically. The total exploration costs of drilled wells include expenses related to locating oil and natural gas through geophysical surveys and exploratory drilling, covering both research and drilling expenditures. The total development (completion) costs of completed oil wells include expenses for rigs and drilling fluids, casing and cement, frac pumps, equipment, proppant, completion fluids, flowback, and other costs related to geology, location, and sources. Drilling expenses account for nearly 15% of the total completion costs (EIA, 2016). Refiner acquisition costs, meanwhile, include the price of crude oil, transportation expenses, and additional fees such as tariffs and insurance for imported oil (U.S. Energy Information Administration, nd). The exploration and completion cost data are collected from the Statista database[9]. We calculated the exploration and completion costs for drilled and completed oil wells by applying the national average costs to the total number of drilled and completed wells in each region. From the descriptive statistics tables (Table 1, Table 2, and in the appendix Tables 7 to 13), we observe that the mean and standard deviation of exploration costs are significantly lower than development costs. The variation in these costs across regions can be attributed to factors such as geological and reservoir complexity, well depths, regulations, infrastructure availability, and land acquisition costs EIA (2016). The Haynesville region had the lowest mean real total exploration costs for drilled wells and development costs for completed wells, at 0.15 million and 0.76 million U.S. dollars, respectively. In contrast, the Permian region had the highest mean real total exploration costs for drilled wells and development costs for completed wells, at 1.82 million and 9.31 million U.S. dollars, respectively. The higher mean total costs in the Permian region are mainly due to the greater number of drilled and completed wells, driven by the region's favorable geology and size, established infrastructure, and higher production rates compared to other regions (EIA, 2016). Real Refiner acquisition costs[10] vary less regionally compared to exploration and development costs and are measured in dollars per barrel, with the minimum mean at 0.22 and the maximum mean at 0.26.

[9]Exploration and completion cost data from Statista are in nominal terms. We get the real exploration and completion costs from these nominal costs by dividing them by the Consumer Price Index (CPI), sourced from the(U.S. Bureau of Labor Statistics, 2024)

[10]Refiner acquisition cost data from (U.S. Energy Information Administration, 2024e) are in nominal terms. We get the real refiner acquisition costs from these nominal costs by dividing them by the Consumer Price Index (CPI), sourced from the(U.S. Bureau of Labor Statistics, 2024)

Monthly data on refiner acquisition costs, uncompleted oil wells, prices, reserves, production, and crude oil exports are collected from the U.S. Energy Information Administration (U.S. Energy Information Administration, 2024a,e,c,b,d). We use average weekly contract prices to estimate monthly future oil and natural gas prices. Locked contract prices are known to attract investments and significantly impact uncompleted oil wells, as noted in studies by Chen and Linn (2017) and Mugabe et al. (2021). According to Mugabe et al. (2021), active rigs significantly impact uncompleted oil wells. Hence, we have controlled active rig count instead of rig count in this study. Furthermore, Mugabe et al. (2021) identifies that the well-completion decision hinges on pipeline capacity. Therefore, pipeline capacity is represented in this study as pipeline capacity per drill well for each month, a more appropriate metric that accounts for infrastructure details and captures the essence of pipeline capacity more effectively. Similar to costs, the uncompleted oil wells, reserves, and production vary across regions.

This study uses real disposable personal income data as a proxy for real GDP due to the unavailability of monthly real GDP data. We also use monthly real interest rate data. Both the real disposable personal income and interest rate data are sourced from the Federal Reserve Bank of St. Louis Federal Reserve Bank of St. Louis (2023b,a) and capturing the economic conditions. Prices, real interest rate, and real GDP are invariant across regions. Detailed descriptions of the variables and summary statistics are provided in Table 1 and Table 2 below, while Tables 7 to 13 can be found in the Appendix.

Table 1 includes information about variables such as future oil and natural gas price, real interest rate, and real GDP. These variables are uniform for both the U.S. and all its' regions since data at the regional level are not available for these particular variables. Table 2 delves into the specifics of variables that exhibit variations between the U.S. and the individual regions. Tables 7 to 13 in the Appendix offer a comprehensive breakdown of the variables, providing a detailed understanding of their characteristics and differences across regions.

Table 1: Descriptive Statistics: Variables Description and Unit Root Results for Invariant Variables Across Regions and National

Variable, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
p_{oil}, Crude Oil in Real Dollars per Barrel	71	0.24	0.07	0.14	0.44	-8.41
$p_{natural\,gas}$, Real Dollars per Million Btu	71	0.01	0.0013	0.008	0.02	-8.31
Real Interest Rate, Percent	71	0.67	0.28	0.17	1.31	11.4
Real GDP, Billions of Chained 2012 Dollars	71	13829.82	654.59	12579.5	14885.9	-7.02

Notes: Btu is British Thermal Unit. Real Interest rate is 10-Year Real Interest Rate, Percent, Monthly, Not Seasonally Adjusted. Real GDP is Real Disposable Personal Income: Billions of Chained 2012 Dollars, Monthly, Seasonally Adjusted Annual Rate.

Table 2: Descriptive Statistics: Variables Description and Unit Root Results for the U.S. at the National Level

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	6192.38	1003.98	4656	8422	-5.23
Exploration costs of total drill, Real million U.S. dollars	71	4.94	1.52	3.40	8.03	-8.5
Developemnt costs of total complete wells, Real million U.S. dollars	71	26.17	9.15	13.48	43.90	-8.7
Refiner acquisition costs, Real dollars per barrel	71	0.24	0.07	0.12	0.43	5.04
Oil reserve per newly drilled, $\frac{MillionBarrels}{unit}$	71	2.95	1.03	1.47	5.86	-8.4
Gas reserve per newly drilled, Billion Cubic Feet/unit	71	32.34	10.97	14.70	61	-8.3
Oil reserve ratio, $\frac{MillionBarrels}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.0001	0.0001	0.00002	0.0004	57.5
Gas reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.001	0.001	0.0002	0.005	54.5
Pipeline capacity per newly drilled oil wells, Million standard cubic feet per day (mmcfd)	71	44.67	27.52	18.60	125.99	-7.6
Rigs count units	71	848.25	330.54	314	1528	-2.3
Export, Thousand Barrels	71	186638.7	48782.64	102416	289253	-11

Notes: Oil Reserve ratio is the ratio of oil reserve and oil reserve plus cumulative oil and natural gas production. Gas Reserve ratio is the ratio of natural gas reserve and natural gas reserve plus cumulative oil and natural gas production. The unit of oil production is bbl/d (Barrel per day) and and natural gas production is Mcf/d (Thousand cubic feet per day). Export is total crude oil and petroleum products exports.

6 Results

Our model employs the first differences of variables, a common approach to render their stationarity to analyze the influence of costs, inventory, and other economic factors on uncompleted oil wells' growth. Table 1 to Table 13 (except Tables 5 and 6) present the results of unit root and cointegration tests. The Dickey-Fuller unit root test results in Table 1 to confirms that the economic variables are stationary and cointegrated, either in I (0) or I (1). Additionally, F statistics in Table 7 and Table 13 indicate that these variables are indeed cointegrated at the regional level, but not at the national level. Furthermore, Table 14 reveals that uncompleted oil wells' growth at periods t and $t-1$ exhibit serial correlation at both the national and regional level. Consequently, all the assumptions which are required for the generalized ARDL (NARDL) and ARDL (NARDL) with an error correction framework are satisfied at the regional level, but not at the national level. ARDL and NARDL models yield almost identical results at both levels. Therefore, we choose to report the better-performing model between ARDL and NARDL based on the R^2 of the estimated models and RMSE from the 10 observations out-of-sample forecast analysis, as presented in Table 15. According to Table 15, ARDL performs better than the NARDL models for the U.S., Permian, Eagle Ford, Bakken, Appalachia, and Anadarko regions, where NARDL performs better for the Permian, Niobrara, and Haynesville regions.

National and Regional Results

We first present the results for the uncompleted oil wells of the U.S., followed by the results for each region: Permian, Niobrara, Haynesville, Eagle Ford, Bakken, Appalachia, and Anadarko. Additionally, we present the results of the long-run and short-run uncompleted oil wells analysis at the regional level.

The impact of costs and other economic variables varies at both national and regional levels, likely due to each region's unique characteristics—such as geology, location, resource availability, production focus, and differing environmental regulations. Tables 3 and 4 present the outcomes of the generalized ARDL (NARDL)[11] models. The results reveal that uncompleted oil wells' growth in the current period are strongly influenced by their previous status at both national and regional levels, with a coefficient of 0.66 at the national level and an average coefficient of 0.74 (min: 0.46 (Table 3), max: 0.89 (Table 4)). Additionally, in the Haynesville region, the coefficient for previous period's exploration costs is 0.27, indicating that higher exploration costs in the previous period also contribute to the growth of uncompleted wells in the current period. This suggests that producers tend to continue exploration activities in regions with higher potential profits without completing past unfinished wells, which can lead to an accumulation of uncompleted oil wells.

Exploration and development costs are significant at the regional level but insignificant at the national level. Exploration costs show a significant positive effect at the regional level, with an average coefficient of 200.07 (min: 112.64 (Table 3), max: 255.76 (Table 4))[12], indicating that higher costs may deter new exploration, prompting producers to drill wells in previously explored areas, potentially increasing the number of uncompleted oil wells if the drilled wells yield losses or other wells are expected to generate higher profits. Conversely, development costs have a negative impact at the regional level, averaging -33.97 (min: -42.49 (Table 4), max: -29.71 (Table 3)), implying that increased development expenditures discourage producers from drilling new wells and encourage them to complete previously paused prospective wells, resulting in a reduction of uncompleted oil wells.

The findings of this study also indicate heterogeneous impacts of refiner acquisition costs, oil and natural gas prices, reserves (oil and natural gas reserves per new drill, oil and natural gas reserve ratios), rig count, pipeline capacity, and export on the growth of uncompleted oil wells both nationally and regionally. For example, in the Niobrara region, the coefficient of the previous period's refiner acquisition costs is -729.76 (Table 3), indicating that a 1 dollar per barrel increment in refiner acquisition costs growth decreases uncompleted oil

[11] ARDL for U.S., Eagle Ford, Bakken, Appalachia, and Anadarko regions and NARDL models for the Permian, Niobrara, Haynesville regions.

[12] The coefficient is significant at the 10% level of significance in the Anadarko region

Table 3: Results of Uncompleted Oil Wells: U.S., Permian, Niobrara, and Haynesville

Variables	U.S.	Permian	Niobrara	Haynesville
Uncompleted oil wells$_{t-1}$	0.66***	0.75***	0.83**	0.46***
	(0.14)	(0.10)	(0.1)	(0.17)
Uncompleted oil wells$_{t-2}$	-	-	-	0.39***
				(0.13)
Ex. cost	-49.47	112.64***	230.34***	189.82***
	(189.39)	(42.00)	(36.67)	(34.70)
Dev. cost	2.90	-29.71***	-37.93***	-33.91***
	(46.51)	(6.81)	(4.62)	(4.05)
Ref. acq. cost$_{t-1}$	672.20	1241.18	-729.76***	-159.24
	(4021.0)	(903.01)	(205.30)	(141.46)
$p_{oil_{t-1}}$	-1465.59	-1220.27	607.96**	65.15
	(3861.44)	(771.93)	(271.79)	(117.31)
Oil reserve ratio	9.50×10^7	1.62×10^5*	1.93×10^8	-1.13×10^7***
	(1.62×10^8)	(9.43×10^4)	(1.28×10^8)	(3.91×10^6)
Oil reserve ratio$_{t-1}$	2.37×10^7	-	-1.16×10^8**	-3.40×10^6
	(8.03×10^7)		(5.35×10^7)	(3.67×10^6)
Oil reserve ratio$_{t-2}$	-1.11×10^8	-	-1.38×10^8***	2.85×10^6*
	(7.32×10^7)		(5.88×10^7)	(1.61×10^6)
Gas reserve ratio	-4.94×10^6	3.99×10^7**	-4.75×10^6	2.85×10^6***
	(1.16×10^6)	(1.80×10^5)	(4.21×10^6)	(9.96×10^5)
Gas reserve ratio$_{t-2}$	6.98×10^6	-4.05×10^7***	6.07×10^6***	-2.99×10^5
	(4.24×10^6)	(1.21×10^5)	(1.94×10^6)	(3.96×10^5)
Gas reserve ratio$_{t-3}$	-	2.16×10^7***	-	-
		(9.06×10^5)		
Pipeline cap.$_{t-2}$	4.07**	1.09	-	-
	(1.88)	(5.04)		
Pipeline cap.$_{t-4}$	-5.27***	-	-	-
	(1.79)			
Rig count	-1.68*	-1.46***	-0.27	0.13
	(0.98)	(0.46)	(0.73)	(0.16)
Rig count$_{t-1}$	1.85	1.66***	0.43	0.12
	(1.18)	(0.46)	(0.59)	(0.13)
Export	0.002**	0.001	-0.001	3.99×10^{-5}
	(0.001)	(0.001)	(0.001)	(4.62×10^{-5})
Export$_{t-3}$	0.0005	-	-	0.0001**
	(0.002)			(5.96×10^{-5})
Wald test statistics	39.89***	3104.5***	246.28***	79.60***
Cointegration: F Stat	1.89	3.91***	8.99***	3.85***

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.

Table 4: Results of Uncompleted Oil Wells: Eagle Ford, Bakken, Appalachia, and Anadarko

Variables	Eagle Ford	Bakken	Appalachia	Anadarko
Uncompleted oil wells$_{t-1}$	0.77***	0.89***	0.69***	0.77***
	(0.08)	(0.10)	(0.10)	(0.13)
Ex. cost	223.13***	255.76***	239.36***	149.45*
	(35.56)	(39.41)	(40.23)	(76.89)
Dev. cost	-31.85***	-42.49***	-31.23***	-30.64***
	(3.24)	(5.36)	(4.35)	(9.02)
Ref. acq. cost	854.34	-76.08	787.55**	-470.72
	(600.01)	(258.81)	(375.64)	(609.55)
$p_{oil_{t-1}}$	-118.04	184.66	-483.95**	581.62
	(516.61)	(233.66)	(222.55)	(440.45)
p_{gas}	-4.24×10^3	-151.13	-3825.32**	1233.52
	(3.03×10^3)	(1691.38)	(1830.31)	(3541.20)
Oil reserve ratio$_{t-1}$	-7.81×10^7	-1.92×10^7**		
	(1.09×10^8)	(7.28×10^6)		
Oil reserve ratio$_{t-2}$	2.79×10^8**	1.86×10^7**	1.28×10^9*	-9.10×10^7
	(1.12×10^8)	(5.92×10^6)	(7.03×10^8)	(2.24×10^8)
Gas reserve ratio	1.49×10^7	8.06×10^6	1.15×10^6***	1.14×10^5
	(8.87×10^6)	(1.18×10^7)	(3.46×10^6)	(4.97×10^6)
Gas Reserves	-5.24	-0.13	-0.82**	3.31
	(3.63)	(16.08)	(0.35)	(4.70)
Pipeline cap$_{t-1}$	-	37.54	-1.20***	-3.95
		(21.78)	(0.39)	(8.31)
Pipeline cap$_{t-3}$	-	-	0.49**	-0.43
			(0.18)	(4.86)
Wald test statistics	61.40***	356.07***	64.35***	61.11***
Cointegration: F Stat	16.42***	11.64***	9.73***	3.41**

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.

wells growth by 729.76 units. However, refiner acquisition costs growth positively impacts the Appalachia region's uncompleted oil wells growth, with a coefficient of 787.55 (Table 4). Future oil prices in the previous period increase uncompleted oil wells growth significantly in Niobrara, with a coefficient of 607.96 (Table 3). However, the coefficients for the previous period's future oil and natural gas prices are -483.95 and -3825.32 (Table 4), respectively, in the Appalachia region, indicating a negative impact on uncompleted oil wells growth due to an increase in future prices.

In Haynesville, a higher oil reserve ratio decreases uncompleted wells, with a coefficient of -1.13×10^7 (Table 3). In the long run, Niobrara and Bakken also show a negative impact on uncompleted wells from previous-period oil reserve growth (lag1 and lag2 coefficients: -1.16×10^8 and -1.38×10^8 (Table 3), respectively) for Niobrara and -1.92×10^7 and 1.86×10^7 (Table 4) for Bakken, suggesting long-term decreases in uncompleted wells as oil reserve increases. Conversely, in Eagle Ford and Bakken, oil reserve growth positively correlates with uncompleted wells, with lag2 coefficient of 2.79×10^8 (Table 4).

In the Permian, gas reserve growth increases uncompleted wells with coefficients of 3.99×10^7, -4.05×10^7, and 2.16×10^7 (Table 3) for lag2 and lag3, respectively. Appalachia shows a similar positive trend in uncompleted wells (coefficient: 1.15×10^6 (Table 4)), but lag1 yields a negative effect of -1.09×10^7 (Table 4), indicating a decrease in uncompleted wells due to gas reserve growth in the general.

Pipeline capacity expansion reduces uncompleted well growth nationally and in Appalachia in the long term, with lagged coefficients of 2 and 3 are 3.89 and -5.74 (Table 4), respectively, at the national level and -1.31 and 0.46 (Table 4) in Appalachia for lag1 and lag3, respectively. In the Permian, rig count growth negatively affects uncompleted wells (coefficient: -1.24 (Table 3)), though prior-period rig count growth (coefficient: 1.51) indicates a contemporaneous increase in uncompleted wells as rig count increases.

The relationship between crude oil exports and uncompleted oil wells is positive at the national level, with a crude oil export coefficient of 0.002 (Table 3). Additionally, in the

Haynesville region, the lagged crude oil export coefficient (lag 3) is 0.0001 (Table 3), indicating that an increase in crude oil exports contributes to the growth of uncompleted oil wells in this region.

Long-Term and Short-Term Impacts

Our cointegration results in Tables 7 and 13 indicate that variables exert distinct long-run and short-run impacts on regional uncompleted oil well (DUC) growth, evidenced by significant F-statistics. Tables 5 and 6 show that exploration, development, refiner acquisition costs, and future natural gas prices have similar long-run effects on uncompleted oil wells' growth, consistent with results from the generalized ARDL and NARDL models. However, a notable exception arises for the prior year's uncompleted oil wells, which have a significant negative long-run impact. The coefficient for the prior year's uncompleted oil wells status is, on average, -0.19 (excluding Bakken, where the coefficient is insignificant), with a range between -0.25 and -0.17. In the Appalachia region, the coefficient for future oil prices is -961.91, indicating a negative long-run effect on DUC growth.

Our cointegration results in Tables 7 and 13 indicate that variables have distinct long-run and short-run impacts on regional uncompleted oil wells' growth through significant F statistics. The outcomes in Tables 5 and 6 show that exploration[13], development, refiner acquisition costs, and future natural gas prices have similar long-run effects on the growth of uncompleted oil wells, consistent with the results of the generalized ARDL and NARDL models. However, a notable exception arises for the prior year's uncompleted oil wells, which have a significant negative long-run impact. The coefficient for the prior year's uncompleted oil wells status is, on average, -0.19 (excluding Bakken, where the coefficient is insignificant), with a range between -0.25 (Table 5) and -0.17[14](Table 5). In the Appalachia region, the coefficient for future oil prices is -964.70 (Table 6), indicating a negative long-run effect on the growth of uncompleted oil wells.

In the short run, only a few variables significantly affect uncompleted oil wells' growth.

[13]The coefficient of the exploration costs for the Anadarko region is insignificant

[14]The coefficient for Haynesville and Anadarko is significant at the 10% level of significance

Table 5: Results of distinct long-run and short-run uncompleted oil wells Well Analysis in the U.S., Permian, Niobrara, and Haynesville

Variables	Permian	Niobrara	Haynesville
Long-run			
Uncompleted oil wells$_{t-1}$	-0.25** (0.01)	-0.17** (0.08)	-0.15 (0.11)
Ex. cost	112.64** (46.06)	230.34*** (34.66)	249.07*** (48.07)
Dev. cost	-29.71*** (6.64)	-37.80*** (6.74)	-45.14*** (8.29)
Ref. acq. cost$_{t-1}$	1836.26 (1430.5)	-834.12** (350.27)	10.31 (158.98)
Short-run			
Uncompleted oil wells$_{t-1}$	-	-	-0.39** (0.17)
Ex. cost	-	-	189.82 (28.10)
Dev. cost	-	-37.93*** (4.73)	-33.91*** (3.24)
Oil reserve	-	-	1.73** (0.81)
Gas Reserve	-	-	-0.22** (0.09)
Gas reserve ratio	3.99×10^7 (1.81×10^7)	-4.75×10^6 (3.95×10^6)	$2.85 \times 10^{6***}$ (7.62×10^5)
Rig count	-1.46*** (0.42)	-0.27 (0.67)	0.13 (0.14)

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.

For instance, an increase in exploration costs leads to higher uncompleted oil wells' growth in the Haynesville, Bakken, and Anadarko regions, while development costs negatively impact uncompleted oil wells' growth in the Niobrara and Haynesville regions. However, an increase in rig counts reduces uncompleted oil wells' growth in the Permian region. In the Haynesville region, an increase in oil reserves positively impacts the growth of uncompleted oil wells, whereas an increase in gas reserves has a negative effect. In the Appalachia region, increased refiner acquisition costs have a positive relationship with the growth of uncompleted oil wells, while increased gas reserve per drill and pipeline capacity decreases the growth of uncompleted oil wells. These short-term findings align with the results of the generalized model, with the exception that an increase in the previous period's uncompleted oil wells' growth reduces contemporaneous uncompleted oil wells' growth in the Haynesville region.

In both the long run and short run, exploration cost growth positively impacts the growth of uncompleted oil wells in the Bakken region, while development cost growth negatively affects growth in the Niobrara and Haynesville regions.

Impact of the U.S. Crude Oil Export Ban Repeal on Uncompleted Oil Wells Growth

Table 16 and 17 present the estimated results from the impact of the repeal of the U.S. crude oil export ban. This analysis includes a dummy variable as an interaction term with export in equations (8) and (9), instead of using the export variable alone to capture the export ban removal impact. The results Table 16 and Table 17 indicate that the 2016 repeal of the U.S. crude oil export ban significantly impacts the growth of uncompleted oil wells at both the national level and in the Haynesville region. The coefficients associated with the export ban are 0.002 at the national level (16) and 0.0001 (16) for Haynesville at lag3. The statistically significant coefficients in Table 16 and 17 are nearly identical to those in Tables 3 and 4.

All the results discussed above and the reported coefficients are significant individually, at least at the 5% level of significance, unless otherwise noted. Wald test results (3 and

Table 6: Results of distinct long-run and short-run uncompleted oil wells Well Analysis in Eagle Ford, Bakken, Appalachia, and Anadarko

Variables	Eagle Ford	Bakken	Appalachia	Anadarko
Long-run				
Uncompleted oil wells$_{t-1}$	-0.23*** (0.08)	-0.11 (0.10)	-0.31*** (0.10)	-0.23* (0.13)
Ex. cost	223.13*** (36.21)	308.07*** (58.16)	239.20*** (39.10)	155.16 (114.10)
Dev. cost	-31.85*** (3.62)	-42.49*** (5.23)	-31.23*** (4.05)	-30.674*** (7.48)
Ref. acq. cost$_{t-1}$	689.98 (818.54)	-343.16 (261.48)	1026.68** (382.44)	-1179.23 (704.67)
p_{oil}	-746.97 (798.84)	348.95 (327.63)	-964.70** (370.07)	969.94 (802.99)
p_{gas}	-4236.89 (3068.06)	-151.13 (1722.12)	-3825.32** (1546.81)	1233.52 (2956.09)
Short-run:				
Ex. cost	-	255.76*** (33.45)	-	149.45** (69.36)
Ref. acq. cost	854.34 (633.10)	-76.08 (213.96)	787.55** (341.69)	-470.72 (573.98)
Gas reserve per drill	-	-0.13 (12.25)	-0.82** (0.40)	3.31 (4.19)
Pipeline cap.$_{t-1}$	-	-	-0.75*** (0.26)	-
Pipeline cap.$_{t-2}$	-	-	-0.49*** (0.17)	-

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.

4) indicate the considered variables are significant jointly at the 1% level of significance. We choose the better-performing model between ARDL and NARDL based on R^2 of the estimated models and RMSE from the out-of-sample forecast analysis, as presented in Table 15.

7 Discussion

The empirical findings align with our theoretical results regarding the impact of exploration and development costs on the growth of uncompleted oil wells. The positive relationship between exploration costs and uncompleted oil wells' growth suggests that higher exploration costs may deter new exploration, prompting producers to drill wells in previously explored areas. This may increase the number of uncompleted oil wells if the newly drilled wells yield losses or if other wells are expected to generate higher profits. Conversely, development costs have a negative relationship with the uncompleted oil wells' growth, implying that increased development expenditures discourage producers from drilling new wells, encouraging them instead to complete previously paused wells, resulting in a reduction of uncompleted oil wells' growth. The findings show that the previous year's uncompleted oil wells have a strong positive effect on the current period's uncompleted oil wells' growth, aligning with the expectation that producers continue to explore profitable sites before completing previously drilled wells. This result supports both our priori expectation and Levitt (2016)'s conclusions on producer behavior.

Higher refiner acquisition costs lead to contrasting effects on uncompleted well growth between Niobrara and Appalachia due to differences in production costs, crude quality, and infrastructure efficiency (EIA, 2016; Hart Energy, 2014; Rextag, 2022; Sonnenberg, 2011). Niobrara's lower production costs and lighter oil quality incentivize completions, while Appalachia's higher costs and heavier oil reduce profitability, leading to delayed completions and a buildup in uncompleted wells.

Higher refiner acquisition costs lead to opposite effects in uncompleted oil wells between Niobrara and Appalachia due to differences in production costs, crude quality, and infrastructure efficiency (EIA, 2016; Hart Energy, 2014; Rextag, 2022; Sonnenberg, 2011). Niobrara's lower production costs and lighter oil quality incentivize completions, while Appalachia's higher costs and heavier oil reduce profitability, leading to delayed completions and a buildup in uncompleted wells.

In Niobrara, the previous period's future oil price growth significantly and positively correlates with uncompleted well growth, likely due to increased drilling during high oil prices. This observation is consistent with our priori expectation and the findings of Chen and Linn (2017). In contrast, in Appalachia, there is a negative relationship between uncompleted oil wells' growth and both the previous period's future oil and natural gas prices. This negative impact may occur because, in Appalachia, an increase in future prices prompts higher production, which ultimately reduces uncompleted oil wells' growth. Higher future prices locked in through contracts help producers attract investors, which is crucial for completing the wells (Mugabe et al., 2021). This observation supports our priori expectation and is consistent with Mugabe et al. (2021), highlighting the inverse relationship between future prices and uncompleted oil wells' growth.

Increased oil reserve ratios reduce uncompleted wells in Niobrara, Haynesville, and Bakken, where infrastructure efficiency and lower costs support quicker transitions to production (EIA, 2016). Conversely, in regions like Eagle Ford, infrastructure tight oil formations often lead to increased uncompleted wells, as completions are delayed until market conditions improve (U.S. Energy Information Administration, 2016).

The oil and gas reserve exhibit varying impacts. Increased oil reserves ratios reduce uncompleted wells in Niobrara and Haynesville, where infrastructure efficiency and lower costs support quicker transitions to production (EIA, 2016). Conversely, in regions like Eagle Ford and Bakken, infrastructure bottlenecks (Federal Reserve Bank of Minneapolis, 2013) and tight oil formations (U.S. Energy Information Administration, 2016)often lead to increased uncompleted wells, as completions are delayed until market conditions improve.

Higher gas reserve ratios increase uncompleted wells' growth in Permian, Niobrara, and Appalachia due to infrastructure constraints, handling costs, and strategic producer decisions. For example, the Permian is the largest U.S. oil and gas producer, while Appalachia is primarily a gas-producing region. Increased gas reserves may spur drilling, but takeaway bottlenecks and strategic timing often lead to uncompleted well growth (Federal Reserve Bank of Minneapolis, 2013; U.S. Energy Information Administration, 2023; SP Global Commodity Insights, 2023). Additionally, in Appalachia and Permian region, higher gas reserve ratios are associated with an increase in uncompleted oil wells, likely due to challenges in maintaining production levels, necessitating additional drilling. These challenges are faced by Permian and Appalachia, which has older, more mature wells compared to regions like Anadarko and Bakken, known for their younger reservoirs (Wikipedia, 2024). As reserves ratio increases in Permian and Appalachia, producers may need to increase drilling activities to maintain production, resulting in more uncompleted oil wells. However, in Appalachia, higher gas reserves per drill are linked to decreased uncompleted wells, as increased reserves encourage producers to complete both previously paused and newly drilled wells.

Regarding infrastructure, increased pipeline capacity reduces uncompleted oil wells' growth nationally and in Appalachia, as improved transportation options encourage producers to complete wells and bring products to market more quickly.

The impact of rig count and crude oil export varies by region. In Permian, increased rig counts correlate with fewer uncompleted wells, as producers complete both paused and new wells. However, a rise in previous periods' rig count is associated with the increment of uncompleted oil wells' growth in Permian, consistent with Mugabe et al. (2021). The analysis also reveals that increased crude oil exports over the past three periods lead to more uncompleted wells in Haynesville, a region marked by technological efficiency, low production costs (Statista, 2024), minimal refining needs, and robust infrastructure for export-oriented production (Rextag, 2023). Higher crude oil exports may encourage producers to focus on completing only high-profit drilled wells while leaving other projects paused. This aligns with our expectations and suggests that crude oil exports are key drivers of well completion behavior in Haynesville, likely due to its minimal refining needs and export-oriented infrastructure. In contrast, crude oil exports do not significantly impact uncompleted well growth in the other six regions, likely due to higher refining requirements. As exports rise, domestic producers tend to charge higher prices than foreign oil, shrinking profit margins for refiners, reducing demand for U.S. tankers, and ultimately leaving producers' decisions to drill or complete wells unaffected by increased exports (U.S. Government Accountability Office, 2021). This highlights the importance of regional characteristics in determining well completion behavior.

Additionally, our cointegration results indicate that exploration and development costs, future natural gas prices, and gas reserves have similar long-run and short-run impacts on uncompleted oil wells' growth as shown by the generalized model (Table 3 and Table 4) across regions. However, the previous year's uncompleted oil wells' growth has a significant negative long-run impact. This outcome is logical, as investments in uncompleted oil wells remain unproductive, with producers continually exploring new wells for higher profits and leaving existing projects on hold, which results in producers becoming more selective in drilling new wells and leads to a decline in uncompleted oil wells' growth over the long term. This finding aligns with prior research by Oil and Gas (2022); Williams-Derry (2021). Moreover, in the Appalachia region, future oil and gas price growth has a negative long-run impact on uncompleted oil wells' growth. This may occur because rising future prices prompt higher production, leading to a reduction in uncompleted oil wells' growth. This observation aligns with our initial hypothesis and is consistent with Mugabe et al. (2021), further supporting the inverse relationship between future prices and uncompleted oil wells' growth. The short-term findings generally align with the generalized model.

The repeal of the U.S. crude oil export ban significantly impacts uncompleted well growth both nationally and in the Haynesville region. Increased exports may drive to complete the high yield drilled oil wells only, contributing to uncompleted well growth nationally. Similarly, in Haynesville, which requires minimal refining and has export-oriented infrastructure (Rextag, 2023), producers may prioritize to complete high-yield drilled wells only, adding to uncompleted well growth. In contrast, other regions do not exhibit a significant impact from the export ban repeal. This may be due to declining profit margins for refiners, as domestic producers charge higher prices than foreign oil (U.S. Government Accountability Office, 2021). As a result, the expanded U.S. crude oil market post-repeal has reduced demand for domestic tanker transport, leaving producers' drilling or completion decisions unaffected by the export ban repeal. This outcome aligns with the U.S. U.S. Government Accountability Office (2021) report, which highlighted insignificant impact of the U.S. crude oil export ban lift on overall production.

8 Conclusion

This study develops a testable model and empirically validates its' findings using Autoregressive Dynamic Lag Models (ARDL) and Nonlinear ARDL (NARDL) as empirical strategies to analyze the influence of inventory, costs, and economic factors on uncompleted oil wells' growth. A key contribution of this research is the inclusion of exploration and development costs, which significantly impact uncompleted oil wells at the regional level. Our findings show that higher exploration costs tend to increase uncompleted oil wells' growth, as producers shift their focus to previously explored areas rather than incurring new exploration costs. On the other hand, increased development costs encourage the completion of paused projects, leading to a reduction in uncompleted oil wells. This dynamic highlights the importance of understanding cost structures when managing oil well inventories. Moreover, the status of uncompleted oil wells from the previous year significantly and positively affects their growth in the current period, suggesting that producers continue exploring new sites without completing earlier projects, which leads to an accumulation of uncompleted oil wells.

Regionally, our results reveal significant variations in how economic factors impact uncompleted oil wells. In the Niobrara region, future oil price growth positively correlates with uncompleted well growth, driven by increased drilling activity. In contrast, the Appalachia region experiences a negative relationship between uncompleted oil wells and both future oil and natural gas prices, suggesting that higher prices prompt greater production and consequently reduce uncompleted well growth.

Infrastructure improvements, such as increased pipeline capacity, help reduce uncompleted wells' growth nationally and particularly in Appalachia, as better transport options encourage faster well completion. The relationship between rig counts and uncompleted wells also varies by region: in the Permian, more rigs are associated with fewer uncompleted wells, while in other regions, increased rig counts do not significantly impact uncompleted well growth. Furthermore, crude oil exports significantly influence uncompleted well growth only in Haynesville, where natural gas production dominates. This finding underscores the importance of regional characteristics in determining completion behavior and highlights the nuanced dynamics of oil and natural gas production.

The study also finds that the repeal of the U.S. crude oil export ban significantly impacts uncompleted oil wells' growth positively, both at the national level and in the Haynesville region.

Overall, the study demonstrates that economic factors significantly influence the growth of uncompleted oil wells, with variations across different regions due to their unique characteristics, policies, and production focuses. This analysis is vital for several reasons. New oil and natural gas production brings economic development (Feyrer et al., 2017) but also has harmful effects on human health due to environmental contamination (such as water, air, and soil) (Hill and Ma, 2017; Hill, 2018; Meng and Ashby, 2014). It is rational to consider that the economic development impact of uncompleted oil wells is not as significant as that of ongoing oil-producing wells. Additionally, uncompleted oil wells exert serious negative environmental externalities. Given the extent of the issues generated by uncompleted oil wells and their significance in oil production, the findings of this study contribute to a deeper understanding of the factors driving the growth of uncompleted oil wells. These insights have substantial implications for policymakers and industry stakeholders. By recognizing the regional disparities in responses to economic and operational factors, stakeholders can better tailor strategies to optimize well completion rates and enhance overall production efficiency. This empirical research, which focuses on the influence of inventory, costs, and other economic factors on uncompleted oil wells, equips policymakers to effectively manage the petroleum industry while determining the optimal quantity of uncompleted oil wells to mitigate environmental pollution over time.

There are several ways to extend this paper. The study currently covers the time frame from 2013 to 2019 due to data constraints. Future research could extend the study by incorporating a larger span of yearly-level data, which would capture the impacts of investments more accurately through longer lags or cumulative lags of investments. Additionally, certain details are unavailable, such as state-level uncompleted oil wells data, well depths, cost breakdowns (exploration, rig and drilling fluid, casing and cement, frac pumps, and proppant expenses), lease information, service work, storage costs, proved but still undrilled wells (PUDs), and the impact of rival firms' decisions. Incorporating these data in future studies could improve the performance of the estimated model and enhance out-of-sample forecast accuracy. Furthermore, future research could delve deeper into the impact of state policies on the growth of uncompleted oil wells in each state.

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A Appendix:

A.1 Derivation of the Exploration and Development Model:

The production of the well $q(s)$ depends on the remaining petroleum reserves, $R(s)$ and the completed oil wells, $w_1(t)$. Hence, we can write $q(s)$ as,

$$q(s) \quad = \quad w_1(t)R(s) \tag{S1}$$

The stock of the petroleum reserves, $R(s)$ holding the number of completed oil wells, $w_1(t)$ fixed in a field at any given time, $s \geq t$ is,

$$R(s) \quad = \quad R_0 e^{-w_1(t)(s-t)} \tag{S2}$$

where the initial reserves at time 0 is R_0 and the motion of the petroleum reserves follows,

$$\frac{\partial R(t)}{\partial t} \equiv \dot{R} = -q(t) \, where \, R(0) = R_0 > 0 \tag{S3}$$

Here, $q(t)$ is the field production. Hence, the production at time $s \geq t$ is,

$$q(s|w_1(t)) \quad = \quad w_1(t)R_0 e^{-w_1(t)(s-t)} \tag{S4}$$

Here, $w_1(t)$ the completed oil wells and $w_2(t)$ the uncompleted oil wells.

Note that Boyce and Nøstbakken (2011) include drilling costs but does not include uncompleted oil wells and completion costs of the well. In our exploration and development model, we consider both uncompleted oil wells and completeion costs of the wells. In our model, the number of drilled wells at time t be "$w(t)$" in each field. Here, $w(t) = w_1(t) + w_2(t)$ where

$w_1(t)$ is the completed oil wells and $w_2(t)$ is the uncompleted oil wells. C_O is the operating costs, C_D is the costs to complete the well not including drilling costs and C_W is the drilling costs where $C_D > C_W > C_O$. We can write the present value of a field rent as equation (1), which is as follows.

$\Pi_t \;=\; \int_t^T e^{-r(s-t)}[p^e(s)q(s|w_1(t)) - C_O w_1(t)]ds \;-\; C_W w(t) \;-\; C_D w_1(t)$

Here, t is the time when the field is discovered, T is the time when the resouce is exhaused, and $r > 0$ is the discount rate. The drilling decision depends on the expectation of the future prices. The expected rate growth in price is g and price at period s is $p^e(s)$. So, the expected price at time s is $p^e(s) \;=\; p(t)e^{g(s-t)}$. Now, if $r \;>\; g$, then the firm produces at the present period. So, the firm produces at the present period if the expected price at time s is, $p^e(s) \;=\; p(t)e^{r(s-t)}$.

The production at time $s \geq t$ is $q(s|w_1(t))$ where $w_1(t)$ is the completed oil wells. The time difference of period s to t is $s-t$. Let, θ is the completed oil wells, which is the proportion of the drilled wells. As the production increases the reserve falls. Field production decreases at the rate $\frac{q'(s)}{q(s)} \;=\; -\theta w(t)$ (MacAvoy and Pindyck, 1973). In other words, $\frac{q'(s)}{q(s)} \;=\; -w_1(t)$, since $\theta w(t) \;=\; -w_1(t)$.

When the oil well is drilled and completed then the oil well continues to generate profit when the revenues are greater than operating costs, C_O. For the exponential growth of the $p(t)$ and $q(T|w_1(t))$ and C_O goes to 0 as t goes to ∞, we can write the quasi-rents stream from the completed oil wells as

$$\begin{aligned} V(w_1) \;&\approx\; \int_t^{\infty} e^{-r(s-t)}[p^e(s)q(s|w_1(t)) - C_O w(t)]ds \\ &= \frac{p(t)R_0 w_1(t)}{r-g+w_1(t)} \end{aligned} \tag{S5}$$

We can observe that the quasi-rents stream from the completed oil wells, $V(w_1)$ depends on the number of the completed oil wells on the field $(w_1(t))$, reserves (R_0), price $(p(t))$, difference between the discount rate (r) and the price growth (g). Hence, the $V(w_1)$ is a concave function with respect to the number of completed oil wells on the field, w_1, which means $V'(w_1) > 0$ and $V''(w_1) < 0$.

Let $\alpha(t) \in (0, 1)$ denote the proportion of recoverable reserves at the available technology level in period t. The quasi-rents from the completed oil wells, based on the recoverable reserve proportion at the available technology in period t, are given by

$$\alpha(t)V(w_1) \tag{S6}$$

For simplicity, we write $\alpha(t)$ as α.

Let the number of drilled exploration wells is $x(t)$ and $\rho x(t)$ drilled exploration wells are successful in a field. Drilling activity, d, depends on the drilling costs, C_d, where $C_d^{'}(d) > 0$ and $C_d^{''}(d) > 0$.

Now, let's explore the contracting equilibrium between the landowners and petroleum (e.g. oil and natural gas) producing firms incorporating uncompleted oil wells and completion costs in the Boyce and Nøstbakken (2011) model. In this context, the exploration and development firm makes payments to the mineral rights owner, denoted as $\varnothing_x$ and $\varnothing_d$, respectively. The profits earned on each lease by the exploration and development firms are represented as π_x and π_d, respectively. Therefore, we can express: π_x = Profits earned on each lease by an exploration firm; π_d = Profits earned on each lease by a development firm; $\varnothing_x$ = Payment to the mineral rights owner by an exploration firm; and $\varnothing_d$ = Payment to the mineral rights owner by a development firm.

Similar to Boyce and Nøstbakken (2011), the expected profits of the exploration firm are can be written as follows,

$$E[\pi_x] \quad = \quad M(\rho\pi_x - \varnothing_x) - C_x^{\tau} \tag{S7}$$

Here, M is the exploration firm's contract with the mineral rights owner, ρ is the probability that oil is discovered in the land, C_x^{τ} is the fixed costs of the exploration well with available technology. So, each mineral rights owners rent from the exploration firm is as

$$R_x \quad = \quad \varnothing_x, x = 1, 2, \ldots\ldots\ldots, M \tag{S8}$$

Here, $\varnothing_x$ is the payment to the mineral rights owner by an exploration firm. Let N is the total number of mineral rights owners in the economy. Hence, the mineral rights owner rent who waits to choose and contract with a development firm is,

$$E[R_d] \quad = \quad \rho\varnothing_d, d = M + 1, \ldots\ldots\ldots., N \tag{S9}$$

Here, ρ is the probability that oil is discovered in the land, and $\varnothing_d$ is payment to the mineral rights owner by a development firm. So, the expected profit of the earned on each lease by a development firm using equation (S8) and equation (S9) is,

$$E[\pi_d] \quad = \quad \rho(\pi_d - \varnothing_d) \tag{S10}$$

Here, $E[\pi_d]$ is the expected profit of the earned on each lease by a development firm.

Considering free entry (Yuan, 2002) into exploration and development of oil fields, at the equilibrium $E[\pi_x] = 0$ and $E[\pi_d] = 0$. Hence, at the equilibrium, $\varnothing_x = \rho\pi_x - ((C_x^{\tau})/M)$ [From equation (S7)] and $\varnothing_d = \pi_d$ [From equation (S10)]. A risk neutral mineral rights owner will be indifferent between writing a contract with an exploration and development firm if the following conditions satisfies, $R_x = E[R_d]$. Here, the mineral rights owner rents from the exploration and development firm are R_x and $E[R_d]$, respectively. Hence, we can write, $\varnothing_x = \rho\varnothing_d$ from equation (S8) and (S9). So, $\rho\pi_x - ((C_x^{\tau})/M) = \rho\varnothing_d$. From the above equations we can write,

$$M\rho(\pi_x - \pi_d) \quad = \quad C_x^\tau \tag{S11}$$

Hence, $\pi_x > \pi_d$ is necessary for equilibrium to coexist between development and exploration firms. Here, M is the exploration firm's contract with the mineral rights owner, ρ is the probability that oil is discovered in the land, π_x is the profits earned on each lease by an exploration firm, π_d is the profits earned on each lease by a development firm, and C_x^τ is the fixed costs of the exploration well with available technology.

Now, let's determine π_x and π_d where π_x is the profits earned on each lease by an exploration firm and π_d is the profits earned on each lease by a development firm; Holding M constant, the total number of wells drilled on the field after discovery, w is as follows,

$$w \quad = \quad Mw_x + (N - M)w_d \tag{S12}$$

Since the exploration firms' equilibrium choices w_x wells to develop per lease, M is the exploration firm's contract with the mineral rights owner, N is the total number of mineral rights owners in the economy, and $N - M$ symmetric development firms' equilibrium choices to develop w_d wells per lease, hence, π_x and π_d are equal.

Now, incorporating the completion costs we can write the $M\pi_x$ and π_d for each exploration and development firm as follows,

$$M\pi_x \quad = \quad \frac{Mw_x}{w}[\alpha V(w_1) - C_w^\tau w - C_D^\tau w_1], x = 1, 2, \ldots\ldots\ldots\ldots, M \tag{S13}$$

$$\pi_d = \frac{w_d}{w}[\alpha V(w_1) - C_w^\tau w - C_D^\tau w_1], d = M+1, M+2, \ldots\ldots, N \tag{S14}$$

Here, $V(w_1)$ is the quasi-rents from the completed oil wells (w_1), the α, τ are the recovery, drilling and after drilling to complete technology, respectively. w the total number of wells drilled on the field after discovery, C_w^τ = Drilling costs after exploration drilling with available technology, and C_D^τ = Fixed costs of completing the exploration well after drilling with available technology.

The idea behind equations (S13) and (S14) is that the exploration firm does not know about the oil and natural gas reserves in a field. Hence, the exploration firm buys M leases where the development firm knows the well has reserves. As a consequence, the development firm buys 1 lease, where reserve is present.

Here, equation (S13) is quasi-rents from the completed oil wells. At the equilibrium from equation (S13) and (S14), we get as follows,

$\frac{\partial \pi_d}{\partial w_d} = 0$

Since $\frac{\partial \pi_d}{\partial w_d} = [\frac{1}{w} - (\frac{w_d}{w^2})][\alpha V(w_1) - (C_w^\tau w + C_D^\tau w_1)] + \frac{w_d}{w}[[\alpha V'(w_1)\frac{\partial w_1}{\partial w_d} - (C_w^\tau)\frac{\partial w}{\partial w_d} - (C_D^\tau)\frac{\partial w_1}{\partial w_d}]$ from equation (S14).

So, $[\frac{1}{w} - (\frac{w_d}{w^2})\frac{\partial w}{\partial w_d}][\alpha V(w_1) - (C_w^\tau w + C_D^\tau w_1)] + \frac{w_d}{w}[[\alpha V'(w_1)\frac{\partial w_1}{\partial w_d} - (C_w^\tau)\frac{\partial w}{\partial w_d} - (C_D^\tau)\frac{\partial w_1}{\partial w_d}] = 0$

We cannot say $\frac{\partial w_1}{\partial w_d}$ =1 because as the development well increases it does not mean that the completed well also w_1 increases, which is different from Boyce and Nøstbakken (2011) model where $\frac{\partial w}{\partial w_d} = 1$.

Hence,

$$\frac{w_d}{w}\alpha V'(w)\frac{\partial w_1}{\partial w_d} + (1 - \frac{w_d}{w})\alpha\frac{V(w_1)}{w} = C_w^\tau + \frac{C_D^\tau}{w}(w_1 + w_d\frac{\partial w_1}{\partial w_d} - \frac{w_d w_1}{w})) \quad for\, d = 1...N-M \tag{S15}$$

Similarly, Since $\frac{\partial M\pi_x}{\partial Mw_x} = 0$, we can write the following equation (S16) from equation (S13),

$$\frac{Mw_x}{w}\alpha V'(w)\frac{\partial w_1}{\partial Mw_x} + (1 - \frac{Mw_x}{w})\alpha\frac{V(w_1)}{w} = C_w^\tau + \frac{C_D^\tau}{w}(w_1 + Mw_x\frac{\partial w_1}{\partial Mw_x} - Mw_x\frac{w_1}{1})$$
$$for\, d = 1, \dots M \tag{S16}$$

Subtracting equation (S15) from equation (S16) we get,

$$\alpha V'(w_1)(\frac{Mw_x}{w}\frac{\partial w_1}{\partial Mw_x} - \frac{w_d}{w}\frac{\partial w_1}{\partial w_d})] \quad +\alpha\tfrac{V(w_1)}{w}(\tfrac{w_d}{w} - \tfrac{Mw_x}{w}) \quad +C_D^\tau\frac{w_1}{w^2}(Mw_x - w_d)$$
$$-C_D^\tau(\frac{Mw_x}{w}\frac{\partial w_1}{\partial Mw_x} - \frac{w_d}{w}\frac{\partial w_1}{\partial w_d}) = 0 \tag{S17}$$

Equation (S17) satisfies if $Mw_x = w_d$. This outcome aligns with Boyce and Nøstbakken (2011) model.

Now, from equation (S13) and equation (S14) we can write,

$$M\pi_x = \pi_d = w_d/w(\alpha V(w_1) - C_w^\tau w - C_D^\tau w_1) \tag{S18}$$

Both equation (S11) and equation (S18) cannot hold.

Hence, no equilibrium occurs between exploration and development firm when there is exploration well related fixed costs. The development firm cannot make a contract if there is no exploration firm. As a consequence, there is only exploration firm, which indicates $N = M$. So, the equilibrium number of develop (drilled) wells, w* in the economy satisfies the following equation (S19),

$$\alpha V'(w_1*)\frac{\partial w_1^*}{\partial w^*} \quad = \quad C_w^\tau + C_D^\tau \frac{\partial w_1^*}{\partial w*} \tag{S19}$$

Th equation (S19) represents the Nash equilibrium because it yeilds an efficient outcome with a common property resource in the presence of fixed costs (Boyce and Nøstbakken, 2011).

A.2 Contractual Failures' Effect Deation

Contractual failure can happen due to the market failure such as no free entry, private or asymmetric information (Hendricks and Porter, 1988; Kellogg, 2011). If there is contractual failure, then in the symmetric Nash equilibrium $N \geq n$ where the number of the development wells, N are drilled and n is the developing firms (This indicates the number of wells (N) can be equal to or greater than the number of development firms (n)) satisfies the following equation,

$$\frac{1}{n}\alpha V'(w_n)\frac{\partial w_{1_n}}{\partial w_{d_n}} + (1 - \frac{1}{n})\frac{\alpha V(w_{1_n})}{w_n} \quad = \quad C_x^\tau + \frac{C_D^\tau}{w_n}(w_{1_n} + w_{d_n}\frac{\partial w_{1_n}}{\partial w_{d_n}} - \frac{w_{1_n}}{n}) \tag{S20}$$

[Since, N number of development firm has N wells under the contractual failure. Consequently, one firm has 1/n portion. Hence, $\frac{w_d}{w}$ of equation (S15) can be expressed as $\frac{1}{n}$. Equation (S15) is:

$\frac{w_d}{w}\alpha V'(w)\frac{\partial w_1}{\partial w_d} + (1 - \frac{w_d}{w})\frac{\alpha V(w_1)}{w} = C_x^\tau + \frac{C_D^\tau}{w}(w_1 + w_d\frac{\partial w_1}{\partial w_d} - w_d\frac{w_1}{w})$. Substituting $\frac{w_d}{w}$ by $\frac{1}{n}$, we can write equation (S20).

Here, $V(w)$ is concave and w_n increases as development firms, n increases. So, the landowners rent decreases as the development firms, n increases because $\frac{\partial(N\varnothing_x)}{\partial n} = [N\rho(\alpha V'(w_{1_n}) - C_D^\tau)\frac{\frac{\partial w_{1_n}}{\partial w_n}}{\partial n}) - C_w^\tau\frac{\partial w_n}{\partial n}] < 0$.

We find $\frac{\partial(N\phi_x)}{\partial n} < 0$ because when $w_n > w^*$ then $V'(w_{1_n})\frac{\partial w_{1_n}}{\partial n} < C_D^\tau\frac{\frac{\partial w_{1_n}}{\partial w_n}}{\partial n} + C_w^\tau\frac{\partial w_n}{\partial n}$. From equation (S19), at the equilibrium, $\alpha V'(w_1*)\frac{\partial w_1^*}{\partial w^*} = C_w^\tau + C_D^\tau \frac{\partial w_1^*}{\partial w*}]$

A.3 Comparative Static:

A.3.1 Completed Oil Wells:

For mathematical simplification, lets assume, $(\partial w_1^*)/\partial w^* = 1$.

Now, our equation (2) becomes, $\alpha V'(w_1*) = C_x^\tau + C_D^\tau$

Similar to Boyce and Nøstbakken (2011), Let, $\tau = 1, \rho = 0.1, g = 0, r = 0.1, \alpha = 1, P(t)R_0 = p_0 e^{gt} R_0 = 40e^{gt} = 40$,

$$V(w_1*) = \frac{40w_1^*}{0.1 + w_1^*} \tag{S21}$$

Using equation (S19), we get w_1* as follows,

$$w_1^* = \frac{20 - \sqrt{C_x + C_D}}{10\sqrt{C_x + C_D}}; w_1^* > 0 \tag{S22}$$

Now, $(dw_1^*)/(dC_D) = -\frac{20-\sqrt{C_x+C_D}}{20\times\sqrt{C_x+C_D}} - \frac{1}{20\times C_x + C_D} = (dw_1^*)/(dC_w) < 0$. Figure 3 shows the comparative static dynamics of w_1^*.

A.3.2 Uncompleted Oil Wells:

From equation (5) and setting $\varnothing_x = \varnothing_0 e^{rt}$ where $\varnothing_0 = 1$, $t = 12$, and $N = 16$[15] we find,

[15] N = 16 beacuse there are 16 main U.S. exploration companies, such as, ExxonMobil, Chevron, ConcoPhillips etc.(AI, 2024)

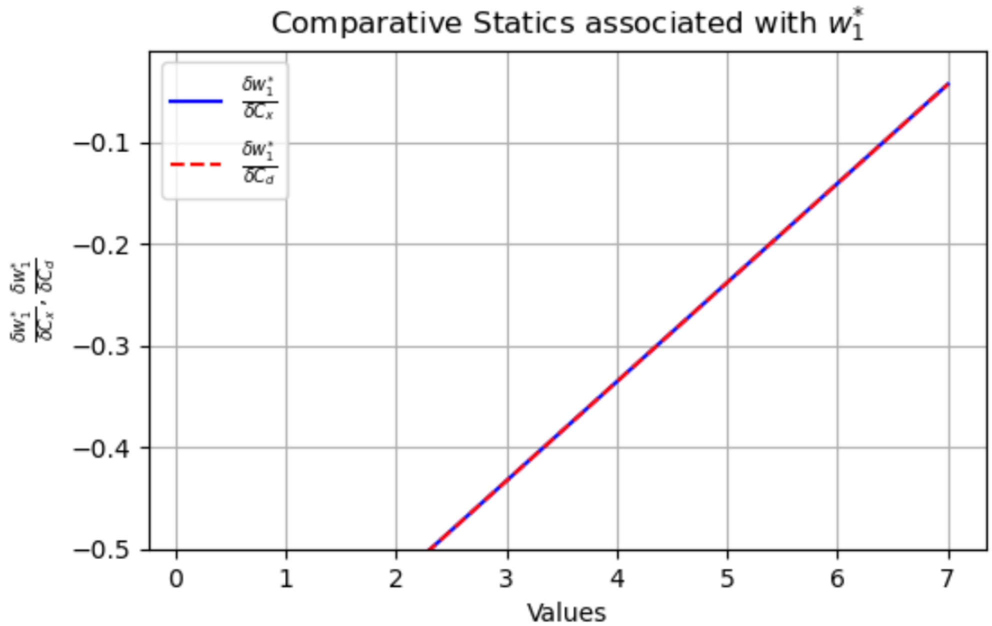
$$
\begin{aligned}
w_2^* &= \frac{N\rho\alpha V(w_1*) - N\rho\tau_1 C_w w_1^* - N\rho\tau_2 C_D w_1^* - \tau_0 C_x - N\varnothing_x}{N\rho\tau_1 C_w} = \\
&= \frac{1.6(\frac{40w_1^*}{0.1+w_1^*}) - 1.6\times C_w \times (\frac{20-\sqrt{C_x+C_D}}{10\sqrt{C_x+C_D}}) - 1.6\times C_D \times (\frac{20-\sqrt{C_x+C_D}}{10\sqrt{C_x+C_D}}) - C_x - 16*1.7}{1.6*C_w}
\end{aligned}
$$

$$
\begin{aligned}
\frac{\delta w_2^*}{\delta C_x} &= 0.625(0.08C_D\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}} + 0.08\frac{C_D}{C_D+C_x} + 0.08C_w\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}} + \\
&\quad 0.08\frac{C_w}{C_x+C_D} + 640\frac{(20-\sqrt{C_x+C_D})^2}{20\,(C_x+C_D)^{3/2}}.\frac{1}{\sqrt{C_x+C_D}(1+\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}})^2} - \\
&\quad 0.08\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}(\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}}+0.1)} + 1 - \frac{0.08}{(C_x+C_D)(\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}}+0.1)})\frac{1}{C_w}
\end{aligned}
$$

$$
\begin{aligned}
\frac{\delta w_2^*}{\delta C_D} &= 0.625(0.08C_D\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}} + 0.08\frac{C_D}{C_D+C_x} + 0.08C_w\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}} + \\
&\quad 0.08\frac{C_w}{C_x+C_D} + 640\times(20-\sqrt{C_x+C_D})\times(\frac{(20-\sqrt{C_x+C_D})}{20\,(C_x+C_D)^{3/2}} + \\
&\quad \frac{1}{20(C_x+C_D)}).\frac{1}{\sqrt{C_x+C_D}(1+\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}})^2} - 0.08\frac{20-\sqrt{C_x+C_D}}{\sqrt{C_x+C_D}} - \\
&\quad 4.8\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}(\frac{20-\sqrt{C_x+C_D}}{(C_x+C_D)^{3/2}}+0.1)} - \frac{4.8}{(C_x+C_D)(\frac{20-\sqrt{C_x+C_D}}{10\sqrt{C_x+C_D}}+0.1)})\frac{1}{C_w}
\end{aligned}
$$

The average exploration cost per drilled oil well and the average development cost per completed oil well are 1.15 and 6.58, respectively (Statista, 2023; U.S. Energy Information Administration, 2024a). The drilling cost is 0.987, which is approximately 15% of the completion costs (EIA, 2016). U.S. has 7 major oil fields and 16 major exploration firms. We are assuming that each field has 16 contracts and total exploratory costs are $1.15\times 16 = 18.5$. When $C_x = 1.15, C_D = 6.58$, and $C_W = 0.987$, we find that $\frac{\delta w_2^*}{\delta C_x} > 0$ and $\frac{\delta w_2^*}{\delta C_D} < 0$. However, $\frac{\delta w_2^*}{\delta C_D} < 0$ does not hold for very high cost values, which is unrealistic for the economy under consideration. Figure 3 shows the comparative static dynamics of w_2^*.

Figure 3: Comparative Statics of w_1^* and w_2^*



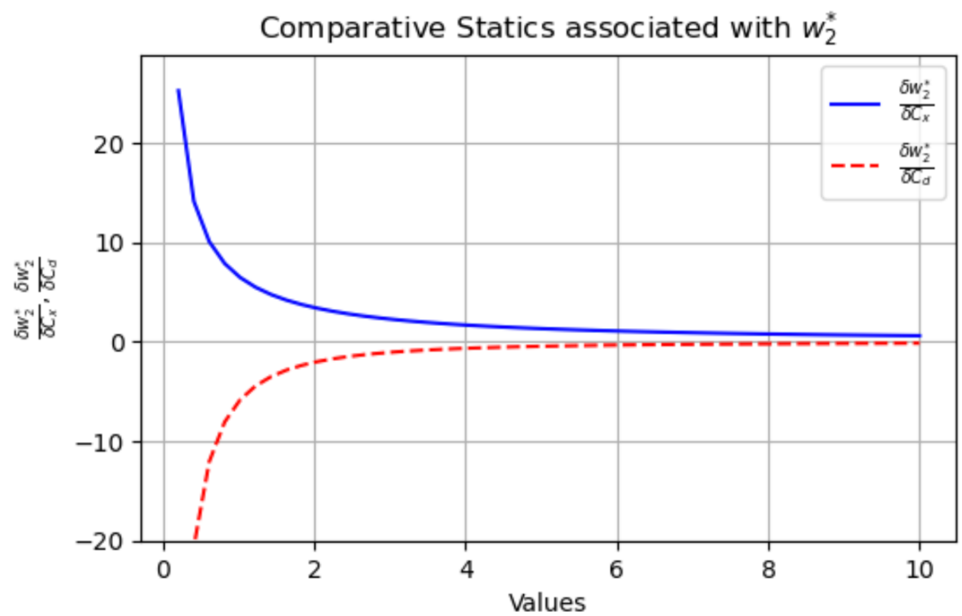


Table 7: Descriptive Statistics: Variables Description and Unit Root Results for Permian

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	1749.54	848.21	707	3400	-4.8
Exploration costs of total drill, million U.S. dollars	71	1.82	0.44	1.06	2.86	-8.7
Developemnt costs of total complete wells, million U.S. dollars	71	9.31	3.12	4.08	15.42	-9.1
Refiner acquisition costs, Dollars per Barrel	71	0.24	0.07	0.12	0.44	-4.9
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	2.5	0.9	1.02	4.75	-8.6
Gas Reserve per drill, Billion Cubic Feet/unit	71	9.02	2.96	4.38	16.87	-9.14
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	8.87×10^{-6}	0.00003	1.69×10^{-6}	0.0003	-32
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00002	0.0001	6.79×10^{-6}	0.0004	-81.6
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	6.65	2.56	3.52	14.24	-9
Rigs Count units	71	374.25	128.45	137	565	-7.6
Export, Thousand Barrels	71	148678.3	46434.29	75542	249777	-11.12

Table 8: Descriptive Statistics: Variables Description and Unit Root Results for Niobrara

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	678.66	103.04	500	870	-5.3
Exploration costs of total drill, million U.S. dollars	71	0.58	0.15	0.31	0.89	-14.73
Developemnt costs of total complete wells, million U.S. dollars	71	3.10	0.87	1.26	4.84	-13.21
Refiner acquisition costs, Dollars per Barrel	71	0.22	0.07	0.11	0.41	-5.8
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	1.96	0.81	1.12	5.56	-10.2
Gas Reserve per drill, Billion Cubic Feet/unit	71	34.21	13.37	19.40	93.81	-10.6
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	2.48e-06	3.20e-06	6.60e-07	0.00002	-75.8
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00005	0.0001	0.00001	0.0004	-66.1
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	22.91	10.35	13.40	67.97	-10.5
Rigs Count units	71	52.01	24.74	16	109	-3.7
Export, Thousand Barrels	71	15960.11	2522.21	10946	22389	-12

Table 9: Descriptive Statistics: Variables Description and Unit Root Results for Haynesville

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	169.48	58	101	359	-6.6
Exploration costs of total drill, million U.S. dollars	71	0.15	0.03	0.05	0.23	-11.96
Developemnt costs of total complete wells, million U.S. dollars	71	0.76	0.21	0.28	1.30	-13.86
Refiner acquisition costs, Dollars per Barrel	71	0.24	0.10	0.12	0.44	-4.9
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	23.51	12.37	11.44	85.38	-10.8
Gas Reserve per drill, Billion Cubic Feet/unit	71	125.10	40.48	64.81	345.85	-11.1
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	6.13×10^{-6}	8.07×10^{-6}	1.12×10^{-6}	0.00005	-61
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00003	0.00003	9.73×10^{-6}	0.0002	-54.6
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	151.95	81.56	81.74	578.14	-10.5
Rigs Count units	71	43.72	13.60	16	63	-5.7
Export, Thousand Barrels	71	148678.3	46434.29	75542	249777	-11.1

Table 10: Descriptive Statistics: Variables Description and Unit Root Results for Eagle Ford

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	1147.47	145.31	958	1434	-5.6
Exploration costs of total drill, million U.S. dollars	71	0.84	0.40	0.42	1.74	-19.54
Developemnt costs of total complete wells, million U.S. dollars	71	4.62	2.15	1.88	10.0	-14.90
Refiner acquisition costs, Dollars per Barrel	71	0.24	0.08	0.12	0.44	-4.9
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	2.30	1.15	0.72	5.85	-8.2
Gas Reserve per drill, Billion Cubic Feet/unit	71	30.43	13.04	8.79	67.39	-9.1
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	2.34×10^{-6}	3.13×10^{-6}	6.77×10^{-7}	0.00002	-81.3
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00003	0.00004	9.33×10^{-6}	0.0003	-63.2
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	0.33	0.18	0.08	0.69	-8.1
Rigs Count units	71	104.20	63.66	30	244	-3.25
Export, Thousand Barrels	71	148678.3	46434.29	75542	249777	-11.1

Table 11: Descriptive Statistics: Variables Description and Unit Root Results for Bakken

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	802.24	61.01	688	923	-6.03
Exploration costs of total drill, million U.S. dollars	71	0.49	0.24	0.26	1.10	-12.19
Developemnt costs of total complete wells, million U.S. dollars	71	2.62	1.31	0.85	5.88	-9.35
Refiner acquisition costs, Dollars per Barrel	71	0.22	0.07	0.11	0.41	-5.8
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	5.10	2.21	1.20	10.99	-12.6
Gas Reserve per drill, Billion Cubic Feet/unit	71	9.14	4.23	2.42	18.25	-11.9
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00001	0.00002	2.23×10^{-6}	0.0001	-69.8
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00001	0.00002	4.94×10^{-6}	0.0001	-75.3
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	7.09	3.35	2.64	16.13	-12.8
Rigs Count units	71	73.85	51.53	24	194	-3.55
Export, Thousand Barrels	71	15960.11	2522.21	10946	22389	-12

Table 12: Descriptive Statistics: Variables Description and Unit Root Results for Appalachia

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	970.08	223.68	658	1319	-6.4
Exploration costs of total drill, million U.S. dollars	71	0.48	0.18	0.24	0.81	-12.50
Developemnt costs of total complete wells, million U.S. dollars	71	2.78	1.03	1.38	5.05	-10.58
Refiner acquisition costs, Dollars per Barrel	71	0.26	0.08	0.13	0.45	-4.5
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	0.14	0.05	0.08	0.29	-12
Gas Reserve per drill, Billion Cubic Feet/unit	71	115.90	49.06	40.68	212.29	-11.4
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	4.75×10^{-8}	7.57×10^{-8}	8.13×10^{-9}	4.33×10^{-7}	-76.3
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00003	0.00003	8.93×10^{-6}	0.0002	-40.5
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	63.27	27.75	24.21	137.83	-11.6
Rigs Count units	71	77.21	26.07	35	131	-3.8
Export, Thousand Barrels	71	9388.06	3285.25	3646	20094	-12.6

Table 13: Descriptive Statistics: Variables Description and Unit Root Results for Anadarko

Variables, Unit	Obs	Mean	Std. Dev.	Min	Max	Test stat (unit root test)
Uncompleted oil wells, units	71	674.92	234.97	311	1098	-5.2
Exploration costs of total drill, million U.S. dollars	71	0.59	0.20	0.22	1.10	-12.73
Developemnt costs of total complete wells, million U.S. dollars	71	2.98	1.23	1.23	5.84	-9.67
Refiner acquisition costs, Dollars per Barrel	71	0.23	0.07	0.11	0.42	-5.5
Oil Reserve per drill, $\frac{MillionBarrels}{unit}$	71	2.46	1.01	1.00	5.36	-12.5
Gas Reserve per drill, Billion Cubic Feet/unit	71	45.98	16.80	22.03	91.89	-12.6
Oil Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	2.29×10^{-6}	2.46×10^{-6}	7.82×10^{-6}	0.00002	-84
Gas Reserve ratio, $\frac{MillionBarrels/}{MillionBarrels+(bbl/d+Mcf/d)}$	71	0.00005	0.00006	0.00001	0.0003	-67.9
Pipeline Capacity per drilled, Million standard cubic feet per day (mmcfd)	71	22.06	8.76	10.64	44.66	-12.6
Rigs Count units	71	123.01	55.04	45	247	-3.7
Export, Thousand Barrels	71	164230.7	48081.11	87377	266877	-10.8

Table 14: Uncompleted Oil Wells Autocorrelation

Regions	Lag 1	Lag 2	Lag3
U.S. (Prob)	0.443 (0.00)	0.28 (0.00)	0.11 (0.00)
Permian (Prob)	0.53 (0.00)	0.42 (0.00)	0.26 (0.00)
Niobrara (Prob)	0.93 (0.00)	0.84 (0.00)	0.75 (0.00)
Haynesville (Prob)	0.91 (0.00)	0.82 (0.00)	0.73 (0.00)
Eagle Ford (Prob)	0.93 (0.00)	0.86 (0.00)	0.77 (0.00)
Bakken (Prob)	0.33 (0.01)	0.26 (0.002)	0.005 (0.01)
Appalachia (Prob)	0.27 (0.02)	0.22 (0.011)	0.03 (0.03)
Anadarko (Prob)	0.97 (0.00)	0.93 (0.00)	0.88 (0.00)

Table 15: RMSE of the Out-of-Sample Forecasts

	ARDL		NARDL		LS		VAR
	R^2	RMSE	R^2	RMSE	R^2	RMSE	R^2
U.S.	**0.80**	**82.35**	0.81	250.02	0.39	104.32	0.74
Permian	**0.80**	**18816.88**	0.80	18866.61	0.2	20987.56	0.63
Niobrara	0.88	11.77	**0.89**	**11.51**	0.32	21.53	0.50
Haynesville	0.94	4.27	**0.94**	**3.64**	0.68	8.50	0.54
Eagle Ford	**0.93**	**18.04**	0.93	24.92	0.55	31.69	0.40
Bakken	**0.89**	**9.41**	0.89	11.49	0.5	17.17	0.51
Appalachia	0.91	11.48	**0.92**	**11.14**	0.43	24.78	0.48
Anadarko	**0.84**	**20.96**	0.84	21.03	0.33	24.25	0.57

Table 16: Results of Uncompleted Oil Wells for Repeal of Export Ban 2016: U.S., Permian, Niobrara, and Haynesville

Variables	U.S.	Permian	Niobrara	Haynesville
Uncompleted oil wells$_{t-1}$	0.62*** (0.14)	0.75*** (0.10)	0.83** (0.1)	0.45*** (0.17)
Uncompleted oil wells$_{t-2}$	-	-	-	0.38*** (0.13)
Ex. cost	-51.76 (177.05)	114.37*** (36.72)	229.74*** (35.27)	197.66*** (34.02)
Dev. cost	7.75 (44.25)	-27.80*** (6.02)	-37.29*** (4.91)	-34.55*** (3.89)
Ref. acq. cost$_{t-1}$	78.54 (4408.27)	846.54 (853.59)	-750*** (189.13)	-155.56 (129.34)
$p_{oil_{t-1}}$	–1131.84 (4093.20)	-963.30 (683.42)	630.21** (249.87)	68.00 (108.16)
Oil reserve ratio	1.01×10^8 (1.33×10^8)	1.57×10^5* (5.69×10^4)	2.01×10^8 (1.27×10^8)	-9.83×10^7*** (3.79×10^6)
Oil reserve ratio$_{t-1}$	2.97×10^7 (6.50×10^7)	-	-1.12×10^8** (4.08×10^7)	-3.26×10^6 (3.73×10^6)
Oil reserve ratio$_{t-2}$	-1.11×10^8 (7.18×10^7)	-	-1.41×10^8*** (5.72×10^7)	2.79×10^6* (1.63×10^6)
Gas reserve ratio	-5.83×10^6 (9.79×10^6)	3.86×10^7** (1.23×10^5)	-5.00×10^6 (4.25×10^6)	2.72×10^6*** (9.94×10^5)
Gas reserve ratio$_{t-2}$	7.14×10^6 (4.19×10^6)	-3.78×10^7*** (9.54×10^5)	6.13×10^6*** (1.88×10^6)	-3.45×10^5 (4.13×10^5)
Gas reserve ratio$_{t-3}$	-	2.22×10^7*** (8.67×10^5)	-	-
Pipeline cap.$_{t-2}$	3.99* (1.72)	0.86 (4.84)	-	-
Pipeline cap.$_{t-4}$	-5.77*** (2.04)	-	-	-
Rig count	-1.73* (0.95)	-1.31*** (0.41)	-0.35 (0.70)	0.13 (0.16)
Rig count$_{t-1}$	1.93 (1.16)	1.56*** (0.50)	0.50 (0.58)	0.14 (0.15)
Export ban	0.002** (0.001)	0.0004 (0.0005)	-0.001 (0.001)	5.36×10^{-5} (5.36×10^{-5})
Export ban$_{t-3}$	-0.001 (0.002)	-	-	0.0001** (5.98×10^{-5})

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.

Table 17: Results of Uncompleted Oil Wells for Repeal of Export Ban 2016: Eagle Ford, Bakken, Appalachia, and Anadarko

Variables	Eagle Ford	Bakken	Appalachia	Anadarko
Uncompleted oil wells$_{t-1}$	0.77*** (0.08)	0.89*** (0.10)	0.69*** (0.10)	0.72*** (0.14)
Ex. cost	212.66*** (36.98)	260.92*** (31.77)	233.15*** (38.63)	153.93* (79.82)
Dev. cost	-32.43*** (3.70)	-43.86*** (5.05)	-30.94*** (4.52)	-26.95*** (7.70)
Ref. acq. cost	1001.85 (644.98)	-105.40 (206.05)	759.69** (363.21)	-56.72 (542.39)
$p_{oil_{t-1}}$	-246.41 (524.32)	167.82 (227.78)	-471.40** (221.37)	282.10 (431.27)
p_{gas}	-4.62×10^3 (3.82×10^3)	-829.49 (1682.19)	-3611.87** (1710.82)	-937.54 (3241.91)
Oil reserve ratio$_{t-1}$	5.42×10^8 (1.03×10^8)	-2.08×10^8*** (9.55×10^6)	1.56×10^9 (1.54×10^8)	-1.78×10^6 (1.56×10^8)
Oil reserve ratio$_{t-2}$	2.74×10^8** (1.30×10^8)	1.99×10^7*** (6.83×10^6)	1.23×10^9* (6.49×10^8)	3.21×10^7 (1.76×10^8)
Gas reserve ratio	1.49×10^7 (9.69×10^6)	8.54×10^6 (9.61×10^6)	1.15×10^7*** (3.39×10^6)	1.95×10^6 (5.12×10^6)
Gas Reserves	-5.38 (3.14)	0.41 (11.73)	-0.83*** (0.33)	4.70 (4.22)
Pipeline cap$_{t-1}$	-	36.72 (27.89)	-1.14*** (0.40)	-2.83 (7.61)
Pipeline cap$_{t-3}$	-	-	0.45** (0.18)	1.12 (5.55)

Notes: The standard deviation (robust) is in parentheses. *** significant at the 1% level, ** significant at the 5% level, * significant at the 10% level, - denotes estimated model does not have coefficient associated the variable.