STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

REBUTTAL TESTIMONY OF ROBERT ARSCOTT, PH.D.

Q: Is Mr. Purvis's notion of "holdback" a reliable measure of the value of oil and gas wells or the likelihood that they will become orphaned?

A: No. The concept of "holdback," as it is described by Mr. Purvis, is not codified in any reliable treatise or textbook on the subjects of finance or economics, nor in any reliable authority of best practices for valuation in the oil & gas industry. In my opinion, "holdback" should not be relied upon to assess the viability of existing oil and gas wells because it does not accurately reflect market value and therefore cannot measure whether a well is a "net liability" as Mr. Purvis suggests.[1] It misrepresents the economic value of producing oil and gas wells and exaggerates the value of asset retirement obligations in comparison to the expected cash flow from continued operations.

[1] Direct Testimony of Mr. Dwayne Purvis Testimony, WELC Exhibit 30, 53:11–12.

Mr. Purvis defines "holdback" as the point in the life of well at which the cumulative value of all future operating profit from continued operations is exactly offset by the anticipated cost of plugging and abandonment.[2] Because the anticipated revenue from the well is declining over time, Mr. Purvis notes that as the well ages beyond that point in time, the sum of cumulative expected profit falls below the anticipated costs of the associated asset retirement obligation. Mr. Purvis characterizes wells in those cases to be "net liabilities."[3] Mr. Purvis notes that this holdback period is reached "surprisingly early"[4] and purports to identify those wells as having significant liability for the state.[5] This is misleading and mischaracterizes both the economic value of wells and the likelihood that they will become orphaned.

To illustrate the flaws in Mr. Purvis's notion of "holdback," consider his example, on pages 28 and 29 of his testimony, in which a well is expected to continue to produce $25 million in cumulative cash flow over the next 13 years, at which point it would need to be plugged at an expected cost of exactly $25 million. Because the expected positive cash flow is exactly offset by the expected cost of asset retirement, the well has reached "holdback." This is at odds with the net present value (or "NPV") of the well, which is $25 million in Mr. Purvis's example.[6] On that point, Mr. Purvis states, "[i]f a company were to pay $25 million for the field, operate the well according to plan, and then pay for decommissioning, then it would lose $25 million dollars for its many years of work. All of

[2] *Id.,*29: 15–17.
[3] *Id.*, 29, 15–17.
[4] *Id.*31:12–14.
[5] Purvis, Dwayne. 2022. "Economic Yardsticks for the End of Economic Life: Holdback and Its Adjuncts." Proceedings - SPE Annual Technical Conference and Exhibition 2022-October, *available at* https://doi.org/10.2118/210226-MS
[6] *See* WELC Applicants' Exhibit 38.

the operating profits that came in the door during operations would go back out of the door at the end of operations."[7] However, the NPV is the most common method employed in the valuation of oil and gas wells, implying that the well is indeed worth $25 million at the point of entering "holdback" even though the cumulative sum of cash flows is equal to $0.[8]

This apparent paradox can be reconciled through the application of a fundamental concept in economics known as the time value of money. This concept is foundational in valuation and all other aspects of financial economics. I have taught this concept to hundreds of students over the years and have always introduced it at the beginning of the second lecture of my introductory course in finance. The concept is covered within the first two or three chapters in most introductory finance textbooks because the time value of money is required for understanding almost all other concepts in finance.

The time value of money implies that the value of a dollar today is worth more than the value of a dollar tomorrow. To develop some intuition for why that must be true, consider that a dollar deposited in a risk-free savings account at a rate of 5% interest would grow to $1.05 in one year. Therefore, the dollar received and invested today must be worth more than a dollar received in one year. This also implies that money received or paid at different points in time cannot be added together without first expressing them in equivalent time value. In the same way that adding cash flow denominated in U.S.

[7] Purvis Testimony, 29:10–14.
[8] Society of Petroleum Evaluation Engineers, 2025, 42nd Annual Survey of Parameters Used in Property Evaluation, p. 15.

dollars to cash flow denominated in Canadian dollars makes no economic sense, adding cash flows denominated in different time units makes no sense.

By defining "holdback" as a function of the undiscounted sum of cash flows over time, Mr. Purvis has committed a fundamental error in the calculation of value. "Holdback" mischaracterizes the true economic value of oil and gas wells. As a result, it is unreliable as a metric for investment valuation, including the estimation of a well's value, the decision of when to plug and abandon ("P&A") a well, and in the assessment of the risk that a well will become orphaned.

A simplification of Mr. Purvis's example may serve to provide insight into "holdback's" failings. Instead of a series of cash flows over the next 13 years, consider only two cash flows: a positive $25 million received today, and a negative $25 million paid in exactly one year to P&A the well. The cumulative expected cash flow is equal to zero, meaning this well qualifies as having reached "holdback" and therefore has "no value" according to Mr. Purvis's analysis. If the operator can invest the $25 million today back into operations at an expected rate of return equal to 10%, which I have previously testified is a typical required rate of return for upstream oil and gas projects, that investment would be expected to grow to a value of $27.5 million in one year. At that point, deducting the $25 million to retire the asset would leave the operator a net positive $2.5 million at the end of one year. Clearly, the well in this example has significant economic value, despite the sum of undiscounted cash flows equaling zero.

Mr. Purvis's definition precludes the possibility of any investment over a well's life that might grow over time and offset the value of anticipated costs of asset retirement. Further, he assumes that the funds allocated toward decommissioning a well must come from the well's own cash flow. Those constraints do not reflect the existence of financial markets and the set of investment opportunities available to operators. Operators can and do reinvest cash flow from operations into new projects, including new drilling, workovers, and acquisitions. These are appropriate uses of funds for an upstream oil and gas company with valuable investment opportunities. Many of those activities have an expected rate of return of 10 percent per year or more.[9] Although, those activities may be risky in the sense that actual returns could differ from expected values. Of course, that is true of all industries, not just oil and gas. But, even with the extreme assumption that operators should take no risk in their plans to fund their asset retirement obligations, operators could simply invest in government bonds. Such investments are generally considered to be risk-free, meaning there is no uncertainty as to their payoffs. In the above example, were the $25 million invested today in a US Treasury security maturing in one year at a four percent rate of return, that investment would grow to $26 million in one year's time. Therefore, even in this extreme example in which the operator plans its funding of asset retirement obligations using only risk-free investments, the operator would still capture a surplus of $1 million after paying the costs of plugging and abandonment.

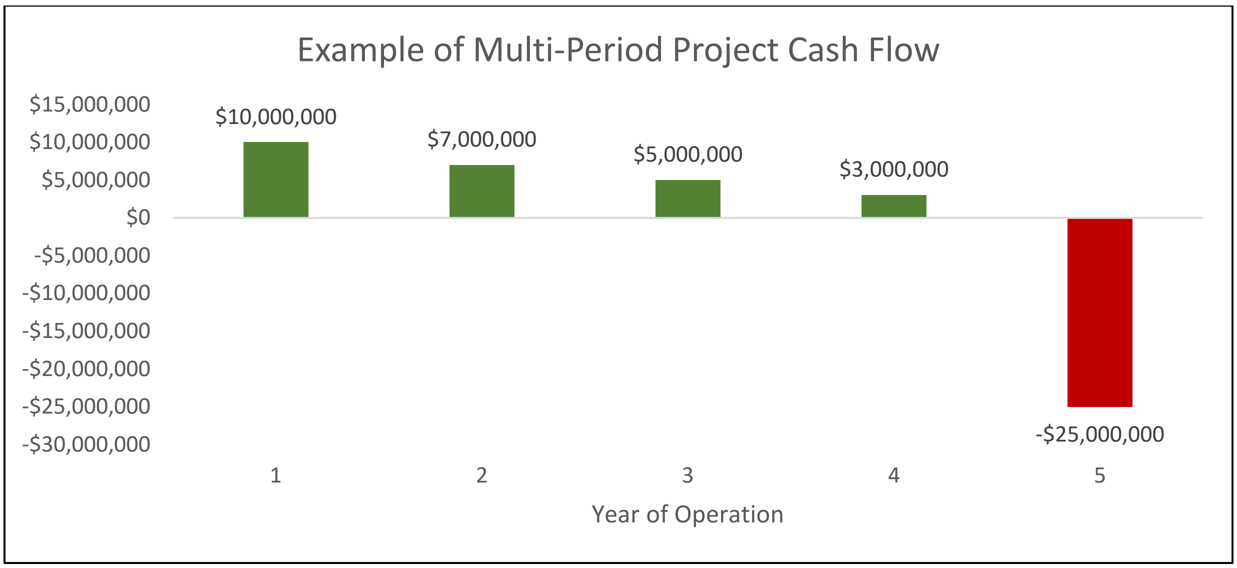
Again, Mr. Purvis's view would characterize that well as having no value. Yet, the well clearly does. And this conflict exemplifies why the concept of "holdback" carries no clear economic meaning.

---

[9] [9] Society of Petroleum Evaluation Engineers, 2025, 42nd Annual Survey of Parameters Used in Property Evaluation, pp.41-42.

The failure of “holdback” to properly account for the time value of money is not limited to the simplistic example of one positive cash flow today and one negative cash flow one year from now. To illustrate this fact, consider an example that more closely resembles the type of cash flow profile of an oil well, in which a series of declining positive cash flows are followed by a single, large outflow at the end of the well’s life. This example is depicted in IPANM Supplemental Exhibit 29.

IPANM Supplemental Exhibit 29



Initially, cash flow is $10 million at the end of Year-1. It then declines to $7 million in Year-2, $5 million in Year-3, and $3 million in Year-4. Finally, the project has a large outflow of negative $25 million in Year-5. The cumulative sum of undiscounted cash flows is equal to $0, so this example would be characterized as having reached “holdback” according to Mr. Purvis at the beginning of Year-1.

The NPV of a project is the gold standard measure of a project’s value. It takes into account not only the expected cash flows associated with a project, but also the necessary rate of return a rational investor would require to invest in the project. Indeed, surveys of petroleum evaluation engineers regularly report that NPV is their preferred method of project evaluation.[10] Assuming a required rate of return of 10 percent, the NPV in this example is $5,158,614.[11] In other words, a rational buyer would be willing to pay, and a rational seller would be willing to sell, the project in Exhibit 29 for $5,158,614 today.

Yet Mr. Purvis would characterize this project as being a "net liability." To understand why that claim must be false, consider the actions of a rational operator. Assuming the operator reinvests cash flows from operations into similar projects which also offer a 10 percent expected rate of return, that operator would expect to have amassed a surplus of $8,308,000 by the end of Year-5, *after paying $25 million to plug and abandon the well*. IPANM Supplemental Exhibit 30 helps to illustrate why that is the case.

IPANM Supplemental Exhibit 30

Year	Beginning Balance	Growth in Savings	Investment or Withdrawal	Ending Balance
1	$0	$0	$10,000,000	$10,000,000
2	$10,000,000	$1,000,000	$7,000,000	$18,000,000
3	$18,000,000	$1,800,000	$5,000,000	$24,800,000
4	$24,800,000	$2,480,000	$3,000,000	$30,280,000
5	$30,280,000	$3,028,000	-$25,000,000	$8,308,000

For ease of interpretation, you can think of the table in IPANM Supplemental Exhibit 30 as depicting a sequence of deposits and withdrawals into a bank account that

[10] Society of Petroleum Evaluation Engineers, 2025, 42nd Annual Survey of Parameters Used in Property Evaluation, p. 15.
[11] Calculations are included in my workpapers submitted with this testimony.

pays a savings rate equal to 10 percent per year.[12] In the first year, the well produces $10 million, which is then deposited into the account. Those funds then grow by a total of $1 million over the course of Year-2. Additionally, the well produces $7 million in year-2, which is also deposited into the account. At the end of Year-2, the account balance is $18 million, which consists of the beginning balance of $10 million, plus the $1 million growth in savings, plus the $7 million from the well in Year-2.That $18 million then grows by $1.8 million over the course of Year-3. The sum of the beginning balance of $18 million, the growth in savings of $1.8 million, and the $5 million from the well in Year-3 equals the Year-3 ending balance of $24.8 million. Similarly, the Year-4 ending balance of $30.28 million is equal to the sum of the initial balance of $24.8 million, the growth in savings of $2.48 million, and the well's cash flow of $3 million.

Finally, in Year-5 the operator pays $25 million to P&A the well. But the operator still has a surplus of $8,308,000 at the end of Year-5. That surplus is exactly equivalent to the project's NPV of $5,158,614. To illustrate that equivalence, IPANM Supplemental Exhibit 31 depicts the same bank account exercise from an initial deposit equal to the project's NPV.

[12] In reality, those funds are reinvested in the company's operations, but that makes no difference for developing the intuition this example is meant to convey.

IPANM Supplemental Exhibit 31

Year	Beginning Balance	Growth in Savings	Investment or Withdrawal	Ending Balance
1	$5,158,614	$515,861	$0	$5,674,476
2	$5,674,476	$567,448	$0	$6,241,923
3	$6,241,923	$624,192	$0	$6,866,116
4	$6,866,116	$686,612	$0	$7,552,727
5	$7,552,727	$755,273	$0	$8,308,000

The investment of the project's NPV grows over time at a 10 percent return per year, ultimately equaling the surplus of $8,308,000 at the end of Year-5. In this way, the NPV expresses the expected economic value of a project in today's dollars. A necessary assumption of the NPV is a rate of return that accurately reflects the opportunity cost of the project's cash flows. In the above example, that rate was assumed to be 10 percent. As stated in my earlier testimony, that rate is typical of projects involving Proved Developed Producing ("PDP") reserves in the oil and gas industry.[13]

For argument's sake, we can consider the amount of money the operator would need to set aside today to exactly cover the anticipated $25 million to plug the well at the end of Year-5. Assuming the operator earns a 10 percent rate of return on its investments, the operator would only need to set aside approximately $15.5 million today, as shown in IPANM Supplemental Exhibit 32.

[13] Society of Petroleum Evaluation Engineers, 2025, 42nd Annual Survey of Parameters Used in Property Evaluation, p. 42.

IPANM Supplemental Exhibit 32

Year	Beginning Balance	Growth in Savings	Investment or Withdrawal	Ending Balance
1	$15,523,033	$1,552,303	$0	$17,075,336
2	$17,075,336	$1,707,534	$0	$18,782,870
3	$18,782,870	$1,878,287	$0	$20,661,157
4	$20,661,157	$2,066,116	$0	$22,727,273
5	$22,727,273	$2,272,727	$0	$25,000,000

Even restricting the operator to risk-free investments, the required savings amount today to offset the projected retirement obligation is far smaller than the face value of that liability. IPANM Supplemental Exhibit 33 depicts the hypothetical investment of $20.5 million today in US Treasury securities with a 4 percent rate of return, which would grow over time *at no risk*, to eventually equal an amount exactly sufficient to cover the expected costs of plugging and abandonment.

IPANM Supplemental Exhibit 33

Year	Beginning Balance	Growth in Savings	Investment or Withdrawal	Ending Balance
1	$20,548,178	$821,927	$0	$21,370,105
2	$21,370,105	$854,804	$0	$22,224,909
3	$22,224,909	$888,996	$0	$23,113,905
4	$23,113,905	$924,556	$0	$24,038,462
5	$24,038,462	$961,538	$0	$25,000,000

Therefore, even in the absence of risk, the amount required to be saved today to offset the anticipated costs of plugging and abandonment is lower than the face value of that anticipated liability. Mr. Purvis notion of “holdback” completely ignores this fact.

Even under Mr. Purvis’s extraordinary requirement that the well must self-fund the cash necessary for its own plugging and abandonment—which I strongly believe is inappropriate in many cases—the returns operators would reasonably expect to earn on their savings implies that project cash flows could be invested, even at risk-free rates, to yield additional cash flow that would offset the anticipated costs of asset retirement. IPANM Supplemental Exhibit 34 depicts a hypothetical strategy in which the well's own cash flows are invested at the risk-free rate of 4%. That strategy would result in a project surplus of $3.1 million. Again, the concept of "holdback" ignores the possibility of such surplus and ignores the existence of, and operators' access to, financial markets. It is not true that, "when a well crosses over into the period of holdback, it is then by definition no longer capable of funding its own decommissioning."[14]

IPANM Supplemental Exhibit 34

Year	Beginning Balance	Growth in Savings	Investment or Withdrawal	Ending Balance
1	$0	$0	$10,000,000	$10,000,000
2	$10,000,000	$400,000	$7,000,000	$17,400,000
3	$17,400,000	$696,000	$5,000,000	$23,096,000
4	$23,096,000	$923,840	$3,000,000	$27,019,840
5	$27,019,840	$1,080,794	-$25,000,000	**$3,100,634**

The costs of asset retirement may be expected to change over time with, for example, the prices for materials and labor used in plugging and remediation activities. Inflation expectations can be, and often are, incorporated into the cash flow projections for any project, including oil and gas wells. The expectation that asset retirement cash flows will grow with inflation does not change the fundamental problems with Mr. Purvis's notion of "holdback." Even if one were to project future plugging costs at their present-day values, the problems I have identified in Mr. Purvis's analysis persist because the expected rate

[14] Purvis Testimony, 53:10–11.

of inflation is, in almost all realistic cases, lower than the nominal discount rates assumed in the NPV calculation. As a result, even a strictly internally funded well can be expected to experience a surplus of funds in excess of its asset retirement costs despite it being in "holdback." Again, these wells are not strictly net liabilities as Mr. Purvis presents.

In his testimony, Mr. Purvis stated that, "[t]he [NPV] concept is commonly applied to decommissioning liabilities despite the fact that decommissioning is not an investment and is not uncertain."[15] This statement is misleading. Firstly, the characterization of cash flows as investments or otherwise is irrelevant in the proper valuation of future cash flows, which must be discounted to account for the time value of money. Secondly, decommissioning costs are uncertain. At the very least, these values are influenced by the uncertain evolution of prices for decommissioning services, which Mr. Purvis not only acknowledges in his testimony, but specifically cites in support of aspects of the proposed rule concerning CPI indexing.[16] Not only are the projected costs of asset retirement uncertain, but their timing is subject to variation as well. Unforeseen mechanical difficulties, for example, would affect the time at which a well is plugged. So too would unexpected changes in commodity prices and the cost of services, which would affect the cash flow associated with a well and therefore its economic life. This illustrates yet another problem with "holdback" insofar as it can only be known in hindsight after the well's economic life has expired. Prior to that time, the uncertainty surrounding changes in commodity prices, cost of services, and other factors affecting the economic life of a well would prevent the determination of exactly when the period of "holdback" begins.

---

[15] Purvis Testimony, 27:17–18.
[16] Purvis Testimony, 71:5–73:17.

The practice of incorporating expected decommissioning costs into NPV analyses of oil and gas wells is entirely appropriate because the anticipated operational cash flows associated with a well would not exist without the accompanying necessity for eventual decommissioning. As a result, the expected costs of asset retirement are typically incorporated, either directly or indirectly, into the NPV analysis of new drilling opportunities.[17] Even in cases in which the drilling operator expects to eventually sell the well to another operator prior to termination of the well's economic life, that potential buyer would be assumed to pay the NPV as of the purchase date of expected remaining cash flows, including those associated with asset retirement. The cash flows anticipated during the "holdback" period are an important component of a well's overall value and are therefore incorporated into an operator's decision to drill new wells and continue the operation of, or to purchase, existing wells. Ignoring the present value of cash flows during "holdback" serves no good purpose and distorts the value of oil and gas wells. For example, if an operator were to P&A a well upon reaching "holdback," the present value of remaining production revenue would be lost, resulting in a needless forfeiture of value.

Mr. Purvis posed the following in his testimony: "[t]he question of policy is always the question of the greatest public good, and the question becomes which is better for the state: immediate orphaning but less total cost, or more total cost over a longer period as more wells become unable to pay their obligations."[18] Setting aside the real-world complexity arising from innumerable possible policy responses, the answer depends on the total costs related to immediate plugging of those orphaned wells, the costs that could

[17] Society of Petroleum Evaluation Engineers, 2025, 42nd Annual Survey of Parameters Used in Property Evaluation, p. 29.
[18] *Id.*, 44:13–16.

reasonably be expected in the future, and also the savings the state could earn on any deferred costs. Certainly, if the present value of deferred costs is lower than the present value of immediate plugging, then the state is economically better off deferring plugging activity even if the total undiscounted sum of those future costs would be higher than in the alternative. But the more important question for the Commission or the Legislature is how large are the "costs related to immediate plugging" for the state if the proposed rules result in a significant number of orphaned wells.

In summary, "holdback" is not a useful metric for the economic evaluation of oil and gas properties, nor does it offer insight into the economic value of future retirement obligations or aid in the planning to fund such obligations. It does not align with fundamental concepts in economics and finance. It ignores the reality of operators' investment possibilities and the existence of financial markets. It has the unfortunate appearance of validity to those not versed in economic or finance theory, but it should not be relied upon in any matter concerning the value of, and planning for, asset retirement obligations.

Q: Do you agree with Mr. Purvis's assertion that the operators expected to exit the industry as a result of the proposed rules "will be missed least"?[19]

A: No, because the proposed rules and circumstances here are different from those considered in the two academic studies Mr. Purvis cited in his testimony. While Boomhower (2019) does find evidence of positive effects related to the introduction of

[19] Purvis Testimony, 44:19–20.

financial assurance requirements in Texas during 2002 and 2003, his measurements were limited to *surviving* firms.[20] Further, that study examines the adoption of financial assurance rules nearly identical to the current financial assurance rules in New Mexico, *i.e.* single-well coverage based on $2 per vertical foot of well depth and blanket coverage for multiple wells. The proposed rules Mr. Purvis supports would represent a change in financial assurance costs that, in some cases, will be significantly larger than the cost increases resulting from the Texas rule change. That raises the likelihood that the composition of firms that would exit in response to the proposed rules will be markedly different than those that exited in response to the Texas rule change. We therefore cannot be certain that the positive effects identified by Boomhower (2019) in Texas will also manifest in New Mexico in response to the rules proposed by Applicants.

The effects identified by Lange & Redlinger (2019), which Mr. Purvis also cites, are in relation to regulatory changes involving not only higher bonding requirements, but also restrictions on waste disposal and the introduction of formal standards and the disclosure of chemicals used in hydraulic fracturing.[21] Their results therefore cannot be attributed to bonding requirements in isolation. Further, their results concerning the introduction of new regulation and the frequency of drilling incidents are correlative, and do not necessarily imply a causal relation between the two.

---

[20] Boomhower, J., 2019. Drilling like there's no tomorrow: Bankruptcy, insurance, and environmental risk. American Economic Review, 109(2), pp.391-426.
[21] Lange, I., and Redlinger, M., 2019, Effects of stricter environmental regulations on resource development, Journal of Environmental Economics and Management, 96, pp. 60-87.

Q: Do you agree with Mr. Purvis that "most companies should be able to stay close or below the 15 percent threshold if they are actively managing their wells to prevent waste and actively plugging wells without clear economic prospects"?[22]

A: It is not clear that *most* companies would be able to avoid the 15 percent threshold. According to Exhibit 52 of Mr. Purvis's testimony, over 52 percent of operators in New Mexico are already in breach of the 15 percent threshold. So, by definition, *most* companies are currently at risk of a significant increase to their financial assurance requirements due to the proposed 15 percent threshold. Further, according to that same exhibit, Mr. Purvis estimates that nearly one in five wells across the state are in portfolios that are currently in breach of the 15 percent threshold.

It is also unclear, under the proposed rules, whether there is a path back to blanket financial assurance coverage for an operator that reduces its proportion of marginal wells below the 15 percent threshold. I do not see any mechanism in the proposed rulemaking that would allow the release of single well bonding for wells that are not "marginal" if the operator reduces its "marginal" inventory below the 15% threshold unless the current regulation allowing for release of financial assurances for wells that "have been covered by another financial assurance that the division has approved" in Subsection A of 19.15.8.12 NMAC will be interpreted to allow an operator to cover its non-marginal wells with a blanket bond once the operator is under the 15% threshold.

Assuming there could be a reversion to blanket coverage for non-marginal wells, I would expect operators to adapt to the proposed rules, if adopted, by immediately

[22] Purvis Testimony, 66:3–5.

plugging marginal and idle wells in order to maintain or resume its ability to secure financial assurance through blanket coverage; however, plugging takes time and the capacity of the state's finite number of contractors to perform the work would likely be strained by the sudden surge in the demand for plugging services. Assuming the services were available to plug such a large number of wells in such a short time, the administrative burden on the regulator charged with granting permits and overseeing the verification of that plugging activity could be significant. Additionally, wells will continue to migrate into marginal status as they age, contributing to the number of wells that would need to be plugged in order to avoid the 15 percent threshold. While it is conceivable that some operators could adapt quickly by plugging wells prior to the implementation of the proposed rules, it is far from certain that *most* operators would have the ability to do so.

Q: Do you agree with Mr. Purvis that the OCD will be capable of efficiently and objectively applying the definition of marginal wells?[23]

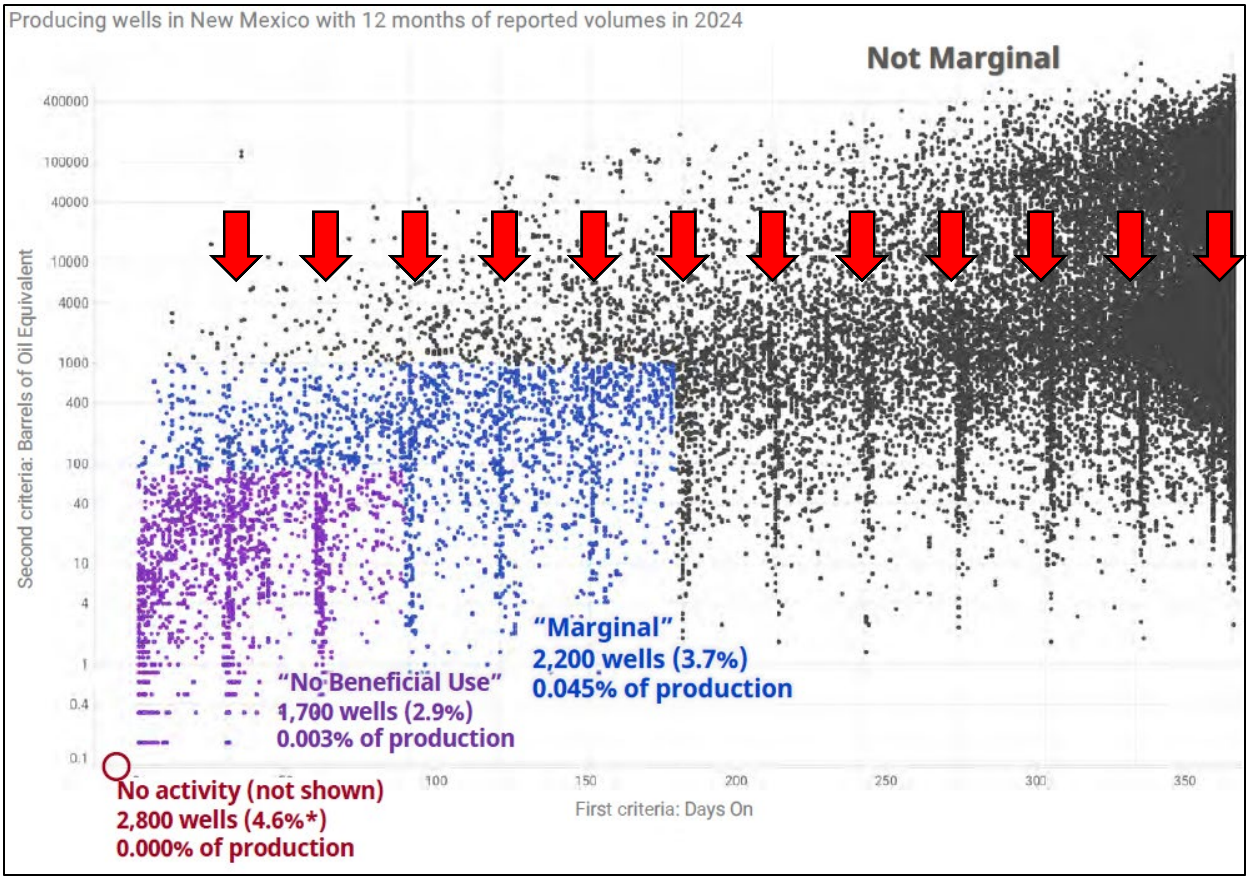
A: It may be difficult to implement the proposed rules as contemplated. Mr. Purvis points out that the classification and identification of marginal wells depend on information self-reported by operators on a monthly basis.[24] Clearly, there is an incentive to avoid the increased financial assurance costs associated with marginal wells, especially if the classification would result in a breach of the 15 percent threshold. As a result, I would expect operators to adjust to the proposed rules by increasing the number of days on which low-producing wells are producing, to whatever extent possible. This might include

[23] Purvis Testimony, pp. 53-54, 21–2.
[24] Purvis Testimony, pp. 53-54, 22–2.

a reduction in the number of production hours per day or it could result in actual increased production over additional days. While this could potentially result in economically inefficient production—for example, producing at times of low commodity prices—it could be to the operator's advantage to do so if the increased financial assurance burden could be avoided. Setting aside the conflict of interest this could create between the operator and other interest owners, the operator's ability to affect the variables used to determine regulatory treatment presents the possibility that reported values may not accurately represent actual production time.

From a practical standpoint, the proposed definition of a marginal well may be difficult to effectively implement. It is likely that operators already report the number of production days somewhat imprecisely. This is evident from some of the exhibits presented by Mr. Purvis. For example, Applicants' Exhibit 40, reproduced below as IPANM Supplemental Exhibit 35, shows evidence of significant bunching at production days exactly equal to a multiple of the number of days in a month, e.g. 30, 60, 90, etc.

IPANM Supplemental Exhibit 35



I have overlaid red arrows to highlight these areas of bunching. The bunching is evident as vertical lines throughout the data at salient day counts. This picture indicates to me that operators already report the number of production days on an approximate basis, most likely rounding to the number of days within a production month. This raises the concern that manipulation of the forcing variable that the OCD would rely upon for implementation of the proposed rules, would dilute the intended policy effect. It is also possible that bad actors might outright mislead the OCD regarding self-reported data, thereby avoiding the proposed regulation intended to address the moral hazard exploited by those same operators. Effective monitoring to ensure these data are accurately reported would likely represent a significant increase to the administrative burden already imposed on the OCD. In the absence of administrative oversight to verify the number of production days, the proposed rules might simply serve to weed out the good actors who file honest reports, while failing to catch the bad actors at the root of the orphaned well issue.

Q: Do you agree that financial assurance should reflect the OCD's historical costs of plugging?

A: No. As I stated in prior testimony, the wells plugged by OCD may not be representative of the typical well in the state. Some of the anecdotes to which OCD witnesses testify seem to confirm that suspicion and suggest that the OCD employs a triage-like analysis to prioritize addressing wells that have known problems.[25] To the extent that those wells are more expensive to plug than the typical well, the historical costs realized by OCD would not accurately reflect typical plugging costs.

As Mr. Powell testified, "wells in good condition are not typically orphaned and plugged by the state."[26] Mr. Powell further stated that, "[m]ost of the orphan wells that the OCD obtains plugging authority on have been neglected for a considerable timeframe or are wells that are in such an adverse downhole condition that the final operator cannot afford to repair or plug the well."[27] Similarly, Mr. Purvis testified that, "[i]t is true that the

[25] See, for example, Appendix E of New Mexico Legislative Finance Committee, 2025, Policy Spotlight– Orphaned Wells, *LFC Program Evaluations.*
[26] Direct Testimony of Brandon Powell, OCD Exhibit 13, 3:4–5.
[27] Powell Testimony, OCD Ex. 13, 3:5–7.

historical portfolio of costs is not a random sample across the state and may be biased toward more expensive wells."[28] The selection of wells plugged by the OCD, therefore, is not representative of the typical well plugged by operators.

Yet, Applicants' experts argue that proposed $150,000 per-well financial assurance required of all single-well operators should reflect OCD's plugging costs. Mr. Purvis has stated that "[t]he financial assurance policy is needed to protect the state, so the amount of protection should be the amount or risk to the state" and that "$150,000 more closely aligns with actual and estimated costs of downhole plugging for which the state needs to protect itself."[29] Similarly, Mr. Powell dismisses the argument that the OCD's costs are inflated by stating, "[that] criticism would have more validity if the OCD was plugging orphan wells that were in similar conditions to most of the wells plugged by industry."[30] By these statements, Applicants' experts appear to simultaneously acknowledge that the state's costs are higher than those of private industry but also that private industry should be burdened by financial assurance amounts that reflect those higher costs. However, as stated in my prior testimony, the imposition of bonding requirements in excess of the expected costs of reclamation are economically unjustified and needlessly introduce additional transaction costs to the continued production of oil and gas.

---

[28] Purvis Testimony, WELC Ex. 30, 41:15–16.
[29] *Id.*, 42:2–3 & 39:7–8.
[30] Powell Testimony, p. 3, 2–4.

Q: Do you agree with Mr. Purvis that the recent trends show that the population of orphan wells is likely to increase significantly in the future?[31]

A: While it is true that the number of documented orphan wells has increased over the past few years, that increase may be due to a change in reporting rather than any real change in the rate at which oil and gas wells are orphaned. There is no single definition of orphaned wells. According to the Department of the Interior's Orphan Well Program Office (2024), "categorizations vary between states and federal agencies as the definition of 'orphaned' is not uniform" and "[t]he uncertainty of the estimated number of total documented and undocumented orphaned wells highlights the challenge that the OWPO faces in administering financial assistance to support plugging, remediating, and reclaiming orphaned wells."[32]

The availability of Bipartisan Infrastructure Law ("BIL") funds administered through Interior's Orphan Well Program Office cannot be ruled out as a significant factor in the classification of orphaned wells by states vying for federal funds under the program. There is a strong incentive to reclassify wells as orphaned after the program was announced in 2021 because the distribution of funds was and continues to be partially based on need. In his testimony, Adam Peltz acknowledged those incentives, stating, "[o]nce states saw that the REGROW Act was in fact likely to pass, state oil and gas agencies scrambled to document their orphan wells because their share of the $4.7 billion was predicated in part

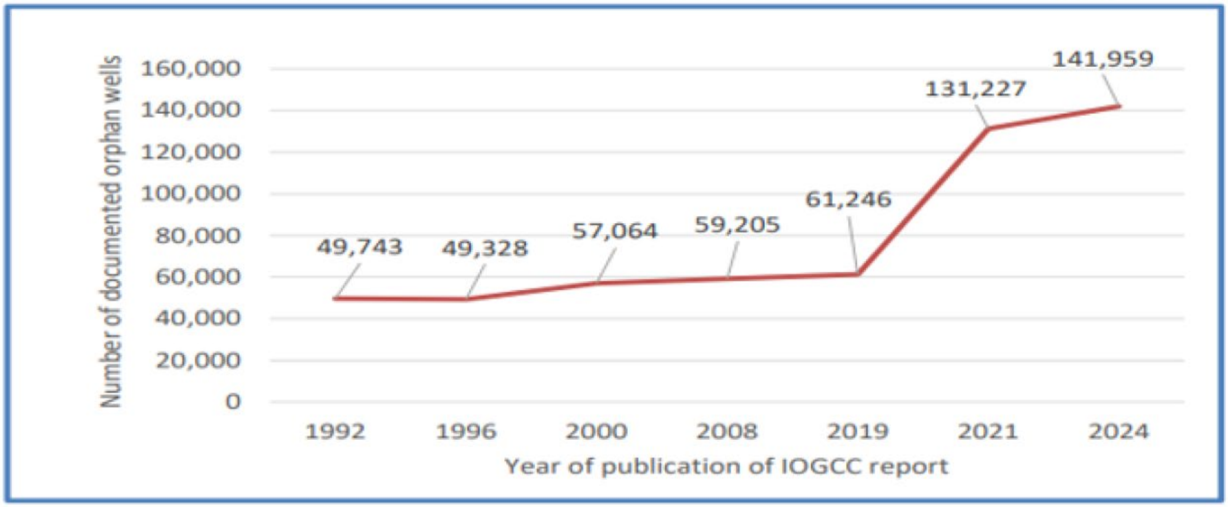
---

[31] Purvis Testimony, p. 10, 16–18.
[32] Orphaned Wells Program Annual Report to Congress, 2024, US Department of the Interior. *Available at* https://www.doi.gov/sites/default/files/documents/2024-11/fy-2024-owpo-annual-congressional-reportfinal-publishing.pdf.

on their documented orphan well population."[33] IPANM Supplemental Exhibit 36 is a reproduction of a chart included in the Department of the Interior Orphan Well Program Office's Annual Report to Congress (2024) that depicts the number of documented orphan wells between 1992 and 2024.[34]

IPANM Supplemental Exhibit 36

Figure 35. Trend in IOGCC published documented orphaned wells.



Between 1992 and 2019, the number of orphaned wells documented nationally ranged between 49,328 and 61,246. The dramatic increase in the number of documented wells in 2021 and 2024 may be more accurately attributed to policy response than a physical increase in the number of wells according to a uniform definition of "orphaned" over time. The recent trends in documented orphaned wells are therefore uninformative for projecting the growth in actual orphaned wells into the future.

[33] Direct Testimony of Adam Peltz, WELC Exhibit 57, 10:11–13.
[34] Orphaned Wells Program Annual Report to Congress, 2024, US Department of the Interior. *Available at* https://www.doi.gov/sites/default/files/documents/2024-11/fy-2024-owpo-annual-congressional-reportfinal-publishing.pdf.

DATE:__September 19, 2025___

ROBERT ARSCOTT, PhD