Update to the Reasonably Foreseeable Development Scenario (RFD) for Oil and Gas Activities in the Farmington Field Office, Northwestern New Mexico

Farmington Field Office, San Juan County, New Mexico

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to:

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Executive Summary

The proposed Reasonably Foreseeable Development (RFD) scenario is to assist BLM's future land use planning efforts for the Farmington Field Office (FFO) by providing projections of potential future oil and gas development activity for the next 30 years (starting in 2025). Included are projections for vertical and horizontal wells drilled, future surface disturbance accompanying this development, water production and use, and oil and gas production volumes.

Evaluation of historical activity and the subsequent future development prediction was separated by geologic plays. Analysis indicates the past major gas plays are mostly depleted and thus at a very mature level of development. Any recent activity and projected future work are considered maintenance of existing resources. Plays exhibiting this behavior are Fruitland Coal, Pictured Cliffs, Mesaverde, Mancos/Gallup (vertical and directional wells outside of the subplays), Dakota and the remaining small plays. No impact on the overall production from each play is expected due to the limited activity.

The significant recent activity has been in two different regions of the Mancos/Gallup play: the Mancos shale basin-centered gas subplay near the Colorado border, and the Mancos/Gallup horizontal well oil subplay, located along the southern perimeter of the basin.

For the Mancos Shale basin-centered horizontal well gas subplay, approximately **500 horizontal well locations** are available to drill and complete in the Mancos Shale reservoir. This estimate is based on the extent of the acreage within a high potential region, 3-mile horizontal well laterals at current spacing, and targeting the Black zone. Three alternative development schedules have been created based on the previous performance and development. The reference case or most likely case is a continuation of the recent activity, the high development case relaxes the external constraints such that the resource can be developed more rapidly, and the low development case which reflects the combination of a limited, less productive resource with external controlling factors.

Predicted for the Mancos/Gallup southern rim horizontal oil subplay is **700 horizontal well locations** available for future development. This subplay is well-defined therefore the remaining development is considered infill rather than extension of undeveloped acreage. This development will consist of diagonal well orientations, approximately 2 ½ -mile lateral lengths, at high-density spacing. The three alternative schedules for this development are: the reference case assumes development will continue at the historical average. The resource is not a limiting factor since the prospect is mostly infill development acquiring proven, developed reserves. The high development case, where the fundamental assumption is that future wells will perform as good or better than past wells. In addition, development will rely on infrastructure, regulatory, and economic factors all favorable for the increase in development. And last, a low development case, based on poor future well's performance compared to past wells, thus reducing the motivation to develop. Less favorable other factors will also play a role in this case.

Projections of future oil and gas production were accomplished by creating decline curves from historical production data and then extrapolated into future years to acquire remaining production for existing wells and future production from new well development. Total San Juan oil forecast is composed of the declining production from existing wells in the Mancos/Gallup southern rim horizontal oil play, the additional production from new wells in the same subplay, and the declining oil production from all other sources. The Mancos/Gallup southern rim horizontal well subplay dominates oil production in the basin, thus predicted future development will continue this increasing trend.

The total San Juan Basin gas forecast is composed of the declining production from existing wells in all plays along with the additional production from new wells in the Mancos Shale basin-centered horizontal gas subplay and the associated gas produced from the Mancos/Gallup southern rim oil subplay. Despite these additions, future gas production will continue to decline for the low and base case and only increase for the high scenario.

For the base case, over the 30-year forecast period, cumulative production from existing and new wells for Federal and non-Federal ownership is estimated to be 413 million BO and 10.5 Tcf gas. The federal share is 64% of the oil and 75% of the gas based on past production, or 265 million BO and 7.9 Tcf gas, respectively.

Within the FFO jurisdiction lies the Chaco Canyon area which includes the Chaco Culture National Historical Park (CCNHP) and associated historic sites. A Federal mineral withdrawal encompassing lands within 10 miles of CCNHP was approved in 2023, removing the possibility of additional oil and gas leasing within this domain until 2043. Existing leases within the withdrawal area were not affected. Within the last 25 years, Fruitland Coal wells have been completed along the north – northeast fringe of the withdrawal area, however, the recent lack of activity within the withdrawal area, the low resource recovery and the rapid declining production of existing wells all suggest a depleted resource of limited extent, subsequently no further Fruitland Coal development within the withdrawal area has been included in the prediction period.

One of the few places where Helium occurs and is produced is the Four Corners Platform of western San Juan County, New Mexico within the FFO jurisdiction. Isolated gas pools have seen sporadic development. Currently, only the North Tocito Dome pool is producing, averaging slightly less than 4.7 MMscf of Helium over the last six years, assuming a constant 7% Helium composition. A detailed study is beyond the scope of this report, but the past Helium production suggests additional occurrences have potential in this region.

Water production has been declining rapidly, corresponding to the decline in Fruitland Coal production. Additional development in the two Mancos subplays will have little impact on altering the future decline in water production, with only the high scenario the exception. Even in the latter, the predicted maximum annual water production does not exceed recent annual values. Total cumulative water production for 30 years ranges between 423 to 565 million BW depending on the scenario. Of this amount, 289 million BW is from the decline from existing wells.

The majority of water used in oil and gas operations is related to stimulation design and requirements and is dependent on the well type, i.e., vertical vs horizontal. Vertical well completions, average 93 Mgals of water usage per well for stimulation purposes, with no discernable trend observed. For the horizontal well development, frac volumes for each subplay are quite different. For the oil subplay, the most recent usage numbers are 110Mbbls per well, which was applied for future wells. Predicted cumulative water usage is under 100 MMbbls for all cases. The source of the water for the oil subplay is over 97% non-potable water.

For the gas subplay, the water volumes are substantially greater, with the most recent usage numbers of 700 Mbbls per well, which was applied for future wells. Predicted cumulative water usage ranges from 121 to 366 MMbbls for all cases. For this subplay, the water source is freshwater from Navajo Reservoir.

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LIST OF ABBREVIATIONS AND ACRONYMS

AAPG	American Association of Petroleum Geologists
BLM	U.S. Bureau of Land Management
BO	Barrels of oil
BOPD	Barrels of oil per day
BSCF or BCF	Billion standard cubic feet (gas)
CCUS	Carbon Capture Underground Storage
DCA	Decline Curve Analysis
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
EIA	U.S. Energy Information Administration
EUR	Estimated ultimate recovery
FFO	Farmington Field Office
FPD	First Production Date
ft	feet, foot
GIS	Geographic Information System
GOR	Gas-oil Ratio, Mscf/STB
GPI	Gross Perforated Interval
Gp	Cumulative gas production
MBO or mstb	Thousand barrels of oil
MBOE	Thousand barrels of oil equivalent
MBBLS	Thousand barrels of liquid
MBW	Thousand barrels of water
MMSCF	Million standard cubic feet (gas)
MMBO	Million barrels of oil
MMBOPD	Million barrels of oil per day
MMBBLS	Million barrels of liquid
NMOCD	New Mexico Oil Conservation Division
ONRR	DOI Office of Natural Resources Revenue
psi	pounds per square inch (pressure)
RFD	Reasonably Foreseeable Development
Tscf	Trillion standard cubic feet of gas
U.S.	United States of America
V+D	vertical + directional wells
WGR	Water-gas rato, bbl/mscf
WOR	Water-oil ratio, bbl/bbl

Introduction

The proposed work is focused on updating the reasonably foreseeable development scenario (RFD) for the Farmington Field Office (FFO) in Northwestern New Mexico and thus establish a baseline scenario that can assist the BLM with land use planning efforts and to analyze the long-term effects that could result from oil and gas activities. To accomplish will require evaluation of historic and current activity, occurrence potential, projected development potential (including projections for vertical and horizontal wells drilled over the next 30 years), estimated future surface disturbance, estimated water use for hydraulic fracturing, and estimated oil and gas production volumes.

The Farmington Field Office administers approximately 4.2 million total acres of all Federal mineral ownership types in San Juan, Rio Arriba, Sandoval, and McKinley Counties (see Figure 1). Currently, Federal oil and gas minerals in the FFO jurisdiction cover 2.73 million acres (66%). Of the Federal minerals, 1.70 million acres (62%) are leased, thus a little more than 1.0 million acres (38%) are currently unleased. Indian-owned oil and gas minerals (allotted and tribal) cover 0.5 million acres (18% of the FFO). Other portions of oil and gas minerals are state-owned, tribally-owned or owned privately and are not subject to BLM's management prescriptions. All the acreages presented herein are based on geographic information systems (GIS) calculations and should be considered approximate.

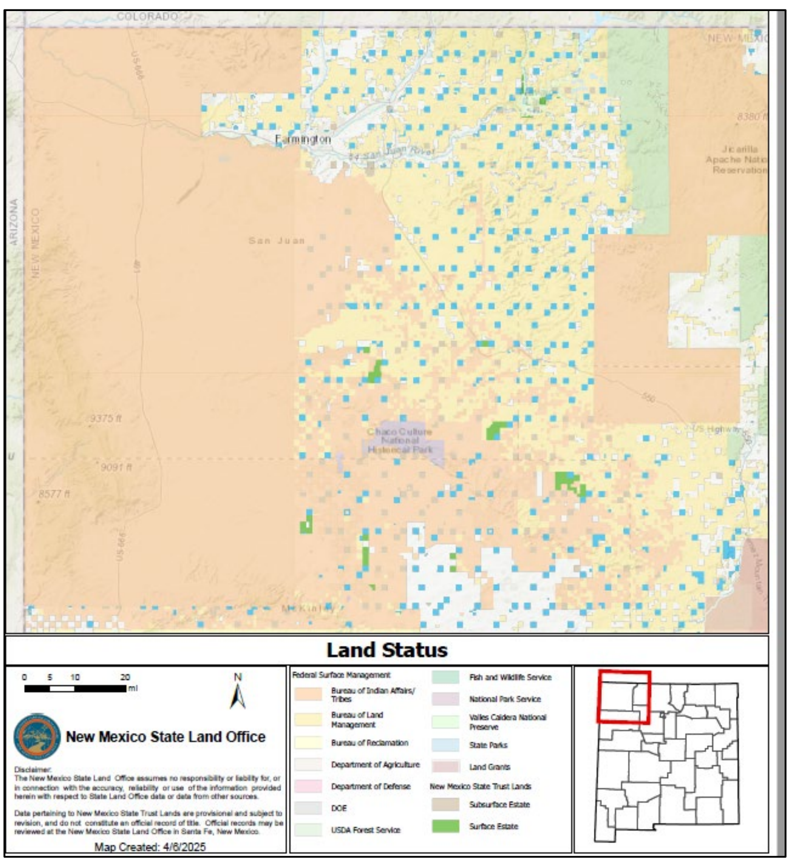

Figure 1. Northwestern New Mexico land ownership map. {Source: NMSLO}

In analyzing historical data, production volumes are reported as a total of what the reservoir or well capacity is, independent of ownership. To acquire the federal portion, the federal volumes reported by DOI Office of Natural Resources Revenue (ONRR) were compared to the total production volumes acquired from NMOCD over a twenty-year (2004-2023) time period for McKinley, Rio Arriba, Sandoval and San Juan counties, New Mexico. Over this time, the federal portion as a percent of the total volume has been constant for both oil and gas at 75% for gas and 64% for oil, respectively. Both values are used to adjust the total volumes to the federal portion.

Data Sources

The information presented in this report was compiled from various sources. Historical and current well data (including production volumes) were acquired primarily through the NMOCD and the GOTECH system. (http://octane.nmt.edu/gotech/) In addition, specific data was analyzed from Enverus™. Geological data were sourced from New Mexico Bureau of Geology and Mineral Resources reports and various professional publications. Information on water usage for stimulation was compiled from FracFocus™.

For quality assurance, all data was checked for anomalies and outliers and decisions made as to validity. Random checks of multiple sources found significant misreporting, general errors in the data and mis-categorized data. Corrections were made when appropriate and the data included in the analysis. If not, the data was excluded so not to bias the results.

Background

Reference to previous RFD work occurs throughout this report and subsequently builds on that past work. For this reason, a summary of the past work provides a good starting point for this study. In July 2001 a comprehensive study of the San Juan Basin was undertaken to determine oil and gas resource potential. Provided was the number of completions per year, accounting for dual completions and commingling. What was not included was the rise of horizontal development that had just begun and a production forecast. A review of completions in Figure 2 shows reasonable agreement in the early years (2002-09) between the annual predicted locations of 623 and the actual of 679, but a rapid falloff in actual completions after 2008 resulted in significant overprediction.

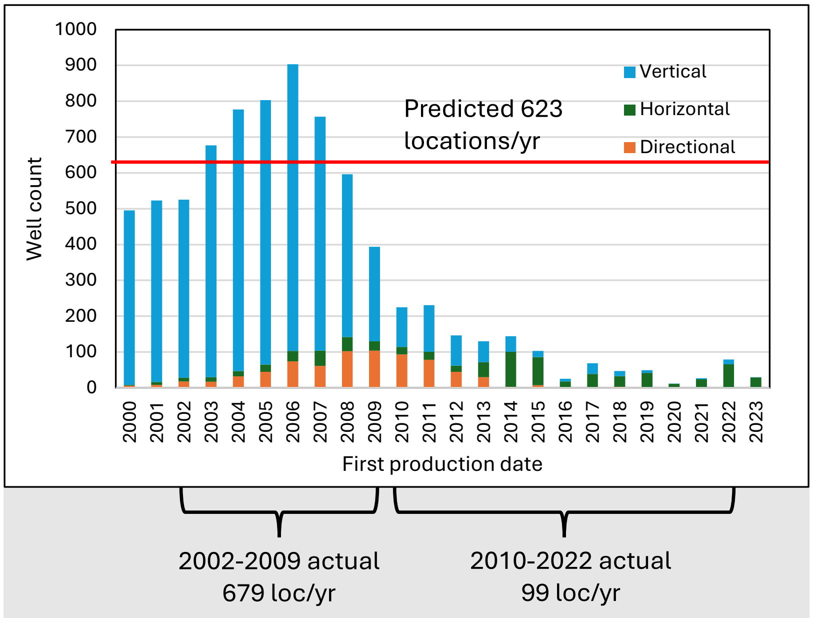

Figure 2. Historical completions for all well types (vertical, directional and horizontal) compared to the annual predicted value. {Source: GOTECH/NMOCD}

The rapid decline in well completions, specifically vertical gas wells, is due to several factors but the primary one is the gas commodity price. This can easily be observed in Figure 3 which shows the correlation between gas price and gas well completions.

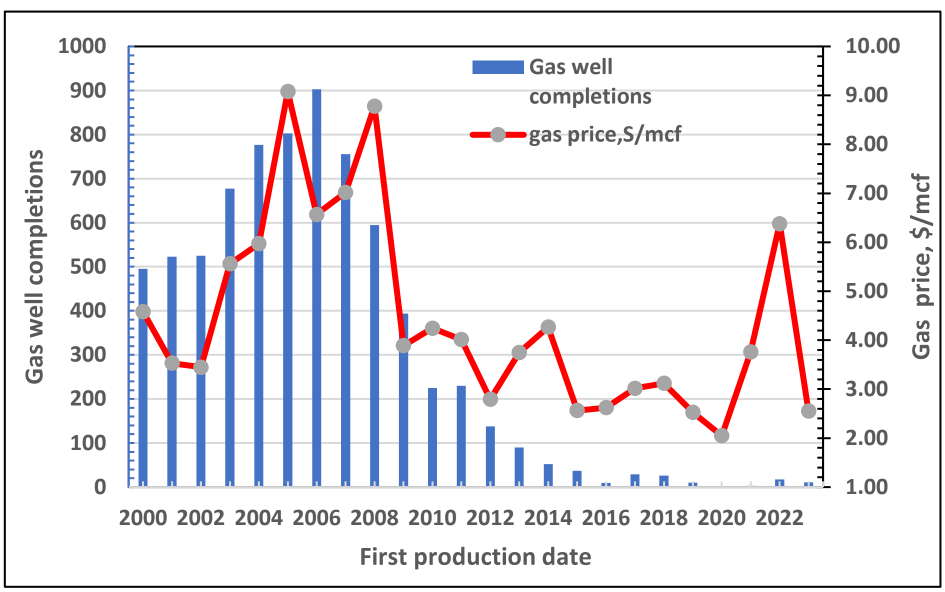

Figure 3. Annual gas well completions are superimposed with average Henry Hub gas price. {Source: gas price…Microtrends, completions…NMOCD}

The omission of horizontal well development in the 2001 report was attempted to be addressed in the 2014 and 2015 RFD updates. In the former, the focus was on the recent Mancos/Gallup horizontal development; the report provided an estimated EUR per horizontal well, but did not provide a production forecast. The 2014 update forecasted 3,650 new wells (2,000 gas, 1,650 oil), but provided no timeline of development. Also provided was a baseline of water usage for stimulation of the horizontal wells and a comparison to past vertical well development. The latter update provided EUR values based on an additional year of production data and confirmed previous development potential regions and associated water usage.

The latest update in 2018 projected 3,200 new wells from 2018 through 2037. (2,300 horizontal, 900 vertical+directional) mostly assumed in the Mancos/Gallup play. Provided were the expected new wells per future year and total production (existing + new development) per future year. A six-year comparison between predicted to actual development (2018-2023) resulted in a reasonable estimate of oil production (55 to 52 MMBO), overprediction of well count (557 to 244), underprediction of gas production (1.6 to 3.1 Bscf) and severe underprediction of water production (5 to 172 MMBW).

Historical Activity
Oil and gas production from the San Juan Basin was discovered in the early-1920s. Over time, the basin has shown an amazing resilience with periodic new discoveries, adoption of new technologies and improved operations. Further details of the history of development of the San Juan Basin can be found elsewhere (RFD 2001) and thus not expanded here.

A snapshot of production performance from 1999 to present (2024) is shown in Figure 4. All production includes McKinley, Rio Arriba, San Juan and Sandoval Counties in New Mexico, respectively. Observe the declining gas production over this time period, the increasing water production to a peak in 2011 and then a decline since then, and the increase in oil production starting in 2014.

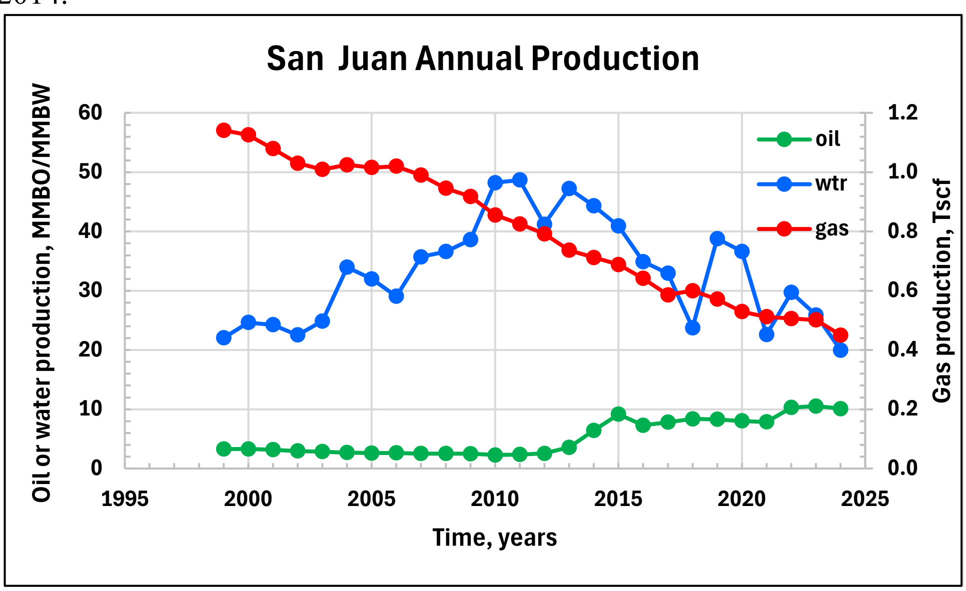

Figure 4. Annual oil, gas and water production for the New Mexico portion of the San Juan Basin. (Source: GOTECH/NMOCD)

Further investigation of these trends was accomplished to identify the underlining reasons for their behavior. For the increasing oil trend in 2014, the total basin oil production was compared to only those wells first drilled and completed since 2012 (Figure 5) in the horizontal Mancos/Gallup oil subplay of the southern rim of the basin. As expected, this new development dominates the oil production from the basin. Further description of this play and its impact on future development are discussed later in this report.

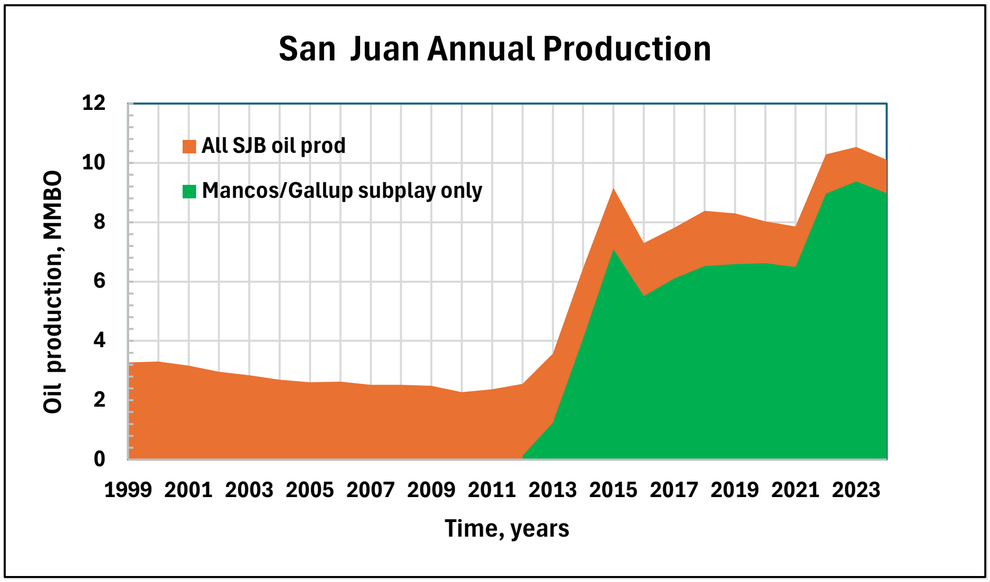

Figure 5. Annual oil production from the NM portion of the San Juan Basin compared to wells first producing since 2012) in the horizontal Mancos/Gallup oil subplay of the southern rim of the basin. (Sources: GOTECH/NMOCD, Enverus^{TM}).

Total annual gas production has declined from 0.86 Tscf in 2010 to approximately 0.47 Tscf in 2024, a 45% drop in 15 years. The declining gas production by geologic play is shown in Figure 6. All the plays except the Mancos are exhibiting a continuous decline over this time period, despite additional wells or completions. Further details of these plays and the impact on future developments are discussed later in this report.

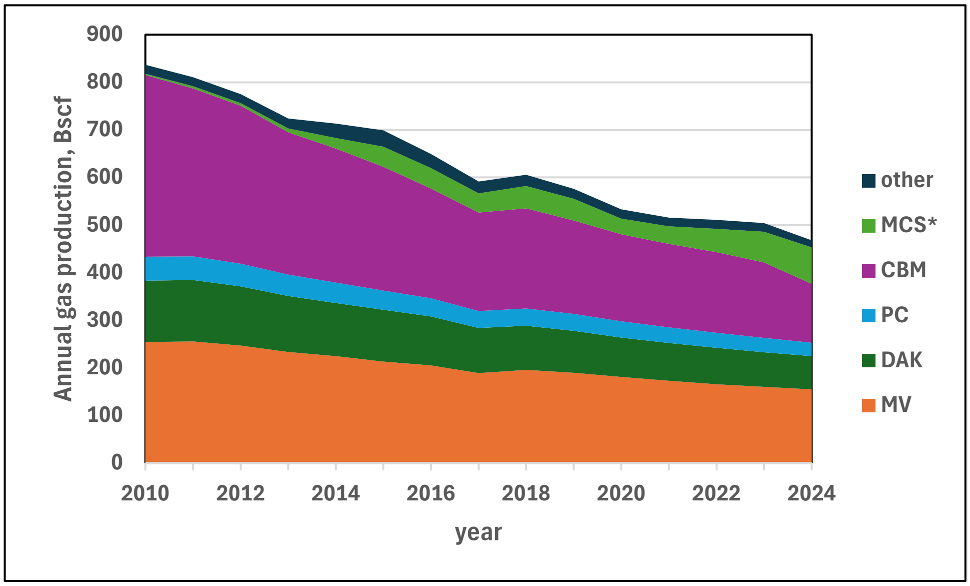

Figure 6. Annual gas production from the NM portion of the San Juan Basin by geologic play (Sources: GOTECH/NMOCD, Enverus^{TM}).

The annual water production trend increases until it reaches a peak in 2011 of approximately 49 MMBW (see Figure 7). Since then, water production has been on an erratic but general decline to approximately 20 MMBW in 2024. CBM accounts for ~50% of the total water production, thus as the CBM gas has declined so has the water production.

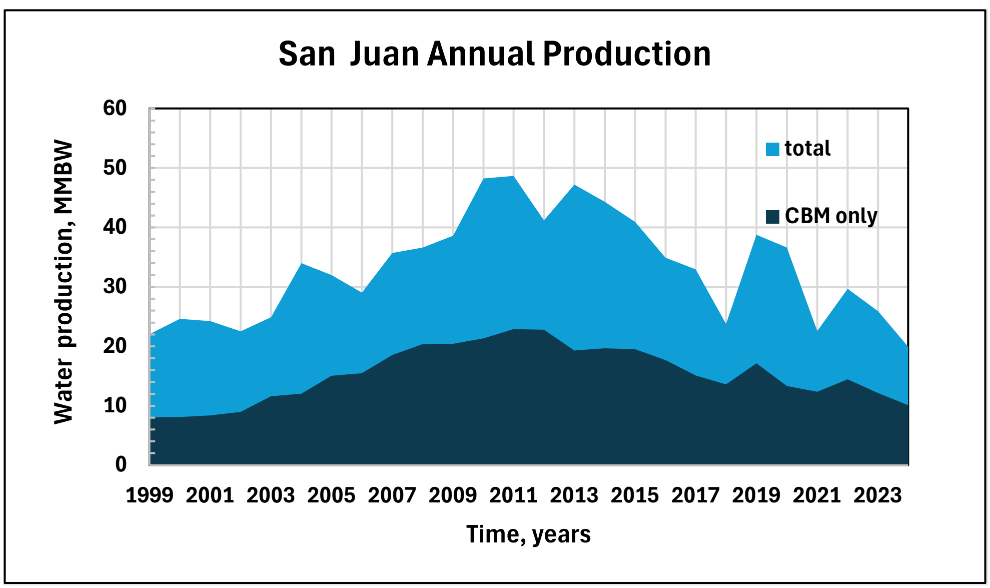

Figure 7. Annual water production from the NM portion of the San Juan Basin compared to wells first producing since 2012 and to CBM. (Sources: GOTECH/NMOCD, Enverus^{TM}).

The well activity, i.e., well completions which first produced for a given year, since 2000 was shown in Figure 2. A magnified view from 2010 is shown in Figure 8. Early in the time, the majority of wells were vertical or directional completions. However, as horizontal technology improved and with the success of the Mancos/Gallup oil and gas subplays, the horizontal completions have become dominant.

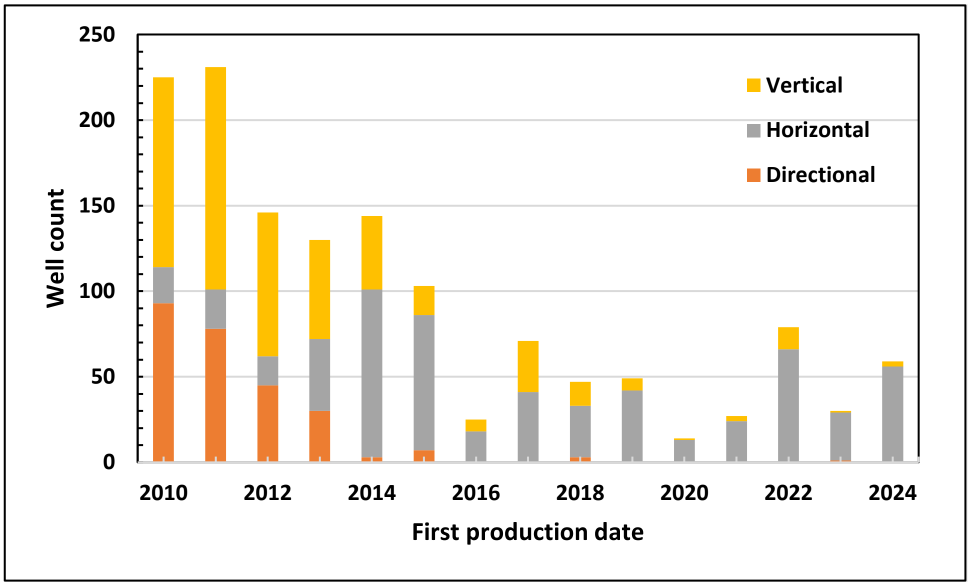

Figure 8. Well count by date of first production and well type: (Source: Enverus™)

The trend of activity is dependent on the application of new technologies, improvements in surface facilities and gathering, and economics. The impact of the latter for gas was shown in Figure 3. Figure 9 is a comparison of Mancos/Gallup horizontal well activity to average yearly oil price. The correlation is not as dramatic as for gas but is still evident. In this case, the delay until 2012 is in response to improved reservoir characterization and horizontal well drilling and completions.

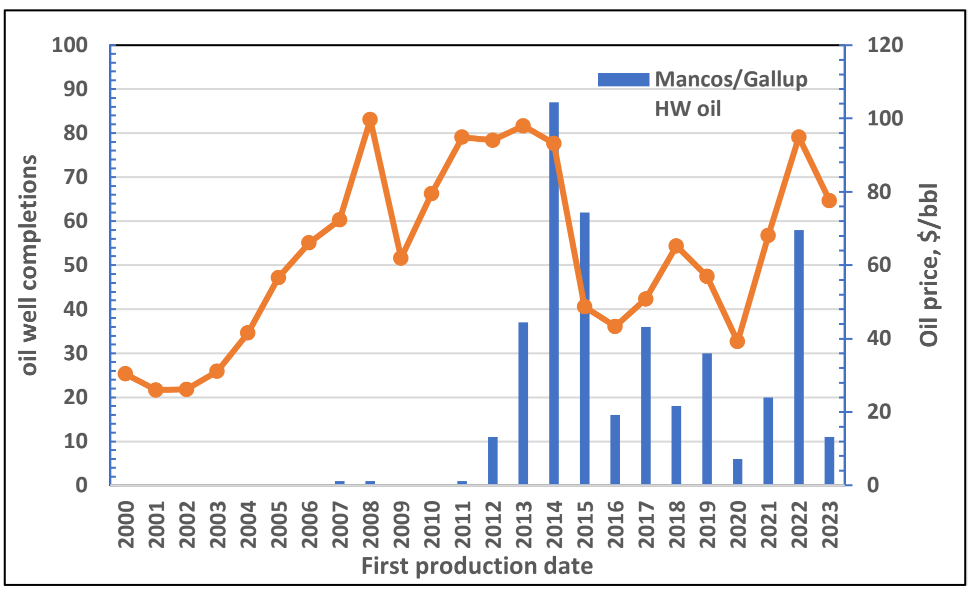

Figure 9. San Juan Basin horizontal oil well completions compared to yearly average oil price. {Source: Enverus and EIA}

Predicted Development

Development Potential by Play

Evaluation of historical activity and the subsequent future development prediction was separated by geologic plays. This approach is believed to be recognizable to most, as it is consistent with how work is proposed and with the previous RFD (2001) and updates (2014, 2015). A summary of the results, with a brief explanation, is given below. Details for each can be found in the appendices.

The result of evaluating the activity and production from 2010 through 2024 provides the basis for projecting the reasonably foreseeable development spanning 30 years beginning in 2025. Table 1 lists the estimated potential by play using the scale shown. Also included are the 2024 activity and the recent trend of that activity.

			Results and Recommendations					
			Potential					
Play	Primary HC	Primary well type	low case	base case	high case	Comments	2024 completions	trend
Fruitland Coal	Gas	V		low		recompletions	31	
Pictured Cliffs	Gas	V		low		recompletions	2	
Mesaverde	Gas	V		low		recompletions	33	
Mancos/Gallup								
Mancos Shale Basin-centered gas subplay	Gas	H	low	moderate	high	horizontal well development	16	increasing
Mancos/Gallup Southern rim oil subplay	Oil	H	moderate	high	very high	horizontal well development	40	constant
Mancos/Gallup V+D	Gas	V		low		recompletions	23	
Dakota	Gas	V		low		new vertical	3	
other*	Gas	V		low		recompletions	0	

Scale	wells/yr
low	<5
moderate	5 - 20
high	20 - 50
very high	>50

Table 1. Estimation of potential by play.

The past major gas plays are mostly depleted and thus at a very mature level of development. The recent activity and projected future work are considered maintenance of existing resources, i.e., recompletions, payadds, commingling of zones, etc. New wells will be scarce and scattered throughout the basin. Plays exhibiting this behavior are Fruitland Coal, Pictured Cliffs, Mesaverde, Mancos/Gallup (vertical and directional wells outside of the subplays), Dakota and the remaining small plays.

The significant recent activity has been in two different regions of the Mancos/Gallup play (Figure 10) and thus to provide a better description these regions have been named subplays. The Mancos shale basin-centered gas subplay has shown recent success from horizontal well development. It is located closer to the Colorado border, in the deeper portion of the San Juan Basin. The Mancos/Gallup oil subplay is located along the southern perimeter of the basin. Development for this subplay has been ongoing since 2010.

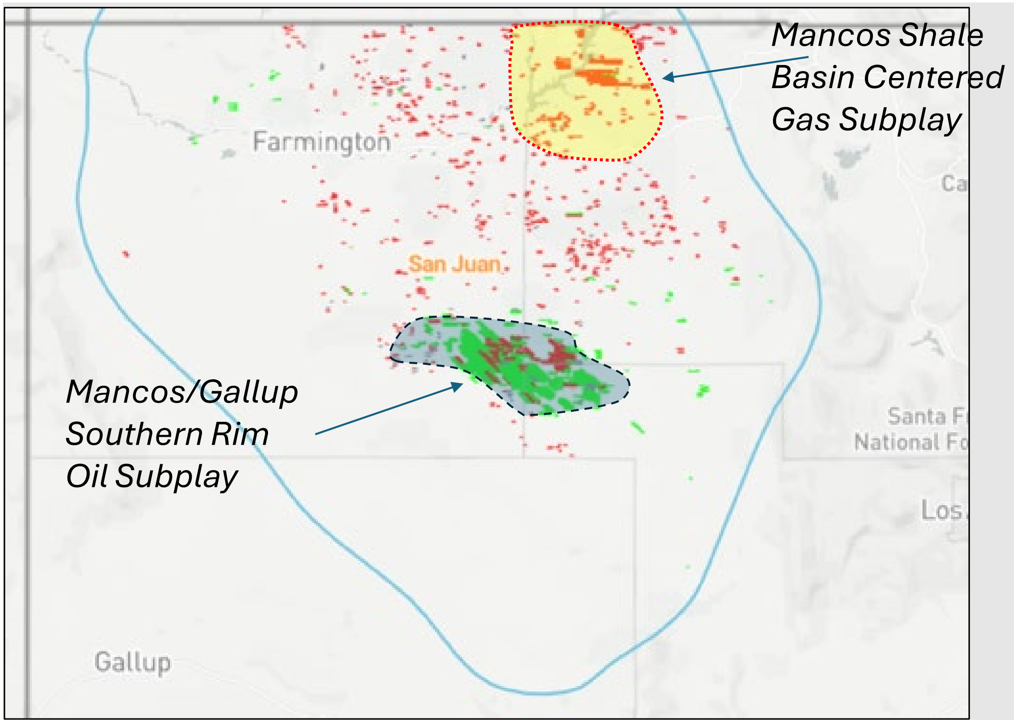

Figure 10. Current (through 2024) Mancos/Gallup wells superimposed with approximate location of subplay boundaries. {Source: Enverus}

Predicted Development Schedule

New well additions in the forecast period are predicted for the Mancos Shale basin-centered horizontal well gas and Mancos/Gallup southern rim horizontal oil subplays, respectively. For the Mancos Shale basin-centered horizontal well gas subplay, approximately **500 locations** are available to drill and complete in the Mancos Shale reservoir. This estimate is based on the extent of the acreage within a high potential region (yellow-shaded region in Figure 10), 3-mile horizontal well laterals at current spacing, and targeting the Black zone. Three alternative development schedules have been created based on the previous performance and development, with consideration of the factors previously discussed.

The **reference case or most likely case** is a continuation of the recent activity, i.e., the addition of 10 new wells per year over the span of the RFD. The assumption is that the subplay is not resource limited but instead other external factors are tempering development. That is, the resource extent is mostly undeveloped, and thus future activity is defined more as extension of past activity than infill development. In other words, the resource exists but it is not well known how successful it will be.

The **high development case** relaxes the external constraints such that the resource can be developed more rapidly. In this case, the addition of 50 new wells per year is assumed, reaching the 500 well maximum in ten years. The assumption is that the resource is highly productive throughout the defined area, with no limiting factors to constrain development. The addition of 50 well per year is expected to be delayed and thus begin in 2026. For 2025, it is proposed that 20 wells be completed. The remaining 30 wells will then be drilled and completed in year 11.

The **low development case** of 5 new wells per year over the life of the RFD reflects the combination of a limited, less productive resource with external controlling factors.

Predicted for the Mancos/Gallup southern rim horizontal oil subplay is **700 locations** available for future development. This subplay is well-defined therefore the remaining development is considered infill rather than extension of undeveloped acreage. This development will consist of diagonal well orientations, approximately 2 ½ -mile lateral lengths, at high-density spacing. An additional benefit of this type of development will be reduced surface disturbance due to the longer lateral length and multiple wells emanating from the same pad. The three alternative schedules for this development are:

The **reference or most-likely case** assumes development will continue at the historical average of 35 new wells per year. This pace will be assumed to be constant, thus after 20 years the forecasted 700 locations will have been developed. The resource is not a limiting factor since the prospect is mostly infill development acquiring proven, developed reserves.

The **high development case** allows for 70 new wells to be drilled over a ten-year period. Since the play is not resource limited, the fundamental assumption is that future wells will perform as good or better than past wells. Subsequently, motivation exists to develop more rapidly. In addition, development will rely on infrastructure, regulatory, and economic factors all favorable for the increase in development.

Conversely, for the **low development case**, 15 new wells per year are forecasted for development for a total of 450 wells completed in 30 years. The decrease in development is primarily based on poor future well's performance compared to past wells, thus reducing the motivation to develop. Less favorable other factors will also play a role in this case.

Additional development in terms of recompletions, pay additions and/or commingling of zones is anticipated for all the remaining mature, depleted gas reservoirs previously mentioned. Historically, approximately 25 workovers per year have occurred, but none have influenced the continuing decline exhibited by each. Subsequently, no change in the forecasted production will occur for this work. Details can be found in the respective Appendices.

Future Estimated Production

Forecasted oil production for 30 years starting with 2025 is shown in Figure 11. Total San Juan oil forecast is composed of the declining production from existing wells in the Mancos/Gallup southern rim horizontal oil play, the additional production from new wells in the same subplay, and the declining oil production from all other sources. The three scenarios in the figure represent the different predictions for the oil subplay, i.e., high for the most aggressive development plan, base for the most likely plan following current trends, and low a reduced development due to unfavorable conditions.

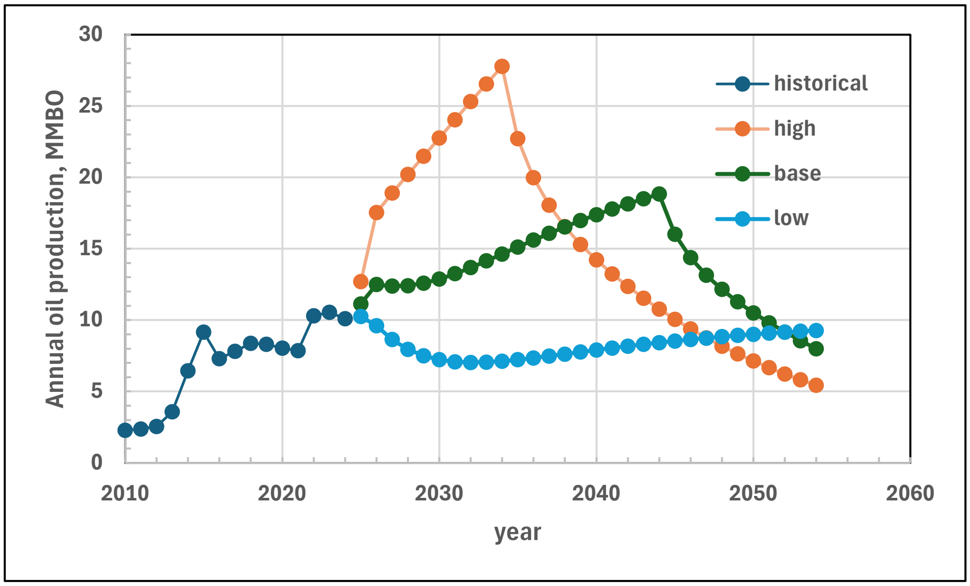

Figure 11. Total predicted San Juan oil production under three scenarios: high, base, and low.

The total San Juan Basin gas forecast is composed of the declining production from existing wells in all plays along with the additional production from new wells in the Mancos Shale basin-centered horizontal gas subplay. Declining production for the former, existing wells, is shown in Figure 12. For comparison purposes, the Mancos (MCS*) in this figure represents all Mancos/Gallup existing production, i.e., Mancos vertical and directional wells, currently producing wells in the Mancos Shale basin-centered horizontal gas subplay, and the associated gas from current wells in the Mancos/Gallup southern rim horizontal oil play. Details for the major historical plays are found in the appendices.

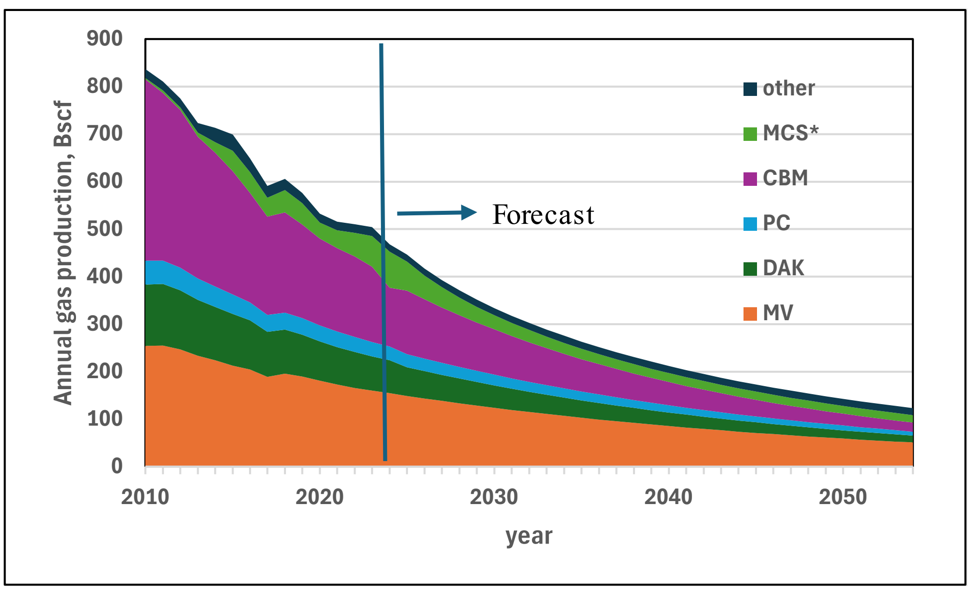

Figure 12. Annual forecasted gas production by play type for currently producing wells.

Note the magnitude of the decline in gas production from the Coalbed Methane and Mesaverde plays. With no significant development anticipated, this trend is predicted to continue. Only the Mancos subplay development has shown an impact (increase) recently and in the forecast period.

The impact of the addition of gas from new wells in the Mancos Shale basin-centered horizontal gas subplay and the associated gas in the Mancos/Gallup southern rim horizontal oil play for the three scenarios (high, base, and low) is shown in Figure 13.

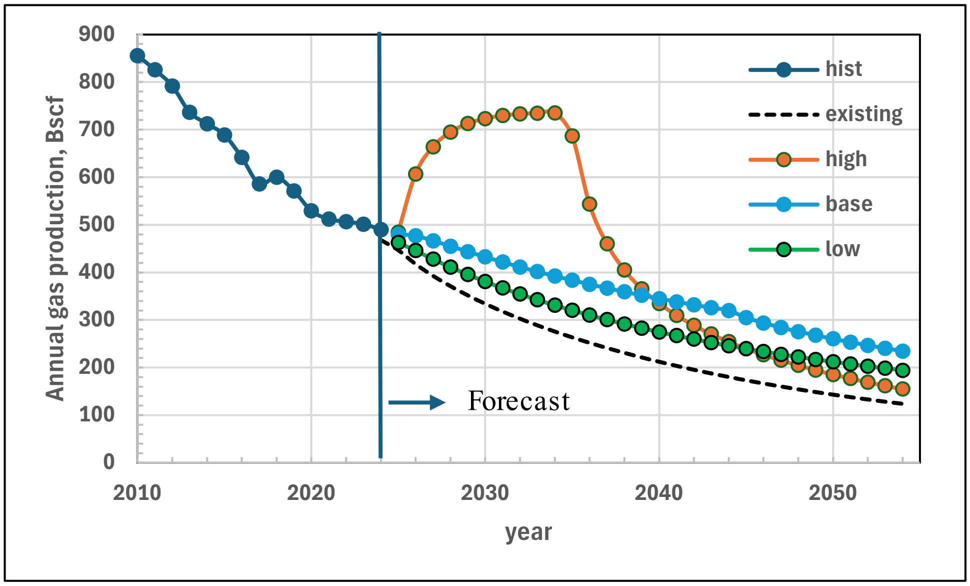

Figure 13. Total predicted San Juan gas production under three scenarios: high, base, and low.

Estimated Surface Disturbance

Oil and gas development projected in the next thirty years will require associated surface development of roads, flowlines and well pads. As discussed previously, new well development will be solely horizontal in the two Mancos/Gallup subplays. Current trends are for multiwell horizontal well surface locations from a single well pad; subsequently minimizing the number of pads and acreage of surface disturbance per well.

The estimated surface disturbance for new well development in Table 2 includes well count, pad count, average acres per pad, average acres for roads and pipelines per pad, and total acres disturbed. The average pad size and accompanying roads and pipelines was derived from approved APDs in the FFO over the last 2 years. Similarly, the average number of wells per pad over the last two years has been 4, and thus considered a reasonable approximation for the predicted development.

Year/status	Wells (n)	Pads (n)	Average pad size (ac)	Total pad area (ac)	Average Road and pipeline area per pad (ac)	Total roads and pipeline area (ac)	Total area disturbed (ac)
Projected horizontal wells (4 wells/pad)	1,200	300	7.1	2,130	3.59	1,077	3,207

Table 2. New surface disturbance over the life of the plan (2025-55) (Federal and non-Federal combined)

For the thirty-year period, it is estimated an additional 3,207 acres of disturbance is required. Not accounted for in the future surface disturbance is the reclamation for sites where wells are P&A.

Impact on Chaco Canyon Area

Within the FFO jurisdiction lies the Chaco Canyon area which includes the Chaco Culture National Historical Park (CCNHP) and associated historic sites. A Federal mineral withdrawal encompassing lands within 10 miles of CCNHP was approved in 2023, removing the possibility of additional oil and gas leasing within this domain until 2043 (Figure 14). Existing leases within the withdrawal area were not affected. Subsequently, this work is to address the question does the area contain potential oil and gas resources and does the predicted development outlined in this report impact that resource?

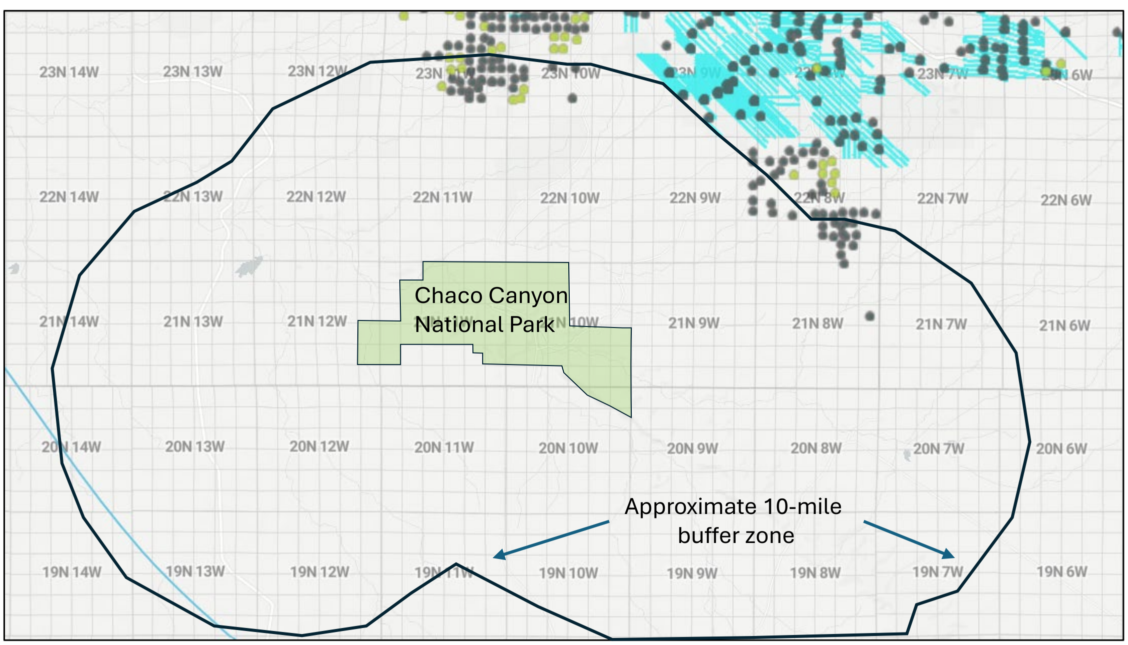

Figure 14. Outline of the 10-mile withdrawal area surrounding Chaco Culture National Historical Park. Also shown in the figure are all wells completed since 2000. {Source: Enverus, BLM}

Since 2000, approximately 65 vertical or directional wells have been drilled within the withdrawal area. These wells are along the fringe of the withdrawal, to the north and northeast (see Fig. 14).

No horizontal wells were found within this area; however, as observed in Figure 14, significant activity has occurred just to the northeast in the Mancos/Gallup oil subplay. The majority of V+D wells are completed in the shallow Fruitland Coal play along with a few very poorly producing Chacra wells. Annual production and well count for this cohort is shown in Figure 15.

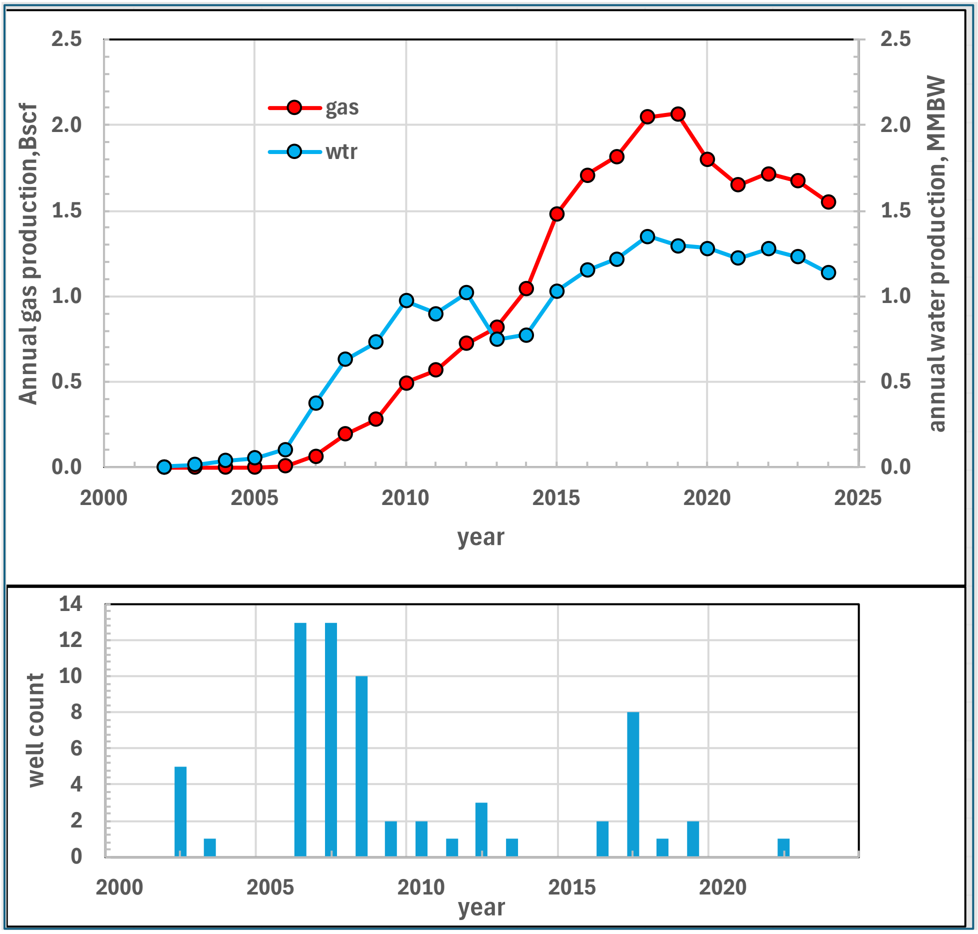

Figure 15. Annual gas and water production and well count for the V+D wells located within the Chaco buffer zone. {Source: Enverus/NMOCD}

The main development occurred in 2006 through 2008, when almost half of all wells were completed. Typical of Fruitland Coal wells, a delay in gas production occurs until sufficient dewatering of the formation. Since peaking in 2019, both gas and water production have exhibited a rapid decline.

Further Fruitland Coal development within the withdrawal area is not likely and thus has not been included in the prediction period. The recent lack of activity, the low resource recovery (~ 0.5 Bscf/well), and the rapid declining production of existing wells all suggest a depleted resource of limited extent. With regards to the Mancos/Gallup horizontal oil subplay, development is expected to continue to the northeast of the buffer zone. The Gallup/Mancos targets appear to get wet updip; i.e. to the southwest, and thus not favorable targets for future development.

Helium Occurrence and potential

Helium is a critical element used for a wide range of essential applications from medical technology to high-tech manufacturing, space exploration, and national defense. Subsequently it is defined as a strategic natural resource. Natural occurring Helium is limited due to a specific set of conditions required to create the Helium reservoir. In general, required is access to deeper, older Precambrian basement rocks of composition that can release Helium. New Mexico is one of the states that has these conditions and has a history of Helium production. A comprehensive report by Broadhead and Gillard (2004) provides an excellent background of Helium production and resources in New Mexico. One of their findings was the Helium production from Paleozoic reservoirs located on the Four Corners Platform in San Juan County, New Mexico. Figure 16 shows the approximate location of the five pools with previous Helium production. All are found in the Four Corners Platform of western San Juan County. Also shown, is a defined occurrence potential area based on the locations of these pools. This area is conceptual, with no detailed geologic, petrophysical or engineering analysis done to support the potential of this area.

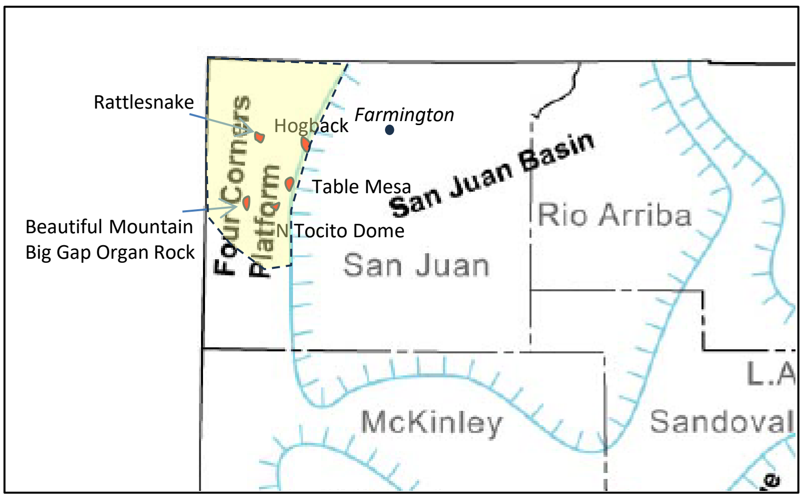

Figure.16 Approximate location of Helium producing pools in San Juan County, NM overlaid on major geologic features. Yellow highlight represents occurrence potential. {Adapted from Broadhead and Gillard, 2004}

A production update from the 2004 report is shown in Figure 17. The Helium production numbers are estimates based on the percent Helium from gas analysis. Only the North Tocito Dome pool is currently producing, averaging slightly less than 4.7 mmscf of Helium over the last six years, assuming a constant 7% Helium composition. Extending the current decline of the North Tocito Dome pool results in 44 mmscf of Helium to be recovered over the future 30 years. Additional Helium resources will require further exploration, and thus future reserves cannot be predicted at this time.

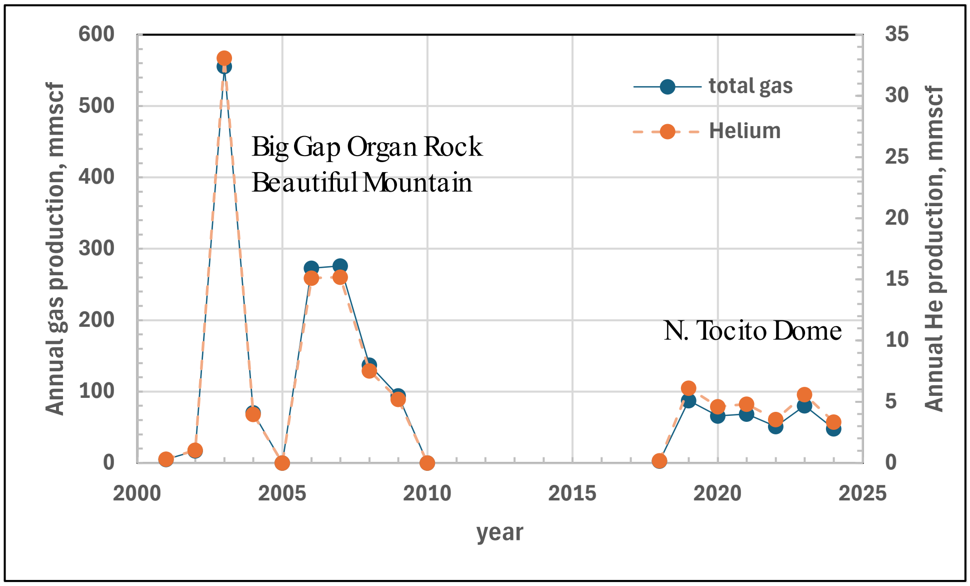

Figure 17. Total gas and Helium gas annual production from select pools with Helium production in San Juan County, New Mexico. {Source: GOTECH/NMOCD}

Estimated Water Production and Use

As water is limited and thus essential in arid New Mexico for agriculture, domestic consumption, industry and other beneficial uses, it is important to assess and predict the associated water production and the corresponding use of water in oil and gas development. Predicting water production has implications towards disposal needs. Understanding the usage of water in oilfield applications relates to production by reducing the disposal needs and potentially freshwater usage.

Water Production

Annual water production since 2010 by geologic play is shown in Figure 18. Extrapolation of the existing water decline is also shown in the figure and results in an estimation of future water production. Observe the continuous reduction in water production, especially in the Fruitland Coalbed Methane.

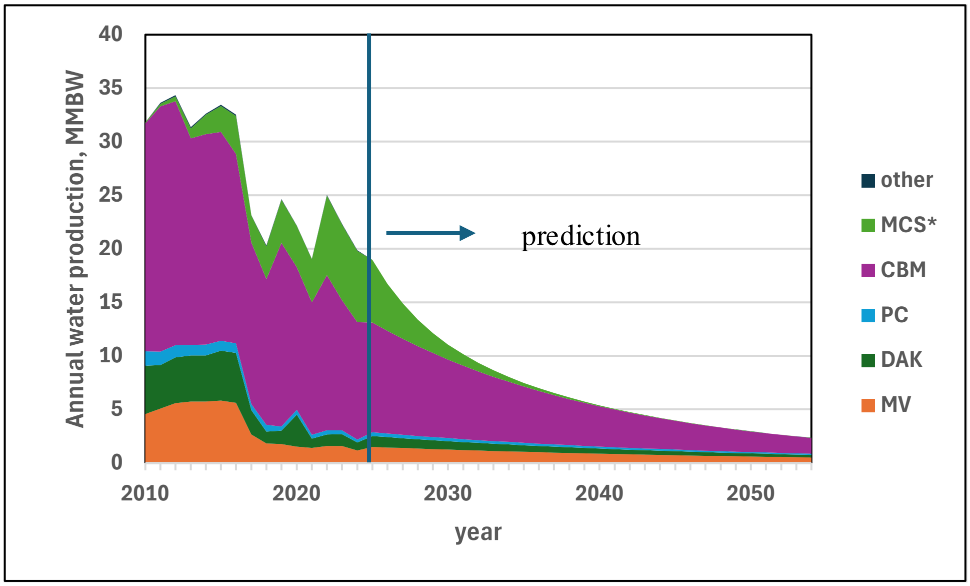

Figure 18. Historical and predicted annual water production by geologic play. {Source: NMOCD/GOTECH}

Additional well development in the two Mancos subplays will result in additional water production. Shown in Figure 19 is the water production forecast for the three scenarios previously defined. These trends are a sum of both the new well and existing well water production. For a comparison, the existing well water production is shown as a dashed line in the figure, thus the difference represents the new well contribution. For all scenarios, the majority of produced water is from the southern rim oil subplay, as entrained water within the oil-bearing zones. On the other hand, the basin-centered subplay is a dry gas with limited water produced. Tabulated predicted water production for all cases can be found in Appendix C of this report.

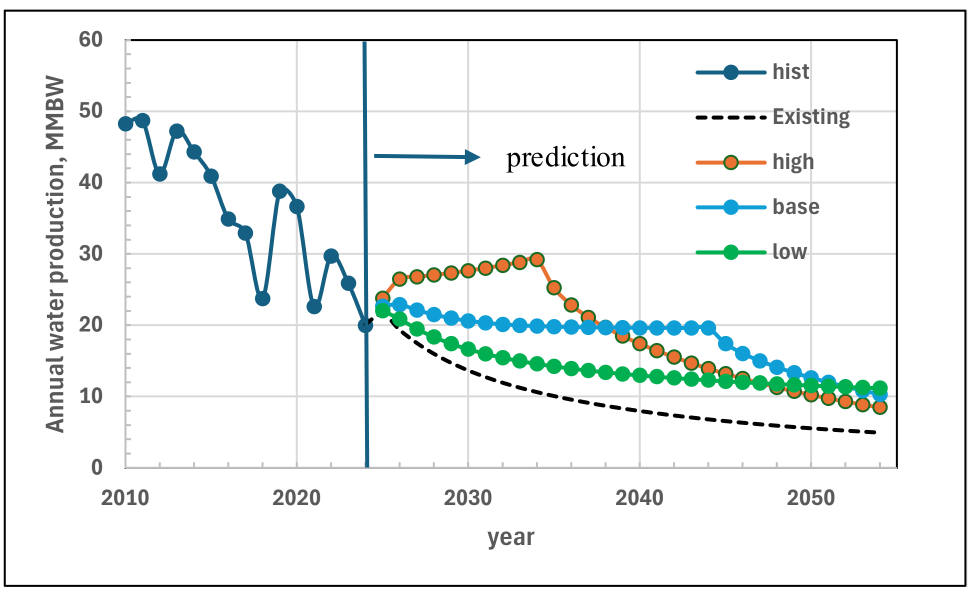

Figure 19. Historical and predicted annual water production for three new well development scenarios (high, base, low). {Source: NMOCD/GOTECH}

Oilfield Water Usage

The majority of water used in oil and gas operations is related to the stimulation design and requirements. Subsequently, to better predict the water usage needed for future development, historical trends of water usage were compiled and evaluated based on the well type since significant differences occur in water usage for vertical vs horizontal well type. The starting point was using FracFocus™ data which provided water volumes and well identifiers. Data for eleven years, from 2013 through 2023, were evaluated and considered sufficient for a reasonable analysis. This data was cross-referenced with NMOCD data[1] to determine the well type and location, and with Enverus™ data to distinguish trends in horizontal well usage.

Over the eleven-year time period, 589 wells reported frac volumes and were identified as vertical well completions, averaging 93 Mgals (~2 Mbbls) of water usage per well for stimulation purposes. The annual trend of well count (wells with reported data) and water usage in Mgals/well is shown in Figure 20. No discernable upward or downward trend is observed.

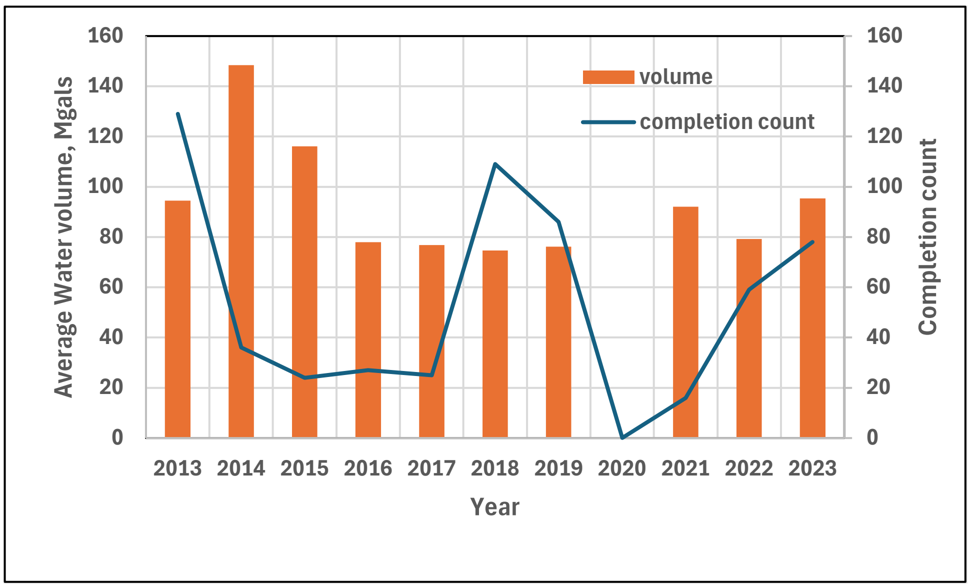

Figure 20. Vertical well average water volume use and well count by year. {Sources: FracFocus, NMOCD}

A comparison with compiled completion data (Figure 21) for Dakota, Mesaverde, Picture Cliffs and Fruitland Coal combined over the same time period, reveals the early years are dominated by new well completions, mostly Dakota-Mesaverde dual completions, and later by payadds, mostly Mesaverde. In both instances, new well completion or payadd, the average frac volume water used is approximately the same.

[1] * A random check of FracFocus vs NMOCD data revealed significant misreporting (e.g. stage volumes missing), errors (e.g. fluid volumes reported in bbls instead of gals), and water volumes reported as non-water volumes.

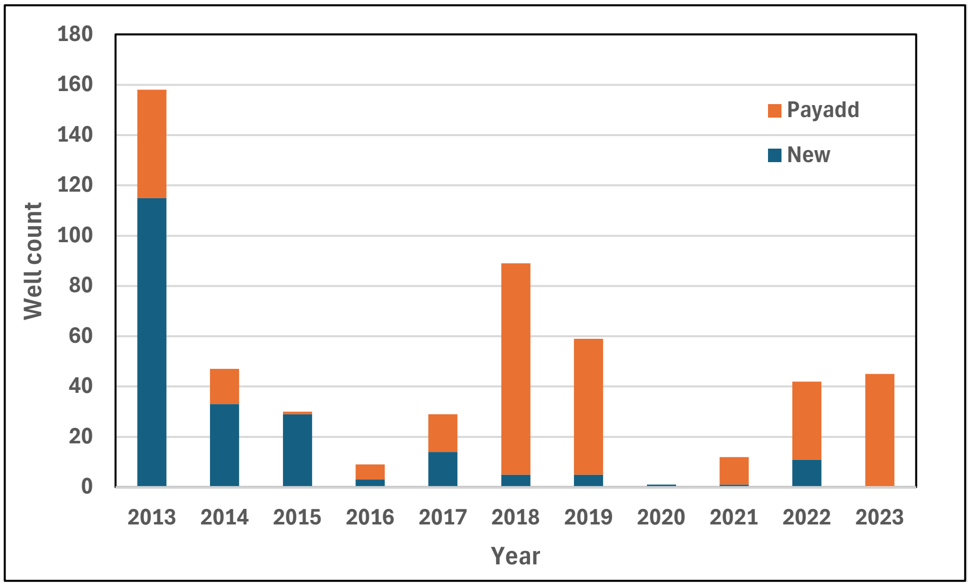

Figure 21. Vertical well completions from 2013 through 2023 separated into new well vs payadd {Source: NMOCD}

As previously noted, the majority of horizontal well development has been in the Mancos/Gallup play. In addition, this development has been subdivided into two sub plays; the Basin-centered Mancos Shale gas play and the southern rim Mancos/Gallup oil play. Frac volumes for each subplay are quite different and thus analyzed separately. As shown in Figure 22, water usage is significantly greater than vertical well usage. For the oil subplay, the average use is ~ 63 Mbbls per well, with an increasing trend over time. A total of 449 wells with reported frac volume data are included in this analysis. For the gas subplay, the water volumes are substantially greater, averaging 500 Mbbls of water per well from a total of 42 wells with reported data.

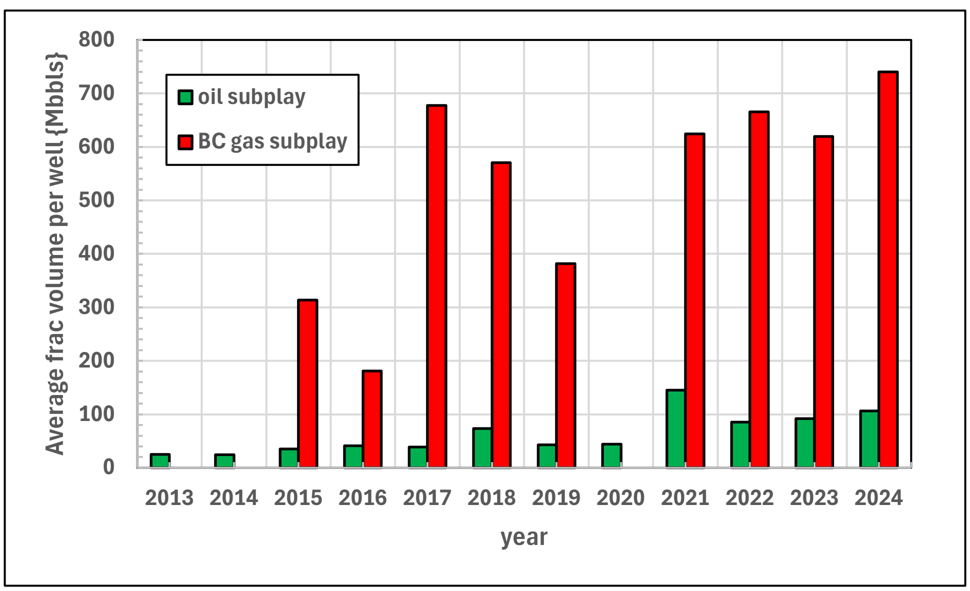

Figure 22. Horizontal well average water volume use by subplay. {Sources: FracFocus, NMOCD}

The difference in volumes between the two subplays reflects the stimulation design used for each. In the oil subplay, due to the low reservoir pressure, the original frac design was an energized fluid i.e., usually a 75-quality foam with Nitrogen gas to add energy in the flowback. As a result, the total water volume was reduced. However, the design has recently changed to a non-energized, slickwater frac design as shown in Figure 23. This design requires more water, thus the increase seen in Figure 22. ***The source of the water for the oil subplay is over 97% non-potable water. That is, it is recycled produced water or is makeup water from the deeper Entrada formation.***

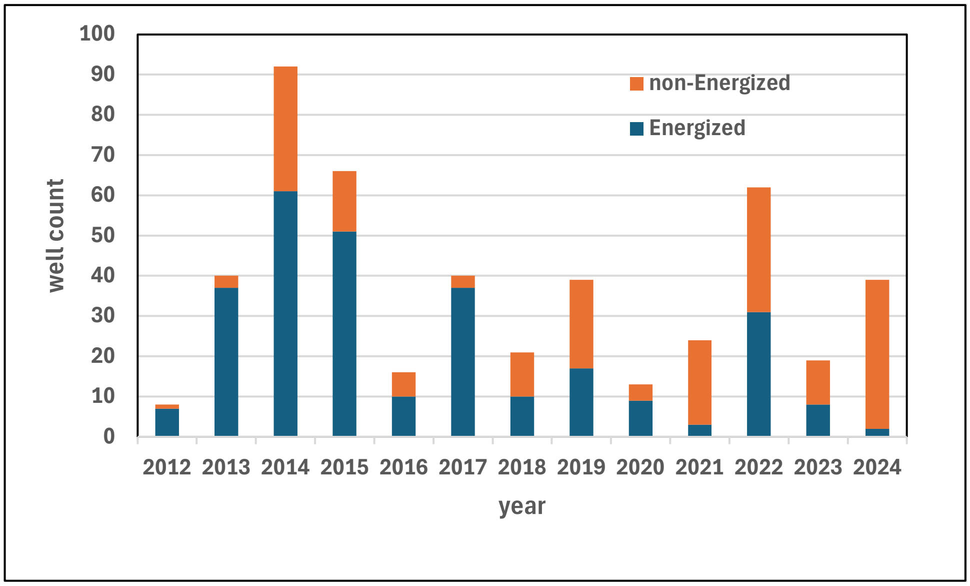

Figure 23. Comparison of non-Energized (slickwater) to energized frac fluid for Mancos/Gallup southern rim horizontal oil subplay. {Source: FracFocus}

In the gas subplay, the design uses large volumes of slickwater. In this case, the ***water source is freshwater from Navajo Reservoir.***

The above volumes were normalized to accommodate for the increase in producing lateral lengths with time. Figure 24 illustrates the trend of the frac volume per gross perforated interval (GPI) {gals/ft} since 2013 and the well count for each year. The average for the entire eleven-year span is 383 gals/ft. However, in the latest three years (2021-24) the average is higher (> 500 gals/ft), confirming the recent increase in water volumes.

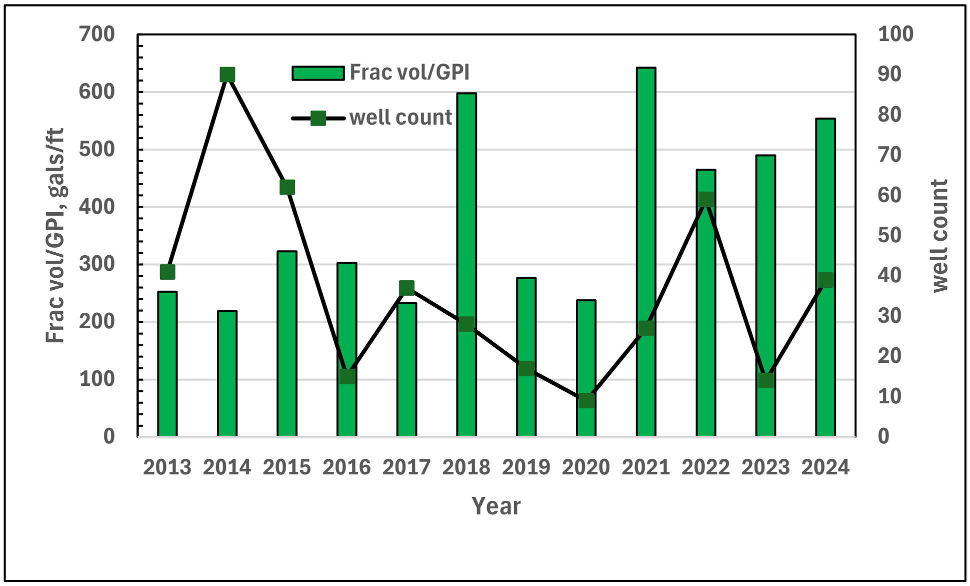

Figure 24. Frac volume per GPI and well count for oil subplay horizontal wells. {Source: FracFocus, NMOCD, Enverus}

For the gas subplay, the average water volume per GPI was 2,681 gals/ft. for the entire time span. Since data is limited and sparse, no trend analysis was attempted.

Predicted future water use is related to the schedule and number of new wells completed as proposed in the three previous scenarios, high, base and low. Shown in Figure 25 is the cumulative water used for stimulation purposes for the southern rim horizontal well oil subplay and in figure 26 the same for the basin-centered horizontal gas subplay.

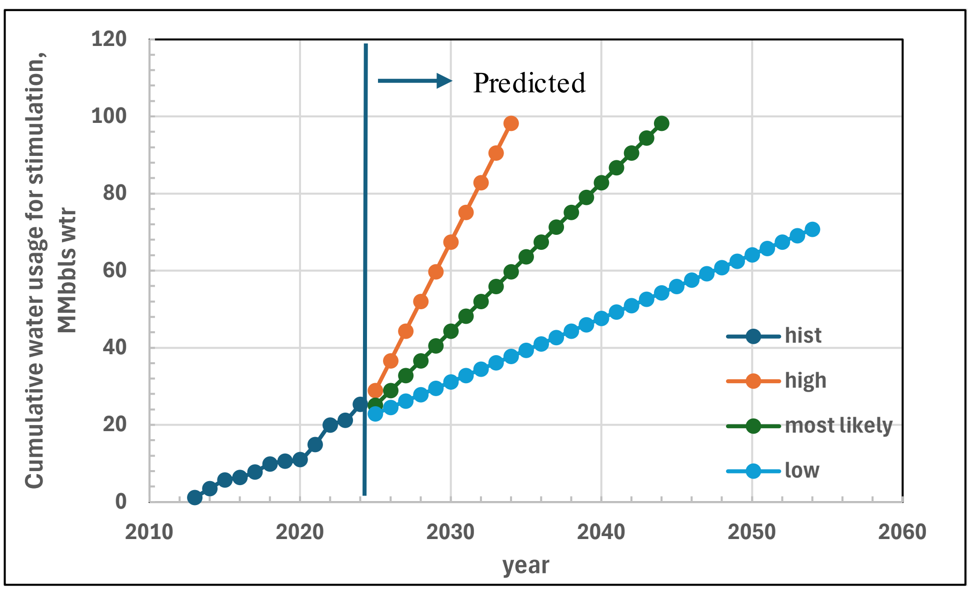

Figure. 25 Cumulative water use for stimulation for the three scenarios of new well additions in the Mancos/Gallup southern rim horizontal well oil subplay. {Source: FracFocus}

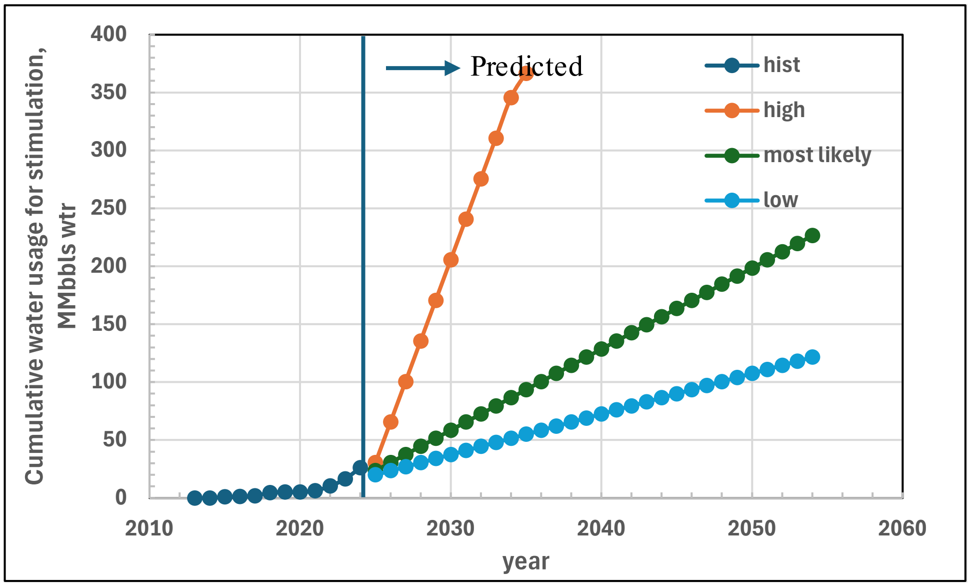

Figure. 26 Cumulative water use for stimulation for the three scenarios of new well additions in the Mancos Shale basin-centered horizontal well gas subplay. {Source: FracFocus}

The basis for these estimates were recent values observed, e.g., 110 Mbbls per well for the oil subplay and 700 Mbbls per well for the gas subplay, respectively.

Potential Impact of Carbon Capture Underground Storage (CCUS) on San Juan Basin development

An ongoing project is currently being conducted under a Department of Energy (DOE) cooperative funding agreement in the San Juan Basin to accelerate deployment of carbon capture, utilization and storage technology at San Juan Generating Station (see Carbonsafe website for details). The goal will be to ensure safe subsurface storage of CO_2 in saline reservoirs by constructing Class VI wells (CO_2 injection wells) that would allow for geologic sequestration of CO_2.

Extensive geologic, petrophysical and simulation efforts have identified targets to best accomplish this goal. (See Appendix D for details). The Jurassic Entrada Sandstone is the main CO_2 injection target, present throughout the San Juan Basin and Four Corners area. The upper Entrada exhibits excellent petrophysical characteristics with porosity ranging upward to approximately 20%, and permeability ranges from 10 to over 500 mD., has excellent confining layers above and below for containment, and has extensive areal extent. Other potential reservoirs identified within the terrestrial Jurassic strata of the San Juan Basin and Four Corners area are the Bluff Sandstone and Salt Wash member of the Morrison Formation.

Multiple methods were used to assess the potential storage capacity of the three saline formations (Entrada, Bluff, and Salt Wash) in the San Juan Basin. These tools use a volumetric method to estimate the storage capacity with storage efficiency factors that were developed from simulations of CO_2 injection into storage formations. Within the three proposed sites (aka hub project), the estimated storage capacity is 240 million metric tons of CO_2 to be stored in the proposed hub project. Preliminary reservoir simulation indicates that each of the three (3) proposed sites can safely store at least 60 million metric tons of CO_2 within a 30-year period, with limited pressure elevation interference between sites.

The estimates of the storage capacity over the larger domain (9,571 square kilometer area of the model) ranged from 6 to 12 gigatons with an average of ~ 10 gigatons of CO_2 storage. This is at least an order of magnitude larger than the potential to be stored in the proposed hub project. Subsequently, significant additional potential to store CO_2 is available.

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Appendix A – Mancos/Gallup Play

The Mancos Shales and Gallup Sandstones consist of multiple members that are both spatial and temporal equivalent and thus are considered a single discreet petroleum system. This system is bounded by the Point Lookout Sandstone of the Mesaverde Group at the top and the Dakota Sandstone at the base. Due to the complex stratigraphy, individual member contributions were not attempted in this work; however, the Mancos/Gallup can be divided into three subplays: the *southern rim oil subplay* associated with the previously developed "Gallup" barrier bars/barrier island sandstone reservoirs along a shoreline trend, the *basin-centered Mancos Shale gas subplay* located basinward (northeast) of the barrier sands in the marine shales, and the naturally fractured, oil-filled Mancos shales subplay along the eastern flanks of the basin. Approximate locations are shown in Figure A-1. The first two have significant future potential and will be discussed in further detail below.

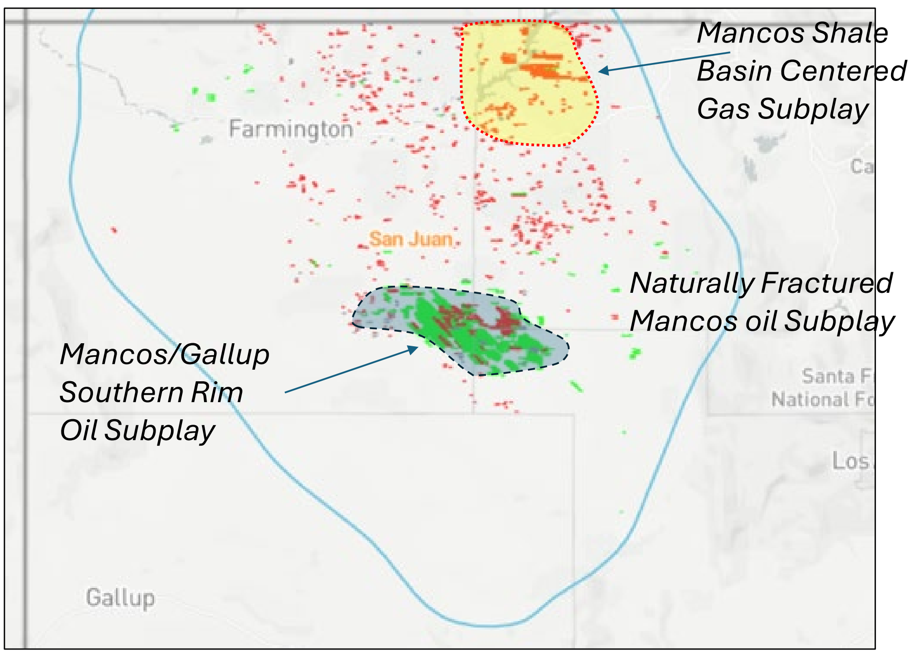

Figure A-1. Current (through 2024) Mancos/Gallup wells superimposed with approximate location of subplay boundaries. {Source: Enverus}

Basin-Centered Mancos Shale Gas Subplay

Mancos Shale development by vertical wells has demonstrated limited gas potential for decades. However, in 2010, significant gas production rates were achieved in the Mancos Shale with the completion of two horizontal wells: Rosa Unit #634A and #634B. Recently, activity has increased in response to the excellent per well performance such that production for December 2024 reached a high of 9.6 Bscf.

Based on results from recent well development, the highest potential for the basin centered gas subplay has been refined to the highlighted region shown in Figure A-2. Within this region wells have demonstrated to be highly productive. The area between the original gas boundary defined by geochemical data and production performance (RFD 2001) and the high potential shaded area is considered low potential for gas. Wells in this area have been less productive, with EURs averaging less than 1.5 Bscf per well.

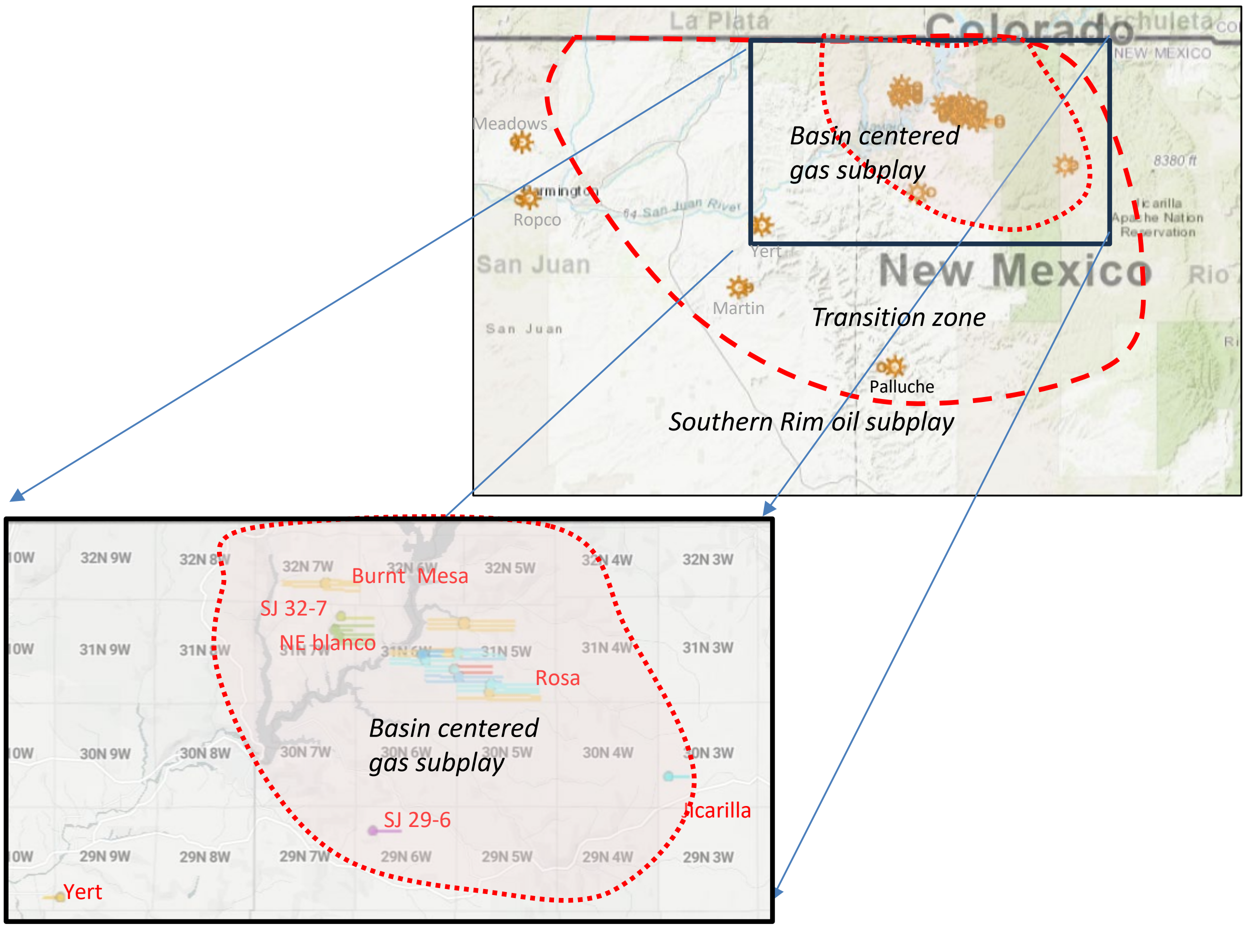

Figure A-2. Location map of the high potential region for gas production completed in the Mancos Shale play. Wells completed in 2024 are colored yellow on the map. {Source: Enverus}

A comparison of the thermal maturity boundary to the limited area of well development (Figure A-2) clearly demonstrates additional constraints that exist that limit the highly productive area. Since structure plays a role in defining the development as "basin-centered" a structure map of the top of the Mancos Formation for the San Juan Basin was previously developed and is shown in Figure A-3. The Mancos is structurally high on the southern rim of the basin and dips to the northeast, reaching its maximum depth along the Colorado border. As a result, the location of the prolific Mancos gas play is defined as a basin-centered gas play, similar to many other gas plays in the San Juan Basin. In this deeper section of the basin, the entire Mancos Shale section reached a gas-window level of maturity (Brister, 2001); whereas, in the surrounding areas, Mancos only reached the oil window level of maturity.

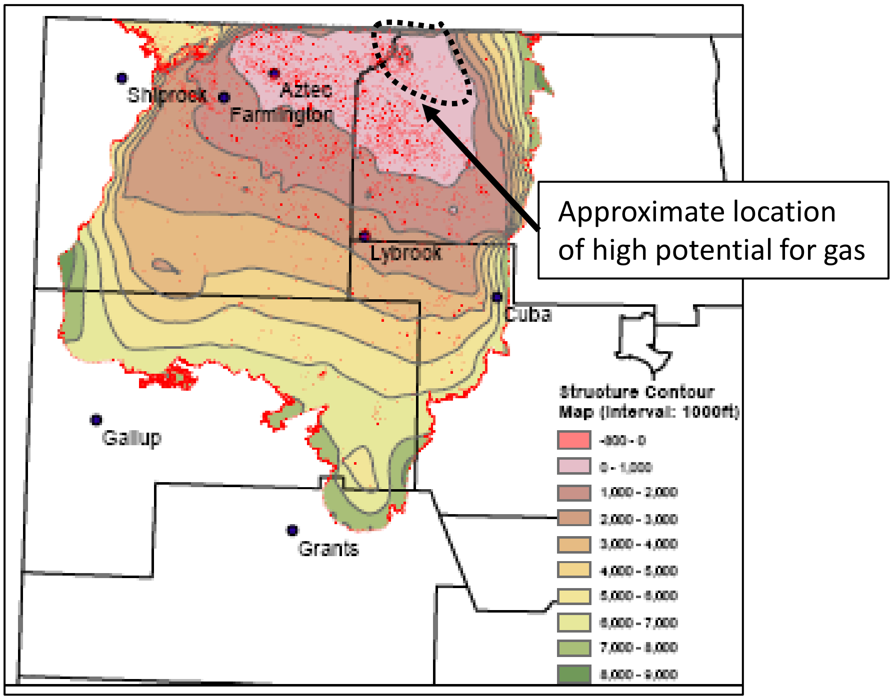

Figure A-3. Top of Mancos structure contour map {Source: RFD, 2012}

Shown in Figure A-3 is the approximate location of the high gas potential region defined previously and shown in Figure A-2. Note to some extent, this boundary (as well as the previous geothermal boundary) follows the Mancos contours.

An additional consideration in defining the limits of the Mancos Shale gas play was whether basement faults contributed to development, similar to the southern rim Mancos/Gallup oil play. The highly productive leases (Rosa Unit, etc) shown in Figures A-2 were superimposed onto a magnified portion of the basement fault map created by Ridgley, et al, in 2013 and is shown in Figure A-4. The correlation is inconclusive since the fault data in this area of the San Juan Basin is limited and not in proximity to the well development. However, the San Juan River and Navajo Lake follow a similar northerly trend in direction and thus is an indicator of the influence of basement faults. In addition, all horizontal wells to date have been drilled in an east to west or west to east direction. This would indicate an operator's preference to create hydraulic fractures in a more northerly direction.

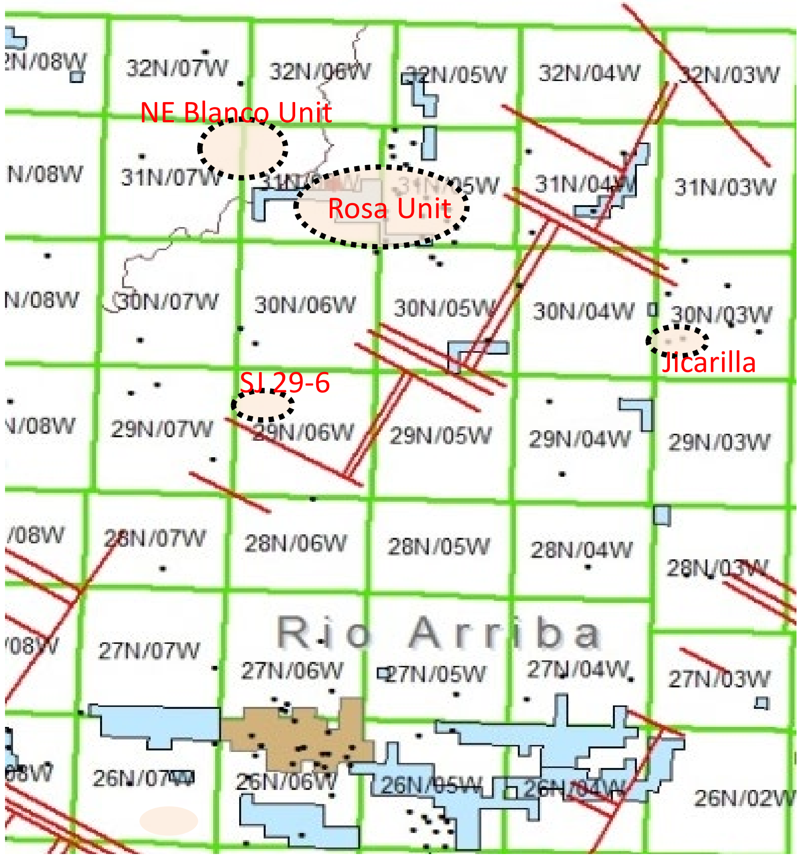

Figure A-4. Basement faults from Ridgley, et al, 2013 superimposed with the highly productive gas leases in the Mancos Shale.

Previous work (RFD, 2015) compared completion and production for both the vertical and horizontal wells in 288 sections in the Mancos shale target area. Preliminary findings suggest the low-quality reservoir is reasonably continuous over the domain of the study area, and therefore the level of production is more completion controlled than by the reservoir quality. The implication is that the entire domain has a high potential to be completed with commercially productive horizontal gas wells.

Production Performance

The basin-centered, Mancos Shale play has proved to be a prolific gas play. As an example, in 2024, an average of 40 wells produced slightly greater than 56 Bscf for the year. This production represents **13% of the total San Juan Basin gas production for the year**. The increase in production since the initial Rosa discovery wells is shown in Figure A-5. As additional wells are completed a corresponding increase in production is observed.

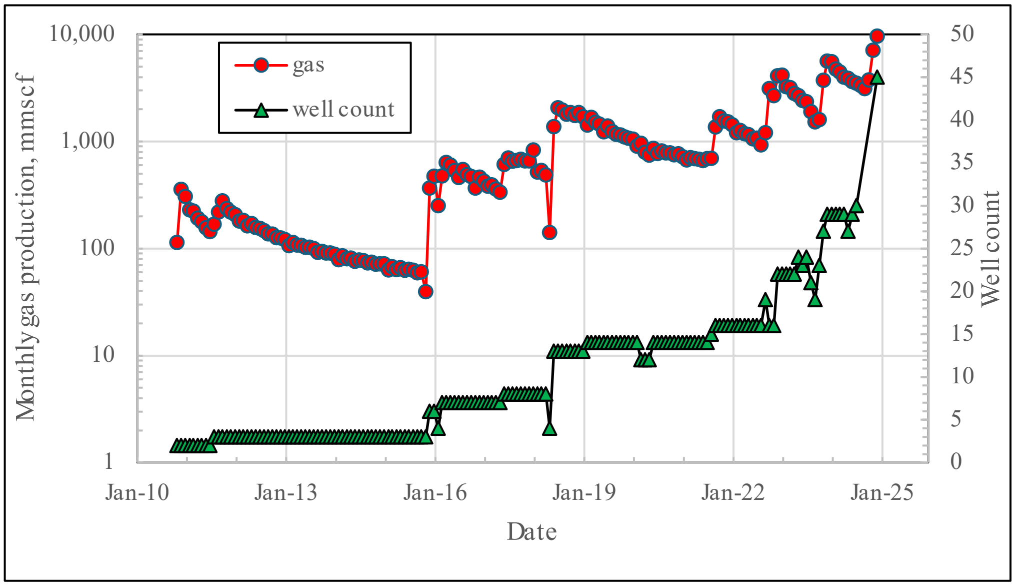

Figure A-5. Monthly gas production and horizontal well count for the Mancos basin-centered cohort. {Source: GOTECH/NMOCD}

To estimate performance, Decline Curve Analysis (DCA) was relied on to determine the Estimated Ultimate Recovery (EUR) per well. With the limited number of horizontal wells completed in the Mancos play, a composite type curve was generated for all wells producing in this play. Figure A-6 is the resulting composite type curve for a single well from this effort. The points represent the historical production and the red line represents the modelled and forecasted production for a single gas well.

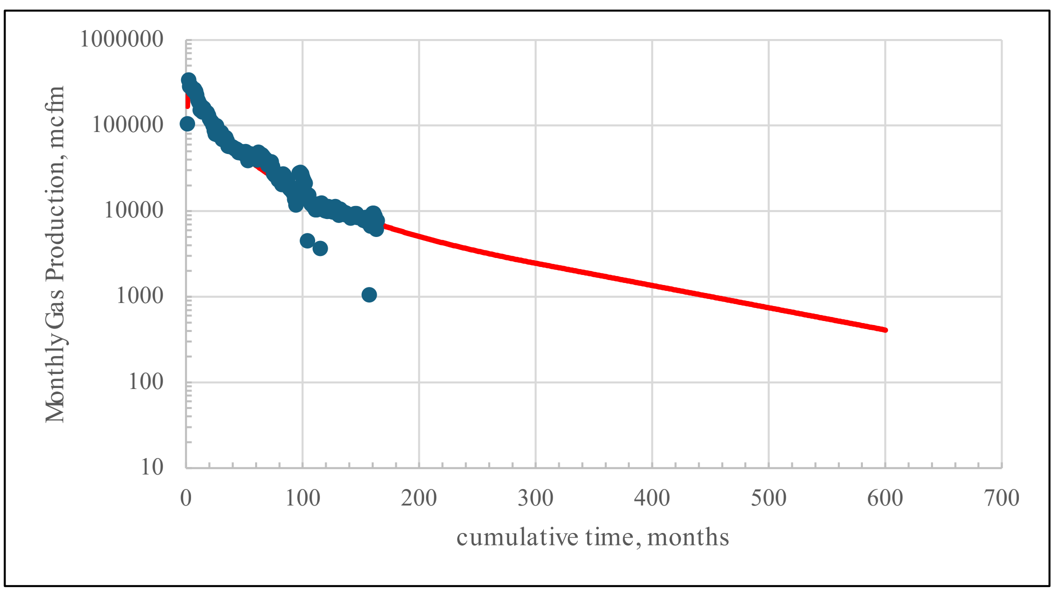

Figure A-6. Mancos Shale type curve generated from the horizontal wells completed in the basin centered gas subplay. {Source: Enverus}

The corresponding cumulative production plot for this cohort of wells is shown in Figure A-7.

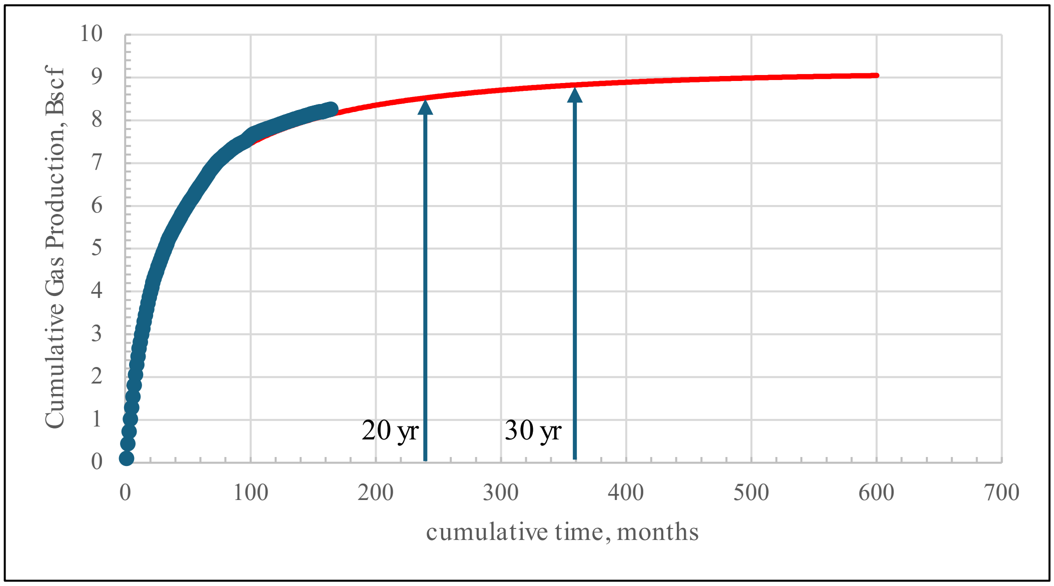

Figure A-7. Mancos Shale cumulative production type curve per well generated from the horizontal wells completed in the basin centered gas subplay. {Source: Enverus}

Initial production rates are very high, thus the rapid rise in cumulative production observed in the first eight years; after which, with a declining rate the cumulative curve flattens out towards depletion. Two EURs are indicated on the figure. For a 20-year life, a given horizontal well is expected to produce 8.5 Bscf and for a 30-year life, the EUR increases to 8.8 Bscf, respectively. The average gross perforated interval (GPI) is 8,400 ft or about 1.5 miles, thus EUR per GPI is approximately 1000 to 1050 Mscf/ft. Based on this average gross perforated interval, a typical horizontal well length is 2 miles.

Two caveats are important to understand about the type curve approach to determine EUR. First, the type curve displayed is dominated by the first two wells drilled (Rosa Unit #634A and B) as their life span is substantially longer than the other wells. The latest completed wells have very limited production history and therefore contribute less to the overall prediction. Second, individual well performance can and will significantly depart from this average. However, as a group the expected value of the group should provide a reasonable approximation for future performance.

Predicted development

To determine the extent of future horizontal gas well development several factors were considered.

First, the extent of the productive area in the high potential region consists of approximately 250,000 acres, of which 10,000 acres are developed thus 240,000 acres are available for future development.

Second, Lateral length of current horizontal wells is approximately 2 miles, with spacing between wells of 1320 ft. or four wells per two sections. The constraint of 2-mile length is conservative with longer laterals occurring in other regions; subsequently future wells are predicted to be 3 miles in lateral length. With regards to the spacing, a smaller spacing has shown some indications of well interference, thus, to avoid a greater spacing was assumed. Applying these two criteria to the acreage available results in approximately 500 locations to drill from Mancos Shale gas.

Third, two target zones exist named Black and Olive. Approximately 300 vertical feet separate the two zones, thus each must be developed and completed individually. An example log near the Rosa Unit is shown in figure A-8 illustrates the vertical separation. To date the main target has been the Black zone with 80% of all completions in this zone.

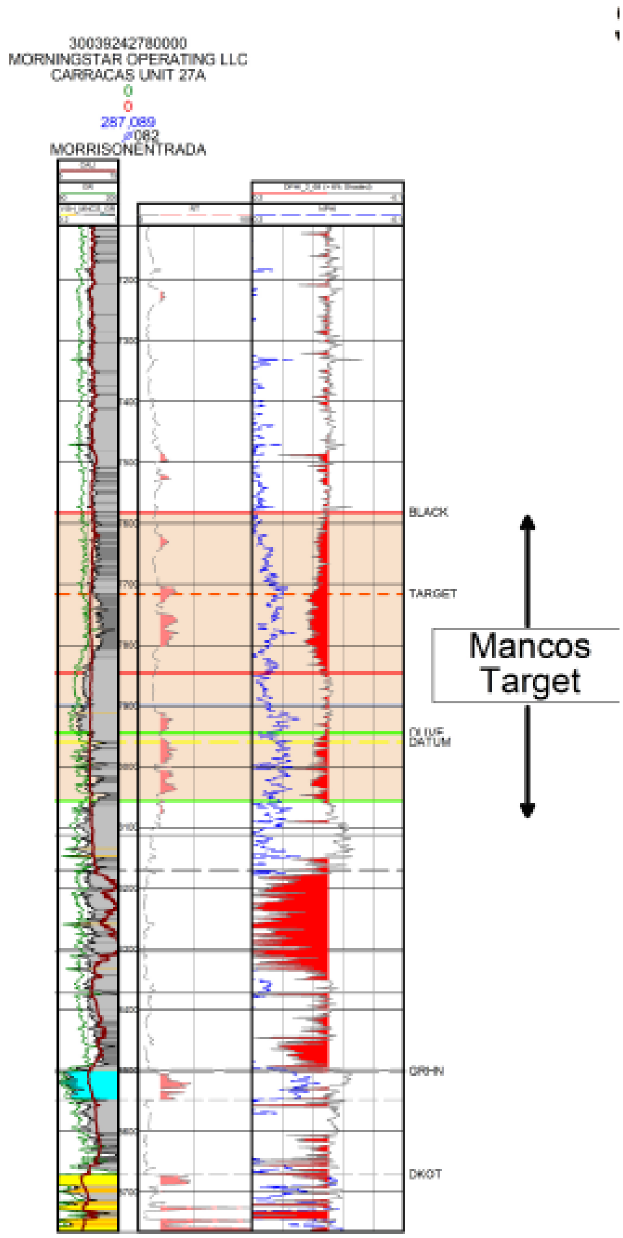

Figure A-8. Example of a type log illustrating the Mancos target zones and vertical separation between the Black and Olive Zones. {Source: NMOCD, Case #24830}

As seen in Figure A-9, the Olive zone's productivity has been less than the Black zone, thus the preference is for the Black zone. In terms of future development, only the Black zone was considered.

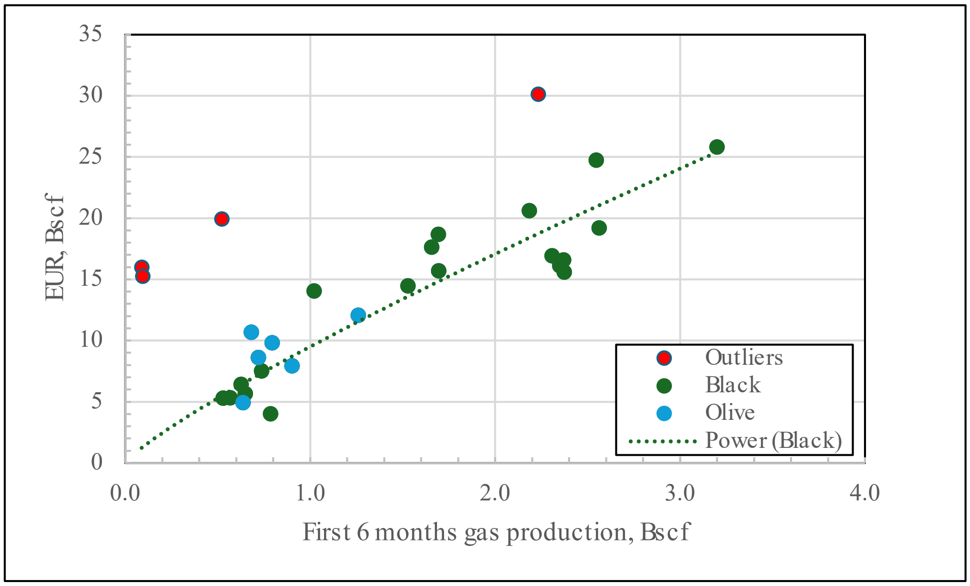

Figure A-9. Mancos Shale gas well EUR vs performance indicator (First 6 mos. Production) for wells with FPD of 2023 or earlier. Note: All outliers are completed in the Black zone. {Source: Enverus, NMOCD}

Fourth, limitations occur that will delay or reduce this potential. Gas prices will play a significant role in the speed of this development. Also, two other factors will inhibit development: lack of high pressure, pipeline capacity to take the gas and the lack of sufficient drilling rigs to handle these longer horizontal wells and time available to drill due to National Forest requirements {per industry conversations}. The outcome of the latter is an estimate of four rigs available and running, capable of drilling 14 wells per year, resulting in 56 wells drilled per year. This includes a fraction of these wells being classified as DUCs and completed the following year. This assumes full capacity with no downtime or other delays. As a comparison, over the last three years (2022-2024) 6, 8 and 16 wells have been completed, thus significant increases in investment will have to occur to meet full capacity.

Predicted Development Schedule

Three alternative development schedules have been created based on the previous performance and development, with consideration of the factors previously discussed.

The **reference case or most likely case** is a continuation of the recent activity, i.e., the addition of 10 new wells per year over the span of the RFD. The assumption is that the subplay is not resource limited but instead other external factors are tempering development. That is, the resource extent is mostly undeveloped, and thus future activity is defined more as extension of past activity than infill development. In other words, the resource exists but it is not well known how successful it will be.

The **high development case** relaxes the external constraints such that the resource can be developed more rapidly. In this case, the addition of 50 new wells per year is assumed, reaching the 500 well maximum in ten years. The assumption is that the resource is highly productive throughout the defined area, with no limiting factors to constrain development. The addition of 50 well per year is expected to be delayed and thus begin in 2026. For 2025, it is proposed that 20 wells be completed. The remaining 30 wells will then be drilled and completed in year 11.

The **low development case** of 5 new wells per year over the life of the RFD reflects the combination of a limited, less productive resource with external controlling factors.

Future Estimated Production

Future estimated production for the Mancos Shale basin-centered gas subplay consists of two components: remaining production from existing wells and the additional production of new wells completed in the future time period. Figure A-10 exhibits declining production from the existing wells.

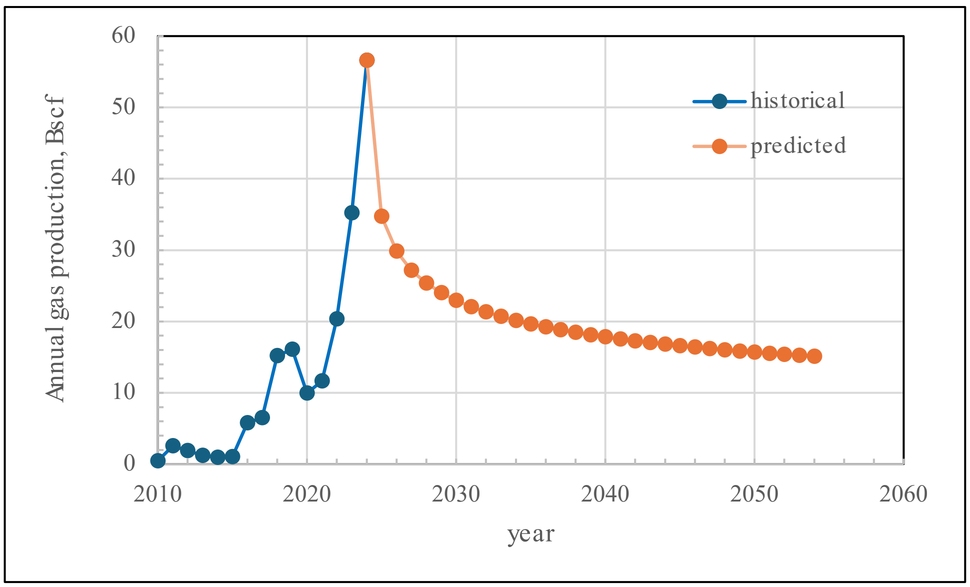

Figure A-10. Future declining production from existing Mancos Shale basin-centered horizontal gas wells.

Due to the upward production trend from the development from 2010 through 2023, the prediction was achieved by compiling a series of decline curves into a composite curve with the resultant shown in the figure. The curve terminates in the year 2055 or 30 years from 2025.

Production from the three cases for new well development has been added to the existing well declining production and the results are shown in Figure A-11.

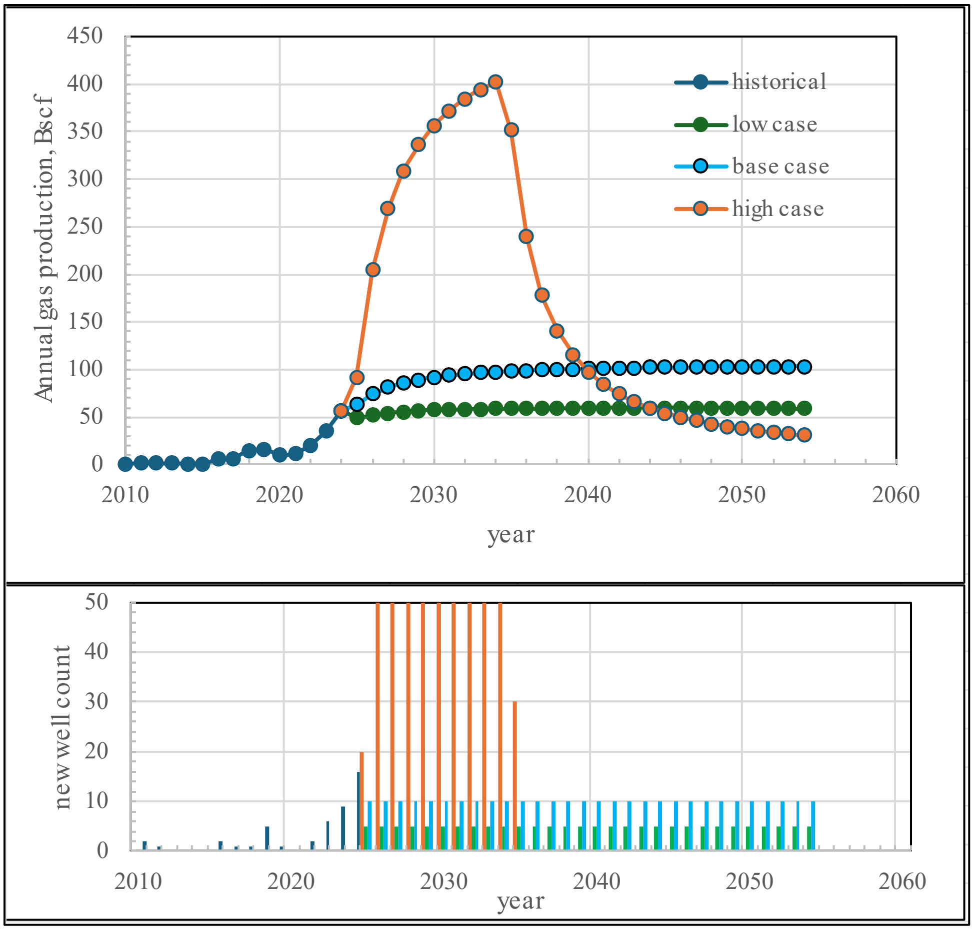

Figure A-11. Forecasted production for development of the Mancos Shale basin-centered gas subplay. Included are the three cases for additional new wells with the declining production of existing wells.

The base case continues the current upward trend but then slows as a point is reached where the decline of existing wells balances the increase from new wells. For the low case, production is immediately balanced between existing wells and new wells thus a constant trend is observed. For the high case, a dramatic increase in production is shown due to the high (50 wells/yr) number of new wells per year. Afterwards, a rapid decline is observed as no new wells are being added and decline of all wells dominates.

Mancos/Gallup Southern Rim horizontal oil subplay

Early successful horizontal tests in the Mancos/Gallup oil subplay in 2010 through 2012 resulted in significant interest and subsequent development, with peak well completions in 2014 (see Figure A-12). Through 2024, 482 horizontal wells have been identified to be completed in this subplay. Oil production has steadily increased over this time with WOR remaining relatively constant and GOR declining.

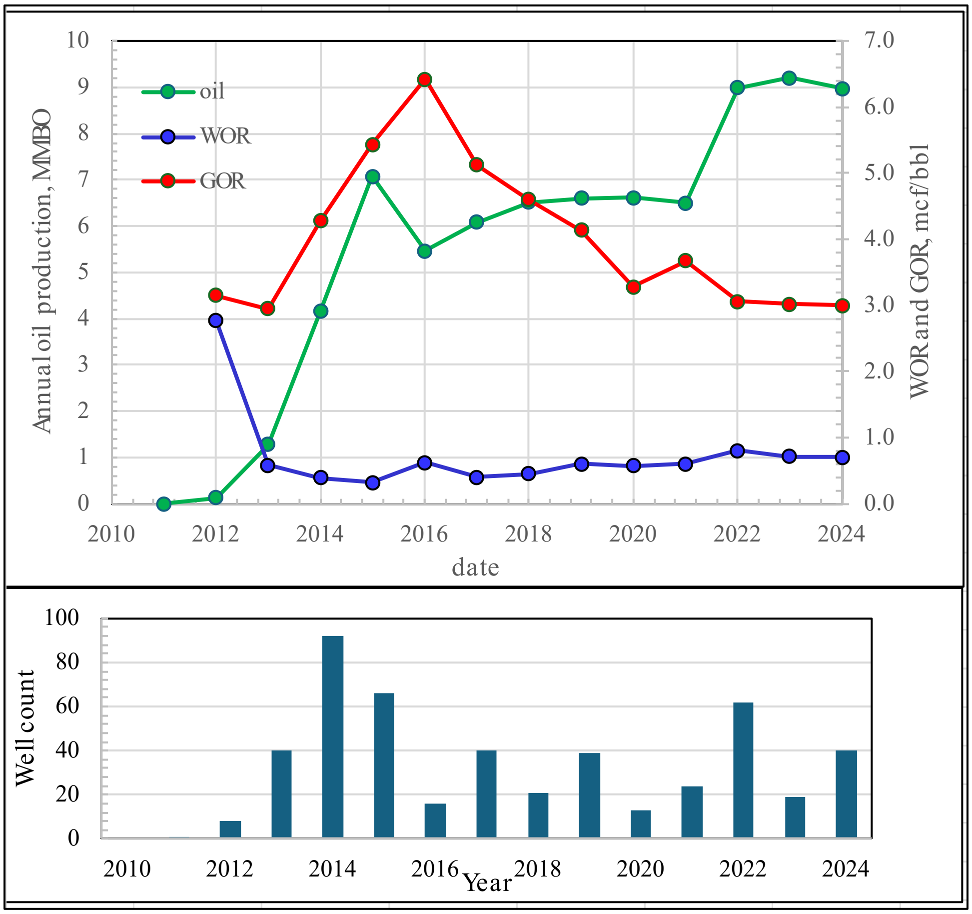

Figure A-12. Annual horizontal completions and production in the Mancos/Gallup southern rim oil subplay. {Source: Enverus, NMOCD}

The overall impact of this development has been to increase oil production from the San Juan Basin (Figure A-13). Oil production has tripled since 2013, with 90% from the Mancos/Gallup subplay region. Cumulative production for this subplay as of January 2025 has been 78 MMBO, 46 MMBW and 312 Bscf gas.

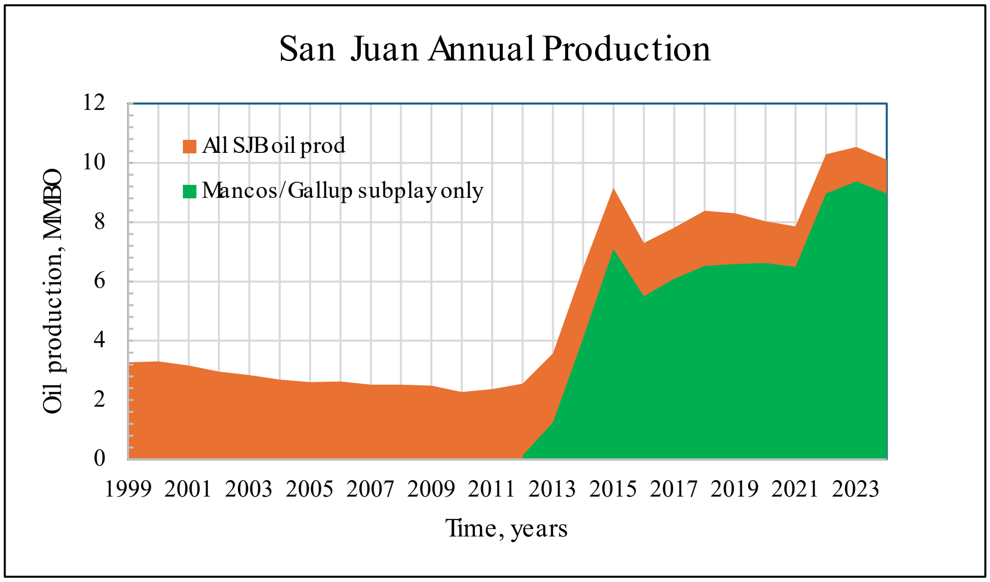

Figure A-13. Mancos/Gallup subplay oil production compared to the total San Juan Basin output. {Source: NMOCD/GOTECH}

Previous work (RFD updates: 10/2014, 8/2015) delineated high, moderate and low oil potential regions based on drilling activity and production performance. Subsequent development has continued to be confined to these boundaries (Figure A-14). Within the high potential region, the best wells appear to be located within the central axis of the region; the Lybrook to Nageezi area. Well performance and recovery decreases for wells along the southern and western periphery of the high potential region.

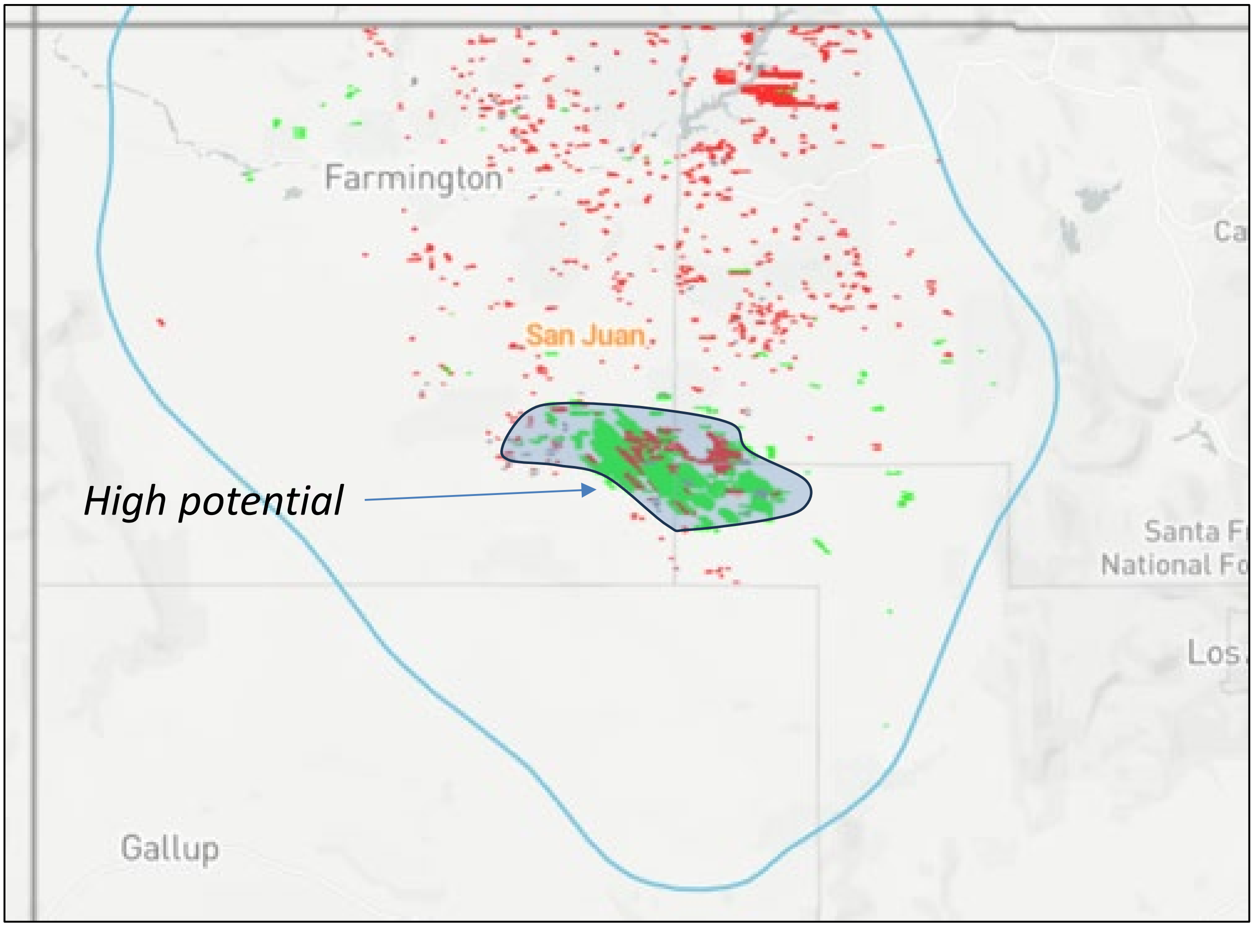

Figure A-14. Current (through 2024) Mancos/Gallup wells superimposed with previous oil potential boundaries. {Source: Enverus}

The extent of the oil prone region is constrained by a variety of factors. Previous work (Brister, 2001; Broadhead, 2013) described the "Gallup/Mancos" play as a series of barrier bars/barrier island sandstone reservoirs along a shoreline trend. Initial vertical well development, shown by pool maps in the RFD 2014 update, illustrates this well-defined northwest to southeast linear trend. The quality of reservoir degrades away from these main channel bodies, i.e., decreasing sand content and subsequent porosity and permeability. In addition, water saturation has shown to increase in a southwesterly "updip" direction, confining development in that direction.

An additional factor is the dominate northeast -southwest stress orientation in the San Juan Basin. Basement fault maps {Ridgley, et al, 2013} have been linked to the Gallup/Mancos development. There does appear to be an alignment of the Northwest-Southeast fault/fracture trend direction to the trend of many of the Gallup pools. However more important is the alignment of the hydraulic fracture direction to the Northeast-Southwest set. Subsequently, most wells have been drilled on a northwest to southeast diagonal trend to take advantage of the hydraulic fracture propagation direction (Figure A-15).

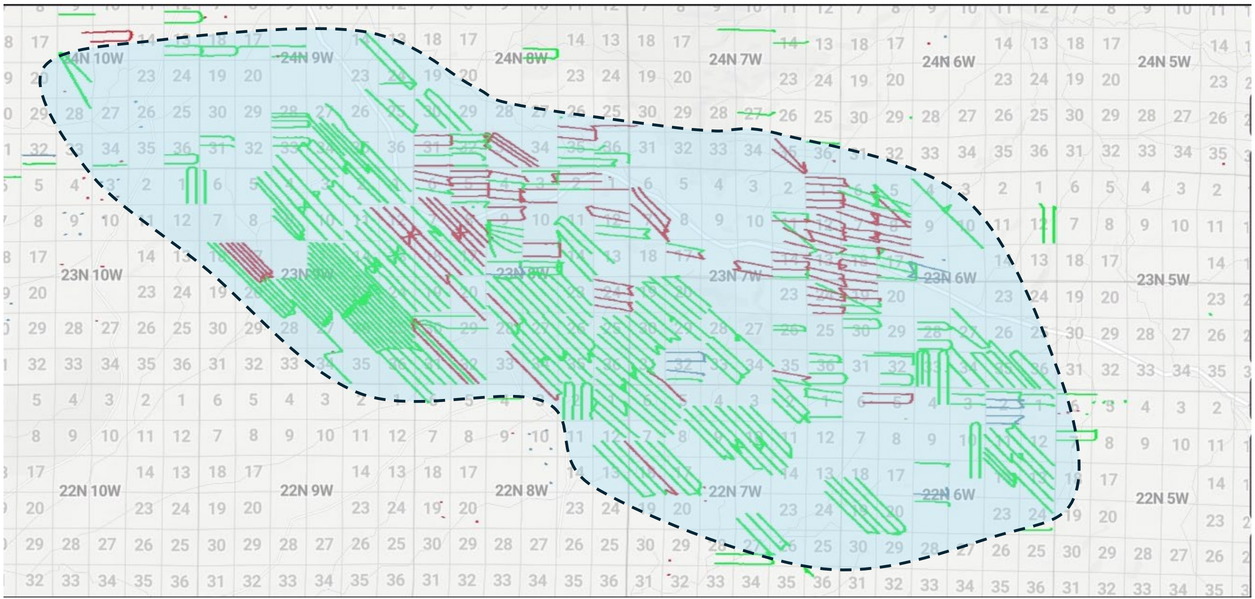

Figure A-15. Current (through 2024) Mancos/Gallup horizontal wells superimposed with previous High Oil potential boundary. Note dominant well orientation NW-SE{Source: Enverus}

Investigations of horizontal well orientation showed significant improvement in overall performance (Table A-1). Diagonal refers to a well that is oriented northwest – southeast as observed in Figure A-15. Parallel refers to horizontal well orientation that is either north-south (standup) or east-west (laydown) directions.

	Parallel	Diagonal
well count	234	237
Ave. EUR,MBO	183	451
Ave. GPI, ft	5600	7088
EUR/GPI, BO/ft	38	65

Table A-1. Comparison of horizontal well orientation on well performance. EUR data is through 2023 well completions.

Note that well counts are approximately equal, however, as Figure A-16 shows the diagonal direction has been more dominant in recent years. Since 2016, approximately 90% of all horizontal wells in this subplay have been drilled in the diagonal direction. In addition, the diagonal wells have longer lateral lengths. Table A-1 shows the Gross Perforated Interval (GPI) on average is 25% longer than the parallel cohort.

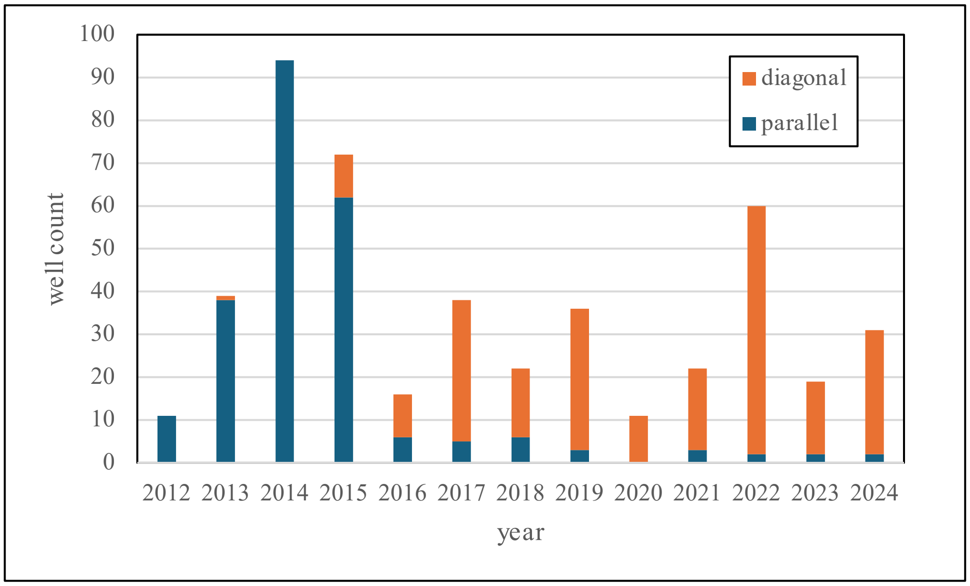

Figure A-16. Comparison of Mancos/Gallup oil subplay horizontal well orientation over time {Source: Enverus, NMOCD}

Aligning well orientation results in fracture stimulation to occur parallel to the maximum horizontal stress direction and thus provide the most efficient fractured volume to be stimulated. The Estimated Ultimate Recovery (EUR) supports this claim with the average diagonal EUR two and half times better than the parallel cohort (Table A-1). Normalized on a per lateral foot basis, the diagonal well recovery (65 BO/ft) is also better than the parallel cohort (38 BO/ft). However, as shown in Figure A-17, the recovery per foot for the diagonal cohort has been slightly decreasing with time.

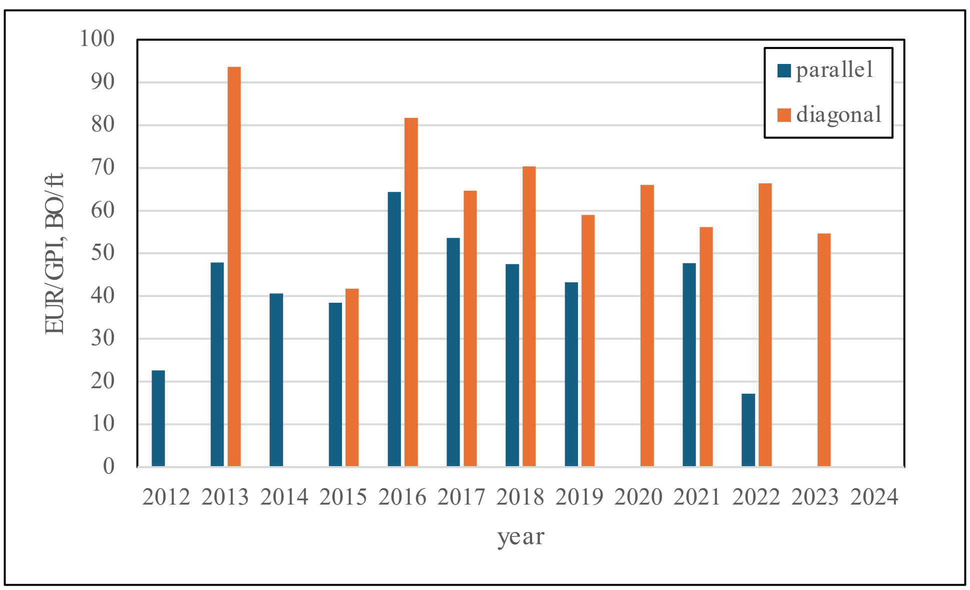

Figure A-17. Comparison of Mancos/Gallup oil subplay horizontal well recovery per lateral foot by orientation over time {Source: Enverus, NMOCD}

Production Analysis
The EUR was derived by using production decline analysis and then developing a type curve for a cohort of wells based on year of first production. Table A-2 provides the results of this analysis. The 20 and 30 labels indicate the duration of the estimate, i.e., 20 or 30 years. These times were selected based on the future forecast for the RFD of 20 and 30 years, respectively.

Year	Well Count	EUR20, MBO	EUR30,MBO
2014	93	161	175
2015	72	156	169
2016	16	321	341
2017	38	355	387
2018	22	263	292
2019	37	316	335
2020	11	415	450
2021	22	359	403
2022	60	520	592
2023	19		

Table A-2. EUR for horizontal wells in the Mancos/Gallup oil subplay by year of first production

In Table A-2, no separation into horizontal well orientation or lateral length was included. Regardless, observing the improvements in recovery with the diagonal orientation is evident. For example, in 2022, only two of the sixty wells are parallel, thus the average results are more weighted to the diagonal well recoveries.

Since these results are statistical, it is important to realize the sample set (cohort) varies and thus for small sample sets the results are less statistically meaningful. Also, the longer the production life, the better the type curve since more data is included in the fit. For that reason, no 2023 type curve was generated as the production life was considered too short.

Predicted Development
Predicted development is based on the following constraints:

1. The extent of the subplay is well-defined (see Figure A-15), therefore the remaining development is considered infill rather than extension of undeveloped acreage.
2. The approval of units has allowed operators to take advantage of the directional stress field by drilling diagonal (NW-SE), resulting in improved stimulation performance. This also allowed for high-density drilling and the ability to drill long laterals. Evidence for the former is shown in Figure A-15 where sections exhibit high-density drilling.
3. The Mancos/Gallup thickness is significant, however, only a single zone is considered a viable target.

As a result of these constraints, 700 locations are available for future development. This development will consist of diagonal well orientations, approximately 2 ½ -mile lateral lengths, at high-density spacing. An additional benefit of this type of development will be reduced surface disturbance due to the longer lateral length and multiple wells emanating from the same pad.

Predicted Development Schedule

To accomplish the above development, three alternative schedules have been created based on the previous performance and development.

The **reference or most-likely case** assumes development will continue at the historical average of 35 new wells per year. This pace will be assumed to be constant, thus after 20 years the forecasted 700 locations will have been developed. The resource is not a limiting factor since the prospect is mostly infill development acquiring proven, developed reserves.

The **high development case** allows for 70 new wells to be drilled over a ten-year period. Since the play is not resource limited, the fundamental assumption is that future wells will perform as good or better than past wells. Subsequently, motivation exists to develop more rapidly. In addition, development will rely on infrastructure, regulatory, and economic factors all favorable for the increase in development.

Conversely, for the **low development case**, 15 new wells per year are forecasted for development for a total of 450 wells completed in 30 years. The decrease in development is primarily based on poor future well's performance compared to past wells, thus reducing the motivation to develop. Less favorable other factors will also play a role in this case.

Future Estimated Production

The future forecast for the Mancos/Gallup oil subplay consists of two components: the production decline from existing wells, and the addition due to future well development. The existing wells production decline was modelled by a series of decline curves to account for the recent activity and upward trend in production as shown in Figure A-18. The production curve was then extended out 30 years to 2055.

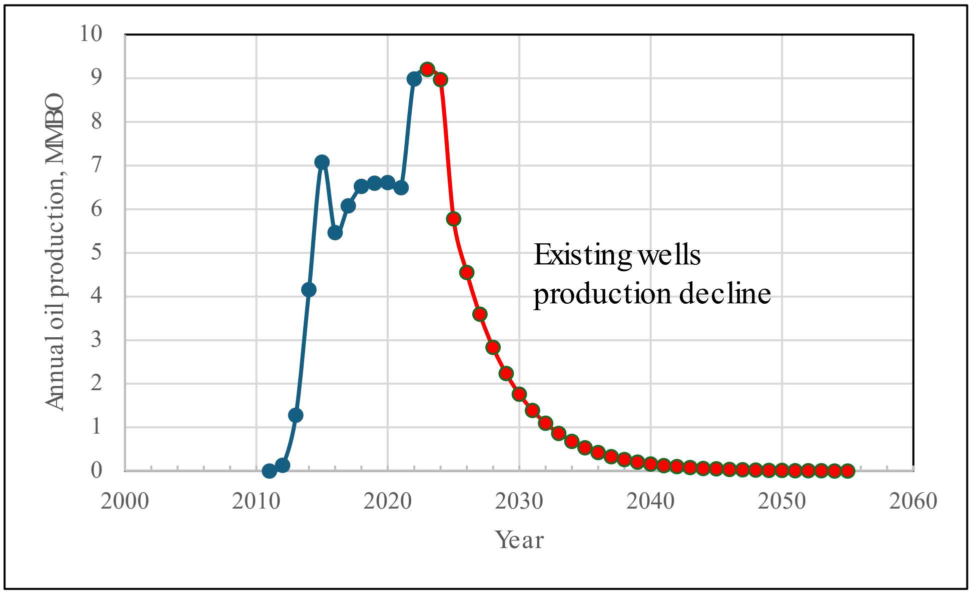

Figure A-18. Historical production and future forecast for existing horizontal wells in the Mancos/Gallup oil subplay. {Source: NMOCD}

For the additional new wells, the type curve for the 2022 cohort was applied and is shown in Figure A-19. This curve was selected because it is representative of the expected design for future well development, i.e. 2-mile, diagonal laterals, and has sufficient production data to create a reasonable match and curve. Subsequently, this production curve will be applied for any new wells predicted.

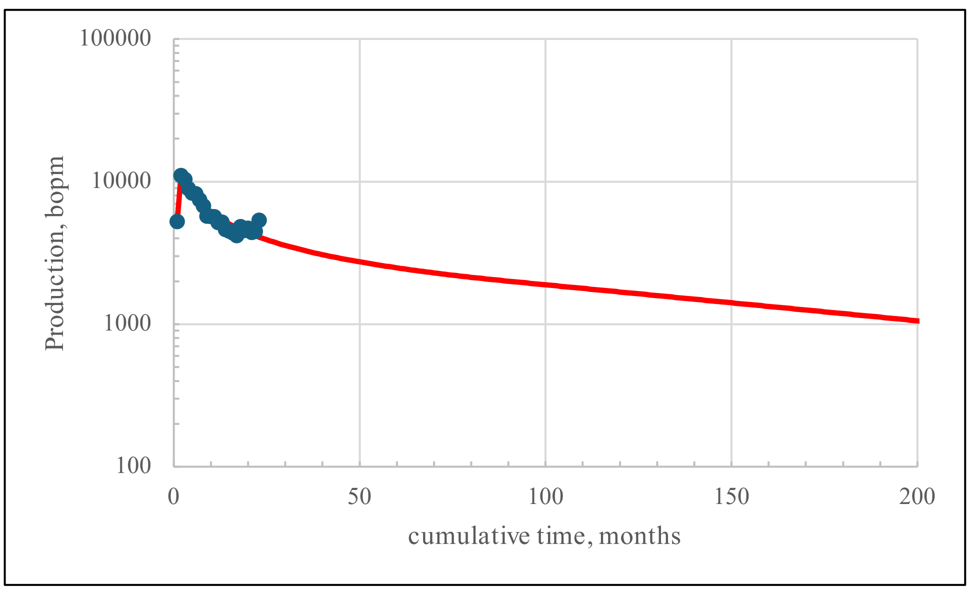

Figure A-19. Production type curve for the 2022 horizontal well cohort. {Source: Enverus, NMOCD}

The production from the three cases for new well development has been added to the existing well declining production and the results are shown in Figure A-20.

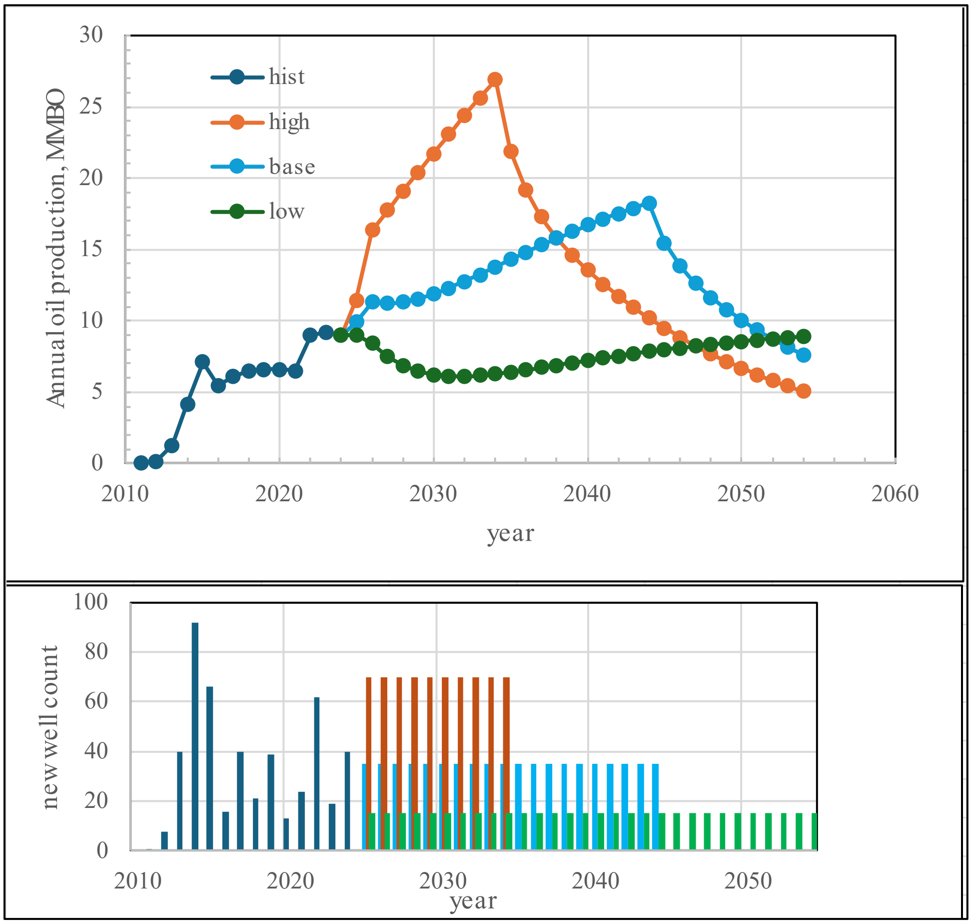

Figure A-20. Forecasted production for development of the Mancos Shale basin-centered gas subplay. Included are the three cases for additional new wells with the declining production of existing wells.

The base case continues the current upward trend but then ends as a point is reached where no new wells are added. For the low case, production initially decreases as the decline of existing wells is greater than the additional production from new wells. As new wells are slowly and continually added this trend reverses and a gentle inclination is observed. For the high case, a dramatic increase in production is shown due to the high (70 wells/yr) number of new wells per year. Afterwards, a rapid decline is observed as no new wells are being added and decline of all wells dominates.

Total Mancos/Gallup Gas Production

The total Mancos/Gallup gas production is composed of three parts: gas production from the Mancos Shale basin-centered horizontal gas subplay, associated gas production from the Mancos/Gallup southern rim horizontal well oil subplay, and gas from the remaining Mancos/Gallup vertical and directional wells. The latter cohort consists of all Mancos or Gallup defined producing wells NOT included in the previous two subplays. The forecasted production for the V+D cohort was based on the historical decline as shown in Figure A-21. Similar to other vertical gas plays, the addition of Mancos completions in existing wells has had no impact on the overall production performance for the cohort. As a result, a straightforward decline was applied.

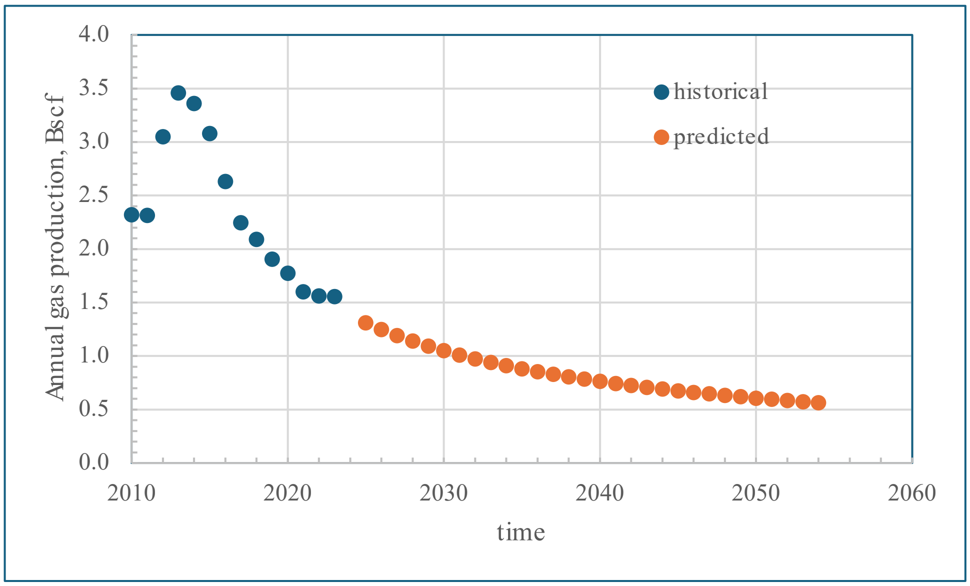

Figure A-21. Historical gas production and forecast for Mancos/Gallup vertical and directional wells. {Source: GOTECH/NMOCD}

A combined graph of all three components displaying only **existing** production is shown in Figure A-22. The Mancos Shale basin-centered gas subplay was previously discussed earlier in this Appendix. The associated gas from the oil subplay was created by assuming a constant GOR of 3 mscf/BO, which is the current value observed (See figure A-12). The Mancos gas vertical and directional existing gas production was taken from Figure A-21.

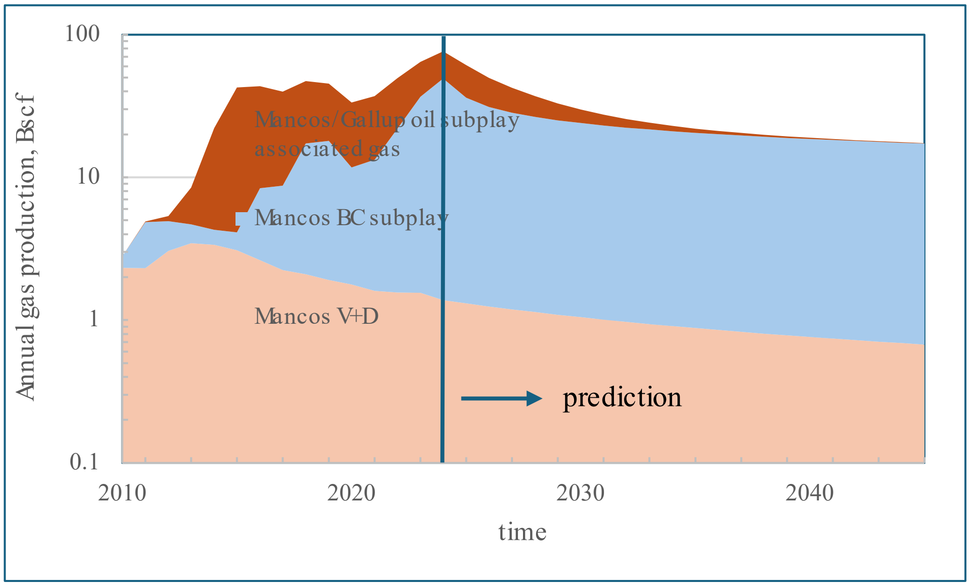

Figure A-22. Annual gas forecasted production for existing wells only for the Mancos Shale basin-centered horizontal gas subplay, associated gas production from the Mancos/Gallup southern rim horizontal well oil subplay, and gas from the remaining Mancos/Gallup vertical and directional wells.

The figure illustrates the positive impact the two subplays have on the overall gas production for the Mancos/ Gallup play; first with the associated gas from the oil subplay circa 2015 and then second, by the more recent development of the basin-centered gas subplay. As the existing wells in the oil subplay deplete the associated gas also declines. This is shown in the figure by the reduction in associated gas over time.

Three scenarios were shown for additional new well development for both subplays: a high development case, a most likely or base case, and a low development case, respectively. These predictions were added to the existing well future production and the results are shown in Figure A-23. The high development case shown in the figure represents both high cases for the individual subplays; i.e, this would be the maximum if both subplays incurred maximum development and favorable conditions. Conversely, the low case represents the low cases for both subplays occurring simultaneously and thus would be the minimum development.

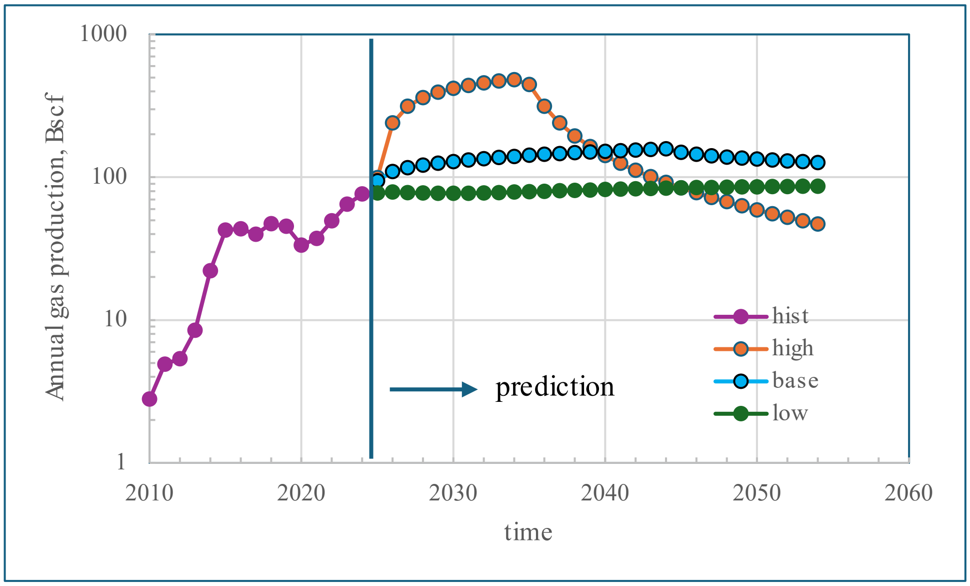

Figure A-23. Annual gas forecasted production for existing wells and including the addition of new well development for three scenarios (high, base, low) for the Mancos Shale basin-centered horizontal gas subplay and the associated gas production from the Mancos/Gallup southern rim horizontal well oil subplay.

As expected, the basin-centered horizontal well gas subplay dominates the predicted production performance, due to both the production from existing wells (Fig. A-22) and the magnitude of the new well additions (Fig. A-11).

Appendix B – Summary of major gas plays

Fruitland Coalbed Methane (CBM) Play

Summary

Very limited future development is predicted for this play. Over the last 10 years (through 2024) less than 6 wells have been completed per year, with no impact on the decline of gas production from the CBM play overall. The lack of activity in the Fruitland CBM play can be attributed to the recent limited performance and lack of available (undrained) acreage. Horizontal wells have better EURs, averaging ~3 Bcf, than vertical and directional wells, averaging 0.55 Bcf. However, if the EUR is normalized to the GPI, the vertical+ directional value is superior at 7.5 Mcf/ft versus 1.0 Mcf/ft for horizontal wells. Horizontal lengths are typically only one mile, with no trends observed with increasing length as a function of time, mostly due to the limited data in more recent years. Conversely, water production is significantly greater for vertical+directional wells. The impact of water production on use and disposal will be discussed in a later section.

Production/Development History

Although the extraction of gas from the Fruitland Coal began in 1977, it wasn't until the 1990s that commercial quantities of gas were developed. The success was in part due to better understanding of the reservoir flow mechanisms, expanded water handling capabilities, and improved completion strategies. Figure B-1 illustrates the rapid rise in development and corresponding production in the 1990s. The peak occurred in the late 1990s at a rate of ~50 Bscf/month. A second minor increase in gas production occurred in the early 2000s due to infill drilling. Note the water production substantially increased during this period. Since then, gas and water production have been on a steady decline, with minor well development. Cumulative production for the entire play has been over 13 Tcf of gas and 500 MMBW through 2024.

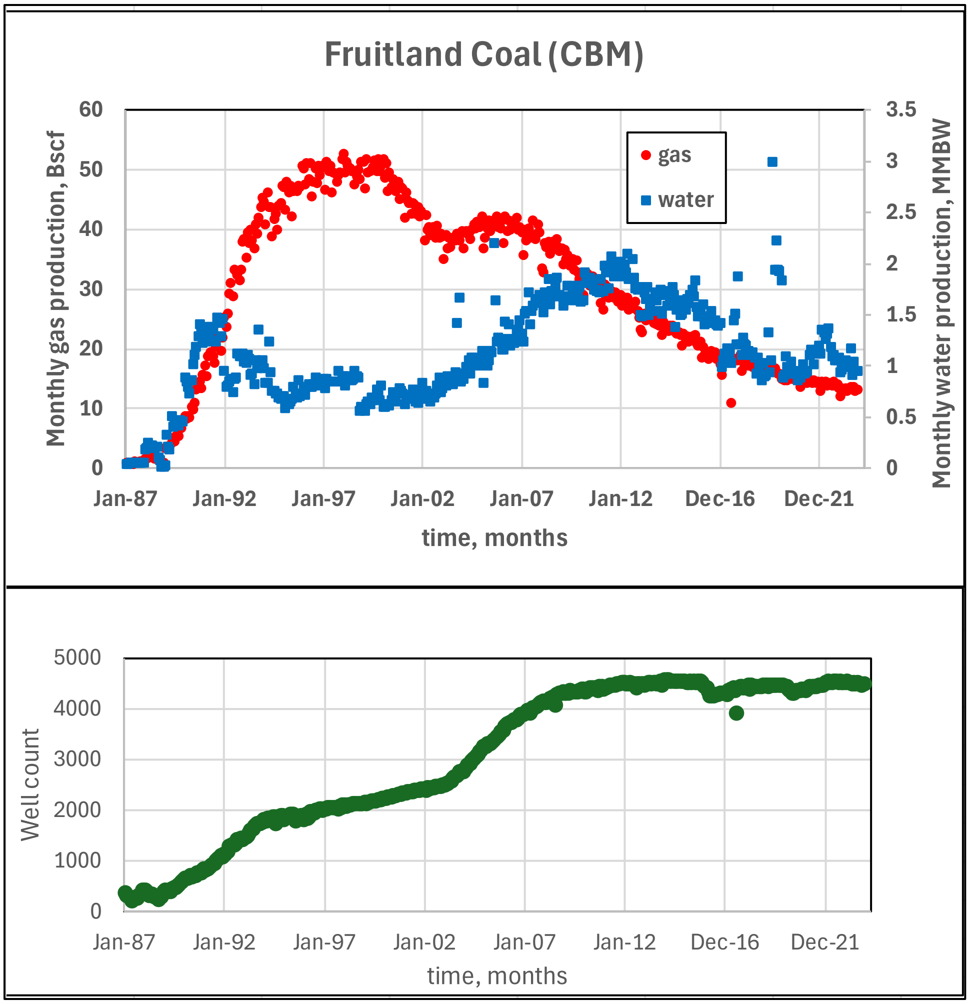

Figure B-1. Historical gas and water production and well count since 1987 for the Fruitland Coal. (Source: GOTECH/NMOCD).

A more detailed investigation into the development since 2010 revealed minor activity over this period. A total of 226 wells were completed (57 horizontal and 169 vertical or directional) with the majority occurring in 2010 and 2011 (Figure B-2). The average Gross Perforated Interval (GPI) for the horizontal wells is less than a mile; thus, the total horizontal length is approximately one mile on average. Also, some horizontal wells are multilaterals, with each lateral averaging one mile or less as well. In all cases, no trends were observable with increasing length as a function of time, mostly due to the limited data in more recent years. Also, in the last two years (2023, 2024) adding Fruitland Coal and commingling with other plays seems to be a priority. In two years, 45 additions have occurred with an increasing trend. Since this zone is shallow, it is likely a future uphole target.

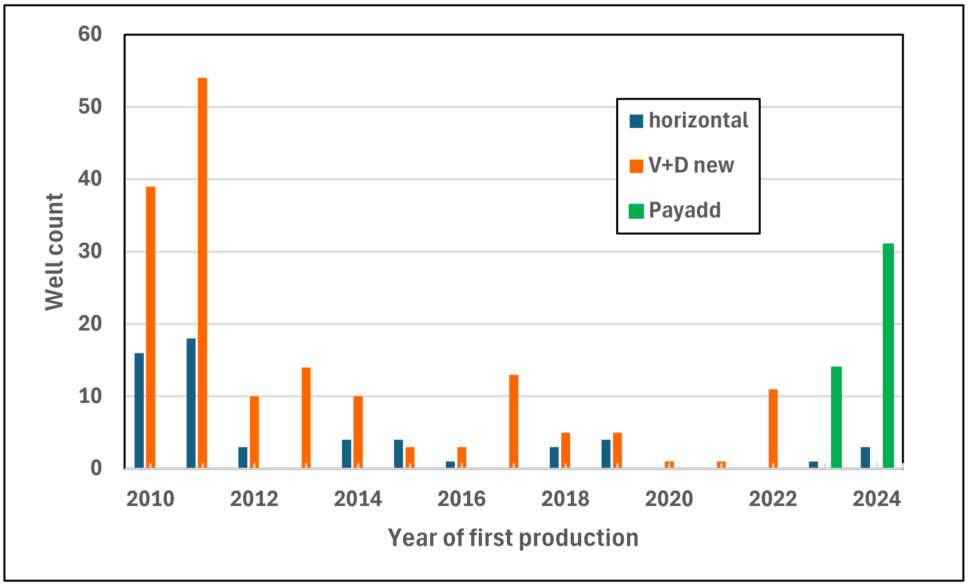

Figure B-2. Well count by date of first production and well type. (Source: Enverus™)

The location of the horizontal well development has been clustered near the Colorado stateline (Figure B-3). Most of these wells have high EURs, averaging ~3 Bcf. The vertical and directional wells are scattered along the west and southwest perimeter of the basin and have low EURs, averaging 0.55 Bcf. However, if the EUR is normalized to the GPI, the vertical+ directional value is superior at 7.5 Mcf/ft versus 1.0 Mcf/ft for horizontal wells.

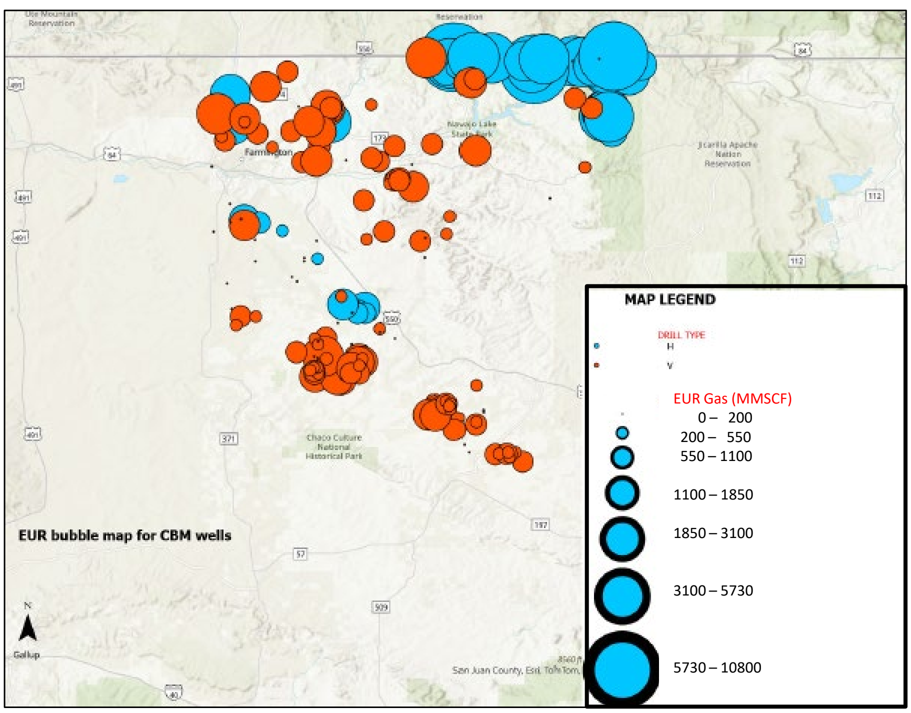

Figure B-3. EUR bubble map (Mcf) for CBM wells completed since 2010. Increasing size of bubble represents increasing EUR. The maximum EUR is 11 Bscf. (Source: Enverus™)

Lack of activity in the Fruitland CBM play can be attributed to the recent poor performance and lack of available (undrained) acreage. Evaluation of the production performance for only the defined cohort of wells (since 2010) is shown in Figures B-4 and B-5, respectively. Monthly gas production per well is shown in Figure B-4 as a stacked area graph, i.e. production from each well type is stacked resulting in the sum of the cohort. Even though there are fewer horizontal wells, gas production outperforms the vertical+directional cohort.

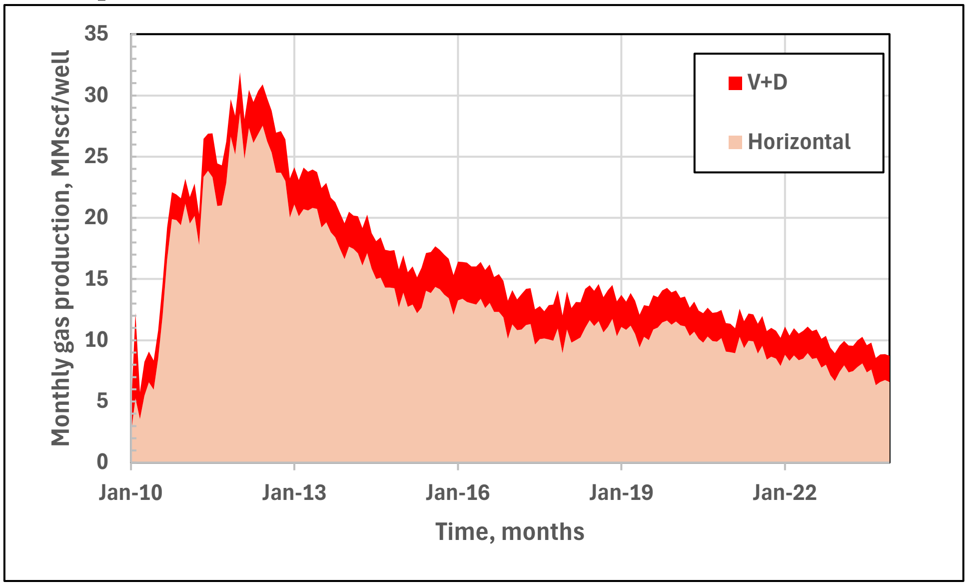

Figure B-4. Stacked area chart of monthly gas production of wells completed since 2010 and separated by well type (Source: Enverus™)

Conversely, the monthly water production shown in Figure B-5 is dominated by the vertical+directional cohort. On a per well basis, a vertical+directional well produces four times more water per month than a horizontal well.

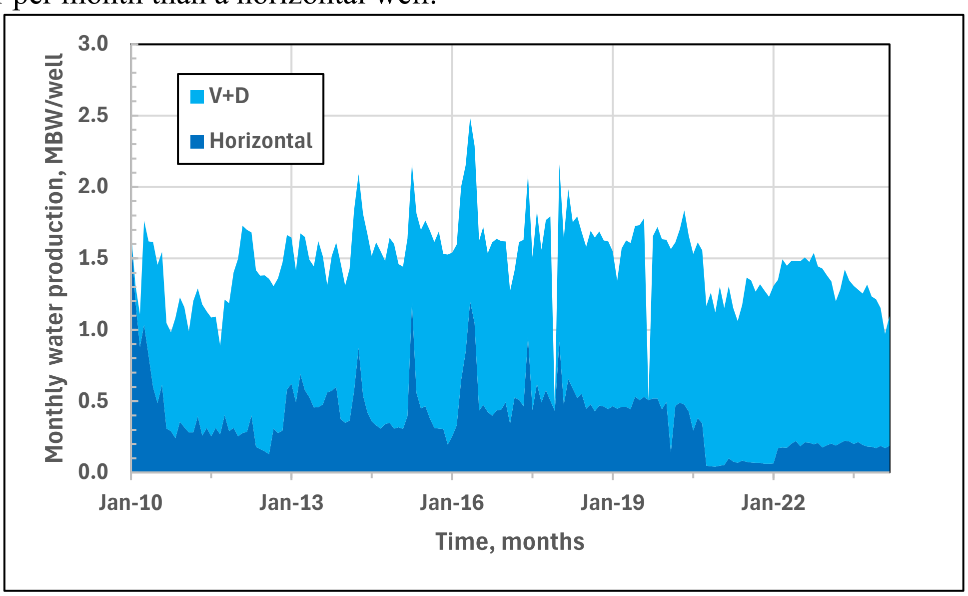

Figure B-5. Stacked area chart of monthly water production of wells completed since 2010 and separated by well type (Source: Enverus™)

Previously, the better gas producing wells were in the "fairway", where high water production was associated with abundant cleating and thus production. To identify if this trend continues to exist, the vertical+directional well cohort was further separated by their cumulative water-gas ratio (WGR). A limit of WGR = 0.1 was used to separate those wells with high water ratios (WGR > 0.1) with those wells with low ratios below the threshold. Figure B-6 shows the relationship between cumulative water and gas production separated by the WGR threshold.

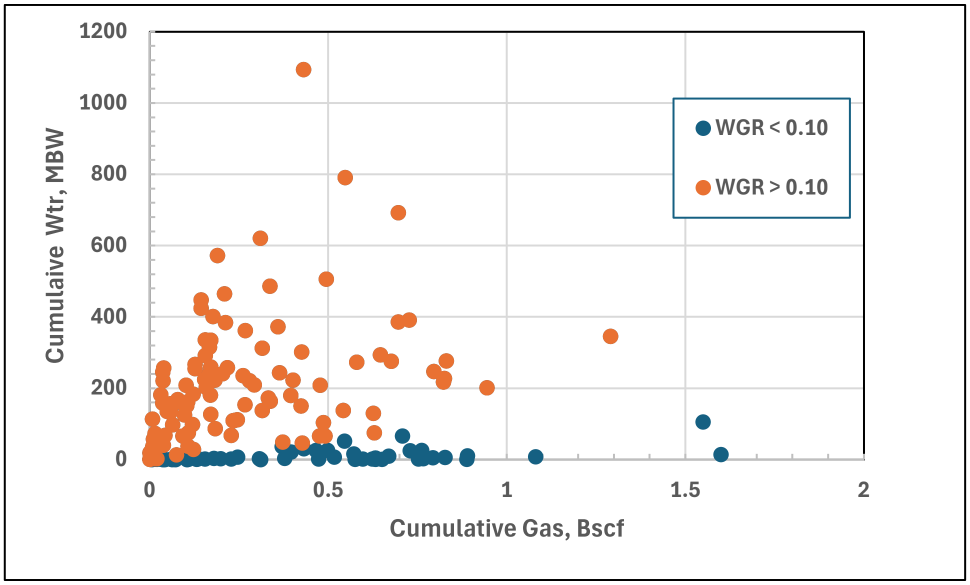

Figure B-6. Cumulative production for CBM vertical +directional wells with first production since 2010. {Source: GOTECH/NMOCD}

The average EUR/well was 643 mmscf/well for the 62 wells with WGR < 0.1, vs 474 mmscf/well for the 107 wells with WGR > 0.1. No further investigation into the reason for this difference was undertaken.

A similar threshold was applied to the 54 horizontal CBM completed since 2010. Only 9 of these wells exhibited a WGR > 0.1, and all are in the same proximity in the southern part of the basin (T25N, R10W). EUR for these wells averaged 0.9 Bscf, better than the vertical+directional wells but less than the 2.9 Bscf EUR for the horizontal CBM wells with WGR < 0.1.

Predicted Development

Very limited future development is predicted for this play based on the minimal activity over the past ten years resulting in no impact on the decline of gas production from the CBM play overall. Based on these constraints, forecasted production follows the existing decline trend of the Basin Fruitland Coal play (Figure B-7).

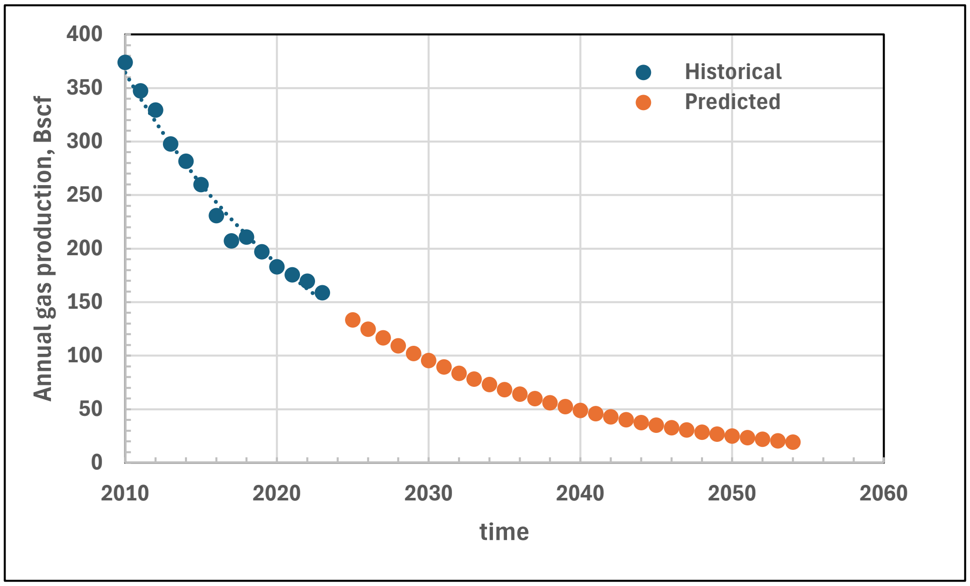

Figure B-7. historical and predicted annual gas production for the Basin Fruitland Coal Play. {Source: GOTECH/NMOCD}

As shown in Figure B-1, water production has also been declining since its peak in 2012. Continuing the decline for the 30-yr forecast period provides an estimate of future water production (Figure B-8). The implication is that additional water disposal will not be necessary but instead be focused on replacement and maintenance.

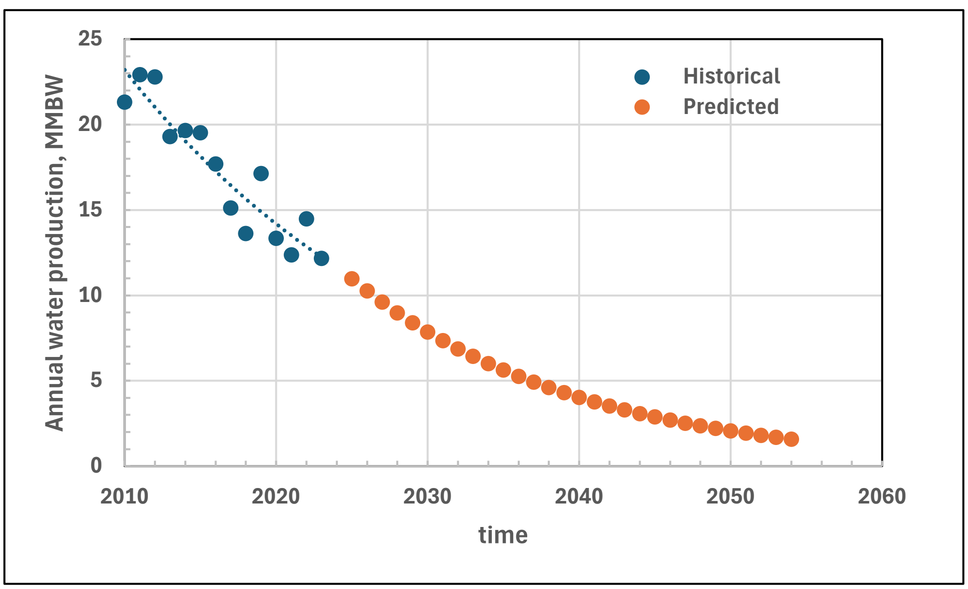

Figure B-8. historical and predicted annual water production for the Basin Fruitland Coal Play. {Source: GOTECH/NMOCD}

Pictured Cliffs Gas Play

Summary

Future development is predicted to be limited for this shallow gas play, which will result in no impact on the overall decline in gas production. Over the last 10 years (through 2023) only ten wells have been new completions in the Pictured Cliffs and all were in 2010 and 2011, respectively. As a shallow pay zone, most of the activity has been Pictured Cliffs payadds (114) to existing wells. Again, this effort is too minor and has not arrested the decline the total Pictured Cliffs production from the San Juan Basin. The lack of activity can be attributed to significant depletion that has occurred in this reservoir.

Historical

The Pictured Cliff reservoirs established production in the 1950s and thus is one of the prolific, vintage reservoirs of the San Juan Basin. Cumulative production as of 1/1/2024 is 4.6 Tscf, or approximately 84% of the gas-in-place (GIP=5.5 Tscf, AGA,1992 study).

Pictured Cliffs reservoirs are primarily described as channel sands, creating a well-defined reservoir boundary exhibiting rapid lateral changes in well production. Consequently, stepout drilling is believed limited, with infill locations the only option. In a previous study (RFD, 2001), drainage area calculations did not support the widespread potential for 80-acre infill development. Average recovery was estimated to be 0.53 Bscf/well, based on production analysis from offset production.

Recent lack of development has confirmed the previous conclusion of limited to no potential. Only 10 V+D wells were completed in the Pictured Cliffs, all in 2010 and 2011. Since then, no new PC wells have been completed. Figure B-9 shows that three new well completions are Pictured Cliff only, seven new wells that are multizone completions, and 114 existing wells that added the Pictured Cliffs as a payadd in the given year. Since this reservoir is shallow, it is anticipated this play as an uphole potential for deeper wells; however, this requires the optimum PC location to be the same as the deeper pay zones.

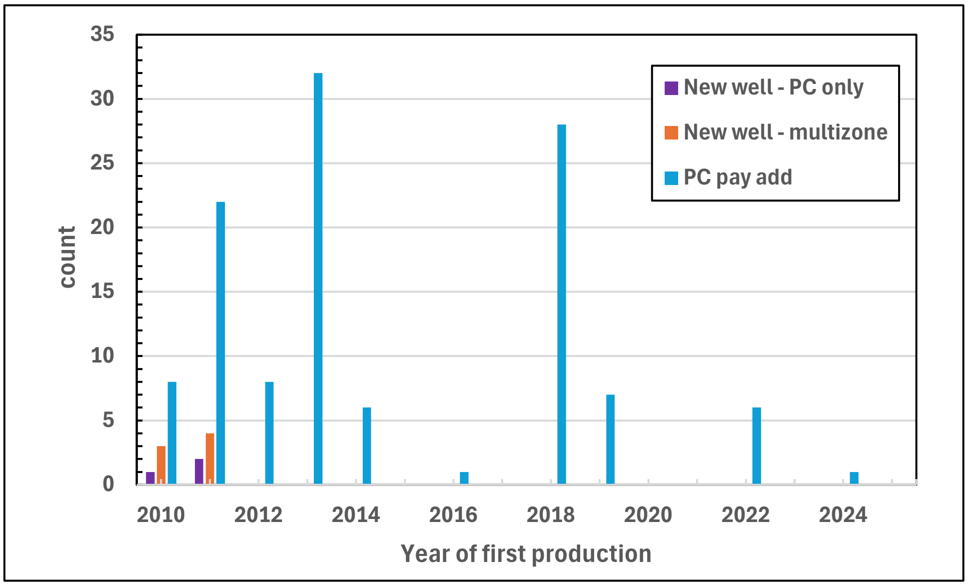

Figure B-9. Pictured Cliffs development activity: Pictured Cliffs only new wells, Multizone new wells, and payadds. {Source: NMOCD, Enverus}

Average EUR/ well for the new Pictured Cliffs wells (10) is 0.42 Bscf and for 114 payadds is 0.365 Bscf, respectively. Both are consistent with the previous estimate ~0.5 Bscf.

Three horizontal wells were attempted in 2010-11 in the Picture Cliffs (Figure B-10), two were productive and one was P&A. All three wells are in T30N, R4W (See Fig. B-10). EUR for the two producing wells is 2.2 and 5.3 Bscf, respectively. Both are relatively short laterals (GPI), thus the recovery per foot is high. Since then, no additional horizontal completions have been attempted in the Pictured Cliffs, despite the excellent recovery of two of the three wells.

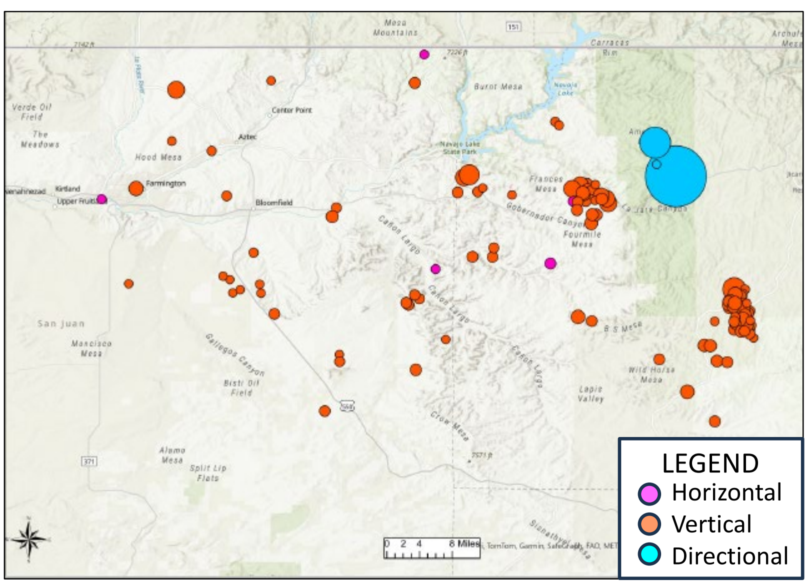

Figure B-10. Location of Pictured Cliffs completions (new and payadds) since 2010 by drill type. {Source: Enverus}

The results of the completion activity (new wells and payadds) have had a minimal impact on the total Pictured Cliffs production from the San Juan Basin. Shown in Figure B-11 is the monthly gas production since January 2010 for all active Pictured Cliffs completions (ALL), for new Pictured Cliffs completions (Spud since 1/1/2010), and all Pictured Cliffs completions with first production since 1/1/2010 (FPD 1/1/2010). The difference between the last two is the addition of payadds in the FPD group.

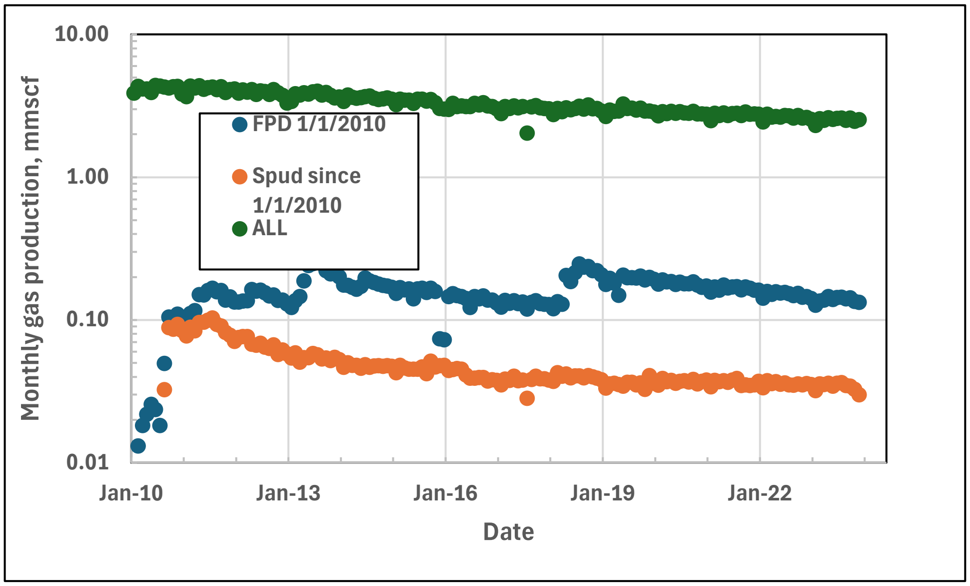

Figure B-11. Pictured Cliffs monthly gas production: (ALL)-all active producing Pictured Cliffs wells, (Spud since 1/1/2010)- Pictured Cliffs single and multizone new wells, and (FPD 1/1/2010)- Pictured Cliffs new wells + payadds. {Source: NMOCD, Enverus}

The new well production (single and multizone) exhibits a constant declining trend because all the wells first came on production in the early years. Figure B-12 is the well count corresponding to the categories in Figure B-11 and clearly shows the limited early activity and no new wells subsequently added since then. For both cases, Spud and FPD, there is no impact on the total Pictured Cliffs production. Observe in Figure B-11, the total Pictured Cliffs production is an order of magnitude greater than the new wells and payadds and thus exhibits no deflection due to the listed activity. Same occurs for well count (Figure B-12), where all Pictured Cliffs producers are several orders of magnitude greater than the others. The average well produces approximately 9 mmscf per year or 25 mcfd. These low producing numbers are an indicator of the high level of depletion that has occurred and the marginal economics that exist.

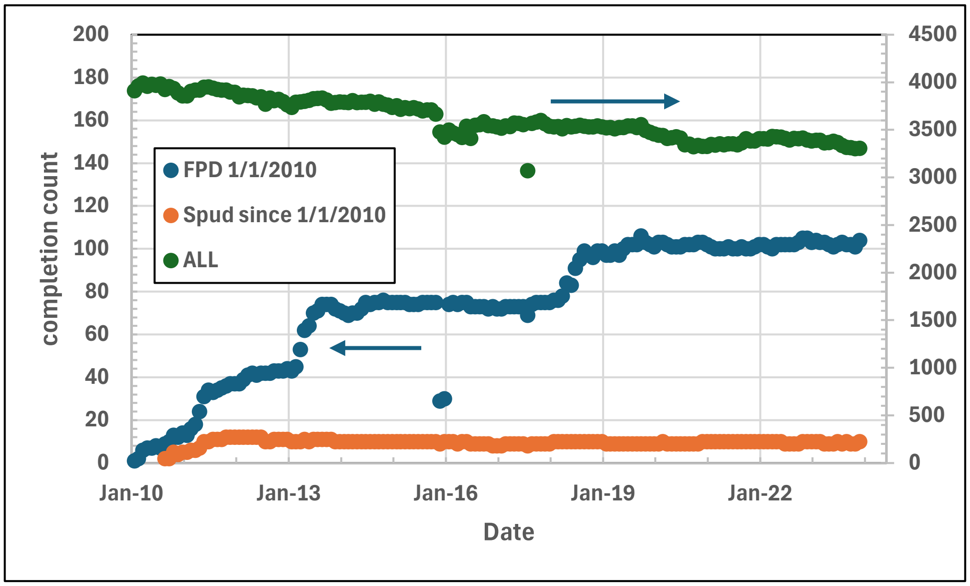

Figure B-12. Pictured Cliffs monthly completion count: (ALL)-all active producing Pictured Cliffs wells, (Spud since 1/1/2010)- Pictured Cliffs single and multizone new wells, and (FPD 1/1/2010)- Pictured Cliffs new wells + payadds. {Source: NMOCD, Enverus}

Future Prediction

Recent activity, whether as payadds or new wells, has been minimal and has had no discernable impact on the total production from the Pictured Cliffs. As a result, future production is confined to the continuing depletion of existing Pictured Cliffs wells. Figure B-13 depicts this decline with a starting date of 2025 and ending date 30 years later.

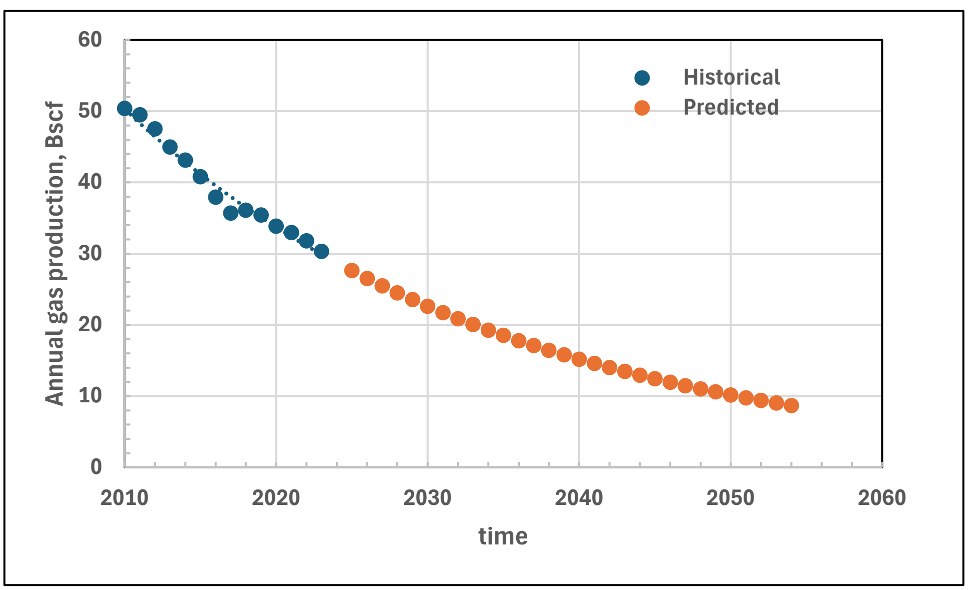

Figure B-13. Historical production decline (2010-2023) and future prediction of performance for the Picture Cliffs. {Source: GOTECH}

The average daily production for a Picture Cliffs well in 2023 was 25 mscfd. This rate is marginal and suggests a decrease in future active well count due to reaching the economic limit. Historically from 2010 through 2023 the Picture Cliffs well count has averaged a 50 well decrease each year. Assuming this rate continues, the active well count in 30 years will have declined to 1,850, i.e., 1500 wells that have been abandoned in the Pictured Cliffs. With the Pictured Cliffs the best shallow uphole target and with remaining shallower targets limited in extent and productivity, it is assumed these wells will be P&A. The impact of this decrease should be considered in future activity projections.

Mesaverde Gas Play

Summary

Future development or this play will be limited to payadds within the Mesaverde and commingling with previous producing zones. Other than one well completed in 2024, the last new well in Mesaverde was in 2015. Since then, Mesaverde payadds have been dominant, with no indication this trend will change. No horizontal well test was identified in the Mesaverde. This is not surprising since the Mesaverde contains numerous pay zones distributed thoughout the thick formation. As a result, the total Mesaverde production will continue its downward trend over the project life.

Historical

Discovered in 1927, the Blanco Mesaverde Pool, has been one of the most prolific gas producing reservoirs in the San Juan Basin area. Cumulative production as of 1/1/2024 has been 52 MMBO, 13.8 Tscf, and 83 MMBW. The latest monthly production for December 2023 was 30 MBO, 13 Bscf, and 136 MMBW; respectively. Past development has been mostly infill drilling to smaller spacings. The low permeability, multilayers and discontinuous geology of the Mesaverde lead to the success of repeated reductions in well density (One well per 320-acres in 1949, two wells per 320 acres (160-acre spacing) in 1974, four wells per 320 acres (80-acre spacing) in 1998, and 40-acres in 2018). A previous statistical study (RFD, 2001) determined a Mesaverde well on 160-acre development will average 1.1 Bscf per well, approximately one-third the recovery of the initial 320-acre development. Expectations for 80-acre development was 1 Bscf/well, approximately the same as a 160-acre well.

Recent activity has dramatically declined since 2010 (Figure B-14). Shown are the new well completions that are Mesaverde only, new wells that are multizone completions with the Mesaverde, and existing wells that occurred as Mesaverde payadds in the given year. Only 16 wells have been single Mesaverde new wells with the highest concentration in the early years with the last well completed in 2015. The majority of new wells, 262, (~90%) are multizone completions, with almost all dual completed with the deeper Dakota. Again, most dual completed wells are in the early years with the last recorded one in 2015. Since 2016, the focus has been on Mesaverde payadds, most to existing Dakota wells. Approximately 330 payadds since 2016 are shown in Figure 1, with the highest year in 2018.

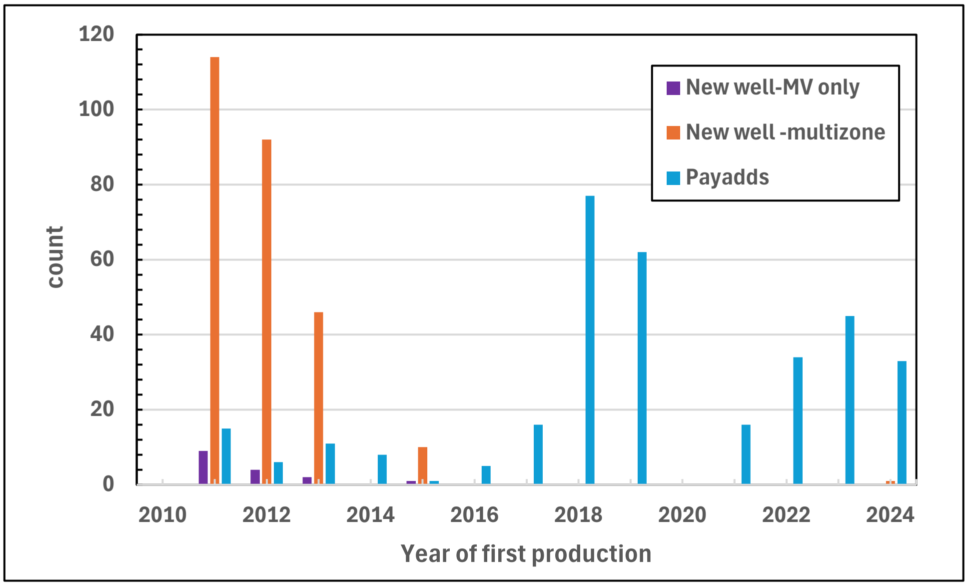

Figure B-14. Mesaverde development activity: Mesaverde only new wells, Multizone new wells, and payadds. {Source: NMOCD, Enverus}

The results of this activity have had a minimal impact on the total Mesaverde production from the San Juan Basin. Shown in Figure B-15 is the monthly gas production since January 2010 for all active Mesaverde completions (ALL), for new Mesaverde completions (Spudded since 1/1/2010), and all Mesaverde completions with first production since 1/1/2010 (FPD 1/1/2010). The difference between the last two is the addition of payadds in the FPD group. These payadds are responsible for the increase in production seen in Figure B-15 starting in 2017.

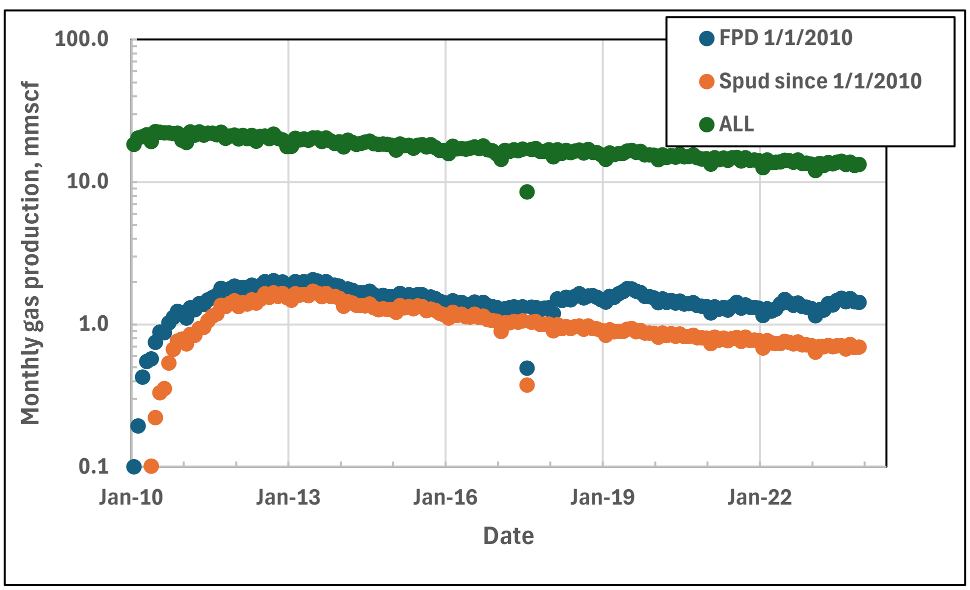

Figure B-15. Mesaverde monthly gas production: (ALL)-all active producing Mesaverde wells, (Spud since 1/1/2010)- Mesaverde single and multizone new wells, and (FPD 1/1/2010)- Mesaverde new wells + payadds. {Source: NMOCD, Enverus}

The new well production (single and multizone) exhibits a constant declining trend as a result of the majority of wells first coming into production in the early years. Figure B-16, which is the well count corresponding to the categories in Figure B-15, clearly shows the early activity, pre-2013, and then flattens later when no new wells are added. For both cases, Spud and FPD, there is no impact on the total Mesaverde production. Observe in Figure B-15, the total Mesaverde production is an order of magnitude greater than the new wells and payadds, exhibiting no deflection due the listed activity. Same occurs for well count (Figure B-16), where all Mesaverde producers are an order of magnitude greater than the others.

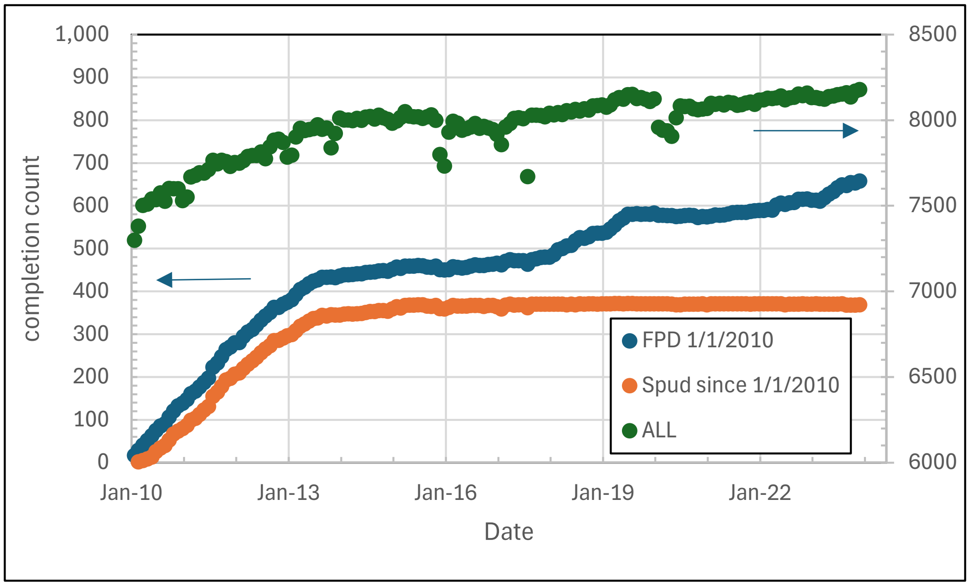

Figure B-16. Mesaverde monthly completion count: (ALL)-all active producing Mesaverde wells, (Spud since 1/1/2010)- Mesaverde single and multizone new wells, and (FPD 1/1/2010)- Mesaverde new wells + payadds. {Source: NMOCD, Enverus}

Using production decline curve analysis, the EURs were determined separately for both the new wells and payadds. The new well completions have a better average EUR of 685 mmscf compared to the payadds which are expected to recover 434 mmscf. Both are below the previous estimates of recovery of 1 Bscf for the older wells at larger spacings. Initial IPs or early production are comparable to previous wells, but EURs are less due to the overall depletion that has occurred over time.

Horizontal well development

The Mesaverde is not conducive to horizontal well development due to the numerous thin, gas productive layers spanning over a large vertical thickness. In addition, previous vertical well development has created limited opportunities to locate the horizontal lateral without interference or being depleted. Records show one horizontal Mesaverde well completed in 2010 with an EUR of only 281 mmscf. Due to the reasons stated above and the limited productivity from the horizontal test, no additional horizontal well development has occurred since.

Predicted development

As demonstrated by the historical trend, any additional Mesaverde development will likely be payadds to existing wells. Even with this development, no change in the overall decline of the Mesaverde production is anticipated. Based on these constraints, forecasted production follows the existing decline trend of the Mesaverde (Figure B-17)

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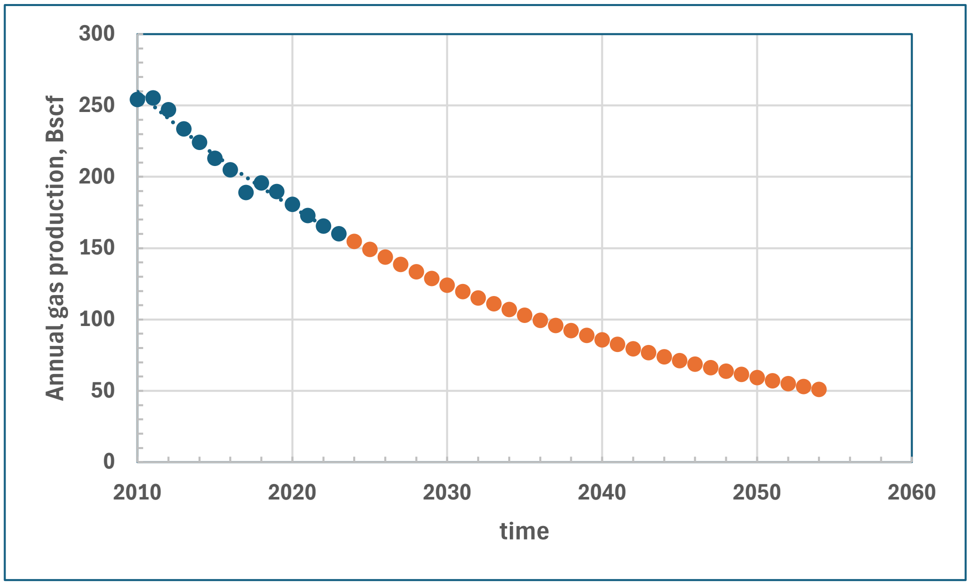

Figure B-17. historical and predicted annual gas production for the Blanco Mesaverde Pool. {Source: GOTECH/NMOCD}

In addition, the Blanco Mesaverde pool produces associated oil or condensate. The historical GOR has been consistent throughout the 14-year time period at 370 scf/bbl. This GOR is expected to continue through the prediction time period as well. The number of zone abandonments will increase as the Mesaverde reaches an economic or productive limit. However, the opportunities for uphole recompletions and/or commingling will limit the number of well abandonments.

Basin Dakota Gas Play

Summary

Very limited future development is predicted for this play. Over the last eight years (2016 through 2023) only one Dakota well was completed. In addition, the Dakota is not a primary target for adding pay due to it being the deepest of the major gas plays. Furthermore, no successful horizontal test of the Dakota was identified, leading to the conclusion that it is not a candidate to pursue. As a result, the total Basin Dakota production will continue its downward trend over the project life.

Historical

The Basin Dakota Pool was created in 1960 by consolidating numerous small Dakota reservoirs with an original spacing of 320 acres. Spacing has been reduced to two wells (160 acre spacing) on 320-acre Gas Proration Unit (GPU) in the late 1970s and again to four wells on 320-acre GPU (80 acre spacing) in 2002. Both subjected to certain distance constraints. The high reservoir pressure encountered in pilot infill wells, the reservoir heterogeneity and the improvement in fracture stimulation techniques suggested infill drilling as a viable means to capture missed reserves. However, in the RFD (2000) report, a statistical study showed the recovery of wells drilled prior to 1979 averaged 1.7 Bscf/well; while wells drilled after 1/1/1979 only averaged 0.50 Bscf/well; suggesting a level of depletion has occurred.

The Basin Dakota Pool has been a major gas producer for the San Juan Basin. As of January 2024, cumulative production has been 52 MMBO, 7.3 Tscf, and 77 MMBW. Monthly production for December 2023 was 18 MBO, 5.5 Bscf, and 88 MBW; respectively.

With limited resources and well locations remaining, recent activity has dramatically declined. Figure B-18 shows the new well completions that are Dakota only, new wells that are multizone completions with the Dakota, and existing wells that attempted to recomplete or add the Dakota in the given year. Since 2010, forty wells were drilled as Dakota new wells with the highest concentration prior to 2015. Most new wells, 385, (~90%) are multizone completions, with almost all dual completed with the shallower Mesaverde. Again, most dual completed wells are in the early years. Very few Dakota recompletions or payadds were attempted, which is not surprising since this is the deepest of the significant gas producing zones.

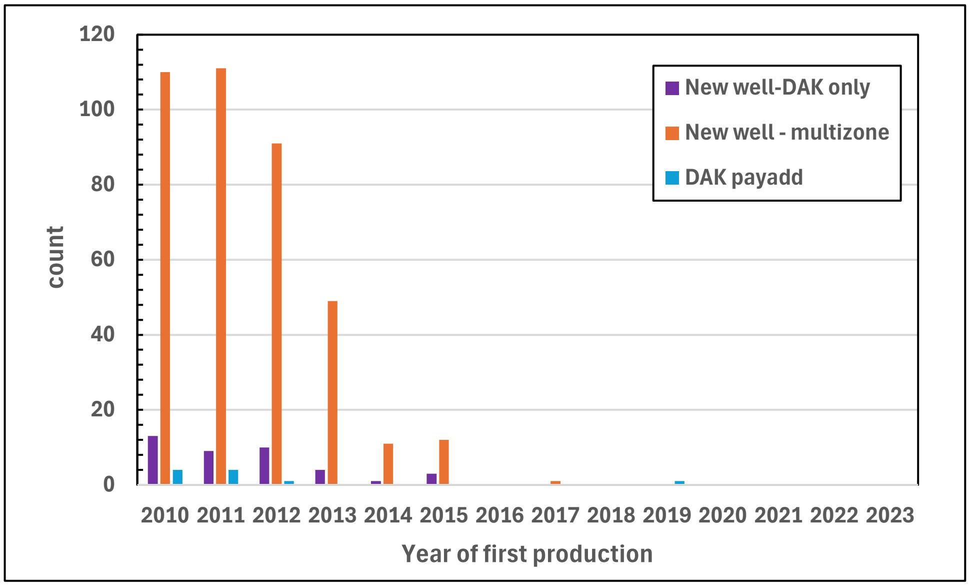

Figure B-18. Dakota development activity: Dakota only new wells, Multizone new wells, and payadds. {Source: NMOCD, Enverus}

The location of the activity described above is shown in Figure B-19 along with the Dakota EURs for each well. Observe the activity is scattered in the entire Basin Dakota pool, with no definitive trends. The lack of trends confirms the randomness of the remaining work, i.e., open infill locations and commingling opportunities. In this work, no attempt was made to separate development or recovery from the Dakota members, i.e., TwoWells, Paguate and Cubero, as that was outside of the scope of work.

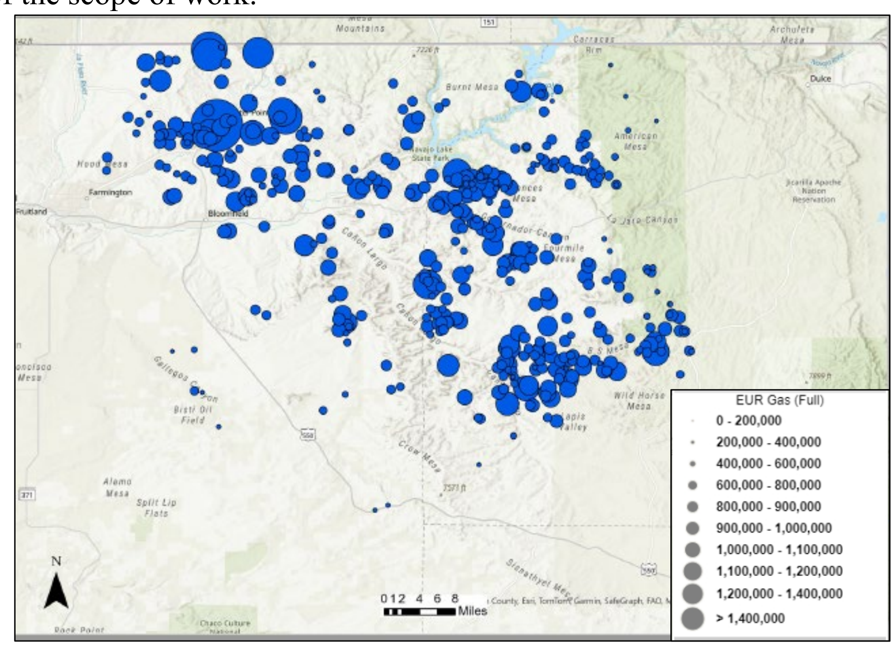

Figure B-19. Location and EUR data of the new well completions that are Dakota only, new wells that are multizone completions with the Dakota, and existing wells that attempted to recomplete or add the Dakota from 2010 through 2023. {Source:Enverus/NMOCD}

The results of this activity have had a minimal impact on the total Dakota production from the San Juan Basin. Shown in Figure B-20 is the monthly gas production since January 2010 for all active Dakota completions (ALL), for new Dakota completions (Spudded since 1/1/2010), and all Dakota completions with first production since 1/1/2010 (FPD 1/1/2010). The difference between the last two is the addition of recompletion/payadds in the FPD group, and as can be observed the impact is minimal.

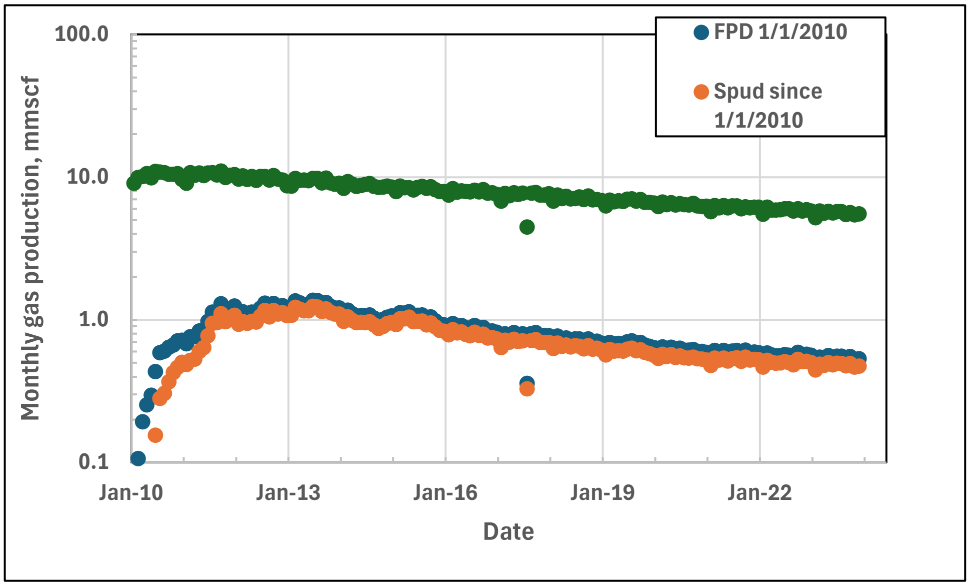

Figure B-20. Dakota monthly gas production: (ALL)-all active producing Dakota wells, (Spud since 1/1/2010)- Dakota single and multizone new wells, and (FPD 1/1/2010)- Dakota new wells + payadds. {Source: NMOCD, Enverus}

The new well production (single and multizone) exhibits a constant declining trend as a result of the majority of wells first coming into production in the early years. Figure B-21, which is the well count corresponding to the categories in Figure B-20, clearly shows the early activity prior to 2013 and then flattens later when no new wells are added. For both cases, Spud and FPD, there is no impact on the total Dakota production. Observe in Figure B-20, the total Dakota production is an order of magnitude greater than the new wells and payadds, exhibiting no deflection due the listed activity. Same occurs for well count (Figure B-21), where all Dakota producers are an order of magnitude greater than the others.

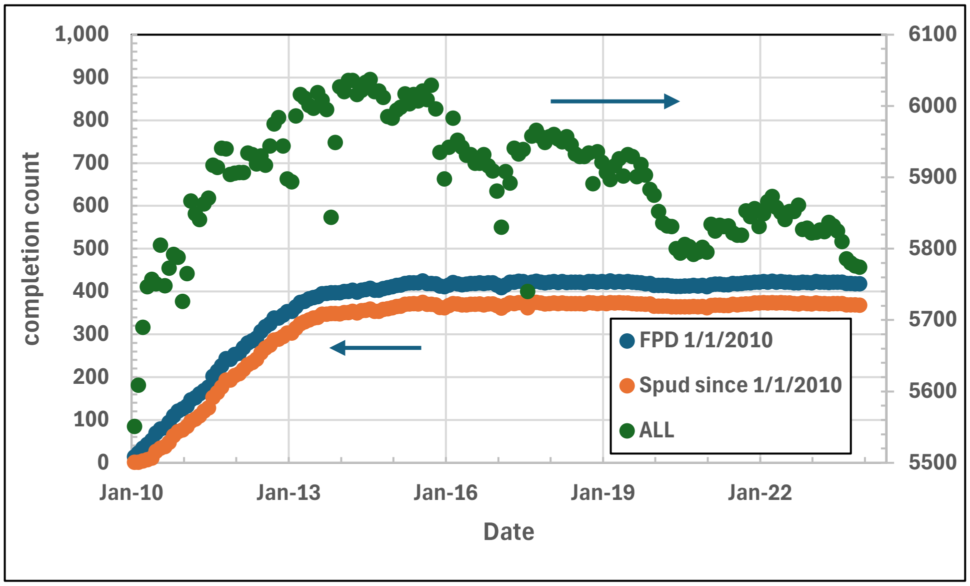

Figure B-21. Dakota monthly completion count: (ALL)-all active producing Dakota wells, (Spud since 1/1/2010)- Dakota single and multizone new wells, and (FPD 1/1/2010)-Dakota new wells + payadds. {Source: NMOCD, Enverus}

The average EUR for the 425 wells completed since 2010 is 0.47 Bscf per well. This recovery is consistent with the previous estimate of 0.5 Bscf/well in the 2000 RFD, and suggests depletion is widespread and consistent throughout the basin.

Horizontal well development

Scanning records resulted in no horizontal wells in the Basin Dakota pool. Gallup-Dakota pool development is discussed in the Gallup section of the report.

Predicted development

As demonstrated by the historical trend, additional significant Dakota development is not expected. The Dakota is not a good candidate for recompletion or payadd due to its depth and has limited resources available to add new wells. Any work that is accomplished will not impact on the overall decline as observed in the previous Dakota activity (Fig. B-20). Based on these constraints, forecasted production follows the existing decline trend of the Dakota (Figure B-22).

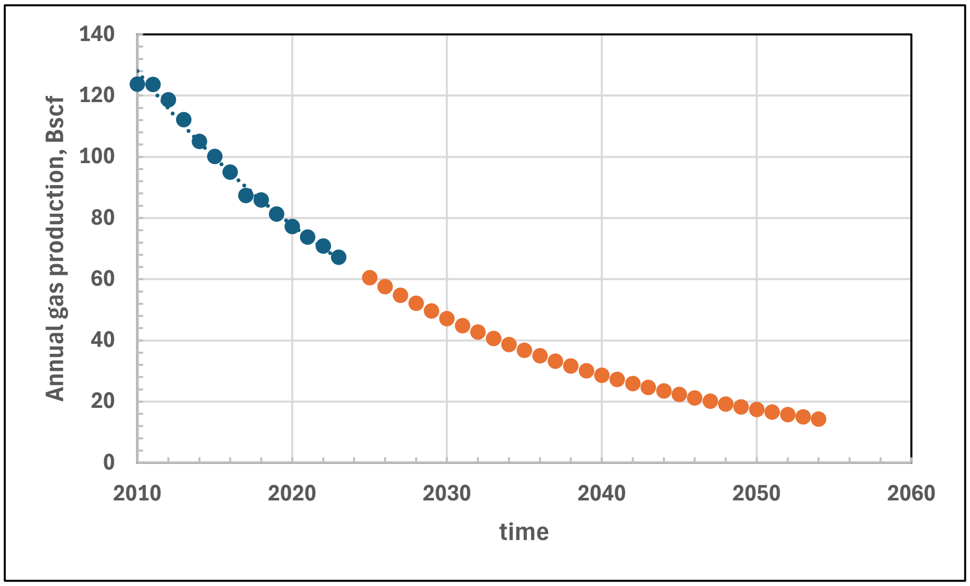

Figure B-22. historical and predicted annual gas production for the Basin Dakota Pool. {Source: GOTECH/NMOCD}

In addition, the Basin Dakota pool will continue to produce oil/condensate. The historical GOR has been consistent throughout the 14-year time period at 250 scf/bbl. This GOR is expected to continue through the prediction time period as well. The number of zone abandonments will increase as the Dakota reaches an economic or productive limit. However, the opportunities for uphole recompletions and/or commingling will limit the number of well abandonments.

Appendix C

Annual Summary of Forecast Data

Projections for Oil, Gas and water production and well count for Federal and Non-Federal ownership
CASE I – Base case

Year	New Federal					Existing Federal					New non-Federal				
	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)
2024							15765	6.47	367.5	12.9					
2025	30	30	1.00	25.0	14.5	0	15656	6.13	334.9	13.8	15	15	0.56	8.3	8.2
2026	30	60	3.23	44.7	14.6	0	15562	4.76	312.9	12.4	15	30	1.82	14.9	8.2
2027	30	90	4.18	55.3	14.1	0	15467	3.73	294.5	11.2	15	45	2.35	18.4	8.0
2028	30	120	4.99	63.0	13.7	0	15373	2.95	278.2	10.2	15	60	2.81	21.0	7.7
2029	30	150	5.69	69.0	13.4	0	15279	2.36	263.6	9.4	15	75	3.20	23.0	7.6
2030	30	180	6.32	73.9	13.2	0	15185	1.92	250.4	8.7	15	90	3.56	24.6	7.4
2031	30	210	6.90	78.0	13.0	0	15091	1.57	238.2	8.2	15	105	3.88	26.0	7.3
2032	30	240	7.44	81.6	12.9	0	14997	1.31	226.9	7.6	15	120	4.19	27.2	7.2
2033	30	270	7.94	84.8	12.8	0	14903	1.11	216.4	7.2	15	135	4.47	28.3	7.2
2034	30	300	8.41	87.6	12.7	0	14809	0.95	206.6	6.8	15	150	4.73	29.2	7.1
2035	30	330	8.84	90.1	12.7	0	14715	0.83	197.4	6.4	15	165	4.97	30.0	7.1
2036	30	360	9.25	92.4	12.6	0	14621	0.74	188.8	6.1	15	180	5.20	30.8	7.1
2037	30	390	9.63	94.4	12.6	0	14526	0.66	180.7	5.8	15	195	5.42	31.5	7.1
2038	30	420	9.98	96.3	12.6	0	14432	0.60	173.0	5.6	15	210	5.61	32.1	7.1
2039	30	450	10.31	98.1	12.6	0	14338	0.55	165.8	5.3	15	225	5.80	32.7	7.1
2040	30	480	10.62	99.7	12.6	0	14244	0.51	159.0	5.1	15	240	5.97	33.2	7.1
2041	30	510	10.90	101.1	12.6	0	14150	0.47	152.5	4.9	15	255	6.13	33.7	7.1
2042	30	540	11.17	102.5	12.5	0	14056	0.44	146.3	4.7	15	270	6.28	34.2	7.1
2043	30	570	11.42	103.7	12.5	0	13962	0.42	140.5	4.5	15	285	6.42	34.6	7.1
2044	30	600	11.65	104.9	12.5	0	13868	0.39	135.0	4.4	15	300	6.56	35.0	7.1
2045	8	608	9.88	99.0	11.1	0	13774	0.37	129.7	4.2	2	302	5.56	33.0	6.3
2046	8	616	8.84	95.6	10.3	0	13680	0.36	124.7	4.1	2	304	4.97	31.9	5.8
2047	8	624	8.08	93.2	9.6	0	13585	0.34	120.0	3.9	2	306	4.54	31.1	5.4
2048	8	632	7.45	91.2	9.0	0	13491	0.32	115.5	3.8	2	308	4.19	30.4	5.1
2049	8	640	6.91	89.6	8.5	0	13397	0.31	111.2	3.7	2	310	3.89	29.9	4.8
2050	8	648	6.43	88.1	8.1	0	13303	0.30	107.1	3.5	2	312	3.62	29.4	4.5
2051	8	656	5.99	86.8	7.7	0	13209	0.28	103.2	3.4	2	314	3.37	28.9	4.3
2052	8	664	5.59	85.5	7.3	0	13115	0.27	99.5	3.3	2	316	3.14	28.5	4.1
2053	8	672	5.21	84.4	6.9	0	13021	0.26	96.0	3.2	2	318	2.93	28.1	3.9
2054	8	680	4.86	83.3	6.6	0	12927	0.25	92.6	3.2	2	320	2.73	27.8	3.7
sum			229.1	2542.7	345.9			35.5	5361.0	184.8			128.9	847.6	194.6

Year	Existing non-Federal					Total Federal					Total non-Federal				
	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)
2024		5255	3.64	122.5	7.2										
2025	0	5219	3.45	111.6	7.8	30	15686	7.13	359.9	28.3	15	5234	4.01	120.0	15.9
2026	0	5187	2.68	104.3	7.0	30	15622	7.99	357.6	27.0	15	5217	4.50	119.2	15.2
2027	0	5156	2.10	98.2	6.3	30	15557	7.92	349.7	25.3	15	5201	4.45	116.6	14.3
2028	0	5124	1.66	92.7	5.8	30	15493	7.94	341.2	24.0	15	5184	4.47	113.7	13.5
2029	0	5093	1.33	87.9	5.3	30	15429	8.05	332.6	22.9	15	5168	4.53	110.9	12.9
2030	0	5062	1.08	83.5	4.9	30	15365	8.24	324.3	21.9	15	5152	4.63	108.1	12.3
2031	0	5030	0.89	79.4	4.6	30	15301	8.48	316.2	21.2	15	5135	4.77	105.4	11.9
2032	0	4999	0.74	75.6	4.3	30	15237	8.75	308.5	20.5	15	5119	4.92	102.8	11.5
2033	0	4968	0.62	72.1	4.0	30	15173	9.05	301.2	20.0	15	5103	5.09	100.4	11.2
2034	0	4936	0.54	68.9	3.8	30	15109	9.36	294.2	19.5	15	5086	5.27	98.1	11.0
2035	0	4905	0.47	65.8	3.6	30	15045	9.68	287.5	19.1	15	5070	5.44	95.8	10.7
2036	0	4874	0.41	62.9	3.4	30	14981	9.99	281.2	18.8	15	5054	5.62	93.7	10.5
2037	0	4842	0.37	60.2	3.3	30	14916	10.29	275.1	18.4	15	5037	5.79	91.7	10.4
2038	0	4811	0.34	57.7	3.1	30	14852	10.58	269.4	18.2	15	5021	5.95	89.8	10.2
2039	0	4779	0.31	55.3	3.0	30	14788	10.86	263.9	17.9	15	5004	6.11	88.0	10.1
2040	0	4748	0.29	53.0	2.9	30	14724	11.13	258.6	17.7	15	4988	6.26	86.2	9.9
2041	0	4717	0.27	50.8	2.8	30	14660	11.38	253.6	17.4	15	4972	6.40	84.5	9.8
2042	0	4685	0.25	48.8	2.6	30	14596	11.61	248.8	17.2	15	4955	6.53	82.9	9.7
2043	0	4654	0.23	46.8	2.5	30	14532	11.84	244.2	17.1	15	4939	6.66	81.4	9.6
2044	0	4623	0.22	45.0	2.4	30	14468	12.05	239.9	16.9	15	4923	6.78	80.0	9.5
2045	0	4591	0.21	43.2	2.4	8	14382	10.25	228.7	15.3	2	4893	5.77	76.2	8.6
2046	0	4560	0.20	41.6	2.3	8	14296	9.20	220.3	14.3	2	4864	5.17	73.4	8.1
2047	0	4528	0.19	40.0	2.2	8	14209	8.42	213.2	13.5	2	4834	4.73	71.1	7.6
2048	0	4497	0.18	38.5	2.1	8	14123	7.77	206.7	12.8	2	4805	4.37	68.9	7.2
2049	0	4466	0.17	37.1	2.1	8	14037	7.22	200.7	12.2	2	4776	4.06	66.9	6.9
2050	0	4434	0.17	35.7	2.0	8	13951	6.73	195.2	11.6	2	4746	3.78	65.1	6.5
2051	0	4403	0.16	34.4	1.9	8	13865	6.28	190.0	11.1	2	4717	3.53	63.3	6.2
2052	0	4372	0.15	33.2	1.9	8	13779	5.86	185.0	10.6	2	4688	3.30	61.7	6.0
2053	0	4340	0.15	32.0	1.8	8	13693	5.47	180.4	10.2	2	4658	3.08	60.1	5.7
2054	0	4309	0.14	30.9	1.8	8	13607	5.11	175.9	9.8	2	4629	2.88	58.6	5.5
			20.0	1787.0	103.9			264.6	7903.7	530.7			148.9	2634.6	298.5

Case II –High case scenario

Year	New Federal Spud Count	New Federal Active Well Count	New Federal Oil Production (MMbbl/yr)	New Federal Gas Production (Bscf/yr)	New Federal Water Production (MMbbl/yr)	Existing Federal Spud Count	Existing Federal Active Well Count	Existing Federal Oil Production (MMbbl/yr)	Existing Federal Gas Production (Bscf/yr)	Existing Federal Water Production (MMbbl/yr)	New non-Federal Spud Count	New non-Federal Active Well Count	New non-Federal Oil Production (MMbbl/yr)	New non-Federal Gas Production (Bscf/yr)	New non-Federal Water Production (MMbbl/yr)
2024							15765	6.47	367.5	12.9					
2025	60	60	1.99	28.5	15.2	0	15656	6.13	334.9	13.8	30	30	1.12	9.5	8.6
2026	82	142	6.46	142.1	16.9	0	15562	4.76	312.9	12.4	38	68	3.63	47.4	9.5
2027	82	224	8.37	203.4	17.1	0	15467	3.73	294.5	11.2	38	106	4.71	67.8	9.6
2028	82	307	9.97	242.8	17.3	0	15373	2.95	278.2	10.2	38	143	5.61	80.9	9.7
2029	82	389	11.38	270.9	17.5	0	15279	2.36	263.6	9.4	38	181	6.40	90.3	9.8
2030	82	471	12.65	292.1	17.7	0	15185	1.92	250.4	8.7	38	219	7.11	97.4	10.0
2031	82	554	13.81	309.0	17.9	0	15091	1.57	238.2	8.2	38	256	7.77	103.0	10.1
2032	82	636	14.88	322.8	18.2	0	14997	1.31	226.9	7.6	38	294	8.37	107.6	10.2
2033	82	718	15.88	334.5	18.4	0	14903	1.11	216.4	7.2	38	332	8.93	111.5	10.4
2034	82	801	16.82	344.5	18.7	0	14809	0.95	206.6	6.8	38	370	9.46	114.8	10.5
2035	23	823	13.70	317.7	16.2	0	14715	0.83	197.4	6.4	8	377	7.71	105.9	9.1
2036	0	823	12.04	218.7	14.6	0	14621	0.74	188.8	6.1	0	377	6.77	72.9	8.2
2037	0	823	10.89	164.3	13.5	0	14526	0.66	180.7	5.8	0	377	6.12	54.8	7.6
2038	0	823	9.99	130.9	12.6	0	14432	0.60	173.0	5.6	0	377	5.62	43.6	7.1
2039	0	823	9.24	108.4	11.8	0	14338	0.55	165.8	5.3	0	377	5.20	36.1	6.7
2040	0	823	8.59	92.1	11.1	0	14244	0.51	159.0	5.1	0	377	4.83	30.7	6.3
2041	0	823	8.00	79.8	10.5	0	14150	0.47	152.5	4.9	0	377	4.50	26.6	5.9
2042	0	823	7.46	70.1	9.9	0	14056	0.44	146.3	4.7	0	377	4.20	23.4	5.6
2043	0	823	6.96	62.2	9.4	0	13962	0.42	140.5	4.5	0	377	3.91	20.7	5.3
2044	0	823	6.49	55.7	8.9	0	13868	0.39	135.0	4.4	0	377	3.65	18.6	5.0
2045	0	823	6.05	50.2	8.4	0	13774	0.37	129.7	4.2	0	377	3.41	16.7	4.8
2046	0	823	5.65	45.5	8.0	0	13680	0.36	124.7	4.1	0	377	3.18	15.2	4.5
2047	0	823	5.27	41.5	7.6	0	13585	0.34	120.0	3.9	0	377	2.96	13.8	4.3
2048	0	823	4.91	37.9	7.2	0	13491	0.32	115.5	3.8	0	377	2.76	12.6	4.1
2049	0	823	4.58	34.8	6.9	0	13397	0.31	111.2	3.7	0	377	2.58	11.6	3.9
2050	0	823	4.27	32.0	6.5	0	13303	0.30	107.1	3.5	0	377	2.40	10.7	3.7
2051	0	823	3.98	29.5	6.2	0	13209	0.28	103.2	3.4	0	377	2.24	9.8	3.5
2052	0	823	3.71	27.3	5.9	0	13115	0.27	99.5	3.3	0	377	2.09	9.1	3.3
2053	0	823	3.46	25.3	5.7	0	13021	0.26	96.0	3.2	0	377	1.95	8.4	3.2
2054	0	823	3.23	23.5	5.4	0	12927	0.25	92.6	3.2	0	377	1.82	7.8	3.1
sum			250.7	4138.2	361.7			35.5	5361.0	184.8			141.0	1379.4	203.4

Year	Existing non-Federal Spud Count	Existing non-Federal Active Well Count	Existing non-Federal Oil Production (MMbbl/yr)	Existing non-Federal Gas Production (Bscf/yr)	Existing non-Federal Water Production (MMbbl/yr)	Total Federal Spud Count	Total Federal Active Well Count	Total Federal Oil Production (MMbbl/yr)	Total Federal Gas Production (Bscf/yr)	Total Federal Water Production (MMbbl/yr)	Total non-Federal Spud Count	Total non-Federal Active Well Count	Total non-Federal Oil Production (MMbbl/yr)	Total non-Federal Gas Production (Bscf/yr)	Total non-Federal Water Production (MMbbl/yr)
2024		5255	3.64	122.5	7.2										
2025	0	5219	3.45	111.6	7.8	60	15715	8.12	363.4	29.0	30	5249	4.57	121.1	16.3
2026	0	5187	2.68	104.3	7.0	82	15704	11.22	455.0	29.3	38	5255	6.31	151.7	16.5
2027	0	5156	2.10	98.2	6.3	82	15692	12.10	497.8	28.3	38	5261	6.81	165.9	15.9
2028	0	5124	1.66	92.7	5.8	82	15680	12.93	521.1	27.5	38	5268	7.27	173.7	15.5
2029	0	5093	1.33	87.9	5.3	82	15668	13.75	534.5	26.9	38	5274	7.73	178.2	15.1
2030	0	5062	1.08	83.5	4.9	82	15656	14.56	542.5	26.4	38	5280	8.19	180.8	14.9
2031	0	5030	0.89	79.4	4.6	82	15645	15.38	547.1	26.1	38	5287	8.65	182.4	14.7
2032	0	4999	0.74	75.6	4.3	82	15633	16.19	549.7	25.8	38	5293	9.11	183.2	14.5
2033	0	4968	0.62	72.1	4.0	82	15621	16.99	550.9	25.6	38	5299	9.56	183.6	14.4
2034	0	4936	0.54	68.9	3.8	82	15609	17.77	551.1	25.5	38	5306	10.00	183.7	14.3
2035	0	4905	0.47	65.8	3.6	23	15538	14.54	515.1	22.6	8	5282	8.18	171.7	12.7
2036	0	4874	0.41	62.9	3.4	0	15444	12.78	407.6	20.8	0	5251	7.19	135.9	11.7
2037	0	4842	0.37	60.2	3.3	0	15349	11.55	345.0	19.3	0	5219	6.50	115.0	10.9
2038	0	4811	0.34	57.7	3.1	0	15255	10.59	304.0	18.2	0	5188	5.96	101.3	10.2
2039	0	4779	0.31	55.3	3.0	0	15161	9.79	274.2	17.2	0	5156	5.51	91.4	9.6
2040	0	4748	0.29	53.0	2.9	0	15067	9.10	251.1	16.2	0	5125	5.12	83.7	9.1
2041	0	4717	0.27	50.8	2.8	0	14973	8.48	232.3	15.4	0	5094	4.77	77.4	8.7
2042	0	4685	0.25	48.8	2.6	0	14879	7.91	216.4	14.6	0	5062	4.45	72.1	8.2
2043	0	4654	0.23	46.8	2.5	0	14785	7.38	202.7	13.9	0	5031	4.15	67.6	7.8
2044	0	4623	0.22	45.0	2.4	0	14691	6.89	190.7	13.3	0	5000	3.87	63.6	7.5
2045	0	4591	0.21	43.2	2.4	0	14597	6.43	179.9	12.6	0	4968	3.62	60.0	7.1
2046	0	4560	0.20	41.6	2.3	0	14503	6.00	170.3	12.1	0	4937	3.38	56.8	6.8
2047	0	4528	0.19	40.0	2.2	0	14408	5.60	161.5	11.5	0	4905	3.15	53.8	6.5
2048	0	4497	0.18	38.5	2.1	0	14314	5.23	153.4	11.0	0	4874	2.94	51.1	6.2
2049	0	4466	0.17	37.1	2.1	0	14220	4.89	146.0	10.5	0	4843	2.75	48.7	5.9
2050	0	4434	0.17	35.7	2.0	0	14126	4.57	139.1	10.1	0	4811	2.57	46.4	5.7
2051	0	4403	0.16	34.4	1.9	0	14032	4.27	132.8	9.7	0	4780	2.40	44.3	5.4
2052	0	4372	0.15	33.2	1.9	0	13938	3.99	126.8	9.3	0	4749	2.24	42.3	5.2
2053	0	4340	0.15	32.0	1.8	0	13844	3.73	121.3	8.9	0	4717	2.10	40.4	5.0
2054	0	4309	0.14	30.9	1.8	0	13750	3.48	116.1	8.6	0	4686	1.96	38.7	4.8
			20.0	1787.0	103.9			286.2	9499.2	546.4			161.0	3166.4	307.4

Case III – Low case scenario

	New Federal					Existing Federal					New non-Federal				
Year	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)
2024							15765	6.47	367.5	12.9					
2025	13	13	0.43	12.3	14.1	0	15656	6.13	334.9	13.8	7	7	0.24	4.1	7.9
2026	13	26	1.38	21.5	13.3	0	15562	4.76	312.9	12.4	7	14	0.78	7.2	7.5
2027	13	39	1.79	26.6	12.5	0	15467	3.73	294.5	11.2	7	21	1.01	8.9	7.0
2028	13	52	2.14	30.2	11.7	0	15373	2.95	278.2	10.2	7	28	1.20	10.1	6.6
2029	13	65	2.44	33.1	11.1	0	15279	2.36	263.6	9.4	7	35	1.37	11.0	6.3
2030	13	78	2.71	35.4	10.6	0	15185	1.92	250.4	8.7	7	42	1.52	11.8	6.0
2031	13	91	2.96	37.3	10.2	0	15091	1.57	238.2	8.2	7	49	1.66	12.4	5.8
2032	13	104	3.19	38.9	9.9	0	14997	1.31	226.9	7.6	7	56	1.79	13.0	5.6
2033	13	117	3.40	40.4	9.6	0	14903	1.11	216.4	7.2	7	63	1.91	13.5	5.4
2034	13	130	3.60	41.7	9.3	0	14809	0.95	206.6	6.8	7	70	2.03	13.9	5.3
2035	13	143	3.79	42.8	9.1	0	14715	0.83	197.4	6.4	7	77	2.13	14.3	5.1
2036	13	156	3.96	43.9	8.9	0	14621	0.74	188.8	6.1	7	84	2.23	14.6	5.0
2037	13	169	4.13	44.8	8.7	0	14526	0.66	180.7	5.8	7	91	2.32	14.9	4.9
2038	13	182	4.28	45.7	8.6	0	14432	0.60	173.0	5.6	7	98	2.41	15.2	4.8
2039	13	195	4.42	46.4	8.4	0	14338	0.55	165.8	5.3	7	105	2.49	15.5	4.7
2040	13	208	4.55	47.2	8.3	0	14244	0.51	159.0	5.1	7	112	2.56	15.7	4.7
2041	13	221	4.67	47.8	8.2	0	14150	0.47	152.5	4.9	7	119	2.63	15.9	4.6
2042	13	234	4.79	48.4	8.1	0	14056	0.44	146.3	4.7	7	126	2.69	16.1	4.5
2043	13	247	4.89	49.0	8.0	0	13962	0.42	140.5	4.5	7	133	2.75	16.3	4.5
2044	13	260	4.99	49.5	7.9	0	13868	0.39	135.0	4.4	7	140	2.81	16.5	4.4
2045	13	273	5.09	50.0	7.8	0	13774	0.37	129.7	4.2	7	147	2.86	16.7	4.4
2046	13	286	5.17	50.5	7.7	0	13680	0.36	124.7	4.1	7	154	2.91	16.8	4.3
2047	13	299	5.25	50.9	7.6	0	13585	0.34	120.0	3.9	7	161	2.96	17.0	4.3
2048	13	312	5.33	51.3	7.5	0	13491	0.32	115.5	3.8	7	168	3.00	17.1	4.2
2049	13	325	5.40	51.6	7.5	0	13397	0.31	111.2	3.7	7	175	3.04	17.2	4.2
2050	13	338	5.47	52.0	7.4	0	13303	0.30	107.1	3.5	7	182	3.07	17.3	4.2
2051	13	351	5.53	52.3	7.3	0	13209	0.28	103.2	3.4	7	189	3.11	17.4	4.1
2052	13	364	5.58	52.6	7.3	0	13115	0.27	99.5	3.3	7	196	3.14	17.5	4.1
2053	13	377	5.64	52.8	7.2	0	13021	0.26	96.0	3.2	7	203	3.17	17.6	4.1
2054	13	390	5.69	53.1	7.2	0	12927	0.25	92.6	3.2	7	210	3.20	17.7	4.0
sum			122.7	1299.8	271.0			35.5	5361.0	184.8			69.0	433.3	152.5

	Existing non-Federal					Total Federal					Total non-Federal				
Year	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)	Spud Count	Active Well Count	Oil Production (MMbbl/yr)	Gas Production (Bscf/yr)	Water Production (MMbbl/yr)
2024		5255	3.64	122.5	7.2										
2025	0	5219	3.45	111.6	7.8	13	15669	6.56	347.1	27.9	7	5226	3.69	115.7	15.7
2026	0	5187	2.68	104.3	7.0	13	15588	6.15	334.4	25.7	7	5201	3.46	111.5	14.5
2027	0	5156	2.10	98.2	6.3	13	15506	5.53	321.1	23.7	7	5177	3.11	107.0	13.3
2028	0	5124	1.66	92.7	5.8	13	15425	5.09	308.5	22.0	7	5152	2.86	102.8	12.4
2029	0	5093	1.33	87.9	5.3	13	15344	4.80	296.7	20.6	7	5128	2.70	98.9	11.6
2030	0	5062	1.08	83.5	4.9	13	15263	4.63	285.7	19.4	7	5104	2.60	95.2	10.9
2031	0	5030	0.89	79.4	4.6	13	15182	4.53	275.4	18.4	7	5079	2.55	91.8	10.3
2032	0	4999	0.74	75.6	4.3	13	15101	4.50	265.8	17.5	7	5055	2.53	88.6	9.9
2033	0	4968	0.62	72.1	4.0	13	15020	4.51	256.8	16.8	7	5031	2.54	85.6	9.4
2034	0	4936	0.54	68.9	3.8	13	14939	4.56	248.3	16.1	7	5006	2.56	82.8	9.1
2035	0	4905	0.47	65.8	3.6	13	14858	4.62	240.3	15.6	7	4982	2.60	80.1	8.8
2036	0	4874	0.41	62.9	3.4	13	14777	4.70	232.7	15.0	7	4958	2.64	77.6	8.5
2037	0	4842	0.37	60.2	3.3	13	14695	4.79	225.5	14.6	7	4933	2.69	75.2	8.2
2038	0	4811	0.34	57.7	3.1	13	14614	4.88	218.7	14.1	7	4909	2.74	72.9	8.0
2039	0	4779	0.31	55.3	3.0	13	14533	4.97	212.2	13.8	7	4884	2.79	70.7	7.7
2040	0	4748	0.29	53.0	2.9	13	14452	5.06	206.1	13.4	7	4860	2.85	68.7	7.5
2041	0	4717	0.27	50.8	2.8	13	14371	5.15	200.3	13.1	7	4836	2.89	66.8	7.4
2042	0	4685	0.25	48.8	2.6	13	14290	5.23	194.8	12.8	7	4811	2.94	64.9	7.2
2043	0	4654	0.23	46.8	2.5	13	14209	5.31	189.5	12.5	7	4787	2.99	63.2	7.0
2044	0	4623	0.22	45.0	2.4	13	14128	5.39	184.5	12.2	7	4763	3.03	61.5	6.9
2045	0	4591	0.21	43.2	2.4	13	14047	5.46	179.7	12.0	7	4738	3.07	59.9	6.7
2046	0	4560	0.20	41.6	2.3	13	13966	5.53	175.2	11.7	7	4714	3.11	58.4	6.6
2047	0	4528	0.19	40.0	2.2	13	13884	5.59	170.9	11.5	7	4689	3.15	57.0	6.5
2048	0	4497	0.18	38.5	2.1	13	13803	5.65	166.7	11.3	7	4665	3.18	55.6	6.4
2049	0	4466	0.17	37.1	2.1	13	13722	5.71	162.8	11.1	7	4641	3.21	54.3	6.3
2050	0	4434	0.17	35.7	2.0	13	13641	5.76	159.1	10.9	7	4616	3.24	53.0	6.2
2051	0	4403	0.16	34.4	1.9	13	13560	5.81	155.5	10.8	7	4592	3.27	51.8	6.1
2052	0	4372	0.15	33.2	1.9	13	13479	5.86	152.1	10.6	7	4568	3.29	50.7	6.0
2053	0	4340	0.15	32.0	1.8	13	13398	5.90	148.8	10.5	7	4543	3.32	49.6	5.9
2054	0	4309	0.14	30.9	1.8	13	13317	5.94	145.7	10.3	7	4519	3.34	48.6	5.8
			20.0	1787.0	103.9			158.2	6660.8	455.8			89.0	2220.3	256.4

Footnotes:

1. **for all three cases, predicted data begins in 2025 and is forecasted for 30 years.**
2. **2024 "existing" data is estimate of actual annual production and includes 2024 new federal and non-federal activity**
3. **Allocation of water production for Federal and non-Federal was based on the oil production ratio since the majority of water is associated with the oil production.**

Maximum annual values of oil and gas on a per new well basis

GAS		New=Total (Fed+nonFed)			New - Federal			New - non Federal		
Case	Year of max prod	**Gas Production (Bscf/yr)**	**New Well Count**	**Bscf/yr per well**	**Gas Production (Bscf/yr)**	**New Well Count**	**Bscf/yr per well**	**Gas Production (Bscf/yr)**	**New Well Count**	**Bscf/yr per well**
Low	2054	70.8	150	0.47	53.1	108	0.49	17.7	42	0.42
base	2044	139.9	200	0.70	104.9	151	0.69	35.0	49	0.71
high	2034	459.3	471	0.98	344.5	353	0.98	114.8	118	0.97

OIL		New=Total (Fed+nonFed)			New - Federal			New - non Federal		
Case	Year of max prod	**Oil Production (MMbbl/yr)**	**New Well Count**	**MMbbl/yr per well**	**Oil Production (MMbbl/yr)**	**New Well Count**	**MMbbl/yr per well**	**Oil Production (MMbbl/yr)**	**New Well Count**	**MMbbl/yr per well**
Low	2054	8.89	450	0.02	5.69	282	0.02	3.20	168	0.02
base	2044	18.21	700	0.03	11.65	449	0.03	6.56	251	0.03
high	2034	26.28	700	0.04	16.82	448	0.04	9.46	252	0.04

Year of maximum production defined as year of highest new well annual production (highlighted cells in previous spreadsheets)

New well counts have been divided between new oil and gas wells. Will differ from previous spreadsheets

Single well type curves

Oil typecurve for new well in Southern Rim horizontal well subplay			Gas typecurve for a new well in basin-centered horizontal well subplay	
Figure A-18 in Appendix A			Figure A-6 in Appendix A	
year	BO/well	mmscf/well	year	mmscf/well
1	88882	266.6	1	2868.9
2	55261	165.8	2	1576.9
3	42643	127.9	3	964.3
4	35835	107.5	4	652.0
5	31421	94.3	5	470.9
6	28268	84.8	6	356.4
7	25874	77.6	7	279.4
8	23975	71.9	8	225.0
9	22351	67.1	9	185.2
10	20845	62.5	10	155.1
11	19440	58.3	11	131.9
12	18130	54.4	12	113.6
13	16908	50.7	13	98.8
14	15769	47.3	14	86.8
15	14706	44.1	15	76.9
16	13715	41.1	16	68.5
17	12791	38.4	17	61.5
18	11929	35.8	18	55.5
19	11125	33.4	19	50.4
20	10375	31.1	20	45.9
21	9676	29.0	21	42.0
22	9024	27.1	22	38.6
23	8416	25.2	23	35.6
24	7848	23.5	24	32.9
25	7320	22.0	25	30.6
26	6826	20.5	26	28.4
27	6366	19.1	27	26.5
28	5937	17.8	28	24.6
29	5537	16.6	29	22.9
30	5164	15.5	30	21.3
EUR(30)=	**592354**	**1777**		**8827**
	BO	mmscf		mmscf

Appendix D

Potential Impact of Carbon Capture Underground Storage (CCUS) on San Juan Basin Development (Courtesy of Dr. William Ampomah of NMT/PRRC)

Storage reservoirs: The San Juan Basin (Fig. D-1) is dominantly a gas basin, and it contributes 67% of the natural gas and 5% of the oil produced within the state of New Mexico. Since production started in the early 1900's, over 40,000 wells have been drilled and most of the oil and many of the gas plays have been depleted. These depleted plays provide an opportunity to utilize those reservoirs for CO2 storage. While most of the production is within Cretaceous-age strata, older strata within the basin (Jurassic to Paleozoic) and on the uplifted margins are potential storage sites. Sea-level changes were common during Cretaceous sedimentation; therefore, the Late Cretaceous units exhibit enormous variations in thickness and position in the sedimentary section (Fig. D-2).

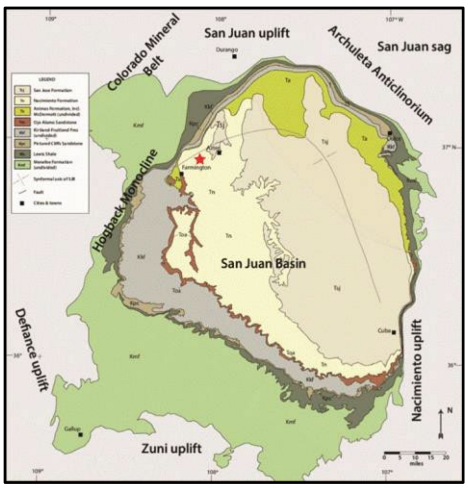

Fig. D-1 A simplified geologic map of the Four Corners area and the San Juan Basin.

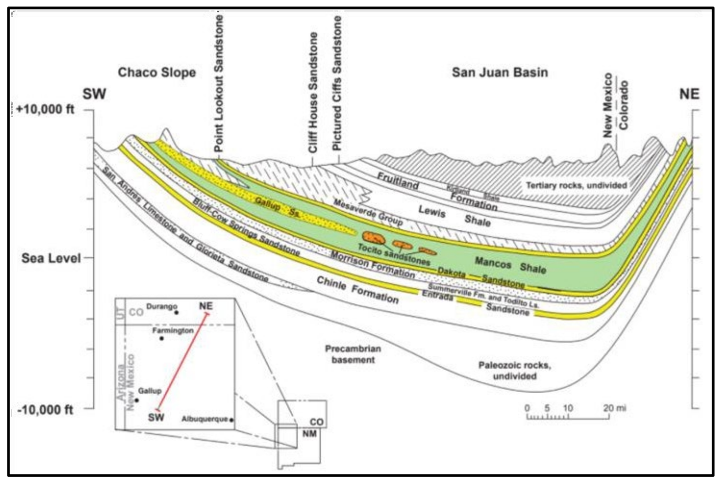

Fig.D-2 A schematic NE-SW cross section of the San Juan Basin from Stone et al. (1983).

The Jurassic Entrada Sandstone (Fig. D-3), the main CO_2 injection target, is present throughout the San Juan Basin and Four Corners area (New Mexico, Arizona, Utah, Colorado). The Entrada Sandstone was deposited as part of a widespread eolian sand sea or erg consisting of sand dunes, interdunal deposits and playa lake deposits (Massé and Ray, 1995; Anderson and Lucas, 1996; Dyer and Donoho, 2008). Within the San Juan Basin, the Entrada deposits range from 100 to 275 feet thick and consist of siltstones to medium/coarse-grained sandstones that are planar to trough cross-bedded. The composition of the sandstones are mostly quartz and feldspars grains with scattered rock fragments. Laminae of heavy minerals help define the crossbedding within the dune surfaces. Typically, the lower half of the Entrada Sandstone is finer grained, more cemented, and poorly sorted than the upper section. Diagenesis of these sandstones play an important role in porosity and permeability development, beyond simple compaction. Porosity and permeability are much higher in the upper Entrada Sandstone throughout the basin because of feldspar diagenesis and relative lack of cementation. Both core analyses as well as petrophysical analysis of porosity logs demonstrate this conclusion. The ELAN petrophysics for the Pathfinder well (API 30-045-35172), including log and core porosity and permeability measurements are shown in Figure D-4. Within the upper Entrada, porosity ranges upward to approximately 20%, and the permeability ranges from 10 to over 500 mD. The lower Entrada is less than 10% porosity and 1 mD permeability. To date, we have completed the petrographic analyses on outcrops and several wells that have core available.

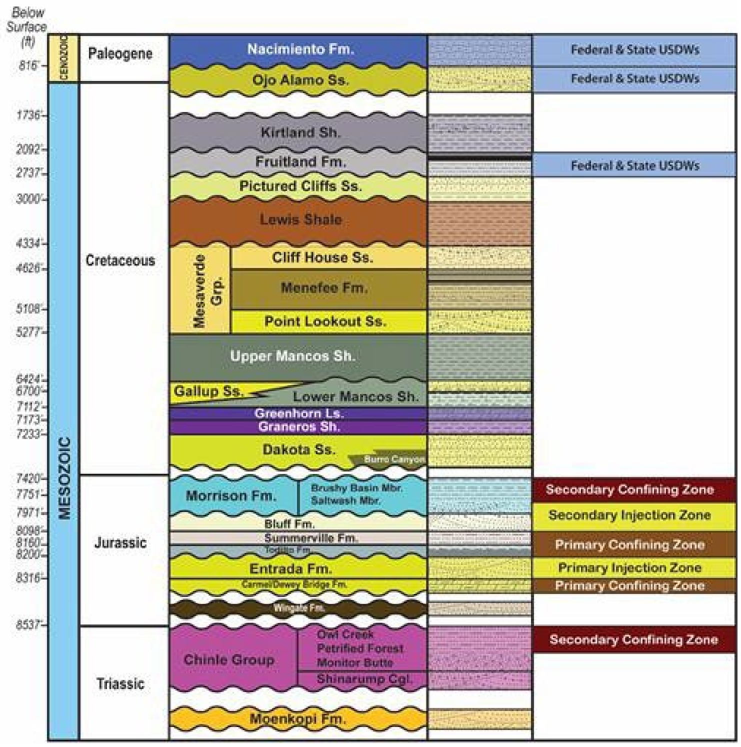

Fig. D-3. Stratigraphic column for the San Juan Basin spanning the Triassic to Paleogene-aged rocks. The injection and confining zones and aquifers are noted as well as the depths of the formations (not to scale).

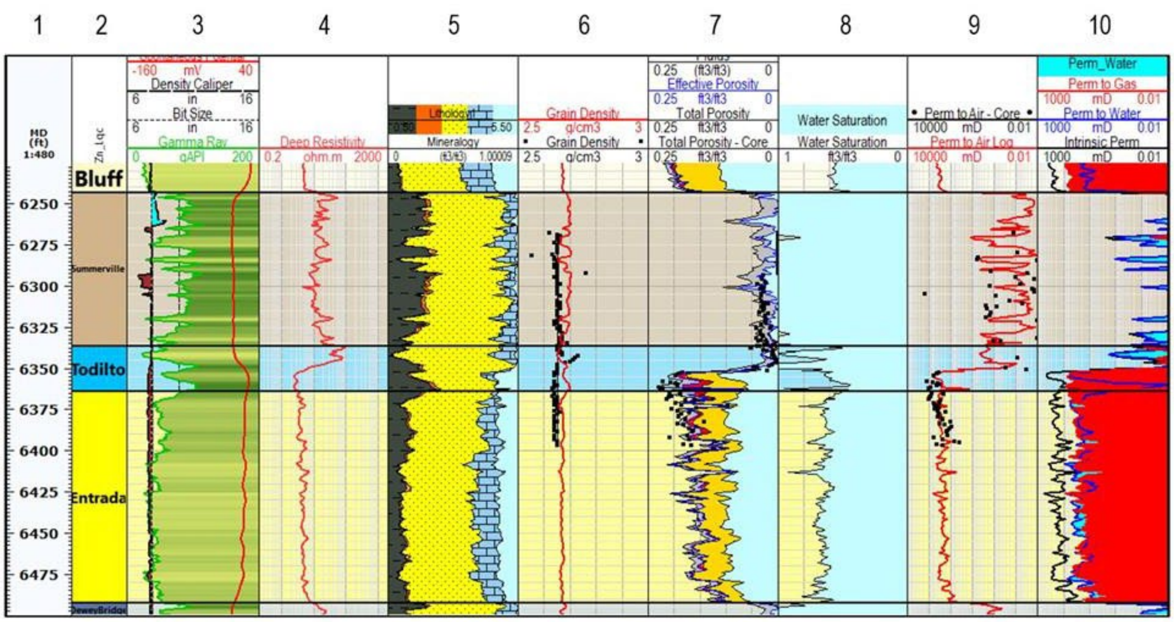

Fig. D-4. The ELAN petrophysics for the Pathfinder well API 30-045-35172 well. Track 1 shows the measured depths, Track 2 shows the formation names, Track 3 shows the gamma ray, caliper and spontaneous potential, Track 4 shows the deep resistivity curve, Track 5 shows the mineralogy, Track 6 shows the grain density with the core data in black, Track 7 shows the porosity analysis with the core data in black, Track 8 shows the water saturation, and Track 9 shows the permeability to air with the core data in black, and Track 10 shows the log derived permeability.

The only production within the Entrada Sandstone is restricted to several very small fields (the Entrada-Media fields) in the southeastern part of the basin. These fields are located under the Todilto salina; in addition to the organic-rich limestones being thicker in this area, there are thick anhydrite deposits preventing upward migration of hydrocarbons out of the Todilto strata. Instead, hydrocarbons moved downward into the Entrada Sandstone (Vincelette and Chittum, 1981). Most of these Entrada wells have been played out.

Other potential reservoirs within the terrestrial Jurassic strata of the San Juan Basin and Four Corners area are the Bluff Sandstone and Salt Wash member of the Morrison Formation. The Bluff Sandstone was deposited during another episode of widespread eolian sand sea migration from the northwest Four Corners into the San Juan Basin area. Like the Entrada Sandstone, the Bluff Sandstone occurs throughout the region, ranging from 150 to 250 feet thick, and are planar to trough cross-bedded. The sandstones consist of siltstones to coarse-grained sandstones (Anderson and Lucas, 1992; Lucas and Heckert, 2003; Lucas, 2020) and are composed of quartz, feldspars, and scattered rock fragments. Heavy minerals are not as common as in the Entrada Sandstone, reflecting the different source areas for the sands. The porosity and permeability data from cores of the Bluff Sandstone is limited (average of 8% from a single saltwater disposal well), because the Bluff Sandstone is not an active exploration target within the San Juan Basin. Within these arid terrestrial sediments, there is almost no source of organics that produce hydrocarbons. Based on well log analysis, the log porosity ranges up to 18%. The log-measured permeability ranges from 0 to 88 mD (averages 11 mD).

The Morrison Formation, overlying the Bluff Sandstone, represents the gradual change in the depositional environments from arid eolian to temperate, fluvial, lake, and deltaic deposits (Hansley, 1989; Lucas and Heckert, 2003). The Salt Wash member was deposited under arid to semi-arid conditions in alluvial fan, alluvial plain, and braided stream complexes and ranges from 250 to 500 feet thick within the San Juan Basin and Four Corners area. On well logs, selecting the top of the Salt Wash member is somewhat arbitrary. The change from sandstones and conglomerates to an interval rich in shales and siltstones with scattered sand channels (Brushy Basin member, fluvial) was selected as the Salt Wash top.

The Salt Wash member consists of very fine- to coarse-grained, poorly to well sorted, tabular to trough cross-bedded, conglomerate, sandstones, siltstones, and minor mudstones (Hansley, 1987; Lucas and Heckert, 2003). The alluvial/braided channel deposits are composed of quartz, feldspars, and sedimentary rock fragments with other types of rock fragments, plant debris and clays also present in the unit. Mudstone intervals may represent lacustrine alluvial plain deposits. Porosity within the Salt Wash Member ranges from 0 to 21% with an average of 4% from well log analysis. Measured porosity values in the area average 3%. Permeability values, calculated from the well logs, range from 0 to 18 mD (with an average of 1 mD). Within the CarbonSafe core, some of the channel sands approach the high porosity values. Like the Bluff Sandstone, there is no production from the Salt Wash member in the San Juan Basin.

Confining system: For the primary injection target, the Entrada Sandstone, the underlying confining zone is the Carmel Formation. It is the lowermost Jurassic unit in the San Juan Basin and is also known as the Dewey Bridge Member of Entrada Sandstone elsewhere in the Four Corners area (Condon, 1989; Robertson and O'Sullivan, 2001; Lucas, 2020). The Carmel Formation is transitional from marine limestones in Utah/Arizona to tidal and sabkha flats in the San Juan Basin. The unit consists of a shaly siltstone (quartz, clays and iron minerals dominate) redbeds that have minimal porosity or permeability. No measured values have been found in the literature or company reports, but based on well logs, it has average porosity of 2.9% and permeability of 0.3 mD.

The overlying seal consists of the Summerville and Todilto formations. The Todilto Formation overlies the Entrada Sandstone and fills in any of the topography preserved on the Entrada depositional surface (ie., dunes). Unlike the other confining zones in the region, the Todilto formation is mainly confined to the San

Juan Basin area. The Todilto Formation consists of basal limestones and overlying anhydrite beds that appear to grade upward into the Summerville Formation. It is economically unique, since it also hosts uranium deposits within limestones in the southern part of the San Juan Basin and is the source of the hydrocarbons found in the Entrada Media wells. Todilto deposits range in thickness from 5 to 90 feet in the northwestern part of the basin. Elsewhere in the basin, the Todilto can be over 300 feet thick; a thin (~50-80 feet) organic-rich limestone is overlain by massive anhydrite deposits. The origin of this unit has been debated over the years (Ridgley and Goldhaber, 1983; Evans and Kirkland, 1988; Anderson and Kirkland, 1960; Tanner, 1970), but the best model is that of a salina with a complex interplay of both saline and freshwaters (Lucas et al., 1985). Overall, because of the high organic content and the lack of bioturbation and/or ripples or other wave-formed features, the Todilto waters had to be relatively deep, poorly oxygenated, and possibly chemically stratified. The Todilto carbonate and evaporite deposits have a porosity of ~1% and permeability of ~0.1 mD.

The Summerville deposits are fine-laminated red beds, white eolian sandstones, and gypsum- and/or anhydrite-cemented fine-grained sandstones, siltstones, and mudstones that were deposited in hypersaline tidal flats, alluvial plain/sabkhsa, eolian, fluvial to lacustrine environments and occur throughout the region (Anderson and Lucas, 1992; Lucas, 2020). Based on well log measurements, porosity ranges from 0 to 15% (averages 1.2%) and permeability ranges from 0.0 to 0.5 mD (averages 0.1 mD). The CarbonSAFE core recovered the entire Summerville section, and it showed a transition from salina (Todilto) to aeolian (Bluff) depositional environments. Within the CarbonSAFE core, the redbeds in Summerville are lithologically similar to the Carmel deposits.

For the Bluff and Salt Wash secondary injection zones, the Summerville and Todilto deposits make up the underlying seal. The overlying seal for these stacked siliciclastic sediments is the terrestrial deposits of the Brushy Basin member of the Morrison Formation. The Brushy Basin member was deposited under more temperate conditions with depositional environments ranging from fluvial, lacustrine, alluvial plain to deltas. The Morrison Formation is regionally extensive, with varying names to its members throughout the Four Corners area. Overall, the sediments tend to be finer grained than the Salt Wash, but discrete sandstone channels may be present within the section. These channels can have higher porosity and permeability, but they are not laterally continuous and should not impact the seal's ability to prevent CO_2 migration out of the section.

On outcrop, the Brushy Basin Member is reddish to greenish, bentonitic mudstones and shales interbedded with thin limestones and cross-bedded, conglomeratic sandstones (Lucas and Heckert, 2003). These range in thickness from 200 to 350 feet and contain quartz, feldspars, igneous and sedimentary rock fragments, and miscellaneous heavy minerals (Hansley, 1990). The finer-grained fraction (calcareous mudstones/shales and siltstones) consists of quartz, feldspars, illite, smectite, mixed-layered clays, and bentonite. Porosity from well logs within the Brushy Basin member ranges from 0.2 to 25.3% with an average of 6.9%. Measured porosity values range from 9.5 to 20%. These high porosity values are from the sandstone horizons (channel bar sediments), not the finer grained horizons. These sandstone horizons are encased in finer-grained, less permeable, and porous, mudstones and siltstones. Permeability values calculated from well logs range from 0 to 21.2 mD (average 1.8 mD). Measured permeability is 0.79 mD.

Subsurface structural element: The San Juan Basin formed during Laramide compressional deformation starting at 75 million years ago and continuing into Eocene time (Baltz, 1967; Cather, 2004). The Hogback monocline separates the Four Corners platform on the west from the San Juan Basin to the east (Fig. D-5). An interpreted seismic line that was collected across the Hogback monocline shows an east-verging reverse fault zone that is about 2000 feet wide with 1500–2000 feet of offset (Taylor and Huffman, 1988). The northwest-trending faults deformed early Paleozoic to Triassic sedimentary rocks and both northwest- and northeast-trending structures were active during Laramide deformation. Right-lateral movement is associated with the northeast-trending faults and left-lateral movement is preserved on northwest-trending faults. In addition, Taylor and Huffman (1998) used industry and USGS seismic lines to map northeast- and northwest-trending faults that offset the top of the Proterozoic basement across the San Juan Basin; these faults do not offset Mesozoic rocks.

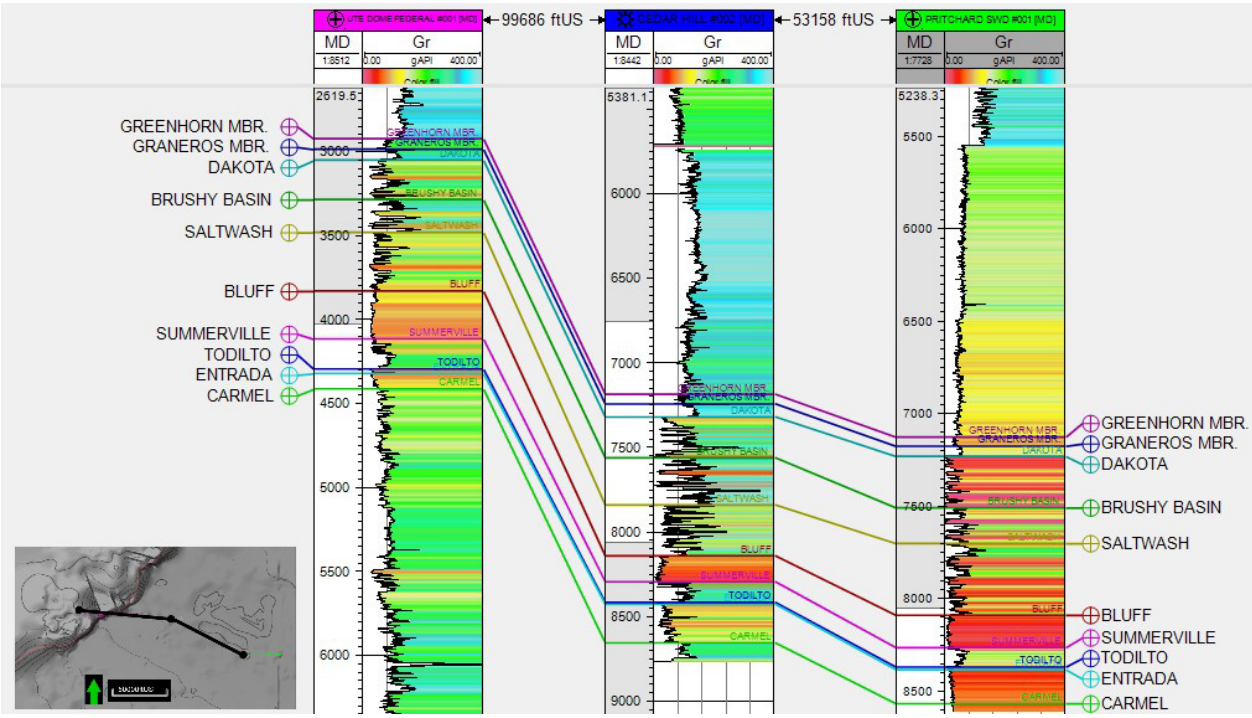

Fig. D-5. A well correlation cross-section across the Hogback monocline into the San Juan Basin.

The geologic structure of the interior of the San Juan Basin on the Geologic Map of New Mexico (2003) and on regional-scale cross sections (e.g., Stone et al., 1983) is generally depicted as being relatively simple; although small amplitude folds have been recognized on the Four Corners Platform west of the Hogback monocline (Beaumont, 1954). Within the basin, detailed structure contour maps on Cretaceous units in oil and gas fields in the San Juan Basin (Fassett, 1978; 1983) reveal north- to northwest-striking folds with amplitudes on the order of 75 to 100 ft. Tremain et al. (1994) also note east- to ESE-striking faults in the subsurface just southeast of Farmington and along the margin of the basin northwest of Farmington that cut the Fruitland/Pictured Cliffs contact. This folding and faulting is associated with transgressional Laramide deformation. As the basin formed during Laramide deformation, surrounding highlands rose, and fluvial systems flowed east and southeast across the basin, depositing Paleocene, and Eocene sedimentary rocks. The basin continued to fill until 26 to 27 million years ago; 1.2 km of material has been eroded from the basin since that time (Cather et al., 2008).

The tight sandstones or sand-rich shale beds equivalent to the Gallup Sandstone are more easily fractured and may already contain natural fractures Sandstone (Ridgley et al., 2013; Broadhead, 2015). The encasing muddy Mancos Shale, Mesa Verde Formation and Lewis Shale are generally unfractured in the central basin (Ridgley et al., 2013; Dubiel, 2013; their toughness is largely due to their ductility and laminated texture (McCarthy and Garcia, 2016). The ductility and thinly laminated nature of the terrestrial mudstones of the Brushy Basin Formation of the upper Morrision will have prevented the formation and propagation of fractures. While local sand bodies in the Brushy Basin Member may have small fractures, they are highly unlikely to be through-going fractures; analog settings in the Mesa Verde Formation and Mancos Shale demonstrate that if fractures exist, they will be small and will terminate at shale partings and bed boundaries.

Underground Source of Drinking Water (USDW): Several formations within the proposed sites qualify as underground sources of drinking water (USDW) according to the EPA standards for a Class VI well (US EPA, 2015). The USDWs in this area are divided into shallow aquifers: the San Jose, La Plata, and Animas alluvial system, the Nacimiento Formation, and the Ojo Alamo Sandstone; and deeper oil and gas bearing formations: the Kirtland-Fruitland Formation, the Menefee Formation, the Upper Mancos Shale, and the Morrison Formation. In terms of regional geology, the Fruitland Formation and Kirtland Shale are difficult to differentiate by well log and are grouped together. The lowermost USDW varies as a function of location within the area.

Near the proposed site in northern New Mexico, in descending order by depth and traveling from east to west across the San Juan Basin, the lowermost USDWs are the Ojo Alamo Sandstone, the Kirtland-Fruitland Formation, the Menefee Formation, the Upper Mancos Shale, and the Morrison Formation (Fig. D-6). The Ojo Alamo Sandstone is the lowermost USDW in most of the San Juan Basin of New Mexico east of the Hogback monocline and north of the Kirtland-Fruitland Formations outcrop belt. The Ojo Alamo Sandstone is unconformably overlain by the Nacimiento Formation and produces water regionally. The Olo Alamo reaches 400 ft thick and based on well log data, depth to its bottom near the proposed site ranges from approximately 260-1,570 ft bgs.

Well analysis indicates that the Kirtland-Fruitland Formations have many wells with high production and low (<10,000 mg/L) TDS in the San Juan Basin of New Mexico. The Kirtland-Fruitland Formations forms a USDW mostly along its outcrop margin in the western basin. However, small pockets of water that meet the USDW requirements are found in the more eastern and northern sections of the San Juan Basin). Within the study area, the combined Kirtland-Fruitland Formation may reach up to 1,700 ft thick. In the wells closest to the proposed injection site, depth to the bottom of the Kirtland-Fruitland Formation ranges from approximately 315-2,230 ft bgs. The outcropping region of the Menefee Formation within the Mesaverde Group is the next USDW of the proposed site. The Mesaverde Group outcrops west (down-section) of the Kirtland-Fruitland Formation in the San Juan Basin and groundwater wells are typically completed in the Menefee Formation, with some in the Cliff House Sandstone. Where it forms a USDW, the Menefee Formation typically ranges from 600-800 ft thick and well logs report the formation bottom occurs at a depth of approximately 430-2,969 ft bgs.

The next USDW is the Upper Mancos Shale which outcrops to the north and west of the Mesaverde Group in the northwest corner of the study area. Although no water wells exist in this area, a freshwater zone was found in production data for the northwest striking band of Gallup Sandstone within the Mancos Shale within this outcrop region. Because the Gallup Sandstone exists at the stratigraphic boundary between the Lower and Upper Mancos Shale (Broadhead, 2015), and is only present in the southwestern section of the San Juan basin, the Upper Mancos was defined as the lowermost USDW in the area where freshwater is present in the Gallup Sandstone. The Upper Mancos Shale is up to 1,000 ft thick and depth to its bottom ranges from around 140 to 990 ft bgs within the USDW zone.

The Morrison Formation west of the Hogback monocline forms a USDW. Groundwater wells follow a mostly linear pattern south along the structure. Freshwater in the Morrison Formation is generally recharged in outcrops and from precipitation in the Chuska Mountains which travels towards the San Juan River, consistent with the location of water wells that define the USDW zone. The thickness of the water bearing units of the Morrison Formation are approximately 250-550 ft thick. Based on the NMOSE well driller reports, depth to the bottom of the Morrison Formation within the USDW zone is approximately 974 to 3,343 ft bgs.

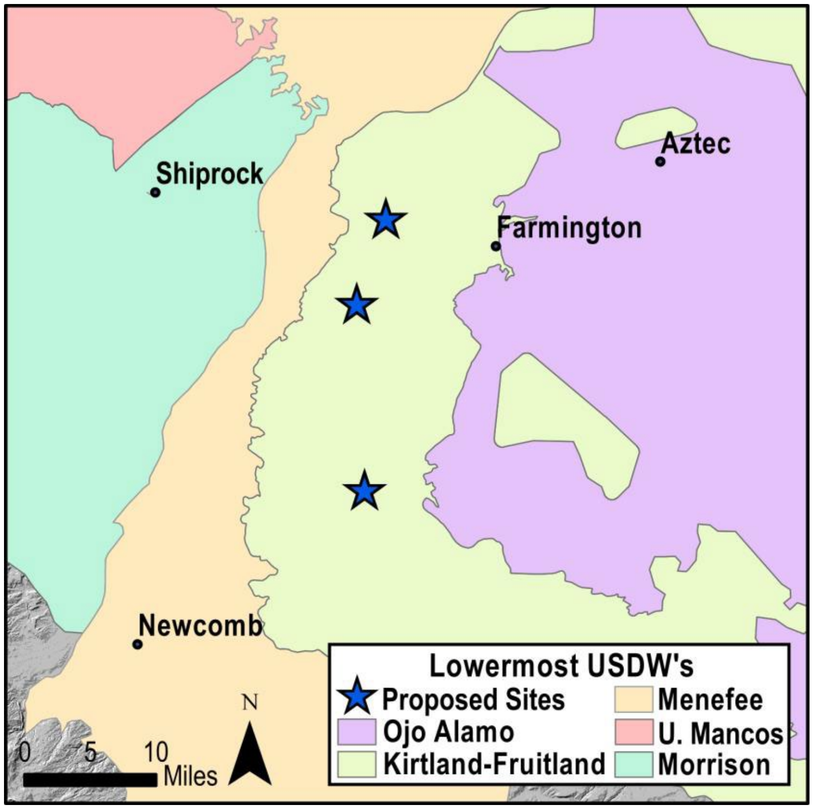

Fig. D-6. Areal extent of all underground sources of drinking water within the project region.

Legacy wellbores: Within the area of interest associated with proposed injection sites, Fourteen (14) wells that penetrate the storage complex (Entrada) were identified, among which two (2) Plugged and Abandoned (P&A) wells potentially requiring corrective action; Six (6) P&A wells that do not require corrective action; five (5) saltwater disposal wells that are actively injecting into the Entrada formation; and one (1) acid gas injection well that is actively injecting into the Entrada formation. Figure D-7 provides the distribution of the offset wells.

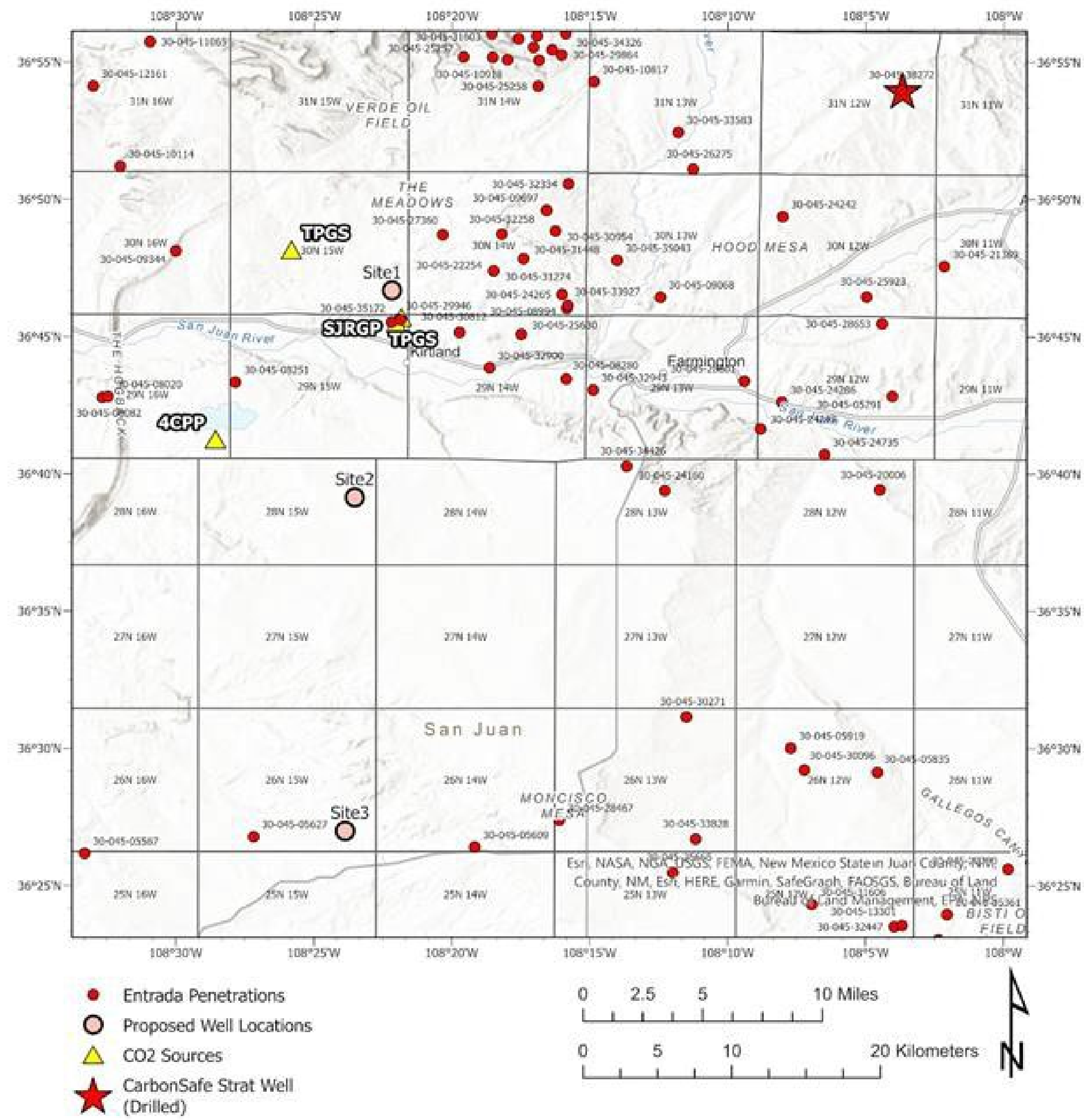

Fig. D-7. Summary of known legacy wellbores that penetrate the storage complex.

Prediction of site performance:

Estimation of storage capacity: The CO2-SCREEN tool (Goodman et al. 2011) as well as the Parametric method (Ampomah et al. 2016) used to assess the potential storage capacity of the three saline formations in the San Juan Basin. These tools use a volumetric method to estimate the storage capacity with storage efficiency factors that were developed from simulations of CO2 injection into storage formations. Physical parameters for the storage capacity model were obtained from the geological model developed as part of regional efforts (Table D-1). The geological model covers an area of 9,571 square kilometers, which is roughly half the total area of the San Juan Basin. Injection zones in three formations (Entrada, Bluff, and Saltwash) were considered. The estimates of the storage capacity over the 9,571 square kilometer area of the model ranged from 6 to 12 gigatons with an average of ~ 10 gigatons of CO2 storage. This is at least an order of magnitude larger than the potential 240 million metric tons of CO2 to be stored in the proposed hub project.

Table D-1. Input data for uncertainty analysis and statistical assessments of the storage capacities

	Storage formation	Entrada		Bluff		Saltwash		
		Mean	Std. Dvi.	Mean	Std. Dvi.	Mean	Std. Dvi.	total
Input Data in the uncertainty analysis	Area, sq-mi	3695.4	0.0	3695.4	0.0	3695.4	0.0	-
	Thickness, ft	155.5	15.6	182.7	18.3	339.6	34.0	-
	Porosity, frac	0.1	0.0	0.1	0.0	0.1	0.0	-
	Pressure, psi	2494.7	249.5	2175.6	217.6	2219.1	221.9	-
	Temperature, F	160.7	44.9	147.4	43.5	143.8	43.2	-
Statistical assessments of the storage capacity, *million tones*	P10	1690		1688		2708		6086
	P50	2441		2492		3969		8901
	P90	3434		3547		5547		12527
	Mean	2542		2592		4125		9259

Modeling of proposed injection scenario: The preliminary reservoir simulation indicates that each of the three (3) proposed sites can safely store at least 60 million metric tons of CO_2 within a 30-year period, with limited pressure elevation interference between sites. A geologic model that encompasses 60.25 miles by 60.50 miles square of the northwest San Juan Basin was established to perform the injection modeling. The grids distribute in I, J, and. K directions are 241 X 242 X 30 with 1,749,660 cells in total. It consists of nine (9) geological zones, where Salt Wash, Bluff, and Entrada are the potential storage zones, and Brushy Basin, Summerville and Todilto are the primary seals. The model is based upon data obtained through careful characterization review of existing well tops and available seismic data. Petrophysical properties are interpreted from available well logs. The porosity and permeability maps of the top layer Entrada saline formation are shown in Figure D-8. The average porosity of Entrada is 11% and permeability is 69 mD. The model was initialized by hydrostatic head equilibrium calculation at the mid-depth of Entrada formation where the initial pressure at the well location is approximately 3400 psi. The simulation model includes relative permeability curves with capillary and dissolution trapping mechanisms. An initial history matching was performed based on historical saltwater injection within the model domain.

Given the hub conception and expected CO_2 sources around the basin, 3 separate sites were targeted in the simulation with the injection rate of each site to be 2.0 million metric tons of injection rate for 30 years. The scheduled rate of 2.0 MT/year sustained steadily throughout the entire 30 years of active injection period at each site. After 30 years of injection (2060), simulation revealed that a total of 180 million metric tons of CO_2 can be evenly distributed at three targeting injection sites. During and after the CO_2 injection, the plume tends to migrate to the southern basin following the dip. Additionally, pressure elevation at the center of each injection site is expected to be around 600 psi on average and will dissipate over time once the injection is stopped. Based on the post-injection behavior analysis, reservoir pressure dissipated at the injection sites quickly. After 5 years of post-injection, the pressure returned to approximately 145 psi higher than the initial pressure. The reservoir pressure perturbation within the model domain is shown in Figure D-9. Therefore, our preliminary study substantiated that the Four Corners Region of the San Juan Basin is capable of containing at least 50 million metric tons of CO_2 per each site, and is propitious serving as one of the CO_2 storage hubs in Western U.S.

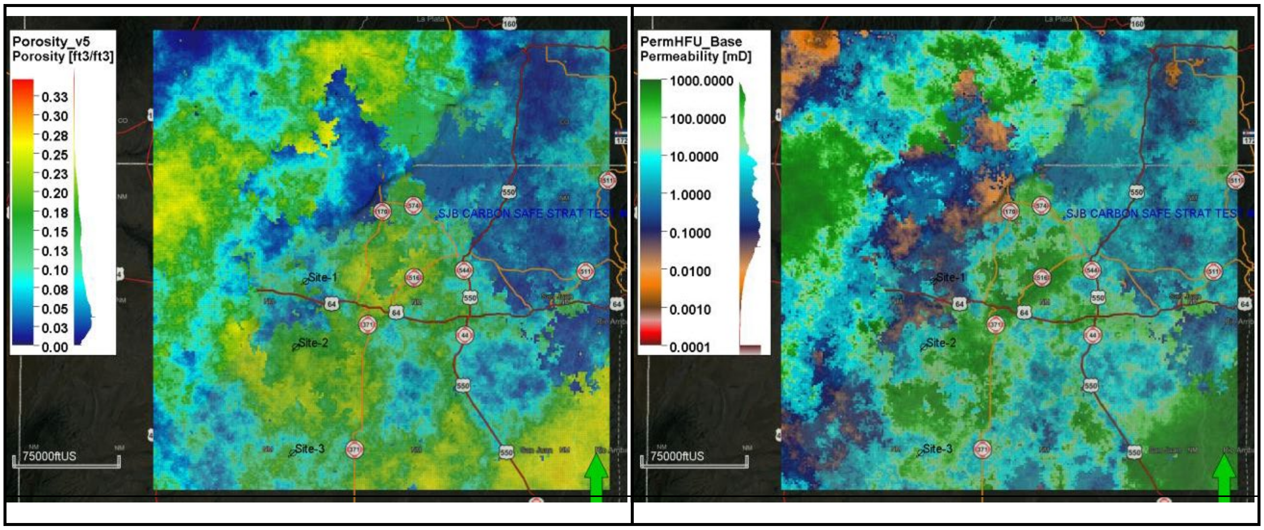

Fig. D-8. Top view of porosity (left) and permeability (right) distribution for the Entrada formation.

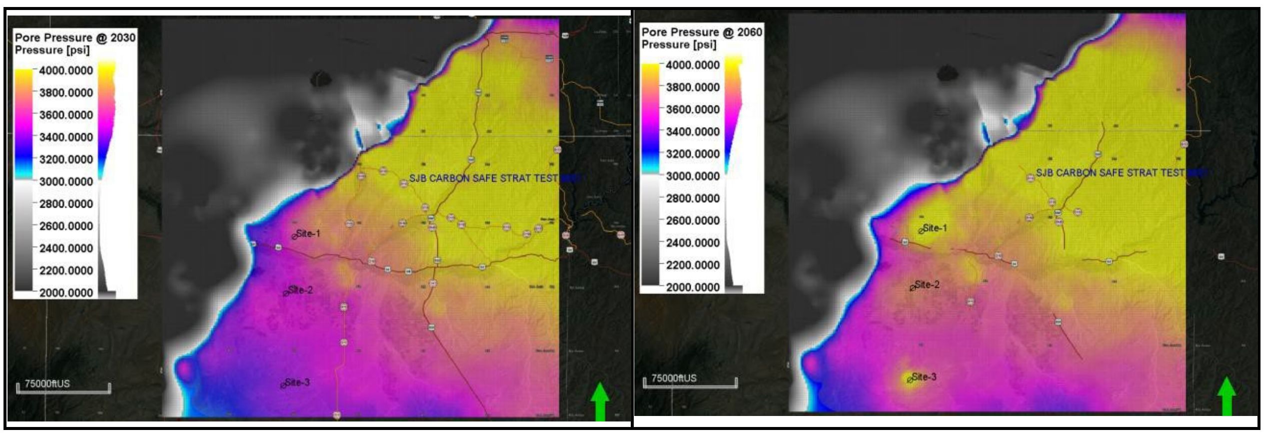

Fig. D-9. Reservoir Pressure in Entrada at 2030 (prior to injection, left) and at 2060 (end of injection, right)

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