ELECTRONICALLY FILED WITH RCA

August 15, 2025

Regulatory Commission of Alaska
701 W. 8th Avenue, Suite 300
Anchorage, Alaska 99501

Subject: Tariff Advice No. 576-8; Chugach Electric Association, Inc. Beluga River Unit Gas Transfer Price Update; with Reserve Study and Asset Retirement Obligation updates.

Commissioners:

The tariff filing described below is transmitted to you for filing in compliance with the Alaska Public Utilities Regulatory Act and Sections 3 AAC 48.200 – 3 AAC 48.470 of the Alaska Administrative Code. The purpose of this filing is to update Chugach Electric Association, Inc.'s (Chugach) transfer price of natural gas produced from its working interest ownership in the Beluga River Unit (BRU) for rates effective October 1, 2025.

TARIFF SHEET NUMBER		CANCELS SHEET NUMBER		SCHEDULE OR
ORIGINAL	REVISED	ORIGINAL	REVISED	RULE NUMBER
98.1	5th Revision	98.1	4th Revision	BRU Gas Transfer Price

If approved, the proposed changes in this filing will increase the BRU gas transfer price (GTP) by 9 percent from $6.65 to $7.25 per Mcf.[1] As a result, the average Residential member consuming 525 kWh will see a 0.8 percent, or approximately $0.90, increase to their total bill. The City of Seward d/b/a Seward Electric System (Seward) will see an average bill increase of approximately $8,827, or 1.4 percent, as measured at transmission delivery. The BRU GTP proposed in this filing will be included in Chugach's upcoming quarterly cost of power adjustment filing for rates effective October 1, 2025.[2] Gas from Chugach's working interest ownership in the BRU continues to be used to meet current and future firm load requirements on its system.

This filing is not for a new service, will not result in the termination of an existing service, conflict with any other schedule or rate contained in Chugach's operating tariff, or in any other way adversely impact customers or the public. Chugach provides electric service to approximately 90,000 retail members with 113,000 retail metered locations and wholesale customer Seward. Chugach is projecting annual revenues of approximately $392.2 million for the calendar year 2025.

[1] The $6.65 per Mcf GTP is based on Chugach's February 15, 2025 gas transfer price filing submitted under Tariff Advice No. 566-8.

[2] Per Chugach's Operating Tariff, fuel and purchased power rate adjustments can be implemented prior to Commission approval with recognition that any changes resulting from Commission review will be adjusted through the balancing account and reflected in the subsequent filing.

Chugach Electric Association, Inc.
5601 Electron Drive, P.O. Box 196300 Anchorage, Alaska 99519-6300 ● (907) 563-7494 Fax (907) 562-0027 ● (800) 478-7494
www.chugachelectric.com ● info@chugachelectric.com

Background

The BRU GTP mechanism formulates pricing on a per Mcf basis for the following cost components: 1) Field Operations, reflecting the operating expenses related to the production of BRU gas volumes; 2) Asset Retirement Obligation (ARO) Surcharge, reflecting contributions to the ARO fund which will be used to pay the future costs for dismantlement, removal and restoration (DR&R) of the BRU field; and 3) Capital Reserve Surcharge (CRS), reflecting contributions towards forward funding capital expenditures for development and improvement projects at the BRU.

Chugach is required to submit BRU GTP filings to update the BRU GTP by February 15 and August 15 of each year. The February 15 filing reflects actual operating costs for the prior period, and projections for the rate effective period. The August 15 filing incorporates the results submitted in the February 15 filing, with updates reflecting available actual operating cost results as well as other adjustments to forecasted expenses as necessary. This filing reflects actual field operating expenses for January 1 through December 31, 2024, and a combination of actual and projected operating expenses for January 1 through December 31, 2025.

Summary of Results

The proposed update to the BRU GTP reflects the results of the 2025 BRU Reserve Study and 2025 BRU ARO Study (2025 BRU Studies). With this proposed update, the BRU GTP will increase from $6.65 to $7.25 per Mcf. The field operations component of the GTP is increasing by 4.37 percent, from $3.72 to $3.89 per Mcf. The ARO surcharge is increasing from $0.47 to $0.68. The Capital Reserve Surcharge is increasing from $2.46 to $2.68. The main drivers for these increases are from the incorporation of increased capital development and resulting increase to Asset Retirement Obligations from the 2025 BRU Study. In addition, the adjusted Operating Expense balancing account remains at $5.8 million for this filing. Although Chugach realized an increase in reserve volumes, the Study indicated 15 additional wells to be drilled, as well as increase of approximately $35 million in gross Asset Retirement Obligation expenses. This update also reflects underlift activity with Hilcorp Alaska (Hilcorp). Chugach has underlifted approximately 2 Bcf through June 2025 year-to-date, and has received approximately $9.4 million in settlement. Chugach has included two new exhibits in this update to track and present underlift activity and its effect on reserve forecasts. Exhibit 8 displays the updated reserve study, as well as forecast adjustments related to underlift. Exhibit 9 calculates Chugach's actual versus Working Interest Ownership share of Joint Interest Billing expenses, and underlift settlement amounts. Invoices provided to Hilcorp for Q1 and Q2 have been provided in Attachment A.

2025 Updates to the BRU Reserve Study and ARO Cost Estimates

In compliance with Order No. U-19-085(33)/U-19-091(32)/U-20-071(15) (Order 15), Chugach has updated the gas reserve study concurrently with the cost estimates for its ARO. The 2025 updates were prepared for Chugach by Petrotechnical Resources of Alaska (PRA), with Ryder Scott Company LP (Ryder Scott) providing validation of the 2025 Reserve Study, CONAM Construction Company (CONAM) providing the updated surface cost estimates, and PRA providing the subsurface cost estimates in the 2025 ARO Study. In compliance with Order 15, the 2025 Reserve Study was prepared in conformance with the current Petroleum Resources

Management System (PRMS) standards and a P50/P75/P90 sensitivity analysis on the results of the study.

The BRU Reserve study is provided in Attachments B and C. The 2025 ARO Study is provided in Attachment D, including estimates for both surface and subsurface obligations. The results of these studies are summarized below.

Reserve Study Update

The results of the 2025 Reserve Study indicate that there are 88 Bcf gross remaining reserves to be produced from the BRU over its economic life, which extends through March 2035. The study analyzed the existing and planned wells to determine that there are 63 Bcf remaining proven reserves, and 25 Bcf probable and possible reserves, for a total of 88 Bcf gross remaining reserves that can be economically produced. Table 1 compares the remaining reserve projections provided in the 2022 reserve study (based on reserves from 2025 through 2035) with the 2022 reserve study (based on adjusted remaining reserves from 2025 through 2034).

Table 1: BRU Field Remaining Reserves
Comparison of 2025 and 2022 Reserve Studies

	Remaining Reserves (Bcf)	
Reserve Study	Total Field	Chugach's Share
2025 Study	88	56
2022 Study (adj.)	65	44
Difference	23	12

The 2025 BRU reserve study projects that the remaining reserves are 88 Bcf.[2] The updated estimates include a one-year increase in the economic life of the field and remaining reserve volumes that are 23 Bcf higher than the previous study results. In the 2025 Reserve Study, the current and future planned wells were analyzed on a well-by-well basis.

In recent years, the production decline trends that have been observed since 2008, have been steeper than historical trends. This resulted in slightly lower forecasted reserves than recent annual updates have shown. The recent drilling campaign that began in 2022, has increased active well counts to 27. The additional wells have replenished depleted reserves, but increasing the base reserves has become increasingly difficult. Although decline rates are higher than historical trends, the field is still benefiting from continued drilling. Recent wells are finding instances of higher pressures in Beluga, indicating additional resources not yet discovered. The 2025 reserve study indicates that based on current operating costs, end of field life will likely occur when the gross field-level production rate reaches approximately 6 MMscf/d in 2035.

[2] The 2022 Reserve Study results indicated that there were 65 Bcf remaining reserves. During the period between 2022 and 2024, approximately 40 Bcf was extracted from the BRU. The 65 Bcf adjusted remaining reserve volume is calculated based on the total remaining reserves reduced by the volumes extracted.

For this study, eight proven undeveloped wells are scheduled to be added to production; five wells are planned in 2025, and three additional wells are scheduled for 2026. Fifteen probable and possible wells are scheduled between 2027 and 2030. These additional wells are estimated to have a probable reserve recovery of 1.7 Bcf per well. At the time the 2025 Reserve study was prepared, 27 wells were actively producing, with two new wells already producing in 2025.

Chugach's working interest ownership of the BRU is 66.67 percent. Net of field use, Chugach's share of the remaining reserves is approximately 56 Bcf. Compared to the 2022 Reserve Study results, as adjusted by actual volumes extracted during years 2022 through 2024, which had projected Chugach's share of the remaining reserves to be 44 Bcf, the 2025 Reserve Study results reflect an increase of 12 Bcf. Table 2, below, provides a comparison for Chugach's share of BRU production based on the 2022 and 2025 reserve study projections.

Table 2: Chugach's Share of BRU Production
Comparison of 2025 and 2022 Reserve Studies
Gas Volumes Delivered - Net of Field Use (Mcf)

Year	2025 Study	2022 Study	Difference
2025	9,078,667	8,581,082	497,585
2026	8,495,000	7,883,312	611,688
2027	7,461,667	6,692,245	769,421
2028	6,518,667	5,545,037	973,630
2029	5,844,667	4,390,410	1,454,256
2030	5,560,333	3,500,990	2,059,343
2031	5,360,000	2,804,570	2,555,430
2032	3,362,667	1,958,344	1,404,323
2033	2,147,667	1,521,057	626,610
2034	1,418,333	622,864	795,469
2035	272,000	0	272,000
	55,519,667	43,499,912	12,019,754

The 2025 Reserve Study also projects a longer economic life for the BRU. The update projects the economic life of the field will be through March 2035, rather than June 2034, as indicated in the previous study.

ARO Cost Estimates

The results of the 2025 ARO Study indicate that the nominal cost for DR&R of the total BRU field will be $129 million (2025 dollars), or approximately $36.7 million higher than the $93.5 million cost estimate contained in the 2022 ARO Study, as shown in Table 3 below:

Table 3: BRU Asset Retirement Obligation Cost Estimates
Comparison of 2025 and 2022 Updates

Description	2025 Study	2022 Study	Difference
Surface	$56,304,000	$52,395,000	$3,909,000
Subsurface	$72,640,128	$41,156,585	$31,483,543
Total	$128,944,128	$93,551,585	$35,392,543

To address concerns raised by the Commission,[3] Chugach included the costs to remove gravel pads, roads, airstrip, piping, cable, and other buried items including concrete foundations and slabs. Because Chugach did not exclude these items from its ARO, it was not necessary to perform a probability weighted sensitivity study analysis of actual BRU DR&R including these costs.[4]

The cost estimates in the 2025 ARO Study are based on the study period labor and equipment costs needed to complete the planned remediation project work. The study evaluates the costs for surface work and subsurface work. The nominal cost increase between the 2022 ARO Study and the 2025 ARO Study is $35 million, which is comprised of a $3.9 million increase in surface costs and a $31.5 million increase for subsurface costs.

The 2025 ARO Study for surface remediation costs is $3.9 million higher than the 2022 ARO Study. This difference is primarily attributed to additional pad development compared to the 2022 ARO Study, including labor and equipment costs. In the current year update, there are a total of 45 wells that will need to be plugged and abandoned, which results in an increase in the subsurface ARO cost estimate of $31.5 million.

Supporting Exhibits and Attachments

Exhibits 1 and 1.1: Summarize actual costs and gas production levels for calendar year 2024 and actual and projected costs and gas production levels through December 31, 2025, for determination of the updated GTP for Chugach's share of gas from the BRU.

Exhibits 2 through 4: Summarize the cost projections for the ARO, projected and actual ARO fund activity, and the calculation of the ARO surcharge.

Exhibits 5 and 5.1: Summarize the projected capital improvement costs, capital reserve surcharge revenue, funds to be borrowed and repaid to the Future Gas Purchases (FGP) fund, and the BRU Capital Reserve Surcharge calculation.

Exhibits 6 and 6.1: Summarize actual and projected costs for the acquisition price and the deferred costs of the acquisition.

[3] Order 15, page 31 of 47, lines 5 through 13.
[4] *Id.*, lines 19 and 20.

Exhibits 7 through 7.3: Summarize the balances of the ARO fund, BRU Reserve fund (formerly the Deferred Regulatory Liability for Gas Sales account), FGP fund, and BRU Construction Work in Progress.

Exhibit 8: Summarizes and adjusts the reserve estimates utilized in the filing, as well as tracks and allocates underlift activity.

Exhibit 9: Recalculates and tracks underlift settlement volumes and expenses on a quarterly basis.

Attachment A: Invoices paid by Hilcorp Alaska for the reimbursement for underlift expense reimbursement.

Attachment B: Proven and Probable Gas Reserves Estimate – Petrotechnical Resources Alaska

Attachment C: Estimated Future Reserves Attributable to Certain Leasehold Interests in the Beluga River Unit – Ryder Scott Company, L.P.

Attachment D: 2025 Asset Retirement Obligation Study – Beluga River Unit – Petrotechnical Resources Alaska.

Explanation of Tariff Sheet Changes

Tariff Sheet No. 98.1: This tariff sheet reflects the updated transfer price of Chugach's share of natural gas produced from BRU.

Questions regarding this filing should be directed to David Caye, Manager, Regulatory Affairs at 907-762-4842 or david_caye@chugachelectric.com.

Sincerely,

CHUGACH ELECTRIC ASSOCIATION, INC.

Arthur W. Miller

Arthur W. Miller
Chief Executive Officer
P.O. Box 196300
Anchorage, Alaska 99519-6300
Telephone: 907-762-4758
Arthur_miller@chugachelectric.com

Attachments

cc: Kat Sorenson, Seward City Manager, City of Seward (electronically)

TRANSFER PRICE OF CHUGACH ELECTRIC ASSOCIATION, INC.
NATURAL GAS PRODUCED FROM THE BELUGA RIVER UNIT

Effective Date	Total	Field Operations	ARO Surcharge	Capital Reserve Surcharge	
Post Acquisition:					
January 1, 2021	$2.73	$2.63	$0.10	---	
April 1, 2021	$3.39	$3.28	$0.11	---	
October 1, 2021	$3.58	$3.48	$0.10	---	
March 4, 2022	$3.60	$3.48	$0.12	---	
April 1, 2022	$2.90	$2.79	$0.11	---	
May 13, 2022	$3.64	$2.79	$0.11	$0.74	
October 1, 2022	$4.50	$2.57	$0.52	$1.41	
April 1, 2023	$4.81	$2.35	$0.54	$1.92	
October 1, 2023	$5.49	$2.62	$0.57	$2.30	
April 1, 2024	$6.45	$3.43	$0.53	$2.49	
October 1, 2024	$6.42	$3.40	$0.53	$2.49	
April 1, 2025	$6.65	$3.72	$0.47	$2.46	
October 1, 2025	$7.25	$3.89	$0.68	$2.68	N

Exhibit 1

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 1: Transfer Price of Chugach Produced Natural Gas - Actual Activity
Calendar Year: 2024

1	Description	Account Number	Actual
2			
3	Field Operating Expenses		
4	Operation, Supervision and Engineering	Accts. 75900 - 76400	$3,309,607
5	Operation, Compression Plant	Accts. 75900 - 76400	$0
6	Maintenance, Supervision and Engineering	Accts. 75900 - 76400	$3,217
7	Maintenance, Compression Plant	Accts. 75900 - 76400	$0
8	Other Production Expense	Accts. 75900 - 76400	$9,928,822
9	Subtotal		$13,241,646
10			
11	Field Production Expenses		
12	Royalties (Gas Well)	Account 75810	$7,727,941
13	Taxes Other than Production	Account 94081	$0
14	Production / Severance Taxes	Account 94091	$2,288
15	Subtotal		$7,730,229
16			
17	Administrative and General Expense		
18	Salaries	Accts. 92000 - 92800	$701,103
19	Outside Services	Accts. 92000 - 92800	$87,951
20	Insurance	Accts. 92000 - 92800	$145,788
21	Misc. General Expense	Accts. 92000 - 92800	$0
22	Subtotal		$934,843
23			
24	Depreciation and Amortization Expense		
25	Field Depreciation Expense	Account 94300	$5,608,282
26	Amortization of Acquisition cost	Account 94060	$114,584
27	Subtotal		$5,722,866
28			
29	Interest Expense and Margin		
30	Interest on Long-Term Debt	Account 42700	$434,832
31	Interest Expense - Other	Account 42810	$12,576
32	Margin		$243,571
33	Subtotal		$690,979
34			
35	Other Revenues		
36	Gas Royalty Payments Received	Account 49500	($139,758)
37	Subtotal		($139,758)
38			
39	Total Amount to be Collected		$28,180,804
40			
41	Cost of Gas Balancing Account as of December 31, 2023		$7,477,269
42			
43	Adjusted Amount to be Collected		$35,658,073
44			
45	Chugach Gas from BRU (Mcf)	Actual (Mcf)	8,790,881
46			
47	Gas Transfer Price, before ARO and Capital Reserve Surcharges ($/Mcf)	L. 43 / L. 45	$4.06
48	ARO Surcharge	Exhibit 4	$0.47
49	Capital Reserve Surcharge	Exhibit 5	$2.46
50	Gas Transfer Price ($/Mcf)		$6.99

Exhibit 1.1

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 1.1: Transfer Price of Chugach Produced Natural Gas - Projected Activity
Calendar Year: 2025

1	Description	Account Number	Actual/Projected
2			
3	Field Operating Expenses		
4	Operation, Supervision and Engineering	Accts. 75900 - 76400	$3,099,734
5	Operation, Compression Plant	Accts. 75900 - 76400	$0
6	Maintenance, Supervision and Engineering	Accts. 75900 - 76400	$356
7	Maintenance, Compression Plant	Accts. 75900 - 76400	$0
8	Other Production Expense	Accts. 75900 - 76400	$9,299,202
9	Subtotal		$12,399,292
10			
11	Field Production Expenses		
12	Royalties (Gas Well)	Account 75810	$5,904,668
13	Taxes Other than Production	Account 94081	$0
14	Production / Severance Taxes	Account 94091	$1,718
15	Subtotal		$5,906,386
16			
17	Administrative and General Expense		
18	Salaries	Accts. 92000 - 92800	$580,404
19	Outside Services	Accts. 92000 - 92800	$1,096,687
20	Insurance	Accts. 92000 - 92800	$234,938
21	Misc. General Expense	Accts. 92000 - 92800	$0
22	Subtotal		$1,912,029
23			
24	Depreciation and Amortization Expense		
25	Field Depreciation Expense	Account 94300	$3,319,527
26	Amortization of Acquisition cost	Account 94060	$89,384
27	Subtotal		$3,408,911
28			
29	Interest Expense and Margin		
30	Interest on Long-Term Debt	Account 42700	$327,699
31	Interest Expense - Other	Account 42810	$12,576
32	Margin		$408,330
33	Subtotal		$748,605
34			
35	Other Revenues		
36	Gas Royalty Payments Received		($105,368)
37	Subtotal		($105,368)
38			
39	Total Amount to be Collected		$24,269,854
40			
41	Original - Cost of Gas Balancing Account as of December 31, 2024		$7,634,769
42	Adjustmet from Stipulation[1]		($1,797,559)
43	Adjusted Balancing Account as of December 31, 2024		$5,837,210
44			
45	Adjusted Amount to be Collected		$30,107,064
46			
47	Chugach Gas from BRU (Mcf)	Projected (Mcf)	7,730,437
48			
49	Gas Transfer Price, before ARO and Capital Reserve Surcharges ($/Mcf)	L. 45 / L. 47	$3.89
50	ARO Surcharge	Exhibit 4	$0.68
51	Capital Reserve Surcharge	Exhibit 5	$2.68
52	Gas Transfer Price ($/Mcf)		$7.25

[1] Adjustment from Stipulation on Docket No. U-24-009

Exhibit 2

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 2: Asset Retirement Obligation Summary

Description	BRU Interest
Chugach BRU Field Abandonment Cost in 2034 (Nominal $) [1]	$104,788,115.0200
Chugach's Gas Field Abandonment Cost in 2025 (year-end $)	$85,962,752
Estimated Future Inflation [2]	2.00%
End of BRU Economic Life [3]	2035
Remaining Life of ARO [4]	10
Total Life of ARO (2016 - 2035)	20

[1] Equals total Chugach cost of field abandonment (Exhibit 3).

[2] The Anchorage CPI-U is located at https://live.laborstats.alaska.gov/cpi/index.cfm. The inflation factor is based on the 15-year rolling average Anchorage CPI-U and is updated every 3 years. The next update will be in 2028.

[3] End of BRU life estimate is based on 2025 Reserve Study by prepared Ryder Scott LP.

[4] Remaining Life of ARO equals the number of years from 2025 through 2035.

Exhibit 3

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 3: Cost of Field Abandonment [1]

Year	Anchorage CPI-U (15 Year Average) [2]	Cost of BRU Field Abandonment[3]	
		Total Field	Chugach Portion
2025	2.00%	$128,944,128	$85,962,752
2026	2.00%	$131,523,011	$87,682,007
2027	2.00%	$134,153,471	$89,435,647
2028	2.00%	$136,836,540	$91,224,360
2029	2.00%	$139,573,271	$93,048,847
2030	2.00%	$142,364,736	$94,909,824
2031	2.00%	$145,212,031	$96,808,021
2032	2.00%	$148,116,272	$98,744,181
2033	2.00%	$151,078,597	$100,719,065
2034	2.00%	$154,100,169	$102,733,446
2035	2.00%	$157,182,173	$104,788,115

[1] Methodology was submitted to the Commission on January 27, 2014 and adjudicated under U-14-009.
[2] Inflation factor is based on 15-year average of the Anchorage Consumer Price Index (CPI-U).
Source: https://www.bls.gov/regions/west/data/cpi_tables.pdf
[3] The cost of field abandonment is based on the 2025 Asset Retirement Obligation (ARO) study prepared by CONAM Construction Company, Estimate for Beluga River Unit Gas Field Cost of Abandonment of Surface/Subsurface Assets Revision No. 2 June 30, 2025.

Present Value			
TOTAL FIELD ARO	2025	2022	Difference
Surface	$56,304,000	$52,395,000	$3,909,000
Subsurface	$72,640,128	$41,156,585	$31,483,543
Total	$128,944,128	$93,551,585	$35,392,543
CHUGACH WIO	2025	2022	Difference
Surface	$37,536,000	$34,931,747	$2,604,254
Subsurface	$48,426,752	$27,439,095	$20,987,657
Total	$85,962,752	$62,370,842	$23,591,910

Future Value Chugach Share			
CHUGACH WIO	2025 Study	2022 Study	Difference
Future Value	$104,788,115	$79,101,308	$25,686,807

Exhibit 4

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 4: ARO Surcharge and Projected Fund Balance through December 31, 2034

[A] End of Period	[B] ARO Future Value [1]	[C] ARO Fund Balance (BOP)	[D] Remaining ARO Requirement (BOP)	Earnings	Goal Seek Denominator	Reserve Estimate Total BRU (Mcf)	[E] ARO Surcharge ($/Mcf)	[F] Annual BRU Production (Mcf) [2]	[G] ARO Surcharge Revenue	[H] Projected ARO Fund Interest Earned [3]	[K] ARO Fund Balance (EOP)	[L] ARO Fund Requirement (EOP)
	[2035 Value]	[K] Prior Period	[B] - [C]				[G23]/[F23]	[Ryder Scott Est.]	[E]x[F]	[C]x[CPI-U+200 BP]	[C]+[G]+[H]	[B]-[K]
12/31/2025	$104,788,115	$35,752,657	$69,035,458	$ 30,785,548	$38,249,910	56,440,582	$0.68	7,730,437	$5,238,934	$1,430,106	$42,421,697	$62,366,418
12/31/2026	$104,788,115	$42,421,697	$62,366,418				$0.68	8,393,891	$5,688,559	$1,696,868	$49,807,124	$54,980,991
12/31/2027	$104,788,115	$49,807,124	$54,980,991				$0.68	7,372,857	$4,996,602	$1,992,285	$56,796,011	$47,992,104
12/31/2028	$104,788,115	$56,796,011	$47,992,104				$0.68	7,146,554	$4,843,236	$2,271,840	$63,911,087	$40,877,028
12/31/2029	$104,788,115	$63,911,087	$40,877,028				$0.68	6,480,576	$4,391,901	$2,556,443	$70,859,432	$33,928,683
12/31/2030	$104,788,115	$70,859,432	$33,928,683				$0.68	6,199,627	$4,201,501	$2,834,377	$77,895,310	$26,892,805
12/31/2031	$104,788,115	$77,895,310	$26,892,805				$0.68	6,001,678	$4,067,351	$3,115,812	$85,078,473	$19,709,642
12/31/2032	$104,788,115	$85,078,473	$19,709,642				$0.68	3,322,644	$2,251,763	$3,403,139	$90,733,375	$14,054,740
12/31/2033	$104,788,115	$90,733,375	$14,054,740				$0.68	2,122,105	$1,438,155	$3,629,335	$95,800,865	$8,987,250
12/31/2024	$104,788,115	$95,800,865	$8,987,250				$0.68	1,401,452	$949,767	$3,832,035	$100,582,667	$4,205,448
12/31/2035	$104,788,115	$100,582,667	$4,205,448				$0.68	268,763	$182,141	$4,023,307	$104,788,115	$0
Totals								56,440,582	38,249,910	30,785,548		
								-				
								Check				

[1] See Exhibit 2 for the calculation of the future value asset retirement obligation.

[2] The BRU production projections are based on the 2025 Reserve Study prepared by Ryder Scott. Future year production volumes are adjusted by the difference between prior period projected and actual production.

[3] The 2025-2035 projected interest earned assumes the targeted minimum return set in the ARO Investment Fund Guidelines (Section 3.E), which is CPI-U + 200 basis points.

Exhibit 5

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 5: BRU Capital Reserve Surcharge and Projected Fund Balance through December 31, 2034

Year	Capital Reserve Balance (BOP)	Projected Capital Expenditure [1]	Proj. CapEx and Loan Balance	Remaining Reserve	Surcharge ($/Mcf)	Deliveries off Field (Mcf) [2]	Surcharge Revenue	Balance of Borrowed Funds				Capital Reserve Balance (EOP)	
								BOP	Loan Amount	Repayment	EOP		
2024	($32,665,285)	$0			$2.43	8,790,881	$21,404,221	($32,665,285)	($1,584,354)	$0	($34,249,639)	($34,249,639)	Actual
2025	($34,249,639)	$24,889,115	$151,175,267	56,440,582	$2.68	7,730,437	$20,705,861	($34,249,639)	($4,183,254)	$0	($38,432,893)	($38,432,893)	
2026	($38,432,893)	$22,328,065			$2.68	8,393,891	$22,482,914	($38,432,893)	$0	$154,849	($38,278,044)	($38,278,044)	
2027	($38,278,044)	$22,362,627			$2.68	7,372,857	$19,748,088	($38,278,044)	$0	($2,614,539)	($40,892,583)	($40,892,583)	
2028	($40,892,583)	$25,086,405			$2.68	7,146,554	$19,141,939	($40,892,583)	$0	($5,944,466)	($46,837,049)	($46,837,049)	
2029	($46,837,049)	$16,882,363			$2.68	6,480,576	$17,358,127	($46,837,049)	$0	$475,764	($46,361,285)	($46,361,285)	
2030	($46,361,285)	$2,688,526			$2.68	6,199,627	$16,605,609	($46,361,285)	$0	$13,917,083	($32,444,202)	($32,444,202)	
2031	($32,444,202)	$2,688,526			$2.68	6,001,678	$16,075,405	($32,444,202)	$0	$13,386,879	($19,057,324)	($19,057,324)	
2032	($19,057,324)	$0			$2.68	3,322,644	$8,899,652	($19,057,324)	$0	$8,899,652	($10,157,672)	($10,157,672)	
2033	($10,157,672)	$0			$2.68	2,122,105	$5,684,026	($10,157,672)	$0	$5,684,026	($4,473,646)	($4,473,646)	
2034	($4,473,646)	$0			$2.68	1,401,452	$3,753,769	($4,473,646)	$0	$3,753,769	($719,877)	($719,877)	
2035	($719,877)	$0			$2.68	268,763	$719,877	($719,877)	$0	$719,876	($1)	($1)	
Totals		$116,925,628				56,440,582	$151,175,267		($4,183,254)	$38,432,892			

[1] Projected capital expenditures are adjusted for projected inflation

[2] The BRU production projections are based on the 2025 Reserve Study prepared by Ryder Scott. Future year production volumes are adjusted by the difference between prior period projected and actual production.

Exhibit 5.1

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 5.1: BRU Capital Forecast Adjustment to Allocate the Difference between 2023 Forecast and Actual Costs

Year	Capital Expenditure					Allocation of Difference	Adjusted CapEx Projections
	Forecast	Actual	Difference	Underlift[1]	Underlift Allocation		
12/31/2024				$4,007,388			
2025	$31,635,832			$6,746,717	($6,746,717)	($6,746,717)	$24,889,115
2026	$22,328,065					$0	$22,328,065
2027	$22,362,627					$0	$22,362,627
2028	$22,397,879				$2,688,526	$2,688,526	$25,086,405
2029	$14,193,837				$2,688,526	$2,688,526	$16,882,363
2030	$0				$2,688,526	$2,688,526	$2,688,526
2031	$0				$2,688,526	$2,688,526	$2,688,526
2032	$0					$0	$0
2033	$0					$0	$0
2034	$0					$0	$0
2035	$0					$0	$0
Totals	$112,918,240		$0	$10,754,105	$4,007,388	$4,007,388	$116,925,628

[1]Underlift Expense Paid by Hilcorp, Alaska

Exhibit 6

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 6: Beluga River Unit Projected Amortization and Depreciation Costs

	BOP	Annual		EOP	Depreciation	Acquisition Price		Deferred Cost of Acquisition		
Year	Reserves (Mcf) [1]	Production (Mcf)	Underlift Premium	Reserves (Mcf)	Rate [2]	Deprec. Expense	EOP	Amort. Expense	EOP	
2024	52,290,793	8,790,881		43,499,912	16.81%	$4,300,491	$24,236,150	$114,584	$652,599	Actual
2025	56,440,582	7,730,437		48,710,145	13.70%	$3,319,527	$20,916,623	$89,384	$563,215	Projected
2026	48,710,145	8,393,891		40,316,254	17.23%	$3,604,421	$17,312,202	$97,055	$466,160	
2027	40,316,254	7,372,857		32,943,397	18.29%	$3,165,978	$14,146,224	$85,249	$380,911	
2028	32,943,397	7,146,554		25,796,844	21.69%	$3,068,802	$11,077,422	$82,633	$298,278	
2029	25,796,844	6,480,576		19,316,268	25.12%	$2,782,824	$8,294,598	$74,932	$223,346	
2030	19,316,268	6,199,627		13,116,641	32.10%	$2,662,182	$5,632,416	$71,684	$151,662	
2031	13,116,641	6,001,678		7,114,963	45.76%	$2,577,180	$3,055,236	$69,395	$82,267	
2032	7,114,963	3,322,644		3,792,320	46.70%	$1,426,776	$1,628,460	$38,418	$43,849	
2033	3,792,320	2,122,105		1,670,215	55.96%	$911,253	$717,207	$24,537	$19,312	
2034	1,670,215	1,401,452		268,763	83.91%	$601,798	$115,409	$16,205	$3,107	
2035	268,763	268,763		0	100.00%	$115,409	($0)	$3,107	$0	
Totals		56,440,582				$24,236,150		$652,599		

[1] The reserves in years 2025 through 2035 incorporate the remaining reserves based on the results of 2025 Ryder Scott Gas Reserve study

[2] Depreciation rate calculated on units of production basis: Book value at end of year divided by estimated beginning of year reserves, multiplied by annual production unit

Exhibit 6.1

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 6.1: 2024 Actual Depreciation and Amortization Expense

Year	BOP Reserves (Mcf) [1]	Monthly Production (Mcf) [2]	EOP Reserves (Mcf)	Depreciation Rate [3]	Acquisition Price			Deferred Cost of Acquisition		
					Balance (BOP)	Deprec. Exp.	Accum. Deprec. Exp.	Balance (BOP)	Amort. Exp.	Accum. Amort. Exp.
Dec-22	61,579,306	$789,600	60,789,706	1.46%	$31,333,239	$554,080	$14,664,321	$986,098	$10,569	$430,590
Jan-23	60,789,706	747,204	60,042,502	1.23%	$30,779,160	$513,659	$15,177,980	$975,529	$10,459	$441,049
Feb-23	60,042,502	733,563	59,308,939	1.22%	$30,265,501	$436,524	$15,614,504	$965,070	$8,997	$450,045
Mar-23	59,308,939	735,528	58,573,411	1.24%	$29,828,976	$333,535	$15,948,039	$956,074	$6,496	$456,541
Apr-23	58,573,411	675,567	57,897,844	1.15%	$29,495,441	$345,931	$16,293,971	$949,578	$7,067	$463,608
May-23	57,897,844	637,032	57,260,812	1.10%	$29,149,510	$375,363	$16,669,334	$942,511	$7,669	$471,276
Jun-23	57,260,812	589,203	56,671,609	1.03%	$28,774,147	$386,355	$17,055,689	$934,842	$7,893	$479,170
Jul-23	56,671,609	656,649	56,014,960	1.16%	$28,387,791	$409,673	$17,465,362	$926,949	$8,374	$487,544
Aug-23	56,014,960	676,870	55,338,090	1.21%	$27,978,119	$442,103	$17,907,465	$918,575	$9,033	$496,576
Sep-23	55,338,090	742,404	54,595,686	1.34%	$27,536,015	$483,818	$18,391,283	$909,543	$9,885	$506,461
Oct-23	54,595,686	798,004	53,797,682	1.46%	$27,052,197	$509,428	$18,900,711	$899,658	$10,408	$516,870
Nov-23	53,797,682	772,871	53,024,812	1.44%	$26,542,769	$491,039	$19,391,750	$889,249	$10,033	$526,902
Dec-23	53,024,812	846,738	52,178,074	1.60%	$26,051,730	$543,909	$19,935,659	$879,216	$11,113	$538,016
2022 Alloc	416,386									
Jan-24	52,594,460	849,267	51,745,193	1.61%	$25,507,821	$415,173	$20,350,832	$868,103	$10,895	$548,911
Feb-24	51,745,193	773,333	50,971,860	1.49%	$25,092,648	$378,102	$20,728,934	$857,208	$9,914	$558,824
Mar-24	50,971,860	930,414	50,041,446	1.83%	$24,714,546	$454,959	$21,183,893	$847,294	$13,874	$572,699
Apr-24	50,041,446	875,733	49,165,713	1.75%	$24,259,588	$428,285	$21,612,178	$833,420	$9,418	$582,116
May-24	49,165,713	899,800	48,265,913	1.83%	$23,831,302	$440,119	$22,052,298	$824,002	$11,664	$593,780
Jun-24	48,265,913	776,034	47,489,879	1.61%	$23,391,183	$379,638	$22,431,936	$812,339	$10,091	$603,871
Jul-24	47,489,879	788,050	46,701,829	1.66%	$23,011,545	$385,565	$22,817,501	$802,247	$11,122	$614,994
Aug-24	46,701,829	652,100	46,049,729	1.40%	$22,625,980	$319,089	$23,136,589	$791,125	$7,938	$622,932
Sep-24	46,049,729	465,400	45,584,329	1.01%	$22,306,891	$227,756	$23,364,345	$783,187	$6,121	$629,053
Oct-24	45,584,329	540,350	45,043,979	1.19%	$22,079,135	$264,465	$23,628,811	$777,066	$7,211	$636,263
Nov-24	45,043,979	650,000	44,393,979	1.44%	$21,814,670	$318,203	$23,947,014	$769,855	$8,631	$644,895
Dec-24	44,393,979	590,400	43,803,579	1.33%	$21,496,467	$289,136	$24,236,150	$761,224	$7,704	$652,599
Totals		8,790,881				$4,300,491			$114,584	

[1] BRU gas reserves based on 2022 Ryder-Scott Gas Reserve Study.

[2] Actual 2023 & 2024 production BRU production (Mcf).

[3] Depreciation rate calculated on units of production basis.

Exhibit 7

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 7: ARO Fund Balance
Account: 1285014300-2101

	ARO Fund		Investment Account Performance		ARO Fund [1]		
Date	Balance - BOP	ARO Deposits	Gain / Loss	Management Fees	Balance - EOP	Net Gain / Loss	Return
12/31/2014	----	$7,414,550	$39,956	$0	$7,454,506	$39,956	0.3%
12/31/2015	$7,454,506	$2,326,850	$47,035	$0	$9,828,391	$47,035	0.5%
12/31/2016	$9,828,391	$1,818,800	$150,254	$0	$11,797,445	$150,254	1.4%
12/31/2017	$11,797,445	$1,407,595	$316,723	$0	$13,521,763	$316,723	2.5%
12/31/2018	$13,521,763	$1,263,364	($214,510)	($52,980)	$14,517,637	($267,489)	(1.9%)
12/31/2019	$14,517,637	$948,022	$1,793,806	($55,875)	$17,203,590	$1,737,931	11.6%
12/31/2020	$17,203,590	$1,019,123	$957,068	($57,272)	$19,122,510	$899,796	5.1%
12/31/2021	$19,122,510	$565,213	$1,783,730	($30,287)	$21,441,165	$1,753,442	9.0%
12/31/2022	$21,441,165	$1,713,475	($2,980,254)	($59,516)	$20,114,870	($3,039,770)	(13.6%)
12/31/2023	$20,114,870	$4,678,484	$2,723,842	($59,967)	$27,457,229	$2,663,875	11.9%
12/31/2024	$27,457,229	$5,566,005	$2,808,689	($79,266)	$35,752,657	$2,729,423	9.0%
Totals		$28,721,480	$7,426,339	($395,163)		$7,031,176	

[1] Return is computed on the basis of the Net Gain / Loss divided by the sum of the Balance - BOP plus ARO Deposits multiplied by 50%.

Exhibit 7.1

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 7.1: BRU Reserve Fund (Formerly DRLGS)
Account: 1285015400-2101

BRU Capital Reserve Revenue, Expenditures, and Loan Balances - Monthly Actual Activity											
		Capital Reserve Surcharge Revenue and Capital Expenditures			Loans from Future Gas Purchases Account (FGP)			Loans from General Fund (GF)			
Date	BRU Reserve Fund Balance (BOP)	Deposits (Surcharge Revenue)	Withdrawals[1] (Capital Expenditures)	Net Amount	Loan Amount	Repayment Amount	Outstanding Loan Balance	Loan Amount	Repayment Amount	Outstanding Loan Balance	BRU Reserve Fund Balance (EOP)
Jan-24	($32,665,285)	$1,953,313	$553,063	$1,400,250	$0	$0	($19,560,207)	$0	$1,400,250	($11,704,827)	($31,265,035)
Feb-24	($31,265,035)	$1,778,667	$463,208	$1,315,459	$0	$0	($19,560,207)	$0	$1,315,459	($10,389,368)	($29,949,575)
Mar-24	($29,949,575)	$2,139,952	$976,848	$1,163,104	$0	$0	($19,560,207)	$0	$1,163,104	($9,226,264)	($28,786,471)
Apr-24	($28,786,471)	$2,180,575	$731,208	$1,449,367	$0	$0	($19,560,207)	$0	$1,449,367	($7,776,897)	($27,337,104)
May-24	($27,337,104)	$2,240,502	$1,104,484	$1,136,018	$0	$0	($19,560,207)	$0	$1,136,018	($6,640,878)	($26,201,086)
Jun-24	($26,201,086)	$1,932,325	$3,507,138	($1,574,814)	$0	$0	($19,560,207)	($1,574,814)	$0	($8,215,692)	($27,775,899)
Jul-24	($27,775,899)	$1,962,245	$7,423,632	($5,461,388)	$0	$0	($19,560,207)	($5,461,388)	$0	($13,677,080)	($33,237,287)
Aug-24	($33,237,287)	$1,623,729	$4,316,105	($2,692,376)	$0	$0	($19,560,207)	($2,692,376)	$0	($16,369,456)	($35,929,663)
Sep-24	($35,929,663)	$1,158,846	$3,666,114	($2,507,268)	$0	$0	($19,560,207)	($2,507,268)	$0	($18,876,724)	($38,436,931)
Oct-24	($38,436,931)	$1,345,472	$2,921,307	($1,575,835)	$0	$0	($19,560,207)	($1,575,835)	$0	($20,452,559)	($40,012,766)
Nov-24	($40,012,766)	$1,618,500	$1,001,776	$616,724	$0	$0	($19,560,207)	$0	$616,724	($19,835,835)	($39,396,042)
Dec-24	($39,396,042)	$1,470,096	($3,676,307)	$5,146,403	$0	$0	($19,560,207)	$0	$5,146,403	($14,689,432)	($34,249,639)
Totals		$21,404,221	$22,988,575	($1,584,354)	$0	$0		($13,811,681)	$12,227,327		
Jan-25	($34,249,639)	$1,823,303	$1,004,831	$818,472	$0	$0	($19,560,207)	$0	$818,472	($13,870,960)	($33,431,167)
Feb-25	($33,431,167)	$1,569,945	$971,609	$598,336	$0	$0	($19,560,207)	$0	$598,336	($13,272,624)	($32,832,831)
Mar-25	($32,832,831)	$1,105,560	-$40,307	$1,145,867	$0	$0	($19,560,207)	$0	$1,145,867	($12,126,757)	($31,686,965)
Apr-25	($31,686,965)	$1,237,281	$1,456,217	($218,936)	$0	$0	($19,560,207)	($218,936)	$0	($12,345,693)	($31,905,901)
May-25	($31,905,901)	$1,182,252	$5,053,276	($3,871,024)	$0	$0	($19,560,207)	($3,871,024)	$0	($16,216,717)	($35,776,924)
Jun-25	($35,776,924)	$743,489	-$1,135,384	$1,878,873	$0	$0	($19,560,207)	$0	$1,878,873	($14,337,844)	($33,898,051)
Jul-25											
Aug-25											
Sep-25											
Oct-25								;			
Nov-25											
Dec-25											
Totals		$7,661,830	$7,310,242	$351,588	$0	$0		($4,089,960)	$4,441,547		

BRU Capital Reserve Revenue, Expenditures, and Loan Balances - Annual Actual and Projected											
					FGP		Other: General Fund				
Year	BRU-CRS Fund Balance (BOP)	Surcharge Revenue	Capital Expenditure	Annual Difference	Loan	Repayment	Loan	Repayment		Outstanding Loan Balance	BRU-CRS Fund Balance (EOP)
2023	($19,413,700)	$16,322,716	$29,574,301	($13,251,585)	($19,560,207)	$0	($13,105,078)	$0		($32,665,285)	($32,665,285)
2024	($32,665,285)	$21,404,221	$22,988,575	($1,584,354)	$0	$0	($1,584,354)	$0		($34,249,639)	($34,249,639)
2025	($34,249,639)	$20,705,861	$24,889,115	($4,183,254)	$0	$0	($4,183,254)	$0		($38,432,893)	($38,432,893)
2026	($38,432,893)	$22,482,914	$22,328,065	$154,849	$0	$0		$154,849		($38,278,044)	($38,278,044)
2027	($38,278,044)	$19,748,088	$22,362,627	($2,614,539)	$0	$0		($2,614,539)		($40,892,583)	($40,892,583)
2028	($40,892,583)	$19,141,939	$25,086,405	($5,944,466)	$0	$0		($5,944,466)		($46,837,049)	($46,837,049)
2029	($46,837,049)	$17,358,127	$16,882,363	$475,764	$0	($399,859)		$875,623		($46,361,285)	($46,361,285)
2030	($46,361,285)	$16,605,609	$2,688,526	$13,917,083	$0	$13,917,083		$0		($32,444,202)	($32,444,202)
2031	($32,444,202)	$16,075,405	$2,688,526	$13,386,879	$0	$13,386,879		$0		($19,057,324)	($19,057,324)
2032	($19,057,324)	$8,899,652	$0	$8,899,652	$0	$8,899,652		$0		($10,157,672)	($10,157,672)
2033	($10,157,672)	$5,684,026	$0	$5,684,026	$0	$5,684,026		$0		($4,473,646)	($4,473,646)
2034	($4,473,646)	$3,753,769	$0	$3,753,769	$0	$3,753,769		$0		($719,877)	($719,877)
2035	($719,877)	$719,876	$0	$719,876	$0	$719,876		$0		($1)	($1)
Totals		$151,175,266	$116,925,628	$34,249,638	($19,560,207)	$45,961,426	($18,872,686)	($7,528,533)			
		($0)				$26,401,219.0		($26,401,219)			

[1] Capital expense reimbursement from Hilcorp reflected in quarterly adjustments to Capital Expenditure Withdrawals

Exhibit 7.2

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 7.2: Future Gas Purchases Fund (FGP); Order No. U-06-089(2)
Account: 1285015300-2101

				Loan Transactions with BRU Reserve Fund			
Date	FGP Balance (BOP)	Deposits [1, 2]	Interest	Loan to Reserve Fund	Loan Repayment from Reserve Fund	Outstanding Reserve Loan Balance	FGP Balance (EOP)
Jan-23	$146,508	$0	$0	$0	$656,456	($18,757,244)	$802,963
Feb-23	$802,963	$0	$0	$0	$843,191	($17,914,053)	$1,646,154
Mar-23	$1,646,154	$0	$0	$0	$395,293	($17,518,760)	$2,041,447
Apr-23	$2,041,447	$0	$0	$0	$885,252	($16,633,508)	$2,926,699
May-23	$2,926,699	$0	$0	$0	$61,550	($16,571,958)	$2,988,249
Jun-23	$2,988,249	$0	$0	($1,205,680)	$0	($17,777,638)	$1,782,569
Jul-23	$1,782,569	$0	$0	($1,782,569)	$0	($19,560,207)	$0
Aug-23	$0	$0	$0	$0	$0	($19,560,207)	$0
Sep-23	$0	$0	$0	$0	$0	($19,560,207)	$0
Oct-23	$0	$0	$0	$0	$0	($19,560,207)	$0
Nov-23	$0	$0	$0	$0	$0	($19,560,207)	$0
Dec-23	$0	$0	$0	$0	$0	($19,560,207)	$0
Subtotal		$0	$0	($2,988,249)	$2,841,741		
Jan-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Feb-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Mar-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Apr-24	$0	$0	$0	$0	$0	($19,560,207)	$0
May-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Jun-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Jul-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Aug-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Sep-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Oct-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Nov-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Dec-24	$0	$0	$0	$0	$0	($19,560,207)	$0
Subtotal		$0	$0	$0	$0		

[1] Funds in the Future Gas Purchases account are deposited in a money market mutual fund.

[2] In December 2021, the intracompany loan was paid in full, including principal and accrued interest.

Exhibit 7.3

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 7.3: Construction Work in Progress as of December 31, 2024
Account: 1077000000-2102

Project No.	Description	Total
P2220134	AFE 222-00134 BRU Rate Add Pr	$0
P2220344	AFE 222-00344	$0
P2220411	AFE 222-00411	$0
P2220413	AFE 222-00413-BRU 212-24T DECO	$0
Total		$0

Exhibit 8

Chugach Electric Association, Inc.
Anchorage, Alaska

Exhibit 8: 2025 Study Reserves Adjustment

Ryder Scott BRU Gas Reserve Study Based on December 31, 2024 - BRU Adjusted Reserve Projections

Year	Ryder Scott Projections	Chugach WIO	Difference	Underlift	Less 20% Premium Underlift Returned	Deliveries Off Field	Allocation of Difference	Adjusted Proj.	Actual / Proj.	**Exhibit 5**
2024				1,518,333					Actual	-
Jun-25	4,425,270	5,086,074	(660,804)	2,009,034		3,077,040		3,077,040	Actual	**3,077,040**
2025	4,653,397							4,653,397	Proj.	**4,653,397**
2025	9,078,667			2,009,034			(2,009,034)	7,730,437	Actual/Proj.	**7,730,437**
2026	8,495,000						(101,109)	8,393,891	Proj.	**8,393,891**
2027	7,461,667						(88,810)	7,372,857	Proj.	**7,372,857**
2028	6,518,667				705,473		627,887	7,146,554	Proj.	**7,146,554**
2029	5,844,667				705,473		635,909	6,480,576	Proj.	**6,480,576**
2030	5,560,333				705,473		639,293	6,199,627	Proj.	**6,199,627**
2031	5,360,000				705,473		641,678	6,001,678	Proj.	**6,001,678**
2032	3,362,667						(40,023)	3,322,644	Proj.	**3,322,644**
2033	2,147,667						(25,562)	2,122,105	Proj.	**2,122,105**
2034	1,418,333						(16,881)	1,401,452	Proj.	**1,401,452**
2035	272,000						(3,237)	268,763	Proj.	**268,763**
Total	55,519,667		(660,804)	3,527,367	2,821,893		260,112	56,440,582		56,440,582
					705,473	Premium on underlift				
	Adjusted Total on Exhibits 4-6:				3,527,367		2025-5	Remaining Reserve		**56,440,582**

Exhibit 9

Chugach Electric Association, Inc
Anchorage, Alaska

Exhibit 9: Underlift Settlement

	Production Data				Joint Interest Billing - Expenses					Operating Expense		Capital Expense		Underlift Settlement
Month	Gross Field Production	NET Production WIO	Deliveries (Includes OBA)	Actual Underlift	Gross O&M Expense	Gross Capital Expenses	GROSS Billed Monthly JIB Amount	NET Billed Monthly JIB Amount	Underlift Share	OPEX	OPEX-Underlift	CAPEX	CAPEX-Underlift	Underlift Settlement
1/1/2025	1,338,175	892,117	732,748	159,368	$1,312,090	$1,639,298	$2,951,388	$1,967,592						
2/1/2025	1,200,251	800,168	631,779	168,388	$2,196,375	$1,577,449	$3,773,824	$2,515,883						
3/1/2025	1,278,773	852,515	443,522	408,993	$1,396,651	$1,476,193	$2,872,845	$1,915,230						
Q1 Settlement	3,817,199	2,544,800	1,808,049	736,749	$4,905,116	$4,692,940	$9,598,056	$6,398,704	19.30%	$4,905,116	$946,725	$4,692,940	$905,774	$1,852,499
4/1/2025	1,244,005	829,337	496,900	331,758	$2,054,814	$2,418,834	$4,473,648	$2,982,432						
5/1/2025	1,292,191	861,461	474,800	386,363	$1,779,811	$7,757,219	$9,537,030	$6,358,020						
6/1/2025	1,280,125	853,417	298,590	554,138	$1,387,856	$7,344,681	$8,732,537	$5,821,691						
Q2 Settlement	3,816,321	2,544,214	1,270,290	1,272,259	$5,222,482	$17,520,734	$22,743,215	$15,162,143	33.34%	$5,222,482	$1,741,035	$17,520,734	$5,840,943	$7,581,979
Total YTD	7,633,520	5,089,014	3,078,339	2,009,008	$10,127,597	$22,213,674	$32,341,271	$21,560,848		$10,127,597	$2,687,761	$22,213,674	$6,746,717	$9,434,477

[1] Invoices reflecting the underlift settlement are included as Attachment A

40%

Attachment A

Chugach Electric Association, Inc.

Anchorage, Alaska 99519-6300
Anchorage, AK 99519-6300

Phone No. (907) 563-7494

CHUGACH
POWERING ALASKA'S FUTURE

Bill To
Hilcorp Alaska, LLC 3800 Centerpoint Dr, Suite 100 Anchorage, AK 99503 Attn: Donna Johnson

Date	Invoice #
4/28/2025	39702

Due Date
5/28/2025

Item	Class	Description	Amount
14300 143 00 2101		Beluga River Gas Inventory Agreement	1,852,501.39

4/28/25

CM
4/28/25

4-28-2025

Total	$1,852,501.39

Attachment A
Page 2 of 3

Copy Accounting

Chugach Electric Association, Inc.

Anchorage, Alaska 99519-6300
Anchorage, AK 99519-6300

Phone No. (907) 563-7494

CHUGACH
POWERING ALASKA'S FUTURE

Bill To
Hilcorp Alaska, LLC 3800 Centerpoint Dr, Suite 100 Anchorage, AK 99503 Attn: Donna Johnson

Date	Invoice #
7/30/2025	39885

Due Date
8/29/2025

Item	Class	Description	Amount
14300 143 00 2101		Beluga River Gas Inventory Agreement - Quarter 2	7,581,981.54

7/29/25

Total	$7,581,981.54

CM
7/29/25

7-30-2025

Attachment A

Copy Accounting

Attachment B

Petrotechnical Resources Alaska

3000 A Street
Suite 410
Anchorage, AK 99503

June 24, 2025

Daniel Herrmann
Manager Natural Gas & Energy Resources
Chugach Electric Association
5601 Electron Dr
Anchorage, AK 99518

RE: Beluga River Unit-- Proven and Probable Gas Reserves Estimate

Dear Mr. Herrmann:
At your request, Petrotechnical Resources Alaska (PRA) has prepared an interim report of estimated proved reserves attributable to certain leasehold interests of Chugach Electric Association (CEA) in the Beluga River Unit (BRU) as of December 31, 2024. The subject properties are located in the state of Alaska. The reserve volumes were estimated based on the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and European Association of Geoscientists and Engineers (EAGE) 2018 Petroleum Resources Management System (SPE-PRMS), which were revised in June 2018 and modified in June 2019 and consolidated in August 2022.

The properties evaluated by PRA represent 100 percent of the total net proved, probable and possible gas reserves of CEA in the Beluga River Unit, operated by Hilcorp Alaska (HAK), as of December 31, 2024. The reserve volumes were estimated based on unescalated price and cost parameters (zero percent discount rate and zero percent inflation) and are presented below in Table 1. The production decline trends of recently drilled wells are steeper than historical trends; this results in a lower forecasted reserve than the prior year; the major factors were decreased spacing, reduced target volumes and pressures and water encroachment. There are currently 15 locations identified which are anticipated to be drilled in the next four years. These locations are considered Proven Undeveloped (PUD) and Probable reserves with one Possible location in 2026 to test a

Sterling seismic anomaly. Beyond 2028, eight more locations of Probable and Possible reserves are scheduled to be exploited.

Reserves (EOFL of 3/2035)	MMSCF
Production history (AOGCC)	1,478,833
Proven Developed Producing Reserve	42,992
Proven Developed Non-Producing Reserve	4,049
Proven Undeveloped, 10 development wells + wellwork	15,671
Gross Proven Reserves (P1)	**62,712**
Proven Fuel Consumption	2,973
Royalty Gas, 12.5%	7,467
Gross Proven Reserves (less Fuel and royalty)	52,272
CEA Net Proven (P1)	**34,848**
Gross Probable (P2)	16,943
Gross Possible Reserves (P3)	8,302
Gross Probable & Possible (P2+P3)	**25,245**
Fuel Consumption	1,705
Royalty gas 12.5%	2,943
Gross Probable and Possible less fuel & royalty	20,598
CEA Net Probable & Possible (P2+P3)	**13,732**
Gross Proven, Probable & Possible (3P)	87,957
CEA Net Proven, Probable & Possible (3P)	**48,580**
CEA Available Gas (Net 3P plus 2/3 of Royalty)	**55,520**

Table 1. Estimated Volumes and Reserves of Beluga River Unit as of December 31, 2024

All gas volumes in Table 1 are expressed in billions of cubic feet (BCF) at the official temperature and pressure of 60°F and 14.65 psia [20 ACC 25.990 (30) and AS 43.82.900 (3)].

Developed producing well forecasts were generated using individual well production performance trends and extrapolated as future production. Individual wells were also evaluated using inflow performance and material balance to confirm the production performance trends.

The wells at BRU were drilled from 1967 to 2024 (Figure 1). The first set of wells were drilled in the late 1960's to supply the power plant, followed by another set of wells in the 1980's when a supply gas pipeline was connected to BRU. The field remained constrained until after 2005 when it began to decline. After the field started to decline, wells were added between 2008 and 2014. Finally, a renewed interest has seen twelve wells drilled since 2020. Between 1990 and 2021, the well count fluctuated between 10 and 21 and averaged 14 wells online, indicating that development drilling was keeping up with well attrition and field decline. The recent drilling campaign that began in 2022 has steadily increased the active well count to 27. The additional wells have mitigated the field decline rate. Increasing the reserve base is becoming more difficult. As the spacing decreases the proportion of finding additional recovery versus existing reserve is smaller.

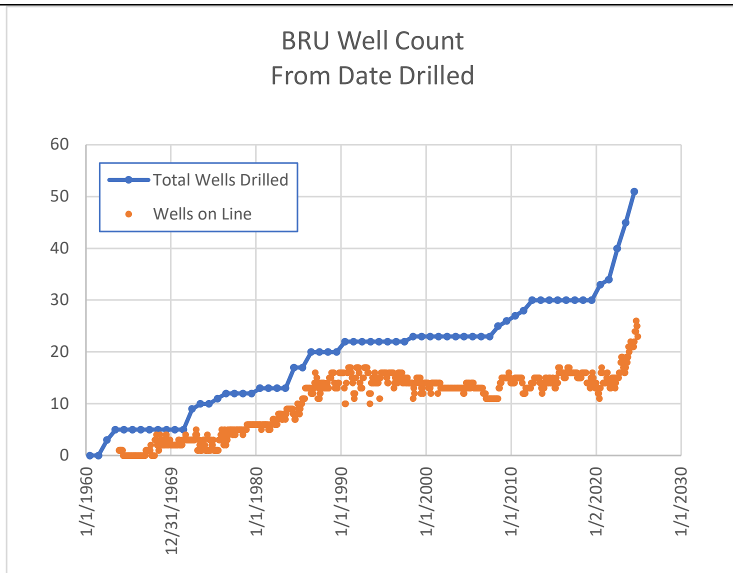


Figure 1. BRU Drilling History and Monthly Active Well Count

Production started in 1968 and was constrained until 2005, when the field went on decline. Historical production is shown in Figure 2. The Year-End 2021 (YE2021) PDP forecast is shown as a field decline prior to initiating recent drilling. YE2022 PDP and YE2023 PDP forecasts demonstrate the benefits of drilling new wells. Decline rates of the newer wells are trending higher than the historical average. YE2024 PDP forecast indicates that production declines of new wells are steeper than originally forecast, but the field benefits from continued drilling. Recent wells that twin older shut-in producers are finding instances of higher pressures in the Beluga zone, indicating additional resource. The individual wells exhibit a classic exponential decline trend and this method is used as the primary forecast tool. This is augmented with a Rawlins and Shellhardt backpressure estimations. Agreement adds confidence to the decline curve analysis; any deviations may indicate potential wellwork opportunities. Individual well history plots with forecast are included in the Appendix. Increased water production became a challenge starting in 2005, increasing production problems and operational difficulties compared to the early history of BRU. These challenges caused production interruptions or premature well failure. Continuous monitoring, well and facility maintenance mitigated these challenges. It is assumed that the operator plans to repair wells that become marginal producers and return them to production as soon as practical. Based on current operating costs, with all wells producing, the end of field life will likely occur at a gross field-level production rate around 6 MMscf/d in 2035.

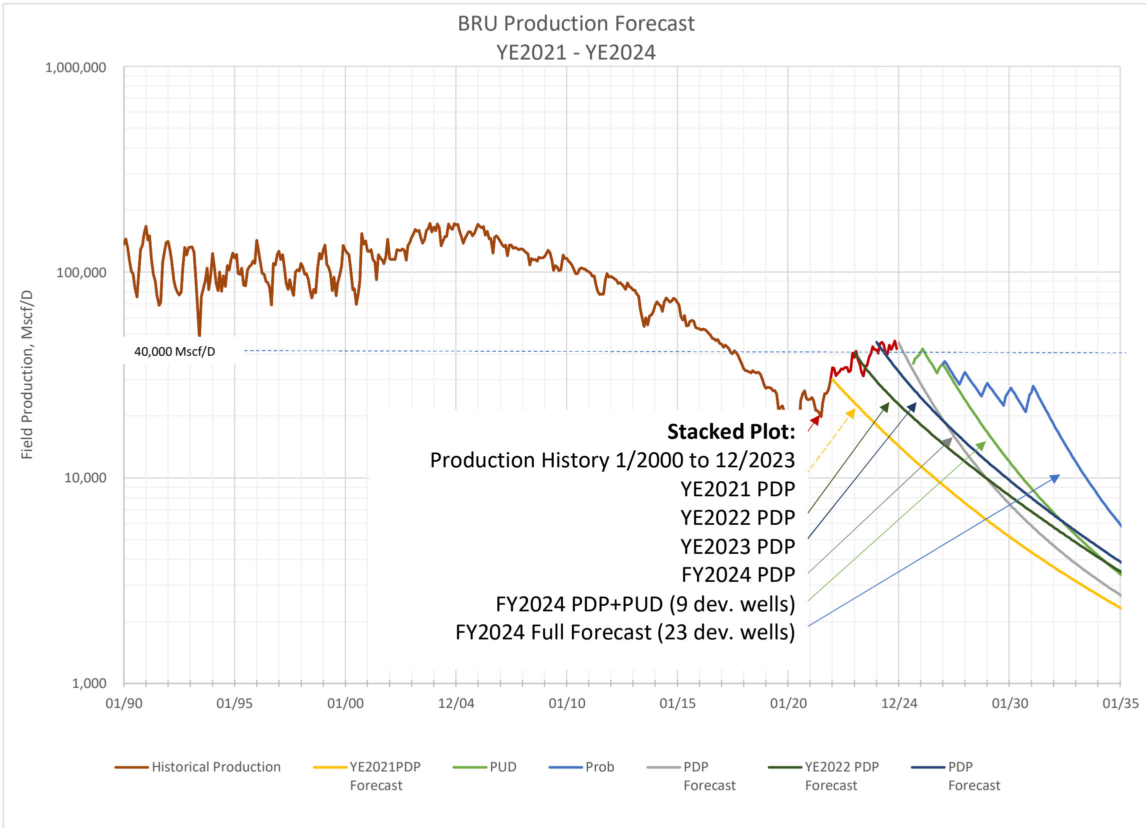


Figure 2. Comparison of historical production versus YE2021, YE2022 & YE2023 forecasts

Wellwork Activity in 2024

Wellwork for 2024 was identified via the AOGCC well history files and HAK records. Each well was evaluated by looking for production increases around the time of the wellwork or the request to the AOGCC. It appears that active wellwork on existing wells added 9.2 MMscf/D, although some of the rate gain was short-lived. Table 3 details the reported well interventions in 2024.

2024 Wellwork					
Well	Appx Date	Treatment	Pre-Rate Mscf/D	Post-Rate Mscf/D	Change
214-13	9/15/2024	Perforated	786	2,673	1,887
222-24	10/2/2024	Well Clean Out			
222-24	10/2/2024	Repair / Replace Tubing			
222-24	10/2/2024	Perforated	1,649	2,277	628
232-04	7/3/2024	FCO & Perf	-	-	-
241-23	10/58/24	Perf	-	-	-
242-04	3/13/2024	Perforated	212	2,021	1,809
244-27	2/29/2024	Perforated	446	5,385	4,939
Totals			3,093	12,356	9,263

Table 3. 2024 Reported Well Interventions

Changes to the individual well reserves are shown in Table 4. Two methods were used to evaluate each well: traditional time-dependent constant percentage decline curve analysis and a time-independent inflow performance coupled to material balance. The decline curve analysis was used as the primary evaluation method and the inflow performance was utilized for confirmation. Confidence in the results is increased if the two analyses yield similar results. Individual well analyses are given in the Appendix.

Reserve Changes YE2023 to YE2024					
Well	YE2023 Reserve MMscf	2024 Prod MMscf	YE2023 adj to 1/1/25	YE2024 Reserve MMscf	Comment
14-19		-	-		
211-03		-	-		
211-26	2,951	370	2,581	2,540	
211-35	6,038	1,026	5,012	1,815	Revised decline
212-18			-		
212-24			-		
212-24T			-		
212-25			-		
212-26	1,418	518	900	1,429	Revised decline / Water decline
212-35	4,320	461	3,859	3,813	
212-35T	2,461	662	1,799	4,884	Better Performance in 2024
213-26	4,558	1,344	3,214	3,274	
214-13	1,350	415	935	1,325	Perforation
214-26	5,591	641	4,950	2,239	Steeper decline / Water production
214-35			-		
221-23			-		
221-26	-	199	-	3,035	New well
221-35	5,295	831	4,464	1,546	Steeper decline / Water production
222-24	2,661	580	2,081	2,047	Well repair
222-26	-	274	-	1,816	New Well
222-34	1,532	439	1,093	1,023	
223-24	1,912	467	1,445	1,273	
223-34	2,912	694	2,218	621	Steeper decline / Water production
224-13			-		
224-23			-		
224-23T	4,506	588	3,918	3,817	
224-34			-		
232-04			-		
232-09			-		
232-23			-		
232-26	57	-	57	1	Water production / Well shut-in
233-23	2,825	506	2,319	1,633	Revised decline trend
233-23T	-	245		3,844	New well
233-27	3,575	620	2,955	2,808	
241-23	4,539	287	4,252	413	Steeper decline / Water production
241-26	-	967	-	6,210	New well
241-34			-		
241-34S	-	257		828	New well
241-34T	4,571	1,106	3,465	4,101	Revised decline trend
242-04	1,853	456	1,397	945	Steeper decline trend / Perforation
243-34	3,763	408	3,355	1,789	Well problems. Revised forecast.
244-04			-		
244-23			-		
244-27	1,626	1,228	398	2,070	Perforation
Total	70,314	15,589	15,589	61,139	

Table 4. Variance Forecast Changes YE2023 Forecast to YE2024 Actual

YE2024 Forecast

The five 2025 approximate locations proposed by the operator in Figure 3 are shown as orange lines; black circles are CEA identified opportunities; red triangles are twinning opportunities. The current development philosophy of the operator and the majority owner is to continue drilling lowest risk development opportunities targeting Beluga zones. This includes 160-acre infill locations, as well as 80-acre infills and twins of wells in non-producing Upper Beluga intervals. The targets are primarily the more channelized Beluga sands. The more continuous Sterling sands are considered to be at low pressure. However, potentially isolated Sterling sands have been identified in recent drilling (Figure 4). An isolated Sterling amplitude was interpreted to the west (Figure 5). This is a possible development opportunity. PRA has estimated average reserve recovery for the next six years of drilling of 23 wells to be 16 BSCF PUD, 15 BSCF Probable and 7 BSCF Possible. The operator and CEA are in agreement on continued drilling in the near future.

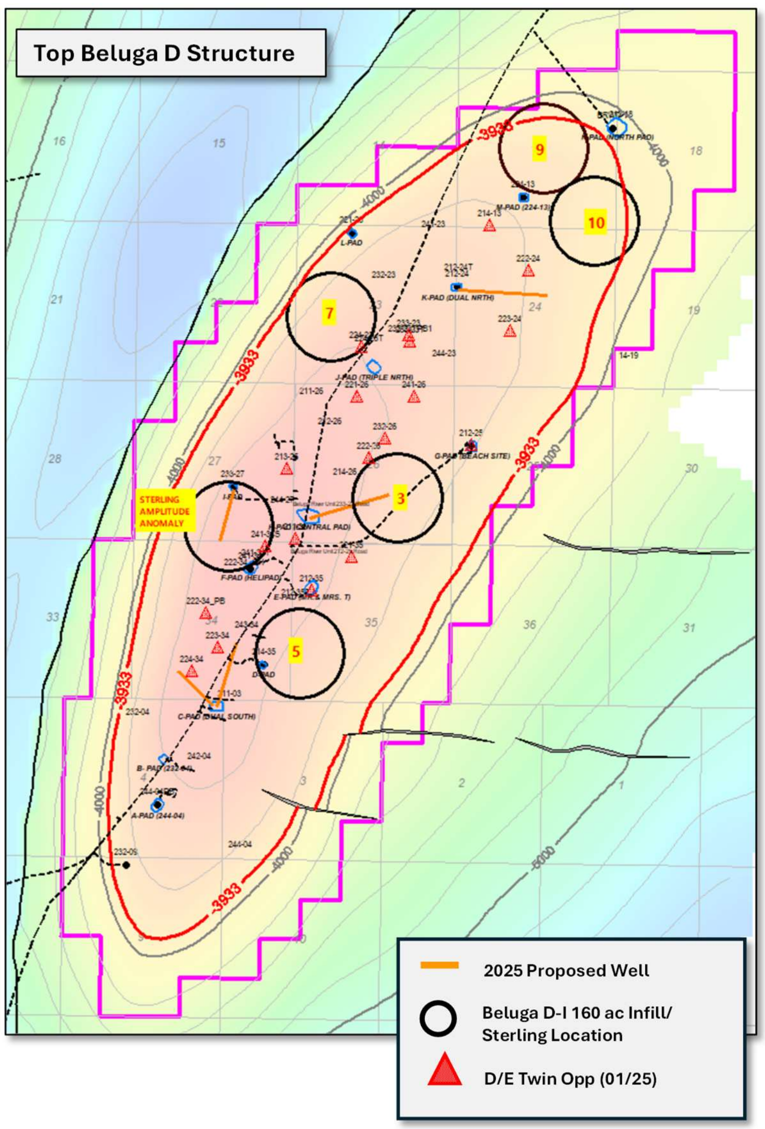


Figure 3. BRU and HAK 2025 Planned Locations, Remaining 160 Acre Infill and D/E Twin Locations

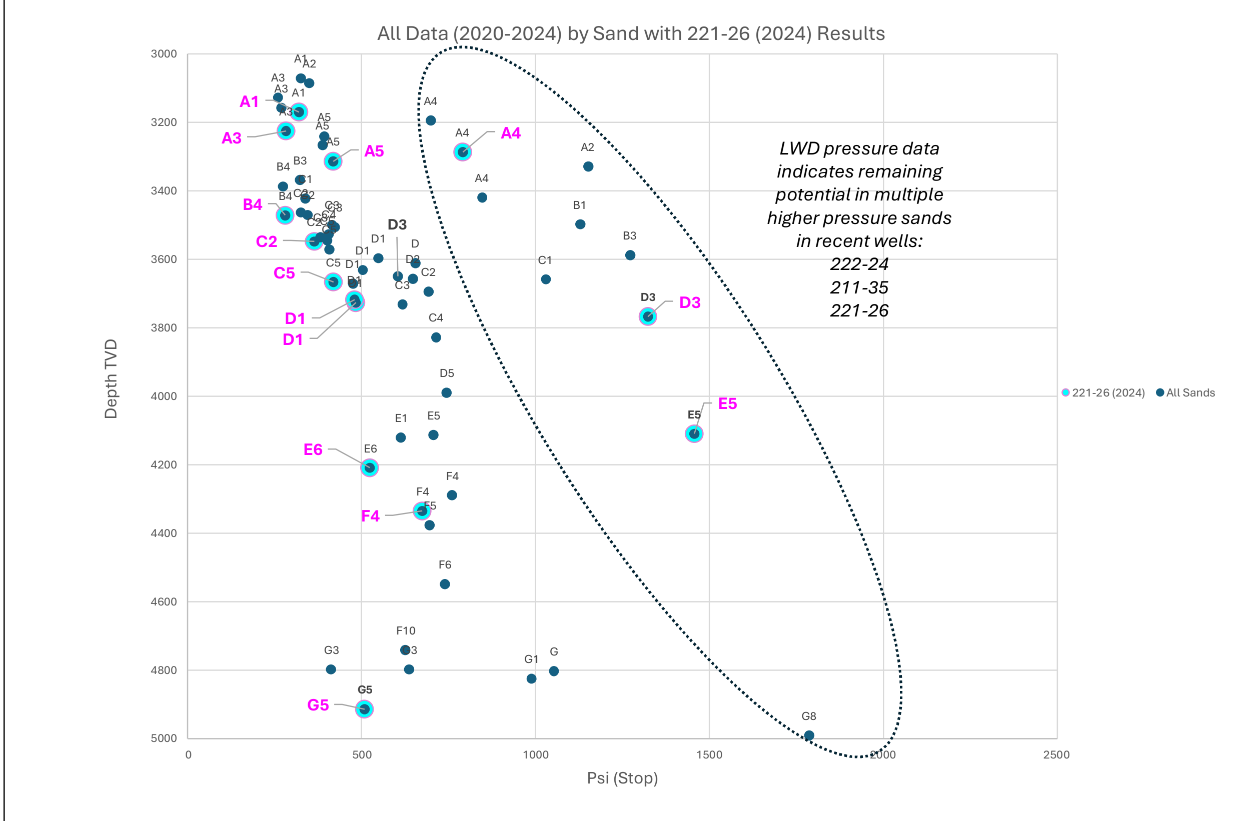


Figure 4. Recent Drilling Shows Elevated Sterling Pressures (refer to Zones A, B & C only)

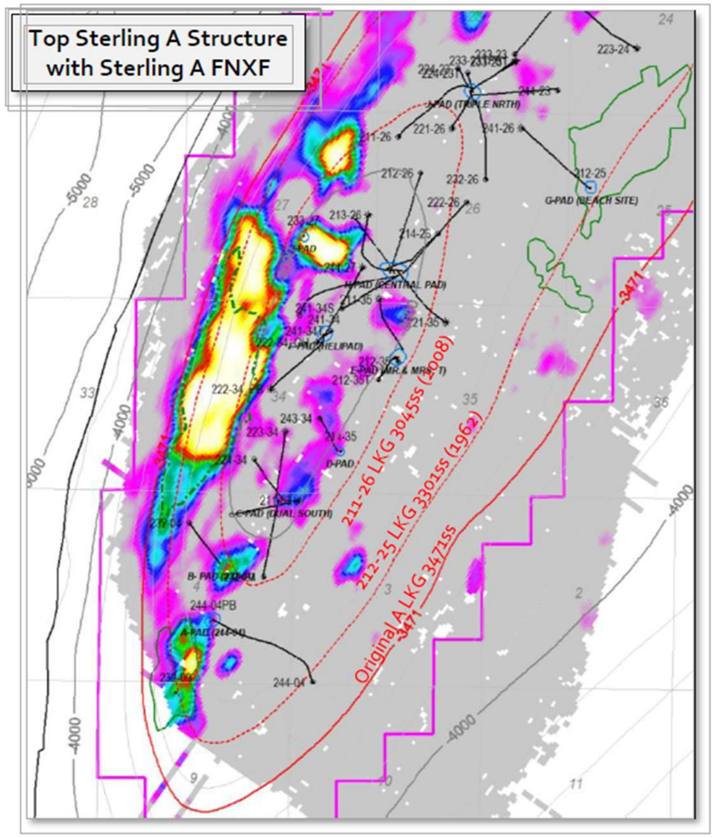


Figure 5. Identified Sterling Anomaly West of Field Top of Structure

The future development wells are summarized in Table 5. Locations to be drilled in 2025 and high probability 2026 targets are identified as PUD, while the remainder on the schedule represent Probable and Possible reserve targets. The reserves are mid-range geologic volume estimates of type-well recoveries based on zones, location, target size and timing. A total of twenty-three potential targets have been identified with 41 BSCF of prognosed reserves.

The variance analysis, given in Table 6, follows the reserve changes from YE2021, YE2022 and YE2023 reserve estimates. The total reserves are diminishing due to reservoir depletion, tighter spacing, water encroachment, and diminishing target reservoir volume associated with new wells.

The prevailing Cook Inlet gas price for Q1 2025 of $8.39/Mscf published by the Alaska Department of Revenue (https://tax.alaska.gov/programs/oil/prevailing/cook.aspx) was used for the end of field life calculations. The YE2024 end of field life is calculated to be in 2035. A table of the reserve accounting for this reserve report is given in Table 6. A table of the calculations is given at the end of the Appendix.

	Well Location	Class	Drill Date	Reserves	Class Total
PDNP	221-26	Wellwork	7/1/2025	439	
	241-23	Wellwork	7/1/2025	1,008	
	241-26	Wellwork	7/1/2025	2,606	4,053
PUD	2025-S26	PUD	8/1/2025	1,688	
	2025-S34E2	PUD	9/1/2025	1,206	
	2025-S34W2	PUD	10/1/2025	1,206	
	2025-S27Blga	PUD	11/1/2025	2,727	
	2025-S24	PUD	12/1/2025	3,199	
	2026-PRA5	PUD	8/1/2026	1,589	
	2026-Twin1	PUD	9/1/2026	2,030	
	2026-Twin2	PUD	10/1/2026	2,025	15,671
Probable	2027-Twin3	Prob	8/1/2027	2,206	
	2027-Twin4	Prob	9/1/2027	2,204	
	2027-Twin5	Prob	10/1/2027	2,196	
	2028-Twin6	Prob	8/1/2028	1,920	
	2028-Twin7	Prob	9/1/2028	1,916	
	2028-Twin8	Prob	10/1/2028	1,907	
	2029-PRA10	Prob	8/1/2029	1,557	
	2030-PRA7	Prob	8/1/2030	1,519	
	2030-PRA9	Prob	9/1/2030	1,518	16,943
Possible	2026-S27Strlg	Possible	11/1/2026	3,273	
	2029-Twin9	Possible	9/1/2029	890	
	2029-Twin10	Possible	10/1/2029	887	
	2029-Twin11	Possible	11/1/2029	885	
	2030-Twin12	Possible	10/1/2030	863	
	2030-Twin13	Possible	11/1/2030	1,505	8,302

Table 5. Schedule of YE2024 Well Development
Based on Geologic Estimates of Net Volume

Reserve Changes YE2023, YE2022 & YE2021 BSCF	YE2024	YE2023	YE2022	YE2021
End of Field Life	Mar-35	Mar-35	Feb-35	Jun-34
Production history (AOGCC)	1,479	1,463	1,449	1,437
Proven Developed Producing Reserve	43	60	58	45
Proven Developed Non-Producing Reserve	4	0	2	9
Proven Undeveloped + wellwork	16	22	29	31
Gross Proven Reserves	63	82	89	86
Gross Probable & Possible Reserves	25	23	17	23
Gross Proven+Probable & Possible Reserves	88	105	105	109
Estimated Ultimate Recovery	2	1,568	1,555	1,546
Fuel Consumption	5	6	6	6
Gross Reserves less fuel consumption	83	99	99	104
Royaty Gas 12.5%	10	12	12	13
CEA Net Proven+Probable & Possible Reserves	49	58	58	60
CEA Available Gas (Net Proven+Probable plus 2/3 of Royalty)	56	66	66	69

Table 6. Gross and Net Reserves Comparison (BSCF)

CEA Net Volumes

Table 7 shows the yearly volumes and annual average rates for all the reserve categories discussed: Proved Developed Producing, Proved Undeveloped Probable and Possible reserves. Table 8 shows the estimated yearly gas deductions and CEA net (66.666666%) gas volumes expressed in terms of annual volume and annual average rate.

	Proven Developed Producing		Proven Non-Producing		Proven Undeveloped		Probable + Possible		Total	
Year	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann.Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF
2025	35.8	13,084	1.4	520	1.3	472	-	-	38.6	14,075
2026	23.1	8,442	2.5	904	10.6	3,853	-	-	36.2	13,199
2027	15.8	5,781	2.0	736	11.5	4,204	2.5	929	31.9	11,649
2028	11.4	4,164	1.5	547	7.2	2,620	7.9	2,905	28.0	10,235
2029	8.5	3,103	1.1	406	4.6	1,662	11.1	4,054	25.3	9,224
2030	6.6	2,396	0.8	302	3.0	1,080	13.7	5,018	24.1	8,796
2031	5.2	1,900	0.6	226	2.0	714	15.5	5,657	23.3	8,497
2032	4.2	1,545	0.5	169	1.3	479	9.0	3,308	15.0	5,502
2033	3.5	1,273	0.3	126	0.9	323	5.4	1,955	10.1	3,677
2034	2.9	1,068	0.3	95	0.6	221	3.3	1,200	7.1	2,583
2035	2.6	237	0.2	20	0.5	43	2.4	220	5.8	520
Total Volume		42,992		4,049		15,671		25,245		87,957

Table 7. Estimated Yearly Average Rates and Total Gross Volumes

	P1+P2+P3 Proved+Probable+Possible		Fuel Gas Consumption		Royalty Gas (12.5%) (historically available to CEA)		100% WIO Gross Volume		Net Gas to CEA Interest	
Year	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Net Ann. Avg. MMSCF/D	Net Gas Volume MMSCF
2025	38.6	14,075	1.25	456	4.7	1,702	32.6	11,917	21.8	7,944
2026	36.2	13,199	1.25	456	4.4	1,593	30.5	11,150	20.4	7,433
2027	31.9	11,649	1.25	456	3.8	1,399	26.8	9,794	17.9	6,529
2028	28.0	10,235	1.25	458	3.3	1,222	23.4	8,556	15.6	5,704
2029	25.3	9,224	1.25	456	3.0	1,096	21.0	7,672	14.0	5,114
2030	24.1	8,796	1.25	456	2.9	1,043	20.0	7,298	13.3	4,865
2031	23.3	8,497	1.25	456	2.8	1,005	19.3	7,035	12.9	4,690
2032	15.0	5,502	1.25	458	1.7	631	12.1	4,414	8.0	2,942
2033	10.1	3,677	1.25	456	1.1	403	7.7	2,818	5.1	1,879
2034	7.1	2,583	1.25	456	0.7	266	5.1	1,861	3.4	1,241
2035	5.8	520	1.25	113	0.6	51	4.0	356	2.6	238
Total Volume		87,957		4,678		10,410		72,870		48,580

Table 8. Estimated Yearly Gas Deductions as Yearly Average Rates and Total Gross Volumes

The proved and probable reserves included in this report were calculated from information obtained from CEA, Hilcorp and public information. The forecast volumes conform to the definitions of reserves in the 2018 SPE-PRMS as modified in 2019, compiled in 2022 and sponsored and approved by the SPE, WPC, AAPG, SPEE, SEG, SPWLA and EAGE. Reserves are estimated using constant price and cost parameters.

Reserve Definitions from PRMS (2018)

Reserves are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions."

Proved Reserves are "those quantities of petroleum that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be commercially recovered from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations."

Proved Developed Producing Reserves are "expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate."

Proved Non-Developed Producing Reserves are "shut-in and behind pipe reserves."

Proved Undeveloped Reserves are "quantities expected to be recovered through future significant investments." The calculated volume and risk-weighted volume difference should be no more than 10%.

Probable Reserves are "those additional Reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves……there should be at least a 50% probability the actual quantities recovered will equal or exceed the estimate."

Possible Reserves are "those additional Reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Probable Reserves….there should be at least a 10% probability that the actual quantities recovered will equal or exceed the estimate."

Standards of Independence and Professional Qualifications

Petrotechnical Resources Alaska (PRA) is professionally licensed in the State of Alaska to provide independent petroleum engineering consulting services. This reserves examiner has been licensed in the State of Alaska as a Professional Petroleum Engineer since 2000, has worked with PRMS for eleven years and estimated Cook Inlet gas reserves for eight years.

Terms of Usage

This report was prepared for the exclusive use and sole benefit of Chugach Electric Association and may not be put to other use without prior written consent of such use. The data and work papers used in preparation of this report are available for examination by authorized parties.

Sincerely,

John C Braden
Petrotechnical Resources Alaska
Alaska EP-10151

STATE OF ALASKA
49TH
24 June 2025
John C. Braden
EP-10151
REGISTERED PROFESSIONAL ENGINEER

Cc: Bart Armfield – CEA
Hans Thompson - CEA

Appendix

Shut-in Wells

Below is a table of shut-in wells at Beluga River Unit. These wells are not included in the active well forecast. The shut-in wells and active wells comprise all of the wells in the Beluga River Unit.

Beluga River Unit Shut-in Wells			
Well	First Produced	Last Produced	Produced MMscf
14-19	5/1/1964	5/1/1964	-
211-03	12/1/1986	5/1/2015	74,089
212-18	5/1/1985	11/1/1997	6,175
212-24	1/1/1979	11/1/2005	44,445
212-24T	7/1/2010	3/1/2022	10,158
212-25	3/1/1968	11/1/2021	23,434
212-26	9/1/2020	12/1/2023	3,142
214-35	9/1/1982	4/1/2020	15,538
221-23	1/1/1982	7/1/1994	5,953
224-13	8/1/1983	5/1/2011	26,683
224-23	11/1/1985	4/1/2011	106,113
224-34	12/1/1986	5/1/2021	164,621
232-04	2/1/1967	11/1/2018	74,149
232-09	1/1/1987	3/1/1997	17,655
232-26	11/1/1985	4/1/2023	63,762
241-26	8/1/2024	11/1/2024	967
241-34	1/1/1973	9/1/2019	172,801
244-04	12/1/1972	11/1/2016	138,489
244-23	10/1/2012	3/1/2023	8,108

Beluga River Unit Shut-in Wells

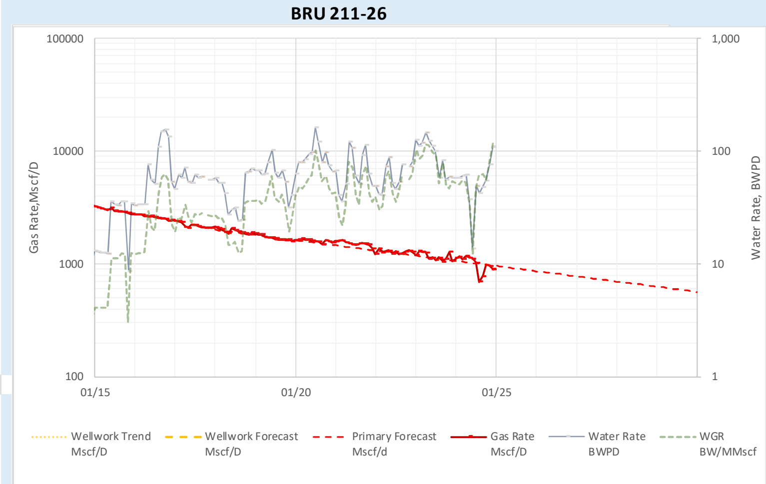
Individual Well Analyses

Well Performance Evaluation

- Plots
  - Monthly to Daily rate comparison
  - Time-rated decline curve analysis (DCA)
    - Longer time frame
    - Best fit %/yr
  - Inflow performance coupled with P/z vs Gp
    - $Q=C(P_r^2-P_{bhf}^2)^n$
    - Used two years or less of data
    - Used FTP to calculate P_{bhf} , C=0.6 and mostly <250 psi drawdown
    - Fit dP^2 vs Q and then Gp
- Compare remaining reserves of two methods
  - Located in summary table

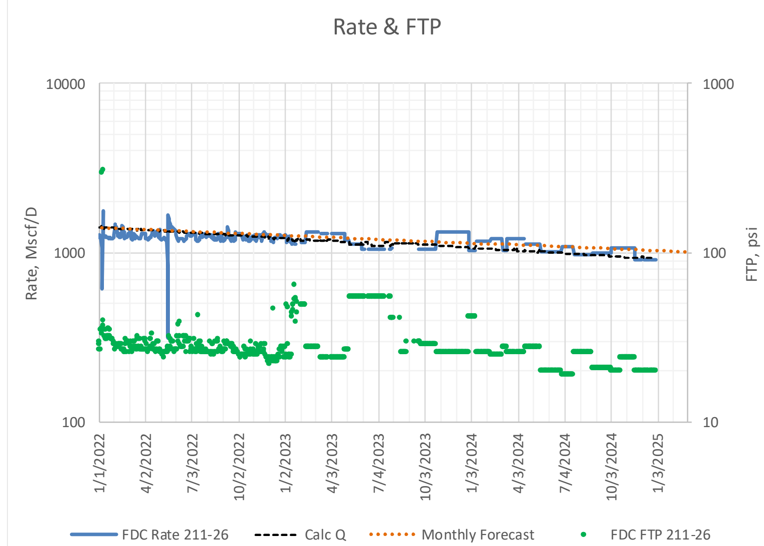
The following well forecasts are displayed in two parts. The left side is an exponential decline curve forecast. This it taken from State of Alaska AOGCC monthly production data, which reports monthly allocated volumes of gas and water. The right hand side is an inflow performance relationship used to supplement the DCA. The rate and flowing tubing pressure values used for the inflow performance are taken from the raw (unallocated) morning report (aka FDC Report).

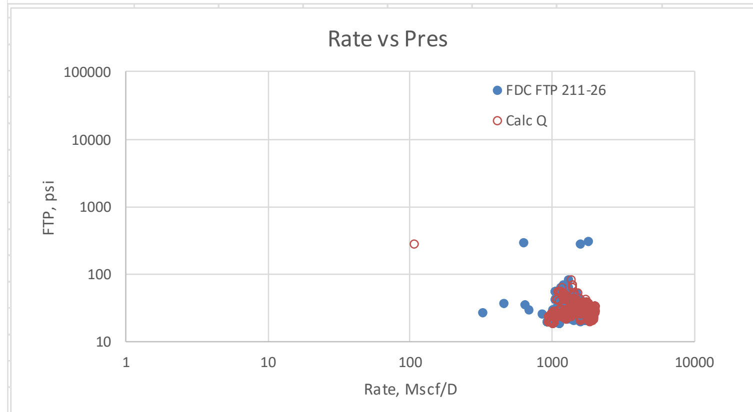
Beluga River Unit Active Well Forecasts



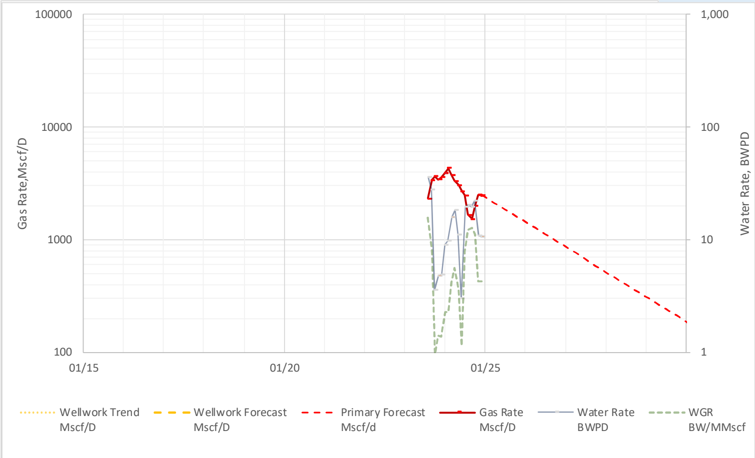
Gp(12/2024), MMscf	18,646	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	2,540	Decline Trend Start Date	1/2018	
First Produced	10/2008	Initial Trend Rate, Mscf/d	2000	-
Last Produced	12/2024	Decline, %/yr	10.0	13.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	2,540	-

					1/1/2024
	211-26				
Pr(start of forecast)	380	n	0.8	Pr(1/2024)	260 psi
Gp remaining, MMscf	2700	C	0.15		



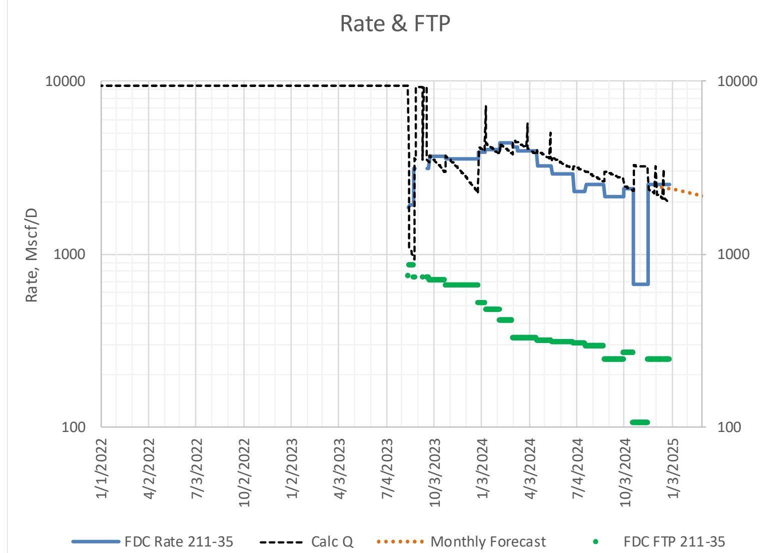


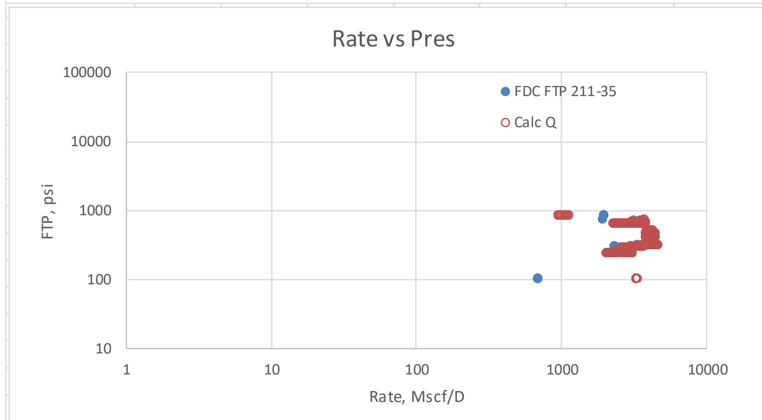
BRU 211-35



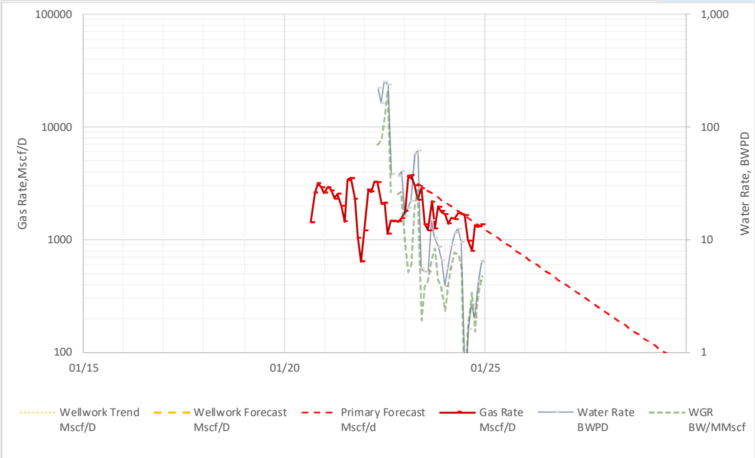
Gp(12/2024), MMscf	1,503	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,815	Decline Trend Start Date	12/2024	
First Produced	8/2023	Initial Trend Rate, Mscf/d	2500	-
Last Produced	12/2024	Decline, %/yr	40.0	0.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,815	-

				1/1/2024
	211-35			
Pr(start of forecast)	1000	n	0.8	Pr(1/2024) 860 psi
Gp remaining, MMscf	1100	C	0.15	



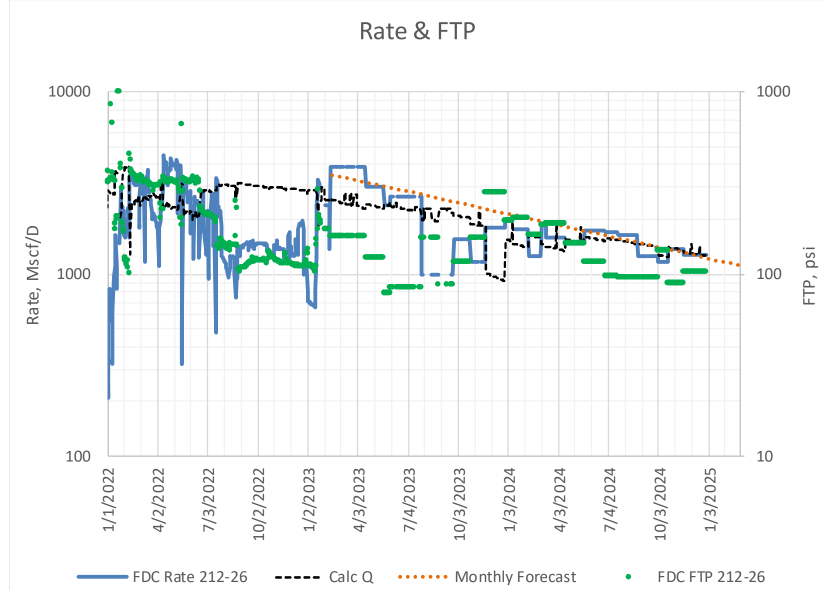


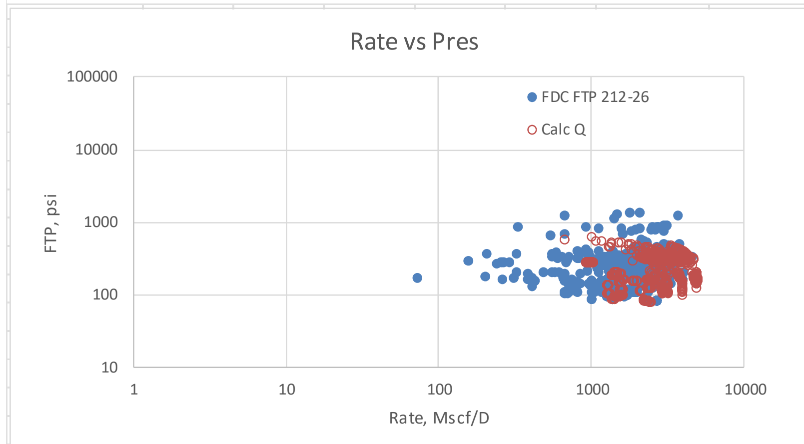
BRU 212-26



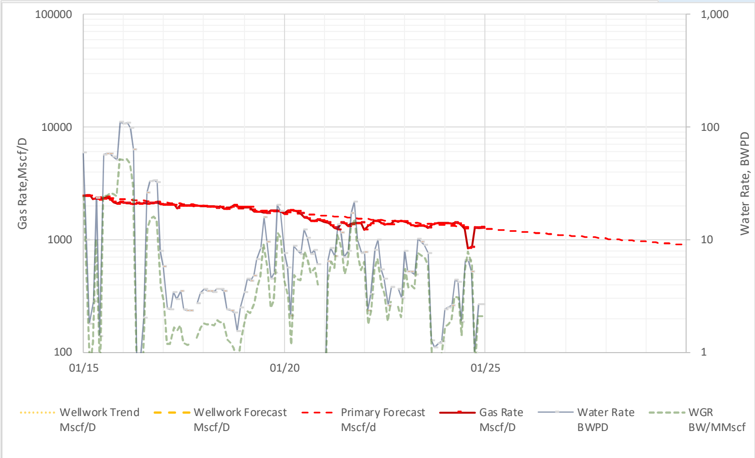
Gp(12/2024), MMscf	3,142	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,429	Decline Trend Start Date	2/2023	
First Produced	9/2020	Initial Trend Rate, Mscf/d	3600	-
Last Produced	12/2024	Decline, %/yr	43.0	25.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,429	-

				1/1/2024	
	212-26				
Pr(start of forecast)	750	n	0.8	Pr(1/2024)	390 psi
Gp remaining, MMscf	1500	C	0.15		



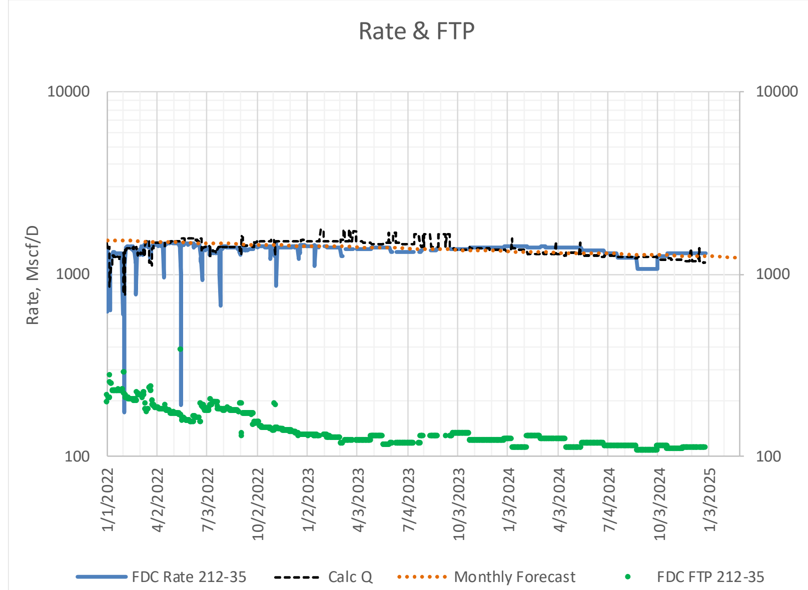


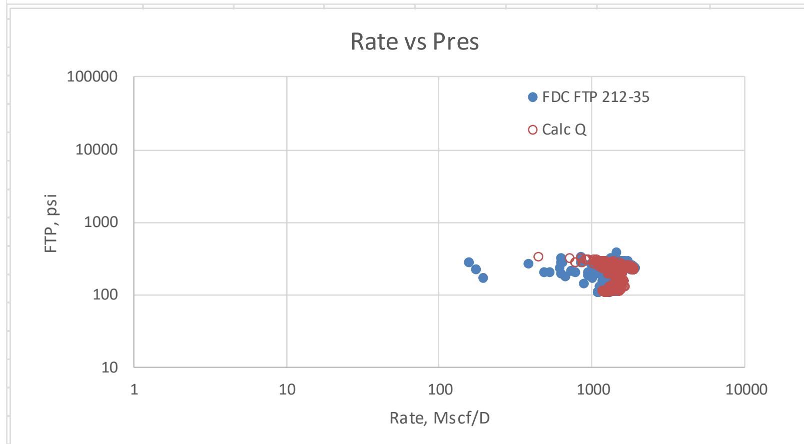
BRU 212-35



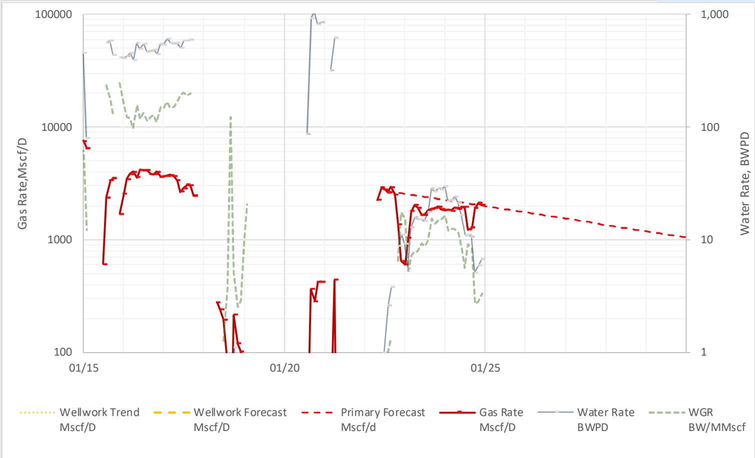
Gp(12/2024), MMscf	68,066	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	3,813	Decline Trend Start Date	1/2005	
First Produced	9/1967	Initial Trend Rate, Mscf/d	4800	-
Last Produced	12/2024	Decline, %/yr	6.5	25.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	3,813	-

				1/1/2024	
	212-35				
Pr(start of forecast)	450	n	0.8	Pr(1/2024)	330 psi
Gp remaining, MMscf	3800	C	0.15		





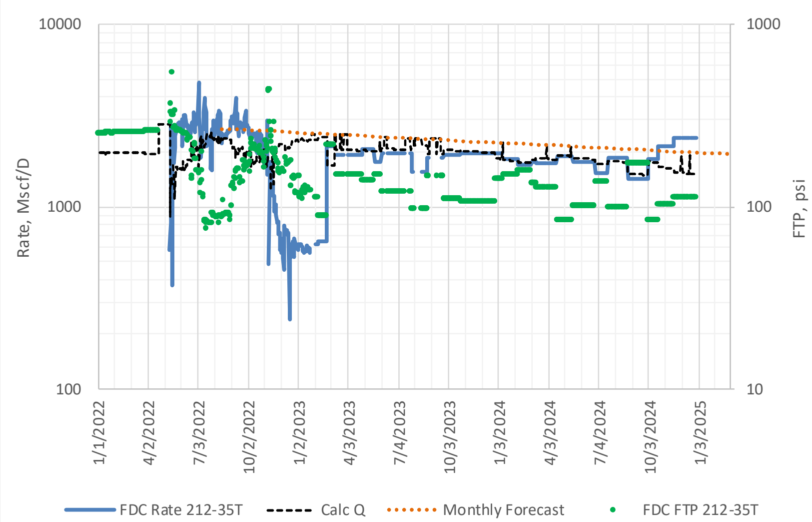
BRU 212-35T



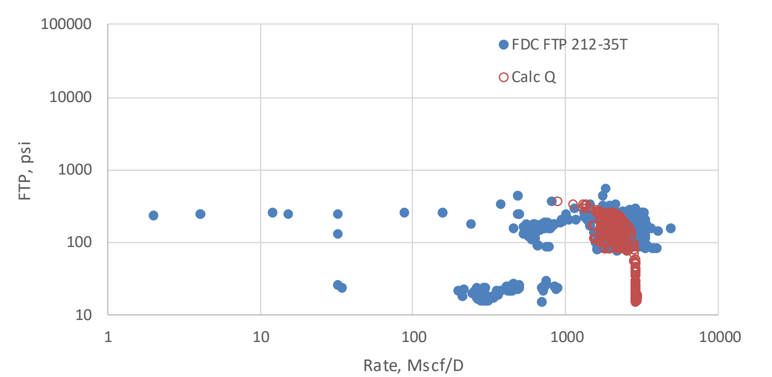
Gp(12/2024), MMscf	102,229	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	4,884	Decline Trend Start Date	8/2022	
First Produced	10/1998	Initial Trend Rate, Mscf/d	2700	-
Last Produced	12/2024	Decline, %/yr	12.0	40.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	4,884	-

					1/1/2024
	212-35T				
Pr(start of forecast)	475	n	0.8	Pr(1/2024)	410 psi
Gp remaining, MMscf	4800	C	0.15		

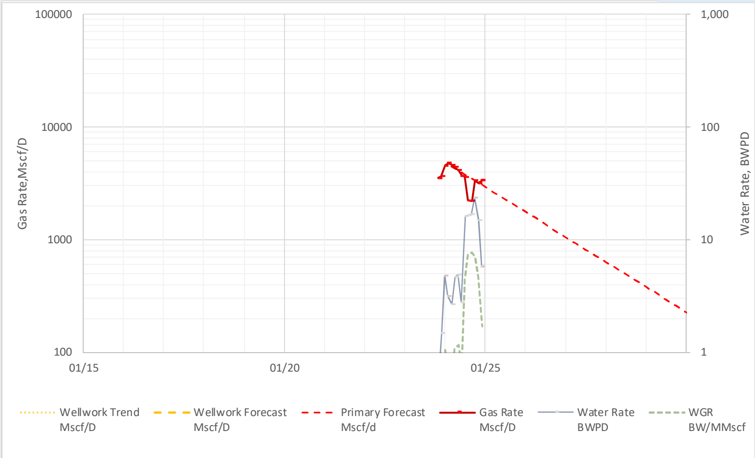
Rate & FTP



Rate vs Pres



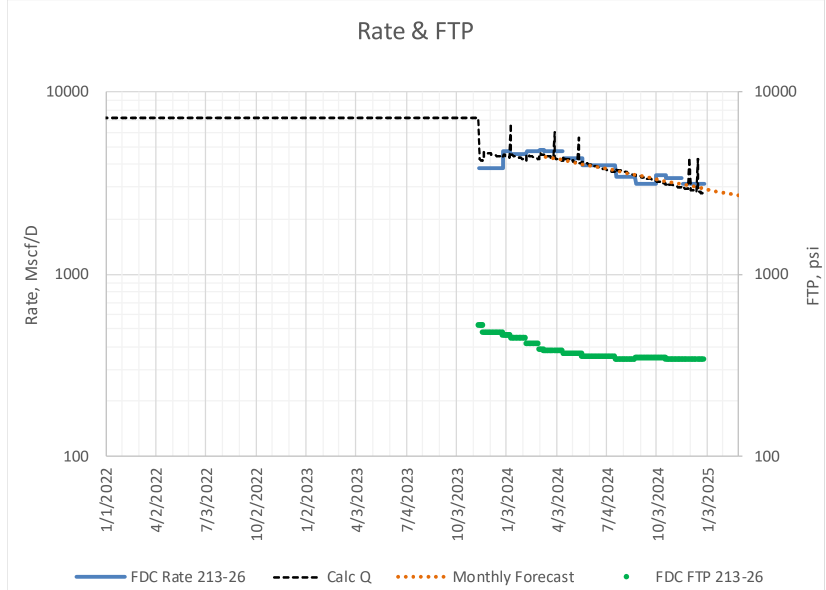
BRU 213-26

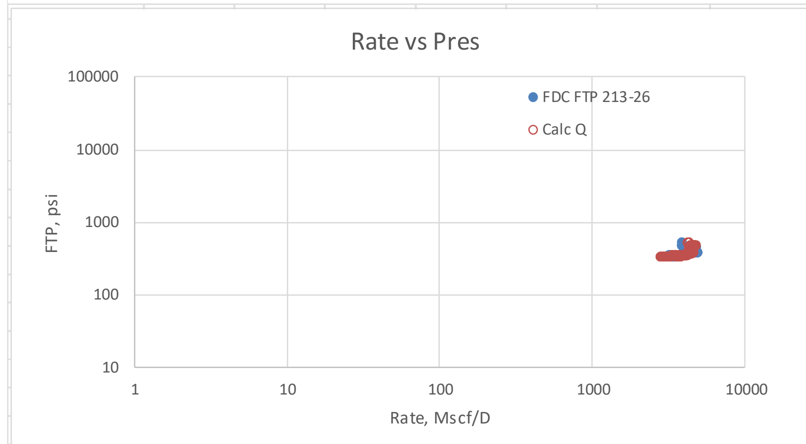


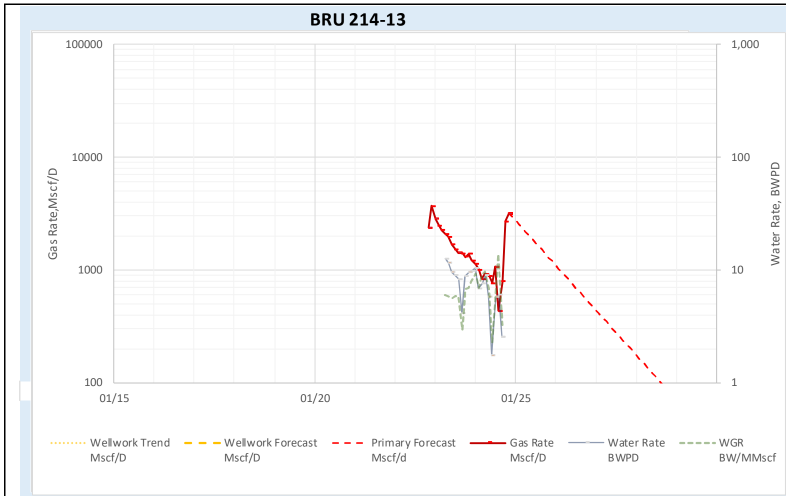
Gp(12/2024), MMscf	1,524	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	3,274	Decline Trend Start Date	3/2024	
First Produced	11/2023	Initial Trend Rate, Mscf/d	4500	-
Last Produced	12/2024	Decline, %/yr	40.0	0.0
		Wellwork Date		
		Wellwork Initial Rate, Mscf/d		-
		Forecast(1/2025), MMscf	3,274	-

Last 10 years of production displayed
Well forecast estimated to 1/2035
EOFL determined on field level

				1/1/2024
	213-26			
Pr(start of forecast)	850	n	0.8	Pr(1/2024) 820 psi
Gp remaining, MMscf	3200	C	0.15	

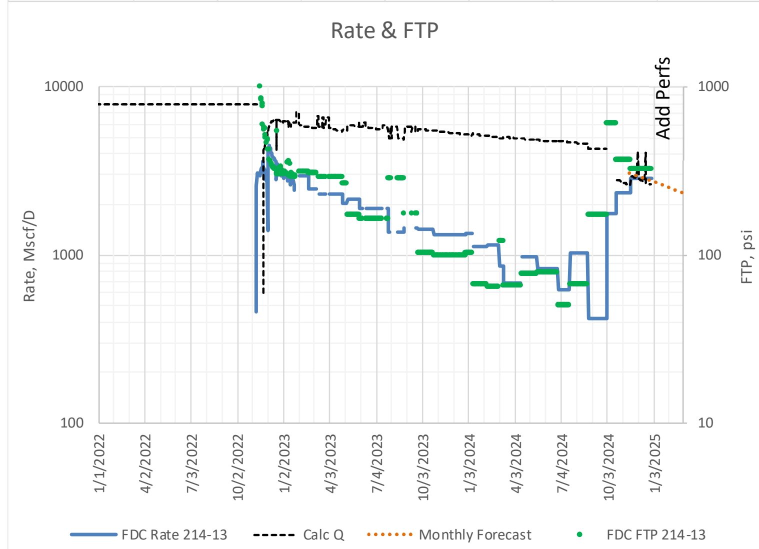


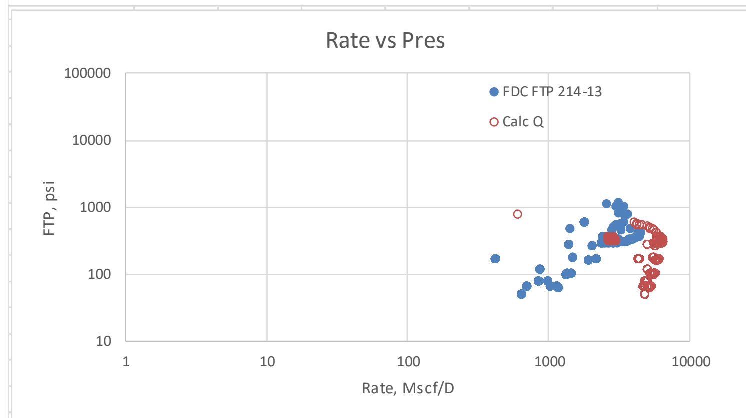




Gp(12/2024), MMscf	1,251	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,325	Decline Trend Start Date	11/2024	11/1/2024
First Produced	11/2022	Initial Trend Rate, Mscf/d	3200	-
Last Produced	11/2024	Decline, %/yr	60.0	20.0
Last 10 years of production displayed		Wellwork Date		2/1/2025
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,325	-

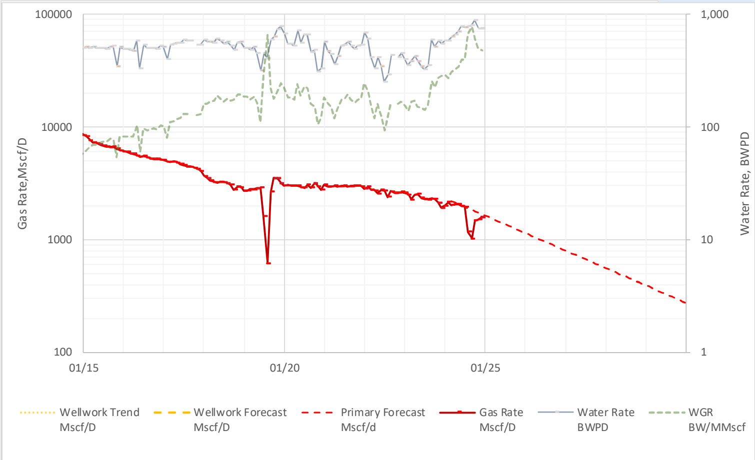
				1/1/2024
	214-13			
Pr(start of forecast)	900	n	0.8	Pr(1/2024) 700 psi
Gp remaining, MMscf	1800	C	0.15	





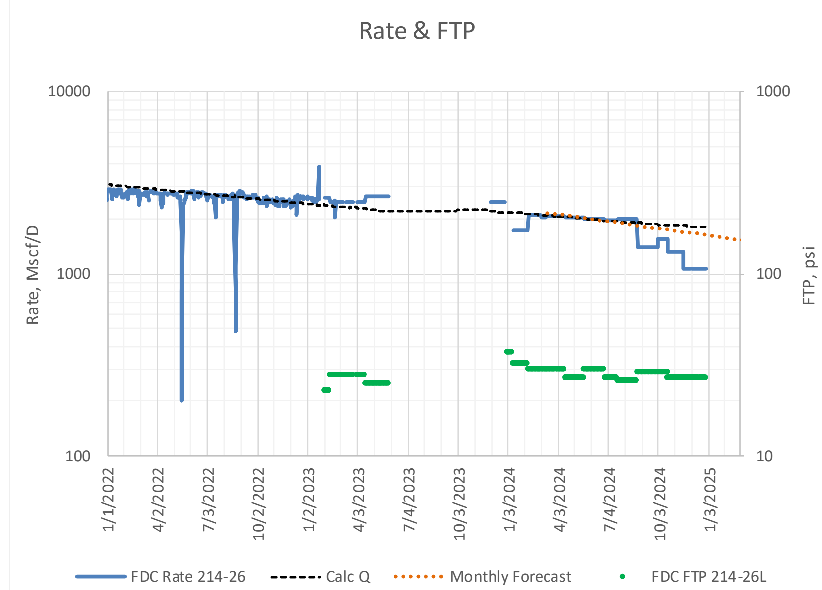
Backpressure performance forecast affected by add perfs.

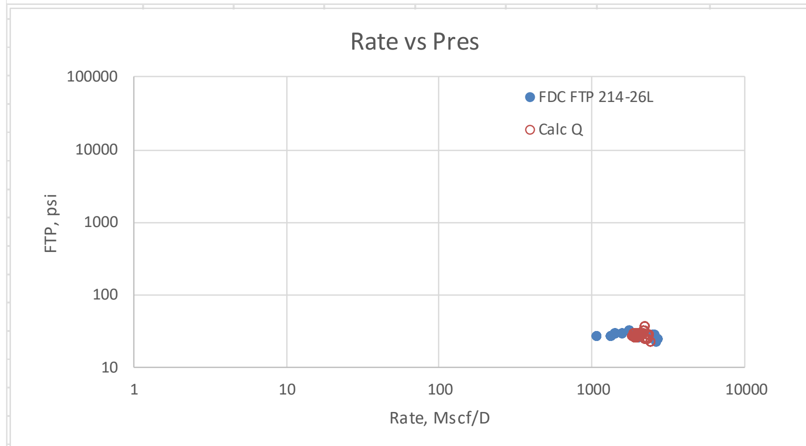
BRU 214-26



Gp(12/2024), MMscf	138,255	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	2,239	Decline Trend Start Date	3/2024	
First Produced	12/1990	Initial Trend Rate, Mscf/d	2200	-
Last Produced	12/2024	Decline, %/yr	30.0	23.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	2,239	-

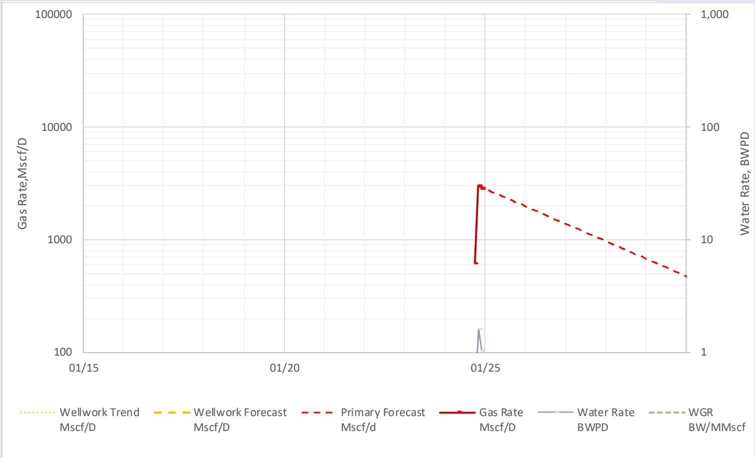
				1/1/2024	
	214-26				
Pr(start of forecast)	650	n	0.8	Pr(1/2024)	400 psi
Gp remaining, MMscf	3900	C	0.15		





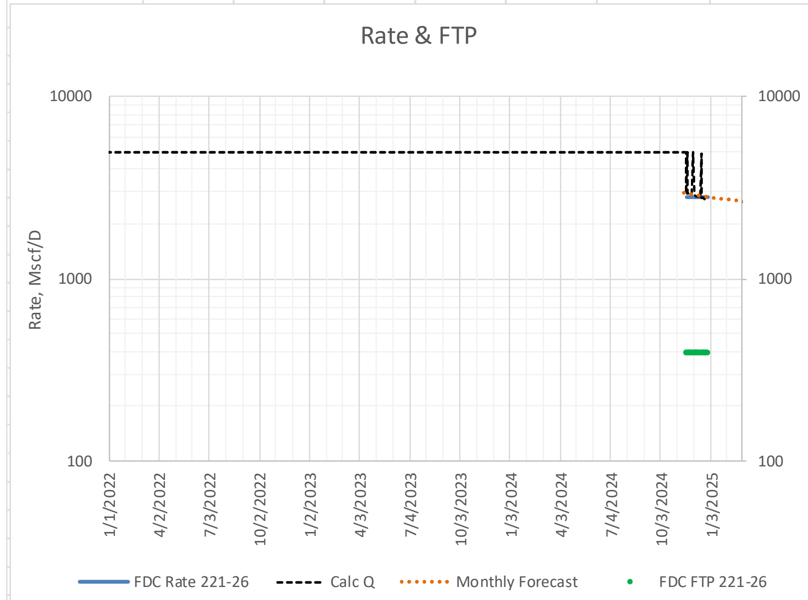
Recent drop in production suggests potential wellwork.

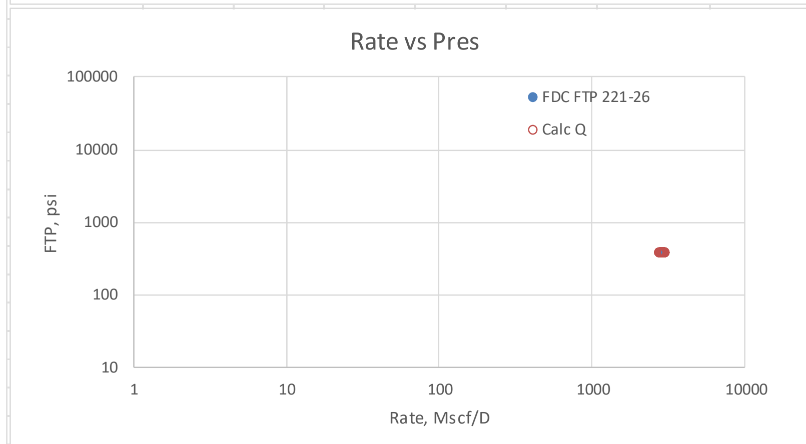
BRU 221-26



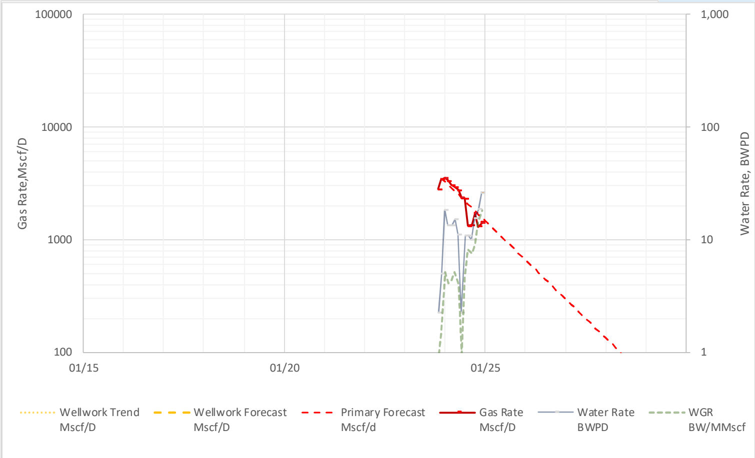
Gp(12/2024), MMscf	199	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	3,035	Decline Trend Start Date	11/2024	7/1/2024
First Produced	10/2024	Initial Trend Rate, Mscf/d	3000	-
Last Produced	12/2024	Decline, %/yr	30.0	23.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	3,035	-

					1/1/2024
	221-26				
Pr(start of forecast)	675	n	0.8	Pr(1/2024)	670 psi
Gp remaining, MMscf	3100	C	0.15		



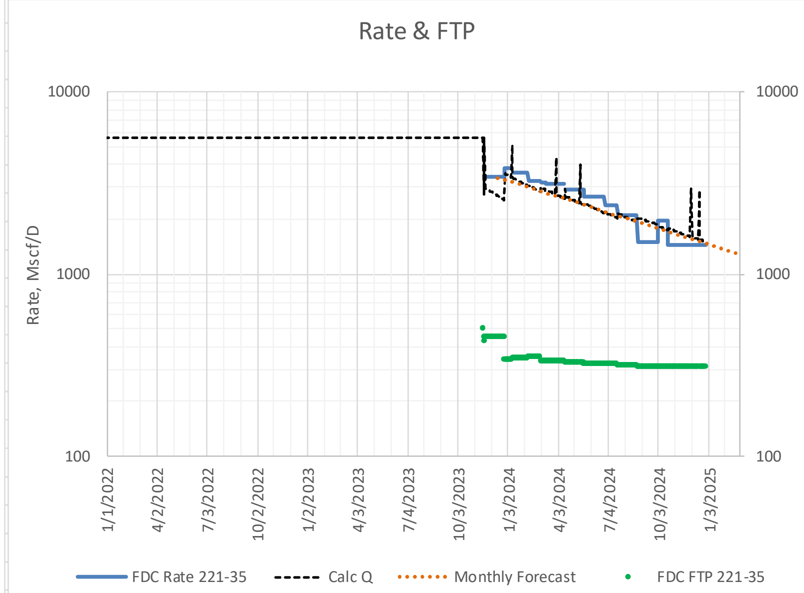


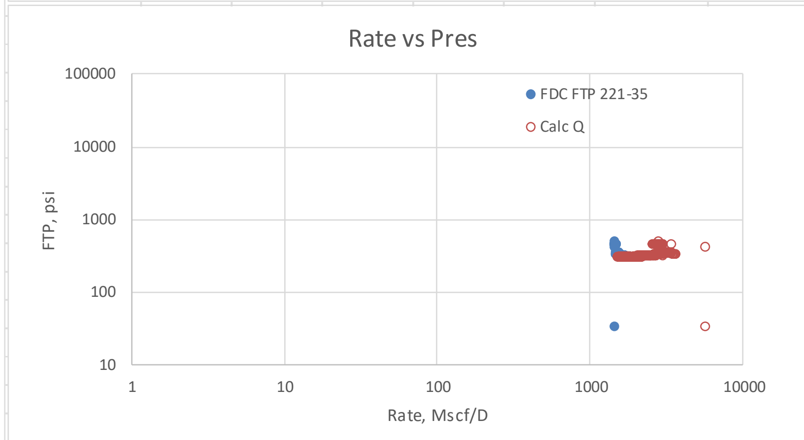
BRU 221-35



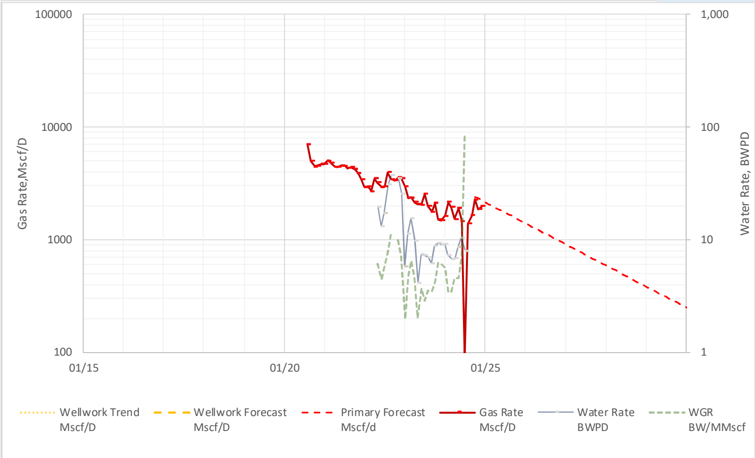
Gp(12/2024), MMscf	970	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,546	Decline Trend Start Date	12/2023	
First Produced	11/2023	Initial Trend Rate, Mscf/d	3500	-
Last Produced	12/2024	Decline, %/yr	55.0	0.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,546	-

				1/1/2024	
	221-35				
Pr(start of forecast)	725	n	0.8	Pr(1/2024)	690 psi
Gp remaining, MMscf	1500	C	0.15		



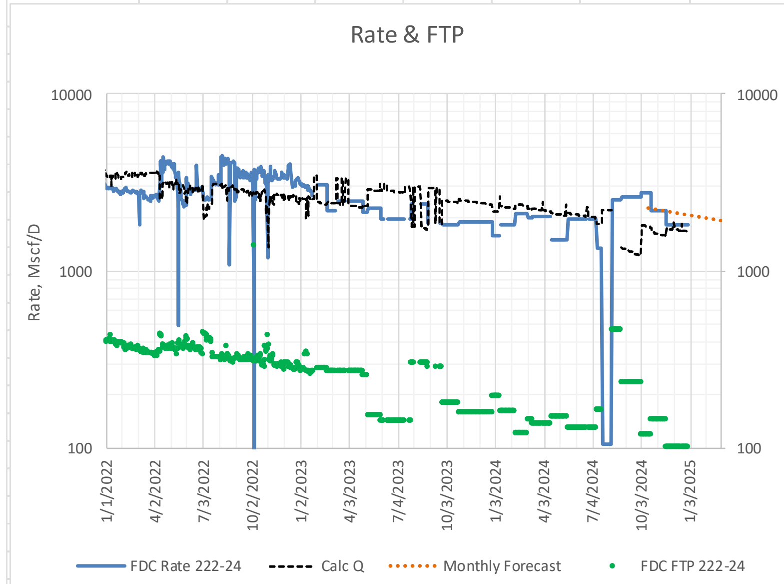


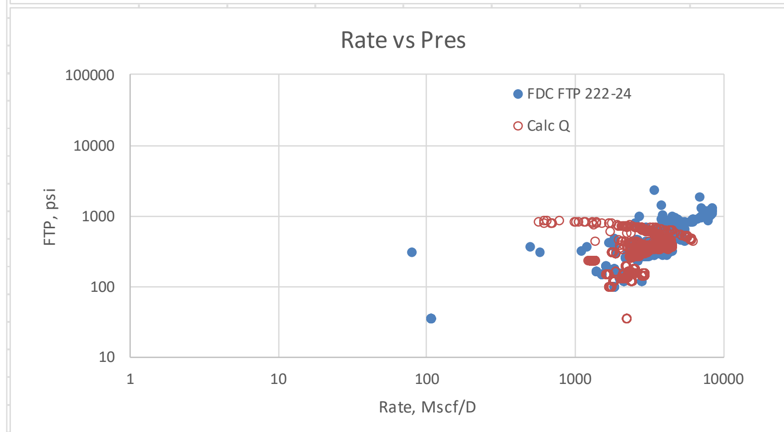
BRU 222-24



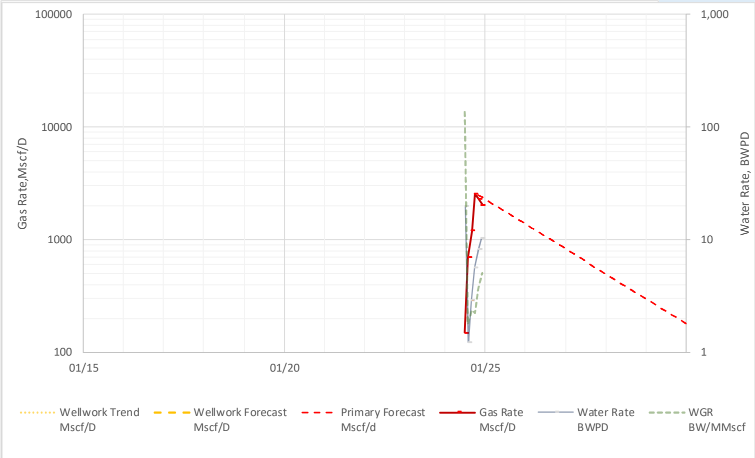
Gp(12/2024), MMscf	4,886	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	2,047	Decline Trend Start Date	10/2024	
First Produced	8/2020	Initial Trend Rate, Mscf/d	2400	-
Last Produced	12/2024	Decline, %/yr	35.0	23.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	2,047	-

				1/1/2024	
	222-24				
Pr(start of forecast)	1000	n	0.8	Pr(1/2024)	460 psi
Gp remaining, MMscf	2000	C	0.15		





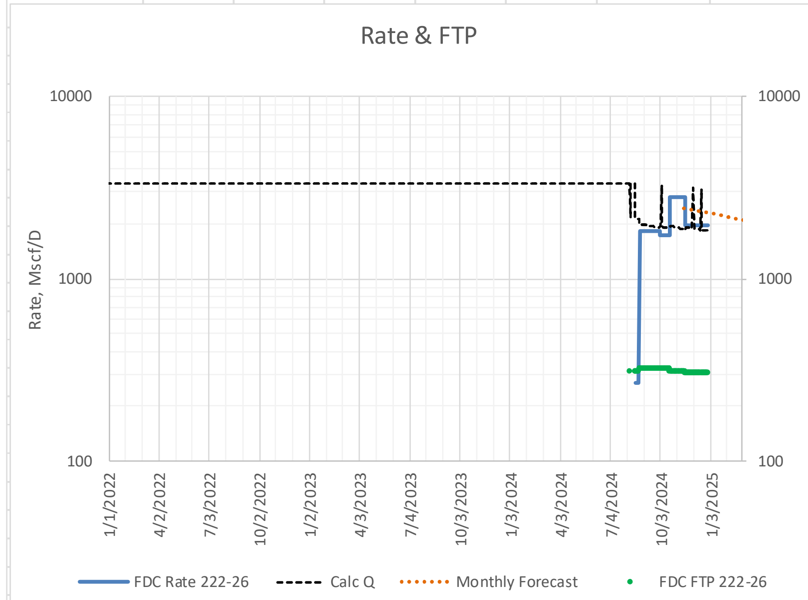
BRU 222-26

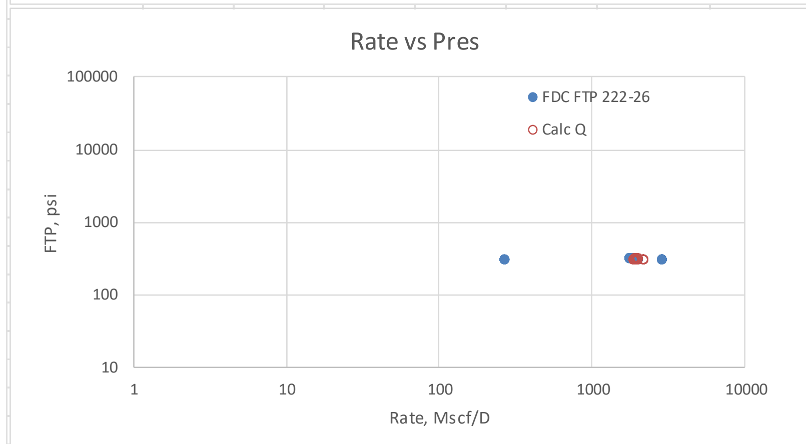


		Decline Info	Primary	Inc. Wellwork
Gp(12/2024), MMscf	274	Decline Trend Start Date	11/2024	7/1/2024
Forecast(1/2025), MMscf	1,816	Initial Trend Rate, Mscf/d	2500	-
First Produced	7/2024	Decline, %/yr	40.0	23.0
Last Produced	12/2024	Wellwork Date		1/1/2050
		Wellwork Initial Rate, Mscf/d		-
		Forecast(1/2025), MMscf	1,816	-

Last 10 years of production displayed
Well forecast estimated to 1/2035
EOFL determined on field level

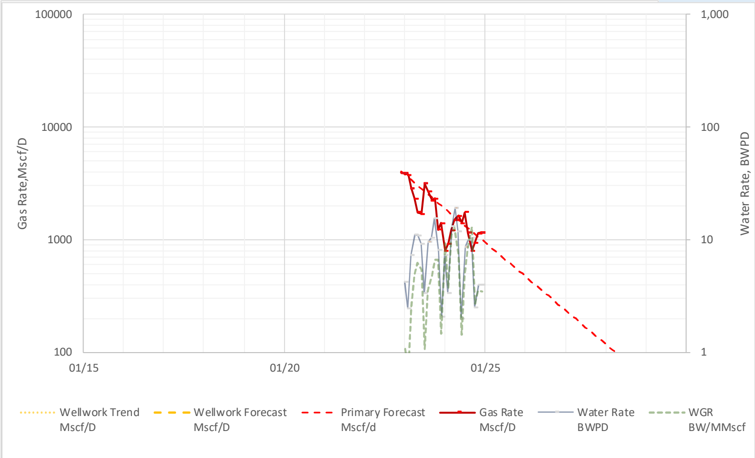
					1/1/2024
	222-26				
Pr(start of forecast)	525	n	0.8	Pr(1/2024)	520 psi
Gp remaining, MMscf	3700	C	0.15		





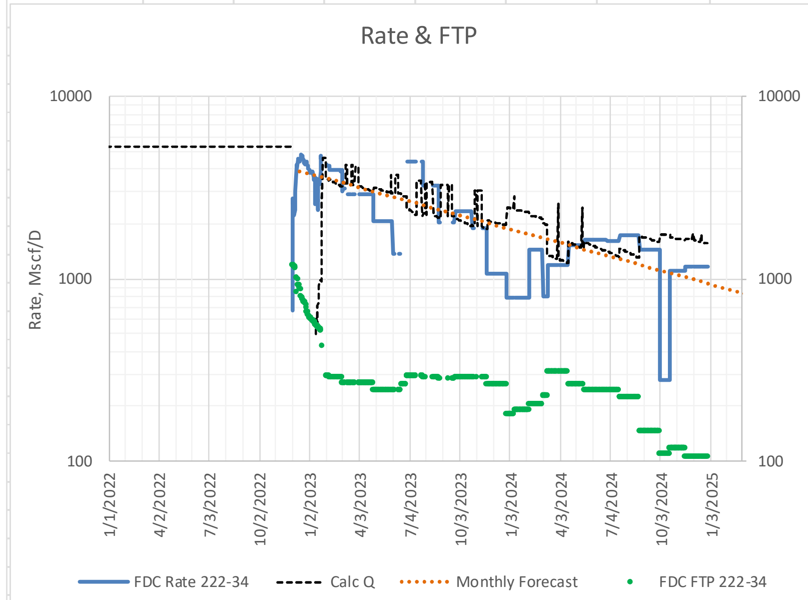
Forecast difference suggests potential wellwork.

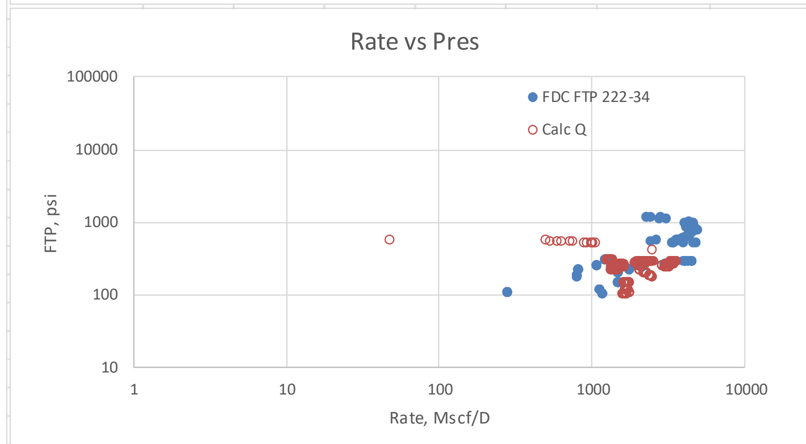
BRU 222-34

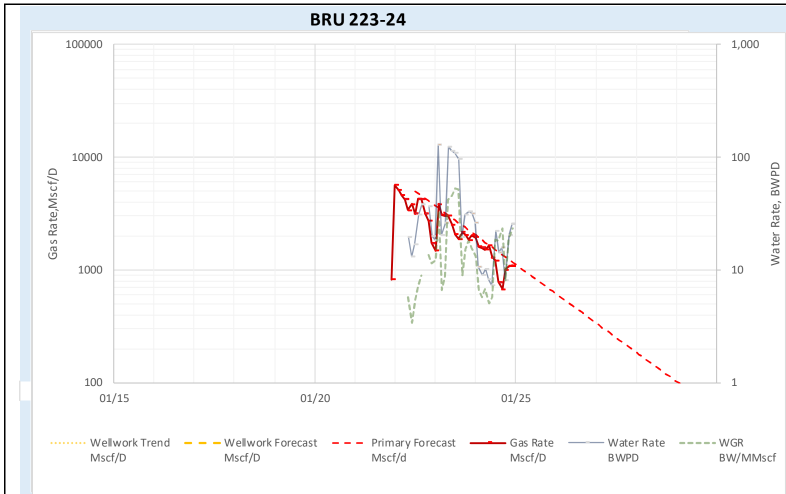


Gp(12/2024), MMscf	1,432	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,023	Decline Trend Start Date	12/2022	
First Produced	12/2022	Initial Trend Rate, Mscf/d	4000	-
Last Produced	12/2024	Decline, %/yr	50.0	20.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,023	-

					1/1/2024	
	222-34					
Pr(start of forecast)	700		n	0.8	Pr(1/2024)	470 psi
Gp remaining, MMscf	1000		C	0.15		

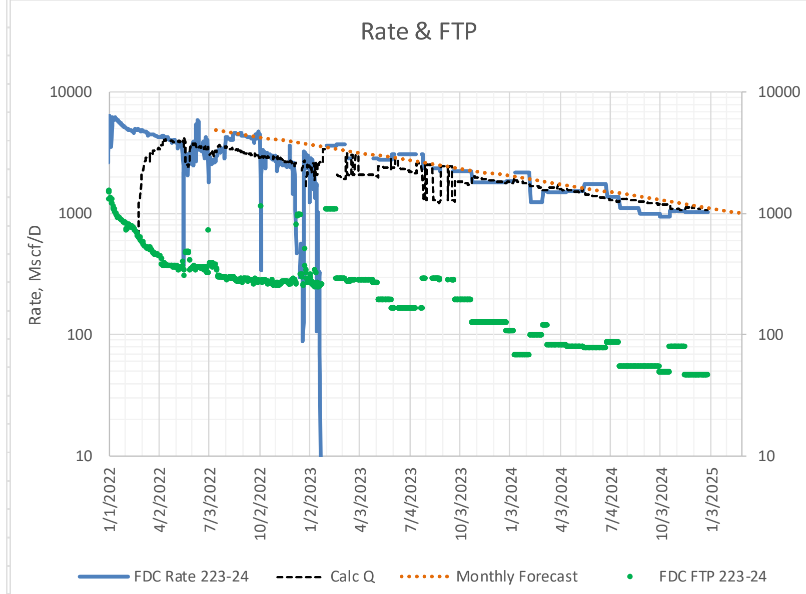


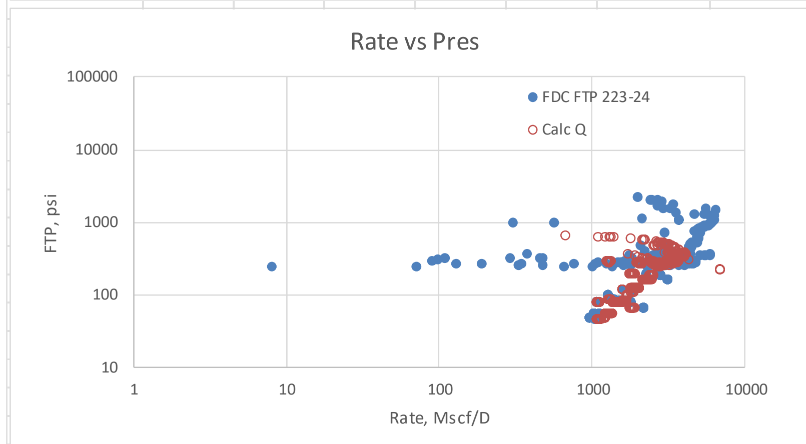




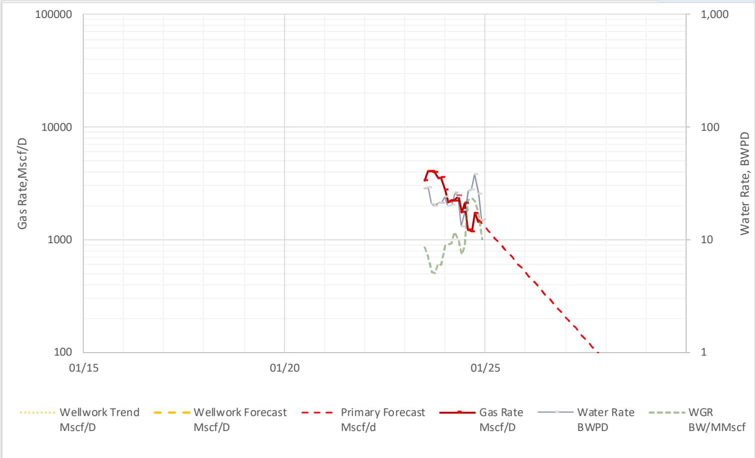
Gp(12/2024), MMscf	2,742	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,273	Decline Trend Start Date	7/2022	
First Produced	12/2021	Initial Trend Rate, Mscf/d	5000	-
Last Produced	12/2024	Decline, %/yr	45.0	24.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,273	-

				1/1/2024
	223-24			
Pr(start of forecast)	850	n	0.8	Pr(1/2024) 380 psi
Gp remaining, MMscf	800	C	0.15	



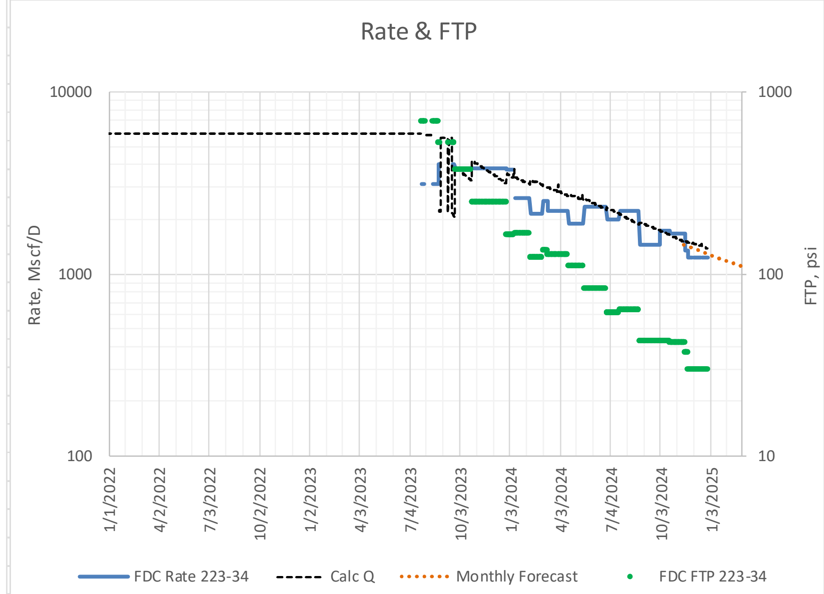


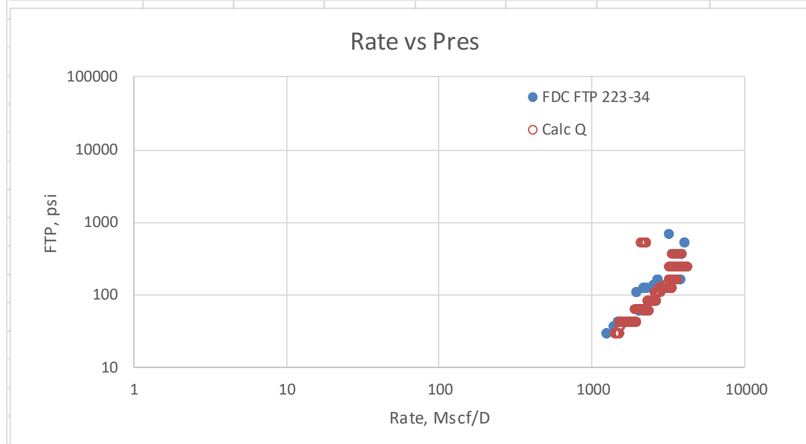
BRU 223-34



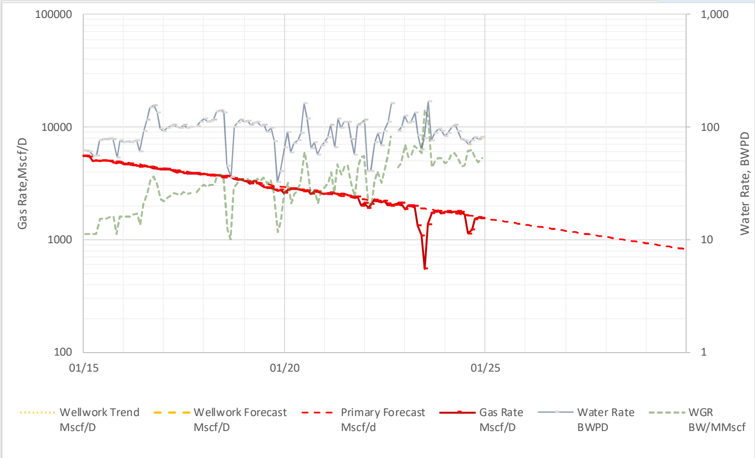
Gp(12/2024), MMscf	1,331	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	621	Decline Trend Start Date	11/2024	
First Produced	7/2023	Initial Trend Rate, Mscf/d	1500	-
Last Produced	12/2024	Decline, %/yr	60.0	0.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	621	-

				1/1/2024
	223-34			
Pr(start of forecast)	750	n	0.8	Pr(1/2024) 580 psi
Gp remaining, MMscf	600	C	0.15	



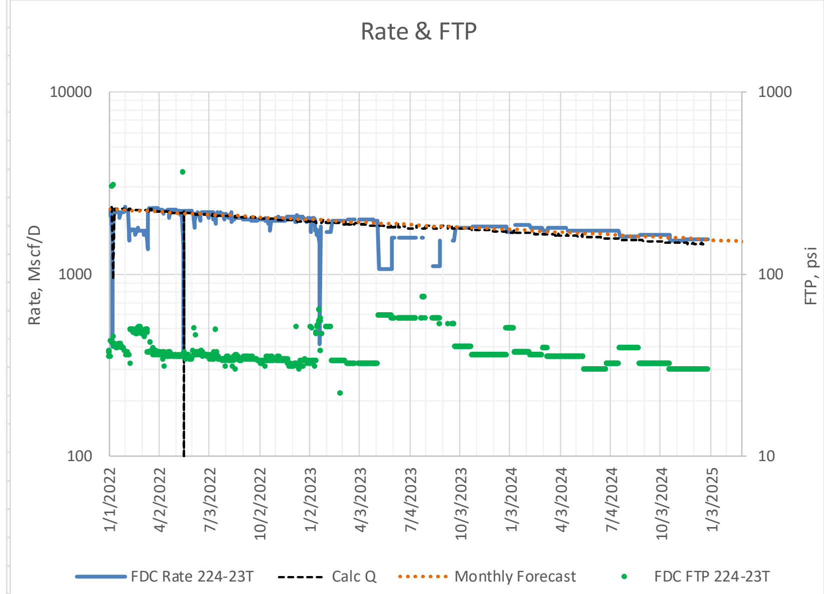


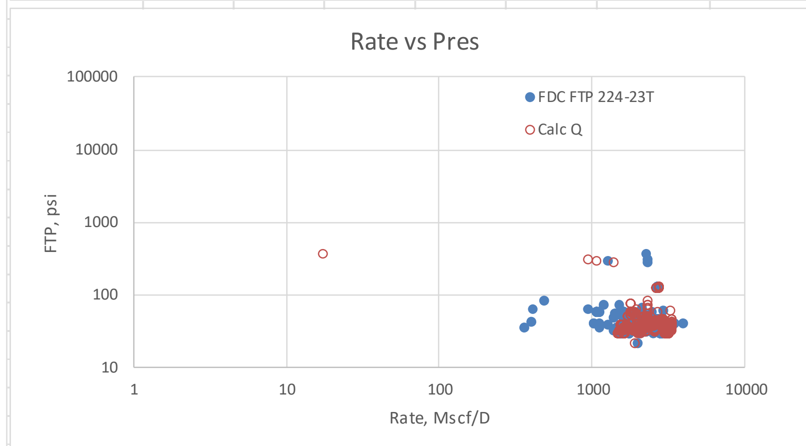
BRU 224-23T



Gp(12/2024), MMscf	17,958	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	3,817	Decline Trend Start Date	11/2015	
First Produced	10/2011	Initial Trend Rate, Mscf/d	5000	-
Last Produced	12/2024	Decline, %/yr	12.0	12.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	3,817	-

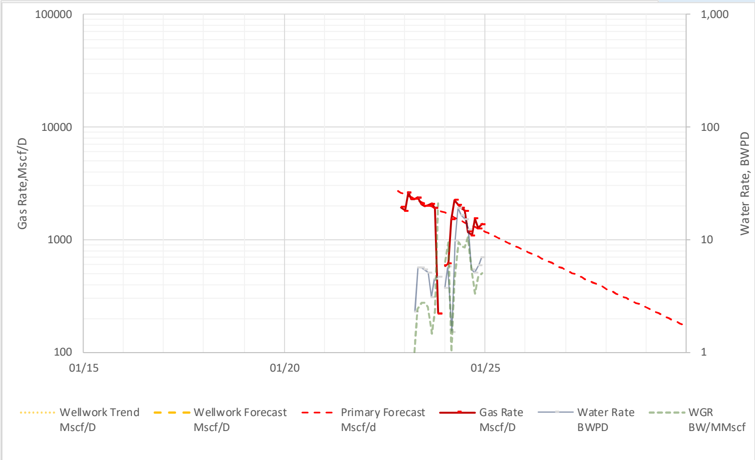
				1/1/2024	
	224-23T				
Pr(start of forecast)	525	n	0.8	Pr(1/2024)	350 psi
Gp remaining, MMscf	4300	C	0.15		





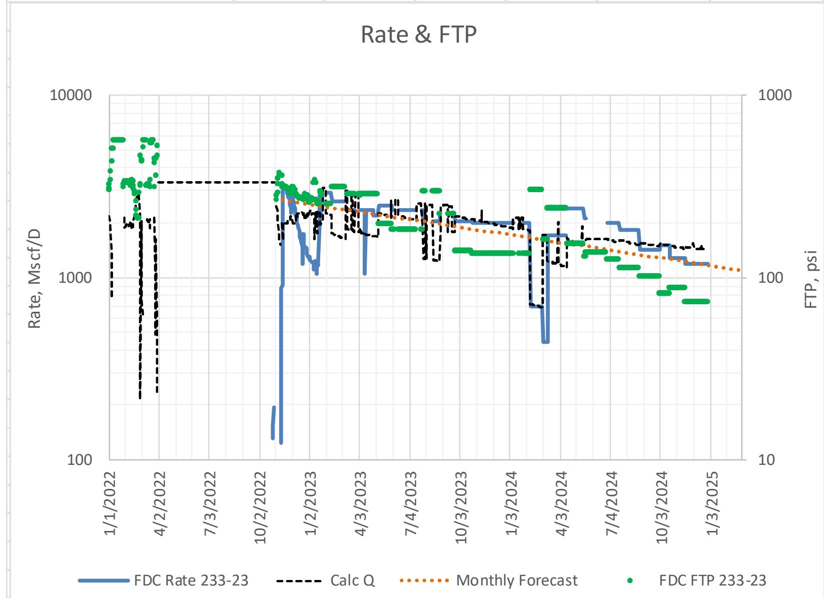
Forecast difference suggests potential wellwork.

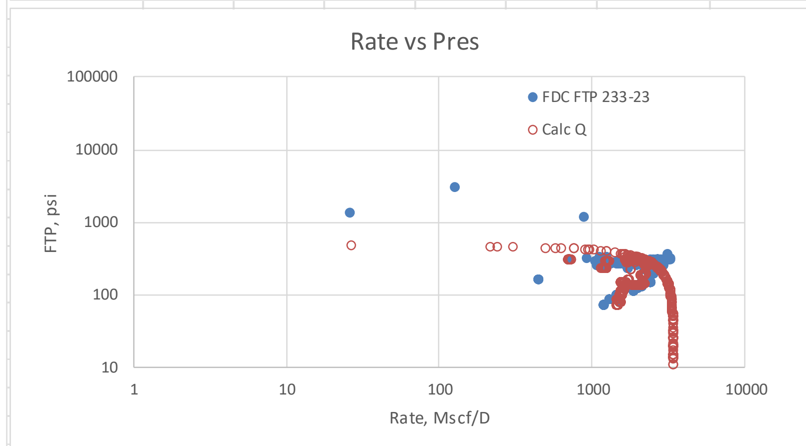
BRU 233-23



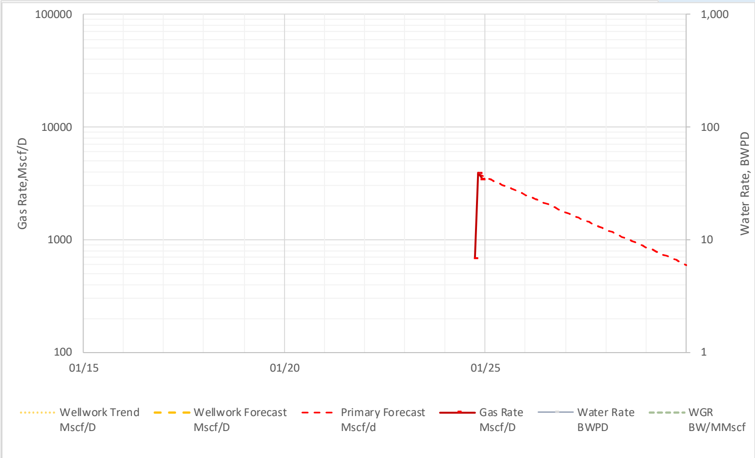
Gp(12/2024), MMscf	1,221	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,633	Decline Trend Start Date	11/2022	
First Produced	10/2022	Initial Trend Rate, Mscf/d	2700	-
Last Produced	12/2024	Decline, %/yr	32.0	20.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,633	-

					1/1/2024	
	233-23					
Pr(start of forecast)	525		n	0.8	Pr(1/2024)	400 psi
Gp remaining, MMscf	1500		C	0.15		



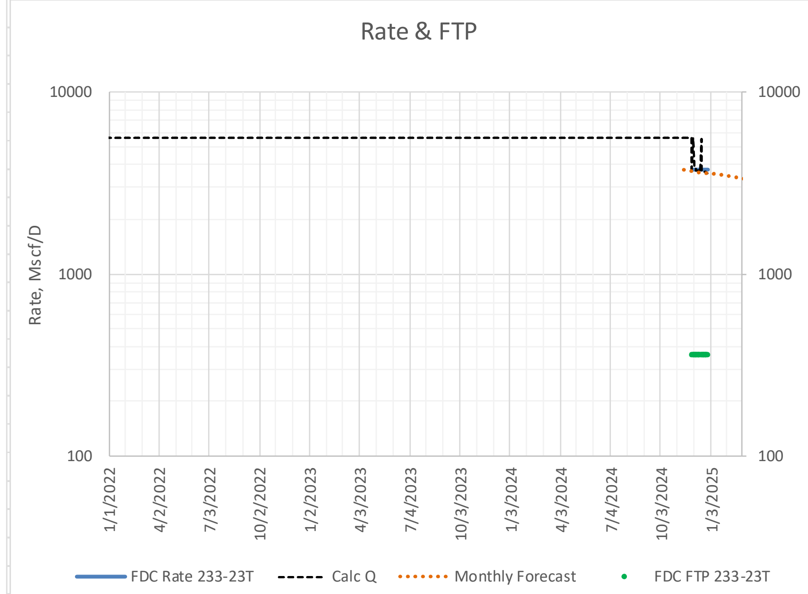


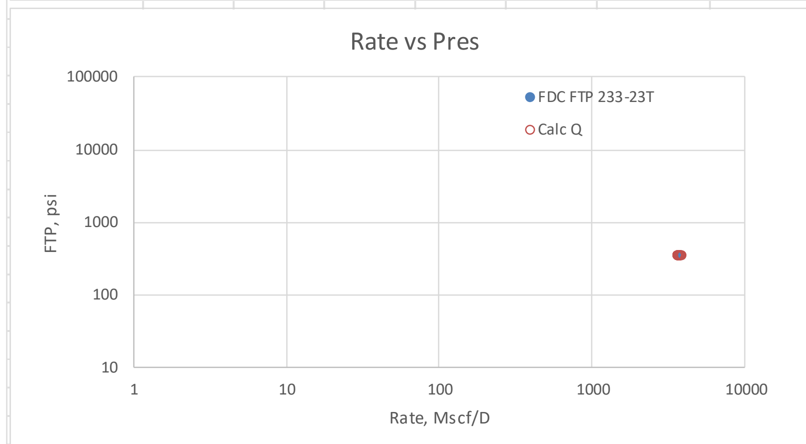
BRU 233-23T



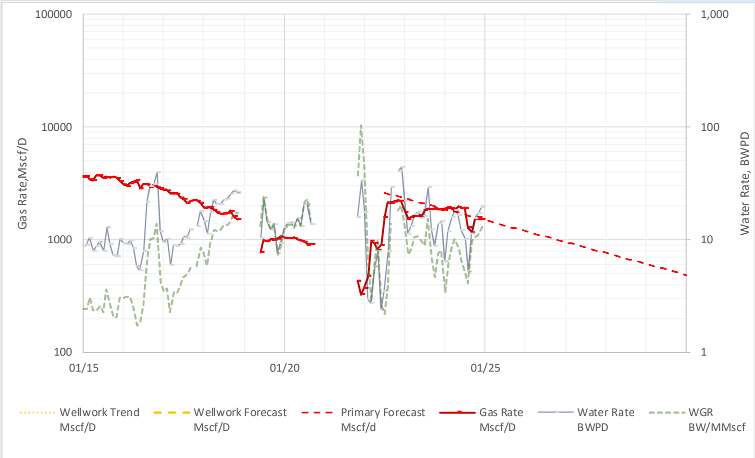
Gp(12/2024), MMscf	245	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	3,844	Decline Trend Start Date	11/2024	7/1/2024
First Produced	10/2024	Initial Trend Rate, Mscf/d	3800	-
Last Produced	12/2024	Decline, %/yr	30.0	23.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	3,844	-

					1/1/2024
	233-23T				
Pr(start of forecast)	725	n	0.8	Pr(1/2024)	720 psi
Gp remaining, MMscf	3800	C	0.15		



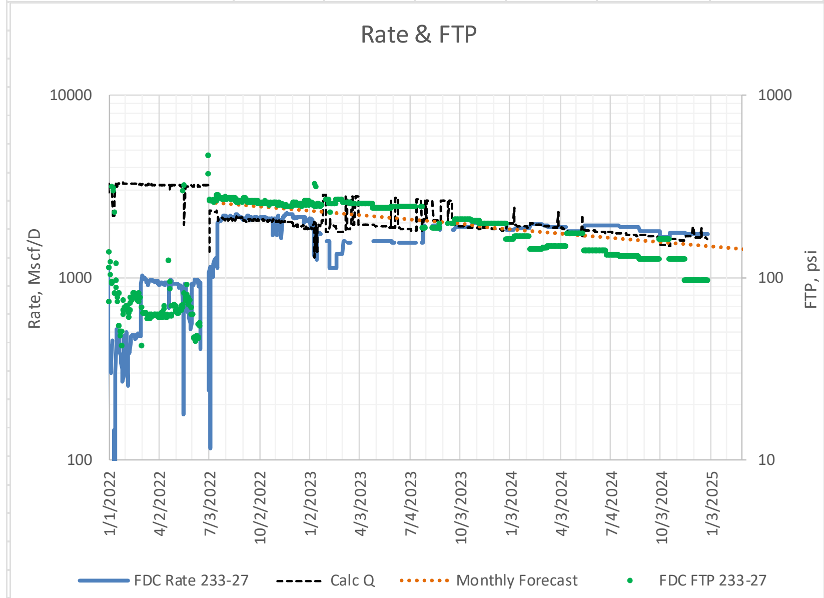


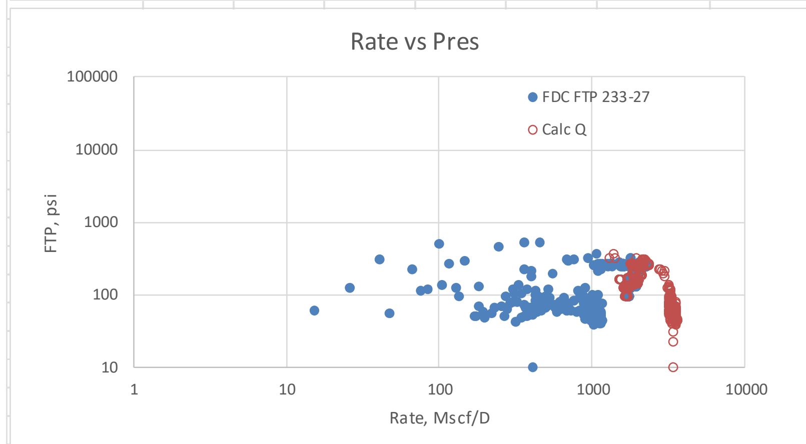
BRU 233-27



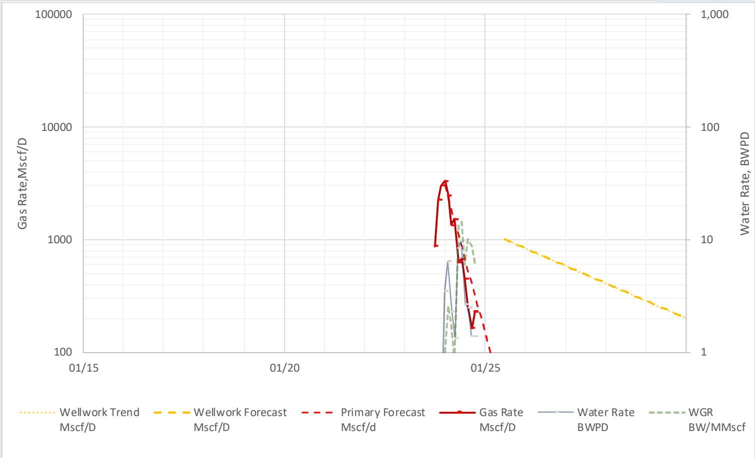
Gp(12/2024), MMscf	68,610	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	2,808	Decline Trend Start Date	7/2022	
First Produced	5/1968	Initial Trend Rate, Mscf/d	2600	-
Last Produced	12/2024	Decline, %/yr	20.0	25.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	2,808	-

				1/1/2024
	233-27			
Pr(start of forecast)	550	n	0.8	Pr(1/2024) 430 psi
Gp remaining, MMscf	2900	C	0.15	



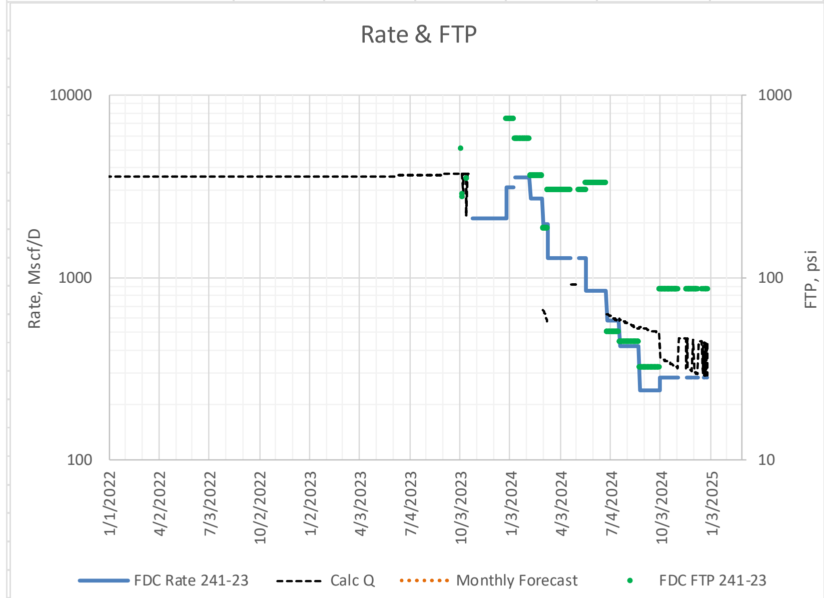


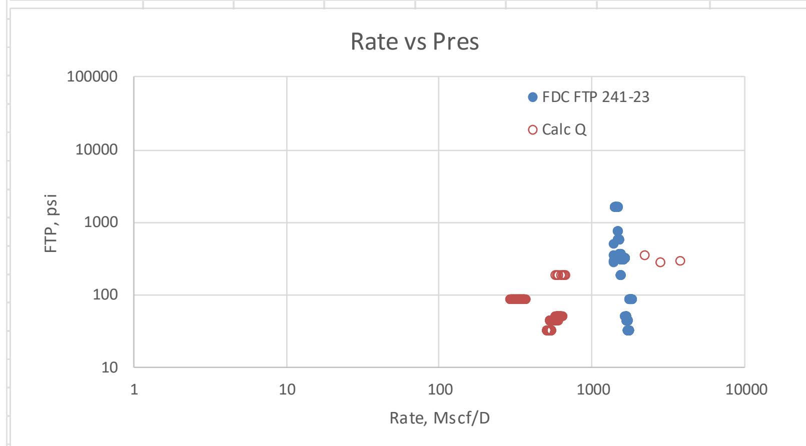
BRU 241-23



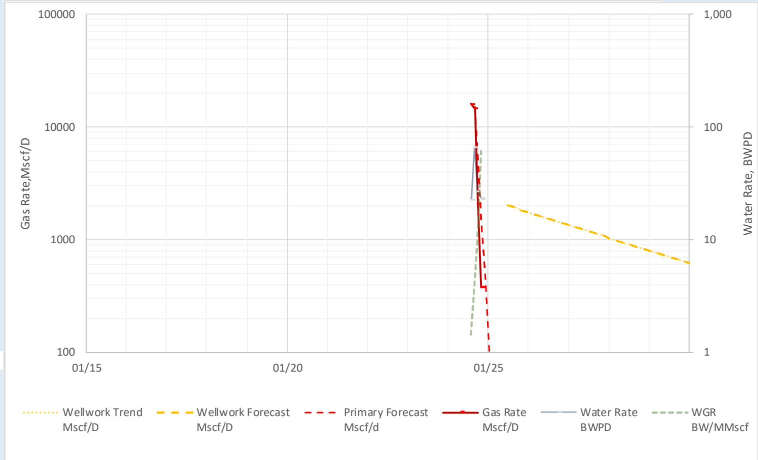
Gp(12/2024), MMscf	462	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	413	Decline Trend Start Date	1/2024	7/1/2025
First Produced	10/2023	Initial Trend Rate, Mscf/d	3000	1,000
Last Produced	10/2024	Decline, %/yr	95.0	30.0
Last 10 years of production displayed		Wellwork Date		7/1/2025
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		1,000
EOFL determined on field level		Forecast(1/2025), MMscf	413	1,000

				1/1/2024
	241-23			
Pr(start of forecast)	550	n	0.8	Pr(1/2024) 440 psi
Gp remaining, MMscf	100	C	0.15	



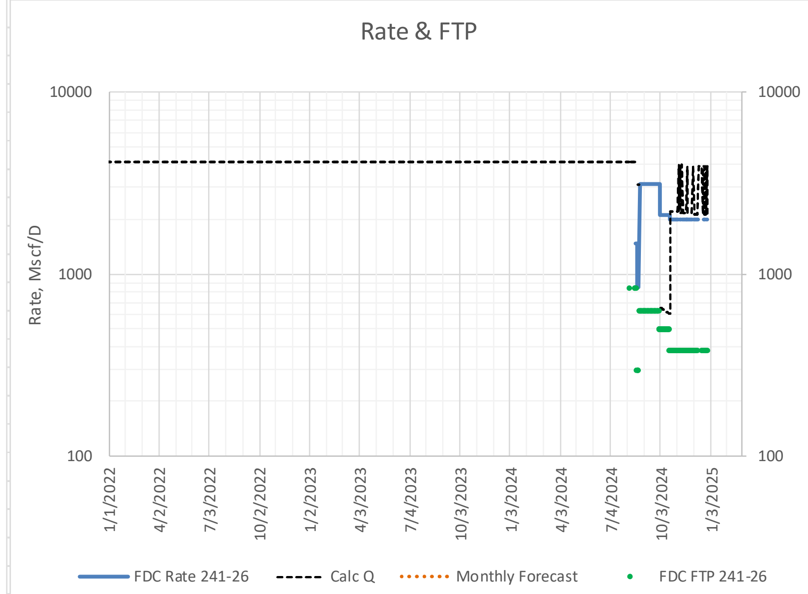


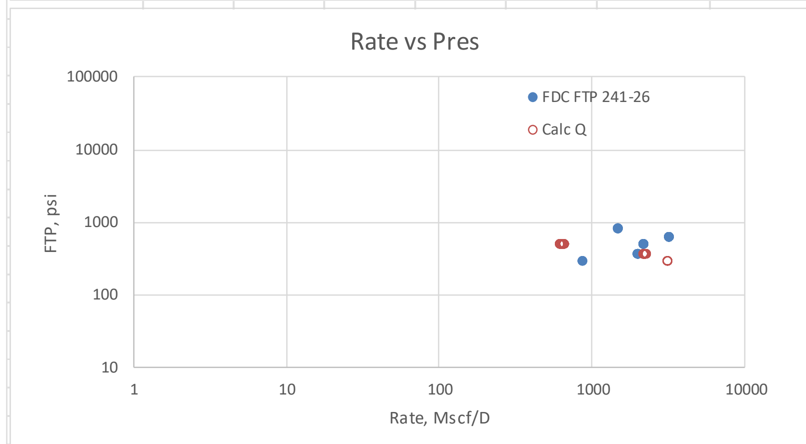
BRU 241-26



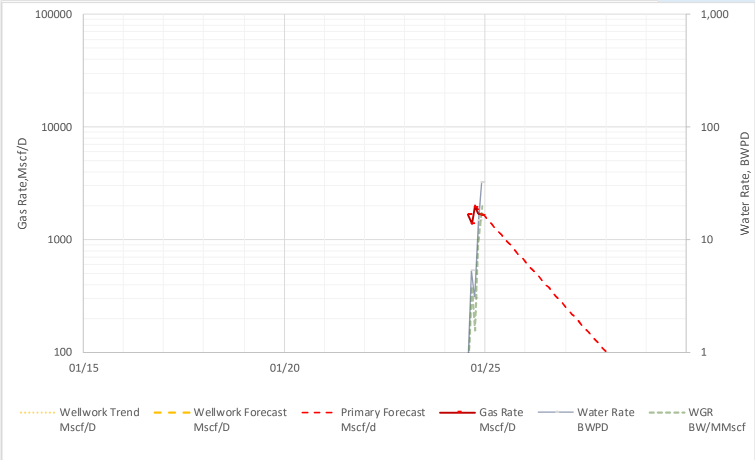
Gp(12/2024), MMscf	967	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	666	Decline Trend Start Date	9/2024	7/1/2025
First Produced	8/2024	Initial Trend Rate, Mscf/d	15000	2,000
Last Produced	11/2024	Decline, %/yr	100.0	23.0
Last 10 years of production displayed		Wellwork Date		7/1/2025
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		2,000
EOFL determined on field level		Forecast(1/2025), MMscf	666	2,590

					1/1/2024	
	241-26					
Pr(start of forecast)	600		n	0.8	Pr(1/2024)	600 psi
Gp remaining, MMscf	6200		C	0.15		



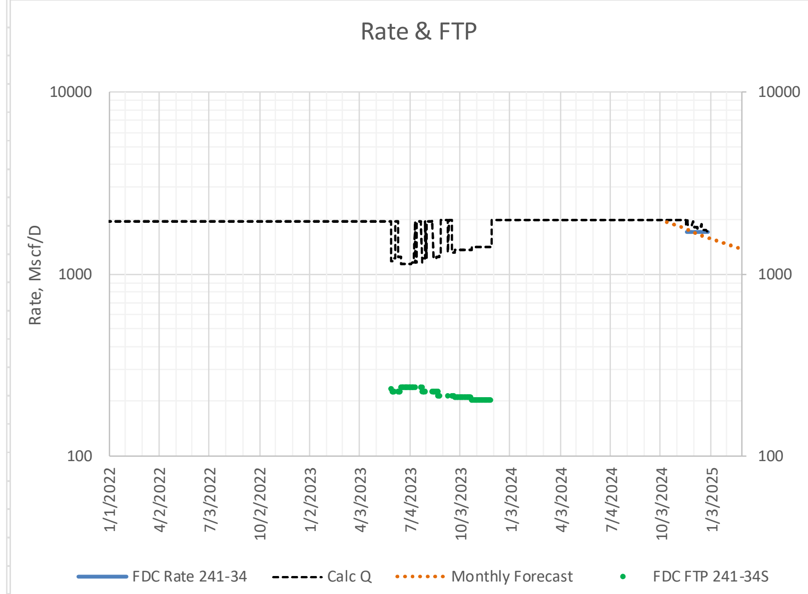


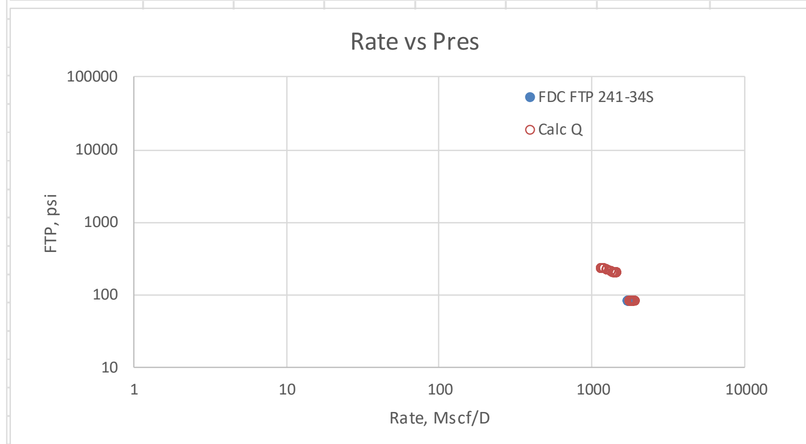
BRU 241-34S



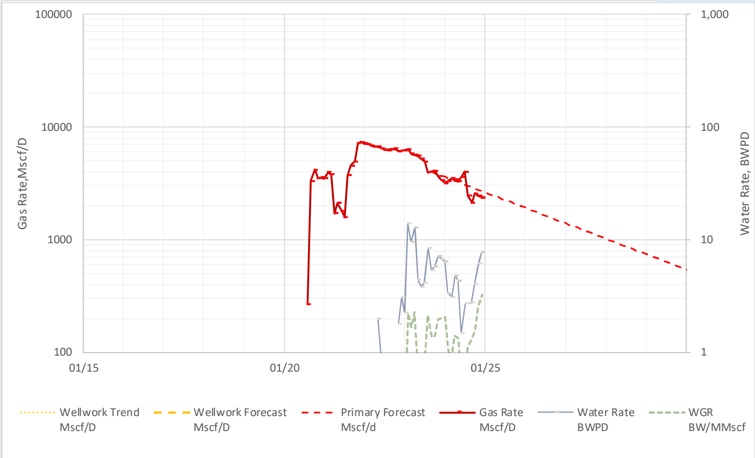
Gp(12/2024), MMscf	257	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	828	Decline Trend Start Date	10/2024	7/1/2024
First Produced	8/2024	Initial Trend Rate, Mscf/d	2000	-
Last Produced	12/2024	Decline, %/yr	60.0	23.0
Last 10 years of production displayed		Wellwork Date		1/1/2050
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	828	-

					1/1/2024
	241-34S				
Pr(start of forecast)	375	n	0.8	Pr(1/2024)	380 psi
Gp remaining, MMscf	1000	C	0.15		





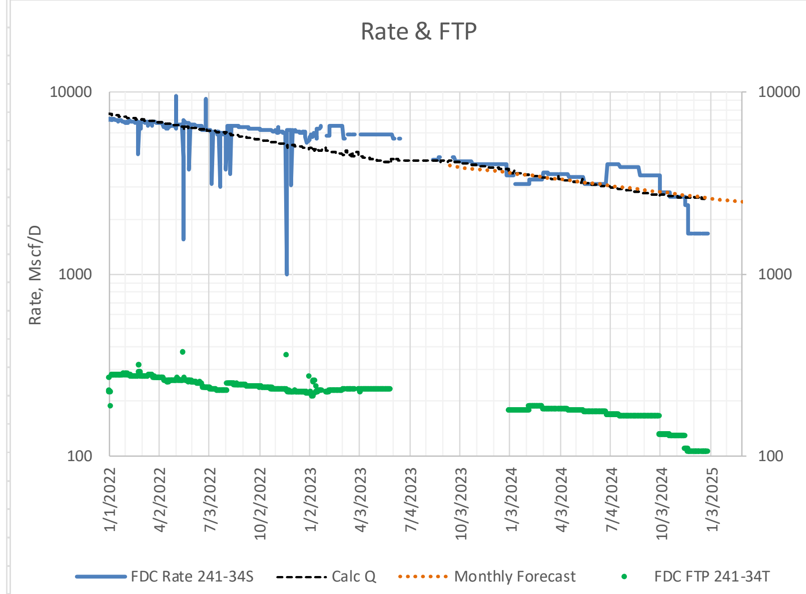
BRU 241-34T

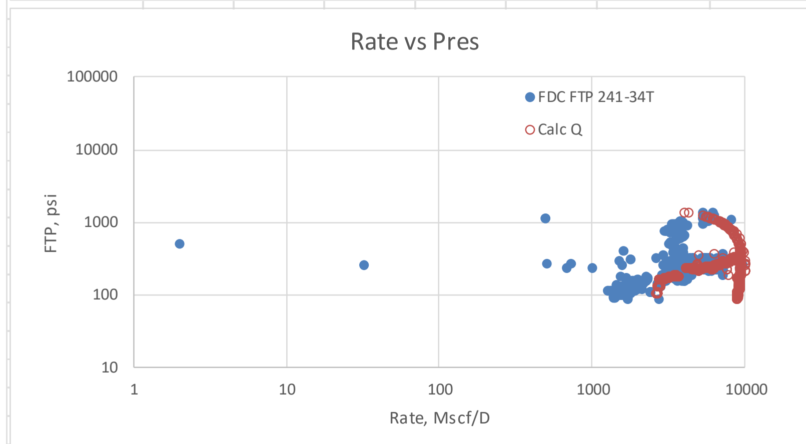


		Decline Info	Primary	Inc. Wellwork
Gp(12/2024), MMscf	7,063			
Forecast(1/2025), MMscf	4,101	Decline Trend Start Date	9/2023	
First Produced	8/2020	Initial Trend Rate, Mscf/d	4000	-
Last Produced	12/2024	Decline, %/yr	27.0	0.0
		Wellwork Date		
		Wellwork Initial Rate, Mscf/d		-
		Forecast(1/2025), MMscf	4,101	-

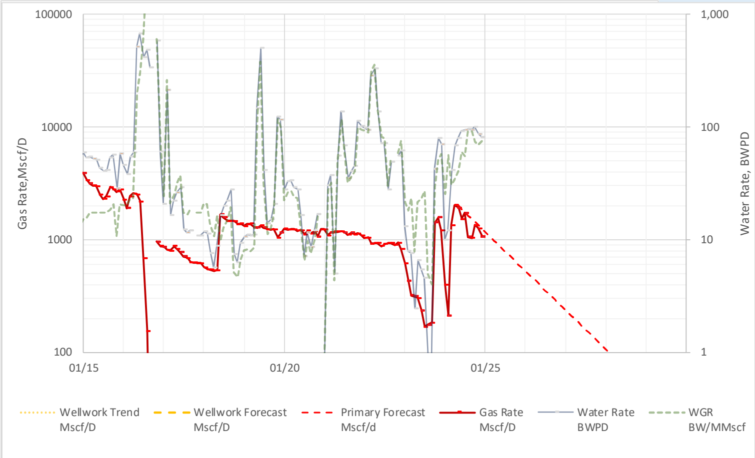
Last 10 years of production displayed
Well forecast estimated to 1/2035
EOFL determined on field level

					1/1/2024
	241-34T				
Pr(start of forecast)	1850	n	0.8	Pr(1/2024)	1000 psi
Gp remaining, MMscf	4100	C	0.06		



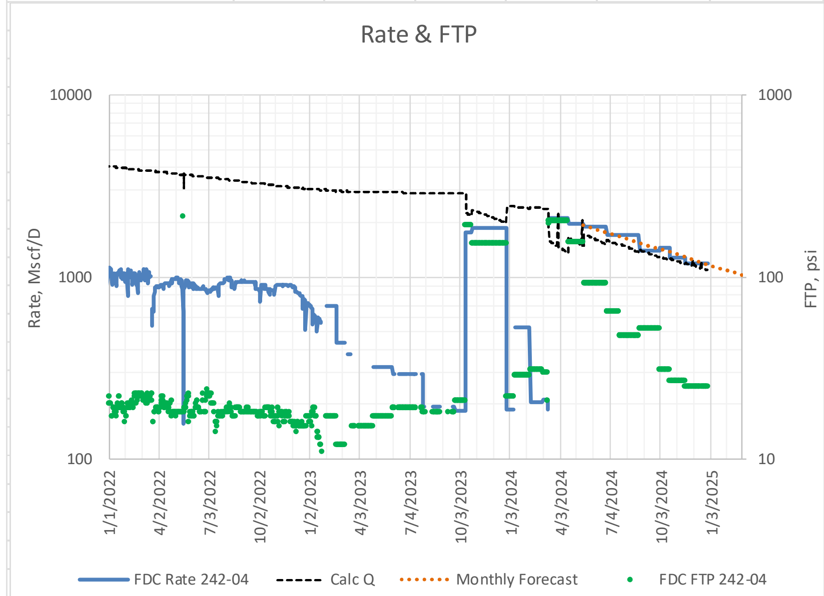


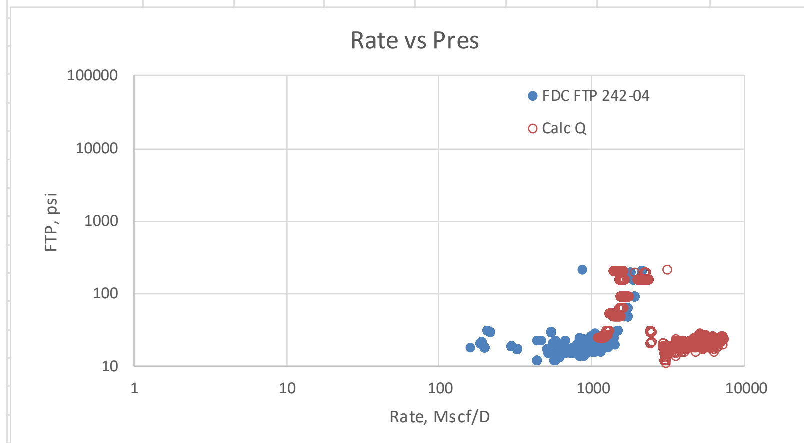
BRU 242-04



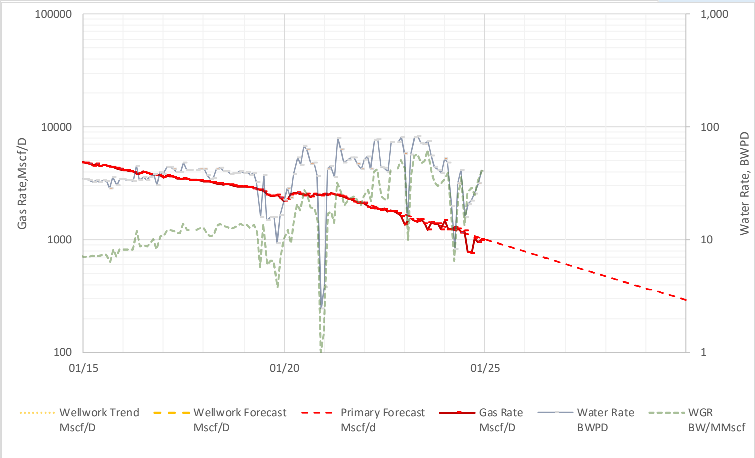
			Primary	Inc. Wellwork
Gp(12/2024), MMscf	5,186	Decline Info		
Forecast(1/2025), MMscf	945	Decline Trend Start Date	5/2024	
First Produced	7/2014	Initial Trend Rate, Mscf/d	2000	-
Last Produced	12/2024	Decline, %/yr	55.0	20.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	945	-

				1/1/2024
	242-04			
Pr(start of forecast)	850	n	0.8	Pr(1/2024) 430 psi
Gp remaining, MMscf	600	C	0.15	



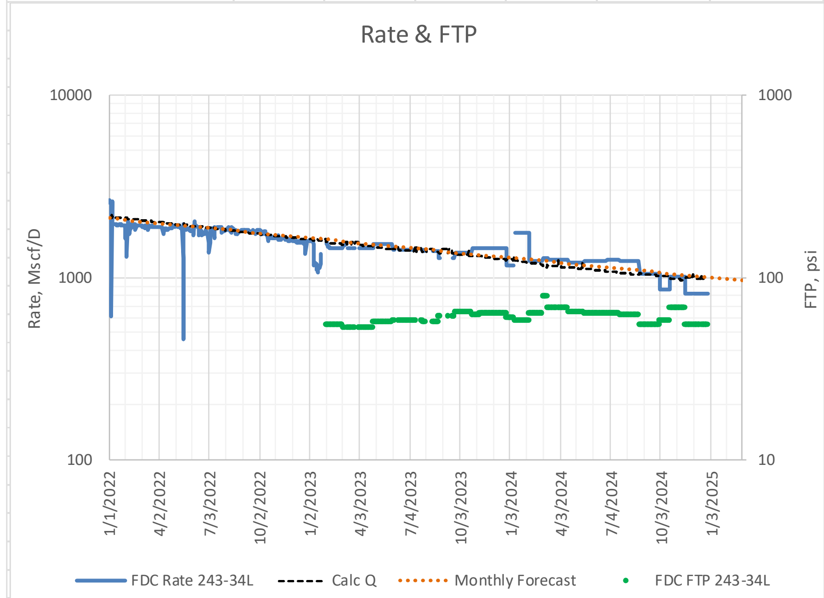


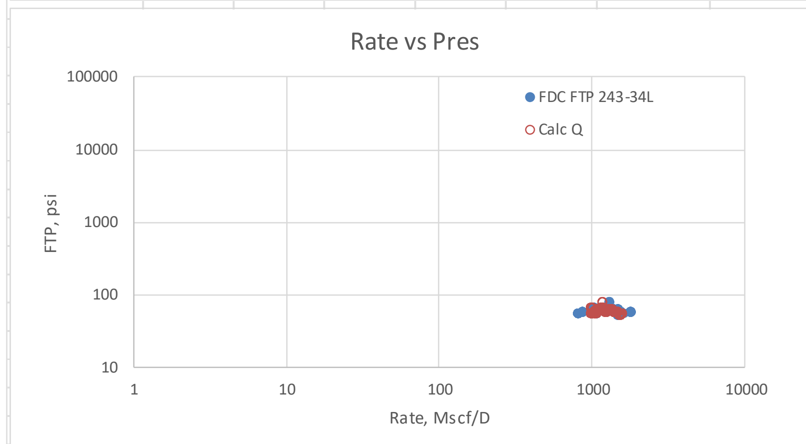
BRU 243-34



Gp(12/2024), MMscf	23,183	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	1,789	Decline Trend Start Date	5/2021	
First Produced	8/2008	Initial Trend Rate, Mscf/d	2500	-
Last Produced	12/2024	Decline, %/yr	22.0	11.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	1,789	-

				1/1/2024
	243-34L			
Pr(start of forecast)	575	n	0.8	Pr(1/2024) 290 psi
Gp remaining, MMscf	1800	C	0.15	

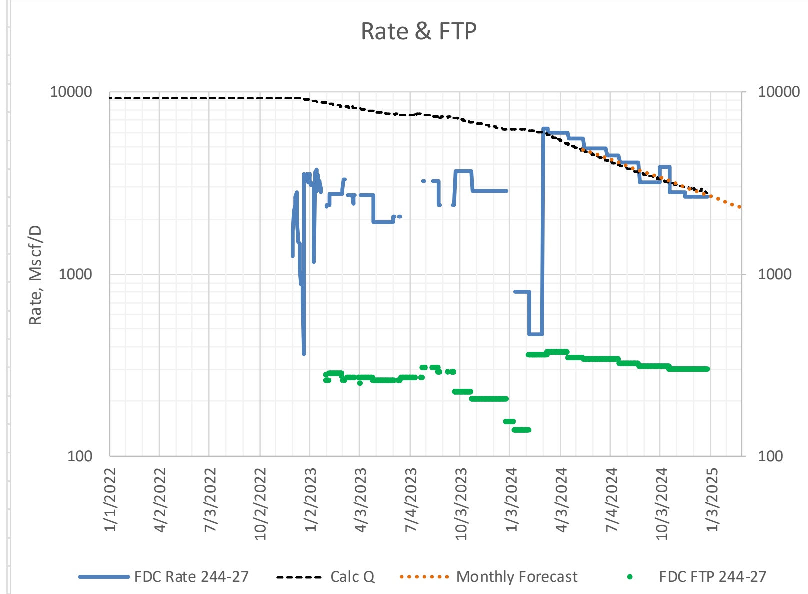


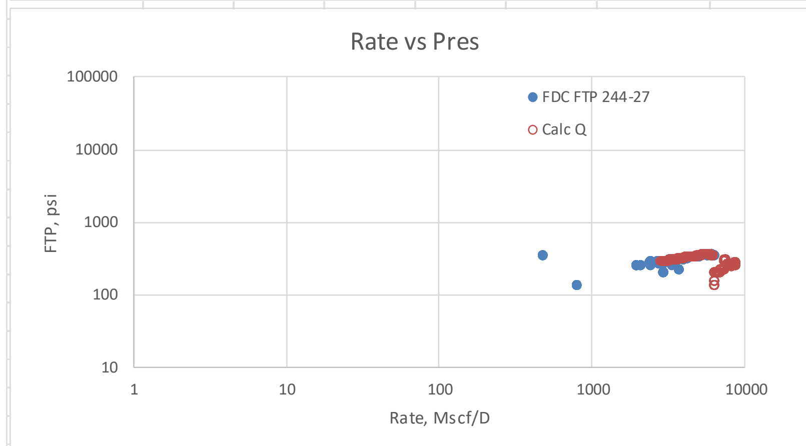


BRU 244-27

Gp(12/2024), MMscf	2,278	Decline Info	Primary	Inc. Wellwork
Forecast(1/2025), MMscf	2,070	Decline Trend Start Date	5/2024	
First Produced	12/2022	Initial Trend Rate, Mscf/d	5000	-
Last Produced	12/2024	Decline, %/yr	60.0	20.0
Last 10 years of production displayed		Wellwork Date		
Well forecast estimated to 1/2035		Wellwork Initial Rate, Mscf/d		-
EOFL determined on field level		Forecast(1/2025), MMscf	2,070	-

				1/1/2024	
	244-27				
Pr(start of forecast)	3500	n	0.8	Pr(1/2024)	2730 psi
Gp remaining, MMscf	1900	C	0.02		





End of Field Life Calculation

End Historical Prod	12/1/2024	Max Cash Flow	$ 388,660,662	
Reserve Date	1/1/2025	EOFL	3/1/2035	
Annual OpEx, $	11,500,000	Gp 12/2024	1,478,833	Historical P CEA Net
Fuel Gas, Mscf/d	1250	Gp est to 1/2025	-	Forecast to Reserve start date
Gas Price, $/Mscf	8.39	PDP 1/2025	42,992	Active Producers
Royalty, %	12.5%	PNP 1/2025	4,049	SI wells and PDP wellwork
Tax, $/Mscf	0.177	PUD 1/2025	15,671	Development Wells
CEA Interest	0.66666666	Prob 12/2021	25,245	

MSCF/D

Year	Date	YE Date	Historical Production Mscf/D	Production Estimate Mscf/D	PDP Forecast Mscf/D	PNP Incr. Wellwork Mscf/D	PUD Incr. Wellwork Mscf/D	PUD Mscf/D	Prob+Poss Mscf/D	Total Rate Mscf/D
2021	1/1/2021	12/31/2020	23,910	-	-	-	-	-	-	23,910
2022	1/1/2022	12/31/2021	29,638	-	-	-	-	-	-	29,638
2023	1/1/2023	12/31/2022	40,356	-	-	-	-	-	-	40,356
2024	1/1/2024	12/31/2023	42,017	-	-	-	-	-	-	42,017
2025	1/1/2025	12/31/2024	42,394	-	-	-	-	-	-	42,394
2026	1/1/2026	12/31/2025	-	-	28,791	2,654	-	7,107	-	38,552
2027	1/1/2027	12/31/2026	-	-	19,170	2,364	-	12,779	-	34,314
2028	1/1/2028	12/31/2027	-	-	13,460	1,752	-	9,146	6,471	30,828
2029	1/1/2029	12/31/2028	-	-	9,863	1,300	-	5,750	10,426	27,339
2030	1/1/2030	12/31/2029	-	-	7,496	967	-	3,700	13,401	25,565
2031	1/1/2031	12/31/2030	-	-	5,868	721	-	2,426	16,175	25,190
2032	1/1/2032	12/31/2031	-	-	4,706	539	-	1,615	12,014	18,874
2033	1/1/2033	12/31/2032	-	-	3,851	403	-	1,087	6,994	12,335
2034	1/1/2034	12/31/2033	-	-	3,207	303	-	739	4,218	8,467
2035	1/1/2035	12/31/2034	-	-	2,710	227	-	506	2,633	6,077
2036	1/1/2036	12/31/2035	-	-	2,318	171	-	348	1,699	4,536
2037	1/1/2037	12/31/2036	-	-	2,001	129	-	240	1,128	3,499
2038	1/1/2038	12/31/2037	-	-	1,744	97	-	167	770	2,778
2039	1/1/2039	12/31/2038	-	-	1,530	74	-	116	537	2,256
2040	1/1/2040	12/31/2039	-	-	1,350	56	-	80	381	1,868

Cumulative Production

Year	Dev Well Cost $	Period Cash Flow (less fuel, royalty, OpEx,tax, DevWellCost) $	Cum Cash Flow $	EOFL	Gp Cum MMscf	Gp Cum est MMscf	PDP Cum MMscf	PNP Cum MMscf	PUD Cum MMscf	Prob + Poss Cum MMSCF
2021	-	-	-	12/1/2020	1,428,331	-	-	-	-	-
2022	-	-	-	12/1/2021	1,437,038	-	-	-	-	-
2023	-	-	-	12/1/2022	1,449,422	-	-	-	-	-
2024	-	-	-	12/1/2023	1,463,111	-	-	-	-	-
2025	-	-	-	12/1/2024	1,478,833	-	-	-	-	-
2026	30,000,000	44,378,760	44,378,760		-	-	13,084	520	472	-
2027	30,000,000	34,078,941	78,457,700		-	-	21,526	1,423	4,325	-
2028	18,000,000	34,944,280	113,401,980	12/1/2027	-	-	27,306	2,159	8,529	929
2029	18,000,000	28,743,385	142,145,365	12/1/2028	-	-	31,470	2,706	11,148	3,834
2030	24,000,000	15,515,474	157,660,839	12/1/2029	-	-	34,572	3,112	12,810	7,887
2031	24,000,000	8,443,126	166,103,965	12/1/2030	-	-	36,968	3,414	13,891	12,906
2032	-	38,290,212	204,394,177	12/1/2031	-	-	38,868	3,640	14,604	18,563
2033	-	24,725,549	229,119,726	12/1/2032	-	-	40,413	3,809	15,084	21,871
2034	-	11,654,398	240,774,123	12/1/2033	-	-	41,686	3,935	15,407	23,826
2035	-	3,794,174	244,568,297	12/1/2034	-	-	42,754	4,030	15,628	25,025
2036	-	(1,165,501)	243,402,796		-	-	-	-	-	-
2037	-	(4,446,376)	238,956,420		-	-	-	-	-	-
2038	-	(6,673,769)	232,282,651		-	-	-	-	-	-
2039	-	(8,262,846)	224,019,805		-	-	-	-	-	-
2040	-	(9,429,858)	214,589,947		-	-	-	-	-	-

Attachment C

CHUGACH ELECTRIC ASSOCIATION

Estimated

Future Reserves

Attributable to Certain Leasehold Interests

in the

Beluga River Unit

Constant Prices and Escalated Costs

As of

December 31, 2024

STATE OF ALASKA
49TH
SCOTT J. WILSON
EP 7966
REGISTERED PROFESSIONAL ENGINEER

6/26/2025

Scott J. Wilson, PE, MBA.
Alaska License EP 7966
Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

June 26, 2025

Mr. Arthur Miller
Chugach Electric Association
5601 Electron Dr.
Anchorage, AK 99518

Dear Mr. Miller:

At the request of Chugach Electric Association (CEA), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved, probable, and possible reserves of the Beluga River Unit, operated by Hilcorp in the Cook Inlet region of Alaska. The reserves estimates, effective as of December 31, 2024, were prepared by Petrotechnical Resources of Alaska (PRA), acting as agents of CEA. For the purposes of this report, both CEA and PRA will be collectively referred to as "CEA."

The reserves volumes included herein for the reviewed properties were estimated based on the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and European Association of Geoscientists & Engineers (EAGE) 2018 Petroleum Resources Management System (SPE-PRMS), which were revised in June 2018, and used constant price and escalated cost parameters (SPE-PRMS forecast case) provided by CEA. Prices are held constant throughout the life of the properties. The results of our reserves audit, completed on June 26, 2025 are presented herein.

The estimated reserves shown herein represent CEA's estimated net reserves attributable to the leasehold interests in certain properties owned by CEA and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2024. The properties reviewed by Ryder Scott incorporate CEA's reserves determinations and are located in the state of Alaska.

The properties reviewed by Ryder Scott account for all of the total net proved, probable, and possible gas reserves of CEA as of December 31, 2024.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by CEA, it is our opinion that the overall procedures and methodologies utilized by CEA in preparing their estimates of the proved, probable, and possible reserves as of December 31, 2024 comply with the 2018 SPE-PRMS definitions and guidelines and that the overall proved, probable, and possible reserves for the reviewed properties as estimated by CEA are, in the aggregate by category, reasonable within the established audit tolerance guidelines set forth in the SPE auditing standards.

The estimated reserves presented in this report, as of December 31, 2024, are related to hydrocarbon prices based on constant price parameters. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by CEA attributable to CEA's interest in properties that we reviewed are summarized as follows:

CONSTANT PRICE AND ESCALATED PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests of
Chugach Electric Association
As of December 31, 2024

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	
Audited by Ryder Scott Net Reserves				
Gas – MMcf	27,137	2,556	9,892	39,584

	Probable Undeveloped	Possible Undeveloped
Audited by Ryder Scott Net Reserves		
Gas – MMcf	10,695	5,240

Values may not sum to total due to rounding

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Estimated volumes assigned to royalty interests and used in operations are included in the table above. Historically, 66.666666% of royalty volumes after deducting fuel have been made available for CEA's operations and are shown below.

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	
Audited by Ryder Scott 2/3 Royalty Reserves				
Gas – MMcf	3,392	319	1,236	4,948

	Probable Undeveloped	Possible Undeveloped
Audited by Ryder Scott		
2/3 Royalty Reserves		
Gas – MMcf	1,337	655

Values may not sum to total due to rounding

Reserves Included in This Report

The proved, probable, and possible reserves included herein conform to the definitions of reserves sponsored and approved by the SPE, WPC, AAPG, SPEE, SEG, SPWLA and EAGE as set forth in the 2018 SPE-PRMS and where applicable, based on constant price and escalated cost parameters (SPE-PRMS forecast case). The estimated quantities of reserves presented in this report, based on these parameters, may differ significantly from the quantities which would be estimated using constant price and cost parameters (SPE-PRMS constant case). Refer to the full SPE-PRMS, which can be located at https://www.spe.org/en/industry/reserves/ for the complete definitions and guidelines.

The various reserves development and production status, as described in this report, are also fully defined in the SPE-PRMS located in the website mentioned above. The developed proved non-producing reserves included herein consist of the Shut-in and Behind Pipe status categories.

Accumulated gas production imbalances, if any, were not taken into account in the proved, probable, and possible gas reserves estimates reviewed. The proved, probable, and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Recoverable petroleum resources may be classified according to the SPE-PRMS into one of three principal resources classifications: prospective resources, contingent resources, or reserves. Only the reserves classification is addressed in this report. The distinction between prospective and contingent resources depends on whether or not there exists one or more wells and other data indicating the potential for moveable hydrocarbons (e.g. the discovery status). Discovered petroleum resources may be classified as either contingent resources or as reserves depending on the chance that if a project is implemented it will reach commercial producing status (e.g. chance of commerciality - P_c). The distinction between various “classifications” of resources and reserves relates to their discovery status and increasing chance of commerciality. Commerciality is not solely determined based on the economic status of a project, which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions addressed in the determination of commerciality also include technological, economic, legal, environmental, social, and governmental factors. While economic factors are generally related to costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes. At CEA’s request, this report addresses only the proved, probable, and possible reserves attributable to the properties reviewed herein.

All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. Estimates will generally be revised only as additional geologic or engineering data becomes available or as economic conditions change.

Reserves are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions." The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved.

Proved oil and gas reserves are "those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations."

Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Probable reserves are "those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves." For probable reserves, it is "equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves" (cumulative 2P volumes). Possible reserves are "those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than probable reserves." For possible reserves, the "total quantities ultimately recovered from the project have a low probability to exceed the sum of the proved plus probable plus possible reserves" (cumulative 3P volumes).

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty.

The reserves volumes quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable. Petroleum reserves under different categories such as proved, probable, and possible should not be aggregated with each other without due consideration of the appreciable differences in the criteria associated with their categorization.

Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves quantities involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of these data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of recoverable hydrocarbons is identified, the evaluator must determine the uncertainty associated with the incremental quantities of those recoverable hydrocarbons. If the quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of incremental recoverable quantities that addresses the inherent uncertainty in the estimated quantities reported.

Estimates of reserves quantities and their associated categories or classifications may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of the recoverable quantities and their associated categories or classifications may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves prepared by CEA were estimated by performance methods, the volumetric method, analogy, material balance or a combination of methods. CEA estimated proved producing reserves by performance methods or material balance using production and pressure data available through December 2024. The data utilized were obtained from public sources and were considered sufficient for the intended purpose.

The proved developed non-producing and the proved, probable, and possible undeveloped reserves that we reviewed were estimated by the volumetric method, analogy or a combination of methods. The data utilized from the analogues, as well as well data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

To estimate recoverable oil and gas reserves, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on the cost and price assumptions as noted herein, and forecasts of future production rates. Under the SPE-PRMS Section 1.1.0.6, “reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.” While it may reasonably be anticipated that the future prices received for the sale of production may increase or decrease from existing levels, such changes were omitted from consideration in making this evaluation.

As stated previously, proved, probable, and possible reserves must be demonstrated to be commercially recoverable under defined conditions, operating methods and governmental regulations from a given date forward. To confirm that the proved, probable, and possible reserves reviewed by us meet the SPE-PRMS guidelines to be commercially recoverable, we have reviewed certain primary economic data utilized by CEA relating to hydrocarbon prices and costs as noted herein.

PRA furnished us with contract and projected product prices for the properties reviewed. After 3/31/2028, the forecast prices were held constant for the life of each property. Specific economic parameters used in the evaluation are shown in the following table.

Annual Operating Expense	11,500,000	$/yr
Gas Price TA-481-8 (through 3/31/25)	7.78	$/Mscf
Gas Price TA-481-8 (through 3/31/26)	7.86	$/Mscf
Gas Price TA-481-8 (through 3/31/27)	7.95	$/Mscf
Gas Price TA-481-8 (through 3/31/28)	8.04	$/Mscf
Gas Price (4/1/28 forward, AK DOR forecast)	8.39	$/Mscf
Fuel Gas Rate	1,250	Mscf/D
Royalty	12.5	%
Tax Rate	0.177	$/Mscf

The product prices used for each property reviewed by us reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and/or distance from market and were furnished to us by CEA. Such adjustments were accepted by us as factual data.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in CEA's individual property evaluations.

Operating costs furnished by CEA are based on the operating expense reports of Hilcorp and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished by CEA were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by CEA. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by CEA are based on authorizations for expenditure for the proposed work or actual costs for similar projects.

Development costs furnished by CEA were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by CEA.

The estimated net cost of well abandonment was provided by CEA and was accepted without independent verification.

Because of the direct relationship between volumes of undeveloped reserves and development plans, we include in the undeveloped reserves category only those volumes assigned to undeveloped locations, which we reviewed, that we have been assured will definitely be drilled. The operator, Hilcorp has plans to develop new wells within 5 years of initial booking. In accordance with SPE-PRMS guidelines, "a reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives." CEA has assured us of their intent, commitment, and ability to proceed with the development activities included in this report and that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by CEA were held constant throughout the life of the properties.

CEA's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by CEA to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by CEA. Wells or locations that are not currently producing may start producing earlier or later than anticipated in CEA's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hilcorp's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved, probable, and possible reserves actually recovered and amounts of proved, probable, and possible income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a review of the properties in which CEA owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by CEA for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of CEA are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and work papers in an orderly manner. We consulted with these technical personnel and had access to their work papers and supporting data in the course of our audit.

CEA has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of CEA's forecast of future proved, probable, and possible production, we have relied upon data furnished by CEA with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, production taxes per Alaska Statue, recompletion and development costs, development plans, abandonment costs after salvage, product prices, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by CEA. We consider the factual data furnished to us by CEA to be appropriate and sufficient for the purpose of our review of CEA's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by CEA and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

In our opinion, CEA's estimates of future reserves for the reviewed properties were prepared in accordance with generally accepted petroleum engineering and evaluation principles for the estimation of future reserves as set forth in the Society of Petroleum Engineers' Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

The overall proved reserves for the reviewed properties as estimated by CEA are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott found the processes and controls used by CEA in their estimation of proved reserves to be effective.

Furthermore, the probable and possible reserves, respectively and in aggregate, were also found to be reasonably estimated within a tolerance of 10 percent for the reviewed properties. Ryder Scott also found the processes and controls used by CEA in their estimation of these reserves to be effective.

We were in reasonable agreement with CEA's estimates of proved, probable, and possible reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between CEA's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to CEA when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis, by category, the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by CEA.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to CEA. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

This report was prepared for the exclusive use and sole benefit of Chugach Electric Association and may not be put to other use without our prior written consent for such use. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Scott J. Wilson, PE, MBA
Alaska License EP 7966
Senior Vice President

STATE OF ALASKA
49TH
6/26/2025
SCOTT J. WILSON
EP 7966
REGISTERED PROFESSIONAL ENGINEER

SJW (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

Attachment D

Petrotechnical Resources Alaska

3000 A Street, Suite 410
Anchorage, AK 99503
907-272-1232 (voice)
info@petroak.com

June 30, 2025

Arthur Miller
Chief Executive Officer
Chugach Electric Association
5601 Electron Dr
Anchorage, AK 99518

RE: Beluga River Unit—2025 Asset Retirement Obligation Study

Dear Mr. Miller:

At your request, Petrotechnical Resources Alaska (PRA) has prepared an estimate of the Beluga River Unit (BRU) asset retirement obligation (ARO) costs including both removal of the unit surface improvements and plugging and abandonment of the 45 subsurface well bores.

Plugging and abandonment of the wellbores is estimated in accordance with current AOGCC regulatory requirements. For the surface work, a revision was done itemizing specific tasks for gravel removal, and reclamation of the Air Strip.

All the cost estimates are in 2025 dollars.

Shown below is a summary of the cost estimates. More detailed information is available on request. The cost estimates are for 100 percent of the full costs. CEA will have to calculate its own working interest share of the total costs.

Plugging and Abandonment of the Wellbores

Well Types	Definition of well types	Number of wells	Well Names
Type 0	Original Wellbore P&A'd for Sidetrack	2 wells	BRU 211-03 BRU 212-24T
Type 1	Non Intervention	2 wells	BRU 14-19 BRU 224-13
Type 2	Rigless Intervention without CT	2 wells	BRU 232-09 BRU BRWD-1
Type 3	Rigless Intervention with CT	23 wells	BRU 211-26 BRU 212-24 BRU 212-25 BRU 212-26 BRU 212-35 BRU 212-35T BRU 214-26 BRU 214-35 BRU 222-24 BRU 223-24 BRU 224-23 BRU 224-23T BRU 224-34 BRU 232-04 BRU 232-23 BRU 232-26 BRU 233-27 BRU 241-34 BRU 241-34T BRU 243-34 BRU 242-04 BRU 244-04 BRU 244-23
Type 4	Rig Required	2 wells	BRU 212-18 BRU 221-23
Type 5	New Monobore Wells Added	14 wells	BRU 211-35 BRU 213-26 BRU 214-13 BRU 221-26 BRU 221-35 BRU 222-26 BRU 222-34 BRU 223-34 BRU 233-23 BRU 233-23T BRU 241-23 BRU 241-26 BRU 241-34S BRU 244-27

Cost Estimate			
Type 0	$0 each well	2 wells	$0
Type 1	$452,255 each well	2 wells	$904,509
Type 2	$1,143,457 each well	2 wells	$2,286,914
Type 3	$1,839,947 each well	23 wells	$42,318,784
Type 4	$3,405,252 each well	2 wells	$6,810,503
Type 5	$1,451,387 each well	14 wells	$20,319,418
TOTAL Cost Estimate for all 45 Wells	$72,640,128		

The wellbore plugging and abandonment cost estimates were prepared by Mr. Steve Tyler, an engineer employed at PRA with extensive statewide experience in preparing such cost estimates.

Abandonment of the Surface Improvements

With Union Labor Rates	With Non Union Labor Rates	Estimate Description
$63,517,000	$56,304,000	Reconciled Civil Reclamation activities from the 2022 study, including reclamation of the Air Strip. The 2025 estimate does not include removal of Beluga Highway.

The original estimate for removal of the surface improvements is based on the scope of work provided in 2013, and the information obtained during our collective Beluga Gas Filed site visit. The following is a summary of revisions and updates that have been made over the last 12 years.

In 2018, the Revision 1 estimate was updated to reflect 2018 Labor and Equipment rates for comparison against the 2013 estimate, and added scope to include Produced Water Lines, a Small Compressor Building, and Soil Remediations work scope.

In 2022, the Revision 2 estimate added various Civil Work Tasks to restore the site to original/native conditions and has been updated to reflect 2022 Equipment and Labor Rates. Civil Scope included removal of gravel from pads, buried utilities, conveyances, the airstrip, the main spine road, ancillary access roads, scarify, and placement of hydroseed and is presented as a series of options. The estimate considered work performed by merit shop contractor(s) or union contractor(s).

For 2025, Revision 3 reconciled Civil Reclamation activities from the 2022 study, and itemized specific tasks for gravel removal, and reclamation of the Air Strip. Revision 3 does not include reclamation of Beluga Highway. Estimates were prepared using both 2022 and 2025 Equipment and Labor Rates for both Merit Shop and Union contractor work force for comparison.

The cost estimates for abandonment of the surface improvements were prepared by Conam Construction Company, an engineering and construction company headquartered in Anchorage Alaska with extensive experience in Alaska civil engineering work. PRA supervised the Conam work. The Conam estimates are for both union and non-union labor rates.

We are available to discuss the reports with you and your staff at your request.

Standards of Independence and Professional Qualifications
Petrotechnical Resources Alaska (PRA) is professionally licensed in the State of Alaska to provide independent petroleum engineering consulting services.

Terms of Usage
This report was prepared for the exclusive use and sole benefit of Chugach Electric Association and may not be put to other use without prior written consent of such use. The data and work papers used in preparation of this report are available for examination by authorized parties.

Sincerely,

Tom Walsh

Tom Walsh

3000 A Street, Suite 410
Anchorage, Alaska 99503
Tel: 907.272,1232
Email: hr@petroak.com

BRU Surface Abandonment

2025

2025 Assest Retirement Obligation Study - Executive Escalation Summary

UNION					
Work Item	SCOPE OF WORK	2022	2025	NET INCREASE	% INCREASE
1	Mechanical / Electrical Demo	$ 33,312,255.60	$ 47,598,894.10	$ 14,286,638.51	43%
2	Civil Base - Rmv Buried Mech Elect - Scarify and Reclaim Pads	$ 9,968,114.53	$ 11,442,682.44	$ 1,474,567.91	15%
3	Civil Excavate, Remove Gravel from Pads and Access Roads	$ 2,898,731.54	$ 3,283,218.49	$ 384,486.96	13%
4	Airport Scarify and Reclaim - Revegetate	$ 972,898.34	$ 1,192,204.97	$ 219,306.63	23%
	TOTALS	**$ 47,152,000.00**	**$ 63,517,000.00**	**$ 16,365,000.00**	**35%**

NON - UNION					
Work Item	SCOPE OF WORK	2022	2025	NET INCREASE	% INCREASE
1	Mechanical / Electrical Demo	$ 32,244,821.67	$ 42,225,936.16	$ 9,981,114.49	31%
2	Civil Base - Rmv Buried Mech Elect - Scarify and Reclaim Pads	$ 9,798,398.67	$ 10,171,803.17	$ 373,404.50	4%
3	Civil Excavate, Remove Gravel from Pads and Access Roads	$ 2,846,063.96	$ 2,888,531.98	$ 42,468.02	1%
4	Airport Scarify and Reclaim - Revegetate	$ 949,715.70	$ 1,017,728.69	$ 68,012.99	7%
	TOTALS	**$ 45,839,000.00**	**$ 56,304,000.00**	**$ 10,465,000.00**	**23%**

General Notes:

1. Distribution of the 30% Contingency and Management Costs are extended linearly by cost, and not a function of manhour or level of effort to administrate on behalf of the owner, by others.
2. The 2025 and 2022 comparisons considers the mutually aggreed scope of services for reclamation, and utilizes 2022 Labor and Equipment Rates.

Other costs and Fees such as 3rd Party Trucking, disposal fee, fuel, barging, camp services are retained at 2025 Rates to simplify presentation.

Work Item 1: Includes demolition of mechanical and electrical modules, and any other identifiable surface assets seen onsite at drill pads. Overhead powerlines are removed from the pad to the main power distribution system that parallels the main arterial road that traverses the BRU field. on all drill pads. Removal of buried mechanical pipeline collection system, and buried electrical systems on pad is NOT included, and assumed was originally assumed to be abandoned in place. Plugging and grouting of well heads was not a consideration. This work also includes other items discussed in detail about barging and salvage of materials via Kenai OSK dock.

Work Item 2: 2022 Asset retirement study was updated to include removal buried utilities at the drill pads, and reclamation of the site to include scarification of the pads, and access roads. Import and placement of 6" of salvaged topsoil and hydroseeding of pads and roads were considered for reestablishment to background vegetative cover.

Work Item 3: Considers removal of gravel imported to build drill pads and access roads off of the Beluga Highway, which is the main arterial road. Beluga Highway remains intact. Scarification, and hydroseeding already covered under work item 2.

Work Item 4: Considers scarification and reclamation of the airport up to 35 Acres, and retains a 45 FT wide road along the Beluga Highway alignment. Import and placement of 6" of salvaged topsoil and hydroseeding of the airport was considered for reestablishment to background vegetative cover.

2025 GENERAL ASSUMPTIONS AND CLARIFICATIONS

1. Project fuel is based on $6.00/gallon for remote fuel delivery to bulk fuel stores onsite.
2. Abandonment of powerlines is limited to removal of de-energized power systems from buried utilities. Removal
3. of overhead distribution powerlines/systems or lineman work is limited to section from the Pad to the mainline
4. distribution system that parallels the Beluga Highway.
5. Previous Scoping Studies have included a 30% contingency on top of Direct Labor. This condition has been carried forward by previous studies submitted to the client.
6. Previous Scope Studies have included costs that relate to a Project Management Fee, which is extended at a rate of 6% of the overall demolition cost that includes contingency. This condition has been carried forward from previous studies submitted to the client.
7. Previous Scope Studies have included costs that relate to a Engineering and Permit Fees, which is extended at a rate of 7% of the overall demolition cost that includes contingency. This condition has been carried forward by previous studies submitted to the client.
8. Costs are based on 2025 dollars and are not escalated.
9. Assumes no hazardous paint, asbestos or materials are present.
10. Estimate does not include plugging and abandonment of wells.
11. Work shift based on 7-10 hour days per week.
12. No salvage value on demolished equipment or material.
13. Nikiski OSK is the intended dock for Port of Barging and Shipping and receiving for recycling.
14. Camp Space: Peak manpower for Year 1 is (82), and Year 2 is (26) for CONAM Staff and Craft. The current facility on site is NOT able to support the temporary workforce for up to a 100 Bed Temporary Work Force Camp. Subsistence cost / man-day should be adequate to cover a temporary workforce housing unit.
15. Reclamation of the airport retains a 45-foot wide road corridor for the Beluga Highway easement.

Rev. - 6.3.2025

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
COST ESTIMATE SUMMARY

2025 - NON-UNION CONTRACTOR CRAFT LABOR RATES

DESCRIPTION	QUANITY	UNIT	TOTAL COST
LABOR	1	LUMP SUM	$15,857,000
CONSTRUCTION EQUIPMENT	1	LUMP SUM	$15,670,000
OTHER COSTS	1	LUMP SUM	$6,801,000
TOTAL ESTIMATED COST	1	LUMP SUM	$38,328,000
CONTINGENCY	30%	PER CENT	$11,498,000
TOTAL ESTIMATED DEMOLITION COST			**$49,826,000**
PROJECT MANAGEMENT FEE	6%	PER CENT	$2,990,000
ENGINEERING AND PERMITS	7%	PER CENT	$3,488,000
TOTAL ESTIMATED PROJECT COST			**$56,304,000**

ALTERNATE BID BREAK DOWN

Description	Cost	Contingency	Project Mang. Fee	Engineering/Permits	Total
Mechanical / Electrical Demo	$28,744,595.08	$8,623,078.54	$2,242,390.40	$2,615,872.15	$42,225,936.16
Civil Base - Rmv Buried Mech Elect - Scarify and Reclaim Pads	$6,924,283.74	$2,077,212.86	$540,169.29	$630,137.28	$10,171,803.17
Civil Excavate, Remove Gravel from Pads and Access Roads	$1,966,319.51	$589,875.33	$153,394.26	$178,942.87	$2,888,531.98
Airport Scarify and Reclaim - Revegatate	$692,801.67	$207,833.27	$54,046.05	$63,047.70	$1,017,728.69

Total **$56,304,000.00**

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
LABOR SUMMARY

Rev. - 6.3.2025

LABOR COST SUMMARY

DIRECT CRAFT LABOR	QUANTITY	UNIT	TOTAL COST
DIRECT LABOR	101,808	MANHOURS	$8,337,894
INDIRECT LABOR	36,111	MANHOURS	$2,427,003
STAFF LABOR	25,060	MANHOURS	$5,092,430
TOTAL			**$15,857,326**

LABOR COST DETAIL

DIRECT CRAFT LABOR	MANHOURS	COMPOSITE 70 HOUR CREW RATE	TOTAL DIRECT LABOR COST
MAIN GAS GATHERING LINE	846	$83.49	$70,634
A PAD PRODUCTION FACILITIES	944	$83.49	$78,774
B PAD PRODUCTION FACILITIES	975	$83.49	$81,384
C PAD PRODUCTION FACILITIES	4,253	$83.49	$355,049
D PAD PRODUCTION FACILITIES	2,176	$83.49	$181,699
E PAD PRODUCTION FACILITIES	2,984	$83.49	$249,119
F PAD PRODUCTION FACILITIES	2,536	$83.49	$211,756
G PAD PRODUCTION FACILITIES	1,446	$83.49	$120,750
H PAD-TURBINE COMPRESSION FACILITIES	12,608	$83.49	$1,052,623
H PAD-RECIPROCATING COMPRESSION FACILITIES	5,494	$83.49	$458,704
H PAD-PRODUCTION FACILITIES	6,534	$83.49	$545,514
I PAD PRODUCTION FACILITIES	1,111	$83.49	$92,780
J PAD PRODUCTION FACILITIES	4,966	$83.49	$414,641
K PAD PRODUCTION FACILITIES	2,151	$83.49	$179,612
L PAD PRODUCTION FACILITIES	1,165	$83.49	$97,268
M PAD PRODUCTION FACILITIES	1,414	$83.49	$118,036
N PAD PRODUCTION FACILITIES	620	$83.49	$51,765
BRDW1 PAD INJECTION FACILITIES	2,238	$83.49	$186,813
BRDW2 PAD INJECTION FACILITIES	1,786	$83.49	$149,137
METER BUILDINGS	1,255	$83.49	$104,782
PIPE AND STORAGE YARD	2,800	$83.49	$233,735
CAMP AND OFFICE FACILITY	2,061	$83.49	$172,097
PRODUCED WATER LINE	260	$83.49	$21,708
SMALL COMPRESSOR BUILDING	856	$83.49	$71,490
CONTAMINATED SOIL SITES	9,915	$92.57	$917,877
CIVIL - BASE	19,613	$74.61	$1,463,430
CIVIL - EXCAVATE GRAVEL HAUL TO BRU	6,099	$74.61	$455,035
CIVIL - AIRPORT - SCARIFY REVEGATATE	2,703	$74.61	$201,681
SUBTOTAL DIRECT LABOR	**101,808**		**$8,337,894**
INDIRECT CRAFT LABOR			
LOADOUT-40' FLATS	4,800	$66.62	$319,782.67
LOADOUT-SPECIAL HANDLING LARGE AND HEAVY LOADS	1,330	$66.62	$88,606
BARGE LANDING MAINTENANCE	2,380	$66.62	$158,559
CONTRACTOR MOBILIZATION TO SITE	3,000	$66.62	$199,864
CONTRACTOR DEMOBILIZATION FROM SITE	3,000	$66.62	$199,864
SCAFFOLDING	3,000	$66.62	$199,864
INDIRECT CRAFT	14,679	$66.62	$977,905
CIVIL MECHANICAL SUPPORT	3,923	$72.03	$282,557
SUBTOTAL	**36,111**		**$2,427,003**
STAFF			
PROJECT MANAGER	3,500	$259.00	$906,500
PROJECT ENGINEER	3,500	$204.00	$714,000
GENERAL SUPERINTENDENT	5,810	$250.00	$1,452,500
SAFETY SPECIALIST	5,530	$157.00	$868,210
LOADMASTER	3,220	$176.00	$566,720
OFFICE MANAGER	3,500	$167.00	$584,500
SUBTOTAL	**25,060**		**$5,092,430**
TOTAL LABOR	**162,979**		**$15,857,326**

COMPOSITE CREW RATES

DIRECT LABOR-70 HOUR WEEK		RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
LABOR FOREMAN	1	$66.99	$94.25	$5,507
EQUIPMENT FOREMAN	1	$72.71	$102.69	$5,989
PIPEFITTER	2	$84.14	$119.58	$13,906
ELECTRICIAN	2	$84.14	$119.58	$13,906
SKILLED LABORER	4	$58.41	$81.58	$19,136
TOTAL	**10**			$58,444
TOTAL WEEKLY PAYROLL-10 MAN CREW				$58,444
TOTAL MANHOURS WORKED / WEEK				700
COMPOSITE DIRECT HOURLY CREW RATE				$83.49

INDIRECT LABOR-70 HOUR WEEK		STRAIGHT TIME RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
SKILLED LABORER	5	$58.41	$81.58	$23,920
GENERAL LABORER	3	$48.41	$66.81	$11,821
TRUCK DIVER	4	$61.27	$85.80	$20,100
EXPIDITER	1	$58.41	$81.58	$4,784
TOTAL	**13**			$60,625
TOTAL WEEKLY PAYROLL-10 MAN CREW				$60,625
TOTAL MANHOURS WORKED / WEEK				910
COMPOSITE INDIRECT HOURLY CREW RATE				$66.62

SOIL REMEDIATION LABOR-70 HOUR WEEK		RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
LABOR FOREMAN	1	$66.99	$94.25	$5,507
EQUIPMENT FOREMAN	2	$72.71	$102.69	$11,978
ENVIRONMENTAL TECHNICIAN SUBCONTRACTOR	1.15	$100.00	$150.00	$9,775
REMEDIATION EQUIPMENT SUBCONTRACTOR	3	$95.00	$142.50	$24,225
SKILLED LABORER	3	$54.75	$74.96	$13,317
TOTAL	**10**			$64,802
TOTAL WEEKLY PAYROLL-10 MAN CREW				$64,802
TOTAL MANHOURS WORKED / WEEK				700
COMPOSITE DIRECT HOURLY CREW RATE				$92.57

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
CONSTRUCTION EQUIPMENT COST SUMMARY Rev. - 6.3.2025

DESCRIPTION	QUANTITY	UNIT	UNIT COST	TOTAL COST
EQUIPMENT RENTAL	1	LUMP SUM	$11,638,496	$11,638,496
EQUIPMENT FUEL	566,722	GAL	$6.00	$3,400,332
EQUIPMENT MOB/DEMOB KENAI	1	LUMP SUM	$413,200	$413,200
MOBILIZATION/DEMOBILIZATION-300 TON CRANE	2	EACH	$74,000	$148,000
MOB/DEMOB-SOIL REMEDIATION PLANT w/TROMMEL	2	EACH	$35,000	$70,000
TOTAL				**$15,670,028**

CONSTRUCTION EQUIPMENT COST DETAIL

Item Description	Qty	Unit	Day Rate	Total	Daily Fuel Usage / Gals	Total fuel / Gals
300 TON TRUCK CRANE	56	DAYS	$12,200	$683,200	80	4,480
OFFICE TRAILERS	707	DAYS	$146	$103,222		-
BREAK SHACKS - 10' X 40'	1365	DAYS	$64	$87,360		-
TOOL VANS	511	DAYS	$81	$41,391		-
CONNEX	903	DAYS	$29	$26,187		-
ENVIROVAC UNIT	1575	DAYS	$171	$269,325	10	15,750
FLATBED TRUCK - 2 TON	707	DAYS	$151	$106,757	15	10,605
TRUCK TRACTOR	903	DAYS	$494	$446,082	25	22,575
TRAILER - 40' FLATBED	4669	DAYS	$194	$905,786		-
LUBE TRUCK	308	DAYS	$884	$272,272	15	4,620
FUEL TRUCK	315	DAYS	$624	$196,560	15	4,725
MECHANICS TRUCK	434	DAYS	$651	$282,534	12	5,208
LOADER - CATERPILLAR 966H	581	DAYS	$955	$554,855	43	24,983
LOADER - CATERPILLAR 924	105	DAYS	$537	$56,385	30	3,150
TELEHANDELER	903	DAYS	$559	$504,777	10	9,030
CREW CAB - 1 TON 4 X 4-	4298	DAYS	$119	$511,462	7	30,086
BUS - 44 PASSENGER	315	DAYS	$461	$145,215	10	3,150
LOWBOY TRACTOR	392	DAYS	$785	$307,720	20	7,840
LOWBOY TRAILER-60 TON	196	DAYS	$354	$69,384		-
LOWBOY TRAILER-100 TON	511	DAYS	$498	$254,478		-
HYDRAULIC CRANE - 80 TON	392	DAYS	$2,141	$839,272	30	11,760
HYDRAULIC CRANE - 50 TON	196	DAYS	$1,732	$339,472	24	4,704
MANLIFT 60'	588	DAYS	$320	$188,160	11	6,468
WELDING TRUCK	784	DAYS	$212	$166,208	14	10,976
185 CFM AIR COMPRESSOR	868	DAYS	$93	$80,724	7	6,076
EXCAVATOR, HYDRAULIC, CAT 330, W/SHEAR	308	DAYS	$1,440	$443,623	45	13,860
EXCAVATOR, HYDRAULIC, CAT 330, W/ THUMB	189	DAYS	$1,152	$217,728	45	8,505
SOIL THERMO-REMEDIATION MOBILE UNIT w/ TROMMEL PLANT	84	DAYS/ SHFTS	$1,750	$147,000	1540	129,360
DUMP TRUCK 20 CY	105	DAYS	$494	$51,870	17	1,785
FUEL TANK STATION (Thermo Remediation Plant)	70	DAYS	$100	$7,000		-
GENERATOR, 175KW (Thermo Remediation Plant)	70	DAYS	$200	$14,000	90	6,300
GENERATOR, 6-15KW	1484	DAYS	$47	$69,748	14	20,776
DUMPSTERS-20 CY	1176	DAYS	$60	$70,560		-
CIVIL SPECIFIC EQUIPMENT						
CAT 349 W/ THUMB	277	DAYS	$1,183	$327,691	90	24,930
982 LOADER	357	DAYS	$1,124	$401,161	50	17,850
D10 DOZER	238	DAYS	$2,977	$708,431	110	26,180
D8T DOZER	208	DAYS	$1,709	$355,545	75	15,600
D6T DOZER	68	DAYS	$965	$65,620	40	2,720

Item Description	Qty	Unit	Day Rate	Total	Daily Fuel Usage / Gals	Total fuel / Gals
D4 DOZER	196	DAYS	$455	$89,215	35	6,860
ARTICULATED HAUL TRUCKS - BASE BID	80	DAYS	$1,229	$98,280	60	4,800
WATER TRUCK	196	DAYS	$478	$93,770	40	7,840
HYDROSEEDER	196	DAYS	$322	$63,014	15	2,940
16M MOTOR GRADER	119	DAYS	$1,372	$163,292	30	3,570
ARTICULATED HAUL TRUCKS - LOAD/HAUL PAD TO BRU BORROW	451	DAYS	$1,372	$618,862	60	27,060
CAT 349 W/ THUMB - LOAD/HAUL PAD TO BRU BORROW	75	DAYS	$1,183	$88,725	90	6,750
Airport - Articulated Trucks	15	DAYS	$1,229	$18,428	60	5,700
Airport - 349 Excavators	5	DAYS	$1,183	$5,915	90	25,380
Airport - D8 Dozer	30	DAYS	$1,709	$51,281	75	17,850
Airport - D6 Dozer	30	DAYS	$965	$28,950	40	3,920
TOTAL				**$ 11,638,496**		**566,722**

Rev. - 6.3.2025

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
COST ESTIMATE SUMMARY

2025 - UNION CONTRACTOR CRAFT LABOR RATES

DESCRIPTION	QUANITY	UNIT	TOTAL COST
LABOR	1	LUMP SUM	$20,767,000
CONSTRUCTION EQUIPMENT	1	LUMP SUM	$15,670,000
OTHER COSTS	1	LUMP SUM	$6,801,000
TOTAL ESTIMATED COST	1	LUMP SUM	$43,238,000
CONTINGENCY	30%	PER CENT	$12,971,000
TOTAL ESTIMATED DEMOLITION COST			**$56,209,000**
PROJECT MANAGEMENT FEE	6%	PER CENT	$3,373,000
ENGINEERING AND PERMITS	7%	PER CENT	$3,935,000
TOTAL ESTIMATED PROJECT COST			**$63,517,000**

ALTERNATE BID BREAK DOWN

Description	Cost	Contingency	Project Mang. Fee	Engineering/Permits	Total
Mechanical / Electrical Demo	$32,402,049.58	$9,720,315.12	$2,527,686.60	$2,948,842.80	$47,598,894.10
Civil Base - Rmv Buried Mech Elect - Scarify and Reclaim Pads	$7,789,390.29	$2,336,745.03	$607,650.99	$708,896.13	$11,442,682.44
Civil Excavate, Remove Gravel from Pads and Access Roads	$2,234,989.08	$670,476.05	$174,351.69	$203,401.68	$3,283,218.49
Airport Scarify and Reclaim - Revegatate	$811,571.05	$243,463.81	$63,310.73	$73,859.38	$1,192,204.97

Total **$63,517,000.00**

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
LABOR SUMMARY

Rev. - 6.3.2025

LABOR COST SUMMARY

DIRECT CRAFT LABOR	QUANTITY	UNIT	TOTAL COST
DIRECT LABOR	101,808	MANHOURS	$11,841,141
INDIRECT LABOR	36,111	MANHOURS	$3,832,948
STAFF LABOR	25,060	MANHOURS	$5,092,430
TOTAL			**$20,766,519**

LABOR COST DETAIL

DIRECT CRAFT LABOR	MANHOURS	COMPOSITE 70 HOUR CREW RATE	TOTAL DIRECT LABOR COST
MAIN GAS GATHERING LINE	846	$119.84	$101,386
A PAD PRODUCTION FACILITIES	944	$119.84	$113,070
B PAD PRODUCTION FACILITIES	975	$119.84	$116,815
C PAD PRODUCTION FACILITIES	4,253	$119.84	$509,624
D PAD PRODUCTION FACILITIES	2,176	$119.84	$260,804
E PAD PRODUCTION FACILITIES	2,984	$119.84	$357,576
F PAD PRODUCTION FACILITIES	2,536	$119.84	$303,947
G PAD PRODUCTION FACILITIES	1,446	$119.84	$173,320
H PAD-TURBINE COMPRESSION FACILITIES	12,608	$119.84	$1,510,896
H PAD-RECIPROCATING COMPRESSION FACILITIES	5,494	$119.84	$658,407
H PAD-PRODUCTION FACILITIES	6,534	$119.84	$783,011
I PAD PRODUCTION FACILITIES	1,111	$119.84	$133,173
J PAD PRODUCTION FACILITIES	4,966	$119.84	$595,161
K PAD PRODUCTION FACILITIES	2,151	$119.84	$257,808
L PAD PRODUCTION FACILITIES	1,165	$119.84	$139,615
M PAD PRODUCTION FACILITIES	1,414	$119.84	$169,425
N PAD PRODUCTION FACILITIES	620	$119.84	$74,301
BRDW1 PAD INJECTION FACILITIES	2,238	$119.84	$268,144
BRDW2 PAD INJECTION FACILITIES	1,786	$119.84	$214,066
METER BUILDINGS	1,255	$119.84	$150,401
PIPE AND STORAGE YARD	2,800	$119.84	$335,495
CAMP AND OFFICE FACILITY	2,061	$119.84	$247,022
PRODUCED WATER LINE	260	$119.84	$31,159
SMALL COMPRESSOR BUILDING	856	$119.84	$102,614
CONTAMINATED SOIL SITES	9,915	$104.65	$1,037,645
CIVIL - BASE	19,613	$112.49	$2,206,214
CIVIL - EXCAVATE GRAVEL HAUL TO BRU	6,099	$112.49	$685,995
CIVIL - AIRPORT - SCARIFY REVEGATATE	2,703	$112.49	$304,048
SUBTOTAL DIRECT LABOR	**101,808**		**$11,841,141**
INDIRECT CRAFT LABOR			
LOADOUT-40' FLATS	4,800	$104.81	$503,108.35
LOADOUT-SPECIAL HANDLING LARGE AND HEAVY LOADS	1,330	$104.81	$139,403
BARGE LANDING MAINTENANCE	2,380	$104.81	$249,458
CONTRACTOR MOBILIZATION TO SITE	3,000	$104.81	$314,443
CONTRACTOR DEMOBILIZATION FROM SITE	3,000	$104.81	$314,443
SCAFFOLDING	3,000	$104.81	$314,443
INDIRECT CRAFT	14,679	$104.81	$1,538,521
CIVIL MECHANICAL SUPPORT	3,923	$117.04	$459,129
SUBTOTAL	**36,111**		**$3,832,948**
STAFF			
PROJECT MANAGER	3,500	$259.00	$906,500
PROJECT ENGINEER	3,500	$204.00	$714,000
GENERAL SUPERINTENDENT	5,810	$250.00	$1,452,500
SAFETY SPECIALIST	5,530	$157.00	$868,210
LOADMASTER	3,220	$176.00	$566,720
OFFICE MANAGER	3,500	$167.00	$584,500
SUBTOTAL	**25,060**		**$5,092,430**
TOTAL LABOR	**162,979**		**$20,766,519**

COMPOSITE CREW RATES

DIRECT LABOR-70 HOUR WEEK		RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
LABOR FOREMAN	1	$105.65	$137.28	$8,345
EQUIPMENT FOREMAN	1	$110.82	$145.51	$8,798
PIPEFITTER	2	$129.09	$169.61	$20,504
ELECTRICIAN	2	$113.54	$145.17	$17,793
SKILLED LABORER	4	$91.13	$115.57	$28,449
TOTAL	**10**			$83,889
TOTAL WEEKLY PAYROLL-10 MAN CREW				$83,889
TOTAL MANHOURS WORKED / WEEK				700
COMPOSITE DIRECT HOURLY CREW RATE				$119.84

INDIRECT LABOR-70 HOUR WEEK		STRAIGHT TIME RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
SKILLED LABORER	5	$91.13	$115.57	$35,561
GENERAL LABORER	3	$89.41	$112.99	$20,899
TRUCK DIVER	4	$99.54	$128.78	$31,379
EXPIDITER	1	$95.96	$123.43	$7,541
TOTAL	**13**			$95,381
TOTAL WEEKLY PAYROLL-10 MAN CREW				$95,381
TOTAL MANHOURS WORKED / WEEK				910
COMPOSITE INDIRECT HOURLY CREW RATE				$104.81

SOIL REMEDIATION LABOR-70 HOUR WEEK		RATE-40 HOURS / WEEK	OVERTIME RATE-30 HOURS / WEEK	TOTAL WEEKLY PAYROLL
LABOR FOREMAN	1	$105.65	$137.28	$8,345
EQUIPMENT FOREMAN	2	$110.82	$145.51	$17,596
ENVIRONMENTAL TECHNICIAN SUBCONTRACTOR	1.15	$100.00	$150.00	$9,775
REMEDIATION EQUIPMENT SUBCONTRACTOR	3	$95.00	$142.50	$24,225
SKILLED LABORER	3	$54.75	$74.96	$13,317
TOTAL	**10**			$73,258
TOTAL WEEKLY PAYROLL-10 MAN CREW				$73,258
TOTAL MANHOURS WORKED / WEEK				700
COMPOSITE DIRECT HOURLY CREW RATE				$104.65

BELUGA GAS FIELD COST OF ABANDONING SURFACE ASSETS
CONSTRUCTION EQUIPMENT COST SUMMARY Rev. - 6.3.2025

DESCRIPTION	QUANTITY	UNIT	UNIT COST	TOTAL COST
EQUIPMENT RENTAL	1	LUMP SUM	$11,638,496	$11,638,496
EQUIPMENT FUEL	566,722	GAL	$6.00	$3,400,332
EQUIPMENT MOB/DEMOB KENAI	1	LUMP SUM	$413,200	$413,200
MOBILIZATION/DEMOBILIZATION-300 TON CRANE	2	EACH	$74,000	$148,000
MOB/DEMOB-SOIL REMEDIATION PLANT w/TROMMEL	2	EACH	$35,000	$70,000
TOTAL				**$15,670,028**

CONSTRUCTION EQUIPMENT COST DETAIL

Item Description	Qty	Unit	Day Rate	Total	Daily Fuel Usage / Gals	Total fuel / Gals
300 TON TRUCK CRANE	56	DAYS	$12,200	$683,200	80	4,480
OFFICE TRAILERS	707	DAYS	$146	$103,222		-
BREAK SHACKS - 10' X 40'	1365	DAYS	$64	$87,360		-
TOOL VANS	511	DAYS	$81	$41,391		-
CONNEX	903	DAYS	$29	$26,187		-
ENVIROVAC UNIT	1575	DAYS	$171	$269,325	10	15,750
FLATBED TRUCK - 2 TON	707	DAYS	$151	$106,757	15	10,605
TRUCK TRACTOR	903	DAYS	$494	$446,082	25	22,575
TRAILER - 40' FLATBED	4669	DAYS	$194	$905,786		-
LUBE TRUCK	308	DAYS	$884	$272,272	15	4,620
FUEL TRUCK	315	DAYS	$624	$196,560	15	4,725
MECHANICS TRUCK	434	DAYS	$651	$282,534	12	5,208
LOADER - CATERPILLAR 966H	581	DAYS	$955	$554,855	43	24,983
LOADER - CATERPILLAR 924	105	DAYS	$537	$56,385	30	3,150
TELEHANDELER	903	DAYS	$559	$504,777	10	9,030
CREW CAB - 1 TON 4 X 4-	4298	DAYS	$119	$511,462	7	30,086
BUS - 44 PASSENGER	315	DAYS	$461	$145,215	10	3,150
LOWBOY TRACTOR	392	DAYS	$785	$307,720	20	7,840
LOWBOY TRAILER-60 TON	196	DAYS	$354	$69,384		-
LOWBOY TRAILER-100 TON	511	DAYS	$498	$254,478		-
HYDRAULIC CRANE - 80 TON	392	DAYS	$2,141	$839,272	30	11,760
HYDRAULIC CRANE - 50 TON	196	DAYS	$1,732	$339,472	24	4,704
MANLIFT 60'	588	DAYS	$320	$188,160	11	6,468
WELDING TRUCK	784	DAYS	$212	$166,208	14	10,976
185 CFM AIR COMPRESSOR	868	DAYS	$93	$80,724	7	6,076
EXCAVATOR, HYDRAULIC, CAT 330, W/SHEAR	308	DAYS	$1,440	$443,623	45	13,860
EXCAVATOR, HYDRAULIC, CAT 330, W/ THUMB	189	DAYS	$1,152	$217,728	45	8,505
SOIL THERMO-REMEDIATION MOBILE UNIT w/ TROMMEL PLANT	84	DAYS/ SHFTS	$1,750	$147,000	1540	129,360
DUMP TRUCK 20 CY	105	DAYS	$494	$51,870	17	1,785
FUEL TANK STATION (Thermo Remediation Plant)	70	DAYS	$100	$7,000		-
GENERATOR, 175KW (Thermo Remediation Plant)	70	DAYS	$200	$14,000	90	6,300
GENERATOR, 6-15KW	1484	DAYS	$47	$69,748	14	20,776
DUMPSTERS-20 CY	1176	DAYS	$60	$70,560		-
CIVIL SPECIFIC EQUIPMENT						
CAT 349 W/ THUMB	277	DAYS	$1,183	$327,691	90	24,930
982 LOADER	357	DAYS	$1,124	$401,161	50	17,850
D10 DOZER	238	DAYS	$2,977	$708,431	110	26,180
D8T DOZER	208	DAYS	$1,709	$355,545	75	15,600
D6T DOZER	68	DAYS	$965	$65,620	40	2,720

Item Description	Qty	Unit	Day Rate	Total	Daily Fuel Usage / Gals	Total fuel / Gals
D4 DOZER	196	DAYS	$455	$89,215	35	6,860
ARTICULATED HAUL TRUCKS - BASE BID	80	DAYS	$1,229	$98,280	60	4,800
WATER TRUCK	196	DAYS	$478	$93,770	40	7,840
HYDROSEEDER	196	DAYS	$322	$63,014	15	2,940
16M MOTOR GRADER	119	DAYS	$1,372	$163,292	30	3,570
ARTICULATED HAUL TRUCKS - LOAD/HAUL PAD TO BRU BORROW	451	DAYS	$1,372	$618,862	60	27,060
CAT 349 W/ THUMB - LOAD/HAUL PAD TO BRU BORROW	75	DAYS	$1,183	$88,725	90	6,750
Airport - Articulated Trucks	15	DAYS	$1,229	$18,428	60	5,700
Airport - 349 Excavators	5	DAYS	$1,183	$5,915	90	25,380
Airport - D8 Dozer	30	DAYS	$1,709	$51,281	75	17,850
Airport - D6 Dozer	30	DAYS	$965	$28,950	40	3,920
TOTAL				**$ 11,638,496**		**566,722**

3000 A Street, Suite 410
Anchorage, Alaska 99503
Tel: 907.272,1232
Email: hr@petroak.com

BRU Subsurface Abandonment

2025

BRU Plug and Abandonment Recap

Excel File Name: BRU Well P&A Cost Estimate (Updated 04-21-2025).xlsm *Updated: 5/2025*

Well inventory includes

BRU 14-19, BRU 211-03, BRU 211-26, **BRU 211-35,** BRU 212-18, BRU 212-24, BRU 212-24T, BRU 212-25, BRU 212-26, BRU 212-35, BRU 212-35T, **BRU 213-26, BRU 214-13,** BRU 214-26, BRU 214-35, BRU 221-23, **BRU 221-26, BRU 221-35,** BRU 222-24, **BRU 222-26, BRU 222-34,** BRU 223-24, **BRU 223-34,** BRU 224-13, BRU 224-23, BRU 224-23T, BRU 224-34, BRU 232-04, BRU 232-09, BRU 232-23, BRU 232-26, **BRU 233-23, BRU 233-23T,** BRU 233-27, **BRU 241-23, BRU 241-26,** BRU 241-34, **BRU 241-34S,** BRU 241-34T, BRU 243-34, BRU 242-04, BRU 244-04, BRU 244-23, **BRU 244-27** & BRU BRWD-1

NOTE: (14) Wells **underlined with red, bold font** were added November 2024.

NOTE: Well 223-24 was drilled and completed as "Tight Hole".

NOTE: The following 33 Wells have had intervention work 2020 thru 2024. P&A Estimate & schematics were updated

BRU 224-34; BRU 212-26; BRU 241-34T; BRU 212-24T; BRU 222-24; BRU 212-35T; BRU 224-13; BRU 223-24; BRU 233-27; BRU 244-23; BRU 232-04; BRU 222-34; BRU 244-27; BRU 233-23; BRU 214-13; BRU 212-24; BRU 241-04XX; BRU 232-26; BRU 211-03; BRU 211-35: BRU 213-26; BRU 221-35; BRU 223-34; BRU 241-23; BRU 242-04; BRU BRWD-1; BRU 221-26; BRU 222-26; BRU 233-23T; BRU 241-26; BRU 241-34S

NOTE: Updated cost by applying a inflation rate of 24.8% from 2019 to November 2024

Discussion:

Found indications of some of current wells do not have cement covering the surface casing shoe as required in AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements".

P&A cost will reflect having to overlap the csg shoe 100' below and above on all wells unless depicted otherwise.

45 wells were reviewed

14 wells will require Waivers to AOGCC Title 2; 20 AAC 25.112. Well plugging requirements.

2 wells require a workover rig.

37 wells willl require Coil Tubing to facilitate the P&A

2 wells have already been plugged with cement and suspended. Will just need to finish the Abandonment.

Assumptions:

Used 16 Operation hours per day. Exception is the workover rig, used 24 operation hrs per day.

Coil Tubing Unit and accessory equipment assumed to have been mobilized to the West Side.

Workover Rig and accessory equipment assumed to have been mobilized to the West Side.

Individual operation timeline are located in the "*TIMELINE ASSUMPTIONS*" Worksheet.

Each wellbore diagram and proposed diagram on the AOGCC Website is assumed to be represented of the current condition of the well.

BRU Wells that have had Intervention done 2020-2024

186011	BRU 224-34
220058	BRU 212-26
220052	BRU 241-34T
210050	BRU 212-24T
220043	BRU 222-24
198161	BRU 212-35T
173037	BRU 224-13
221072	BRU 223-24
163002	BRU 233-27
212069	BRU 244-23
162037	BRU 232-04
222039	BRU 222-34
222038	BRU 244-27
222050	BRU 233-23
222117	BRU 214-13
172015	BRU 212-24
222051	BRU 241-04XX
184138	BRU 232-26
186010	BRU 211-03
223050	BRU 211-35
223069	BRU 213-26
223077	BRU 221-35
223041	BRU 223-34
223061	BRU 241-23
212041	BRU 242-04
186009	BRU BRWD-1
224098	BRU 221-26
224035	BRU 222-26
224088	BRU 233-23T
224068	BRU 241-26
224077	BRU 241-34S

Results

Well Types	Definition of well types	Number of wells	Well Names
Type 0	Original Wellbore P&A'd for Sidetrack	2 wells	BRU 211-03 BRU 212-24T
Type 1	Non Intervention	2 wells	BRU 14-19 BRU 224-13
Type 2	Rigless Intervention without CT	2 wells	BRU 232-09 BRU BRWD-1
Type 3	Rigless Intervention with CT	23 wells	BRU 211-26 BRU 212-24 BRU 212-25 BRU 212-26 BRU 212-35 BRU 212-35T BRU 214-26 BRU 214-35 BRU 222-24 BRU 223-24 BRU 224-23 BRU 224-23T BRU 224-34 BRU 232-04 BRU 232-23 BRU 232-26 BRU 233-27 BRU 241-34 BRU 241-34T BRU 243-34 BRU 242-04 BRU 244-04 BRU 244-23
Type 4	Rig Required	2 wells	BRU 212-18 BRU 221-23
Type 5	New Monobore Wells Added	14 wells	BRU 211-35 BRU 213-26 BRU 214-13 BRU 221-26 BRU 221-35 BRU 222-26 BRU 222-34 BRU 223-34 BRU 233-23 BRU 233-23T BRU 241-23 BRU 241-26 BRU 241-34S BRU 244-27

Cost Estimate			
Type 0	$0 each well	2 wells	$0
Type 1	$452,255 each well	2 wells	$904,509
Type 2	$1,143,457 each well	2 wells	$2,286,914
Type 3	$1,839,947 each well	23 wells	$42,318,784
Type 4	$3,405,252 each well	2 wells	$6,810,503
Type 5	$1,451,387 each well	14 wells	$20,319,418
	TOTAL Cost Estimate for all 45 Wells		**$72,640,128**

BRU P&A Cost Estimate

			ESTIMATED EXPENDITURE COSTS									
			Well Types									
			Type 1		Type 2		Type 3		Type 4		Type 5	
			Num Units	Estimate	Num Units	Estimate	Num Units	Estimate	Num Units	Estimate	Num Units	Estimate
Cement Bulk Material(Squeeze, Surf Csg Cost Est)	$90,000 /well				1	$90,000	1	$90,000	1	$90,000	1	$90,000
Thru Tbg EZSV/ CIBP	$7,700 each				2	$15,400	2	$15,400	2	$15,400	-	$0
EZSV/ CIBP	$9,500 each				2	$19,000	2	$19,000	4	$38,000	2	$19,000
Pump Truck misc pumping KWF	$14,000 / day				0.23	$3,150	0.23	$3,150	0.23	$3,150	0.23	$3,150
Eline Pre Ops Work Includes Gun cost	$20,800 / day				1 days	$20,800	2 days	$41,600			2 days	$41,600
Cement Unit Pre Ops Work	$20,000 / day				2 days	$40,000	2 days	$40,000			1 days	$20,000
Rig total, all in, burn rate per day.	$86,200 / day								11 days	$948,200		
Rig Mobe/Demobe. Mobing all rig equipment to West Side	$1,200,000	2 wells							0.50	$600,000		
Hilcorp Work Platform	$1,200 / day		3	$3,600	8 days	$9,600	8 days	$9,600	4	$4,800	6 days	$7,200
Crane includes operator	$2,500 / day		3	$7,500	8 days	$20,000	8 days	$20,000	4	$10,000	6 days	$15,000
CTU total, all in, burn rate per day.	$63,000 / day						7 days	$441,000			5 days	$302,400
CTU Mobe/Demobe Spread over CTU Wells	$250,000	37 wells					0.03	$6,757			0.03	$6,757
Contract Labor Includes contract Labor	$7,000 / day		4 days	$28,000	12 days	$84,000	12 days	$84,000	15 days	$105,000	4 days	$28,000
Conductor P&A (Surface plug & bury P&A Plate)	$356,299 each well		1	$178,150	1	$356,299	1	$356,299	1	$356,299	1	$356,299
Engineering	$2,500 / day		4 days	$10,000	12 days	$30,000	12 days	$30,000	15 days	$37,500	4 days	$10,000
Engineering Pre-Work - (6 months of prep work spread across wells)	$300,000		0.25	$75,000	0.25	$75,000	0.25	$75,000	0.25	$75,000	0.25	$75,000
Miscellaneous	$500 / day		4 days	$2,000	12 days	$6,000	12 days	$6,000	15 days	$7,500	4 days	$2,000
Subtotal w/ No Inflation				$304,250		$769,249		$1,237,806		$2,290,849		$976,406
Normalization From 2018	To 2024	Inflation= 25%		$452,255		$1,143,457		$1,839,947		$3,405,252		$1,451,387
		Type Cost		**$452,255 / Type1 Well**		**$1,143,457 / Type2 Well**		**$1,839,947 / Type3 Well**		**$3,405,252 / Type4 Well**		**$1,451,387 / Type5 Well**

API #	Well Name	PTD	Completion Type	Well Status	Activity	Notes	P&A Plan	P&A Surf Equip	Well Type
50-283-10024-00	BRU 14-19	163-020-0		P&A	P&A	Abandon May 15, 1964. 16" Surf Csg to 2551'. Inter. Csg to 8635'. Original TD 14,948'. Plugs: Surf to 120' w/ 60 sx; 8581' to 8752' 140 sx Will require Multiple waivers to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Will require a variance from AOGCC. 1. Dig down 5' below GL. 2. Cut Surf and Intermediate csg strings 3' below GL. Weld P&A Plate. Bury same.	Backhoe, Cmt Blender, Welder, Guillotine Saw.	Type 1
50-283-20079-00	BRU 211-03	186-010-0	P&A'd			WO in April 2022 prep for Redrill			Type 0
50-283-20128-00	BRU 211-26	208-112-0	Single w/ Chem Inj	GAS	Producing	Single String GP.	Bullhead KWF down tbg. EL Perf Screens. Utilize CT to lay-in/sqz cmt across GP Screens. Monitor then test wellbore. MIRU Work Platform & crane. PU tbg string. Circ/Spot 100' cmt on top of pkr. Remove Tbg. RI perf csg w/ 21spf gun 2x above TOC. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Work Platform, Eline, Slickline, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20189-00	BRU 211-35	223-050-0	Monobore w/ Chem Inj & SSSV	GAS	Producing	Schematic depicts SSSV.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across Beluga F thru J. Monitor then test wellbore. MIRU Work Platform & crane. PU tbg string. Circ/Spot 100' cmt on top of pkr. Remove Tbg. RI perf csg w/ 21spf gun 2x above TOC. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Work Platform, Eline, Slickline, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20049-00	BRU 212-18	175-034-0	Single w/ Heater String	GAS	Shut-in	1984 Single String Completion w/ FH Pkrs. & Brown CC safety Jts Will need to retrieve tbg string. Drill CIBP's @ 5580' & 5880' to access unplugged perfs.	Bullhead KWF down tbg. MIRU Rig, BOPE. Test same. Pull heater string. Pull tbg, pkrs completion. RI drill CIBP's. RI Cmt sqz perf intervals. Test Monitor wellbore. RI set CIBP ~150' below intermediate csg shoe. RI perf csg w/ 21spf gun 2x above CIBP. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue Abandoning wellbore. Demobe Rig. Continue P&A.	Workover Rig, Eline, Slickline, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 4
50-283-20037-00	BRU 212-24	172-015-0	Dual w/ Heater String	GAS	Shut-in	May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe. Assume LS tbg clear to 9/14/94 tagged depth @ 4609'. LS x Csg annulus has cmt to 3412' ~400' below SS EOT. Callapsed csg @ 4621'.	Bullhead KWF down LS & SS tbg. EL Perf prod intervals and GP screen. Utilize CT to lay-in/sqz cmt across intervals. Monitor then test wellbore. Open SSD @ 3016'. Punch SS at 3000'. Circ/Spot 500' of cmt on top of Pkr in annulus, LS, SS. MIRU Work Platform & crane. Cut, PU LS, SS & Heater tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20136-00	BRU 212-24T	210-050-0	Single w/ Chem inj		P&A'd	P&A'd 8/5/2010 Sidetract as BRU 233-23			Type 0
50-283-10025-00	BRU 212-25	162-033-0	Single w/ Heater String	GAS	Producing	Assume tbg clear to plug in XN @ 3881'. Fill encountered b	Bullhead KWF down tbg. Ensure csg integrity. Remove plug w/ slickline. MIRU CT Unit. Cleanout to to ETD. Layin/Sqz cmt from 4157' to 3900'. RI perf tbg across Zone A. RI Circ/sqz cmt into zone A. RD CTU. RI Punch tbg above top pkr. Set cmt retainer. Pump/circ 500' of cmt above top pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. Cut tbg above TOC. Pull/remove tbg. RI set CIBP @ 2500'. RI perf csg w/ 21spf gun 2x above CIBP. Establish circulation up Production csg x Surf csg annulus. RI set retainer @ 2200'. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20182-00	BRU 212-26	022-005-8	Single w/ No Hydrate Mitigation	GAS	Producing	Will require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" records depict no cmt across Intermediate csg shoe. Well Work in 2020. May Reqire a Waiver to only P&A Well from upper CIBP.	Bullhead KWF down tbg. Ensure csg integrity. MIRU CT Unit. Cleanout to to ETD. Layin/Sqz cmt from 6545' to 6000'. Tag TOC. RIH set CIBP @ ~2920. Perf Liner @ 2900' & 2600'. RI Lay-in/Sqz cmt to 2500'. RD CTU. Jug test wellbore. MIRU Crane, Work Platform & BOPE. Cut tbg @ 600'. Pull/remove tbg. RI set CIBP @ 500'. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-10027-00	BRU 212-35	162-018-0	Single	GAS	Producing	Will require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" records depict no cmt across Intermediate csg shoe . WO 9/2020	Bullhead KWF down tbg. Ensure csg integrity. EL cut tbg below pkr/above perfs. Slickline shift SSD open, Set Cmt Retainer below pkr. Circ/bullhead cmt below retainer. Circ/spot 10' of cmt above pkr. Punch tbg above TOC. Circ/Jug test wellbore. MIRU Crane, Work Platform & BOPE. Cut tbg @~4000'. Pull/remove tbg. RIH Set CIBP @ ~3860'. Perf Csg @ ~3842. Establist Circulation up 7" x 9-5/8". RI Set Rainer @ ~3680'. RIH w/ tbg stab into retainer. Circ cmt below Retainer & up 7" x 9-5/8" annulus. PU, Spot 10' of cmt above retainer. RU Slickline. Run temp survey to confrim TOC in 7" x 9-5/8" annuli is above shoe. Continue P&A.	Mud Pits, Work Platform, Crane, Backhoe, Eline, Slickline, Cmt Blender & Pump, Welder, Guillotine Saw. In w/ Coil work	Type 3
50-283-20097-00	BRU 212-35T	198-161-0	Single w/ Chem inj	GAS	Producing	May require Multiple waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" records depict no cmt across Intermediate csg shoe. Will need to leave ~1500' of cemented 3-1/2" concentric tbg in well.	Bullhead KWF down CT & CT x Tbg annulus. Ensure csg integrity. MIRU CT Unit. Pull Coil Tbg ESP Completion. EL Perf GP Screens. RI w/ CT. Lay-in/Sqz Cmt from 4800' to 3130'. POOH RD CTU. RI Punch tbg above top pkr. Set cmt retainer. Pump/circ 500' of cmt above top pkr. Jug test wellbore. MIRU Work Platform & Crane. Cut pull tbg above TOC. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20192-00	BRU 213-26	223-069-0	Monobore w/ Chem Inj	Gas	Producing	Monobore completopn. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 2700'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2400'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20187-00	BRU 214-13	222-117-0	Monobore w/ Chem Inj	Gas	Producing	Monobore completopn. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 3100'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~3000'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5

API #	Well Name	PTD	Completion Type	Well Status	Activity	Notes	P&A Plan	P&A Surf Equip	Well Type
50-283-20083-00	BRU 214-26	190-042-0	5" tbg Single w/ Chem inj	GAS	Producing	Was Approved as an Annular Producer up Heater String. WO replace completion Jan 09, 2006 as Single String GP. May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Bullhead KWF down tbg. EL Perf GP screen. Utilize CT to lay-in/sqz cmt across intervals. Monitor then test wellbore. Open CMU Slve above pkr. Circ/Spot 500' of cmt on top of Pkr in annulus. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20067-00	BRU 214-35	180-072-0	Single w/ Heater String	GAS	Shut-in		Bullhead KWF down tbg. EL Perf A & B intervals. Utilize CT to lay-in/sqz cmt across intervals. Monitor then test wellbore. MIRU Work Platform & crane. Cut, PU tbg string. RI perf csg w/ 21spf gun 2x above Pkr. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20054-00	BRU 221-23	176-072-0	Single	GAS	Shut-in		Bullhead KWF down tbg. MIRU Rig, BOPE. Test same. Pull heater string. Pull tbg, pkrs completion. RI drill CIBP's. RI Cmt sqz perf intervals. Test Monitor wellbore. RI set CIBP ~150' below intermediate csg shoe. RI perf csg w/ 21spf gun 2x above CIBP. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue Abandoning wellbore. Demobe Rig. Continue P&A.	Workover Rig, Eline, Slickline, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 4
50-283-20201-00	BRU 221-26	224-098-0	Monobore w/o Chemical Injection	GAS	Producing	Monobore completion w/ no chemical injection. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 2600'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2400'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20193-00	BRU 221-35	223-077-0	Monobore w/ Chem Inj	Gas	Producing	Monobore completopn. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 2700'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2400'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20180-00	BRU 222-24	220-043-0	Monobore w/o Chemical Injectio	GAS	Producing	Monobore Completion WO Aug/2020	Bullhead KWF down tbg. MIRU CT Unit. Cleanout to PBTD. MIRU Cmt Equipment. Utilize CT to lay-in/sqz cmt across intervals. Bring TOC to 5400'. Monitor while WOC. Test wellbore. Demobe CT. MIRU Work Platform, BOPE & crane. Cut tbg @ 700'. PU tbg string. POOH LD same. RIH w/ Eline set CIBP @ 500'. Lay-in/Spot cmt on top of CIBP to Surface.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20195-00	BRU 222-26	224-035-0	Monobore w/ Chem Inj	GAS		Monobore completopn. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 3000'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2700'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20186-00	BRU 222-34	222-039-0	Monobore w/o Chemical Injection	GAS	Producing	Monobore Completion w/ 2-3/8" Velocity String	Bullhead KWF down tbg. Circulate, Balance cmt plug across interval to ~4550'. RI w/ Eline. Cut velocity string @4500'. POOH LD Vel RI set CIBP @ 2650'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2400'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20183-00	BRU 223-24	221-072-0	Single	GAS	Producing	Drilled and completed as "Tight Hole" Monobore Compltion	Bullhead KWF down tbg. Ensure Tbg integrity. Pressure test all annuli. MIRU CTU. RI/CO to PBTD @ 6935'. MIRU cementers. Mix/Pump/Layin/Sqz cmt from PBTD to 4500' . RD CTU. Pressure test wellbore. MIRU Work Platform & Crane and equip. RU Eline. RIH tag TOC. RIH Sever tbg @ 550'. POOH LD Tbg. RIH w/ Eline set CIBP @ 500'. Jug tst wellbore. RI w/ Csg Punch gun. Punch 7" @ 480'. Establish circulation rates & pressures. Mix/Pump/Fill wellbore w/ cmt to surface.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20074-95	BRU 223-26	184-135-0	NOT DRILLED	EXPIR	Expired PTD				
50-283-20188-00	BRU 223-34	223-041-0	Single w/ Chem Inj	GAS		Monobore completopn. Assume PTD Proposed dwg is the actual & current.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals. RI set CIBP @ 2700'. RI punch tbg above Liner Hngr Pkr. Utilize CT to lay-in/circ cmt to ~2400'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20042-00	BRU 224-13	173-037-0	Single	GAS	Suspended	Suspended w/ Cement & CIBP May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Jug test wellbre. MIRU Work Platform & crane. Pull Kill String. Continue P&A.	Work Platform, Pits, Crane, Backhoe, Eline, Slickline, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 1
50-283-20076-00	BRU 224-23	184-137-0	Dual	GAS	Shut-in	Annular Producer up Heater String. Currently has an approved Sundry to P&A w/ CTU & Re-drill	Bullhead KWF down tbg. Ensure csg integrity.. MIRU CT Unit onto LS. Remove Fishes. Cleanout to to ETD. Layin/Sqz cmt from ETD to 3200'. RI cut LS and SS above pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above Pkr. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Work Platform, Pits, Crane, Backhoe, Eline, Slickline, Cmt Blender & Pump, Welder, Guillotine Saw. In w/ Coil work	Type 3
50-283-20157-00	BRU 224-23T	211-080-0	Single w/ isolation string w/ Chem Inj	GAS	Producing	Schematic depicts Surface csg shoe is covered with cmt meeting AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements".	Bullhead KWF down tbg. EL Perf GP screens. MIRU CTU RI lay-in/sqz cmt across intervals. Monitor then test wellbore. MIRU Work Platform & crane. Cut, PU tbg string. Spot 500' of cmt on top of pkr. Pull tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3

API #	Well Name	PTD	Completion Type	Well Status	Activity	Notes	P&A Plan	P&A Surf Equip	Well Type
50-283-20080-00	BRU 224-34	186-011-0	5" tbg Single w/ Chem inj	GAS	Producing	Will require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" records depict no cmt across inter csg shoe. Wellwork completed in 2020,2021 & 2022. May Reqire a Waiver to only P&A Well from upper CIBP.	Bullhead KWF down tbg. EL Perf Top GP screes. MIRU CTU RI lay-in/sqz cmt across interval. RI Perf below csg shoe. Punch tbg above pkr. CT RI lay-in/sqz/circ cmt. Monitor then test wellbore. MIRU Work Platform & crane. Cut, PU tbg string.LD same. RI cut csg. PU LD same. Spot 500' of cmt on top of CIBP. Pull tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-10023-00	BRU 232-04	162-037-0	Single	GAS	Shut-in	Schematic Depicts Surf Csg Shoe DOES NOT have cmt overlap as per AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements". Approved Sundry for CTCO	Bullhead KWF down tbg. Ensure csg integrity.. MIRU CT Unit. Cleanout and remove Plug in X nipple. Continue cleanout to ETD. EL perforate GP Screens. RI w/ CT. Layin/Sqz cmt from ETD to 2790'. RI cut tbg above pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above Pkr. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20075-00	BRU 232-09	184-136-0	Single w/ Heater String	WDSPI	Disoosal		Bullhead KWF down tbg. Pressure test annulus. Ensure tbg clear to EOT. CTCO if not. EL Perf across intervals. Set cmt retainer just below top pkr. Open SSD above top pkr. MIRU Cementers. Bullhead/sqz calculated cmt vol below top pkr. Reverse excess. MIRU Work Platform & crane. Cut, Pull tbg strings. RI perf csg w/ 21spf gun 2x above Pkr. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 2
50-283-20133-00	BRU 232-23	209-057-0	4-1/2" Single	Gas	Producing		Bullhead KWF down tbg. EL Perf GP screen. Utilize CT to lay-in/sqz cmt across intervals. Circ/Spot 500' of cmt above pkr. Monitor then test wellbore. MIRU Work Platform, BOP & crane. Cut tbg 200' below surf csg shoe. Pull tbg string. RI perf csg w/ 21spf gun 2x above Pkr. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20077-00	BRU 232-26	184-138-0	Single w/ Chem inj	GAS	Producing	May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Bullhead KWF down Tbg & tbg x Csg annulus. Ensure Tbg & csg integrity. MIRU CTU. RIH Clean out to btm. Mix cmt. Pump/Lay-in/Sqz cmt from btm to ~4200'. POOH. EL Perf below 13-3/8" shoe. Establish Injection/Circulation down tbg while taking returns out 9-5.8" x 13-3/8" annulus. RI with Cmt retainer set @~3400. RI w/ CT. stab into retainer pump/squeeze/circulate cmt. POOH RD CTU. Jug test wellbore. MIRU Work Platform & Crane. Eline Cut tbg @ 600'. Pull tbg stub out of hole. RIH w/ Eline set 9-5/8" CIBP @ 550'. POOH. RI perf torch punch holes in csg @ 530'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20136-01	BRU 233-23	222-050-0	Monobore w/o Chemical Injection	GAS	Producing	May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Bullhead KWF down tbg. Utilize CT to lay-in/sqz cmt across intervals from CIBP @ 5950' to 4900. RI set CIBP @ 2950'. RI Eline perforate 4-1/2" & 7" csg @ 2855'. Establish Circulation Rates & pressures down 4-1/2" out 7" x 9-5/8" csg. Punch tbg above Liner Hngr Pkr @ 2700'. Utilize CT to lay-in/circ/sqz cmt to ~2500'. MIRU Work Platform & crane. Cut, PU tbg string. Remove Tbg. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20200-00	BRU 233-23T	022-488-0	Monobore w/o Chemical Injection	GAS	Producing		Bullhead KWF down Tbg MIRU CT Unit. RI Clean out to PBTD. POOH. MIRU Eline. RI Punch 3-1/2" Tbg @ 2730' & 2700'. Establish circulation down tbg & out tbg x csg annulus. RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from 5830' to 2500'. POOH RD CTU.RIH Tag TOC. Note in Rpt. Pressure test TOC. MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same. RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-10026-00	BRU 233-27	163-002-0	Single	GAS	Producing	Approved CTCO Sundry. Schematic Depicts Surf Csg Shoe DOES NOT have cmt overlap as per AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements".	Bullhead KWF down tbg. Ensure csg integrity.. EL perforate GP Screens. MIRU CT Unit. Cleanout to ETD. Layin/Sqz cmt from ETD to 3000'. RI cut tbg above top pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot 250' of cmt on top of pkr. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20191-00	BRU 241-23	223-061-0	Monobore w/ Chemical Injection	GAS	Producing		Bullhead KWF down Tbg MIRU CT Unit. RI Clean out to top CIBP. POOH. MIRU Eline. RI Punch 4-1/2" Tbg @ 2820'. Establish circulation down tbg & out tbg x csg annulus. RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from 4154' to 2600'. POOH RD CTU. RIH Tag TOC. Note in Rpt. Pressure test TOC. MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline. Continue P&A	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20197-00	BRU 241-26	224-068-0	Monobore w/o Chemical Injection	GAS	Producing		Bullhead KWF down Tbg MIRU CT Unit. RI Clean out to PBTD. POOH. RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from PBTD to 4700. POOH RD CTU. MIRU Eline. RI w/ CIBP. Set same @ 3000'. RI Punch 3-1/2" Tbg @ 2850' & 2900'. Establish circulation down tbg & out tbg x csg annulus. POOH. RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from CIBP to 2500. POOH RD CTU. MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5

API #	Well Name	PTD	Completion Type	Well Status	Activity	Notes	P&A Plan	P&A Surf Equip	Well Type
50-283-20038-00	BRU 241-34	172-016-0	Dual	GAS	Shut-in	Annular Producer up Heater String! Bypassing pkr & production tubing. Failed WO Sept 2019 10-403 Aproved 03/2020 to P&A	Bullhead KWF down LS & SS tbg. Ensure LS & SS tbg integrity. MIRU CT Unit onto LS. RIH to Fish @ ~4010. Mix/Lay-in cmt on top of fish to 3800'. POOH. Pressure test LS. MIRU Eline. RI Perf LS @ 3000' w/ 10' gun. Establish injection rates & pressures. RIH w/CT. Mix/pump Inject cmt into Beluga A thru D interval. POOH. Pressure test LS. MIRU Eline. RI Perf LS @ 2500'. Establish injection rates & pressures. Establish Circulation down LS while taking returns out 9-5/8" annulus. RIH w/ CT. Mix/Pump/Inject cmt while taking returns on 9 5/8" x 13-3/8" annulus, POOH w/ CT MIRU Crane, Work Platform & BOPE. POOH LD Heater String. Eline Cut LS&SS Tbg @ 620'. POOH LD Tbg. Eline Convey CIBP set same @ 550'. Eline punch csg @ 500'. Mix/Pump/Circulate Cmt to surface.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20198-00	BRU 241-34S	224-0770	Monobore w/ Chem Inj	Gas	Producing	Will require Multiple waivers to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Bullhead KWF down Tbg MIRU CT Unit. RI Clean out to PBTD. Mix cmt. Lay-in/Sqz Cmt from PBTD' to 3600'. POOH. MIRU Eline. RIH w/ Perf guns. Tag TOC note depth. PU Perf 4-1/2" @ 3200'.POOH. RI Punch 4-1/2" Tbg @ 2900'. RI Punch tbg @ 2600'. Establish circulation down tbg & out tbg x csg annulus. RIH w/ CT. Lay-in/Sqz/Circ cement to 2600'. POOH RD CTU.RIH Tag TOC. Note in Rpt. Pressure test TOC. MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20181-00	BRU 241-34T	220-052-0	Single	Gas	Producing	Drilled and Completed as a Monobore Completion May require Multiple waivers to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" records depict no cmt across 9-$^{5}/_{8}$" csg shoe. Will attempt to rectify with P&A Procedure.	Bullhead KWF down tbg. Ensure tbg/csg integrity. MIRU CTU. RI/CO to CIBP @ 5233'. MIRU cementers. Mix/Pump/Layin/Sqz cmt from CIBP to 3800'. MIRU Eline, RI w/ CIBP, set same @ 3500'. RI w/ 6' Perf Guns. Perf @ 2900'. RI Punch tbg @ 2620'. Establish injection rates & pressures. RD Eline. RIH w/ CT. Mix/Pump/Lay-in Cmt from 3500' to 2600' Inject cmt across Shoe. POOH WOC. Eline convey tbg punch gun to 2540'. Establish circulation rates & pressures RIH w/ CT. Mix/Pump/Lay-in Cmt from 2600' to 2000'. POOH WOC. MIRU Work Platform & Crane and equip. RU Slickline. RIH tag TOC. RD Slickline. RU Eline. RIH Sever tbg @ 550'. POOH LD Tbg. RIH w/ Eline set CIBP @ 500'. Jug tst wellbore. Mix/Pump/Fill wellbore w/ cmt to surface.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20124-00	BRU 243-34	208-079-0	Single	Gas	Producing		Bullhead KWF down tbg. Ensure csg integrity.. EL perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 3800'. RI cut tbg above top pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot 500' of cmt on top of pkr. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20164-00	BRU 242-04	212-041-0	Single	Gas	Producing		Bullhead KWF down tbg. Ensure csg integrity. MIRU EL. perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 3560'. RD CTU. WOC. RU Slicklline, Tag TOC. RU Eline. RI punch tbg above TOC. RI Set cmt retainer above tbg punches. RI cut tbg above @ 600'. MIRU cmt unit. Mix/Pump/Circulate cmt through retainer. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore. RU Eline. RI cut tbg above @ 600'. MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot/ Lay-in cmt to surface.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20002-00	BRU 244-04	172-003-0	Triple w/ Heater String	GAS	Shut-in	Triple String Completion w/ Heater String. Bummer. 1000' of cemented CT in 2nd tbg string. May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements" if records depict no cmt across inter csg shoe.	Bullhead KWF down tbg. Ensure csg integrity.. RU EL on #1 Tbg String. RI perforate across intervals. MIRU CT Unit onto #1 Tbg String. RI Layin/Sqz cmt from ETD to 3250'. RD CTU. RU EL. RI cut #1 & #3 tbg strings above top pkr. Jug test wellbore. MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot 500' of cmt on top of pkr. Pull/remove #1 & #2 tbg & heater string. RI w/ EL cut #3 tbg string above CT fish. Test wellbore. Continue P&A.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20165-00	BRU 244-23	212-069-0	Single	GAS	Producing	May require waiver to AOGCC Title 2; 20 AAC 25.112. "Well plugging requirements"	Bullhead KWF down tbg. Ensure csg integrity.. EL perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 5060'. RD CTU. WOC. RU Slicklline, RI tag TOC.RU Eline. RI punch tbg above pkr. RI Set cmt retainer above tbg punches. MIRU cmt unit. Mix/Pump/Circulate cmt through retainer. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore.RU Eline. RI Perf through tbg, below Shoe @ 3460'. RI Set cmt retainer @ 3300'. MIRU cmt unit. Mix/Pump/Circulate cmt through retainer, taking returns on 7" x 9-5/8" annulus. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore.RU Eline. RI cut tbg above @ 600'. MIRU Crane, Work Platform & BOPE. PU tbg. POOH LD Same. RU Eline. RIH set CIBP @ 500'. RI w/ csg punch csg above CIBP. RD Eline. RI w/ Workstring. Lay-in fill 7" & 9-5/8" to surface. POOH. LD Workstring.	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 3
50-283-20185-00	BRU 244-27	222-038-0	Monobore w/o Chemical Injection	GAS	Producing		Bullhead KWF down Tbg MIRU CT Unit. RI Clean out to CIBP @ 5905'. Mix cmt. Lay-in/Sqz Cmt from 5905' to 4200'.POOH. MIRU Eline. RI Tag TOC note depth. PU CIBP. Set same @ 2720'. RI w/ tbg punch gun. Punch 4-1/2" @ 2680'. Establish circulation down tbg & out tbg x csg annulus. POOH.RIH w/ CT. Lay-in/Sqz/Circ cement to 2500'. POOH RD CTU.RIH Tag TOC. Note in Rpt. Pressure test TOC.MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	Coil Unit, Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 5
50-283-20078-00	BRU BRWD-1	186-009-0		WDSP2	Disposal		Bullhead KWF down tbg. Ensure csg integrity. RU EL RI punch tbg 1 joint above pkr. RI set cmt retainer just above pkr. MIRU Cementers. Bullhead calculated volume of cmt below pkr. Reverse out excess. Spot 800' of cmt on top of pkr. RU EL. RI cut tbg above TOC. MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC. Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. Continue P&A.	Mud Pits, Eline, Slickline, Work Platform, Crane, Backhoe, Cmt Blender & Pump, Welder, Guillotine Saw.	Type 2

BRU 14-19 (163-020-0) Type 1

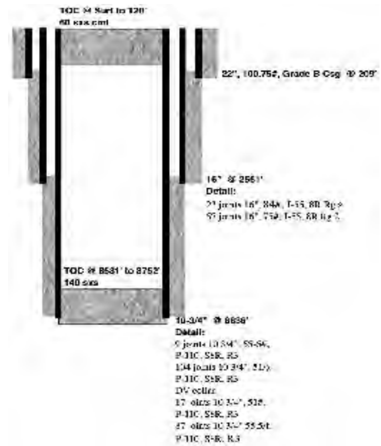
Procedure Summary Timeline

Step #		Line Item Step	Hrs	Days	Accumulative
1		Mobe Conductor P&A equipment to wellsite	12	0.75	0.8 days
2		RU gauges to annuli. Check pressure. Bleed off as needed.	2	0.125	0.9 days
3		Utilize Backhoe to dig down 5' below GL.	16	1	1.9 days
4		RU Guillotine cutter and power pack. Cut Surf and Intermediate csg strings 3' below GL.	8	0.5	2.4 days
5		Mix/Pump cmt to fill all annulis to surface	6	0.375	2.8 days
6		Weld P&A Plate. Bury same.	8	0.5	3.3 days
7					
8					
9					
10					
11					
12					
13					
14					
15					

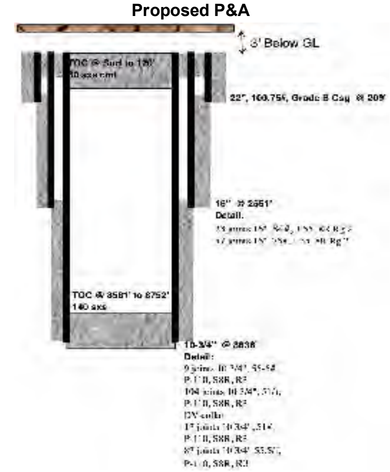
Conductor P&A

BRU_14_19__		
CTU	BRU_14_19__CTU	0 days
CRANE	BRU_14_19__CRANE_Type1	0 days
RIG	BRU_14_19__RIG	0 days
Eline	BRU_14_19__Eline_Type1	0 days
CMTUnit	BRU_14_19__CMTUnit_Type1	0 days

Current



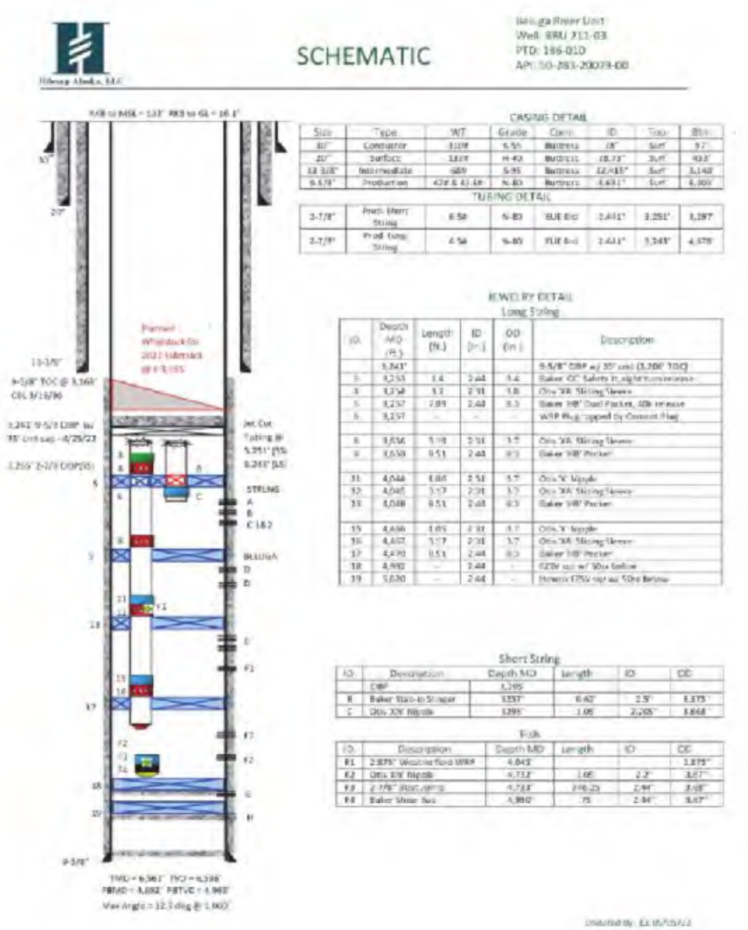
Proposed P&A



BRU 211-03 (186-010-0) Type 0

* Type 0: Original Wellbore P&A'd for Sidetrack, no additional cost to P&A

BRU_211_03_		
CTU	BRU_211_03_CTU	0 days
CRANE	BRU_211_03_CRANE_Type0	0 days
RIG	BRU_211_03_RIG	0 days
Eline	BRU_211_03_Eline_Type0	0 days
CMTUnit	BRU_211_03_CMTUnit_Type0	0 days

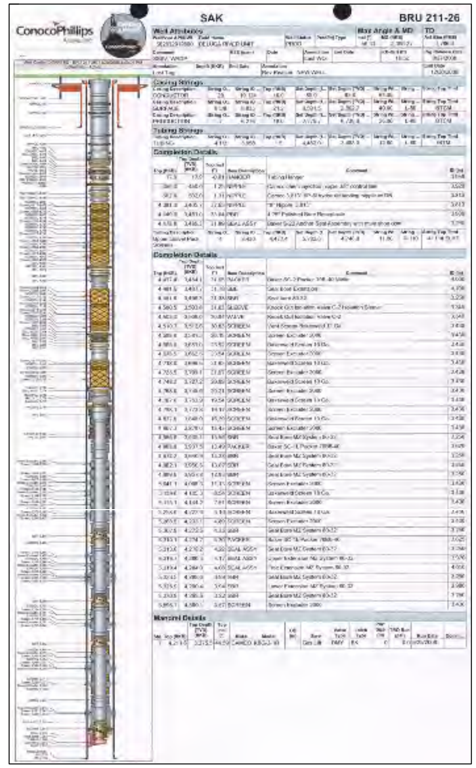


BRU 211-26 (208-112-0) Type 3

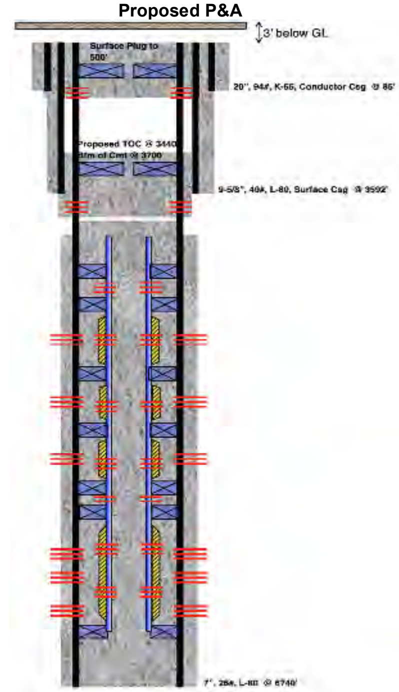
Procedure Summary Timeline

Step #		Line Item Step	Hrs	Days	Accumulative	
1	CMT Unit	Bullhead KWF down tbg.	3.6	0.2	0.2 days	
2	Eline	EL Perf Screens.	21.6	1.4	1.6 days	
3	CTU	Utilize CT to lay-in/sqz cmt across GP Screens. Monitor then test wellbore.	74.4	4.7	6.2 days	
4	CRANE	MIRU Work Platform, BOPE & crane. PU tbg string. Circ/Spot 100' cmt on top of pkr. Remove Tbg.	62.4	3.9	10.1 days	
5	CRANE	RI perf csg w/ 21spf gun 2x above TOC.	14.4	0.9	11.0 days	
6	CRANE	Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe.	9	0.6	11.6 days	
7	CRANE	RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore.	28.8	1.8	13.4 days	
8	CRANE	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	28.8	1.8	15.2 days	
9						
		Continue with Conductor P&A				

BRU_211_26_		
CTU	BRU_211_26_CTU	5 days
CRANE	BRU_211_26_CRANE_Type3	9 days
RIG	BRU_211_26_RIG	0 days
Eline	BRU_211_26_Eline_Type3	2 days
CMTUnit	BRU_211_26_CMTUnit_Type3	1 days



Proposed P&A



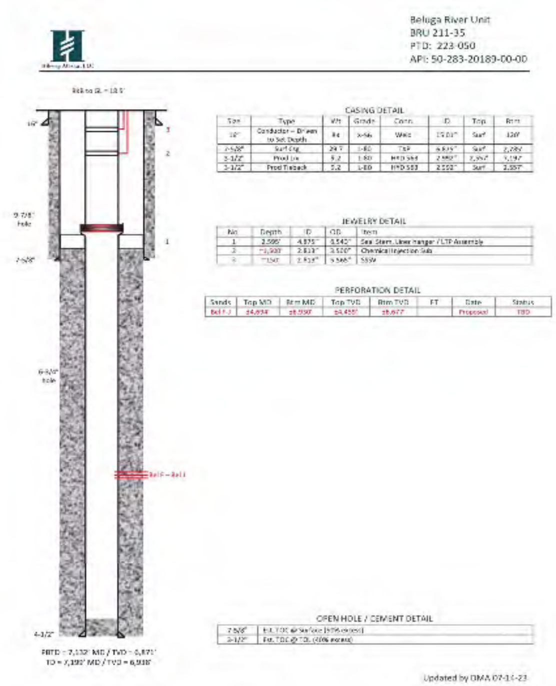
*Additional jewelry and equipment information available on request

BRU 211-35 (223-050-0) Type 5

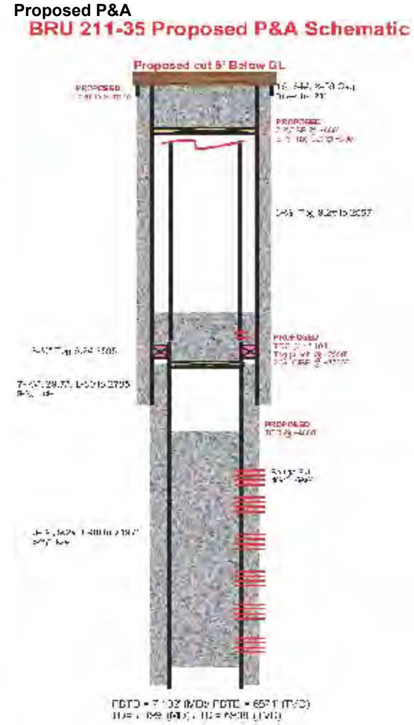
Procedure Summary Timeline

Step #		Line Item Step	Hrs	Days	Accumulative	
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days	
2	CTU	MIRU CTU. Utilize CT to lay-in/sqz cmt across Beluga to 4500'. POOH w/ CT. Monitor then test wellbore.	40.8	2.6	2.8 days	
3	Eline	MIRU Eline. RIH Set CIBP @ 2700'. RI Punch Tbg @ 2550'. Establish Circulation between tbg & csg. POOH w/ Eline.	8	0.5	3.3 days	
4	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 2700'. POOH. WOC. Pressure test tbg. Demobe CT.	40.8	2.6	5.8 days	
5	CRANE	MIRU Work Platform, BOPE & crane. RU Eline. RI cut tbg @ 600'. POOH RD Eline. Demobe same.	45.6	2.9	8.7 days	
6	CRANE	PU tbg string. Remove Tbg. RU Eline. RI set CIBP @ 550' RI w/ tbg. Circ/Spot cmt on top of CIBP to Surf.	25.6	1.6	10.3 days	
		Continue with Conductor P&A				

BRU_211_35_		
CTU	BRU_211_35_CTU	6 days
CRANE	BRU_211_35_CRANE_Type5	5 days
RIG	BRU_211_35_RIG	0 days
Eline	BRU_211_35_Eline_Type5	1 days
CMTUnit	BRU_211_35_CMTUnit_Type5	1 days



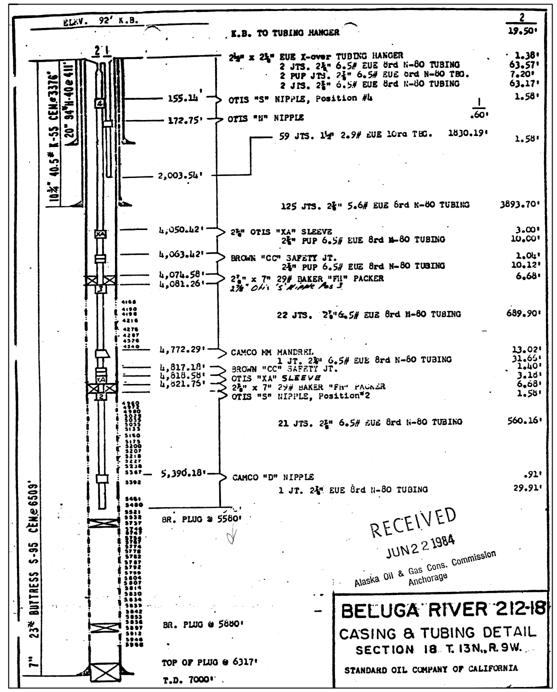
Proposed P&A



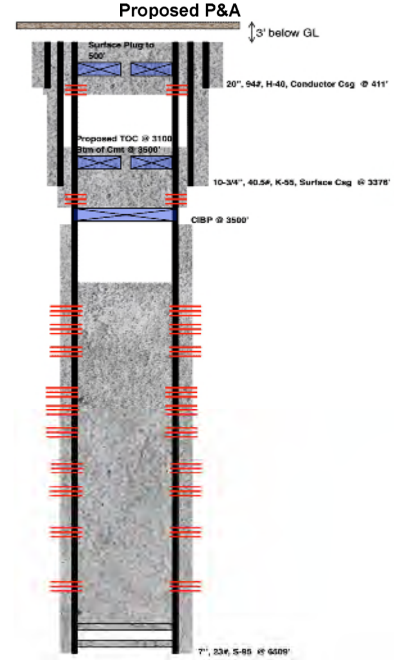
BRU 212-18 (175-034-0) Type 4

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	RIG	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	RIG	MIRU Rig, BOPE. Test same. Pull heater string. Pull tbg, pkrs completion. RI drill CIBP's. Cleanout to ETD.	124.2	5.2	5.3 days
3	RIG	MIRU Cmt Equipt. RI Cmt sqz perf intervals. Test Monitor wellbore.	40.2	1.7	7.0 days
4	RIG	RI set CIBP ~150' below intermediate csg shoe. RI perf csg w/ 21spf gun 2x above CIBP.	7.8	0.3	7.3 days
5	RIG	Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe.	5.4	0.2	7.6 days
6	RIG	RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore.	4.8	0.2	7.8 days
7	RIG	Demobe Rig.	57.6	2.4	10.2 days
8	Crane	MIRU Work Platform & crane.	28.8	1.8	12.0 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. MIRU Cmt Equipt. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	38.4	2.4	14.4 days
Continue with Conductor P&A					
10					
11					
12		RIH Cut & pull Prod csg. RI set CIBP in Surf csg above prod csg stub.			
13		RI with tbg. Spot 100' of cmt ontop of CIBP. POOH.			
14		Dig down 5' below GL.			
15		Cut Surf and Intermediate csg strings 3' below GL. Weld P&A Plate. Bury same.			
16		Top off w/cmt to surface.			
17					

BRU_212_18_		
CTU	BRU_212_18_CTU	0
CRANE	BRU_212_18_CRANE_Type4	5
RIG	BRU_212_18_RIG	11
Eline	BRU_212_18_Eline_Type4	0
CMTUnit	BRU_212_18_CMTUnit_Type4	0



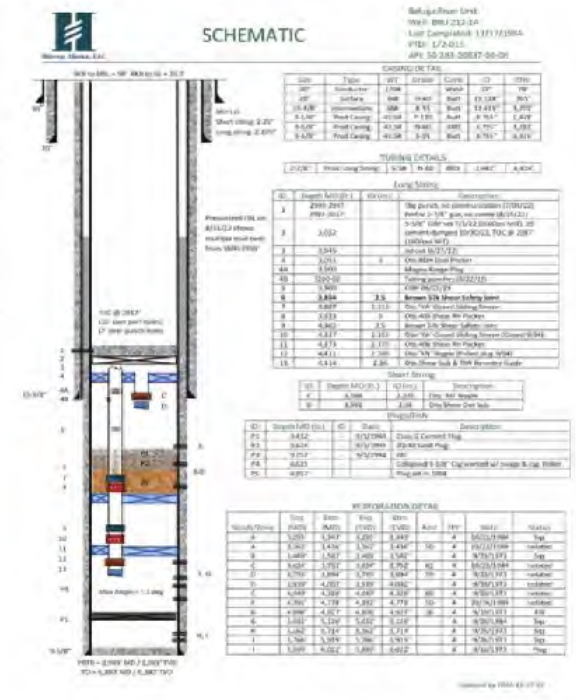
Proposed P&A



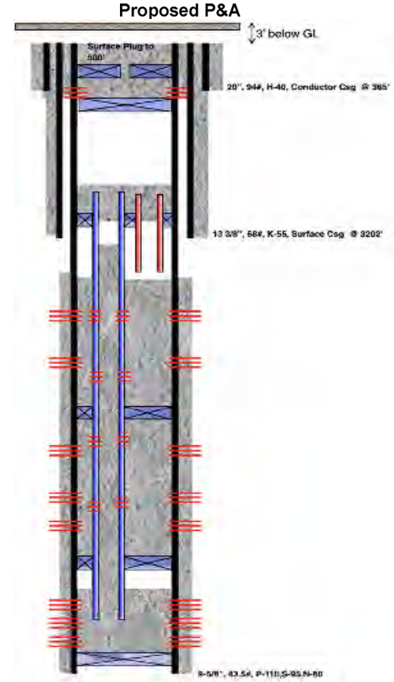
BRU 212-24 (172-015-0) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
	CMTUnit	Bullhead KWF down LS & SS tbg.	7.2	0.5	0.5 days
	Eline	EL Perf prod intervals and GP screen.	14.4	0.9	1.4 days
	CTU	MIRU Coil & Cmt Equipt. Utilize CT to lay-in/sqz cmt across intervals. Monitor then test wellbore. RD CTU	81.6	5.1	6.5 days
	CMTUnit	Open SSD @ 3016'. Punch SS at 3000'. Circ/Spot 500' of cmt on top of Pkr in annulus, LS, SS.	30	1.9	8.3 days
	Crane	MIRU Work Platform & crane. Cut, PU LS, SS & Heater tbg string.	57.6	3.6	11.9 days
		Need Waiver Approved to not staddle Surf Csg shoe with cmt.			
	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	28.8	1.8	13.7 days
Continue with Conductor P&A					

BRU_212_24_		
CTU	BRU_212_24_CTU	6
CRANE	BRU_212_24_CRANE_Type3	6
RIG	BRU_212_24_RIG	0
Eline	BRU_212_24_Eline_Type3	1 days
CMTUnit	BRU_212_24_CMTUnit_Type3	3 days



Proposed P&A

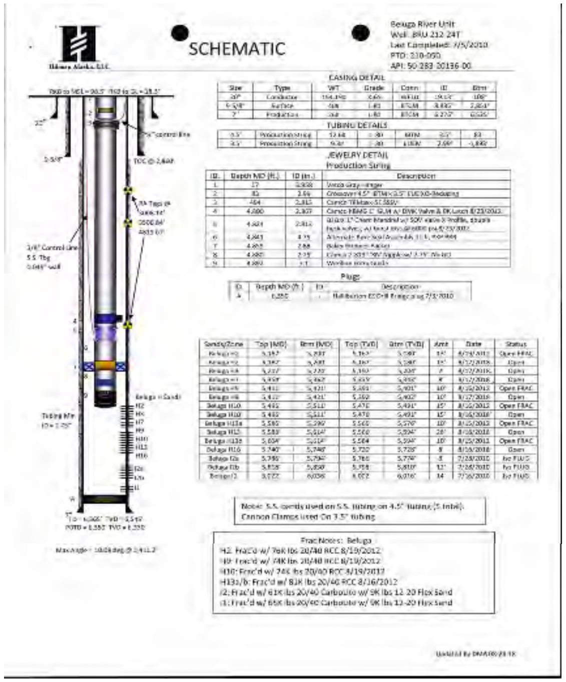


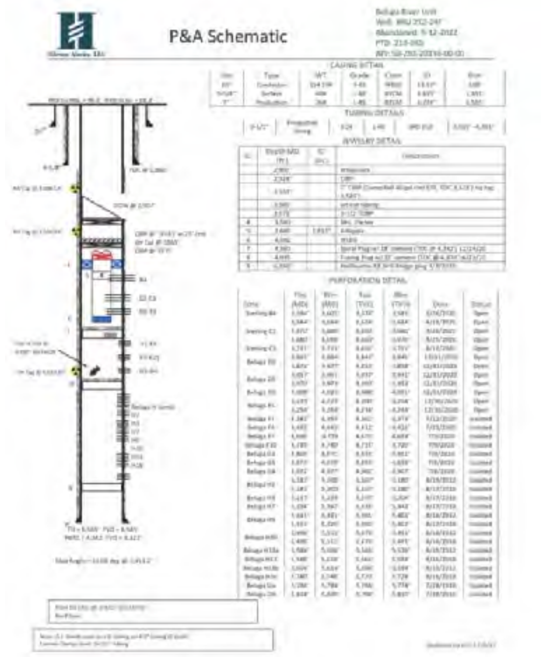
BRU 212-24T (210-050-0) Type 0

* Type 0: Original Wellbore P&A'd for Sidetrack, no additional cost to P&A

BRU_212_24T_

CTU	BRU_212_24T_CTU	0
CRANE	BRU_212_24T_CRANE_Type0	0
RIG	BRU_212_24T_RIG	0
Eline	BRU_212_24T_Eline_Type0	0 days
CMTUnit	BRU_212_24T_CMTUnit_Type0	0 days





BRU 212-25 (162-033-0) Type 3

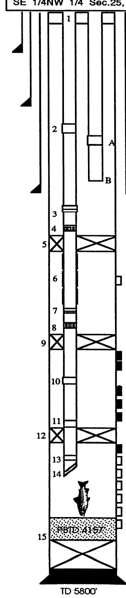
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity.	3.6	0.2	0.2 days
2	Eline	Remove plug w/ slickline.	10.8	0.7	0.9 days
3	CTU	MIRU CT Unit. Cleanout to to ETD. Layin/Sqz cmt from 4157' to 3900'.	50.4	3.2	4.1 days
4	CTU	RI perf tbg across Zone A. RI Circ/sqz cmt into zone A. RD CTU.	38.4	2.4	6.5 days
5	Crane	MIRU Crane, Work Platform & BOPE. RI Punch tbg above top pkr. Set cmt retainer. Pump/circ 500' of cmt above top pkr.	67.2	4.2	10.7 days
6	Crane	Jug test wellbore. Cut tbg above TOC. Pull/remove tbg.	14.4	0.9	11.6 days
7	Crane	RI set CIBP @ 2500'. RI perf csg w/ 21spf gun 2x above CIBP.	7.8	0.5	12.0 days
8	Crane	Establish circulation up Production csg x Surf csg annulus. RI set retainer @ [illegible]	7.2	0.5	12.5 days
9	Crane	RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. POOH. Jug Test wellbore. RD Workplatform, Crane, BOPE.	40.8	2.6	15.0 days
10	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	28.8	1.8	16.8 days
Continue with Conductor P&A					

BRU_212_25_

CTU	BRU_212_25_CTU	6 days
CRANE	BRU_212_25_CRANE_Type3	11 days
RIG	BRU_212_25_RIG	0 days
Eline	BRU_212_25_Eline_Type3	1 days
CMTUnit	BRU_212_25_CMTUnit_Type3	1 days

ARCO Alaska, Inc. Belug[illegible]iver Unit

BRU 212-25	API#: 283-10025-00		Well Type:	Gas Producer
Spud Date: 11/62	Original RKB (Depth Ref):	42	Annulus Fluid:	Diesel
Last Compl: 8/84	Ground Level:	27'	Top of Sterling:	3320'
Schematic Rev: 8/14/92	Maximum Hole Angle:	<1°	ASP: 2628328,323854	
SE 1/4NW 1/4 Sec.25,T13N,R10W,SM	Angle at Perforations:	<1°	Single w/ heater string	



RECEIVED
AUG 27 1992
Alaska Oil & Gas Cons. Commission
Anchorage

Jewelry

	Depth	Length	Equipment	I.D.	O.D.
1	16.40'		Tubing Hanger		
2	542'	1.17'	Otis "X" Nipple	1.875"	2.375"
3	3223'	1.41'	Brown CC Safety		2.375"
4	3253'	2.85'	Otis "XA" Sliding Sleeve		
5	3256'	7.30'	Baker FHL Ret. Pkr. 40M# shear	3.00"	6.078"
6	3294'	60.11'	3 Blast Jts. 3296'-3356'		3"
7	3355'	2.45'	Brown Safety Jt.Straight pull 60M#shear		2.375"
8	3386'	3.05'	Otis "XA" S S (open 6/10/85)		
9	3389'	7.65'	Baker FHL Ret. Pkr. 781-36 DM	3.00"	6.078"
10	3881'	1.30'	Otis "XN" Nipple(Plug set 7/29/92)	1.75"	2.375"
11		1.09'	Tubing Locator Sub	2.406"	3.437"
12	3887'	4.05'	Baker Model "D" Perm Pkr.	3.250"	5.687"
13	3891'	14.96'	Seals Model "D" Extended Bore Pkr.	2.406"	3.234"
14	3903'	.67'	Baker Shear Out Sub	2.00"	2.875"
15	4157'		Top of Plug		
A	573'	1.28'	Otis" XN" Nipple		2.375"
B	2034'		Heater Sring Tubing Tail		

Casing and Tubing

Description	Size	Weight	Grade	Thread	Top	Bottom
Conductor	36"				16.4'	29'
Surface	16"	75#	J-55	8RD	16.4'	288'
Intermediate	10 3/4"	55.5#/51#	N-80	8RD	16.4'	2364'
Production Csg	7"	23#/26#	N-80/P110	8RD	16.4'	5776'
Pruduction Tbg	2 3/8"(1)	4.7#	N-80	EUE-8RD	16.4'	3903'
Heater	2 3/8"(2)	4.7#	N-80	EUE-8RD	16.4'	2034'

Perforations

Zone	MD	Density	Net Footage	Interval	Production Status
A	3338'-3344'	4	6'	Packer	Open 6/85
	3420'	5	SQZ.		Closed
	3437'-3458'	4	SQZ.		Closed
C	3650'-3668'	4	SQZ.		Closed
	3732'-3734'	4	SQZ.		Closed
D	3815'-3825'	4	SQZ		Closed
	3866'-3875'	4	SQZ	Packer	Closed
	3901'-3921'	8	20'		Closed 7/92
	4008'-4014'	16	6'		Closed 7/92
	4014'-4020'	8	6'		Closed 7/92
	4020'-4024'	12	4'		Closed 7/92
E	4056'-4060'	12	4'		Closed 7/92
	4068'-4078'	4	10'		Closed 7/92
	4105'-4111'	4	6'		Closed 7/92

Fish #1: Slickline tools (17' 2"-1.5"OD) 6/22/92 (TTL-1', spang jars-6', open hydraulic jars-4', sinker bar-5', knuckle joint & rope socket-14')

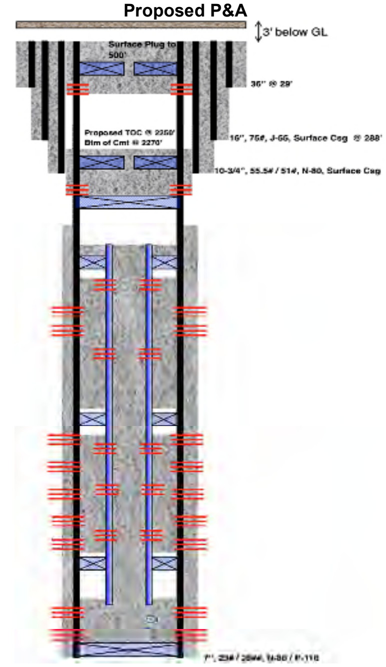
Fish#2: 4-21' strands perf gun wire w/bullnose, 1-2' stra nd 7/19/92

Tag Data

1/25/85	Sinker bar	fluid & sand at 4104' RKB
9/6/85	1.75" gauge ring	X nipple at 3880', no fill
5/4/91	1.8" gauge ring	PX plug at 3881' RKB, no fill
5/3/92	1.75" bailer	fill at 4013' RKB
6/22/92	1.75" bailer	fill at 4090' RKB
8/11/92	1.75" bailer	sand slurry 3500', fill 3839' WLM

JLB 8/14/92

Proposed P&A

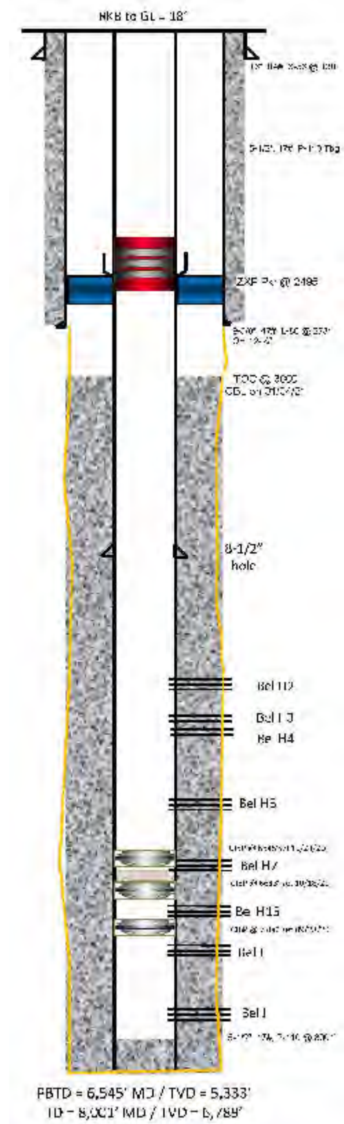


BRU 212-26 (220-058-0) Type 3

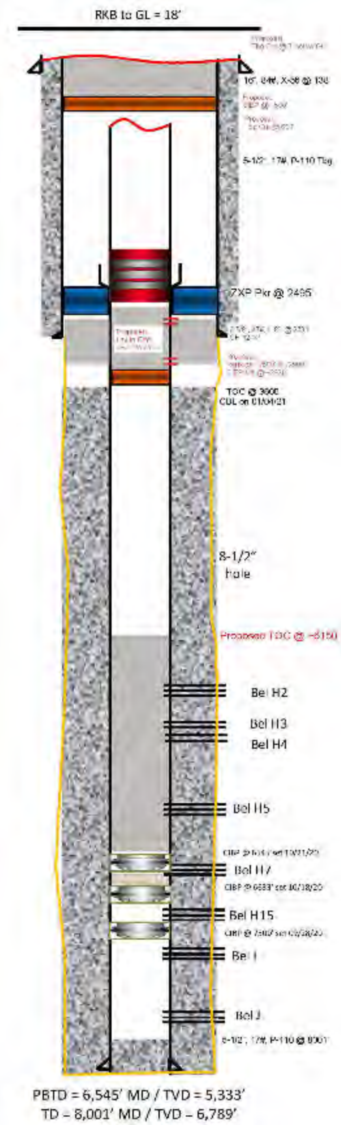
Procedure Summary Timeline					
Step #		**Line Item Step**	**Hrs**	**Days**	**Accumulative**
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity.	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. Cleanout to to ETD. Layin/Sqz cmt from 6545' to 6000'.	60	3.8	4.0 days
3	CTU	RU Slickline RI Tag TOC. Note same on rept.	7.2	0.5	4.4 days
4	CTU	RI Set CIBP @ 2920. RI perf Liner @ 2900' & 2600'. RI Lay-in cmt to 2500'. RD CTU. Jug test wellbore	60.6	3.8	8.2 days
5	Crane	MIRU Crane, Work Platform & BOPE. RI Cut tbg @ 600'.	62.4	3.9	12.1 days
6	Crane	POOH LD Cut tbg. RI w/ CIBP. Set same @ 500'. Jug test wellbore	17.4	1.1	13.2 days
Continue with Conductor P&A					

BRU_212_26_		
CTU	BRU_212_26_CTU	8 days
CRANE	BRU_212_26_CRANE_Type3	5 days
RIG	BRU_212_26_RIG	0 days
Eline	BRU_212_26_Eline_Type3	0 days
CMTUnit	BRU_212_26_CMTUnit_Type3	1 days

Current



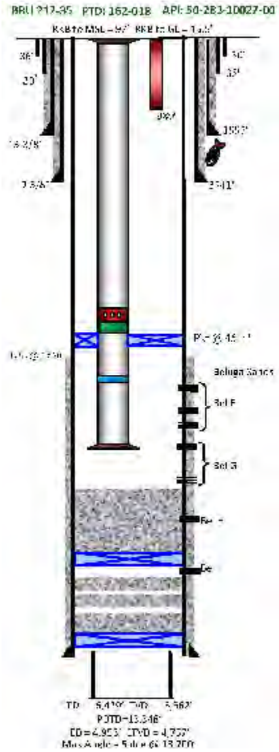
Proposed P&A



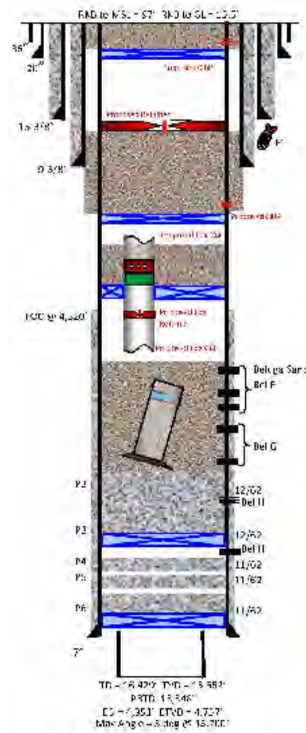
BRU 212-35 (162-018-0) Type 3

Step #		Line Item Step	Hrs	Days	Accumulative
Procedure Summary Timeline					
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity.	3.6	0.2	0.2 days
2	Eline	Mobe Slickline. RI Shit SSD open, Mobe Eline, RIH Cut tbg @ 4575'.	20.4	1.3	1.5 days
3	Eline	Set Cmt Retainer below Pkr.	10.2	0.6	2.1 days
4	CMTUnit	Pump/Circ/bullhead cmt below Retainer. Spot cmt above pkr through SSD. Leave 10' above pkr.	14.4	0.9	3.0 days
5	Eline	Punch tbg above TOC. Circ/Jug test wellbore.	4.2	0.3	3.3 days
6	Eline	RI Cut tbg @ 4000'. RD Eline.	7.2	0.5	3.8 days
7	Crane	MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RU Eline. RI set CIBP @ 3860'. RIH Perf csg @ 3842'. POOH Establish Circulation Rates & pressures. RIH set Cmt Retainer @ 3680'. RD Eline.	65.4	4.1	7.8 days
8	Crane	RIH w/ tbg stab into retainer. Circ/bullhead cmt below Retainer & up 7" x 9-5/8" annulus. PU tbg, Spot 10' of cmt above retainer.POOH. RU Slickline. Run temp survey to confrim TOC in 7" x 9-5/8" annuli is above shoe. RD Demobe Equip.	64.2	4.0	11.9 days
Continue with Conductor P&A					

BRU_212_35_		
CTU	BRU_212_35_CTU	0 days
CRANE	BRU_212_35_CRANE_Type3	9 days
RIG	BRU_212_35_RIG	0 days
Eline	BRU_212_35_Eline_Type3	3 days
CMTUnit	BRU_212_35_CMTUnit_Type3	2 days
		14 days



Proposed P&A

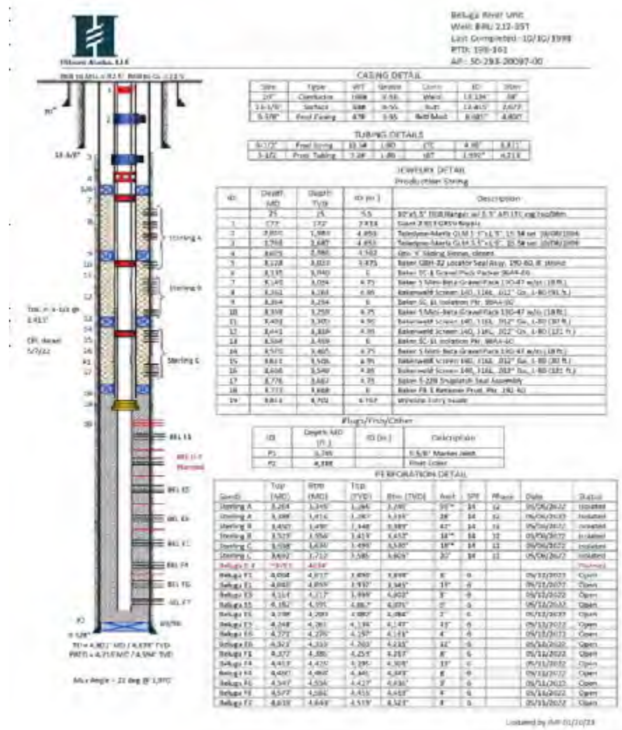


BRU 212-35T (198-161-0) Type 3

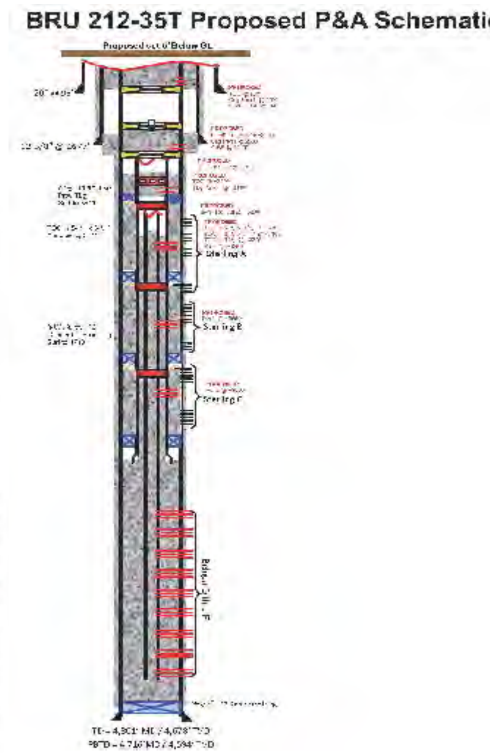
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down 3-1/2" Tbg. Pressure test 5-1/2" x 9-5/8" annulus. Ensure csg integrity.	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RIH Clean out to Btm. MIRU Cementers. Mix/Lay-in cmt to ~3700'. POOH.	60	3.8	4.0 days
3	Eline	MIRU Eline. RI Perforate each productive interval.	19.2	1.2	5.2 days
4	CTU	RI w/ CT. Lay-in/Sqz cmt from ~3600' to ~3250'.	14.4	0.9	6.1 days
5	Crane	MIRU Crane & workplatform. ND Tree, NU BOPE. Pressure test Same. MIRU Eline. RU to 3-1/2" tbg.	55.2	3.5	9.5 days
6	Crane	RI w/ tbg cutter. Sever tbg @ 3200'. POOH w/ Eline. POOH LD 3-1/2" tbg. Pressure test 5-1/2" tbg.	11.4	0.7	10.2 days
7	Crane	RI w/ Eline conveyed tbg punch. Punch 5-1/2" @ 3110'. Establish Circulation from tbg to csg. RI w/ CT. Lay-in Cmt to ~3000'. POOH. RI w/ Eline. Sever 5-1/2" tbg @ 2850' POOH w/ Eline.	49.2	3.1	13.3 days
8	Crane	Pickup, POOH LD 5-1/2" tbg. RU Eline, RI set CIBP above severe tbg stub. Pressure test Wellbore. RI w/ Eline perf guns. Perf 9-5/8" csg @ 2800'. Establish injection rate & pressures. Establish circulation rates & pressures out 9-5/8" x 13-3/8" annulus.	28.8	1.8	15.1 days
9	Crane	RIH w/ Eline set Retainer @ 2500'. RIH w/ CT. stab into retainer. Mix/pump/ circulate cmt out 9-5/8" x 13-3/8" annulus, cover 13-3/8" shoe 100' on ech side. PU. CBU. POOH. Jug test Wellbore.	45.6	2.9	18.0 days
10	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	38.4	2.4	20.4 days
Continue with Conductor P&A					

BRU_212_35T_

CTU	BRU_212_35T_CTU	5 days
CRANE	BRU_212_35T_CRANE_Type3	15 days
RIG	BRU_212_35T_RIG	0 days
Eline	BRU_212_35T_Eline_Type3	2 days
CMTUnit	BRU_212_35T_CMTUnit_Type3	1 days



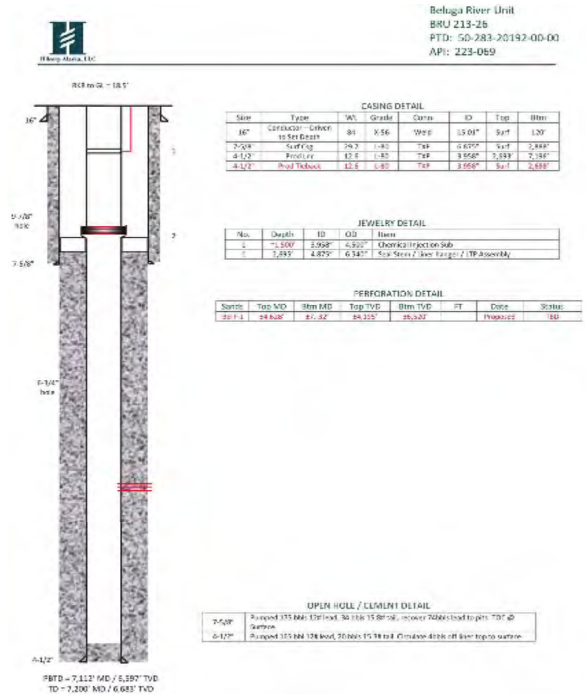
Proposed P&A



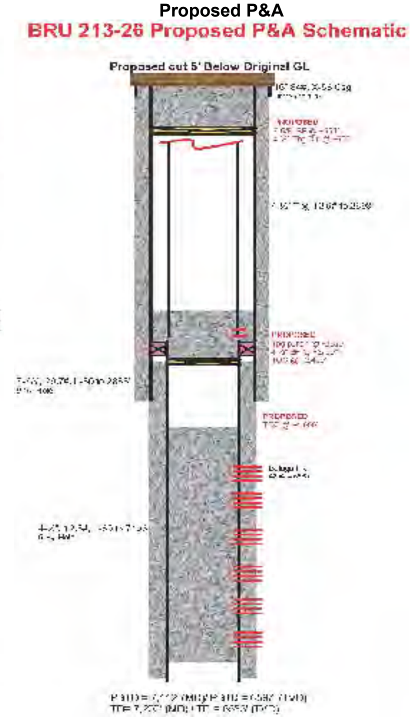
BRU 213-26 (223-069-0) Type 5

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg into Beluga perforations.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. Utilize CT to lay-in/sqz cmt across Beluga to 4000'. POOH w/ CT. Monitor then test wellbore.	40.8	2.6	2.8 days
3	Eline	MIRU Eline. RIH Set CIBP @ 2700'. RI Punch Tbg @ 2550'. Establish Circulation between tbg & csg. POOH w/ Eline.	8	0.5	3.3 days
4	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 2700'. POOH. WOC. Pressure test tbg. Demobe CT.	40.8	2.6	5.8 days
5	CRANE	MIRU Work Platform, BOPE & crane. RU Eline. RI cut tbg @ 600'. POOH RD Eline. Demobe same.	45.6	2.9	8.7 days
6	CRANE	PU tbg string. Remove Tbg. RU Eline. RI set CIBP @ 550' RI w/ tbg. Circ/Spot cmt on top of CIBP to Surf.	25.6	1.6	10.3 days
Continue with Conductor P&A					

BRU_213_26_		
CTU	BRU_213_26_CTU	6 days
CRANE	BRU_213_26_CRANE_Type5	5 days
RIG	BRU_213_26_RIG	0 days
Eline	BRU_213_26_Eline_Type5	1 days
CMTUnit	BRU_213_26_CMTUnit_Type5	1 days



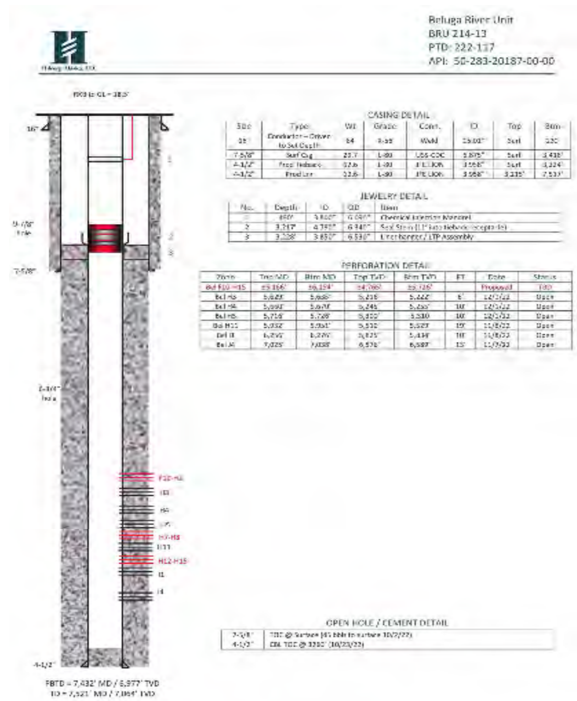
Proposed P&A



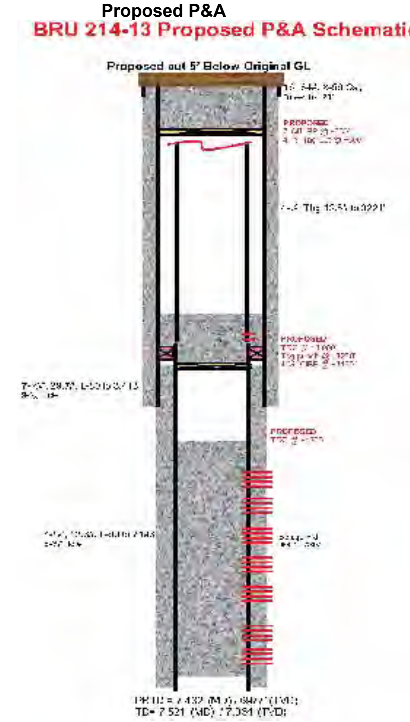
BRU 214-13 (222-117-0) Type 5

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg into Beluga perforations.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. Utilize CT to lay-in/sqz cmt across Beluga to 4350'. POOH w/ CT. Monitor then test wellbore.	40.8	2.6	2.8 days
3	Eline	MIRU Eline. RIH Set CIBP @ 3100'. RI Punch Tbg @ 3200'. Establish Circulation between tbg & csg. POOH w/ Eline.	6	0.4	3.2 days
4	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 3100'. POOH. WOC. Pressure test wellbore. Demobe CT.	12	0.8	3.9 days
5	CRANE	MIRU Work Platform, BOPE & crane. RU Eline. RI cut tbg @ 600'. POOH RD Eline. Demobe same.	46.8	2.9	6.8 days
6	CRANE	PU tbg string. Remove Tbg. RU Eline. RI set CIBP @ 550' RI w/ tbg. Circ/Spot cmt on top of CIBP to Surf.	20.8	1.3	8.1 days
Continue with Conductor P&A					

BRU_214_13_		
CTU	BRU_214_13_CTU	4 days
CRANE	BRU_214_13_CRANE_Type5	5 days
RIG	BRU_214_13_RIG	0 days
Eline	BRU_214_13_Eline_Type5	1 days
CMTUnit	BRU_214_13_CMTUnit_Type5	1 days



Proposed P&A

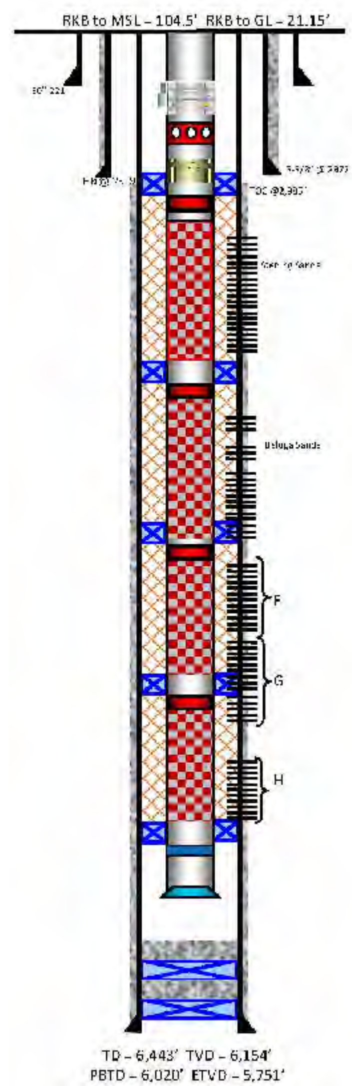


BRU 214-26 (190-042-0) Type 3

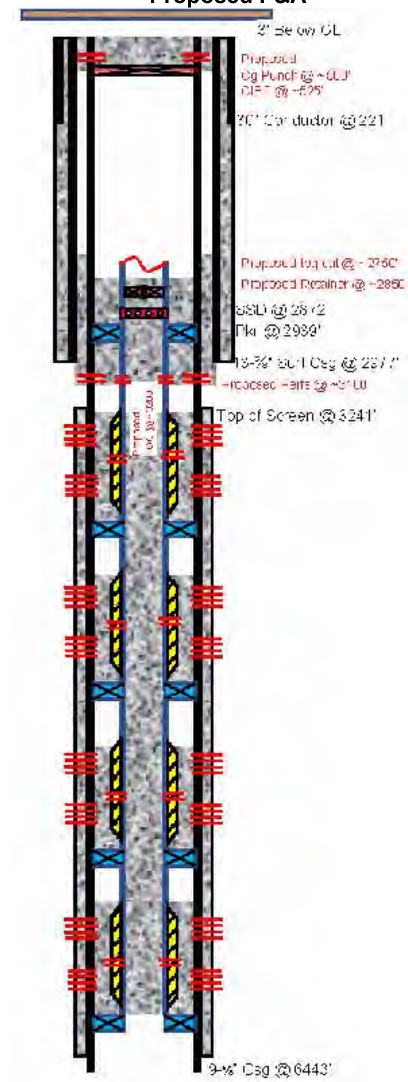
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	Eline	RU EL. RI Perf GP screens. RD Eline. Pump Establish injection rates & pressures	21	1.3	1.5 days
3	CTU	Utilize CT to lay-in/sqz cmt across intervals upto 3200'. Monitor. Jug test wellbore.	50.4	3.2	4.7 days
4	CTU	RU Eline. Perf GP Blank Pipe @ 3100', Establish Circulation rates & pressures down tbg, taking returns out 9-5/8" x 13-3/8" annulus.	16.2	1.0	5.7 days
5	CTU	RU Slickline. Open CMU Slve above pkr. Eline convey Ret, set same @ 2850'.	25.8	1.6	7.3 days
6	CTU	RI w/ CT. With tbg x csg annulus close, establish circulation rate& pressures down CT while taking returns up 9=5/8" x 13-3/8" annulus. Mix/pump to place a significant amount of cmt to achieve overlap of 13-5/8" shoe 100' above & below. (15 bbls)	9	0.6	7.9 days
7	CTU	Open tbg x csg annulus. Continue pumping cmt, place 170' in tbg x csg annulus, above pkr. Pull out of retainer. BU POOH. RD Demobe CT.	33	2.1	9.9 days
8	Crane	MIRU Work Platform & crane. Cut tbg @ ~2750'. PU remove tbg string	88.8	5.6	15.5 days
9	Crane	RIH w/ Eline set CIBP @ 525'. RI perf torch punch holes in csg @ 500'. Establish Circulation. RI w/ tbg. Mix/Pump cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	28.8	1.8	17.3 days
Continue with Conductor P&A					

BRU_214_26_		
CTU	BRU_214_26_CTU	9 days
CRANE	BRU_214_26_CRANE_Type3	8 days
RIG	BRU_214_26_RIG	0 days
Eline	BRU_214_26_Eline_Type3	2 days
CMTUnit	BRU_214_26_CMTUnit_Type3	1 days

Curent



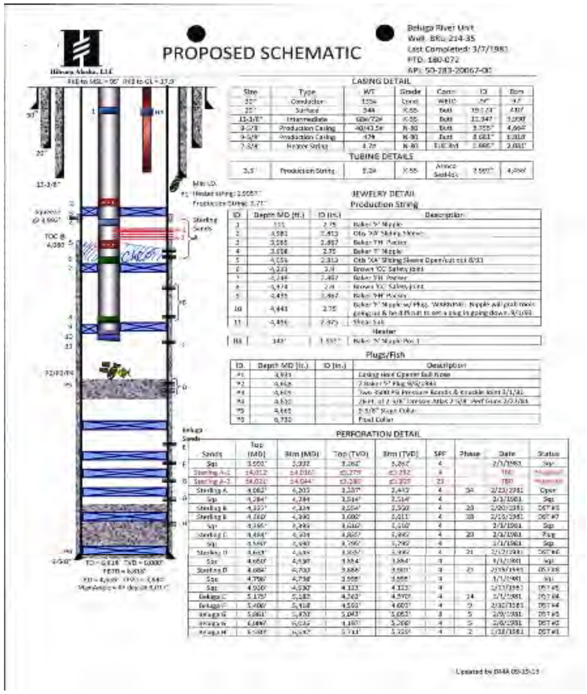
Proposed P&A



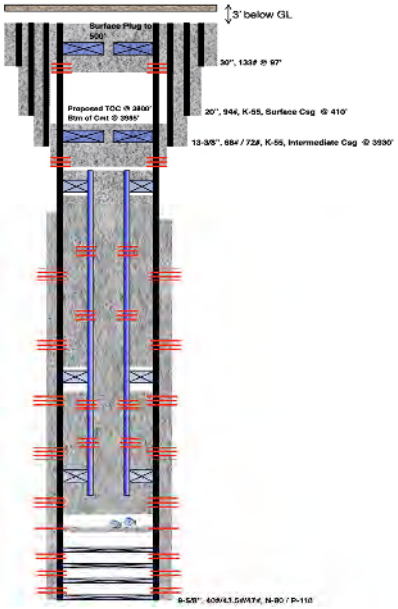
BRU 214-35 (180-072-0) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
CMTUnit		Bullhead KWF down tbg.	3.6	0.2	0.2 days
Eline		EL Perf A & B intervals.	19.2	1.2	1.4 days
CTU		Utilize CT to lay-in/sqz cmt across intervals. Monitor then test wellbore.	79.2	5.0	6.4 days
Crane		MIRU Work Platform, BOPE & crane. Cut, PU tbg string. POOH LD same	69.6	4.4	10.7 days
Crane		RI perf csg w/ 21spf gun 2x above Pkr.	14.4	0.9	11.6 days
Crane		Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe.	7.2	0.5	12.1 days
Crane		RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore.	12	0.8	12.8 days
Crane		RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	14.3 days
Continue with Conductor P&A					

BRU_214_35_		
CTU	BRU_214_35_CTU	5 days
CRANE	BRU_214_35_CRANE_Type3	8 days
RIG	BRU_214_35_RIG	0 days
Eline	BRU_214_35_Eline_Type3	2 days
CMTUnit	BRU_214_35_CMTUnit_Type3	1 days



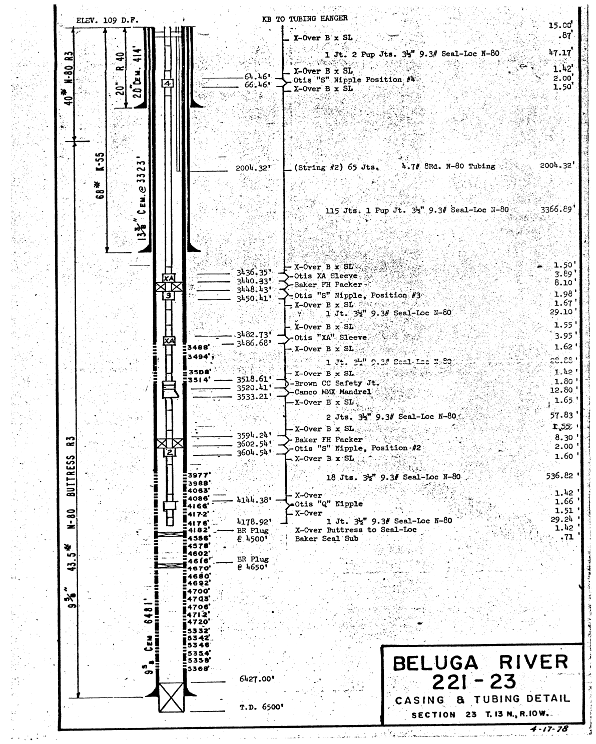
Proposed P&A

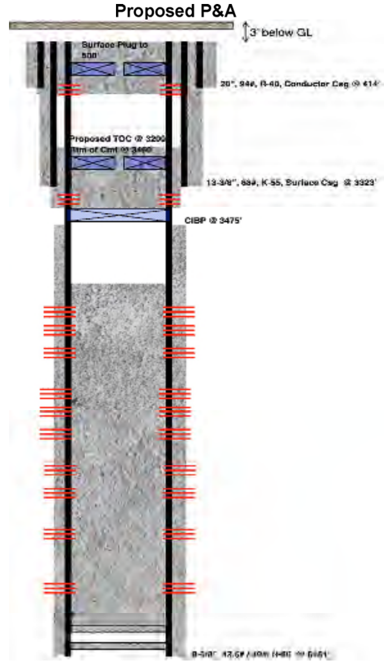


BRU 221-23 (176-072-0) Type 4

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
	Rig	Bullhead KWF down tbg.	3.6	0.2	0.2 days
	Rig	MIRU Rig, BOPE. Test same. Pull heater string. Pull tbg, pkrs completion. RI drill CIBP's.	117	4.9	5.0 days
	Rig	RI Cmt sqz perf intervals. Test Monitor wellbore.	34.2	1.4	6.5 days
	Rig	RI set CIBP ~150' below intermediate csg shoe. RI perf csg w/ 21spf gun 2x above CIBP.	10.2	0.4	6.9 days
	Rig	Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe.	7.2	0.3	7.2 days
	Rig	RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore.	4.8	0.2	7.4 days
	Rig	Continue Abandoning wellbore. Demobe Rig.	70.8	3.0	10.3 days
Crane		RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	11.8 days
Continue with Conductor P&A					

BRU_221_23_		
CTU	BRU_221_23_CTU	0 days
CRANE	BRU_221_23_CRANE_Type4	2 days
RIG	BRU_221_23_RIG	11 days



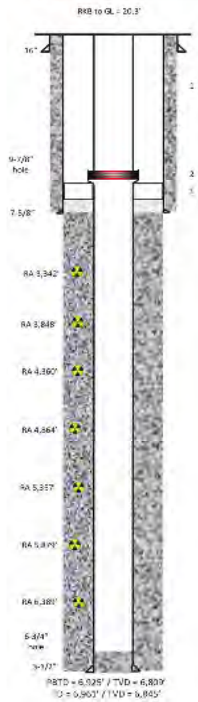


BRU 221-26 (224-098-0) Type 5

Step #		Line Item Step	Hrs	Days	Accumulative
		Procedure Summary Timeline			
1	CMTUnit	Bullhead KWF down Tbg into Beluga perforations.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. Utilize CT to lay-in/sqz cmt across Beluga to 3500'. POOH w/ CT. Monitor then test wellbore.	40.8	2.6	2.8 days
3	Eline	MIRU Eline. RIH Set CIBP @ 2600'. RI Punch Tbg @ 2580'. Establish Circulation between tbg & csg. POOH w/ Eline.	9.6	0.6	3.4 days
4	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 3100'. POOH. WOC. Pressure test wellbore. Demobe CT.	43.2	2.7	6.1 days
5	CRANE	MIRU Work Platform, ND Tree, NU BOPE & RU crane. RU Eline. RI cut tbg @ 600'. POOH RD Eline. Demobe same.	57.6	3.6	9.7 days
6	CRANE	PU tbg string. Remove Tbg. RU Eline. RI set CIBP @ 550' RI w/ tbg. Circ/Spot cmt on top of CIBP to Surf.	22.8	1.4	11.1 days
		Continue with Conductor P&A			

BRU_221_26_		
CTU	BRU_221_26_CTU	6 days
CRANE	BRU_221_26_CRANE_Type5	6 days
RIG	BRU_221_26_RIG	0 days
Eline	BRU_221_26_Eline_Type5	1 days
CMTUnit	BRU_221_26_CMTUnit_Type5	1 days

Beluga River Unit
BRU 221-26
PTD: 224-098
API: 50-283-20201-00-00



CASING DETAIL

Size	Type	Wt	Grade	Conn.	ID	Top	Btm
16"	Conductor – Driven to Set Depth	84	X-56	Weld	15.01"	Surf	136'
7-5/8"	Surf Csg	29.7	L-80 & P-110	GBBTC & DWC/C	6.875"	Surf	2,759'
3-1/2"	Prod Lnr	9.2	L-80	HYD 563	2.992"	2,593'	6,959'
3-1/2"	Prod Tieback	9.2	L-80	EUE	2.992"	Surf	2,568'

JEWELRY DETAIL

No.	Depth	ID	OD	Item
1	21'			Cactus CTF-DNE-CTL hanger, w/ 4" type H BPV profile
2	2,593'	4.875"	6.540"	5-1/2" HRD-E ZXP Liner top packer & Flex lock hanger w/ 3-1/2" XO
3	2,556'	4.700"	6.340"	Seal Stem

PERFORATION DETAIL

Sand	Top MD	Btm MD	Top TVD	Btm TVD	Amt	Date	Comments
Pool Top Sterling A1 3,254' MD / 3,160' TVD							
Beluga D1	±3,776'	±6,864'	±3,679'	±6,749'		Proposed	TBD

NOTES

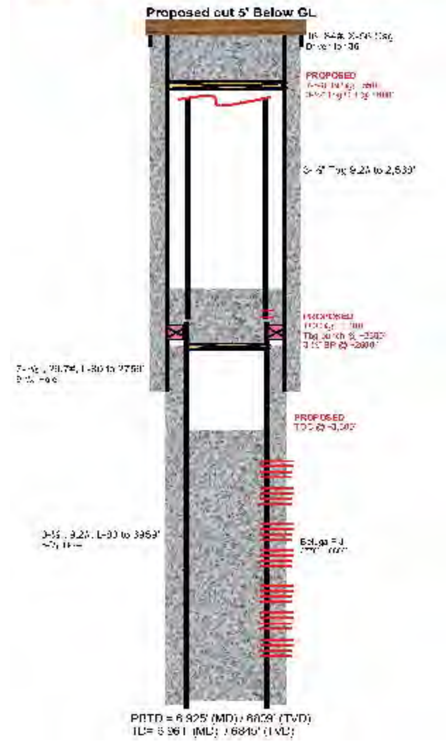
Short Joints w/ RA Tags (~15ft)	3,342', 3,848', 4360', 4864', 5367', 5879', 6389'

OPEN HOLE / CEMENT DETAIL

7-5/8"	166 bbls (382 sx) of 12 ppg lead followed by 36 bbls (174 sx) of 15.8 ppg tail, w/76 bbls of returns to surface 8/26/24. No losses on job.
3-1/2"	177 bbls (315 sx) of 12 ppg Type I lead followed by 27 bbls (122sx) of 15.3 ppg tail in 6.75" hole. 45 bbls of Cement/contaminated returned 9/5/24. 10 bbls lost during job. TOC per CBL run on 9/10/24 is 2,754'

Proposed P&A

BRU 221-26 Proposed P&A Schematic

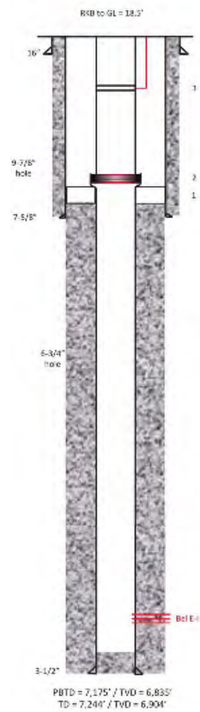


BRU 221-35 (223-077-0) Type 5

Step #		Line Item Step	Hrs	Days	Accumulative
		Procedure Summary Timeline			
1	CMTUnit	Bullhead KWF down Tbg into Beluga perforations.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. Utilize CT to lay-in/sqz cmt across Beluga to 4000'. POOH w/ CT. Monitor then test wellbore.	40.8	2.6	2.8 days
3	Eline	MIRU Eline. RIH Set CIBP @ 2700'. RI Punch Tbg @ 2620'. Establish Circulation between tbg & csg. POOH w/ Eline.	9.6	0.6	3.4 days
4	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 2700'. POOH. WOC. Pressure test wellbore. Demobe CT.	43.2	2.7	6.1 days
5	CRANE	MIRU Work Platform, ND Tree, NU BOPE & RU crane. RU Eline. RI cut tbg @ 600'. POOH RD Eline. Demobe same.	57.6	3.6	9.7 days
6	CRANE	PU tbg string. Remove Tbg. RU Eline. RI set CIBP @ 550' RI w/ tbg. Circ/Spot cmt on top of CIBP to Surf.	22.8	1.4	11.1 days
		Continue with Conductor P&A			

BRU_221_35_		
CTU	BRU_221_35_CTU	6 days
CRANE	BRU_221_35_CRANE_Type5	6 days
RIG	BRU_221_35_RIG	0 days
Eline	BRU_221_35_Eline_Type5	1 days
CMTUnit	BRU_221_35_CMTUnit_Type5	1 days

Beluga River Unit
BRU 221-35
PTD: 223-077
API: 50-283-20193-00-00



CASING DETAIL

Size	Type	Wt	Grade	Conn.	ID	Top	Btm
16"	Conductor – Driven to Set Depth	84	X-56	Weld	15.01"	Surf	120'
7-5/8"	Surf Csg	29.7	L-80	TXP	6.875"	Surf	2,851'
3-1/2"	Prod Lnr	9.2	L-80	HYD 563	2.992"	2,651'	7,244'
3-1/2"	Prod Tieback	9.2	L-80	HYD 563	2.992"	Surf	2,656'

JEWELRY DETAIL

No.	Depth	ID	OD	Item
1	2,651'	4.875"	6.540"	Liner hanger / LTP Assembly
2	2,656'	4.790'	6.340"	Seal Stem
3	1,510'	2.813"	3.500"	Chemical Injection Sub

OPEN HOLE / CEMENT DETAIL

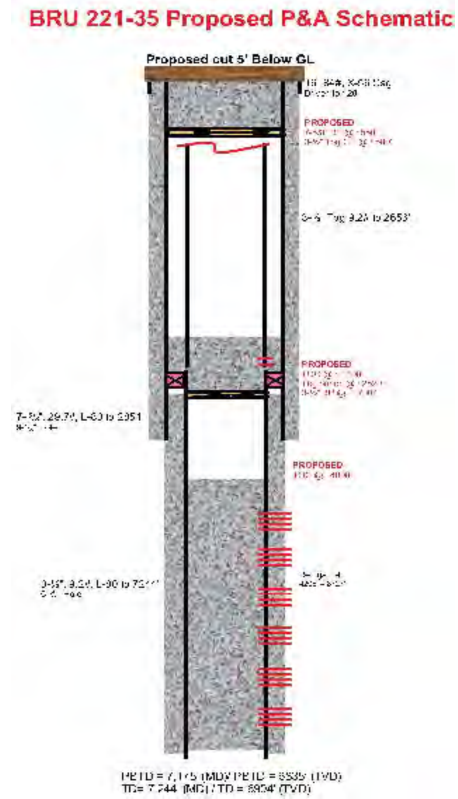
7-5/8"	TOC @ Surface (75% / 50% Lead/Tail excess)
3-1/2"	Est. TOC @ TOL (40% excess)

PERFORATION DETAIL

Zone	Top (MD)	Btm (MD)	Top (TVD)	Btm (TVD)	FT	Date	Status
Bel E-I	±4,205'	±6,727'	±3,911'	±6,394'		Proposed	TBD

Updated by DMA 10-31-2023

Proposed P&A

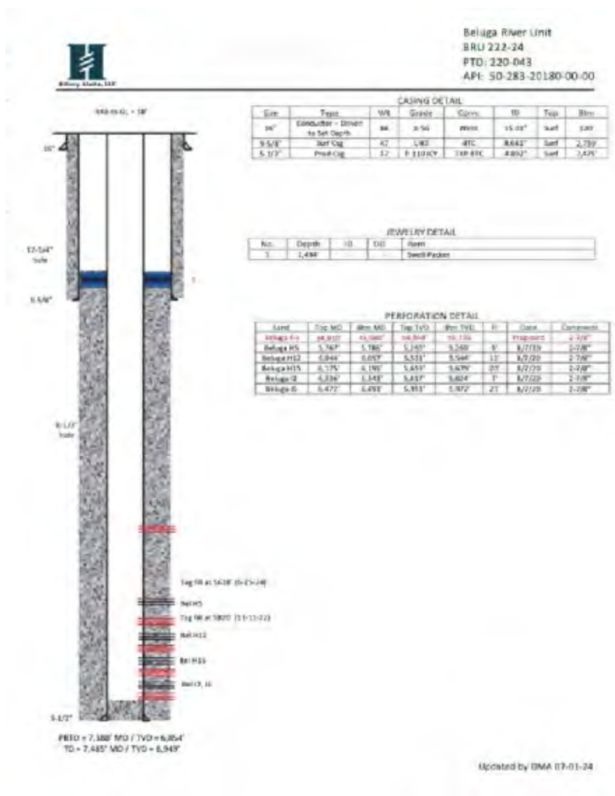


BRU 222-24 (220-043-0) Type 3

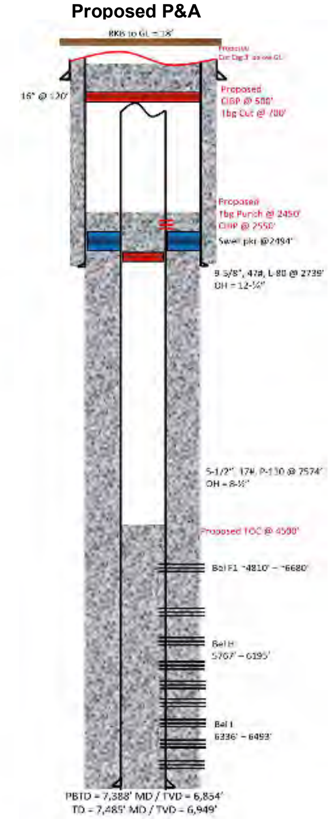
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. Cleanout to PBTD. MIRU Cmt Equipment.	40.8	2.6	2.8 days
3	CTU	Utilize CT to lay-in/sqz cmt across intervals. Bring TOC to 4500'. Monitor while WOC. Test wellbore. Demobe CT.	42.6	2.7	5.4 days
4	Eline	MIRU Eline. RIH Set CIBP @ 2550'. RI Punch Tbg @ 2450'. Establish Circulation between tbg & csg. POOH w/ Eline.	9.6	0.6	6.0 days
5	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP @ 2550'. POOH. WOC. Pressure test wellbore. Demobe CT.	40.8	2.6	8.6 days
6	Crane	MIRU Work Platform, BOPE & crane. Cut tbg @ 700'. PU tbg string. POOH LD same	64.8	4.1	9.5 days
7	Crane	RIH w/ Eline set CIBP @ 500'. Lay-in/Spot cmt on top of CIBP to Srface.	19.2	1.2	10.7 days
Continue with Conductor P&A					

BRU_222_24_		
CTU	BRU_222_24_CTU	8 days
CRANE	BRU_222_24_CRANE_Type3	6 days
RIG	BRU_222_24_RIG	0 days
Eline	BRU_222_24_Eline_Type3	1 days
CMTUnit	BRU_222_24_CMTUnit_Type3	1 days

Current



Proposed P&A

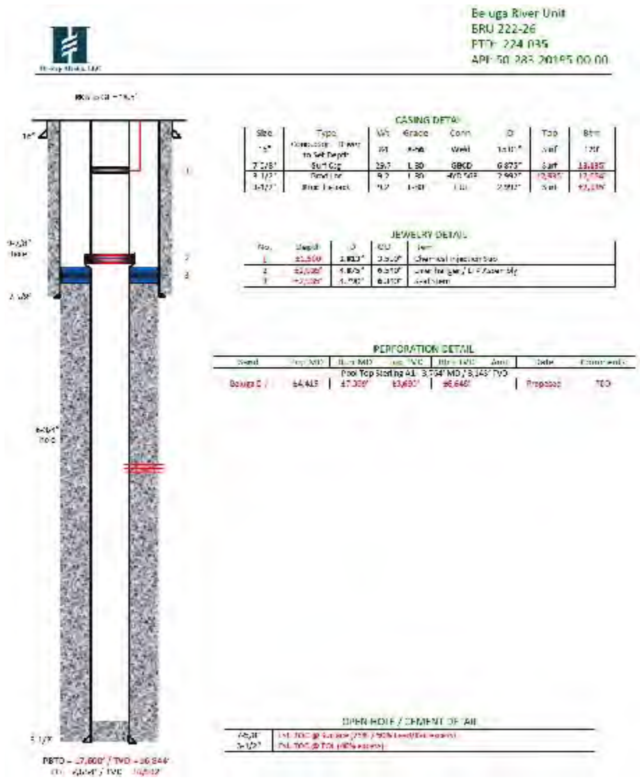


BRU 222-26 (224-035-0) Type 5

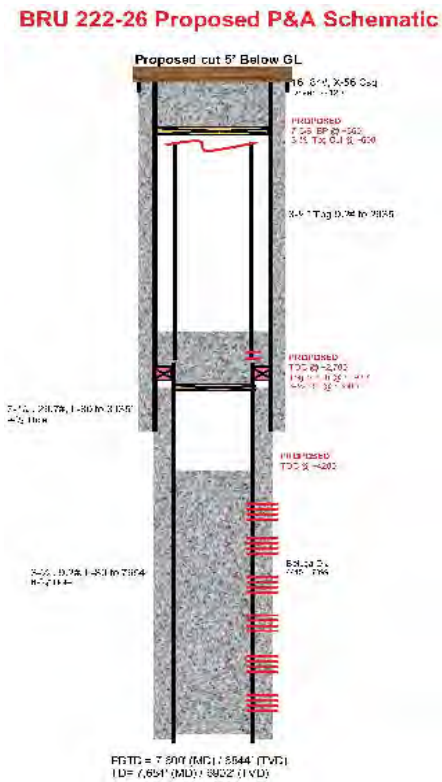
Step #		Line Item Step	Hrs	Days	Accumulative
Procedure Summary Timeline					
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. Cleanout to PBTD. MIRU Cmt Equipment.	40.8	2.6	2.8 days
3	CTU	Utilize CT to lay-in/sqz cmt across Beluga D-J intervals. Bring TOC to 2700'. Monitor while WOC. Test wellbore. Demobe CT.	42.6	2.7	5.4 days
4	Eline	MIRU Eline. RIH Set CIBP @ 3000'. RI Punch Tbg @ 2900'. Establish Circulation between tbg & csg. POOH w/ Eline.	9.6	0.6	6.0 days
5	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP to 2700'. POOH. WOC. Pressure test wellbore. Demobe CT.	40.8	2.6	8.6 days
6	Crane	MIRU Work Platform, BOPE & crane. Cut tbg @ 700'. PU tbg string. POOH LD same	64.8	4.1	9.5 days
7	Crane	RIH w/ Eline set CIBP @ 500'. Lay-in/Spot cmt on top of CIBP to Srface.	19.2	1.2	10.7 days
Continue with Conductor P&A					

BRU_222_26_		
CTU	BRU_222_26_CTU	8 days
CRANE	BRU_222_26_CRANE_Type5	6 days
RIG	BRU_222_26_RIG	0 days
Eline	BRU_222_26_Eline_Type5	1 days
CMTUnit	BRU_222_26_CMTUnit_Type5	1 days

Current



Proposed P&A

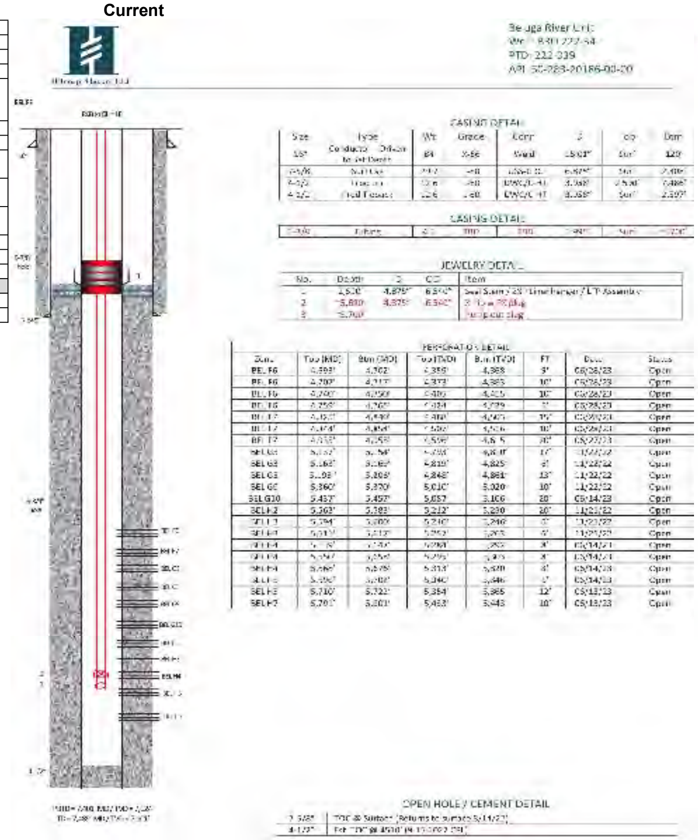


BRU 222-34 (222-039-0) Type 5

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down 2-3/8" tbg & 4-1/2" x tbg annulus.	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. Cleanout to PBTD. MIRU Cmt Equipment.	50.4	3.2	3.4 days
3	CTU	Utilize CT to lay-in/sqz/circulate cmt across Beluga F-H intervals. Bring TOC to 4550' on both tbg & tbg x 4-1/2" annuli. Monitor while WOC. Test wellbore. Demobe CT.	42.6	2.7	6.0 days
4	Eline	MIRU Eline. RIH cut 2-3/8" tbg @ ~4500'. POOH.	7.2	0.5	6.5 days
	Crane	MIRU Work Platform, BOPE & crane. PU POOH/LD 2-3/8" tbg string.	57.6	3.6	10.1 days
	Eline	MIRU Eline. RIH set CIBP in 4-1/2" tbg @ ~2650'. RI with tbg punch gun. Punch 4-1/2" tbg @ 2580'. POOH. RD Eline.	12	0.8	10.8 days
5	CTU	RIH w/ CT. Layin, pump, circ 15bbls of cmt on top of CIBP to 2700'. POOH. WOC. Pressure test wellbore. Demobe CT.	40.8	2.6	13.4 days
6	Crane	MIRU Work Platform, BOPE & crane. Cut tbg @ 700'. PU tbg string. POOH LD same	64.8	4.1	17.4 days
7	Crane	RIH w/ Eline set CIBP @ 500'. Lay-in/Spot cmt on top of CIBP to Srface.	19.2	1.2	18.6 days
Continue with Conductor P&A					

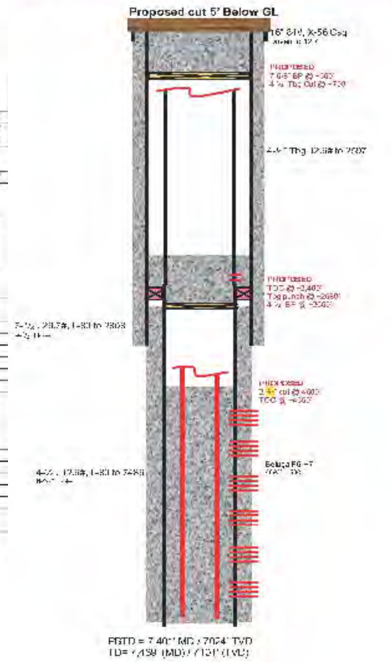
BRU_222_34_		
CTU	BRU_222_34_CTU	9 days
CRANE	BRU_222_34_CRANE_Type5	9 days
RIG	BRU_222_34_RIG	0 days
Eline	BRU_222_34_Eline_Type5	2 days
CMTUnit	BRU_222_34_CMTUnit_Type5	1 days

Current



Proposed P&A

BRU 222-34 Proposed P&A Schematic



BRU 223-24 (2210720) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure Tbg integrity. Pressure test all annuli.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. RI/CO to PBTD @ 6935'. MIRU cementers. Mix/Pump/Layin/Sqz cmt from PBTD to 4500' . RD CTU. Pressure test wellbore.	86.4	5.4	5.6 days
3	Crane	MIRU Work Platform & Crane and equip. RU Eline. RIH tag TOC. RIH Sever tbg @ 550'. POOH LD Tbg.	45.6	2.9	8.5 days
4	Crane	RIH w/ Eline set CIBP @ 500'. Jug tst wellbore. RI w/ Csg Punch gun. Punch 7" @ 480'. Establish circulation rates & pressures. Mix/Pump/Fill wellbore w/ cmt to surface.	29.4	1.8	10.3 days
Continue with Conductor P&A					

BRU_223_24_

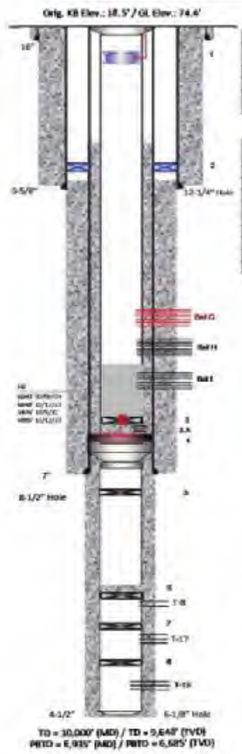
CTU	BRU_223_24_CTU	6 days
CRANE	BRU_223_24_CRANE_Type3	5 days
RIG	BRU_223_24_RIG	0 days
Eline	BRU_223_24_Eline_Type3	0 days
CMTUnit	BRU_223_24_CMTUnit_Type3	1 days

Current

Hilcorp Alaska, LLC

Well: BRU 223-24
PTD: 221-072
API: 50-283-20183-00-00
Completed: 12/22/21

Orig. KB Elev.: 18.5' / GL Elev.: 74.6'



CASING & TUBING DETAIL

Size	Type	Wt	Grade	Conn	ID	Top	Btm
16"	Conductor – Driven to Set Depth	84	X-56	Weld	15.01"	Surf	130'
9-5/8"	Surf Csg	40	L-80	DWC	8.835"	Surf	3,299'
7"	Int. Csg	26	L-80	DWC	6.276"	Surf	7,208'
4-1/2"	Prod Lnr	12.75	P-110	TS-HP	3.958"	6,997'	10,000'
4-1/2"	Tubing	12.75	P-110	TS-HP	3.958"	Surf	7,013'

JEWELRY DETAIL

No.	Depth (MD)	Depth (TVD)	ID	OD	Item
1	1,999'	1,987'	3.958"	5.625"	Chemical Injection Sub
2	2,983'	2,903'	6.276"	8.835"	7" Swell Packer
3	6,935'	6,685'			Cement Retainer (Quadco FH)
3.A	6980-83'				(15) 0.25" Tubing Punch Holes
4	6,997'	6,746'	4.875"	6.540"	Liner hanger / LTP Assembly
5	7,100'	6,845'			CIBP for coil depth control
6	8,665'	8,355'			CIBP w/ 79' cement
7	9,642'	9,300'			CIBP (12/02/21)
8	9,804'	9,458'			CIBP, set 11/28/21 (top of fill at 9807')

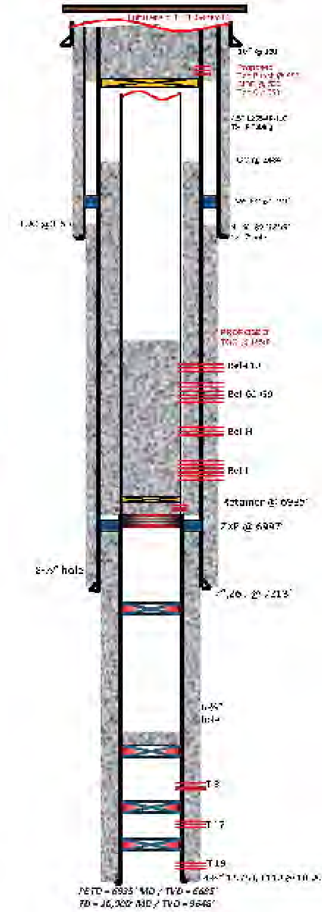
PERFORATION DETAIL							
Zone	Top (MD)	Btm (MD)	Top (TVD)	Btm (TVD)	FT	Date	Status
Top of Pool: 3,089' MD & 3,053' TVD							
Bel F10	±4,899'	±4,908'	±4,752'	±4,761'	±9	TBD	Proposed
Bel G1	±4,930'	±4,940'	±4,780'	±4,791'	±5	TBD	Proposed
Bel G1	±4,956'	±4,964'	±4,806'	±4,813'	±8	TBD	Proposed
Bel G7	±4,979'	±4,991'	±4,828'	±4,839'	±12	TBD	Proposed
Bel G2	±4,995'	±4,997'	±4,843'	±4,845'	±2	TBD	Proposed
Bel G3	±5,014'	±5,019'	±4,861'	±4,865'	±5	TBD	Proposed
Bel G3	±5,068'	±5,072'	±4,912'	±4,916'	±4	TBD	Proposed
Bel G8	±5,151'	±5,160'	±4,990'	±4,999'	±9	TBD	Proposed
Bel G9	±5,165'	±5,159'	±5,004'	±5,008'	±4	TBD	Proposed
Bel G9	±5,177'	±5,186'	±5,013'	±5,026'	±8	TBD	Proposed
Bel H	5,256'	5,276'	5,090'		20	1/30/21	Open
Bel H2	5,344'	5,356'	5,174'	5,168'	14	1/30/21	Open
Bel H3	5,370'	5,378'	5,199'	5,207'	8	1/30/21	Open
Bel H4	5,397'	5,407'	5,225'	5,218'	10	1/30/21	Open
Bel H5	5,458'	5,469'	5,280'	5,294'	14	1/30/21	Open
Bel H	5,671'	5,691'	5,486'	5,505'	20	12/22/21	Open
Bel H	5,717'	5,731'	5,529'	5,543'	14	12/22/21	Open
Bel H	5,744'	5,762'	5,555'	5,572'	18	12/22/21	Open
Bel H	5,839'	5,851'	5,645'	5,656'	12	12/22/21	Open
Bel I	6,043'	6,049'	5,838'	5,843'	6	12/22/21	Open
Bel I	6,055'	6,065'	5,849'	5,859'	10	12/22/21	Open
Bel I	6,066'	6,086'	5,860'	5,879'	20	12/21/21	Open
Bel I	6,185'	6,201'	5,972'	5,987'	16	12/21/21	Open
T-8	8,695'	8,715'	8,384'	8,403'	20	12/2/21	Isolated
T-8	8,720'	8,740'	8,408'	8,427'	20	12/2/21	Isolated
T-17	9,667'	9,687'	9,325'	9,345'	20	11/29/21	Isolated
T-17	9,700'	9,720'	9,357'	9,377'	20	11/29/21	Isolated
T-19	9,906'	9,926'	9,557'	9,646'	20	11/26/21	Isolated

OPEN HOLE / CEMENT DETAIL

9-5/8"	TOC @ Surface (50% excess)
7"	TOC @ 1260' (CBL 10-31-21)
4-1/2" Liner	TOC @ 7069' (CBL 11-24-21)
4-1/2" Tubing	TOC @ 3484' (CBL 12-17-21)

Updated By CAH 01-16-25

Proposed P&A

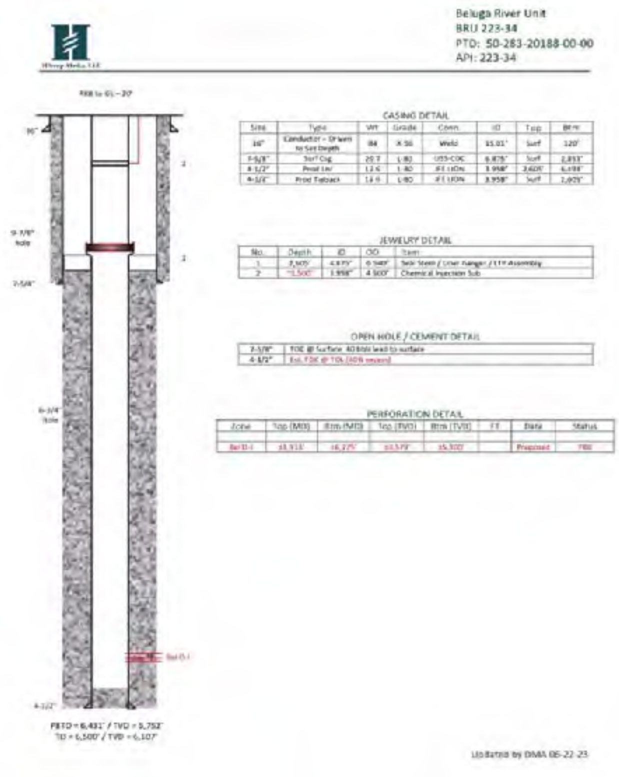


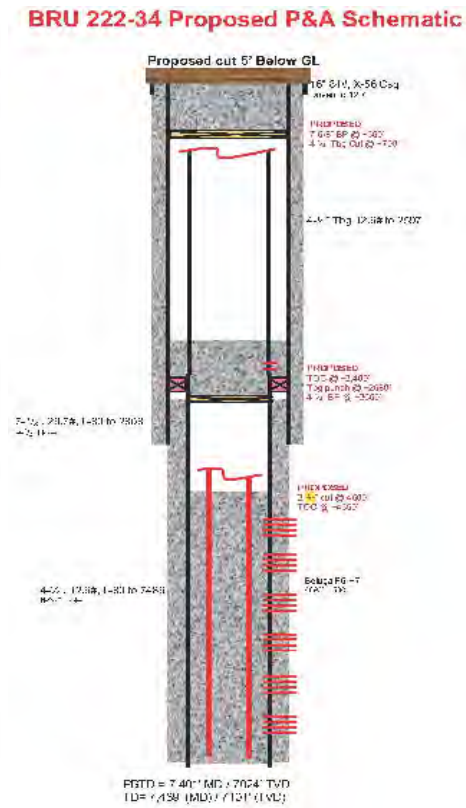
BRU 223-34 (PTD 223041) (Type5)

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	MIRU CTU. RI/CO to PBTD @ 6431'. MIRU cementers. Mix/Pump/Layin/Sqz cmt from PBTD to 3800'. RD CTU.	86.4	5.4	5.6 days
3	Eline	MIRU Eline, RI w/ CIBP, set same @ ~2700'. Punch tbg @ 2570'. Establish circulation betweem tbg & csg. POOH RD Eline.	22.2	1.4	7.0 days
	CTU	RIH w/ CT. Mix/pump/Lay-in/Circ Cemt to 2400'. POOH. RD CT	22.2	1.4	8.4 days
5	Crane	MIRU Work Platform & Crane and equip. RU Slickline. RIH tag TOC. RD Slickline. RU Eline. RIH Sever tbg @ 550'. POOH LD Tbg.	22.2	1.4	9.8 days
6	Crane	RIH w/ Eline set CIBP @ 500'. Jug tst wellbore. Mix/Pump/Fill wellbore w/ cmt to surface.	22.2	1.4	11.2 days
Continue with Conductor P&A					

BRU_223_34_

CTU	BRU_223_34_CTU	7 days
CRANE	BRU_223_34_CRANE_Type5)	3 days
RIG	BRU_223_34_RIG	0 days
Eline	BRU_223_34_Eline_Type5)	2 days
CMTUnit	BRU_223_34_CMTUnit_Type5)	1 days

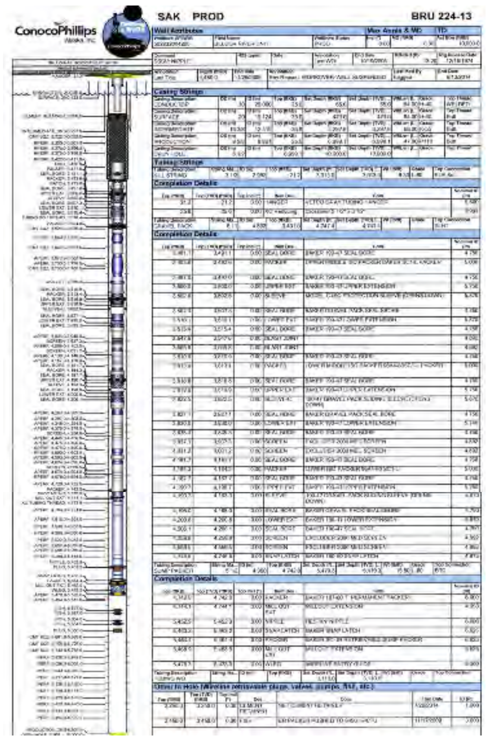


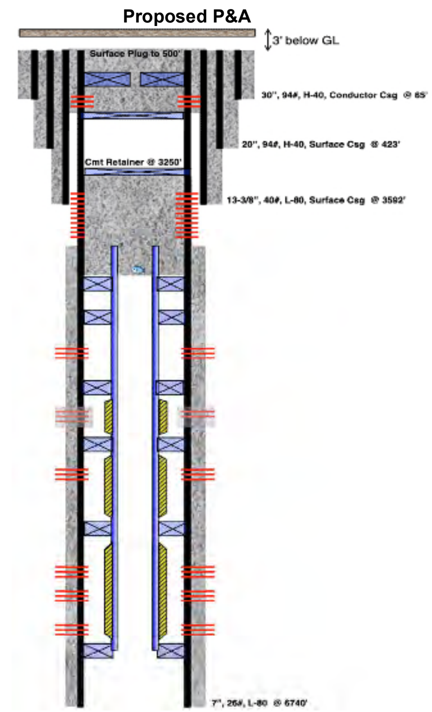


BRU 224-13 (1730370) Type 1

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
		Jug test wellbre.	3.6	0.2	0.2 days
	Crane	MIRU Work Platform & crane. Pull Kill String. Continue P&A.	36	2.3	2.3 days
Continue with Conductor P&A					

BRU_224_13_		
CTU	BRU_224_13_CTU	0 days
CRANE	BRU_224_13_CRANE_Type1	3 days
RIG	BRU_224_13_RIG	0 days





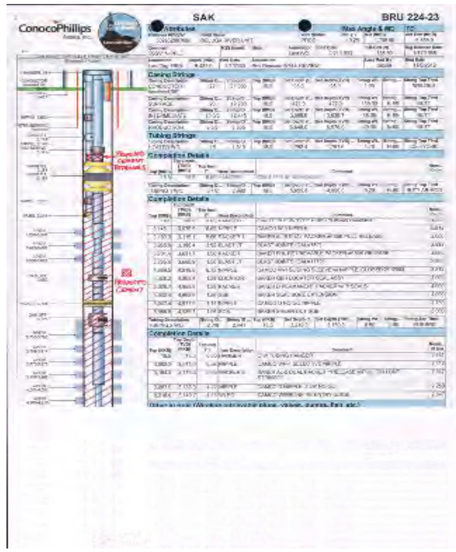
*Additional jewelry and equipment information available on request

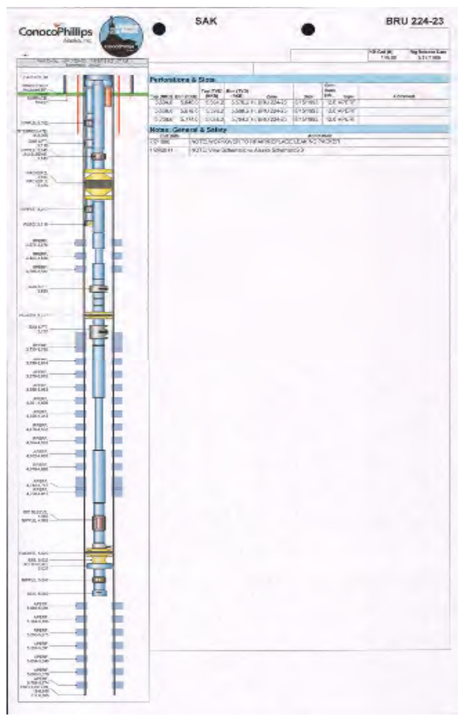
BRU 224-23 (1841370) Type 3

Procedure Summary Timeline					
Step #		**Line Item Step**	**Hrs**	**Days**	**Acumulative**
CMTUnit		Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
CTU		MIRU CT Unit onto LS. Remove Fishes. Cleanout to to ETD. Layin/Sqz cmt from ETD to 3200'.	79.2	5.0	5.2 days
Eline		RI cut LS and SS above pkr. Jug test wellbore.	14.4	0.9	6.1 days
Crane		MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above Pkr.	81.6	5.1	11.2 days
Crane		Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	11.3 days
Crane		RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	12	0.8	12.0 days
Crane		PU leave ~10' above retainer. Test wellbore.	17.4	1.1	13.1 days
Crane		RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	14.6 days
Continue w/ Contuctor P&A					

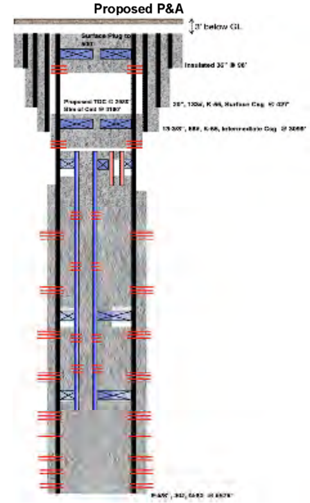
BRU 224 23

CTU	BRU 224 23 CTU	5 days
CRANE	BRU 224 23 CRANE Type3	9 days
RIG	BRU 224 23 RIG	0 days
Eline	BRU 224 23 Eline Type3	1 days
CMTUnit	BRU 224 23 CMTUnit Type3	1 days





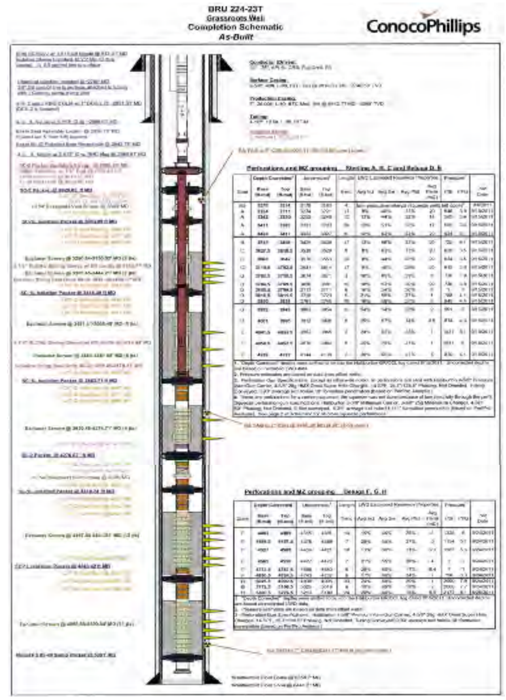
Proposed P&A

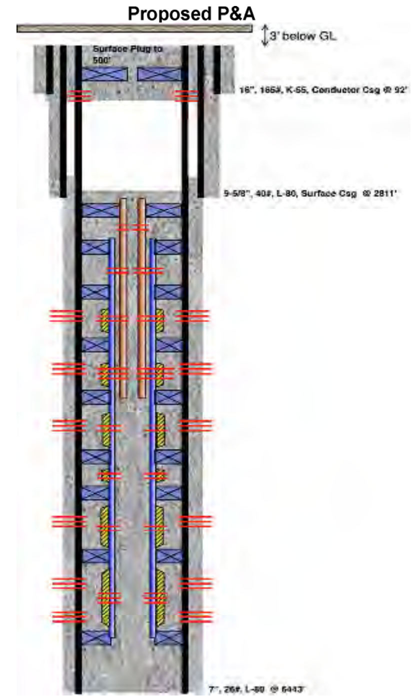


BRU 224-23T (2110800) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	Eline	EL Perf GP screens.	19.2	1.2	1.4 days
3	CTU	MIRU CTU RI lay-in/sqz cmt across intervals. Monitor then test wellbore.	69.6	4.4	5.8 days
4	Crane	MIRU Work Platform & crane. Cut, PU tbg string. Spot 500' of cmt on top of pkr. Pull tbg.	79.2	5.0	10.7 days
5	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	12.2 days
5					
6					
7					
8					
9					
10					
Continue with Conductor P&A					

BRU_224_23T_		
CTU	BRU_224_23T_CTU	5 days
CRANE	BRU_224_23T_CRANE_Type3	7 days
RIG	BRU_224_23T_RIG	0 days
Eline	BRU_224_23T_Eline_Type3	2 days
CMTUnit	BRU_224_23T_CMTUnit_Type3	1 days



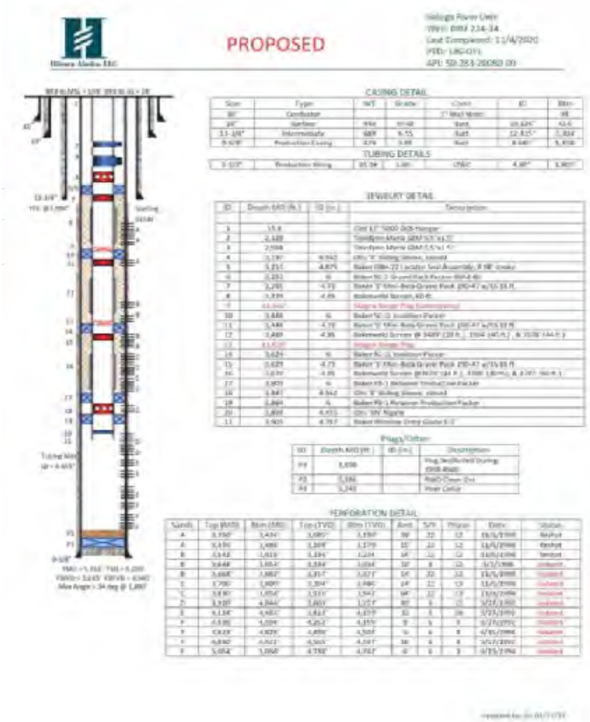


BRU 224-34 (1860110) Type 3

Step #		Line Item Step	Hrs	Days	Accumulative
		Procedure Summary Timeline			
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	Eline	Eline Perf ~3430' to ~3440'. Establish injection rates & pressures.	9.6	0.6	0.8 days
3	CTU	MIRU CTU RIH to ~3400'. Inject/Circulate/Lay-in cmt to 3390'.POOH.	69.6	4.4	5.2 days
4	Eline	Pressure test wellbore. RIH Tag TOC w/ Eline. Perf ~3350' below shoe. Establish injection rates & pressures. RI punch tbg @ ~3240'. Establish circulate rates & pressures down tbg, while taking returns out tbg x csg annulus.	11.4	0.7	5.9 days
5	CTU	RI w/ CT. Mix/pump/inject cmt below 13-3/8" shoe. Circulate cmt down CT, out tbg x csg annulus. Lay-in/circulate cmt to ~3100'. POOH. Monitor then test wellbore.	42.6	2.7	8.6 days
6	Crane	MIRU Work Platform & crane. Cut tbg string @ 620'. PU tbg stub. LD same. RI cut csg @ 600'. PU csg stub. LD same.	79.2	5.0	13.5 days
7	Crane	RI set 13-3/8" CIBP above csg stub. Spot cmt on top of CIBP to surface. RD Demobe equip.	46.2	2.9	16.4 days
		Continue with Conductor P&A			

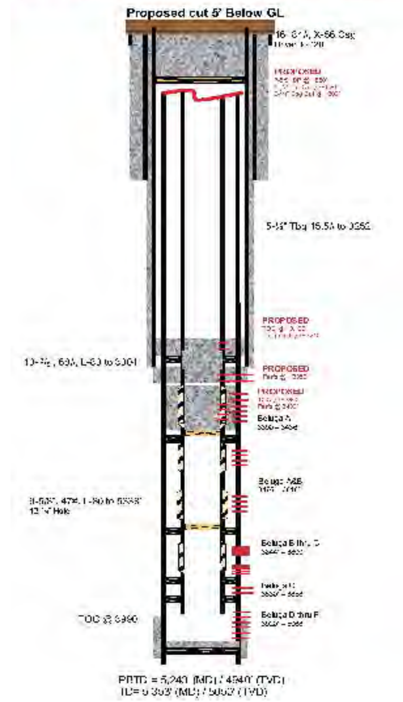
BRU_224_34_		
CTU	BRU_224_34_CTU	8 days
CRANE	BRU_224_34_CRANE_Type3	8 days
RIG	BRU_224_34_RIG	0 days
Eline	BRU_224_34_Eline_Type3	2 days
CMTUnit	BRU_224_34_CMTUnit_Type3	1 days

pressures down tbg, while taking returns out tbg x csg annulus.
RI w/ CT. Mix/pump/inject cmt below 13- 3/8 shoe. Circulate cmt down CT, out



Proposed P&A

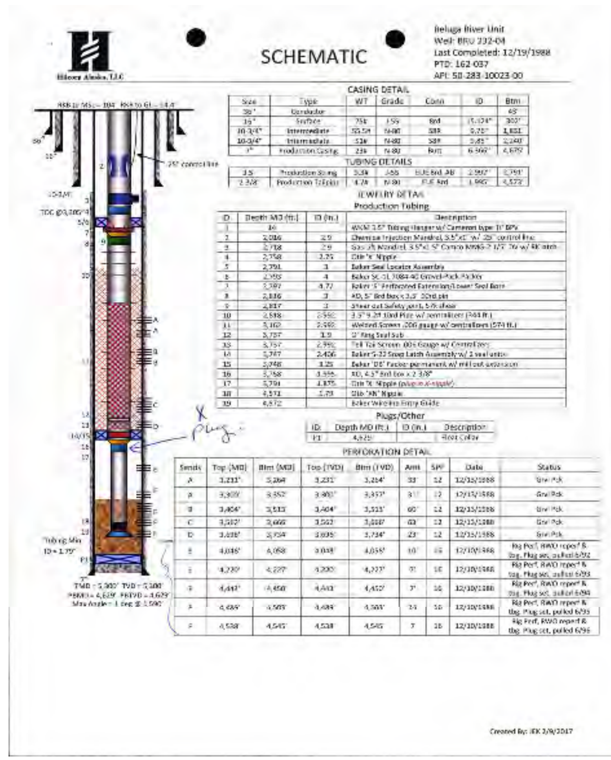
BRU 224-34 Proposed P&A Schematic



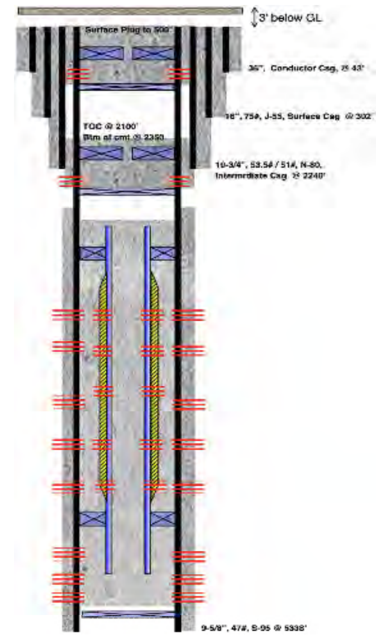
BRU 232-04 (1620370) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. Cleanout and remove Plug in X nipple. Continue cleanout to ETD.	50.4	3.2	3.4 days
3	CTU	EL perforate GP Screens. RI w/ CT. Layin/Sqz cmt from ETD to 2790'. RD CTU	52.8	3.3	6.7 days
4	Eline	RI cut tbg above pkr. Jug test wellbore.	7.2	0.5	7.1 days
5	Crane	MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above Pkr.	67.2	4.2	11.3 days
6	Crane	Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	11.4 days
7	Crane	RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	12	0.8	12.2 days
8	Crane	PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	9	0.6	12.8 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	14.2 days
10					
Continue with Conductor P&A					

BRU_232_04_		
CTU	BRU_232_04_CTU	7 days
CRANE	BRU_232_04_CRANE_Type3	8 days
RIG	BRU_232_04_RIG	0 days
Eline	BRU_232_04_Eline_Type3	1 days
CMTUnit	BRU_232_04_CMTUnit_Type3	1 days



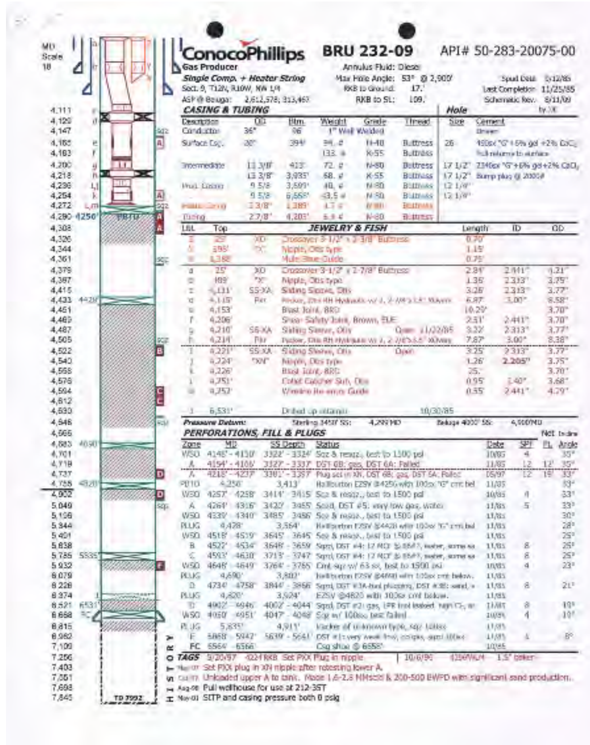
Proposed P&A

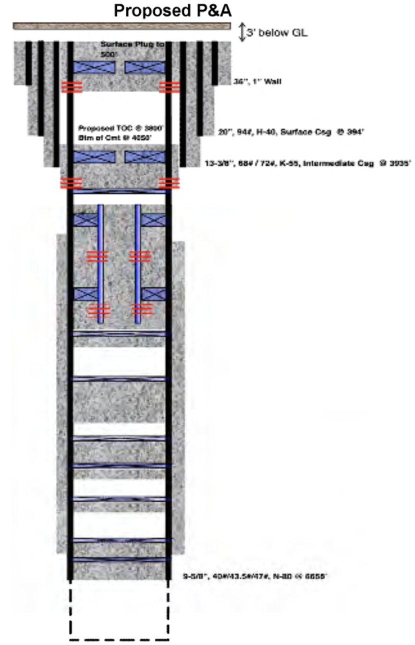


BRU 232-09 (1841360) Type 2

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Pressure test annulus. Ensure tbg clear to EOT. CTCO if not.	3.6	0.2	0.2 days
2	Eline	EL Perf across intervals. Set cmt retainer just below top pkr. Open SSD above top pkr.	12	0.8	1.0 days
3	CMTUnit	MIRU Cementers. Bullhead/sqz calculated cmt vol below top pkr. Reverse excess.	4.8	0.3	1.3 days
4	Crane	MIRU Work Platform & crane. Cut, Pull tbg strings.	60	3.8	5.0 days
5	Crane	RI perf csg w/ 21spf gun 2x above Pkr.	9.6	0.6	5.6 days
6	Crane	Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	5.7 days
7	Crane	RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	10.2	0.6	6.4 days
8	Crane	PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	10.8	0.7	7.1 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	8.5 days
10					
Continue with Conductor P&A					

BRU_232_09_		
CTU	BRU_232_09_CTU	0 days
CRANE	BRU_232_09_CRANE_Type2	8 days
RIG	BRU_232_09_RIG	0 days
Eline	BRU_232_09_Eline_Type2	1 days
CMTUnit	BRU_232_09_CMTUnit_Type2	1 days

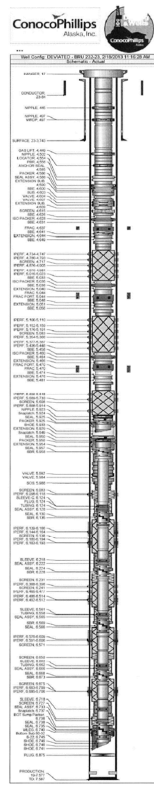




BRU 232-23 (2090570) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg.	3.6	0.2	0.2 days
2	Eline	EL Perf GP screen.	14.4	0.9	1.1 days
3	CTU	Utilize CT to lay-in/sqz cmt across intervals. Punch tbg above pkr. Circ/Spot 500' of cmt above pkr.	76.8	4.8	5.9 days
4	Crane	Monitor then test wellbore. MIRU Work Platform, BOP & crane.	50.4	3.2	9.1 days
5	Crane	Cut tbg 200' below surf csg shoe. Pull tbg string.	16.2	1.0	10.1 days
6	Crane	RI perf csg w/ 21spf gun 2x above Pkr.	9.6	0.6	10.7 days
7	Crane	Establish circulation up Production csg x Surf csg annulus. RI set retainer 120' above intermediate csg shoe.	9	0.6	11.3 days
8	Crane	RI Pump/Circ Cmt below retainer. PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	15.6	1.0	12.2 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	13.7 days
10					
Continue with Conductor P&A					

BRU_232_23_		
CTU	BRU_232_23_CTU	5 days
CRANE	BRU_232_23_CRANE_Type3	8 days
RIG	BRU_232_23_RIG	0 days
Eline	BRU_232_23_Eline_Type3	1 days
CMTUnit	BRU_232_23_CMTUnit_Type3	1 days



SAK — BRU 232-23

Well Attributes / **Max Angle & MD** / **TD**

Wellbore API/UWI	Field Name	Well Status	Incl (°)	MD (ftKB)	Act Btm (ftKB)
502832013300	BELUGA RIVER UNIT	PROD	52.61	2,349.30	7,587.0

Comment	H2S (ppm)	Date	Annotation	End Date	KB-Grd (ft)	Rig Release Date
SSSV: WRDP			Last WO:			10/7/2009

Annotation	Depth (ftKB)	End Date	Annotation	Last Mod By	End Date
Last Tag:		6/3/2012	Rev Reason: SHOW GRAVEL PACK FRACS	osborl	2/14/2013

Casing Strings

Casing Description	String O...	String ID ...	Top (ftKB)	Set Depth (f...	Set Depth (TVD) ...	String Wt...	String ...	String Top Thrd
CONDUCTOR	20	19.124	23.0	84.0	84.0	154.00	X65	Bolted
SURFACE	9 5/8	8.835	22.8	3,742.6	2,952.7	40.00	L-80	BTC-Mod
PRODUCTION	7	6.276	19.0	7,576.5	6,657.9	26.00	L-80	BTC

Tubing Strings

Tubing Description	String O...	String ID ...	Top (ftKB)	Set Depth (f...	Set Depth (TVD) ...	String Wt...	String ...	String Top Thrd
TUBING	4 1/2	3.958	17.3	4,597.1	3,690.3	12.60	C-75	IBTM

Completion Details

Top (ftKB)	Top Depth (TVD) (ftKB)	Top Incl (°)	Item Description	Comment	Nomi... ID (in)
17.3	17.3	-0.01	HANGER	Vetco Gray Tubing hanger	4.500
445.5	445.4	3.12	NIPPLE	Camco CHEMICAL INJECTION NIPPLE with 3/8" C.L.	3.920
497.1	496.9	4.21	NIPPLE	Camco 3.813" BP-6i Landing Nipple	3.813
4,501.8	3,600.5	20.79	NIPPLE	3.813" HES X Nipple	3.813
4,553.7	3,649.5	19.57	LOCATOR	Baker Locator Seal Assembly w/ 2' Space out	3.900
4,556.5	3,652.1	19.49	PBR	Baker 4 3/4" PBR	3.900
4,584.5	3,678.4	18.63	ANCHOR SEAL	E - Anchor Seal Assembly	3.250
4,585.7	3,679.6	18.59	SEAL ASSY	Baker S-22 Seal Assembly with Half mule Shoe	3.250

Tubing Description	String O...	String ID ...	Top (ftKB)	Set Depth (f...	Set Depth (TVD) ...	String Wt...	String ...	String Top Thrd
MULTI-ZONE GRAVEL PACK ASSEMBLY	5 3/4	3.430	4,585.8	5,933.6	5,015.4			

Completion Details

Top (ftKB)	Top Depth (TVD) (ftKB)	Top Incl (°)	Item Description	Comment	Nomi... ID (in)
4,585.8	3,679.6	18.59	PACKER	SC-2 Packer 70B-40	4.000
4,599.8	3,692.9	18.16	SBE	Seal Bore 80-32	3.250
4,604.3	3,697.2	18.02	VALVE	Knock out Isolation Valve C-2 Sleeve	3.320
4,606.8	3,699.6	17.95	VALVE	Knock out Isolation valve C-2	3.340
4,614.6	3,707.0	17.71	SCREEN	Vent Screen Bakerweld	3.930
4,625.7	3,717.6	17.37	SBE	Seal Bore MZ system 80-32	3.250
4,627.9	3,719.7	17.30	ISO PACKER	SC-1L ISOLATION Packer 70B6-40	3.625
4,631.4	3,723.1	17.19	SBE	Seal Bore MZ system 80-32	3.250
4,633.5	3,725.1	17.13	EXENSION	Upper Extension MZ system 80-32	3.970
4,637.3	3,728.7	17.01	FRAC PORT	Frac Extension MZ system 80-32	4.010
4,641.3	3,732.5	16.89	SBE	Seal Bore MZ system 80-32	3.250
4,643.7	3,734.8	16.82	EXTENSION	Lower Extension MZ system 80-32	3.980
4,648.8	3,739.7	16.66	SBE	Seal Bore MZ system 80-32	3.250
4,716.9	3,805.3	14.01	SCREEN	Screen Excluder 2000	3.430
5,032.7	4,115.6	6.72	SBE	Seal Bore MZ system 80-32	3.250
5,034.9	4,117.7	6.68	ISO PACKER	SC-1L Packer 70B6 -40	3.625
5,038.4	4,121.2	6.61	SBE	Seal Bore MZ system 80-32	3.250
5,040.5	4,123.2	6.57	EXTENSION	Upper Extension MZ system 80-32	3.970
5,044.3	4,127.0	6.50	FRAC PORT	Frac Extension MZ system 80-32	4.010
5,048.3	4,131.0	6.42	SBE	Seal Bore MZ system 80-32	3.250
5,050.7	4,133.3	6.37	EXTENSION	Lower Extension MZ system 80-32	3.980
5,055.8	4,138.4	6.27	SBE	Seal Bore MZ system 80-32	3.250
5,083.5	4,166.0	5.72	SCREEN	Screen Excluder 2000	3.430
5,458.2	4,540.1	1.92	SBE	Seal Bore MZ system 80-32	3.250
5,460.4	4,542.3	1.93	ISO PACKER	SC-1L Packer 70B6-40	3.625
5,463.9	4,545.8	3.12	SBE	Seal Bore MZ system 80-32	3.250
5,465.9	4,547.9	3.07	EXTENSION	Upper Extension MZ system 80-32	3.970
5,469.7	4,551.7	2.99	FRAC PORT	Frac Extension MZ system 80-32	4.010
5,473.7	4,555.7	2.90	SBE	Seal Bore MZ system 80-32	3.250
5,476.1	4,558.1	2.84	EXTENSION	Lower Extension MZ system 80-32	3.980
5,481.2	4,563.2	2.73	SBE	Seal Bore MZ system 80-32	3.250
5,607.5	4,689.4	0.61	SCREEN	Screen Excluder 2000	3.430
5,923.1	5,004.9	1.05	NIPPLE	R Nipple	3.250
5,924.1	5,006.0	1.05	Snaplatch	Snaplatch	3.270
5,925.1	5,006.9	1.05	SEAL	Seal Units	3.260
5,933.1	5,014.9	1.05	SHOE	Half Mule shoe 52-40	3.260

Tubing Description	String O...	String ID ...	Top (ftKB)	Set Depth (f...	Set Depth (TVD) ...	String Wt...	String ...	String Top Thrd
CK LOWER ISOLATION STRING	2.89	2.370	5,925.1	6,746.8	5,828.4	6.40	L-80	2-7/8 Hyd 511

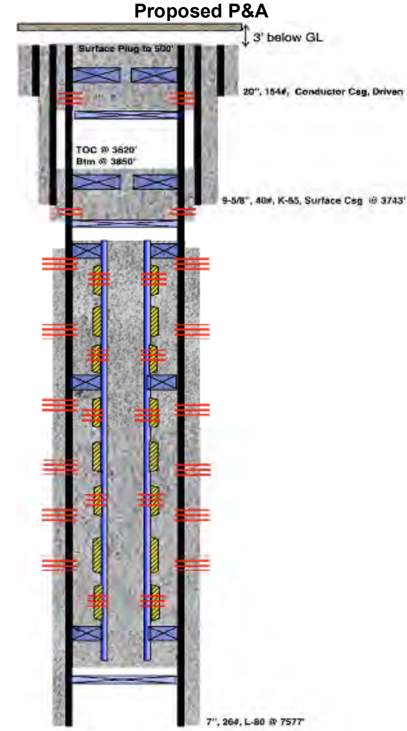
Completion Details

Top (ftKB)	Top Depth (TVD) (ftKB)	Top Incl (°)	Item Description	Comment	Nomi... ID (in)
5,925.1	5,006.9	1.05	PACKER	SC-2 Isolation Packer 70B-40	4.000

Mandrel Details

S... N...	Top (ftKB)	Top Depth (TVD) (ftKB)	Top Incl (°)	Make	Model	OD (in)	Serv	Valve Type	Latch Type	Port Size (in)	TRO Run (psi)	Run Date	Com...
1	4,448.6	3,551.1	22.36	CAMCO	KBG-2	1	GAS LIFT	DMY	BK	0.000	0.0	9/20/2009	

Proposed P&A



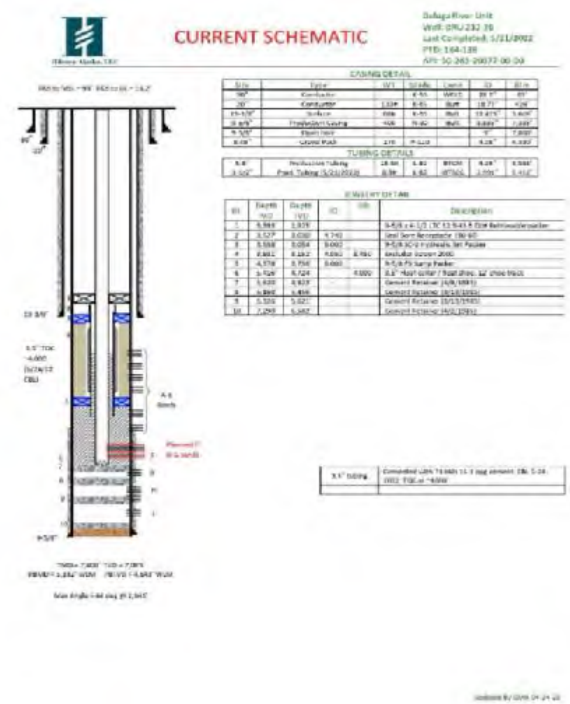
*Additional jewelry and equipment information available on request

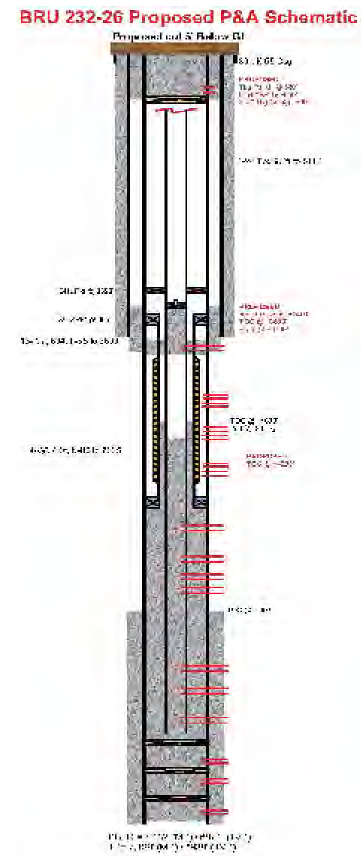
BRU 232-26 (1841380) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg & tbg x Csg annulus. Ensure Tbg & csg integrity.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. RIH Clean out to btm. Mix cmt. Pump/Lay-in/Sqz cmt from btm to ~4200'. POOH.	50.4	3.2	3.4 days
3	CTU	EL Perf below 13-3/8" shoe. Establish Injection/Circulation down tbg while taking returns out 9-5.8" x 13-3/8" annulus. RI with Cmt retainer set @~3400. RI w/ CT. stab into retainer pump/squeeze/circulate cmt. POOH RD CTU.	24.6	1.5	4.9 days
5	Crane	Jug test wellbore. MIRU Work Platform & Crane. Eline Cut tbg @ 600'. Pull tbg stub out of hole.	66.6	4.2	9.1 days
6	Crane	RIH w/ Eline set 9-5/8" CIBP @ 550'. POOH. RI perf torch punch holes in csg @ 530'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	10.5 days
7					
Continue with Conductor P&A					

BRU_232_26_

CTU	BRU_232_26_CTU	5 days
CRANE	BRU_232_26_CRANE_Type3	6 days
RIG	BRU_232_26_RIG	0 days
Eline	BRU_232_26_Eline_Type3	0 days
CMTUnit	BRU_232_26_CMTUnit_Type3	1 days

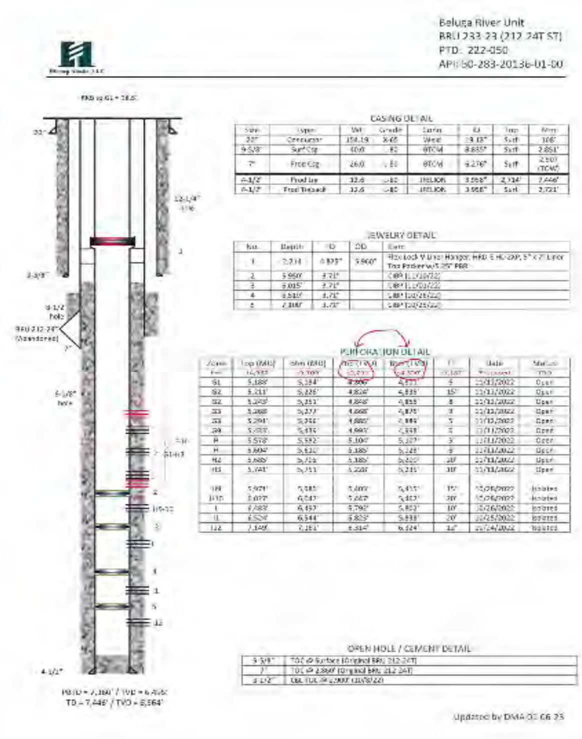




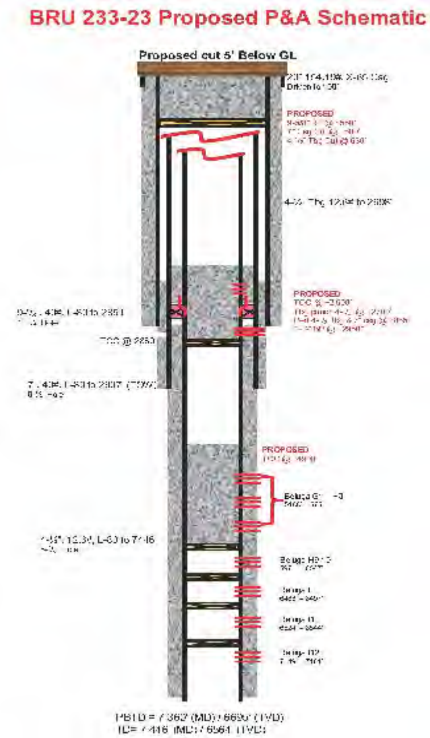
BRU 233-23 (222-050) Type 5

Step #		Line Item Step	Hrs	Days	Accumulative
		Procedure Summary Timeline			
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CT	MIRU CT Unit. RI Clean out to top CIBP @ 5950'. MIRU Cementers.	52.2	3.3	3.5 days
3	CTL	Utilize CT to Lay-in/Sqz Cmt from 5950' to 4900'. POOH RD CTU.	12	0.8	4.2 days
4	Eline	RIH set CIBP @ 2950. RI Perforate 4-1/2" @ 2855'. Establish Injection rates & pressures. RI w/ tbg punch gun. Punch tbg @ 2700'. Establish Circ rates & Pressures down 4-1/2" tbg while taking returns out 4-1/2" x 7" annulus.	16.8	1.1	5.3 days
5	CTU	RI w/ CT. Pump/Layin/sqz cmt. Open tbg X csg annulus. Cont layin/circulate cmt to 2500'. POOH RD CT.	12	0.8	6.0 days
	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	9.2 days
6	Crane	RIH w/ Eline. Cut Tbg @ 630'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RI Eline cut 7" csg @ 600'. CBU. POOH LD 7". RIH set 9-5/8" @ 550'. POOH RD Eline	25.8	1.6	10.8 days
7					
8					
9					
10					
		Continue with Conductor P&A			

BRU_233_23_		
CTU	BRU_233_23_CTU	5 days
CRANE	BRU_233_23_CRANE_Type5	5 days
RIG	BRU_233_23_RIG	0 days
Eline	BRU_233_23_Eline_Type5	2 days
CMTUnit	BRU_233_23_CMTUnit_Type5	1 days



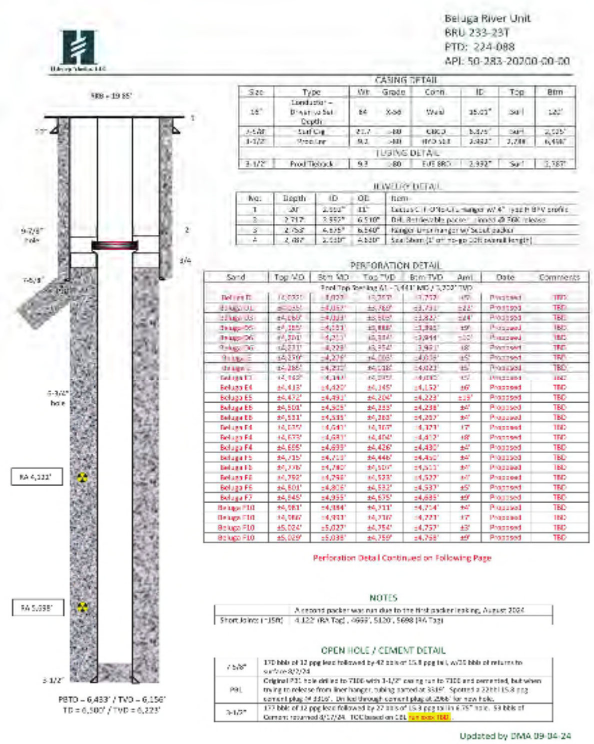
Proposed P&A



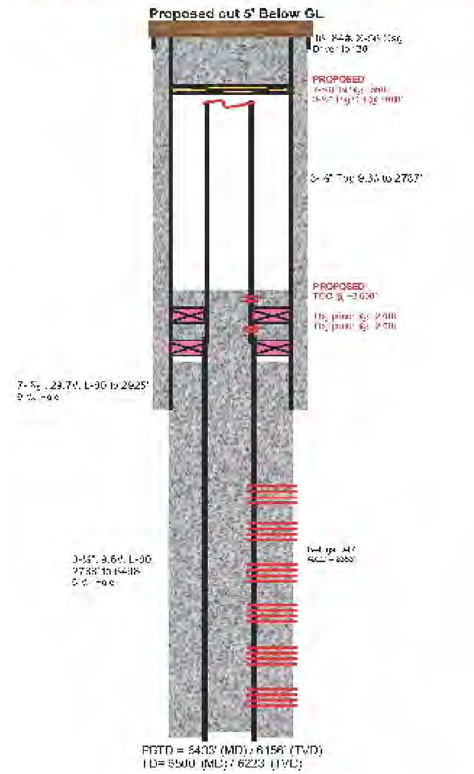
BRU 233-23T (224-088) Type 5

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RI Clean out to PBTD. POOH. MIRU Eline. RI Punch 3-1/2" Tbg @ 2730' & 2700'. Establish circulation down tbg & out tbg x csg annulus.	54	3.4	3.6 days
3	CTU	RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from 5830' to 2500'. POOH RD CTU.	21.6	1.4	5.0 days
4	Eline	RIH Tag TOC. Note in Rpt. Pressure test TOC.	7.2	0.5	5.4 days
5	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	8.6 days
6	Crane	RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	21.6	1.4	9.9 days
7					
Continue with Conductor P&A					

BRU_233_23T_		
CTU	BRU_233_23T_CTU	5 days
CRANE	BRU_233_23T_CRANE_Type5	5 days
RIG	BRU_233_23T_RIG	0 days
Eline	BRU_233_23T_Eline_Type5	1 days
CMTUnit	BRU_233_23T_CMTUnit_Type5	1 days



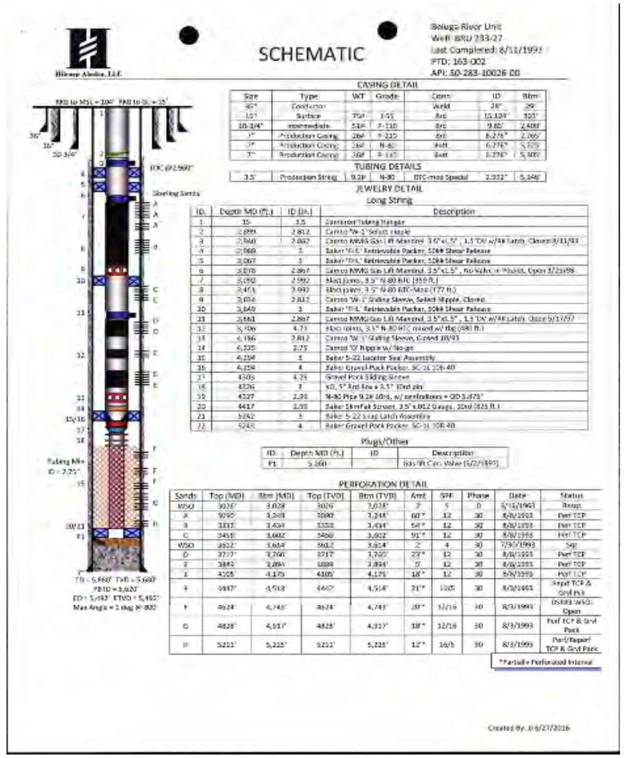
BRU 233-23T Proposed P&A Schematic



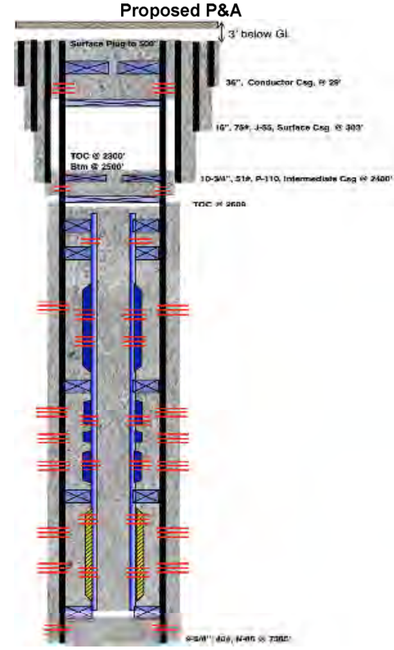
BRU 233-27 (163-002-0) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	EL perforate GP Screens. MIRU CT Unit. Cleanout to ETD. Layin/Sqz cmt from ETD to 3000'.	84	5.3	5.5 days
3	Eline	RI cut tbg above top pkr. Jug test wellbore.	7.2	0.5	5.9 days
4	Crane	MIRr U Crane, Work Platform & BOPE. PU tbg. Circ/Spot 250 of cmt on top of pkr	14.4	0.9	6.8 days
5	Crane	Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC.	59.4	3.7	10.5 days
6	Crane	Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	10.7 days
7	Crane	RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	12	0.8	11.4 days
8	Crane	PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	9	0.6	12.0 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	13.4 days
10					
Continue with Conductor P&A					

BRU_233_27_		
CTU	BRU_233_27_CTU	6 days
CRANE	BRU_233_27_CRANE_Type3	8 days
RIG	BRU_233_27_RIG	0 days
Eline	BRU_233_27_Eline_Type3	1 days
CMTUnit	BRU_233_27_CMTUnit_Type3	1 days



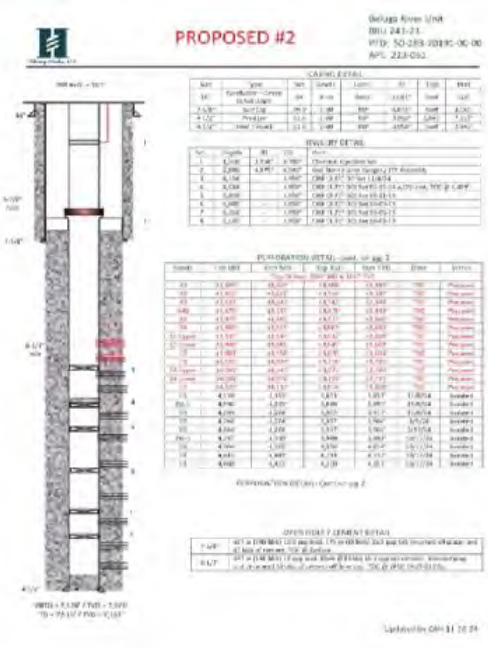
Proposed P&A



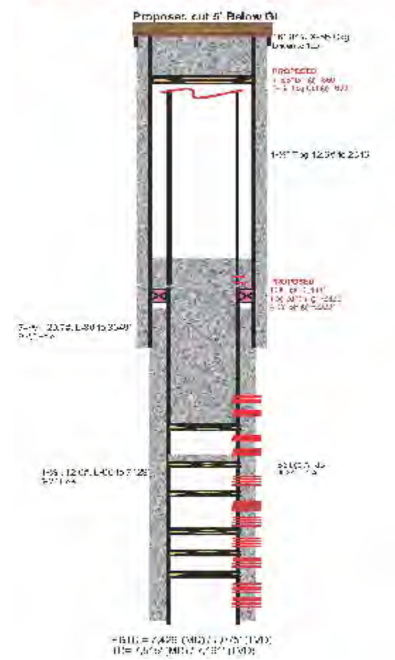
BRU 241-23 (223-061) Type 5

Step #		Line Item Step	Hrs	Days	Accumulative
		Procedure Summary Timeline			
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RI Clean out to top CIBP. POOH. MIRU Eline. RI Punch 4-1/2" Tbg @ 2820'. Establish circulation down tbg & out tbg x csg annulus.	47.4	3.0	3.2 days
3	CTU	RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from 4154' to 2600'. POOH RD CTU.	36	2.3	5.4 days
4	Eline	RIH Tag TOC. Note in Rpt. Pressure test TOC.	7.2	0.5	5.9 days
	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	9.0 days
6	Crane	RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	21.6	1.4	10.4 days
7					
		Continue with Conductor P&A			

BRU_241_23_		
CTU	BRU_241_23_CTU	6 days
CRANE	BRU_241_23_CRANE_Type5	5 days
RIG	BRU_241_23_RIG	0 days
Eline	BRU_241_23_Eline_Type5	1 days
CMTUnit	BRU_241_23_CMTUnit_Type5	1 days



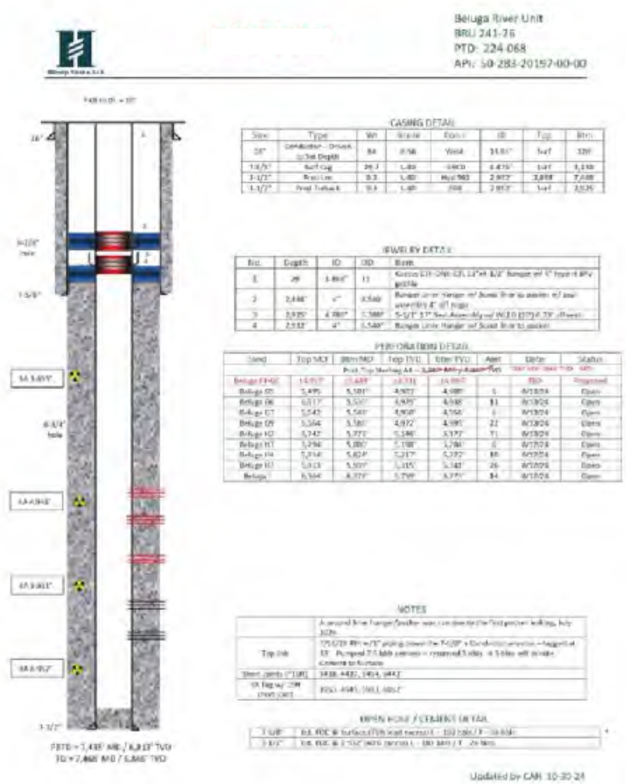
BRU 241-23 Proposed P&A Schematic

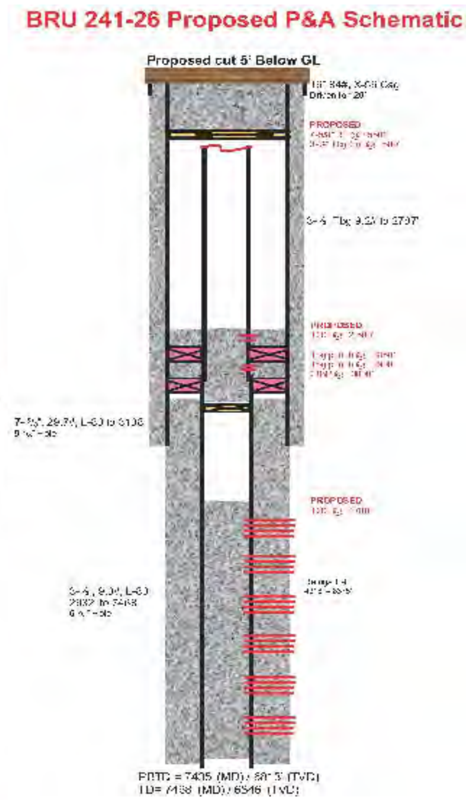


BRU 241-26 (224-068) Type 5

Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RI Clean out to PBTD. POOH.	42.6	2.7	2.9 days
3	CTU	RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from PBTD to 4700. POOH RD CTU.	21.6	1.4	4.2 days
4	Eline	MIRU Eline. RI w/ CIBP. Set same @ 3000'. RI Punch 3-1/2" Tbg @ 2850' & 2900'. Establish circulation down tbg & out tbg x csg annulus. POOH.	16.8	1.1	5.3 days
	CTU	RIH w/ CT. Utilize CT to Lay-in/Sqz Cmt from CIBP to 2500. POOH RD CTU.	13.2	0.8	6.1 days
	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	9.3 days
6	Crane	RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	19.8	1.2	10.5 days
7					
Continue with Conductor P&A					

BRU_241_26_		
CTU	BRU_241_26_CTU	5 days
CRANE	BRU_241_26_CRANE_Type5	5 days
RIG	BRU_241_26_RIG	0 days
Eline	BRU_241_26_Eline_Type5	2 days
CMTUnit	BRU_241_26_CMTUnit_Type5	1 days

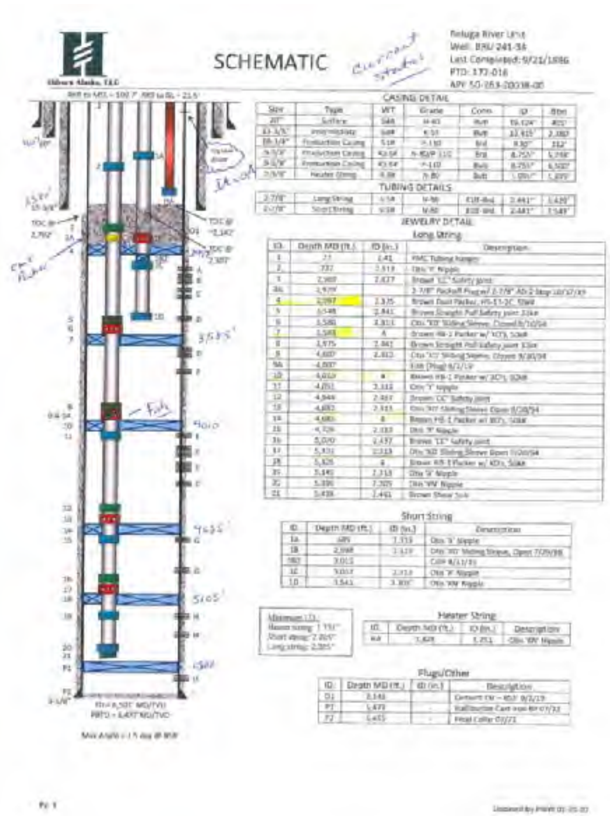




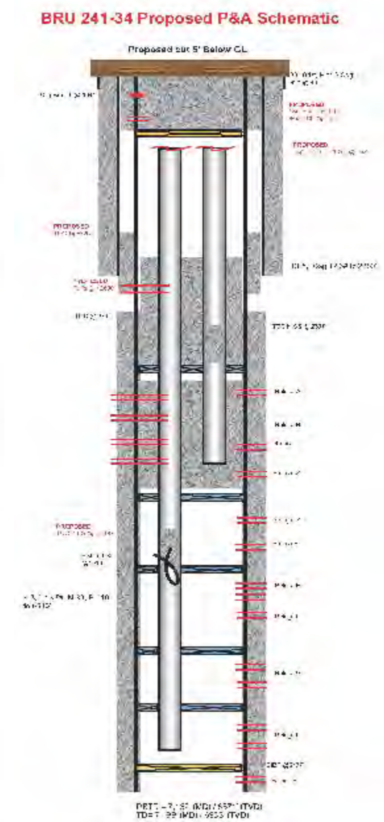
BRU 241-34 (1720160) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down LS & SS tbg. Ensure LS & SS tbg integrity..	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit onto LS. RIH to Fish @ ~4010. Mix/Lay-in cmt on top of fish to 3800'. POOH.	48	3.0	3.2 days
3	Eline	Pressure test LS. MIRU Eline. RI Perf LS @ 3000' w/ 10' gun. Establish injection rates & pressures.	7.2	0.5	3.7 days
	CTU	RIH w/CT. Mix/pump Inject cmt into Beluga A thru D interval. POOH.	38.4	2.4	6.1 days
	Eline	Pressure test LS. MIRU Eline. RI Perf LS @ 2500'. Establish injection rates & pressures. Establish Circulation down LS while taking returns out 9-5/8" annulus.	9.6	0.6	6.7 days
4	CTU	RIH w/ CT. Mix/Pump/Inject cmt while taking returns on 9 5/8" x 13-3/8" annulus, POOH w/ CT	12	0.8	7.4 days
5	Crane	MIRU Crane, Work Platform & BOPE. POOH LD Heater String. Eline Cut LS&SS Tbg @ 620'. POOH LD Tbg. Eline Convey CIBP set same @ 550'. Eline punch csg @ 500'. Mix/Pump/Circulate Cmt to surface.	59.4	3.7	11.1 days
Continue with Conductor P&A					

BRU_241_34_		
CTU	BRU_241_34_CTU	7 days
CRANE	BRU_241_34_CRANE_Type3	4 days
RIG	BRU_241_34_RIG	0 days
Eline	BRU_241_34_Eline_Type3	2 days
CMTUnit	BRU_241_34_CMTUnit_Type3	1 days



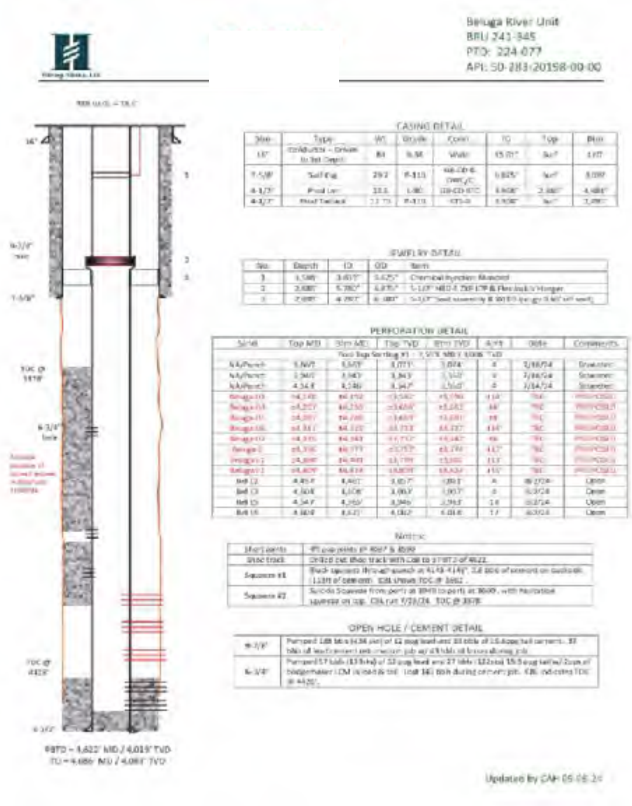
Proposed P&A



BRU 241-34S (224-0770) Type 5

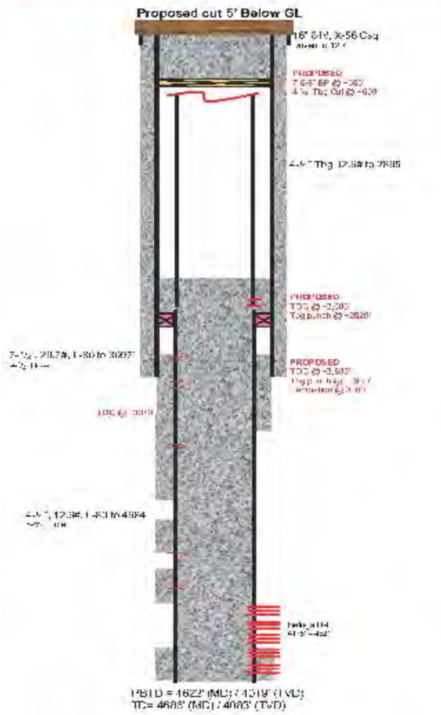
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RI Clean out to PBTD. Mix cmt. Lay-in/Sqz Cmt from PBTD' to 3600'.POOH.	48	3.0	3.2 days
3	Eline	MIRU Eline. RIH w/ Perf guns. Tag TOC note depth. PU Perf 4-1/2" @ 3200'.POOH. RI Punch 4-1/2" Tbg @ 2900'. RI Punch tbbg @ 2600'. Establish circulation down tbg & out tbg x csg annulus.	21		
	CTU	RIH w/ CT. Lay-in/Sqz/Circ cement to 2600'. POOH RD CTU.	36	2.3	5.5 days
	Eline	RIH Tag TOC. Note in Rpt. Pressure test TOC.	7.2	0.5	5.9 days
	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	9.1 days
	Crane	RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	21.6	1.4	10.4 days
Continue with Conductor P&A					

BRU 241 34S		
CTU	BRU 241 34S CTU	6 days
CRANE	BRU 241 34S CRANE Type5	5 days
RIG	BRU 241 34S RIG	0 days
Eline	BRU 241 34S Eline Type5	1 days
CMTUnit	BRU 241 34S CMTUnit Type5	1 days



Proposed P&A

BRU 241-34S Proposed P&A Schematic

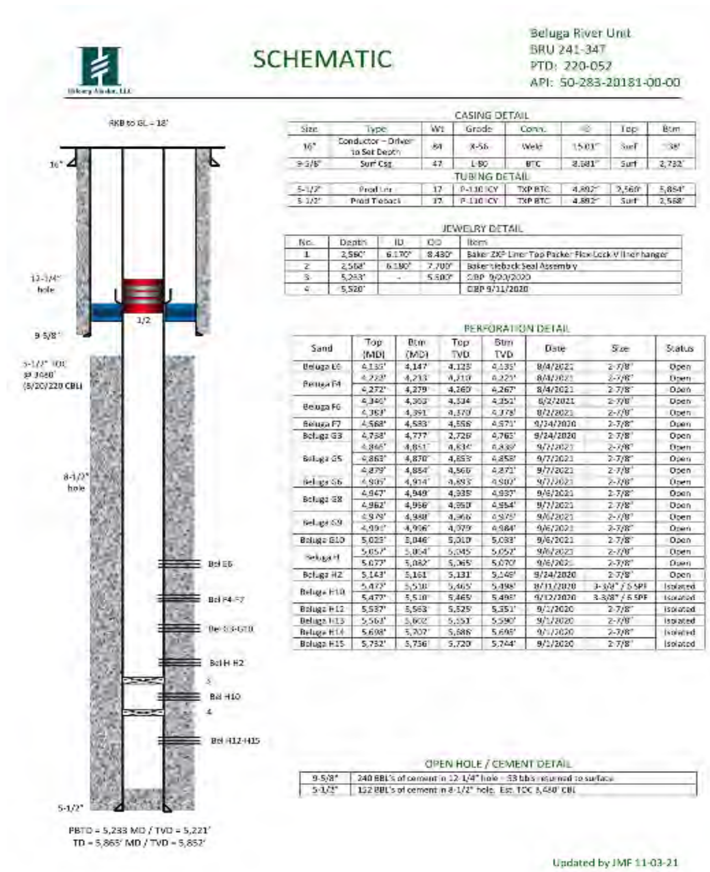


BRU 241-34T (2200520) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure tbg/csg integrity.	3.6	0.2	0.2 days
2	CTU	MIRU CTU. RI/CO to CIBP @ 5233'. MIRU cementers. Mix/Pump/Layin/Sqz cmt from CIBP to 3800'.	48	3.0	3.2 days
3	Eline	MIRU Eline, RI w/ CIBP, set same @ 3500'. RI w/ 6' Perf Guns. Perf @ 2900'. RI Punch tbg @ 2620'. Establish injection rates & pressures. RD Eline.	19.8	1.2	4.5 days
4	CTU	RIH w/ CT. Mix/Pump/Lay-in Cmt from 3500' to 2600' Inject cmt across Shoe. POOH WOC.	13.8	0.9	5.3 days
5	Eline	Eline convey tbg punch gun to 2540'. Establish circulation rates & pressures	9.6	0.6	5.9 days
6	CTU	RIH w/ CT. Mix/Pump/Lay-in Cmt from 2600' to 2000'. POOH WOC.	13.8	0.9	6.8 days
7	Crane	MIRU Work Platform & Crane and equip. RU Slickline. RIH tag TOC. RD Slickline. RU Eline. RIH Sever tbg @ 550'. POOH LD Tbg.	56.4	3.5	10.3 days
8	Crane	RIH w/ Eline set CIBP @ 500'. Jug tst wellbore. Mix/Pump/Fill wellbore w/ cmt to surface.	10.2	0.6	11.0 days
Continue with Conductor P&A					

BRU_241_34T_		
CTU	BRU_241_34T_CTU	5 days
CRANE	BRU_241_34T_CRANE_Type3	5 days
RIG	BRU_241_34T_RIG	0 days
Eline	BRU_241_34T_Eline_Type3	2 days
CMTUnit	BRU_241_34T_CMTUnit_Type3	1 days

Current Schematic



CASING DETAIL

Size	Type	Wt	Grade	Conn.	ID	Top	Btm
16"	Conductor – Driven to Set Depth	84	X-56	Weld	15.01"	Surf	38'
9-5/8"	Surf Csg	47	L-80	BTC	8.681"	Surf	2,732'

TUBING DETAIL

Size	Type	Wt	Grade	Conn.	ID	Top	Btm
5-1/2"	Prod Lnr	17	P-110 ICY	TXP BTC	4.892"	2,560'	5,854'
5-1/2"	Prod Tieback	17	P-110 ICY	TXP BTC	4.892"	Surf	2,568'

JEWELRY DETAIL

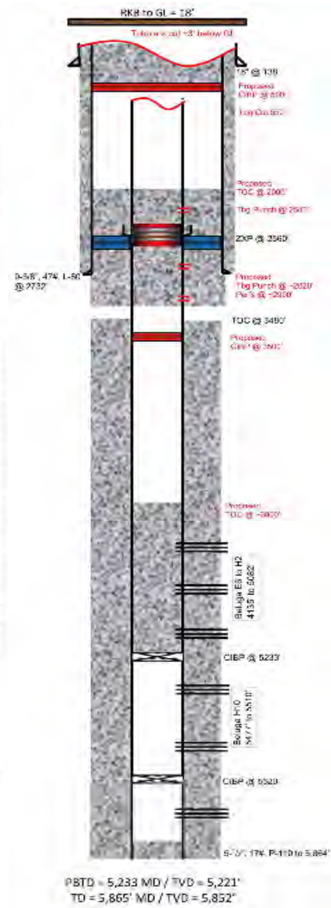
No.	Depth	ID	OD	Item
1	2,560'	6.170"	8.430"	Baker ZXP Liner Top Packer Flex Lock V liner hanger
2	2,568'	6.180"	7.700"	Baker tieback Seal Assembly
3	5,233'	-	5.500"	CIBP 9/23/2020
4	5,520'			CIBP 9/11/2020

PERFORATION DETAIL

Sand	Top (MD)	Btm (MD)	Top TVD	Btm TVD	Date	Size	Status
Beluga E6	4,135'	4,147'	4,123'	4,135'	8/4/2021	2-7/8"	Open
Beluga F4	4,222'	4,233'	4,210'	4,221'	8/4/2021	2-7/8"	Open
	4,272'	4,279'	4,260'	4,267'	8/4/2021	2-7/8"	Open
Beluga F6	4,346'	4,363'	4,334'	4,351'	8/2/2021	2-7/8"	Open
	4,363'	4,391'	4,370'	4,378'	8/2/2021	2-7/8"	Open
Beluga F7	4,568'	4,583'	4,556'	4,571'	9/24/2020	2-7/8"	Open
Beluga G3	4,738'	4,777'	2,726'	4,765'	9/24/2020	2-7/8"	Open
Beluga G5	4,846'	4,851'	4,834'	4,839'	9/7/2021	2-7/8"	Open
	4,863'	4,870'	4,853'	4,858'	9/7/2021	2-7/8"	Open
	4,879'	4,884'	4,866'	4,871'	9/7/2021	2-7/8"	Open
Beluga G6	4,905'	4,914'	4,893'	4,902'	9/7/2021	2-7/8"	Open
Beluga G8	4,947'	4,949'	4,935'	4,937'	9/6/2021	2-7/8"	Open
	4,962'	4,966'	4,950'	4,954'	9/7/2021	2-7/8"	Open
Beluga G9	4,979'	4,988'	4,966'	4,975'	9/6/2021	2-7/8"	Open
	4,991'	4,996'	4,979'	4,984'	9/6/2021	2-7/8"	Open
Beluga G10	5,023'	5,046'	5,010'	5,033'	9/6/2021	2-7/8"	Open
Beluga H	5,057'	5,064'	5,045'	5,052'	9/6/2021	2-7/8"	Open
	5,077'	5,082'	5,065'	5,070'	9/6/2021	2-7/8"	Open
Beluga H2	5,143'	5,161'	5,131'	5,149'	9/24/2020	2-7/8"	Open
Beluga H10	5,477'	5,510'	5,465'	5,498'	8/31/2020	3-3/8" / 6 SPF	Isolated
	5,477'	5,510'	5,465'	5,498'	9/12/2020	3-3/8" / 6 SPF	Isolated
Beluga H12	5,537'	5,563'	5,525'	5,551'	9/1/2020	2-7/8"	Isolated
Beluga H13	5,563'	5,602'	5,551'	5,590'	9/1/2020	2-7/8"	Isolated
Beluga H14	5,698'	5,707'	5,686'	5,698'	9/1/2020	2-7/8"	Isolated
Beluga H15	5,732'	5,736'	5,720'	5,744'	9/1/2020	2-7/8"	Isolated

OPEN HOLE / CEMENT DETAIL

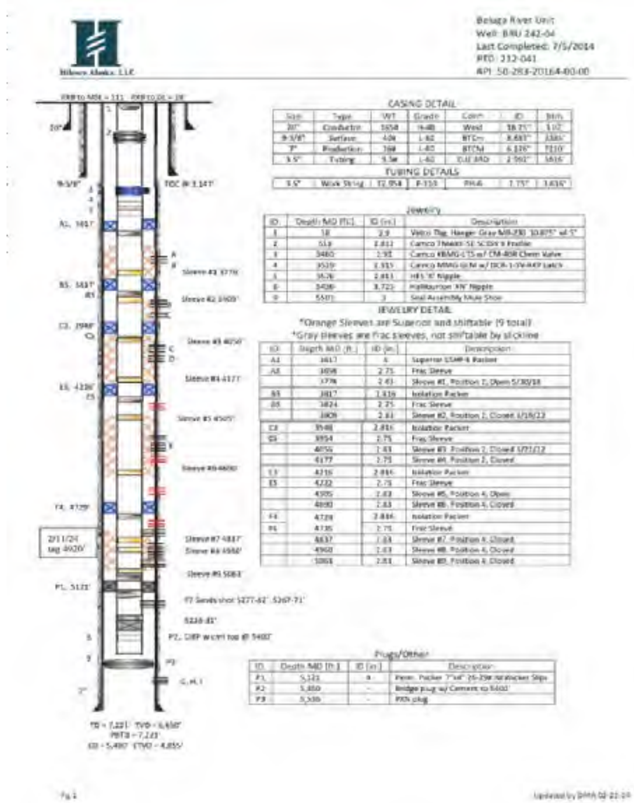
9-5/8"	240 BBL's of cement in 12-1/4" hole - 53 bbls returned to surface
5-1/2"	152 BBL's of cement in 8-1/2" hole. Est. TOC 3,480' CBL



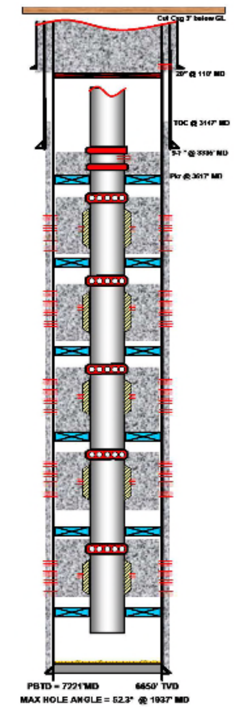
BRU 242-04 (2120410) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	EL perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 3560'. RD CTU. WOC. RU Slickline, RI tag TOC.	106.8	6.7	6.9 days
3	Eline	RU Eline. RI punch tbg above TOC. RI Set cmt retainer above tbg punches.	17.4	1.1	8.0 days
	CMTUnit	MIRU cmt unit. Mix/Pump/Circulate cmt through retainer. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore.	25.2	1.6	9.6 days
	Eline	RU Eline. RI cut tbg above @ 600'.	14.4	0.9	10.5 days
4	Crane	MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot/ Lay-in cmt to surface.	97.8	6.1	16.6 days
10					
Continue with Conductor P&A					

BRU_242_04_		
CTU	BRU_242_04_CTU	7 days
CRANE	BRU_242_04_CRANE_Type3	7 days
RIG	BRU_242_04_RIG	0 days
Eline	BRU_242_04_Eline_Type3	2 days
CMTUnit	BRU_242_04_CMTUnit_Type3	2 days



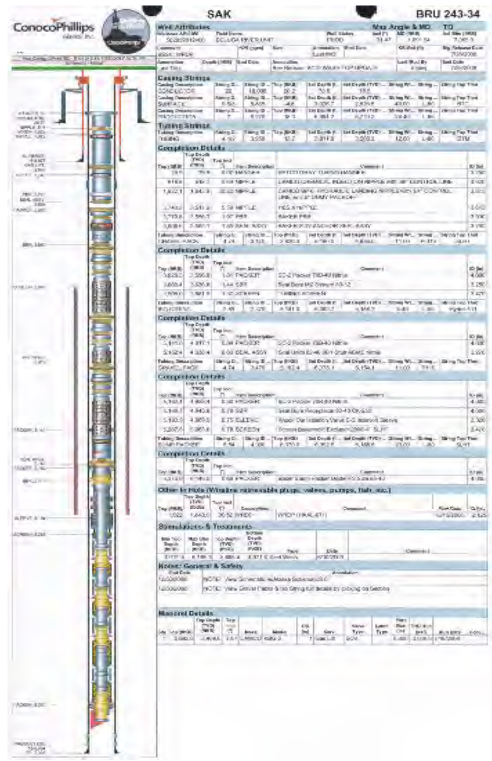
Proposed P&A



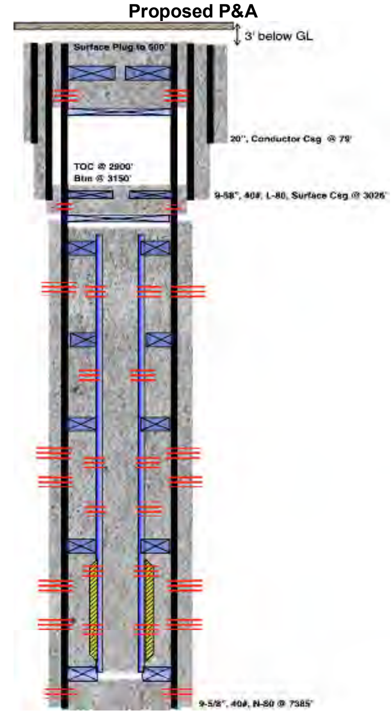
BRU 243-34 (2080790) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	EL perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 3800'. RD CTU.	88.8	5.6	5.8 days
3	Eline	RI cut tbg above top pkr. Jug test wellbore.	7.2	0.5	6.2 days
4	Crane	MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot 500' of cmt on top of pkr.	57	3.6	9.8 days
5	Crane	Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC.	18.6	1.2	11.0 days
6	Crane	Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	11.1 days
7	Crane	RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	12	0.8	11.8 days
8	Crane	PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	9	0.6	12.4 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	13.8 days
10					
Continue with Conductor P&A					

BRU_243_34_		
CTU	BRU_243_34_CTU	6 days
CRANE	BRU_243_34_CRANE_Type3	8 days
RIG	BRU_243_34_RIG	0 days
Eline	BRU_243_34_Eline_Type3	1 days
CMTUnit	BRU_243_34_CMTUnit_Type3	1 days



Proposed P&A



BRU 244-04 (1720030) Type 3

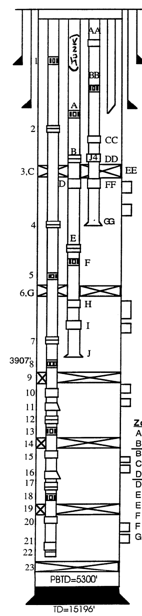
Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
2	CTU	RU EL on #1 Tbg String. RI perforate across intervals. MIRU CT Unit onto #1 Tbg String.	43.2	2.7	2.9 days
3	CTU	RI Layin/Sqz cmt from ETD to 3250'. RD CTU.	42.6	2.7	5.6 days
4	Eline	RU EL. RI cut #1 & #3 tbg strings above top pkr. Jug test wellbore.	14.4	0.9	6.5 days
5	Crane	MIRU Crane, Work Platform & BOPE. PU tbg. Circ/Spot 500' of cmt on top of pkr. POOH.	71.4	4.5	11.0 days
6	Crane	Pull/remove #1 & #2 tbg & heater string. RI w/ EL cut #3 tbg string above CT fish. Test wellbore.	34.2	2.1	13.1 days
7	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	14.6 days
8					
9					
10					
Continue with Conductor P&A					

BRU_244_04_

CTU	BRU_244_04_CTU	6 days
CRANE	BRU_244_04_CRANE_Type3	9 days
RIG	BRU_244_04_RIG	0 days
Eline	BRU_244_04_Eline_Type3	1 days
CMTUnit	BRU_244_04_CMTUnit_Type3	1 days

ARCO Alaska, Inc. **eluga River Unit**

BRU 244-4	API#: 283-20002-00	Well Type: Gas Producer
Spud Date: 2/11/67	Original RKB (Depth Ref): 108'	Annulus Fluid: Diesel
Last Compl: 8/31/72	Ground Level: 88'	To of Sterling: 3313'
Schematic Rev:5/12/97	Maximum Hole Angle: 18°	ASP: 2616086,314043
SE 1/4 Sec. 4, T12N, R10W,SM	Angle at Perforations: 15°	Triple w/ heater string



Jewelry

	Depth	Length	Equipment	I.D.	O.D.
1	3234'	3.20'	Otis "XA" Sleeve		
2	3269'	1.06'	Brown "CC" Safety Jnt.		
3	3280'	5.92'	Triple Brown HS17-3C Pkr.-See #EE	2 .875"	
4	3606'	2.56'	Bown Straight Pull Safety Joint		
5	3640'	3.16'	Otis "XA" Sleeve	2.313"	
6	3643'	7.08'	2-7/8" x 2-7/8" Brown HS17-2C Pkr		
7	3905'	2.78'	Brown Straight Pull Safety Joint		
8	3917'	3.20'	Otis "XA" Sleeve	2.313"	
9	3921'	7.68'	2-7/8" x 2-7/8" Brown H-1-SRP Pkr.		
10	3928'	1.62'	Otis "S" Nipple *Postion 4*	2.313"	
11	4367'	13.04'	Camco "MMA" Mandrel w/ RDO valve		
12	4411'	2.58'	Brown straight Pull Safety Jnt.		
13	4424'	2.95'	Otis "XA" Sleeve Open 9/79	2.313"	
14	4427'	7.65'	Brown H-1-SRP pkr		
15	4435'	1.58'	Otis "S" Nipple *Postion 3*	2.313"	
16	4778'	13.17'	Camco "MMA" Mandrel w/ RDO valve		
17	4822'	2.58'	Brown Straight Pull Safety Joint		
18	4835'	2.95'	Otis "XA" Sleeve Closed 9/79	2.313"	
19	4838'	7.55'	Brown H-1-SRP pkr		
20	4845'	1.58'	Otis "S" Nipple *Postion 2*	2.313"	
21	5289'	.91'	Camco "D" Nipple Plugged 12/73		
22	5290'	.75'	Brown Shear Catcher Sleeve		
23	5300'		Bridge Plug		
A	3268'	3.15'	Otis "XA" Sleeve-**Closed 5/97**	2.313"	
B	3279'	1.20'	"CC" Safety Joint		
C	3280'	5.92'	Triple Brown HS17-3C Pkr.-See #EE	2.875"	
D	3286'	3.57'	Brown Adjustable Union		
E	3627'	2.56'	Brown Straight Pull Safety Joint		
F	3636'	3.17'	Otis "XA" Sleeve Closed 5/97	2.313"	
G	3643'	7.08'	2-7/8" x 2-7/8" Brown HS17-2C Pkr		
H	3650'	2.93'	Brown Adjustable Union		
I	3685'	.94'	Camco "D" Nipple Pulled plug 5.97		
J	3906'	.66	Venturi Shoe		
AA	52'	1.51'	Otis "S" Nipple *Position 2*	1.875"	
BB	3243'	2.88'	Otis "XA" Sleeve	1.875"	
CC	3277'	.82'	O. D. Collar		
DD	3278'	2.54'	J-4 Latch		
EE	3280'	5.92'	2-7/8" x 2-7/8"x 2-3/8" Brown HS17-3C Pkr		
FF	3286'	.98'	Camco "D" Nipple		
GG	3298'	.59'	Venturi Shoe		

JUNK SURFACE 1000' CoiledTubing Cemented in PLACE

Casing and Tubing

Description	Size	Weight	Grade	Thread	Top	Bottom
Surface	22"	100#		Butt		310'
Intermediate	13- 3/8"	68,61#	J-55	8RD		2998'
Production Csg	9 -5/8"	43.5#	P-110,N-80	8RD,Butt		8972'
Tail Liner	7"	32#	P-110	8RD	7570'	12,794'
Production Tbg	2- 7/8"(1)	6.5#	N-80	EUE 8RD		5290'
Production Tbg	2- 7/8"(2)	6.5#	N-80	EUE 8 RD		
Production Tbg	2- 3/8"(3)	4.7#	N-80	EUE 8 RD		3298'
Heater stg	1.9"	2.75#		NU		2020'

Perforations

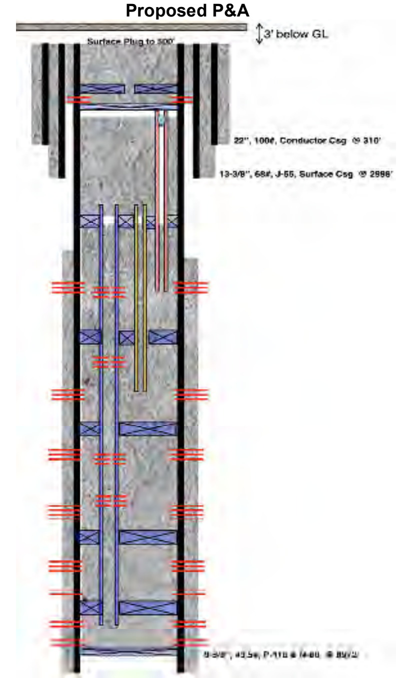
Zone	DIL Depth	TVD Depth	Density	Net Footage.	Interval	Production Status
A	3337'-3524'	3243'-3428'	4	73'	String 3	Open
B upper	3552'-3605'	3455'-3506'	4	37'	Packer	Open
B lower	3664'-3687'	3563'-3582'	4	15'	String 2	Closed 1/97
C	3687'-3844'	3582'-3734'	4	89'		"
D upper		3777'-3797'	4	20'	Packer	Open 8/97
D lower	3949'-4107'	3839'-3992'	4	54'	String 1	Open 9/79
E	4157'-4391'	4040'-4268'	4	36'	Packer	Open
E lower	4453'-4458'	4328'-4333'	4	5'		Closed 9/79
F upper	4540'-4780'	4413'-4646'	4	70'	Packer	Closed
F lower	4861'-4982'	4724'-4738'	4	34'		Closed 12/73
G	5141'-5272'	4992'-5117'	4	25'		Closed

Tag Data

String 1	String 2	String 3
12/87 2.3" Gauge ring to 3650' WLM	12/87 2.3" Gauge ring to 3650' WLM	6/77 Fill @ 3410' ?
5/91 1.5" Bailer, fill at 5238' RKB	5/91 2.3" Gauge ring to Camco 'D' Nipple @ 3686'	9/78 Fill @ 3336' ?
		9/79 Fill @ 3618'
		12/87 1.84" Gauge ring to 3280' WLM
		5/91 1.75" Gauge ring to 3327' WLM

5/12/97

Proposed P&A



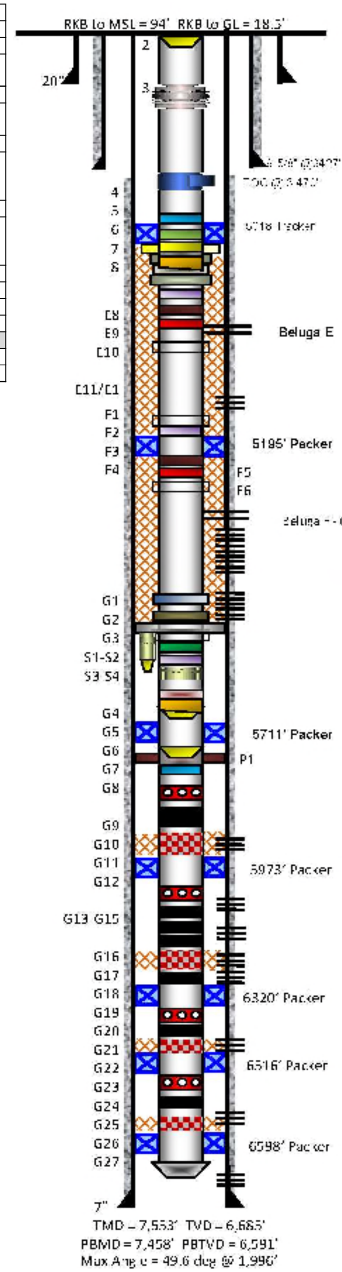
BRU 244-23 (2120690) Type 3

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity..	3.6	0.2	0.2 days
3	CTU	EL perforate GP Screens. MIRU CT Unit. Layin/Sqz cmt from ETD to 5060'. RD CTU. WOC. RU Slicklline, RI tag TOC.	123.6	7.7	8.0 days
4	Eline	RU Eline. RI punch tbg above pkr. RI Set cmt retainer above tbg punches.	17.4	1.1	9.0 days
5	CMTUnit	MIRU cmt unit. Mix/Pump/Circulate cmt through retainer. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore.	25.2	1.6	10.6 days
	Eline	RU Eline. RI Perf through tbg, below Shoe @ 3460'. RI Set cmt retainer @ 3300'.	17.4	1.1	11.7 days
6	CMTUnit	MIRU cmt unit. Mix/Pump/Circulate cmt through retainer, taking returns on 7" x 9-5/8" annulus. Displace wiper plug to retainer. RI w/ Slickline TOC. Jug test wellbore.	25.2	1.6	13.3 days
7	Eline	RU Eline. RI cut tbg above @ 600'.	14.4	0.9	14.2 days
8	Crane	MIRU Crane, Work Platform & BOPE. PU tbg. POOH LD Same. RU Eline. RIH set CIBP @ 500'. RI w/ csg punch csg above CIBP. RD Eline. RI w/ Workstring. Lay-in fill 7" & 9-5/8" to surface. POOH. LD Workstring.	122.4	7.7	21.8 days
9					
10					
11					
Continue with Conductor P&A					

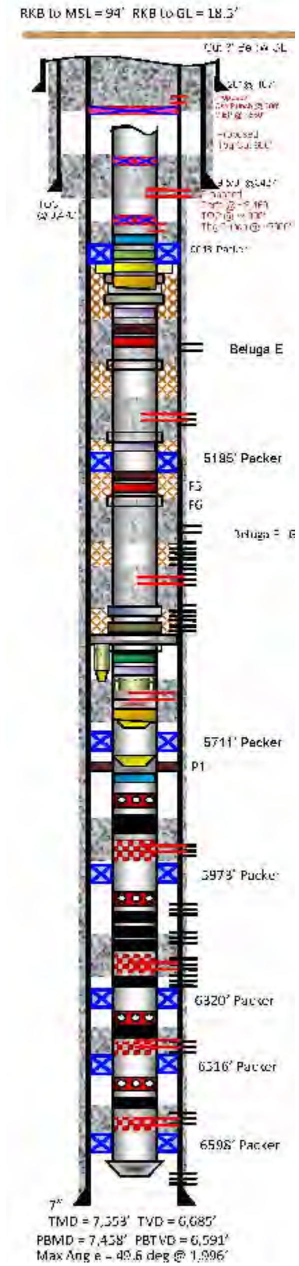
BRU_244_23_

CTU	BRU_244_23_CTU	8 days
CRANE	BRU_244_23_CRANE_Type3	8 days
RIG	BRU_244_23_RIG	0 days
Eline	BRU_244_23_Eline_Type3	4 days
CMTUnit	BRU_244_23_CMTUnit_Type3	4 days

Current



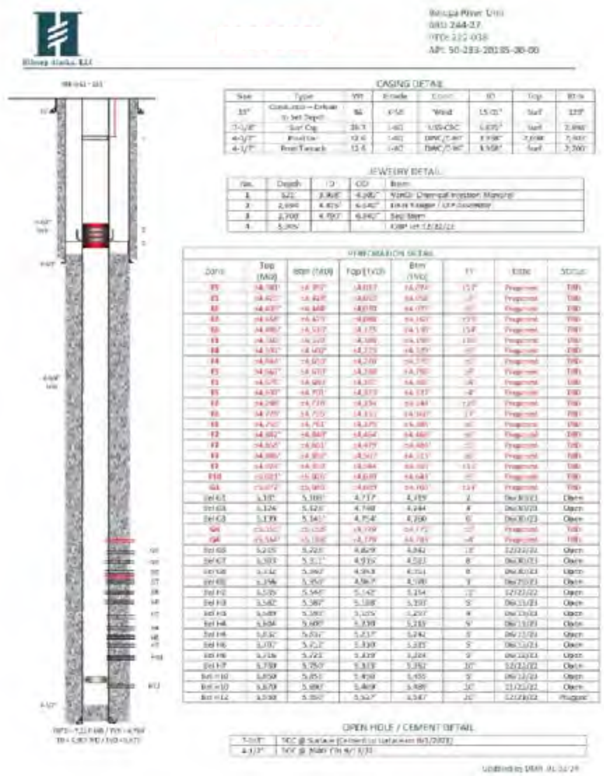
Proposed P&A

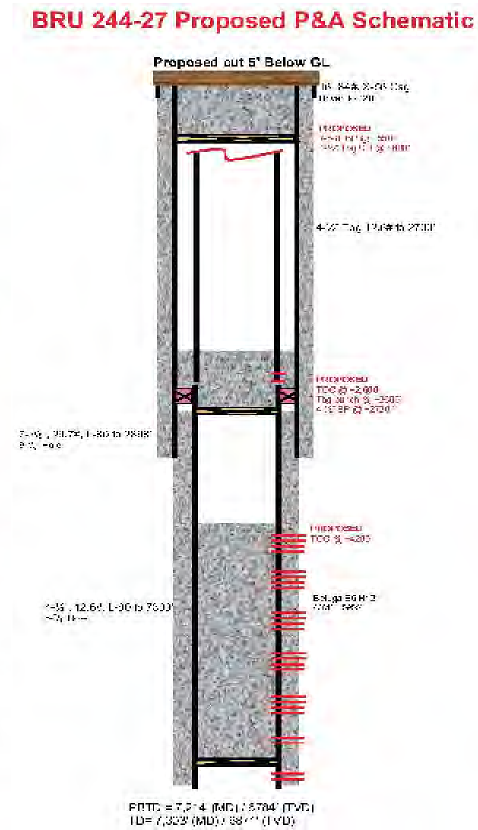


BRU 244-27 (2220380) Type 5

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down Tbg	3.6	0.2	0.2 days
2	CTU	MIRU CT Unit. RI Clean out to CIBP @ 5905'. Mix cmt. Lay-in/Sqz Cmt from 5905' to 4200'.POOH.	48	3.0	3.2 days
3	Eline	MIRU Eline. RI Tag TOC note depth. PU CIBP. Set same @ 2720'. RI w/ tbg punch gun. Punch 4-1/2" @ 2680'. Establish circulation down tbg & out tbg x csg annulus. POOH.	19.2		
	CTU	RIH w/ CT. Lay-in/Sqz/Circ cement to 2500'. POOH RD CTU.	36	2.3	5.5 days
	Eline	RIH Tag TOC. Note in Rpt. Pressure test TOC.	7.2	0.5	5.9 days
	Crane	MIRU Crane & Workplatform. ND Tree. NU BOPE. Test Same.	50.4	3.2	9.1 days
	Crane	RIH w/ Eline. Cut Tbg @ 600'. POOH. MU Landing joint. PU CBU. Pull tbg stub from Wellbore. RIH set 7-5/8" CIBP @ 550'. POOH RD Eline	21.6	1.4	10.4 days
Continue with Conductor P&A					

BRU_244_27_		
CTU	BRU_244_27_CTU	6 days
CRANE	BRU_244_27_CRANE_Type5	5 days
RIG	BRU_244_27_RIG	0 days
Eline	BRU_244_27_Eline_Type5	1 days
CMTUnit	BRU_244_27_CMTUnit_Type5	1 days

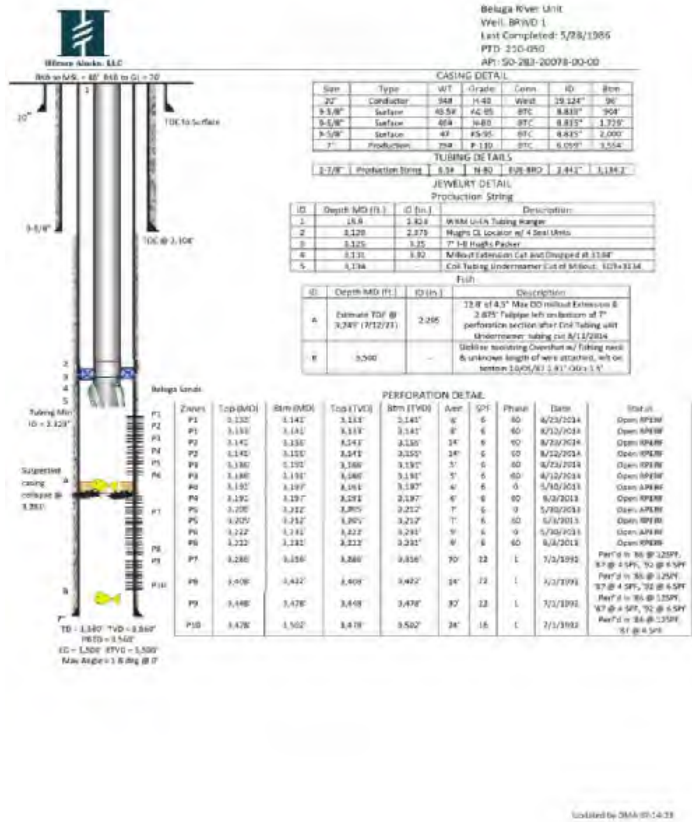




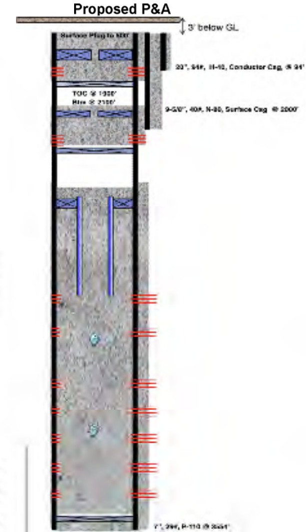
BRU BRWD-1 (1860090) Type 2

Procedure Summary Timeline					
Step #		Line Item Step	Hrs	Days	Accumulative
1	CMTUnit	Bullhead KWF down tbg. Ensure csg integrity.	3.6	0.2	0.2 days
2	Eline	RU EL RI punch tbg 1 joint above pkr. RI set cmt retainer just above pkr.	9.6	0.6	0.8 days
3	CMTUnit	MIRU Cementers. Bullhead calculated volume of cmt below pkr. Reverse out excess.	11.4	0.7	1.5 days
4	CMTUnit	Spot 800' of cmt on top of pkr. RU EL. RI cut tbg above TOC.	9	0.6	2.1 days
5	Crane	MIRU Crane, Work Platform & BOPE. Pull/remove tbg. RI perf csg w/ 21spf gun 2x above TOC.	69	4.3	6.4 days
6	Crane	Establish circulation up Production csg x Surf csg annulus.	1.8	0.1	6.5 days
7	Crane	RI set retainer 120' above Surf Csg shoe. RI Pump/Circ Cmt below retainer.	10.2	0.6	7.2 days
8	Crane	PU leave ~10' above retainer. Test wellbore. POOH LD Tbg.	10.8	0.7	7.8 days
9	Crane	RIH w/ Eline set CIBP @ 700'. RI perf torch punch holes in csg @ 690'. Establish Circulation. RI w/ tbg. Mix/Pump 50 bbls of cmt. Squeeze circulate 25 bbls out punch holes. Open annular. Spot remaining cmt on top of CIBP. PU. CBU. POOH. Jug test Wellbore.	23.4	1.5	9.3 days
10					
Continue with Conductor P&A					

BRU_BRWD_1_		
CTU	BRU_BRWD_1_CTU	0 days
CRANE	BRU_BRWD_1_CRANE_Type2	8 days
RIG	BRU_BRWD_1_RIG	0 days
Eline	BRU_BRWD_1_Eline_Type2	1 days
CMTUnit	BRU_BRWD_1_CMTUnit_Type2	2 days



Proposed P&A



Plugging and Abandonment of the Wellbores

Well Types	Definition of well types	Number of wells	Well Names
Type 0	Original Wellbore P&A'd for Sidetrack	2 wells	BRU 211-03 BRU 212-24T
Type 1	Non Intervention	2 wells	BRU 14-19 BRU 224-13
Type 2	Rigless Intervention without CT	2 wells	BRU 232-09 BRU BRWD-1
Type 3	Rigless Intervention with CT	23 wells	BRU 211-26 BRU 212-24 BRU 212-25 BRU 212-26 BRU 212-35 BRU 212-35T BRU 214-26 BRU 214-35 BRU 222-24 BRU 223-24 BRU 224-23 BRU 224-23T BRU 224-34 BRU 232-04 BRU 232-23 BRU 232-26 BRU 233-27 BRU 241-34 BRU 241-34T BRU 243-34 BRU 242-04 BRU 244-04 BRU 244-23
Type 4	Rig Required	2 wells	BRU 212-18 BRU 221-23
Type 5	New Monobore Wells Added	14 wells	BRU 211-35 BRU 213-26 BRU 214-13 BRU 221-26 BRU 221-35 BRU 222-26 BRU 222-34 BRU 223-34 BRU 233-23 BRU 233-23T BRU 241-23 BRU 241-26 BRU 241-34S BRU 244-27

Cost Estimate			
Type 0	$0 each well	2 wells	$0
Type 1	$452,255 each well	2 wells	$904,509
Type 2	$1,143,457 each well	2 wells	$2,286,914
Type 3	$1,839,947 each well	23 wells	$42,318,784
Type 4	$3,405,252 each well	2 wells	$6,810,503
Type 5	$1,451,387 each well	14 wells	$20,319,418
TOTAL Cost Estimate for all 45 Wells	$72,640,128		

The wellbore plugging and abandonment cost estimates were prepared by Mr. Steve Tyler, an engineer employed at PRA with extensive statewide experience in preparing such cost estimates.

Abandonment of the Surface Improvements

With Union Labor Rates	With Non Union Labor Rates	Estimate Description
$63,517,000	$56,304,000	Reconciled Civil Reclamation activities from the 2022 study, including reclamation of the Air Strip. The 2025 estimate does not include removal of Beluga Highway.

The original estimate for removal of the surface improvements is based on the scope of work provided in 2013, and the information obtained during our collective Beluga Gas Filed site visit. The following is a summary of revisions and updates that have been made over the last 12 years.

In 2018, the Revision 1 estimate was updated to reflect 2018 Labor and Equipment rates for comparison against the 2013 estimate, and added scope to include Produced Water Lines, a Small Compressor Building, and Soil Remediations work scope.

In 2022, the Revision 2 estimate added various Civil Work Tasks to restore the site to original/native conditions and has been updated to reflect 2022 Equipment and Labor Rates. Civil Scope included removal of gravel from pads, buried utilities, conveyances, the airstrip, the main spine road, ancillary access roads, scarify, and placement of hydroseed and is presented as a series of options. The estimate considered work performed by merit shop contractor(s) or union contractor(s).

For 2025, Revision 3 reconciled Civil Reclamation activities from the 2022 study, and itemized specific tasks for gravel removal, and reclamation of the Air Strip. Revision 3 does not include reclamation of Beluga Highway. Estimates were prepared using both 2022 and 2025 Equipment and Labor Rates for both Merit Shop and Union contractor work force for comparison.

The cost estimates for abandonment of the surface improvements were prepared by Conam Construction Company, an engineering and construction company headquartered in Anchorage Alaska with extensive experience in Alaska civil engineering work. PRA supervised the Conam work. The Conam estimates are for both union and non-union labor rates.

We are available to discuss the reports with you and your staff at your request.

Beluga River Unit
2025 Asset Retirement Costs
June 30, 2025

Standards of Independence and Professional Qualifications
Petrotechnical Resources Alaska (PRA) is professionally licensed in the State of Alaska to provide independent petroleum engineering consulting services.

Terms of Usage
This report was prepared for the exclusive use and sole benefit of Chugach Electric Association and may not be put to other use without prior written consent of such use. The data and work papers used in preparation of this report are available for examination by authorized parties.

Sincerely,

Tom Walsh

Tom Walsh