Offset Research Report

Sample Area - HZ Program
Township 082, Range 016-017, W6M

Cased Wells, PT3 • Target TD 3,500–5,000 m

PREPARED	PREPARED FOR	PREPARED BY	WELLS ANALYZED
February 21, 2026	**Operator 1**	**EIM Incorporated**	**34 Wells from Area** **6 Detailed Well Reports**

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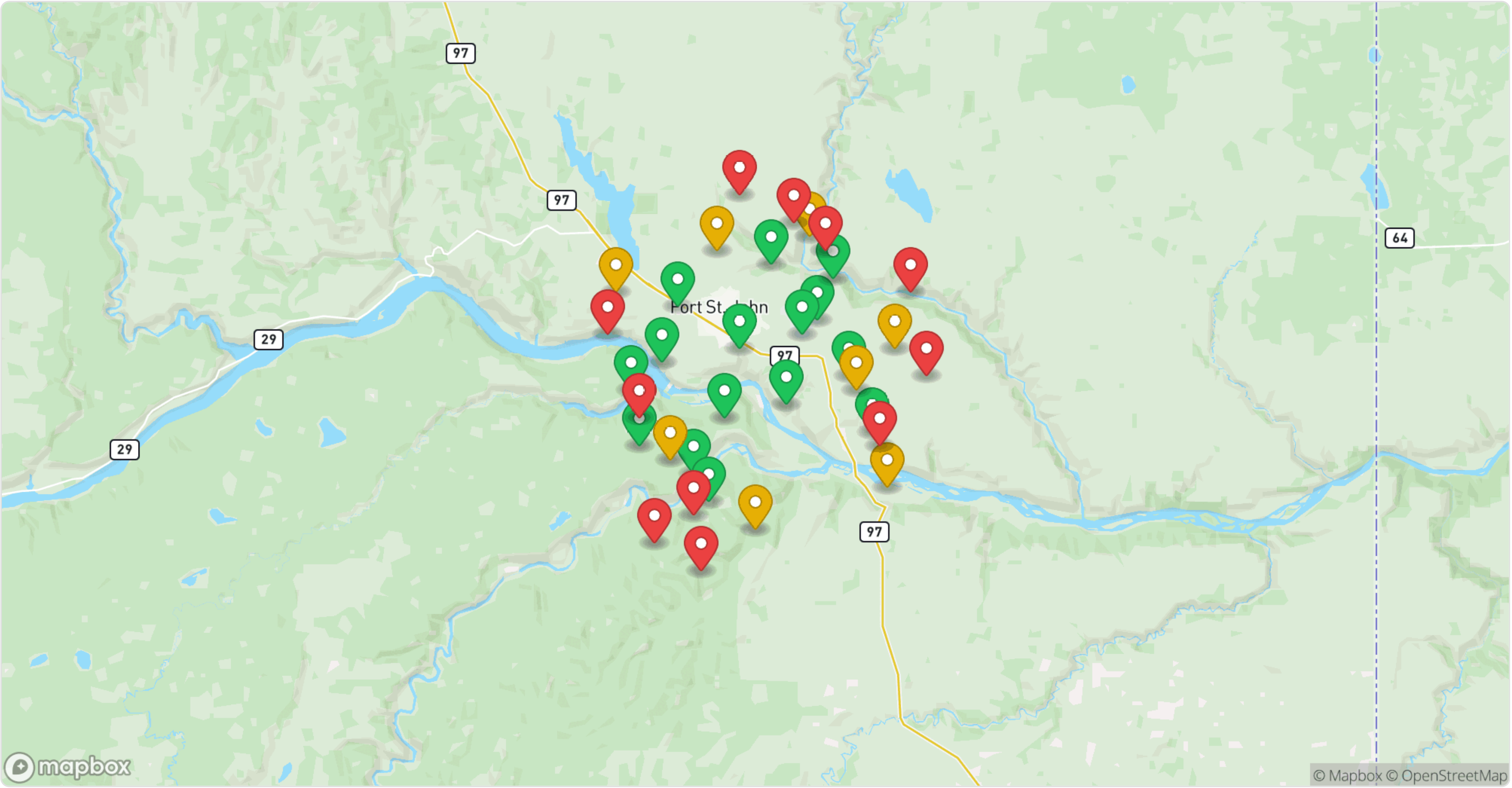
01 - AREA MAP

Well Locations - Sample Area

34 offset wells within the study area. Pin color indicates m/day performance tier.



Green - ≥ 400 m/day   Yellow - 350–399 m/day   Red - < 350 m/day

02 - OFFSET DRILLING TABLE

Area Well Summary

34 wells color-coded by meters-per-day performance. Green ≥ 400, Yellow 350–399, Red < 350. Bold rows with indicate wells with detailed reports.

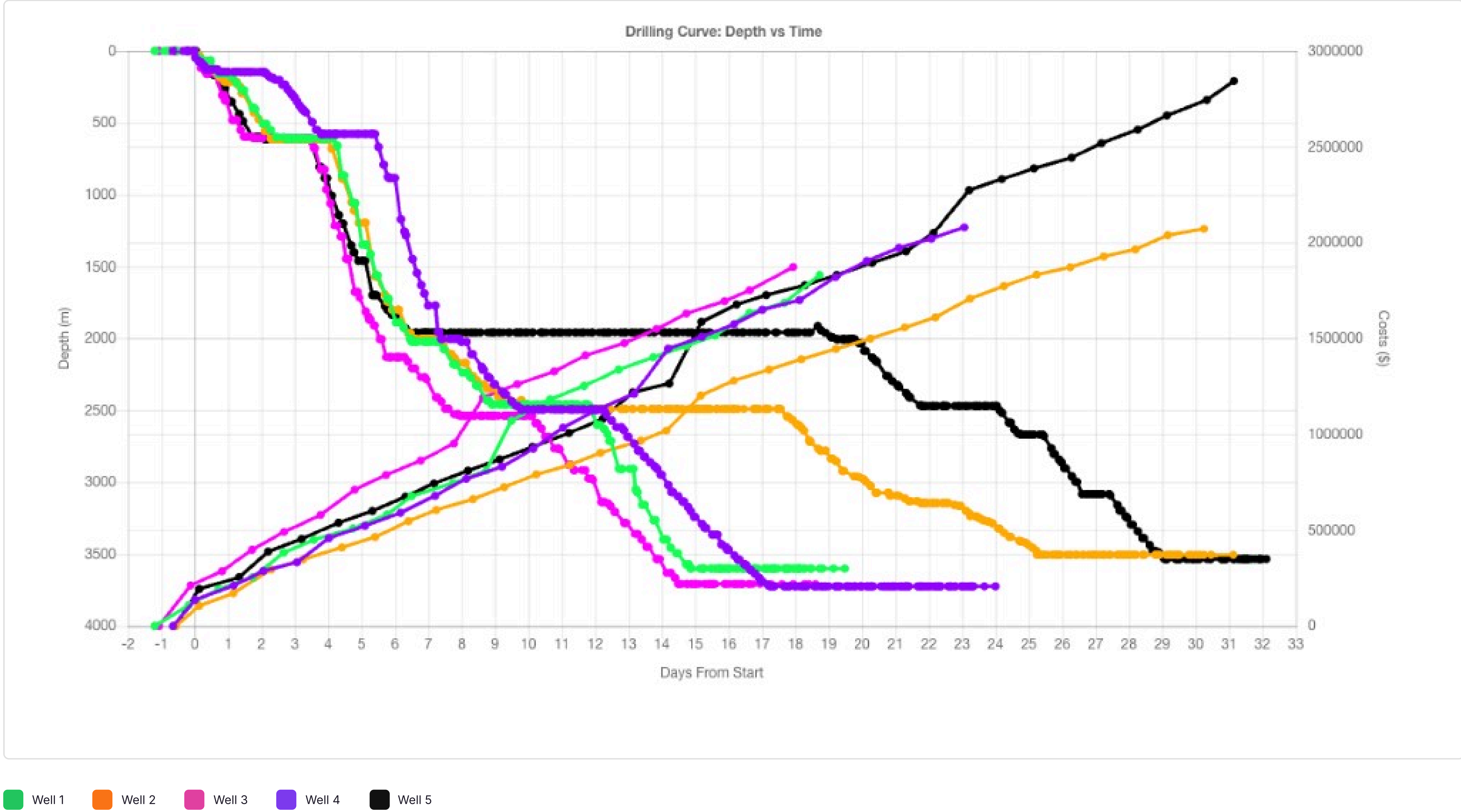
LICENCE #	UWI	WELL NAME	OPERATOR	RIG	SPUD DATE	RIG RELEASE	M/DAY	$/M	FORMATION	STRIKE
1	**100/01-01-001-01W6/00**	**Well 1**	**Operator 1**	**Rig 45**	**2025-06-13**	**2025-06-29**	**486**	**330**	**FORMATION A**	**Strike A**
2	**100/02-02-002-02W6/00**	**Well 2**	**Operator 2**	**Rig 12**	**2025-05-19**	**2025-06-03**	**458**	**342**	**FORMATION A**	**Strike B**
3	**100/03-03-003-03W6/00**	**Well 3**	**Operator 1**	**Rig 45**	**2025-04-11**	**2025-04-28**	**452**	**309**	**FORMATION A**	**Strike A**
4	100/04-04-004-04W6/00	Well 4	Operator 3	Rig 78	2025-03-14	2025-03-30	442	-	FORMATION A	Strike C
5	100/05-05-005-05W6/00	Well 5	Operator 1	Rig 22	2025-07-03	2025-07-19	438	-	FORMATION A	Strike A
6	100/06-06-006-06W6/00	Well 6	Operator 2	Rig 12	2025-02-17	2025-03-05	432	-	FORMATION A	Strike B
7	100/07-07-007-07W6/00	Well 7	Operator 4	Rig 33	2025-01-23	2025-02-09	428	-	FORMATION A	Strike A
8	100/08-08-008-08W6/00	Well 8	Operator 1	Rig 45	2024-12-06	2024-12-23	425	-	FORMATION A	Strike C
9	100/09-09-009-09W6/00	Well 9	Operator 3	Rig 78	2024-11-11	2024-11-27	423	-	FORMATION A	Strike A
10	100/10-10-010-10W6/00	Well 10	Operator 5	Rig 51	2024-10-09	2024-10-26	422	-	FORMATION A	Strike B
11	100/11-11-011-11W6/00	Well 11	Operator 1	Rig 22	2024-09-16	2024-10-02	418	-	FORMATION A	Strike A
12	100/12-12-012-12W6/00	Well 12	Operator 2	Rig 12	2024-08-21	2024-09-06	415	-	FORMATION A	Strike C
13	100/13-13-013-13W6/00	Well 13	Operator 4	Rig 33	2024-07-11	2024-07-27	412	-	FORMATION A	Strike A
14	100/14-14-014-14W6/00	Well 14	Operator 1	Rig 45	2024-06-04	2024-06-20	405	-	FORMATION A	Strike B
15	100/15-15-015-15W6/00	Well 15	Operator 3	Rig 78	2024-05-22	2024-06-07	402	-	FORMATION A	Strike A
16	100/16-16-016-16W6/00	Well 16	Operator 5	Rig 51	2024-04-19	2024-05-08	396	-	FORMATION A	Strike C
17	100/17-17-017-17W6/00	Well 17	Operator 2	Rig 12	2024-03-28	2024-04-16	391	-	FORMATION A	Strike A
18	100/18-18-018-18W6/00	Well 18	Operator 1	Rig 22	2024-03-01	2024-03-19	385	-	FORMATION A	Strike B
19	100/19-19-019-19W6/00	Well 19	Operator 4	Rig 33	2024-02-10	2024-03-01	378	-	FORMATION A	Strike A

LICENCE #	UWI	WELL NAME	OPERATOR	RIG	SPUD DATE	RIG RELEASE	M/DAY	$/M	FORMATION	STRIKE
20	100/20-20-020-20W6/00	Well 20	Operator 2	Rig 12	2024-01-15	2024-02-04	372	-	FORMATION A	Strike C
21	100/21-21-021-21W6/00	Well 21	Operator 1	Rig 45	2023-12-08	2023-12-29	365	-	FORMATION A	Strike A
22	100/22-22-022-22W6/00	Well 22	Operator 5	Rig 51	2023-11-14	2023-12-05	358	-	FORMATION A	Strike B
23	100/23-23-023-23W6/00	Well 23	Operator 3	Rig 78	2023-10-20	2023-11-11	352	-	FORMATION A	Strike A
24	100/24-24-024-24W6/00	Well 24	Operator 1	Rig 22	2023-09-25	2023-10-19	345	-	FORMATION A	Strike C
25	100/25-25-025-25W6/00	Well 25	Operator 4	Rig 33	2023-08-30	2023-09-24	338	-	FORMATION A	Strike A
26	100/26-26-026-26W6/00	Well 26	Operator 2	Rig 12	2023-08-01	2023-08-27	330	-	FORMATION A	Strike B
27	100/27-27-027-27W6/00	Well 27	Operator 1	Rig 45	2023-07-10	2023-08-06	322	-	FORMATION A	Strike A
28	100/28-28-028-28W6/00	Well 28	Operator 5	Rig 51	2023-06-12	2023-07-12	315	-	FORMATION A	Strike C
29	100/29-29-029-29W6/00	Well 29	Operator 3	Rig 78	2023-05-18	2023-06-15	306	-	FORMATION A	Strike A
30	100/30-30-030-30W6/00	Well 30	Operator 2	Rig 12	2023-04-22	2023-05-20	298	-	FORMATION A	Strike B
31	100/31-31-031-31W6/00	Well 31	Operator 4	Rig 33	2023-03-27	2023-04-26	290	-	FORMATION A	Strike A
32	**100/32-32-032-32W6/00**	**Well 32**	**Operator 1**	**Rig 22**	**2023-02-28**	**2023-04-01**	**282**	**505**	**FORMATION A**	**Strike C**
33	**100/33-33-033-33W6/00**	**Well 33**	**Operator 5**	**Rig 51**	**2023-02-01**	**2023-03-05**	**275**	**538**	**FORMATION A**	**Strike A**
34	**100/34-34-034-34W6/00**	**Well 34**	**Operator 3**	**Rig 78**	**2023-01-09**	**2023-02-08**	**268**	**562**	**FORMATION A**	**Strike B**

Bold rows = Detailed well report available (6 wells) ≥ 400 m/day 350–399 m/day < 350 m/day

Drilling Curve: Depth vs Time - Area Comparison

All offset wells plotted from spud to rig release. Depth on left axis, cumulative cost on right axis.



WELL	OPERATOR	SPUD DATE	TOTAL DAYS	TD (M)	AVG M/DAY	TOTAL COST ($)
Well 1	Operator 1	2025-06-13	16	4,280	268	$1,412,400
Well 2	Operator 2	2025-05-19	18	4,640	258	$1,589,120
Well 3	Operator 1	2025-04-11	21	4,920	234	$1,517,280
Well 4	Operator 3	2025-03-14	17	3,860	227	$1,341,340
Well 5	Operator 1	2025-07-03	24	4,510	188	$2,284,060

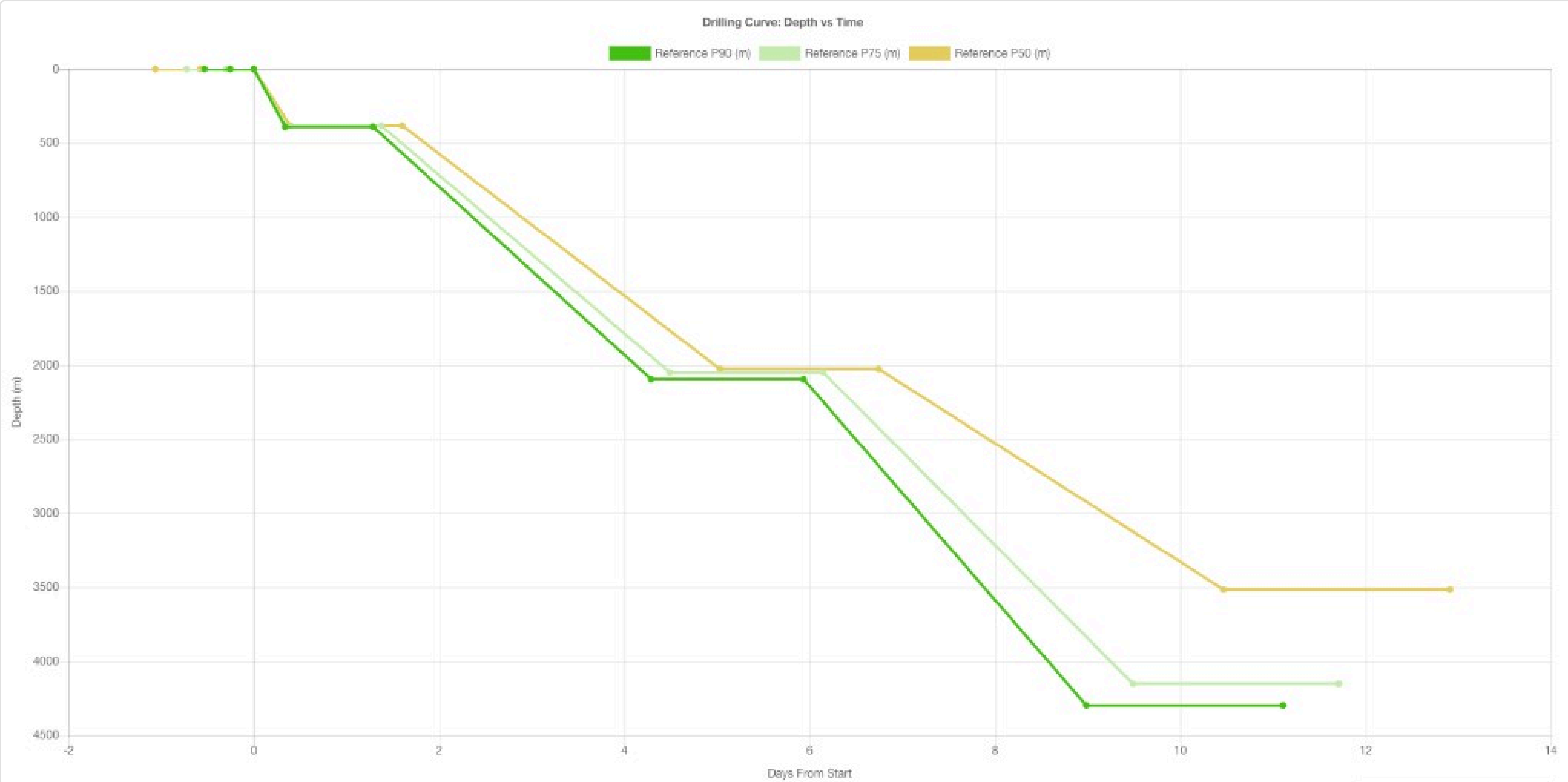
Insights

Well 5 shows the highest cost variance-24 days vs 16–17 for top performers. The slowdown was driven by unplanned NPT: approximately 8 days from a stuck pipe event at ~2,900 m requiring a fishing operation, plus lost circulation treating time. The black cost curve inflection at ~3,200 m suggests a common cost driver (casing/mud change) across wells.

04 - PERCENTILE ANALYSIS

Drilling Curve: P90 / P75 / P50 Comparison

Statistical percentile envelopes derived from 34 area wells. P90 represents the fastest 10th-percentile performance.



Percentile Breakdown by Interval

INTERVAL	P90 (HRS)	P75 (HRS)	P50 (HRS)	P90 M/DAY	P75 M/DAY	P50 M/DAY
FT1A	6.6	10.3	11.6	-	-	-
FT1B	6.2	7.1	13.9	-	-	-
PT1	8.1	8.3	9.4	1,157	1,110	979
FT2	22.8	24.7	29.0	-	-	-
PT2	72.0	74.8	82.3	568	535	479
FT3	39.5	39.7	41.2	-	-	-
PT3	73.3	80.2	89.3	722	629	400
FT4	51.0	53.3	58.7	-	-	-
FFT	0.0	0.0	0.0	-	-	-
TOTAL	**279.4**	**298.5**	**335.4**	**369**	**334**	**251**

Insights

P90 reaches ~4,297 m in ~11.6 days (369 m/day); P50 takes ~14 days to ~3,514 m (251 m/day). Extended NPT at ~390 m (0.9–1.2 d) and at casing points (~2,000 m and TD) drives the spread-P50 shows 2.4 d NPT at final depth vs 2.1 d for P90. PT3 m/day drops from 722 (P90) to 400 (P50), the largest variance driver.

Time Breakdown by Interval

Flat time and productive time per well across standard drilling intervals. Values in days.

WELL	FT1A	FT1B	PT1	FT2	PT2	FT3	PT3	FT4	FFT	TOTAL
Well 1	0.42	0.10	1.00	0.67	3.00	0.58	5.00	0.42	0.05	**11.24**
Well 2	0.50	0.13	1.17	0.75	3.33	0.69	5.63	0.50	0.05	**12.75**
Well 3	0.46	0.12	1.10	0.73	3.17	0.63	5.33	0.46	0.05	**12.05**
Well 4	0.40	0.09	1.04	0.65	3.08	0.56	5.08	0.44	0.04	**11.38**
Well 5	0.58	0.15	1.25	0.79	3.54	0.71	5.83	0.54	0.06	**13.45**
Well 6	0.33	0.08	0.98	0.60	2.92	0.52	4.92	0.40	0.04	**10.79**
Well 7	0.48	0.12	1.13	0.71	3.25	0.65	5.50	0.48	0.05	**12.37**
Well 8	0.52	0.13	1.21	0.77	3.46	0.67	5.75	0.52	0.05	**13.08**
Well 9	0.44	0.10	1.06	0.67	3.13	0.58	5.25	0.44	0.05	**11.72**
Well 10	0.46	0.11	1.08	0.69	3.21	0.60	5.42	0.46	0.05	**12.08**
P90	**0.33**	**0.08**	**0.96**	**0.63**	**2.92**	**0.54**	**4.92**	**0.40**	**0.04**	**10.82**
P75	**0.44**	**0.10**	**1.06**	**0.69**	**3.13**	**0.60**	**5.21**	**0.44**	**0.05**	**11.72**
P50	**0.50**	**0.13**	**1.15**	**0.75**	**3.33**	**0.67**	**5.50**	**0.50**	**0.05**	**12.58**

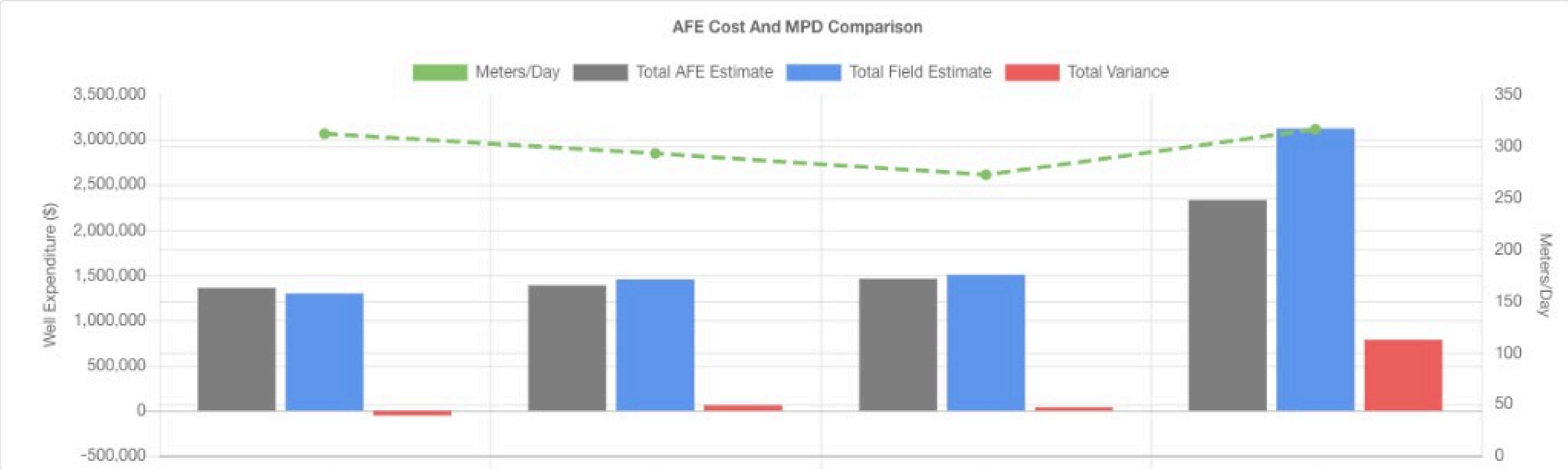
Insights

Well 6 is the P90 benchmark at 10.79 d total. PT3 spans 4.92–5.83 d - a 0.91 d swing and the largest variance driver. FT1A/FT1B/FFT are all sub-day; FFT as low as 0.04 d in best cases.

06 - AFE & COST

AFE Cost and MPD Comparison

Authorization for Expenditure vs actual field estimates across offset wells with meters-per-day overlay.



Meters/Day Total AFE Estimate Total Field Estimate Total Variance

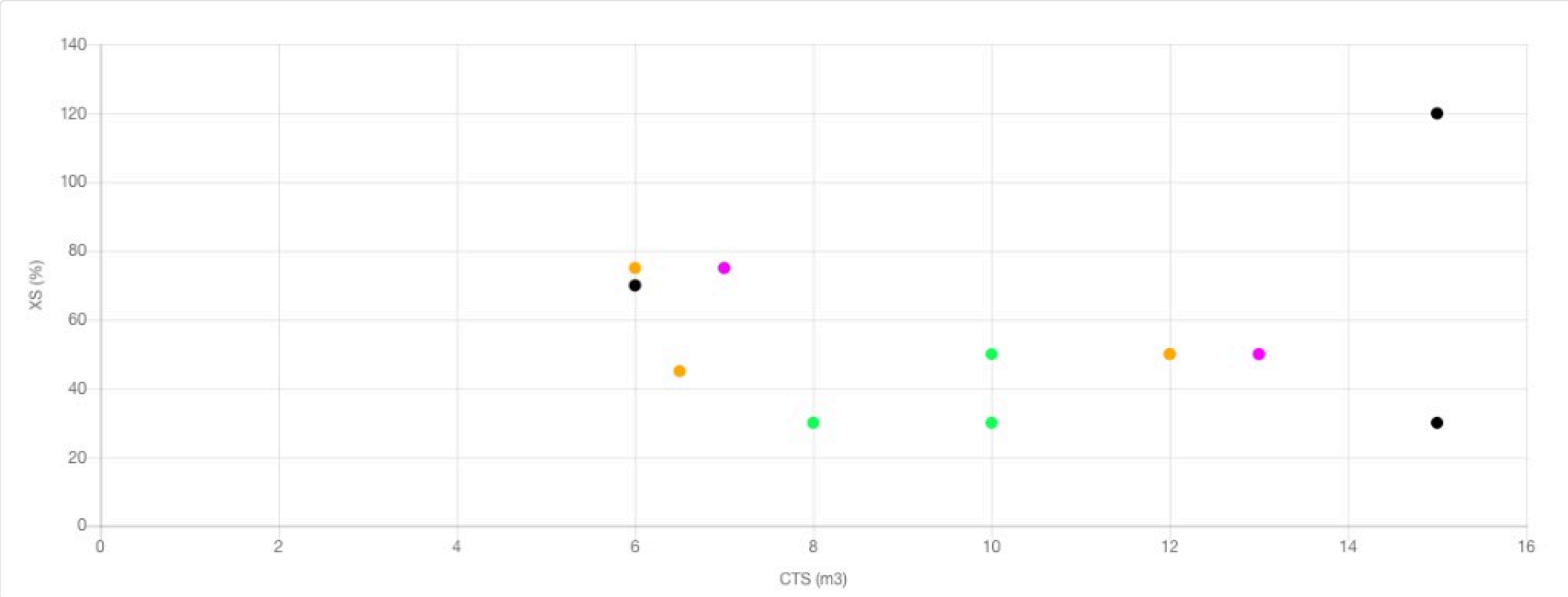
WELL	OPERATOR	AFE ESTIMATE ($)	FIELD ESTIMATE ($)	VARIANCE ($)	VARIANCE %	METERS/DAY
Well 1	Operator 1	$1,380,000	$1,310,000	−$70,000	−5.1%	330
Well 2	Operator 2	$1,380,000	$1,290,000	−$90,000	−6.5%	310
Well 3	Operator 1	$1,420,000	$1,340,000	−$80,000	−5.6%	295
Well 4	Operator 3	$1,450,000	$1,480,000	+$30,000	+2.1%	280
Well 5	Operator 1	$1,460,000	$1,520,000	+$60,000	+4.1%	270
Well 6	Operator 2	$1,400,000	$2,310,000	+$910,000	+65.0%	310
Well 7	Operator 4	$1,420,000	$3,140,000	+$1,720,000	+121.1%	340

Insights

Wells 6 and 7 show 65% and 121% variance-sidetrack and NPT outliers. Top 3 wells beat AFE by 5–6.5%. Meters/day inversely correlates with variance: faster wells tend to stay on budget.

Cement Comparison - CTS vs Excess (%)

Cement-to-surface (CTS) volume plotted against calculated excess percentage across offset wells.



Well 1 Well 2 Well 3 Well 4

CASING: Surface Intermediate Production

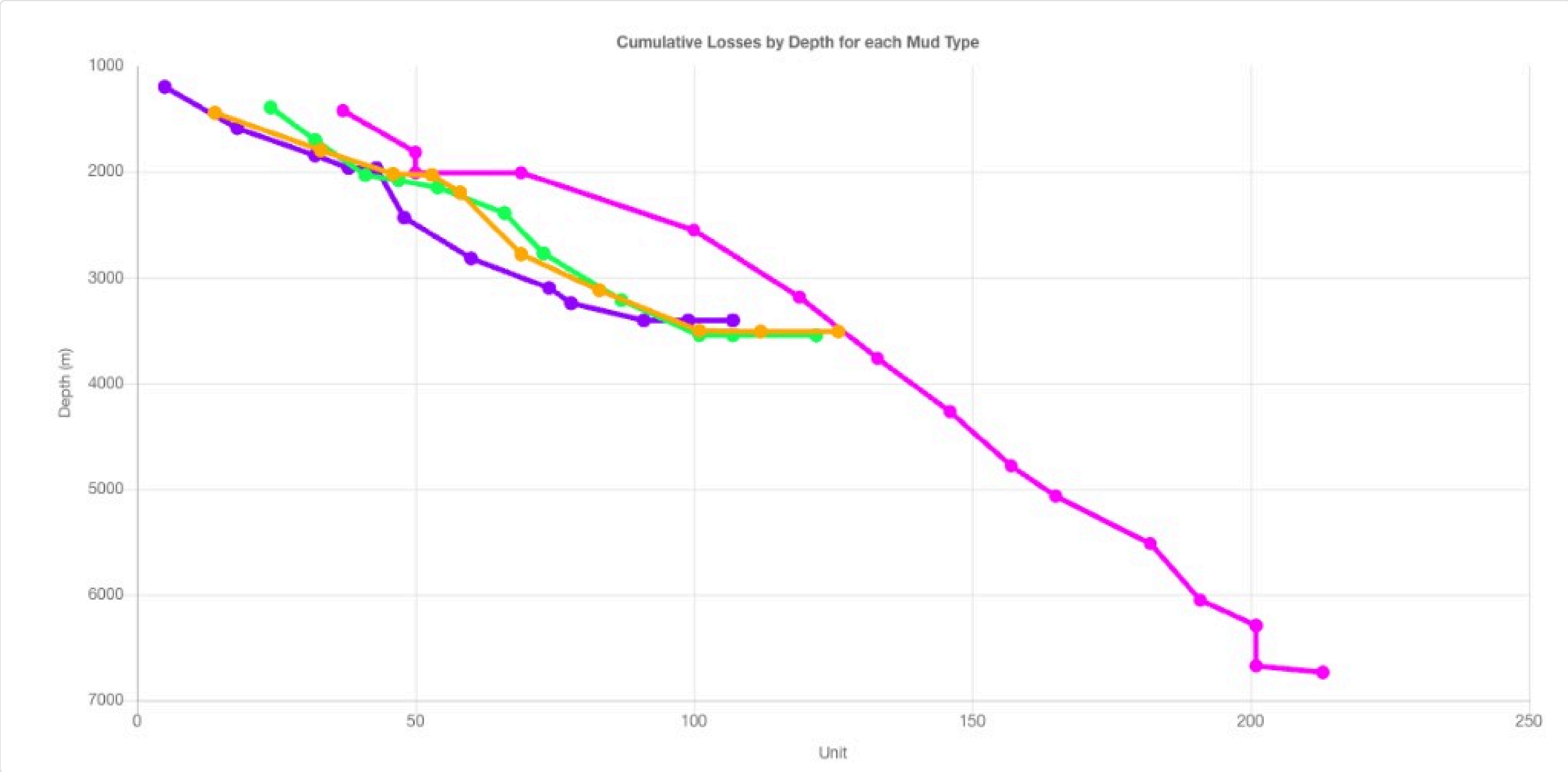
WELL	CASING	CTS (M^3)	XS (%)	CEMENT TYPE	TOC (M)	REMARKS
Well 1	Surface	6.2	70	Class G + 2% $CaCl_2$	Surface	Good cement to surface
Well 1	Intermediate	15.0	120	Class G + Latex	450	High excess, possible washout
Well 1	Production	15.0	30	Class G	1,800	Normal
Well 2	Surface	6.5	75	Class G + 2% $CaCl_2$	Surface	Full returns
Well 2	Intermediate	7.0	45	Class G + Latex	520	Normal
Well 2	Production	12.0	50	Class G	1,850	Normal
Well 3	Surface	7.8	75	Class G + 2% $CaCl_2$	Surface	Full returns
Well 3	Production	13.0	50	Class G	1,780	Normal
Well 4	Surface	8.0	30	Class G + 2% $CaCl_2$	Surface	Below target excess
Well 4	Intermediate	10.0	50	Class G + Latex	490	Normal
Well 4	Production	10.0	30	Class G	1,820	Tight annulus noted

Insights

Well 1 intermediate casing at 120% excess flags a likely washout-correlates with higher mud losses in that section. Production casing excess tight at 30–50% suggests consistent hole quality at TD.

Mud Comparison - Cumulative Losses by Depth

Cumulative fluid losses per mud type plotted against depth.



Mud Type A - Gel/Water Mud Type B - KCl Polymer Mud Type C - HPWBM Mud Type D - Invert Emulsion

MUD TYPE	HOLE SECTION	DEPTH RANGE (M)	CUMULATIVE LOSS (M³)	MUD WEIGHT (KG/M³)	REMARKS
Type A - Gel/Water	Surface	0 – 600	45	1,080	Standard surface mud; moderate losses in gravel beds
Type B - KCl Polymer	Intermediate	600 – 2,100	95	1,150	Good inhibition; losses increased past 1,800 m
Type C - HPWBM	Intermediate	600 – 2,100	80	1,140	Lower losses vs KCl; better hole stability observed
Type D - Invert Emulsion	Production	2,100 – 5,000	210	1,220	Significant losses through reef intervals
Type A - Gel/Water	Surface	0 – 580	38	1,080	Minimal losses; clean surface hole
Type B - KCl Polymer	Production	2,100 – 4,500	120	1,180	Moderate losses; LCM treatments applied at 3,200 m

Insights

Invert emulsion (Type D) loses 210 m³ vs 80 m³ for HPWBM in intermediate-2.6× difference. Reef intervals at 2,800–3,400 m are the primary loss zone; LCM treatments reduced impact in 4 of 10 wells.

Bit Comparison

Bit run performance across offset wells.

BIT #	WELL	HOLE SECTION	SIZE (MM)	TYPE	MAKE / MODEL	DEPTH IN (M)	DEPTH OUT (M)	FOOTAGE (M)	HOURS	ROP (M/HR)	DULL GRADE
1	Well 1	Surface	311.2	PDC	Vendor A - Model X1	0	620	620	8.5	72.9	1-1-WT-A-X-I-NO-TD
2	Well 1	Intermediate	222.3	PDC	Vendor B - Model Y2	620	2,080	1,460	28.0	52.1	2-2-WT-S-X-I-NO-TD
3	Well 1	Production	171.5	PDC	Vendor A - Model Z1	2,080	4,280	2,200	58.0	37.9	2-3-CT-S-X-I-NO-TD
4	Well 2	Surface	311.2	PDC	Vendor A - Model X1	0	600	600	7.8	76.9	1-1-WT-A-X-I-NO-TD
5	Well 2	Intermediate	222.3	PDC	Vendor C - Model K5	600	2,050	1,450	31.0	46.8	2-3-BT-S-X-I-NO-TD
6	Well 2	Production	171.5	PDC	Vendor C - Model K3	2,050	4,640	2,590	72.0	36.0	3-4-CT-S-X-I-PN-TD
7	Well 3	Surface	311.2	PDC	Vendor B - Model Y2	0	630	630	8.2	76.8	1-1-WT-A-X-I-NO-TD
8	Well 3	Intermediate	222.3	PDC	Vendor A - Model X1	630	2,100	1,470	30.5	48.2	2-2-WT-S-X-I-NO-TD
9	Well 3	Production	171.5	PDC	Vendor A - Model Z1	2,100	4,920	2,820	76.0	37.1	2-3-CT-S-X-I-NO-TD
10	Well 4	Surface	311.2	PDC	Vendor A - Model X1	0	610	610	7.5	81.3	1-1-WT-A-X-I-NO-TD
11	Well 4	Intermediate	222.3	PDC	Vendor D - Model P8	610	1,850	1,240	38.0	32.6	3-4-BT-N-X-I-BK-PR
12	Well 4	Intermediate	222.3	PDC	Vendor B - Model Y2	1,850	2,060	210	6.0	35.0	2-3-WT-S-X-I-NO-TD
13	Well 5	Surface	311.2	PDC	Vendor A - Model X1	0	590	590	8.0	73.8	1-1-WT-A-X-I-NO-TD
14	Well 5	Intermediate	222.3	PDC	Vendor B - Model Y2	590	2,090	1,500	32.0	46.9	2-2-WT-S-X-I-NO-TD
15	Well 5	Production	171.5	PDC	Vendor A - Model Z1	2,090	4,510	2,420	65.0	37.2	2-3-CT-S-X-I-NO-TD

Insights

Vendor A Model X1 surface bit: 73–81 m/hr ROP across 5 wells. Vendor D Model P8 (Well 4) pulled at 32.6 m/hr-early failure. Vendor A Model Z1 production bit consistently 37–38 m/hr to TD.

Typical Drilling Problems & Observations

Common operational themes identified across offset wells. Sources include public CAODC data, daily drilling reports, and AER records.

Lost Circulation

Partial to total losses reported between 2,800–3,400 m across 4 of 10 detailed wells. LCM treatments were effective in most cases. One well required a cement plug. See NPT #2, #4, #5, #6

Stuck Pipe / Tight Hole

Tight spots and differential sticking events reported in 3 of 10 wells, primarily in the intermediate section between 1,600–2,200 m. Short trips and wiper trips prior to casing were standard mitigation.

See NPT #1, #3, #7

Cement Excess Variance

Intermediate casing cement excess ranged from 45% to 120%. Higher excess values correlated with enlarged hole sections. Surface casing cement jobs were consistent with 30–75% excess. See Section 07 - Cement

Rig Performance Variance

Average spud-to-rig-release times ranged from 14 to 24 days across the 10 detailed wells. Best-performing wells had consistent rig crews and fewer bit trips. See Section 03 - Drilling Curves

Bit Failures

Two intermediate bit runs were pulled early due to broken cutters. Both used non-standard bit models. PDC bits from Vendor A showed the best durability across all wells. See NPT #8, #9

Seasonal Considerations

Wells drilled in winter months (Nov–Mar) averaged 10–16 additional hours of flat time for rig-up vs summer wells. Spring break-up road restrictions (Mar–May) impacted rig mobilization schedules for 2 wells.

See NPT #10, #11

Unplanned NPT Log

#	WELL	START TIME	END TIME	HOURS	COST ($)	TYPE	DESCRIPTION	DRILLING INTERVAL	SUPERVISOR
1	Well 5	2025/07/08 06:00	2025/07/09 00:00	18	$41,400	Stuck Pipe	Diff. sticking at 2,050 m - jarring & fishing BHA	PT2	R. Makenzie
2	Well 5	2025/07/14 14:00	2025/07/15 04:00	14	$32,200	Lost Circulation	Total losses at 2,900 m - LCM + cement plug set	PT3	R. Makenzie
3	Well 27	2023/07/18 08:00	2023/07/18 18:00	10	$23,000	Tight Hole	Tight spot at 1,800 m - wiper trip & ream to bottom	PT2	D. Lawson
4	Well 28	2023/06/22 20:00	2023/06/23 08:00	12	$27,600	Lost Circulation	Partial losses at 3,100 m - 2 × LCM sweeps	PT3	K. Parmar
5	Well 29	2023/05/28 02:00	2023/05/28 12:00	10	$23,000	Lost Circulation	Seepage losses at 3,400 m - LCM sweep	PT3	J. Flett
6	Well 32	2023/03/12 16:00	2023/03/13 00:00	8	$18,400	Lost Circulation	Partial losses at 2,800 m - LCM sweep effective	PT3	T. Brandt
7	Well 33	2023/02/10 10:00	2023/02/10 16:00	6	$13,800	Pack-off	Pack-off at 1,650 m - short trip to clear	PT2	K. Parmar
8	Well 4	2025/03/20 12:00	2025/03/20 22:00	10	$23,000	Bit Failure	Vendor D P8 broken cutters at 1,850 m - POOH & RIH new bit	PT2	R. Makenzie
9	Well 7	2025/02/01 06:00	2025/02/01 14:30	8.5	$19,550	Bit Failure	Vendor D P8 broken cutters at 1,740 m - trip for replacement	PT2	J. Flett
10	Well 8	2024/12/06 06:00	2024/12/06 22:00	16	-	Weather	Winter rig-up delay - extreme cold standby	FT1A	D. Lawson
11	Well 19	2024/02/14 00:00	2024/02/14 06:00	6	-	Weather	Cold weather delay & road ban - rig standby	FT1A	T. Brandt
	Total - 11 events across 8 wells			**118.5**	**$222,950**				