Artificial Lift R&D Council

New Life for Old Wells: Finding Production and Economic Wins in Gas Wells with Tubing Perforation and Plunger Lift

Dan Fouts, Peak Oil & Gas
David Green, Well Master Corporation

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The Grande Picture

As many as 10% of Laramie Energy's Piceance Basin tight gas wells were non-productive or under-performing due to deep-set tubing or mechanical restrictions in tubing or casing.

A program of evaluating existing completions, prioritizing candidates, perforating and/or cutting tubing, and reestablishing plunger lift has been undertaken.

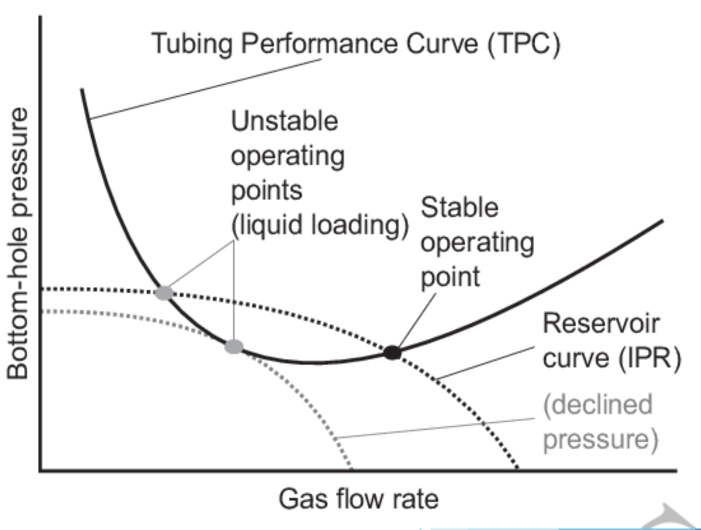
In addition to increasing gas production, benefits include reducing regulatory load, man hours, operating expense, and environmental impacts.

To date, 36 jobs on 33 wells have been completed with 3 wells still in progress, 1 failure, and 1 well that developed a HIT after the job for an 85% success rate that could climb to 94%.

The Process:
What Are We Doing?

1. Identify candidates through routine surveillance, well reviews, or identification by operators, foremen, analysts, or anyone!
2. Determine upside based on production history, decline curve analysis, offset wells, analogs, etc.
3. Vet candidates with thorough top-down trouble shooting, shooting fluid levels, testing casing flow, running slickline, etc.
4. Determine non- or under-performance mechanism.
5. Draft procedure to cut and/or perforate tubing at specified depth, install downhole equipment, and drop a plunger.
6. Do it! Do it! Come on! Do it now!

Candidate Selection:
What kind of wells are we looking for?



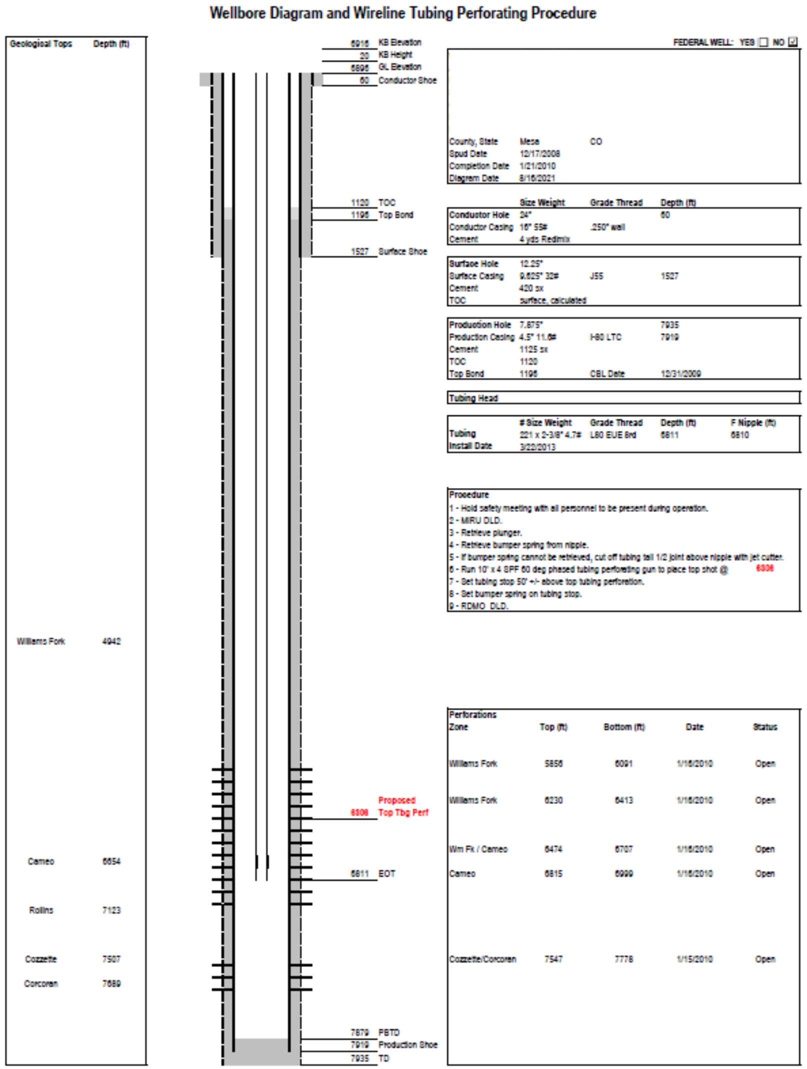
- Tubing perforation candidate characteristics:
  - Cycle on and off due to loading
  - Will not run a plunger
  - Require frequent swabbing
  - Require chemical assistance such as foaming agents
  - Sensitivity to line pressure fluctuations
  - Have known mechanical issues (sanded tubing or plugged tail)
- Candidate prioritization; the best candidates have:
  1. Recent production
  2. Sufficient pressure
  3. Lower liquid ratios

Lean on geo and reservoir folks for insight and input!

Implementation:
Yes, it is this simple.

- General approach for perforating tubing:
  - Immediately above known restrictions or problems.
  - Deeper in wells with recent production and higher pressures.
  - Higher in older, wetter, lower pressure wells with unknowns.
- Procedure:
  1. Retrieve plungers and equipment and/or cut off tubing tail
  2. Perforate or cut tail at pre-determined depth
  3. Set tubing or collar stop
  4. Land bumper spring on stop
  5. Drop plunger
  6. Stick with it!

Wellbore Diagram and Procedure:



Procedure
1 - Hold safety meeting with all personnel to be present during operation.
2 - MIRU DLD.
3 - Retrieve plunger.
4 - Retrieve bumper spring from nipple.
5 - If bumper spring cannot be retrieved, cut off tubing tail 1/2 joint above nipple with jet cutter.
6 - Run 10' x 4 SPF 60 deg phased tubing perforating gun to place top shot @ 6306
7 - Set tubing stop 50' +/- above top tubing perforation.
8 - Set bumper spring on tubing stop.
9 - RDMO DLD.

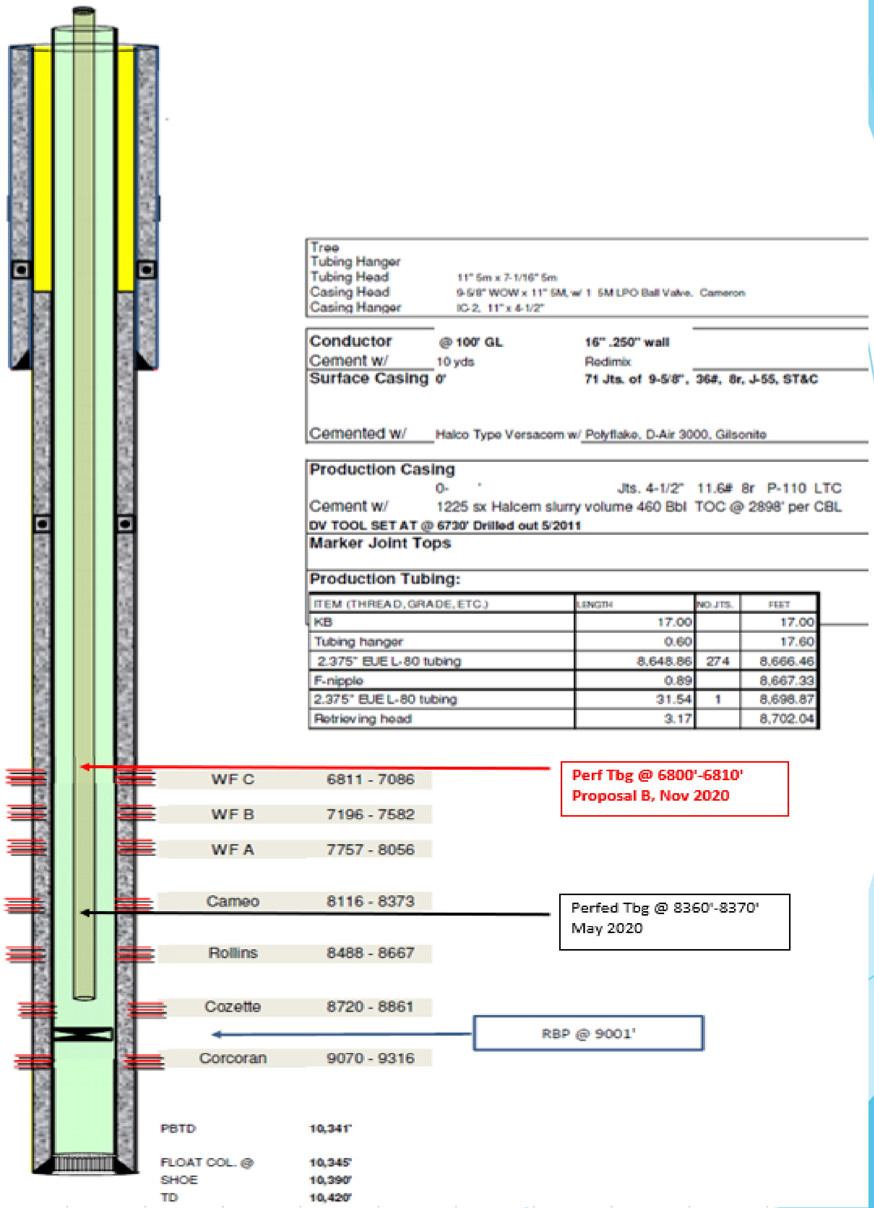
Recommendations:

1. Perforate enough holes for sufficient inflow.
2. If sanding is a potential problem:
   a) Consider a rathole if tail not clear.
   b) Consider setting the stop higher.
3. Tubing stops > collar stops.
4. Use wireline for better depth control and more robust fishing ability.
5. Execute all steps at once.

Case Study, Eh (the First)

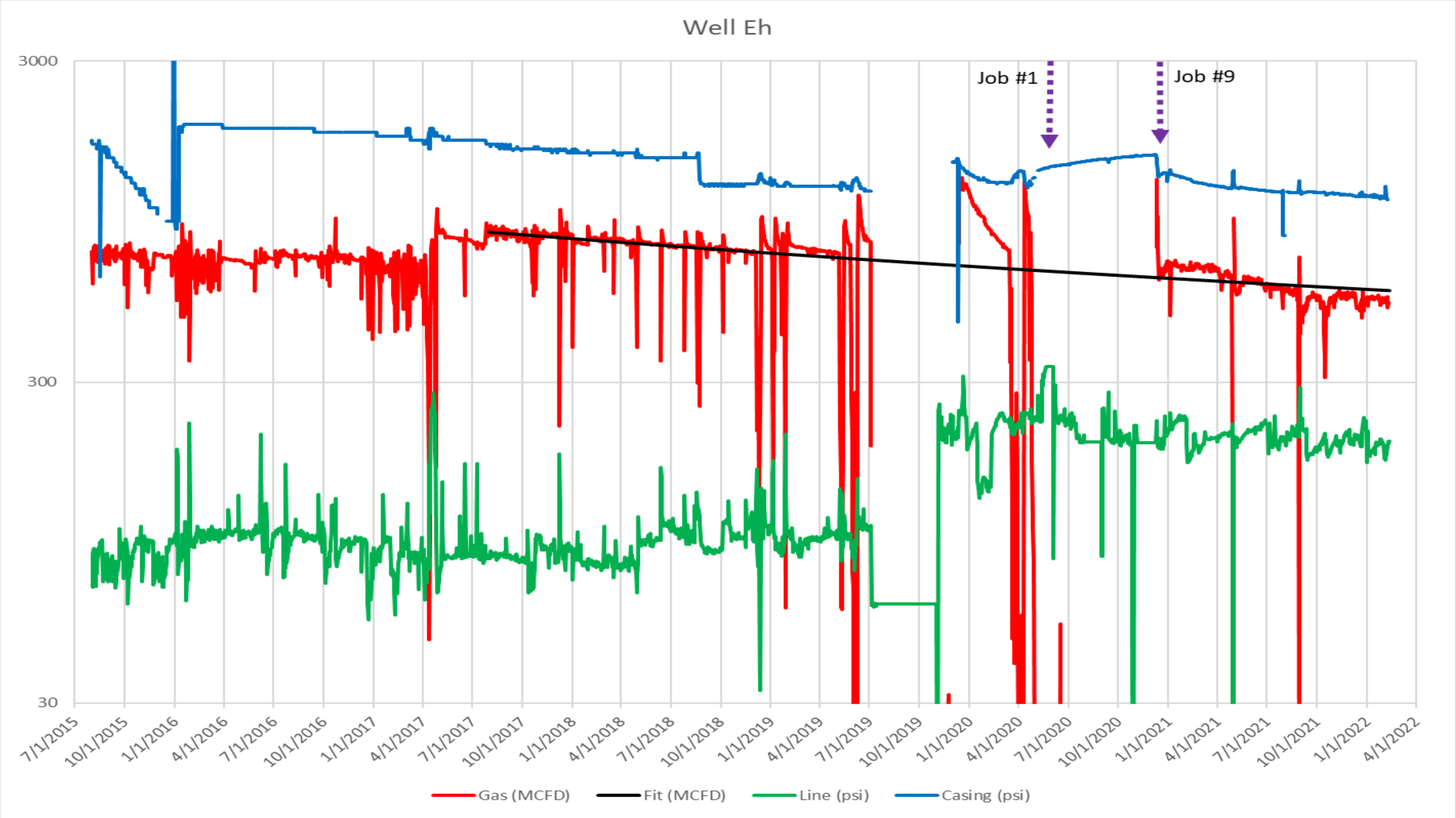
2010 vintage, reported 514 BBLS/MMCF

- Shut-in Q3 2019 due to low gas prices
- Compression removed
- RTP December 2019
- Loaded up March 2020
- Swabbed on April 2020
- Loaded up April 2020
- Initial tubing perforation job on 05/20/20 moved effective tail up 342' (92% to 76%) and was unsuccessful
- Second tubing perforation on 12/08/2020 moved effective tail up another 1549' (to 0%) and was successful

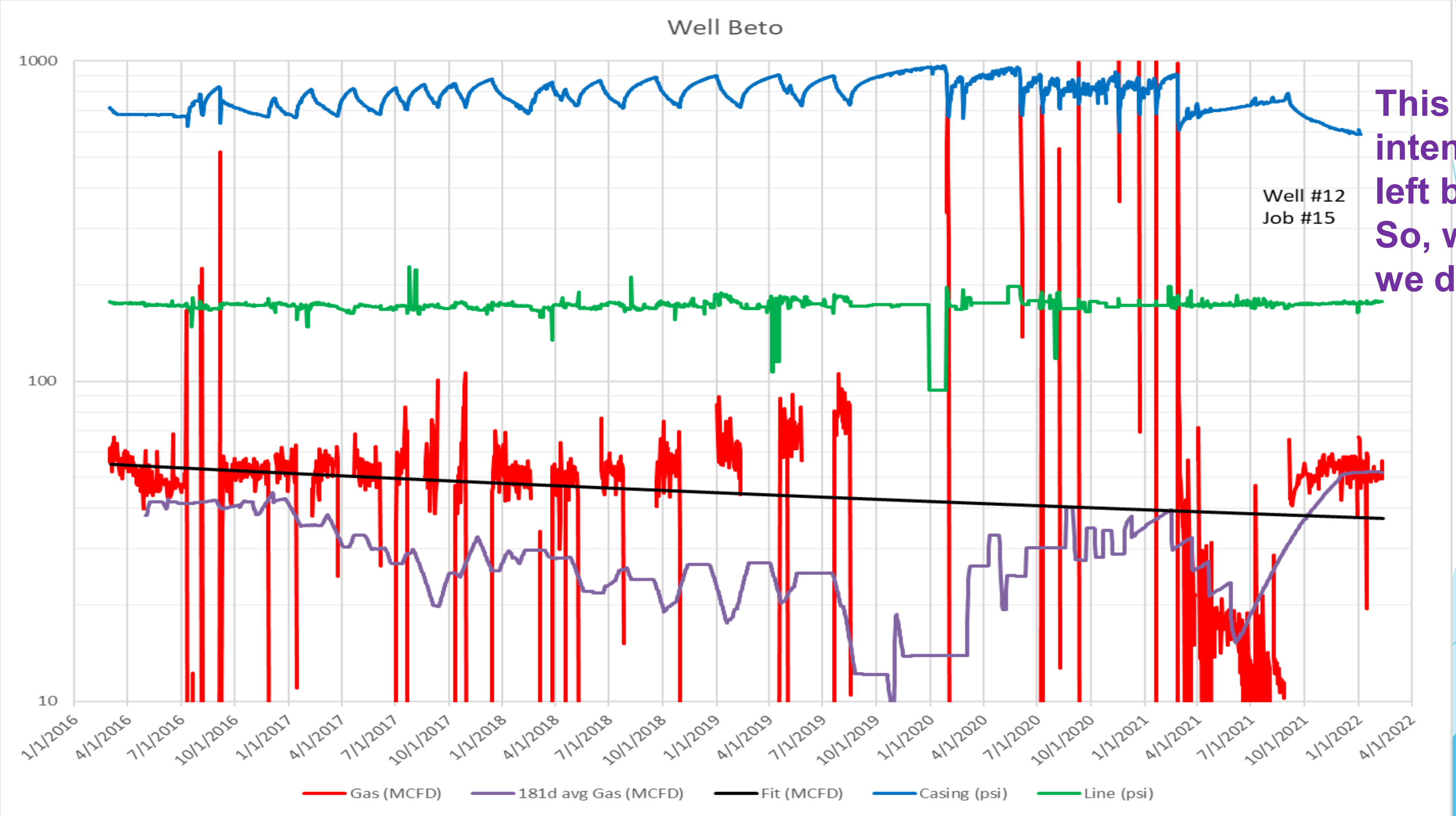


ITEM (THREAD, GRADE, ETC.)	LENGTH	NO. JTS.	FEET
KB	17.00		17.00
Tubing hanger	0.60		17.60
2.375" EUE L-80 tubing	8,648.86	274	8,666.46
F-nipple	0.89		8,667.33
2.375" EUE L-80 tubing	31.54	1	8,698.87
Retrieving head	3.17		8,702.04

Case Study, Eh (the First)



Case Study Beto

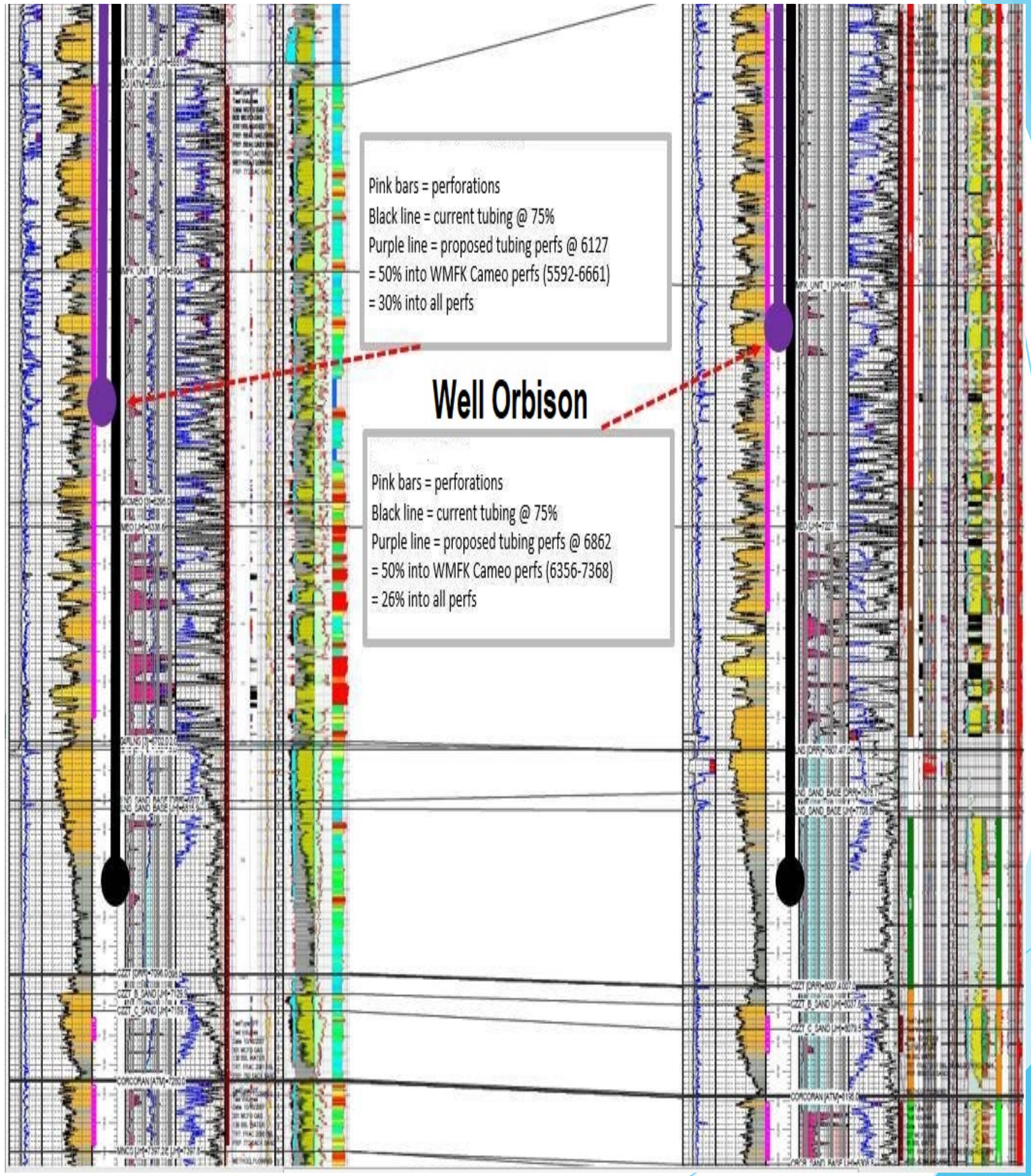


This arrow intentionally left blank! So, when did we do it?

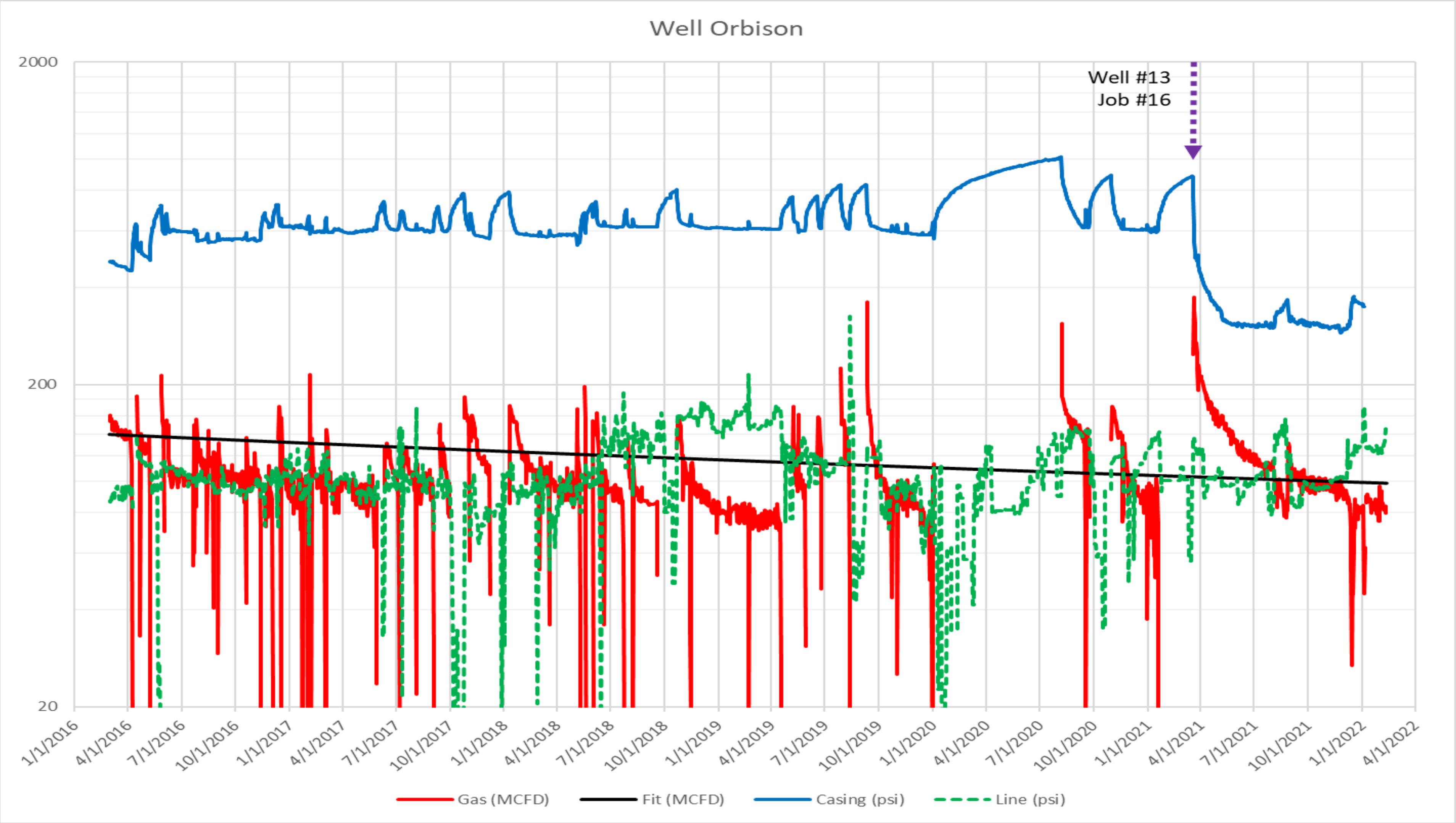
Case Study Orbison

2010 vintage, reported 153 BBLS/MMCF

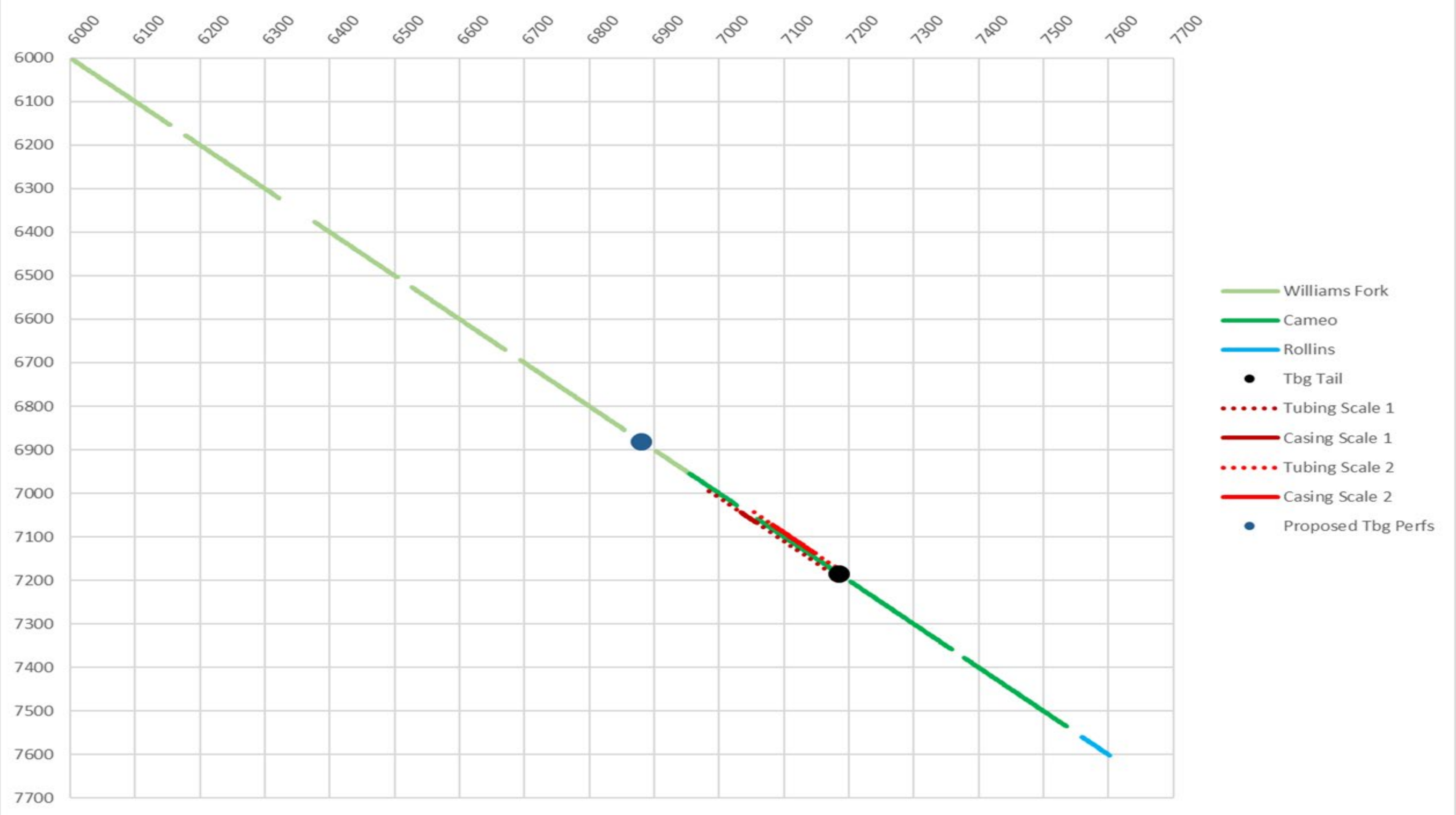
- Loading problems began 2016
- No production for 7 months of 2020
- Upper zones are basin bread and butter, lower zones are better sands → deplete faster → suspected tubing swamped
- Perforated tubing 50% into upper zone perforations, 506' below top completion perforations



Case Study Orbison



Case Study Scalia



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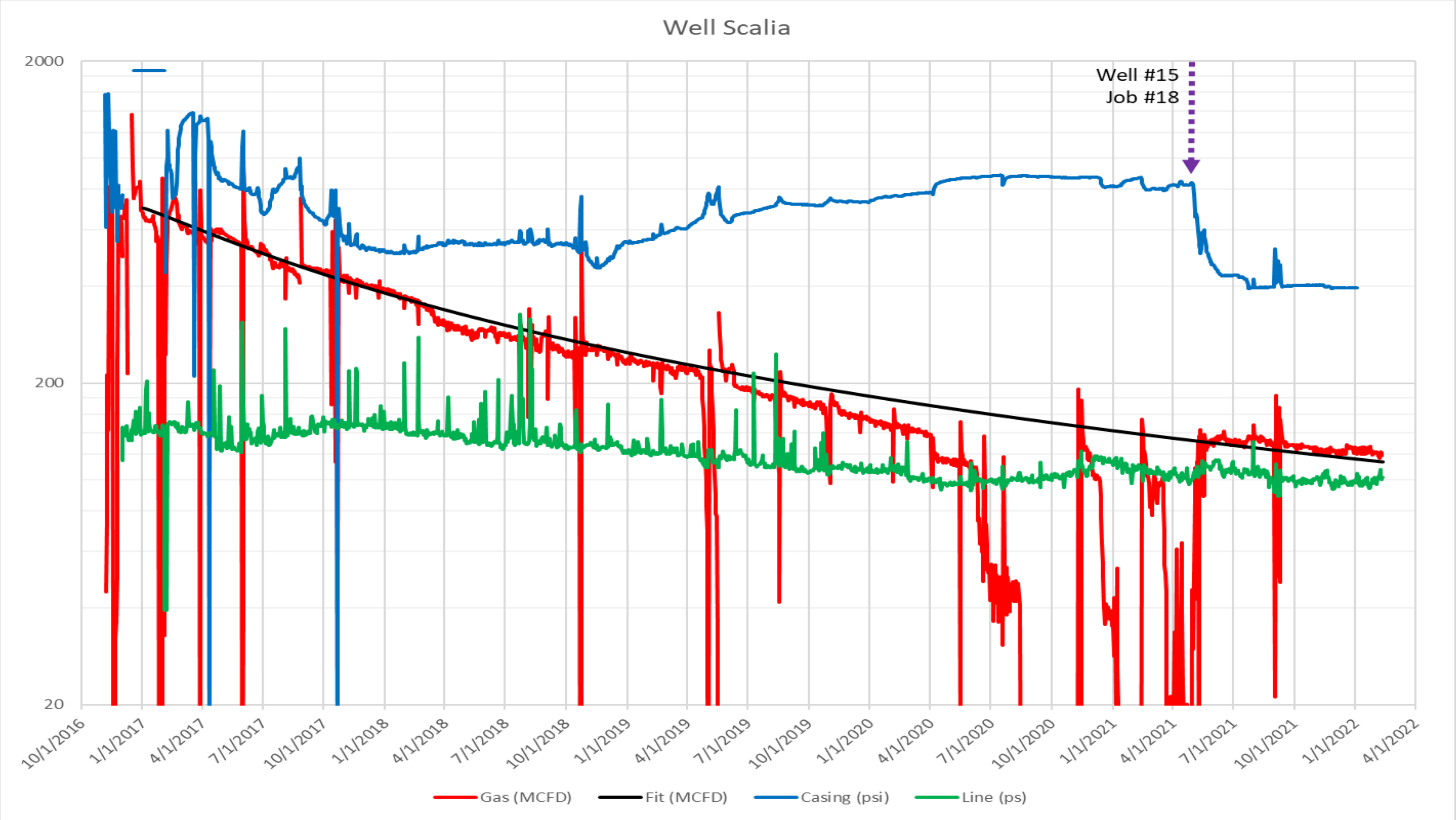
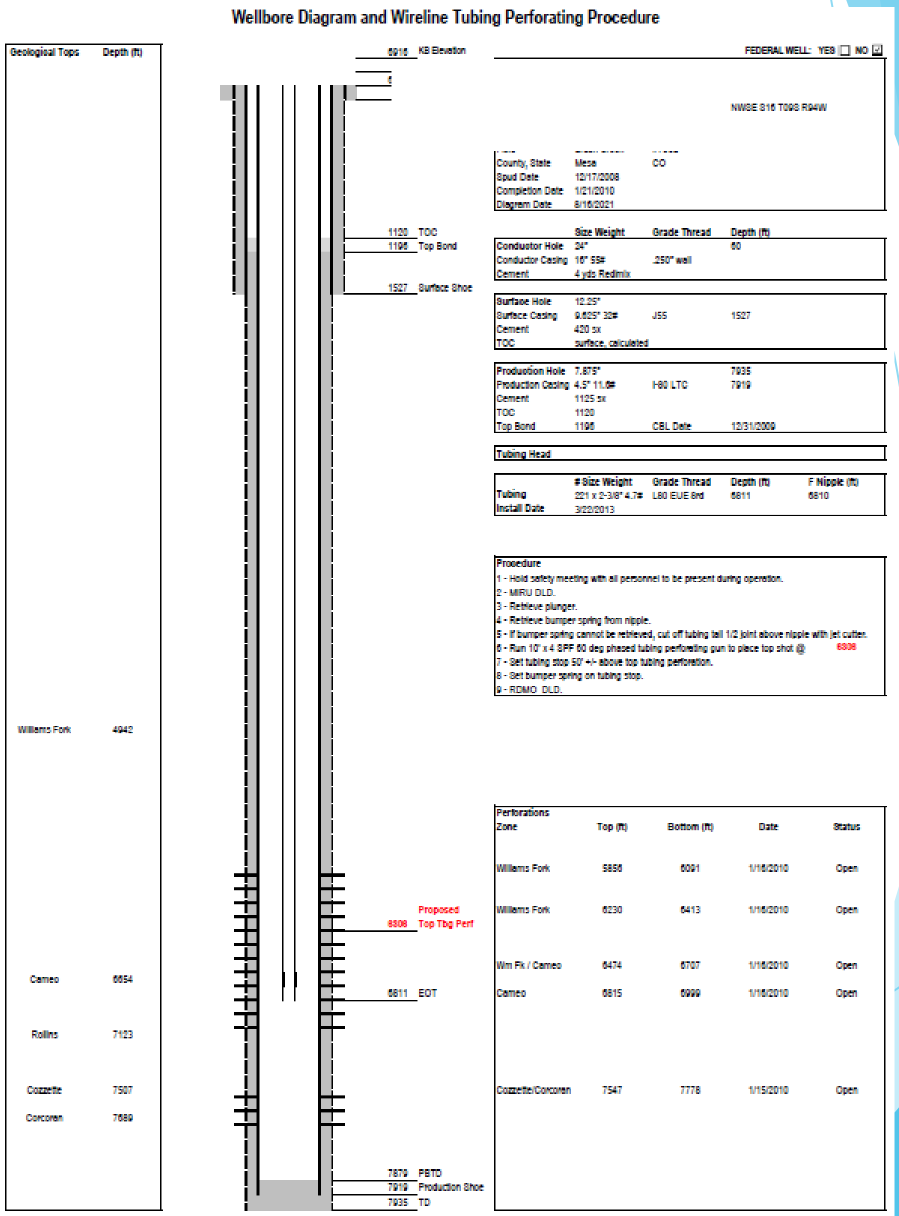


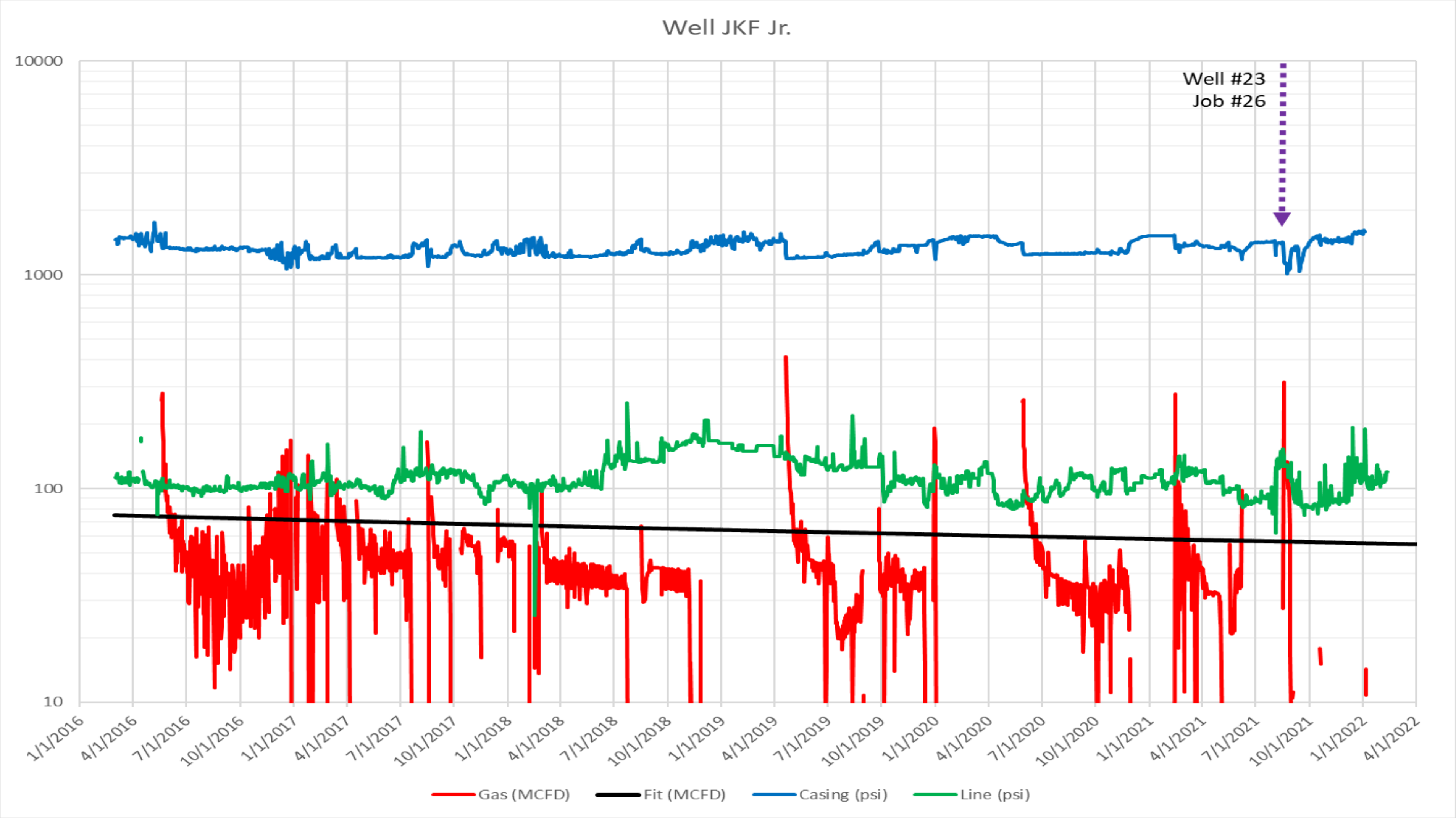
Case Study JFK Jr.

2010 vintage, reported “wet”

- The dog days began on day 1 and are not over
- Cumulative production of 364 MMCF, roughly 25% of an average well
- Water production known to be high but not quantified
- Perforated tubing 550’ below top completion perforation, unsuccessful
- Post-job water yield = 1 BBL / MCF
- Remaining options are pumping a foaming agent, swabbing, reperforating, and pumping cement



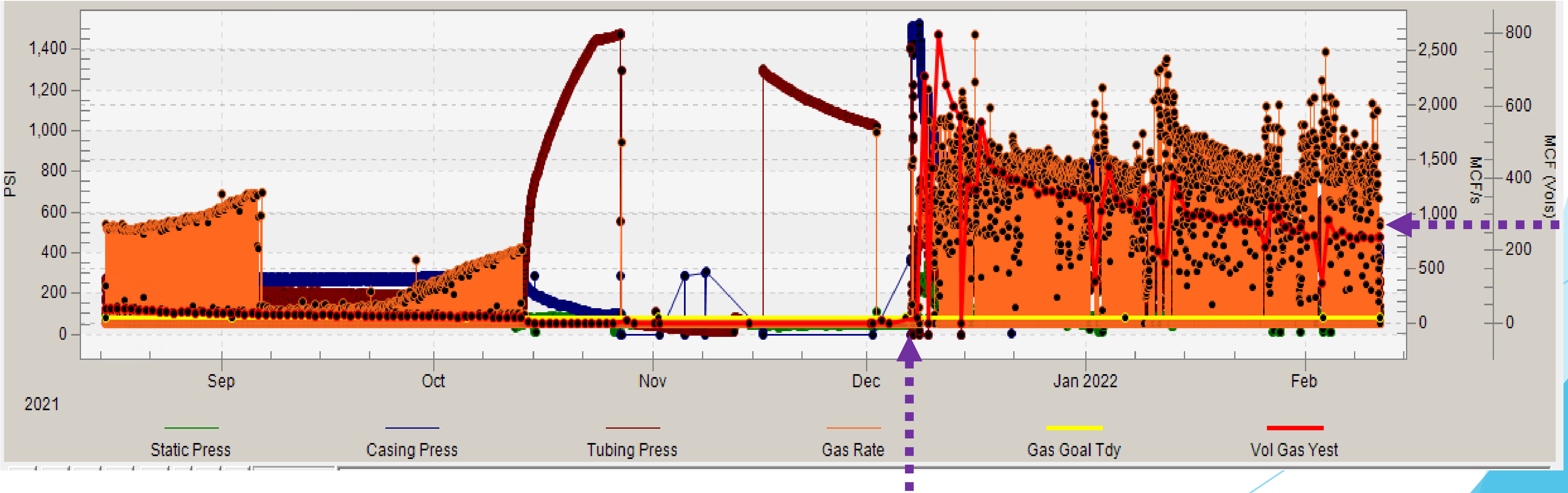
Case Study JFK Jr.



Case Study Vega

2008 vintage, perforations 6928'-8460', tubing tail @ 7591'

- Fell off trend in 2012, subpar well, production ceased in October 2021
- Slickline verified sand @ 7535' on 11/16/2021
- Jet cut tubing tail @ 7478' and set tubing stop on 12/08/2021
- Well flowed for several days, and plunger running since
- Results far exceeding projections



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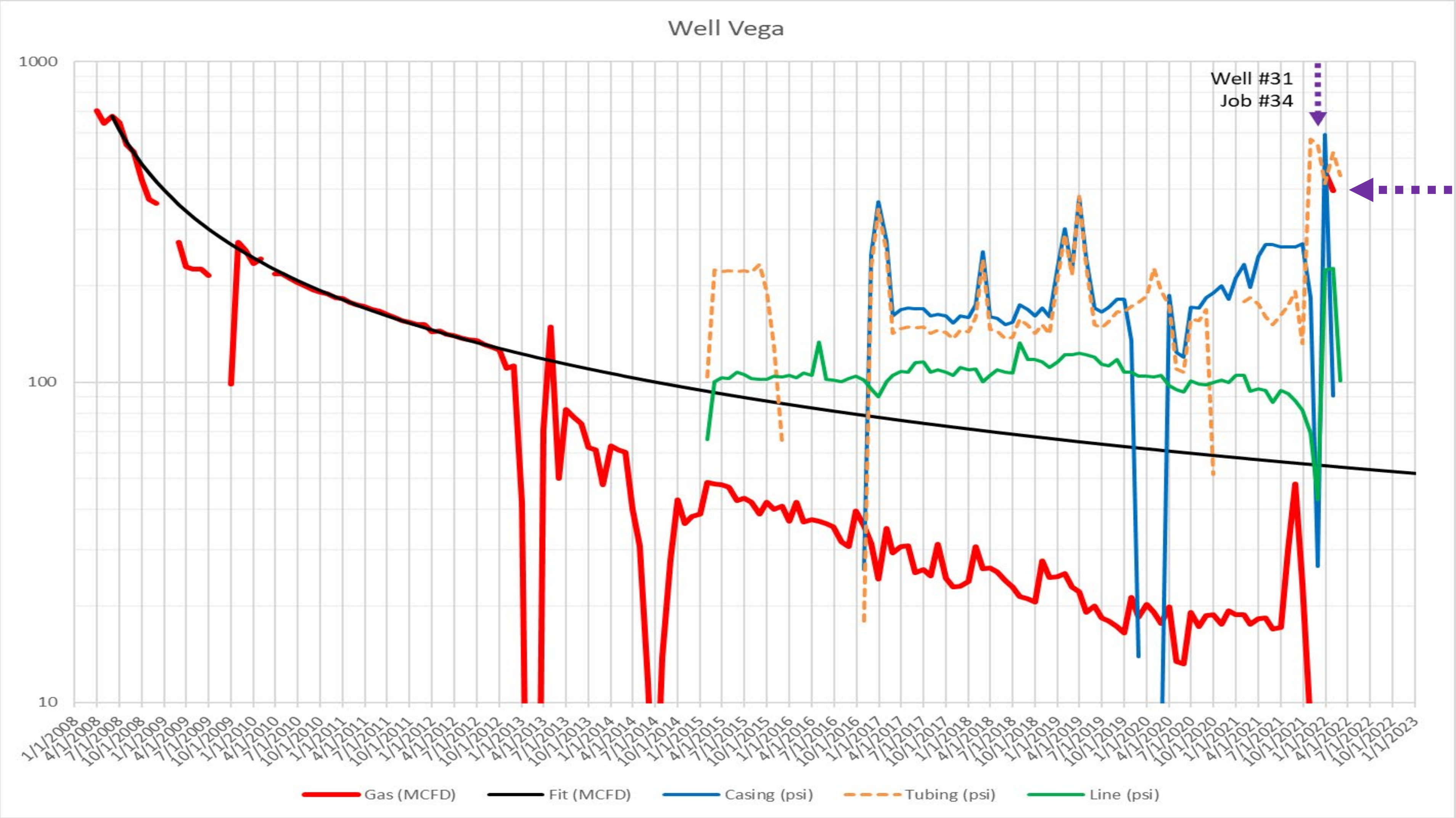
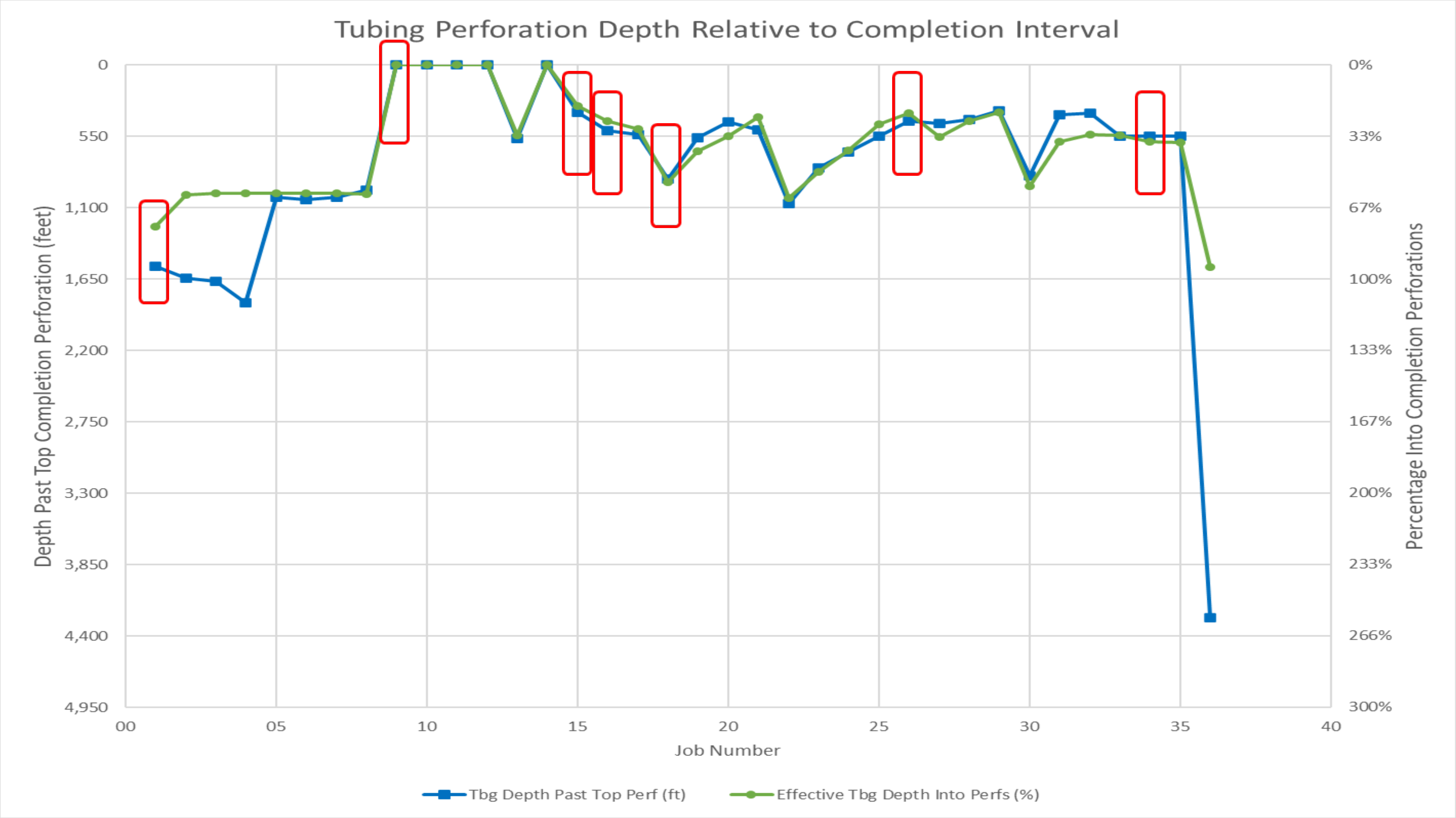
Case Study Vega



Well Table

Job #	Well Alias	Initial Problem	Formations	IP Date (yyyy.mm)	Top Perf (ft)	Btm Perf (ft)	Tbg Tail (ft)	Tbg Into Perfs (%)	Tbg Past Top Perf (ft)	LGR (BBLS / MMCF)	Top Tbg Perf / Cut (ft)	Tbg Into Perfs (%)	Tbg Past Top Perf (ft)	Incre-mental Rate (MCFD)	Do It Again?	Lookback Notes
01	Eh	high water, deep tubing	WmF, Cam, Rol, Coz, Cor	2010.06	6811	8861	8702	92%	1891	514	8360	76%	1549	0	No	still deep
02		high water, deep tubing	WmF, Cam, Coz, Cor	2019.07	7548	10256	9908	87%	2360	95	9190	61%	1642	329	Yes	good
03		Iles, deep tubing	WmF, Cam, Coz, Cor	2018.09	7504	10282	9981	89%	2477	77	9170	60%	1666	395	Yes	good
04		Iles, deep tubing	WmF, Cam, Coz, Cor	2018.09	7166	10224	9921	90%	2755	77	9000	60%	1834	-55	TBD	poor implementation, poss cleaning up prior to job
05		high water, low energy	WmF, Cam, Rol	2015.11	6210	7912	7461	74%	1251	88	7230	60%	1020	41	Yes	ok
06		high water, low energy	WmF, Cam, Rol	2016.01	6396	8118	7677	74%	1281	88	7430	60%	1034	56	No	still deep, req swab, tight spacing, comps flooded
07		high water, low energy	WmF, Cam, Rol	2016.01	6472	8168	7724	74%	1252	88	7490	60%	1018	19	No	still deep, req swab, tight spacing, comps flooded
08		deep tubing, low energy	Man, Dak	2008.11	5325	6931	6875	97%	1550	284	6290	60%	965	51	Yes	ok
09	Eh	high water, deep tubing	WmF, Cam, Rol, Coz, Cor	2010.06	6811	8861	8702	92%	1891	514	6811	0%	0	710	Yes	great, would 1/3 into perfs if could do over again
12		deep tubing, periodic flow	WmF, Cam	2011.01	6326	8126	8115	99%	1789	76	6326	0%	0	10	Yes	ok, established steady production
15	Beto	high water, low energy	WmF, Cam	2005.03	4243	6138	5845	85%	1602	153	4609	19%	366	-6	Yes	good, took several months to establish production
16	Orbison	Iles, deep tubing	WmF, Cam, Coz, Cor	2010.01	6356	8301	7822	75%	1466	54	6862	26%	506	85	Yes	great
17		Iles, deep tubing	WmF, Cam, Coz, Cor	2007.12	5592	7386	6950	76%	1358	69	6127	30%	535	88	Yes	great
18	Scalia	scale	WmF, Cam, Rol	2016.11	6004	7602	7181	74%	1177	55	6880	55%	876	112	Yes	great
22		scale	WmF, Cam, Rol	2018.04	6147	7866	7434	75%	1287	52	7216	62%	1069	122	Yes	great
23		susp high water, poss scale	WmF, Cam	2017.11	5990	7572	7163	74%	1173	59	6781	50%	791	17	Yes	ok
26	JFK Jr.	high water	WmF, Cam, Coz, Cor	2010.01	5856	7778	6811	50%	955	1000	6290	23%	434	TBD	No	loaded up after 14 days, high yield, move to top perf?
30		scale	WmF, Cam	2016.12	6044	7562	7174	74.4%	1130	57	6900	56%	856		Yes	good
34	Vega	tail plugged	WmF, Cam, Rol	2008.03	6928	8460	7591	43.3%	663	NA	7478	36%	550		Yes	great
36		tail plugged	Coz, Cor, Dak	1982.01	2590	7098	6879	95.1%	4289	23	6850	94%	4260		TBD	working

Evolution, so far …



Economic Impact:

Results of the first 32 jobs on 29 wells:

- **Production:** Average 100 MCFD / well 90d incremental gain & 2021 exit rate of 3.5 MMCFD
- **Reserves:** Total addition of 3.2 BCFE or 110 MMCFE/well
- **Cost:** $210,000 or $7,240 / well
- **Value (PV10%):** $5,074,000 or $175,000 / well

Summary, Findings, and Lessons Learned

- Developed a repeatable process to identify and prioritize candidates, perforate and/or cut tubing, and reestablish plunger lift to restore new life to old wells.
  - Acquire as much good data as reasonably possible.
  - Aim to understand well history, completions, geology, what is happening in the reservoir(s), in the well, and at surface, and ultimately the failure mechanism.
  - Determine upside with DCA and comparison to offsets and analogs.
  - Learn from failures, perform periodic lookbacks, and evolve.
  - **Focus on good decision making and be persistent.**
- This approach is <u>low cost, low risk, and high reward</u>.
- Benefits include reducing regulatory load, man hours, operating expense, and environmental impacts (e.g., reduction or elimination of venting).
- General approach for perforating (and cutting) tubing:
  - Immediately above known restrictions or problems.
  - Deeper in wells with recent production and higher pressures.
  - Higher in older, wetter, lower pressure wells with unknowns.

Acknowledgements/Thanks & Questions

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