Artificial Lift R&D Council

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Successfully Pumping the Curve with Thermoplastic Liners

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REVOLUTION RESOURCES

LIGHTNING Production Services

Introduction

Horizontal wells present significant challenges to operators:

- Pad drilling - may increase side loading conditions due to deviated and 'S' shaped wells.
- Artificial lift is usually required as production rates decline after initial completion.
- Rod pumping is a common lift method as it is easy to operate and cost effective.
- Pumping from the curve may be required to maintain commercial production rates.
- Tubing leaks, rod parts and pump failures caused by excessive friction are the most common failure types when pumping in the curve.

Pumping the Curve

- Traditional approach: positioning pump in vertical section
  - Gas interference – gas locking
  - Stuck pump
  - Wells pump off quicker
  - Production decline
  - Advantage: not pumping through deviation
- Lower the pump in the curve
  - Decrease PBHP, increase drawdown = increase production
  - Casing acts like horizontal separator
  - Decrease in gas interference
  - Boost in production in the months after lowering the pump in the curve
  - Increased failures due to deviation

Mechanical Friction & Wear

- Constant contact during cyclic operation between rods, couplings and pump with the tubing creates frictional wear
- Frictional wear results in hole in tubing failures, rod parts and pump failures
- Frictional wear is proportional to the degree of deviation, dog leg severity or side loading
- Drag forces depend on the normal force and the friction coefficient between the rods and the tubing wall
- Wear is enhanced by the presence of corrosion
- Tubing failures are typically the most expensive interventions in a rod pumped operation

Potential Solutions for Frictional Wear

- **Molded rod guides** - used in sacrificial fashion – increase friction in system with coefficient of friction = 0.3 – increase in gearbox loading and surface requirements
- **Roller rod guides** – can come apart due to high loads, wear and corrosion & require fishing job
- **Rod/tubing rotators** - distribute wear along the circumference instead of all on one side
- **Tubing anchors** – put production tubing in tension
- **Spray metal rod couplings** – corrosion resistant but can cause accelerated wear on tubing
- **Continuous rod string:** designed to distribute side load along the entire length of the rod
- **Thermoplastic liners (TPL):** reduce drag forces & mechanical friction with coefficient of friction = 0.1 – reduce gearbox loading, increase production & reduced rod on tubing wear

Thermoplastic Liners

▶ WHAT IS LINED TUBING?

Thermoplastic liner extruded into pipe profile and mechanically bonded to tubing

Various resins used to match wellbore conditions

Can be bonded to new or used tubing

▶ LINED TUBING BENEFITS:

Prevents rod on tubing contact, eliminating steel on steel wear – increased run times

Protects tubing from corrosive reservoir fluids

Eliminates need for rod guides

Lower coefficient of friction than bare steel – reduces rod and surface loading

LPS Thermoplastic Liner Specifications

GENERAL SPECIFICATIONS					
PRODUCT	MAX TEMP.	DIMENSIONS	H_2S	CO_2	COST
LF60	140° F	2 3/8" - 4 1/2"	2%	10%	$
LF99	210° F	2 3/8" - 4 1/2"	2%	10%	$$
LF115	275° F	2 3/8" - 4 1/2"	5%	20%	$$
LF170	340° F	2 3/8" - 4 1/2"	5%	20%	$$$$

Parameter Comparison: Conventional vs. TPL vs. Rod Guides Using Well #1 Data

Type	Gearbox Loading (%)	PPRL (lbs)	Electrical ($)	Polished Rod HP (hp)	Max Rod Loading (%)	Max Side Load (lbs/25ft)	Downhole Stroke (inches)
Bare conventional rods	110%	34709	1868	42.4	106%	664	176.1
Conventional rod with rod guides	119%	36952	2135	49.4	113%	705	168.8
Conventional with TPL	90%	30796	1459	31	92%	595	188.4

- Decreased gearbox loading = smaller surface requirements
- Decreased PPRL
- Electrical Savings
- Decreased Polished rod horsepower = less power needed to lift
- Decreased Max Rod Loading = longer rod life
- Decreased Max side load = less wear & reduced failures
- Increased downhole stroke = more production

Normal Force, Friction Coefficient and Drag Force Comparison with and without TPL

Looking at depth 6644ft for below case study Well #1 where inclination angle is 48.43° and azimuth angle is 180.96° resulting in a DLS of 15.26°/100ft with 421 feet of rods below the bend

Normal Force

$$F_N = L_r \cdot W_r(1 - 0.127 \cdot \gamma_F)\sin\alpha$$

L_r = *length of segment*

W_r = *weight per foot*

γ_F = *fluid specific gravity*

α = *inclination angle*

Drag Force

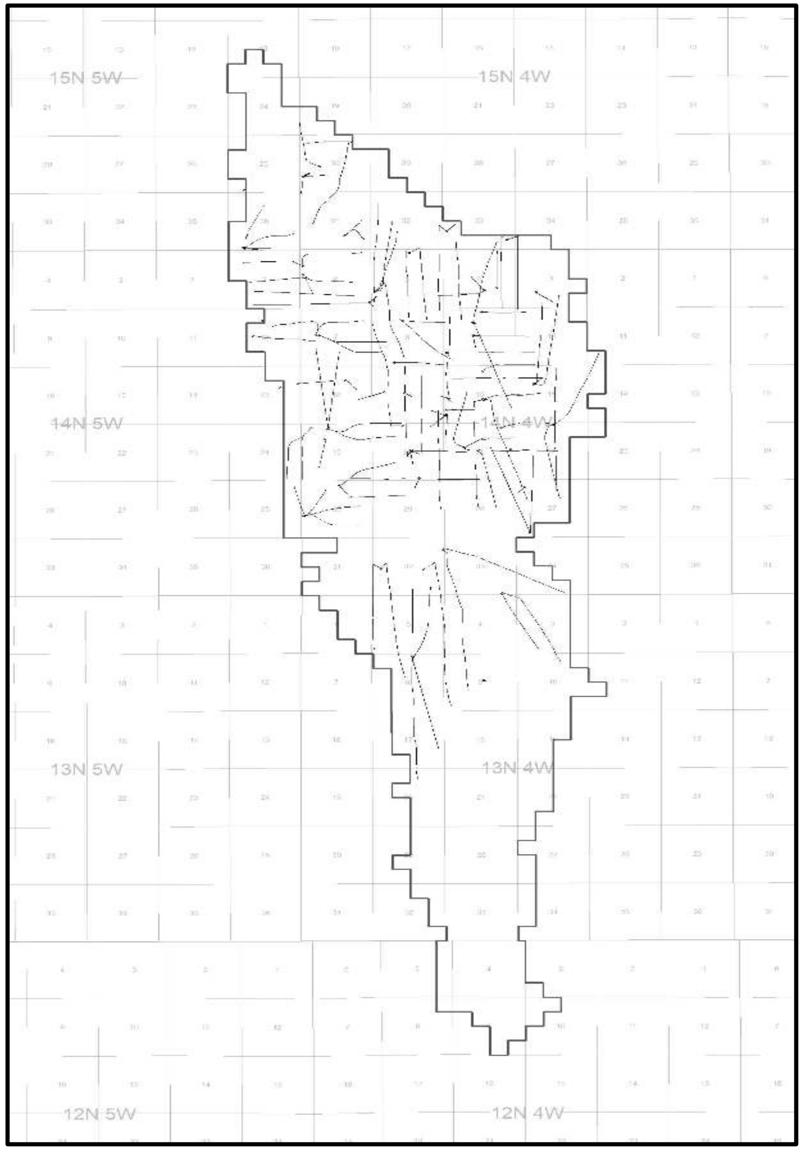
$$F_D = -f_{friction} \cdot |F_N|$$

$f_{friction}$ = friction coefficient

Drag force is reduced by ½ when using TPL from bare conventional rods and 3/5 from rod guides

Type	L (ft)	W_r (lb/ft)	$W_{segment}$ (lb)	F_N (lbf)	$f_{friction}$	F_D (lbf)
Bare Conventional rods	25	2.224	55.6	36.31	0.2	-7.26
Conventional rod with rod guides	25	2.224	55.6	36.31	0.25	-9.08
Conventional with TPL	25	2.224	55.6	36.31	0.1	-3.63

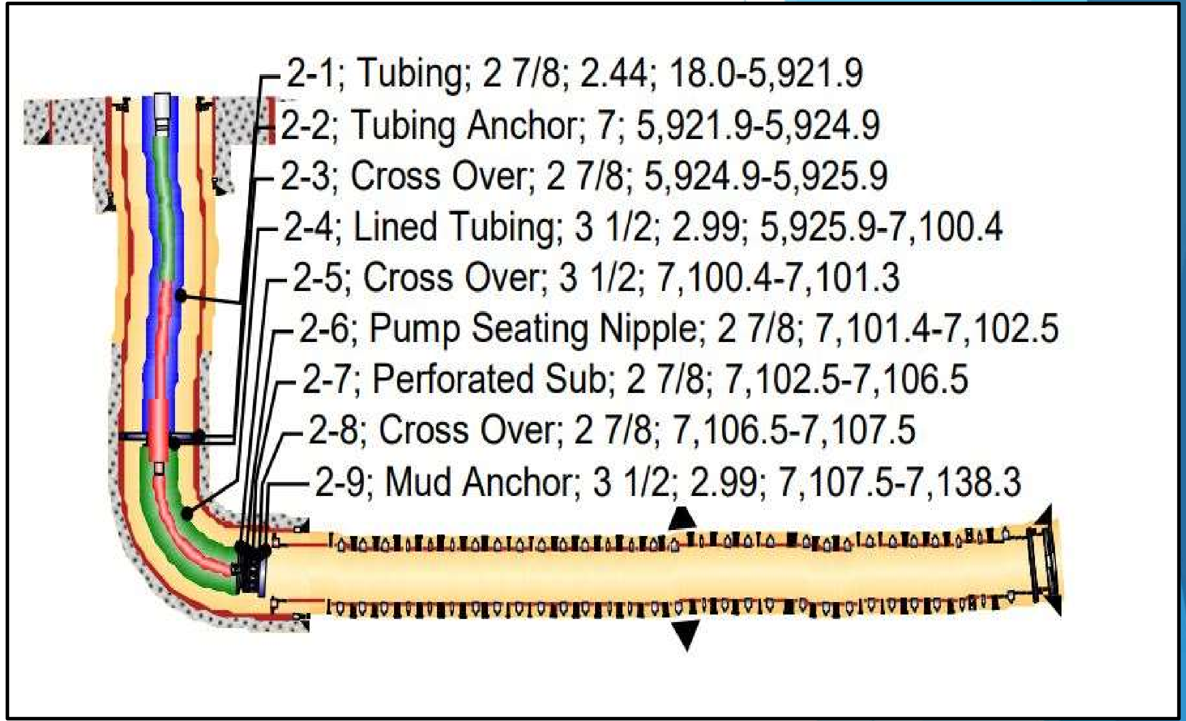
Revolution Case Study – Field Background



- Field Name: West Edmond Hunton Lime Unit (WEHLU)
- Initially drilled vertically in the 1940's
- Began drilling horizontally in 2005
- Since then, over 80 wells drilled horizontally
- Initially produced on ESP then converted to rod pumping after about 1.5 years to
- Field has low bottomhole pressure around 500 psi
- Unable to pump at KOP efficiently

Revolution Case Study – General Set Up

- Wells are 6,700ft in TVD and pumping at 7,200ft in MD with 1-1/4" fiberglass rods and 1.5-1.75" insert pumps at 80-90° inclination
- Pump is set in the curve using LF115 liners
- Wells converted from ESP to rod lift with TPL because of:
  - Repeated ESP failures
  - Tubing failures and rod parts
  - Surface requirement limits



SURVEY DATA WELL #1

MD (ftKB)	Incl (°)	Azm (°)	TVD (ftKB)	VS (ft)	NS (ft)	EW (ft)	DLS (°/100ft)	Build (°/100ft)	Turn (°/100ft)	Unwrap Displace(ft)
6,993.00	82.98	179.99	6,686.37	225.73	-190.49	-402.02	6.42	6.36	-0.91	1,083.27
7,088.00	85.72	180.39	6,695.72	319.00	-285.02	-402.34	2.91	2.88	0.42	1,177.80
7,183.00	88.31	180.47	6,700.67	414.45	-379.88	-403.05	2.73	2.73	0.08	1,272.66

Well #1: Wellbore DLS & OPEX

"Predictive Comparison"

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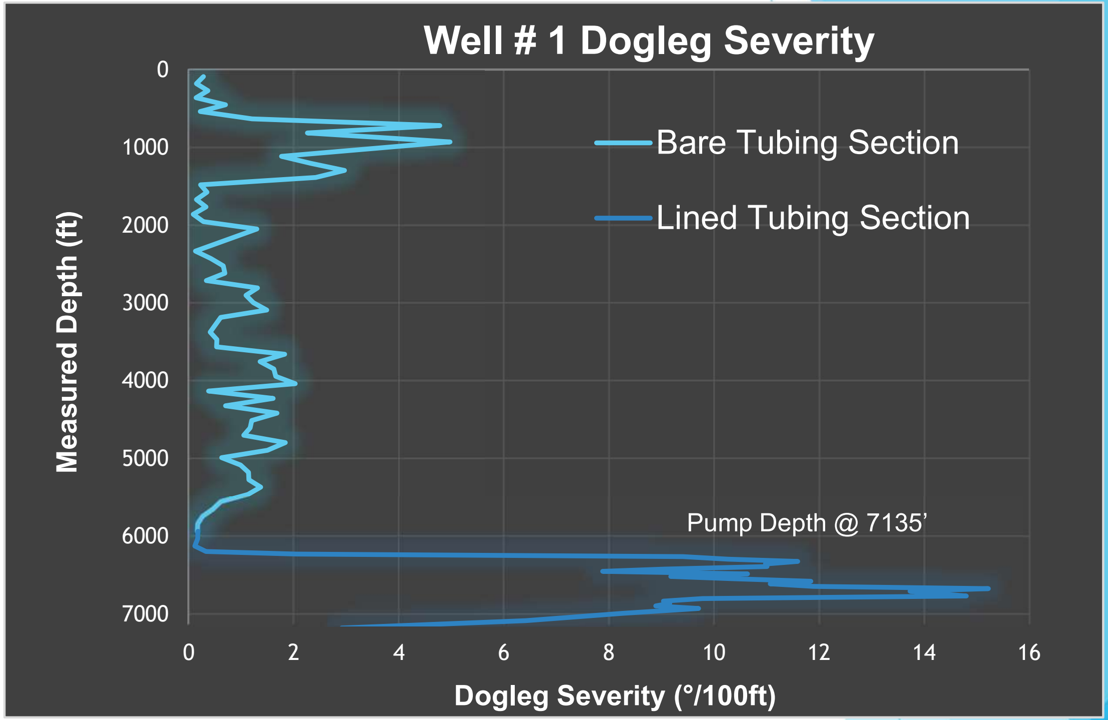
Well # 1 Comparison: TPL vs. Rod Guides		
	Liner	**Rod Guides**
PPRL	31235	33025
MPRL	5859	5218
SPM	5.85	5.87
Downhole stroke	157.8	139.3
GB Loading	93.3	110.7
PU Loading	73	77
Monthly Electric	2012	2273
Production*	330	291
Peak Rod Loading	74	80



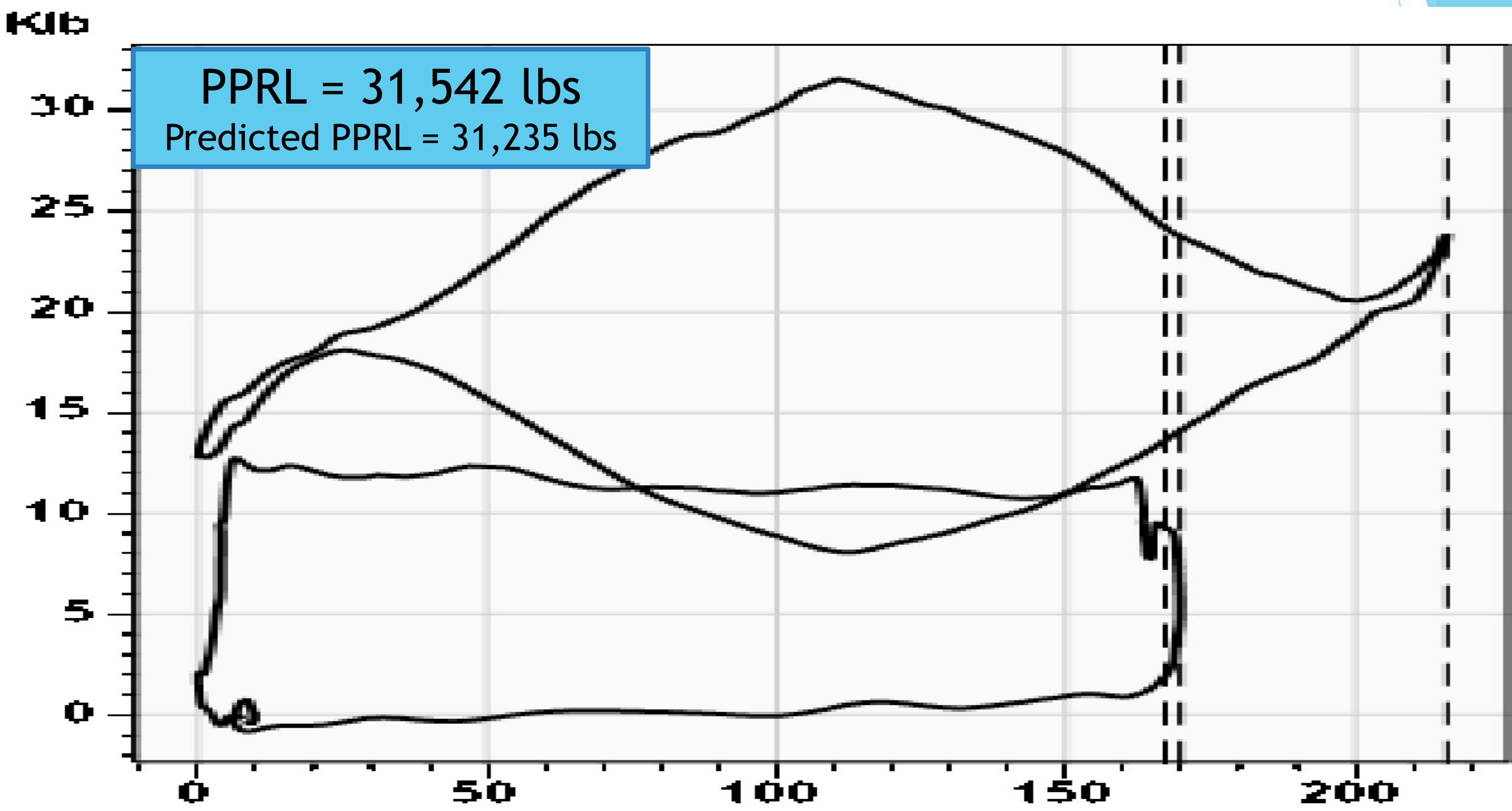
(*) From Dr. Gabor Takacs' "Sucker Rod Pumping Manual":

$$PD = 0.1166 \cdot d^2 \cdot S_p \cdot SPM$$

Where PD is the inferred production in bpd, S_p is the downhole plunger stroke, d is the plunger size in inches and SPM is the pumping speed in strokes/minute

- Downhole stroke increased by 18.5 inches
- PPRL decreased by 1790lbs – MPRL increased by 641lbs
- Gearbox loading decreased by 16%
- PU loading decreased by 5%
- Peak Rod loading decreased by 7.5%
- Electrical Savings 11.5% annually
- Increase in production from 291 bpd to 330 bpd = 13% increase

Well #1 – Pump Card



Well #1 – Production Analysis

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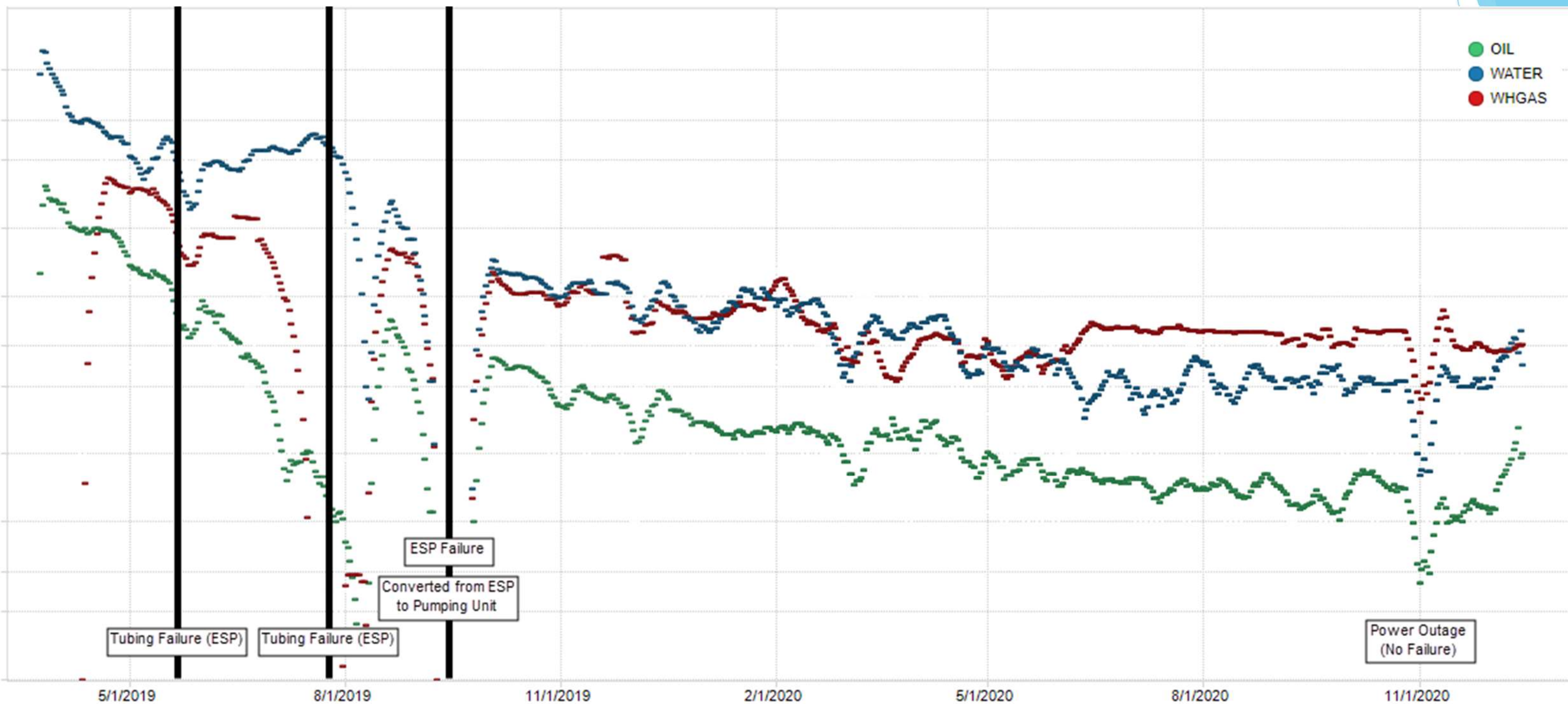
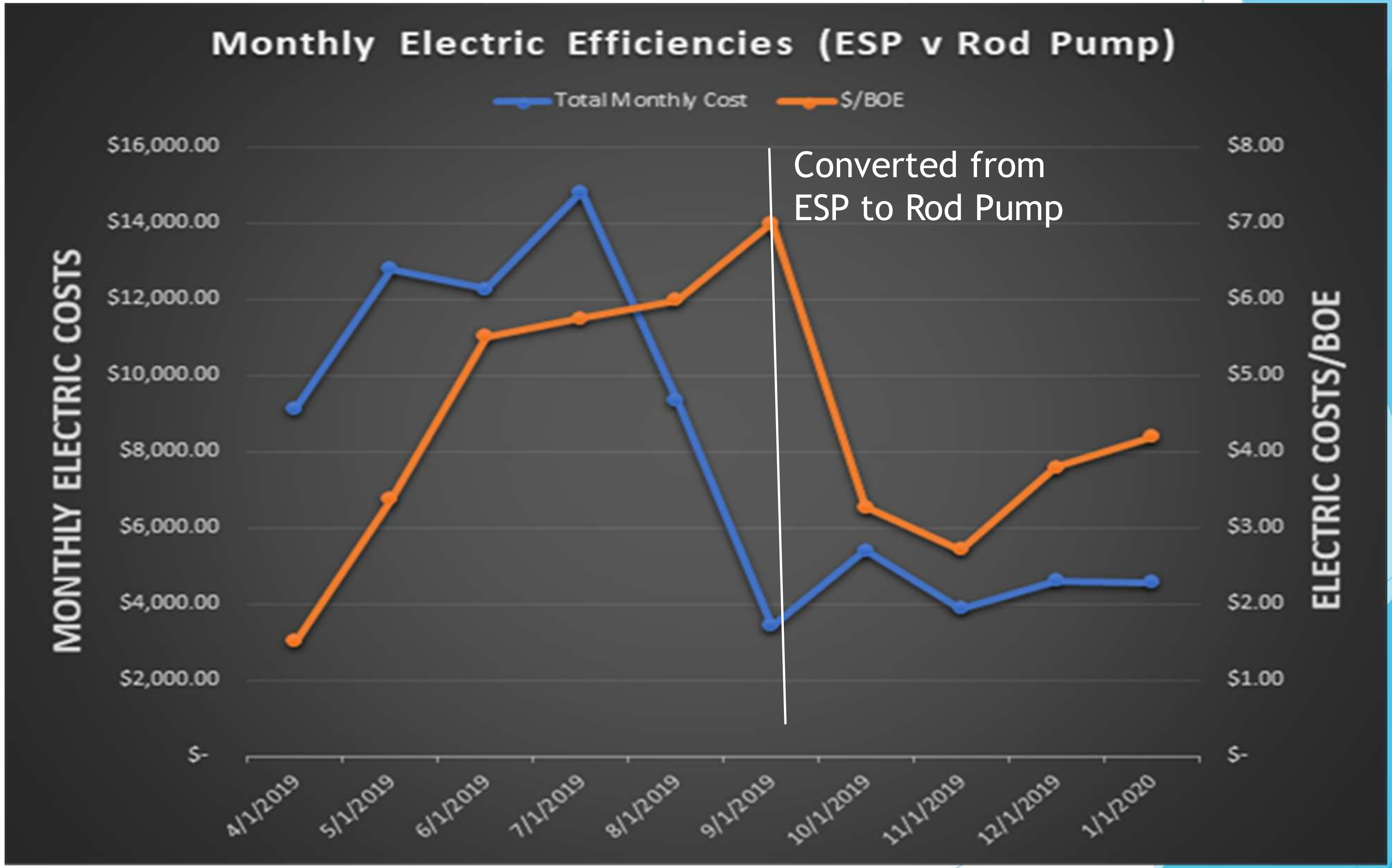


Production Maintained and Stabilized.
ESP failures on average cost $60,000.
Failure rate improved from 3 failures in 8 months to no failure with current runtime of over 15.5 months – this equal to savings of $348,000 so far!

Well #1 Electrical Cost Savings from ESP to Rod Pump

Electrical Cost cut in more than half after conversion = 62% savings

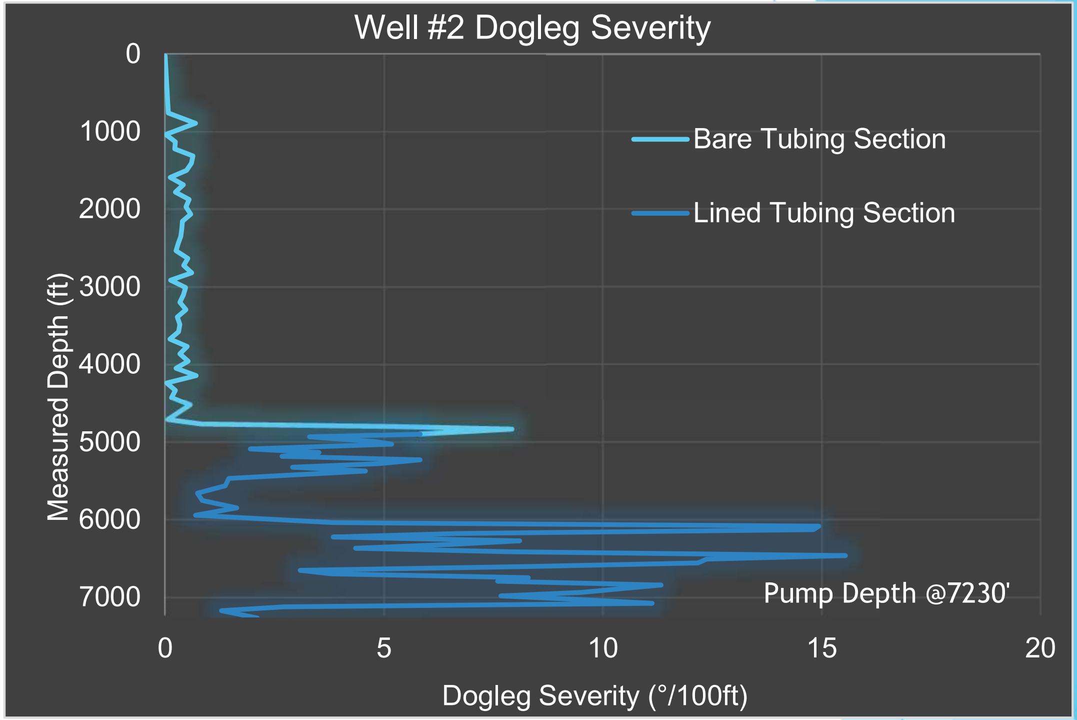
Annual Consumption Savings from $140,088 to $52,464



Well #2: Wellbore DLS & OPEX

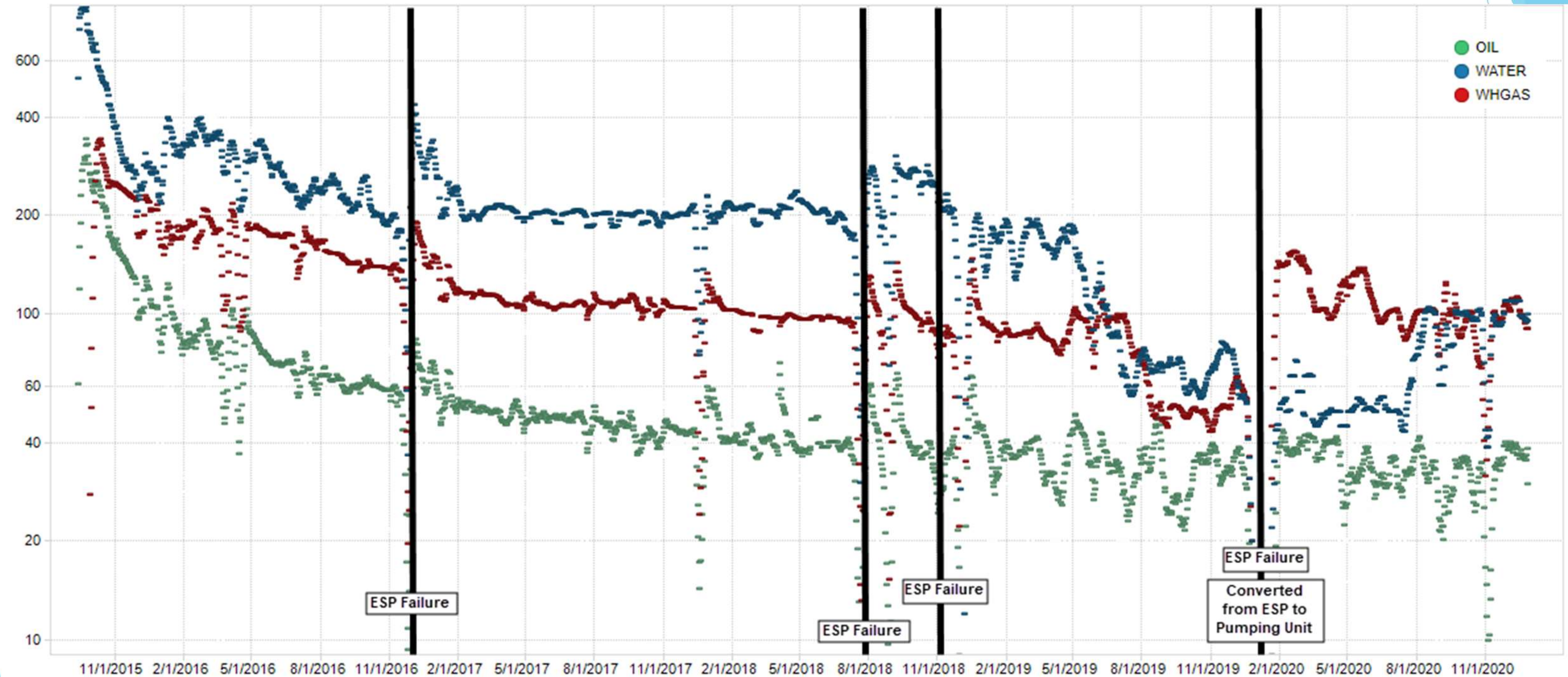
"Predictive Comparison"

Well # 2 Comparison: TPL vs. Rod Guides		
	Liner	Rod Guides
PPRL	24233	25218
MPRL	6814	5856
SPM	6.47	6.52
Downhole stroke	131.7	121.4
GB Loading	85	91
PU Loading	79	83
Monthly Electric	1137	1283
Production*	224	207
Peak Rod Loading	57	62



- Downhole stroke increased by 10.3 inches
- PPRL decreased by 985lbs – MPRL increased by 958lbs
- Gearbox loading decreased by 7%
- PU loading decreased by 5%
- Peak rod loading decreased by 8%
- Electrical savings 11% annually
- Increase in production from 207 bpd to 224 bpd = 8% increase

Well #2 – Production Analysis



Gas production increased after conversion due to consistent production. (ESP not cycling)
Failure rate improved from 2 failures/year to zero failures after converting for the past 11.5 months meaning over $115,000 of savings so far.

Well #3: Wellbore DLS & OPEX

"Predictive Comparison"

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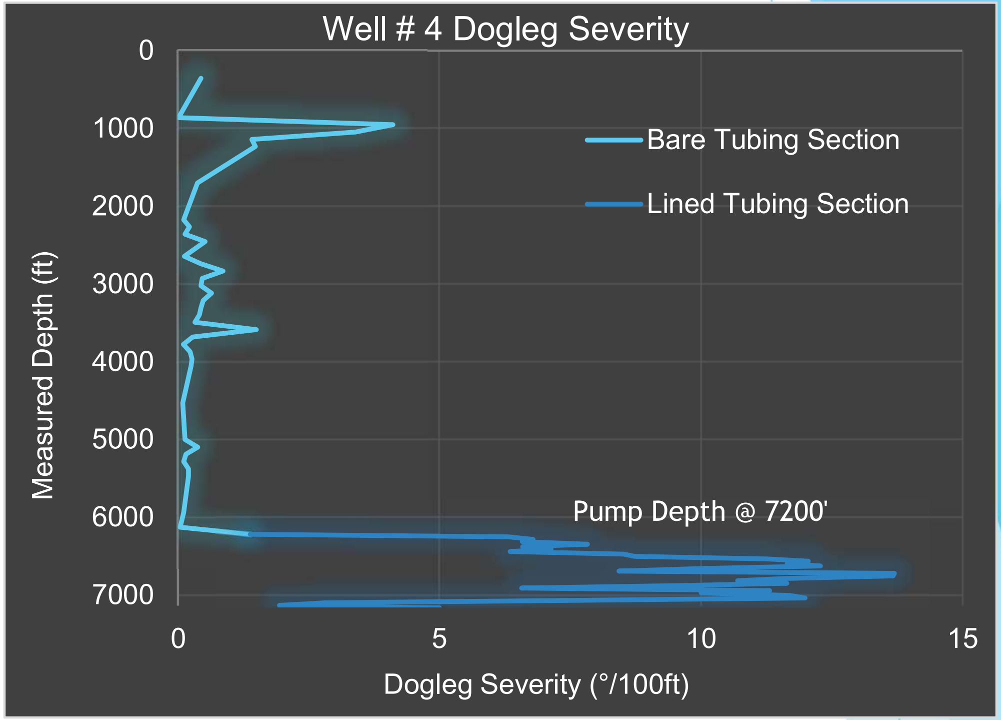
Well # 4 Comparison: TPL vs. Rod Guides		
	Liner	Rod Guides
PPRL	21023	21918
MPRL	8166	7364
SPM	5	5
Downhole stroke	99.7	96.1
GB Loading	77	81.7
PU Loading	69	72
Monthly Electric	620	675
Production*	131	126
Peak Rod Loading	66.5	73.4



- Downhole stroke increased by 3.6 inches
- PPRL decreased by 895lbs – MPRL increased by 802lbs
- Gearbox loading decreased by 6%
- PU loading decreased by 4%
- Peak Rod loading decreased by 9%
- Electrical Savings 3% annually
- Increase in production from 126 bpd to 131 bpd = 4% increase

Well #3 – Production Analysis

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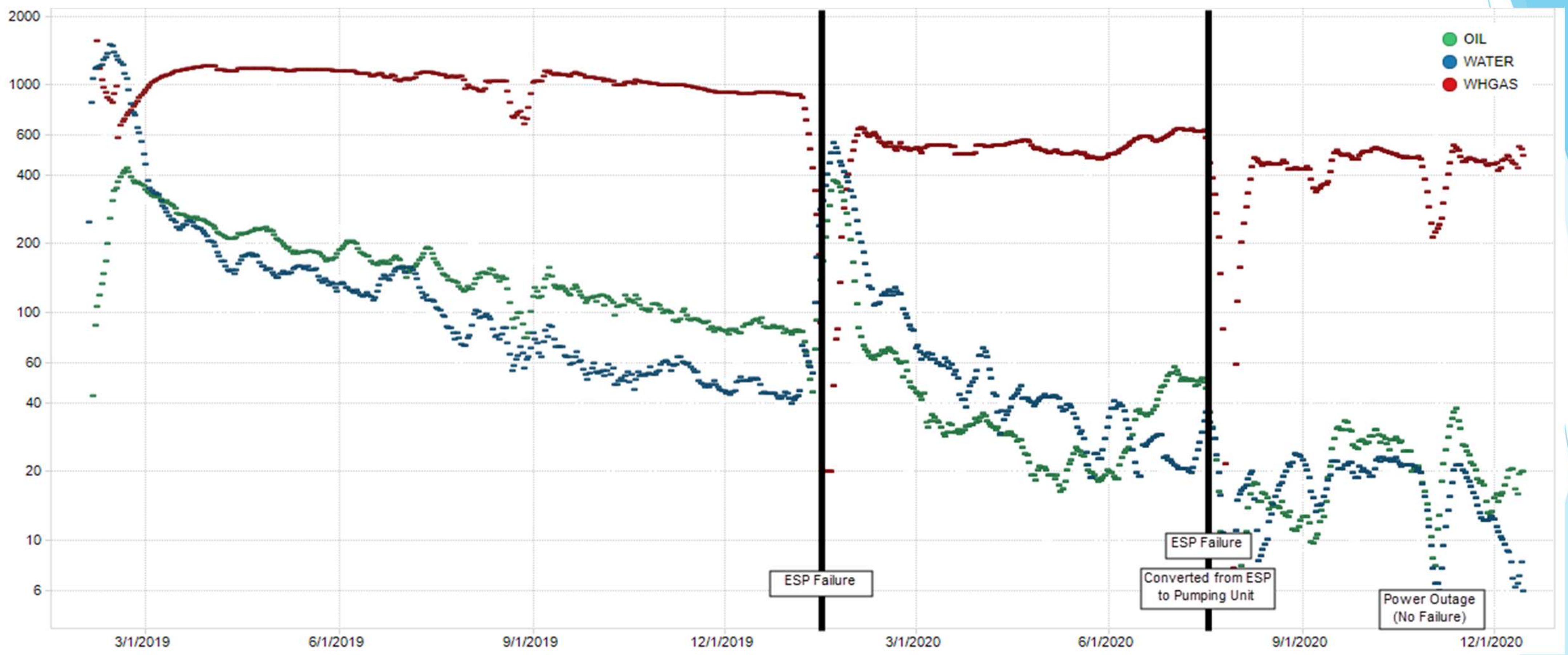

Production Maintained – match wellbore decline expected. Improvement in failure reduction from 2 failures/year to no failures with current runtime of 5.25 months.

Well #4 – Production Analysis

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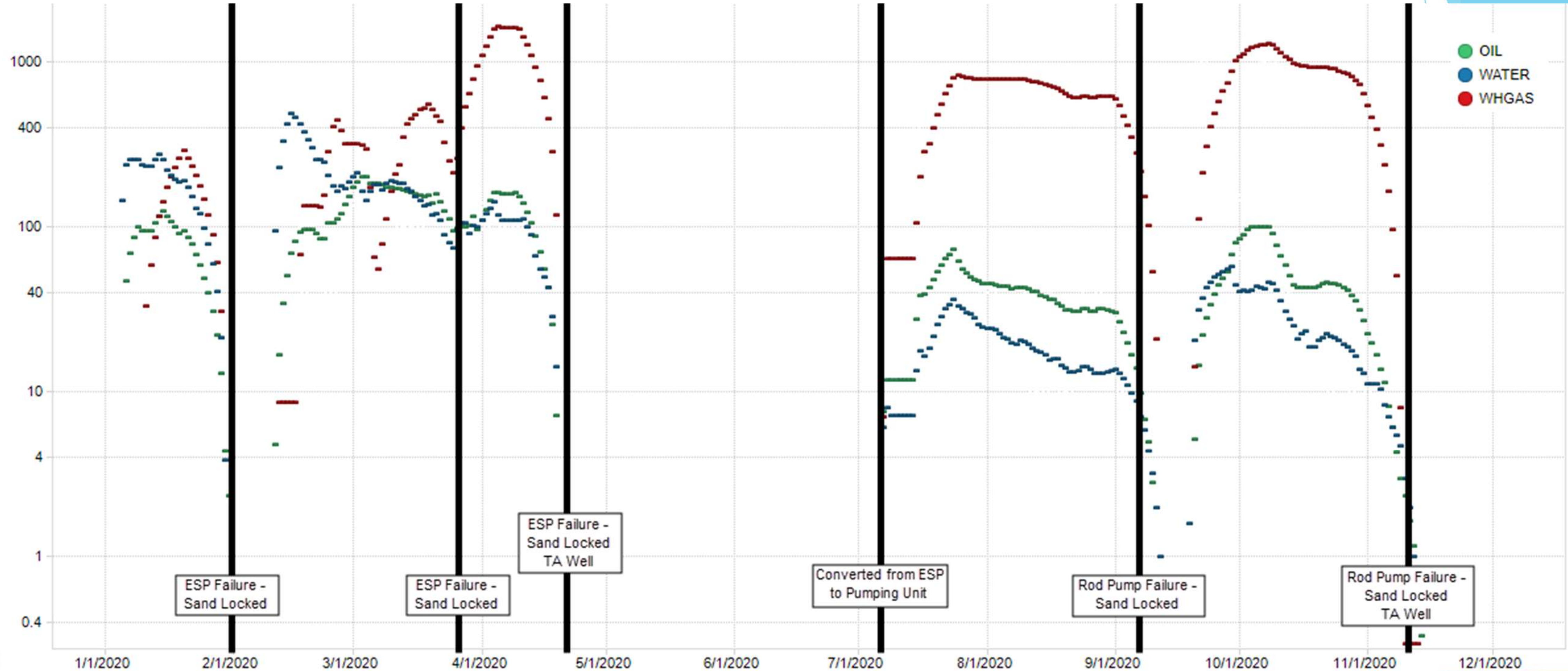

This well had severe issues with solids and intermittent production with failure rate decreasing by half from 4 failures in 5 months to 2 failures in 5.5 months due to sand locking.

Cost Overall Comparison

Category	Well Count	Failures/Year	Investment / Well (after KOP)
Total Liner	20	0.68	$9,175
Rod Guides	19	1.01	$2,219

Category	Avg Repair Cost	Failures Saved/Year	Savings comparing TPL to rod guides
Tubing Leak	$16,500	0.33	$5,445/year/well
Rod / Pump Part	$12,000	0.33	$3,960/year/well

- 33 % reduction in failures when comparing rod guides to thermoplastic liners = totaling in an average of $4,700 savings/year/well
- When converted over the entire field, this equals savings of $89,300/year

Conclusions: Benefits of Using TPL in the Curve

Economic Solution:	Maximize Reservoir Drawdown	Increase Production	Quick Payout
Reduction in Friction:	Reduces Overall System Loading	Decreasing Failure Rates & OPEX	Increases Life of Equipment

Installing thermoplastic liners reduces failure rates and increases life of equipment while pumping through the curve by protecting the tubing from frictional wear.

<u>Thank you:</u> Revolution Resources

We are looking for customers to work with us on documenting additional wells and field trials
Contact us for more information!!!

QUESTIONS?

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