ProductionLink

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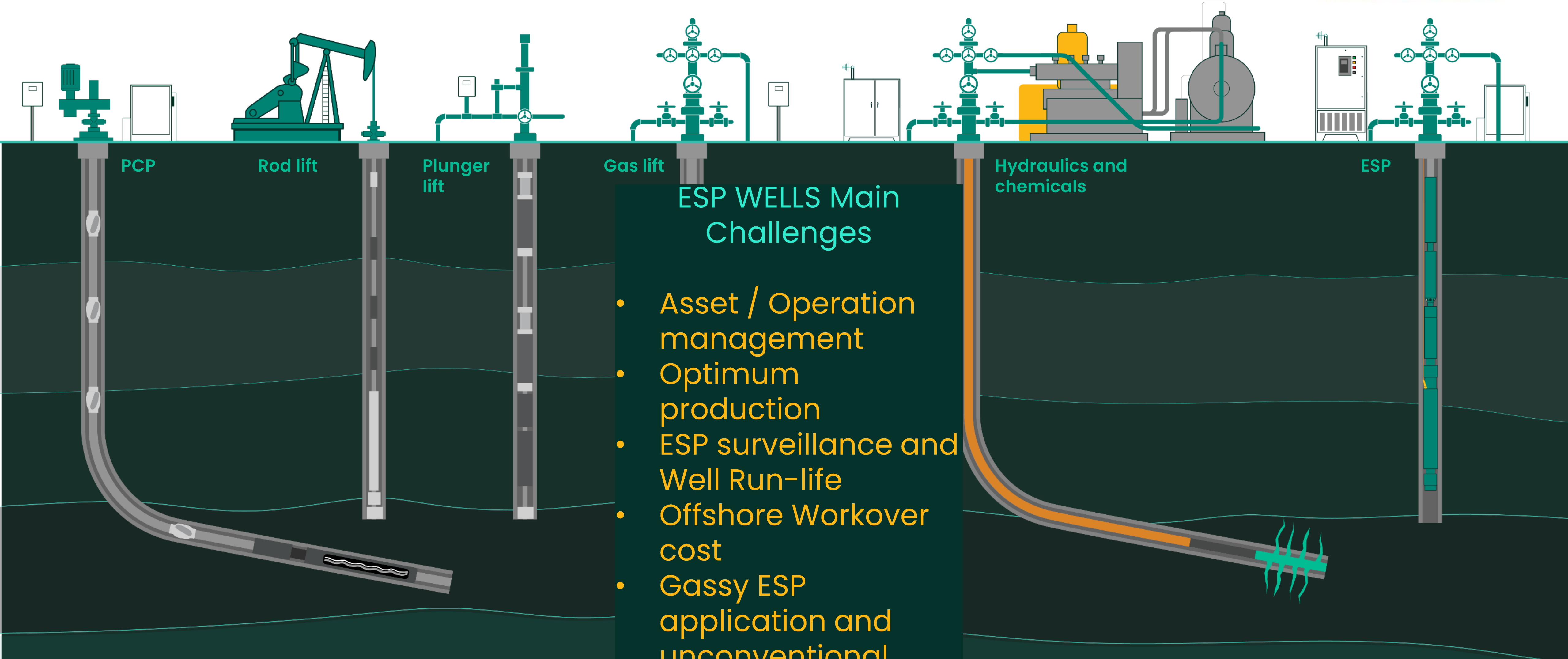
Artificial Lift Optimization through Digitalization and Application transformation

October 31, 2022

Agenda

- Overview
- Artificial Lift Optimization challenges
- ProductionLink Case Studies

Calculating the uncertain



ESP WELLS Main Challenges

- Asset / Operation management
- Optimum production
- ESP surveillance and Well Run-life
- Offshore Workover cost
- Gassy ESP application and unconventional

Artificial Lift production asset management

1 **LIFT DESIGN & SELECTION**
- Selection of lift method
- Sizing of lift system
- Surface facilities

2 **DATA INTEGRATION & SURVEILLANCE**
- Asset data integration
- Performance monitoring
- Smart alarming

3 **WELL MODELING & OPTIMIZATION**
- Evergreen well models
- Lift equipment analytics
- Production forecasting

4 **AUTOMATION & CONTROL**
- Closed-loop remote control
- Edge computing
- Artificial Intelligence

5 **OPERATIONAL MANAGEMENT**
- Service delivery and logistics
- Surface system management
- Equipment quality and traceability

ML & AI Physics-based diagnostics: ESP

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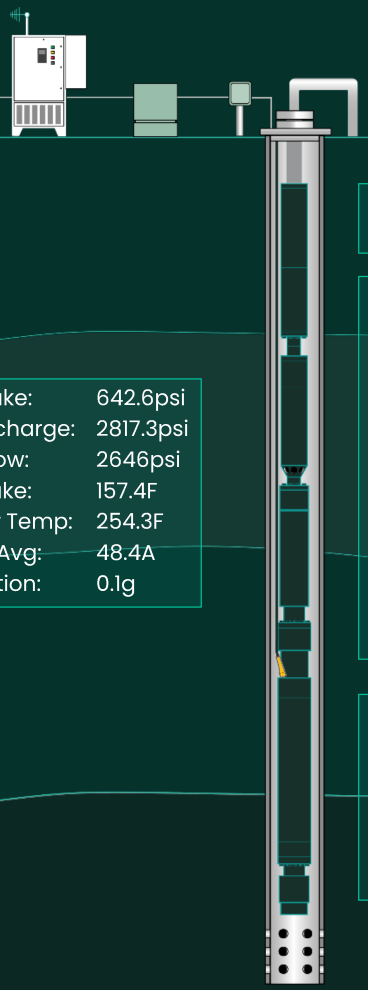
Variable Speed Drive
- Adjust for proper drawdown
- Run advanced algorithms

Run Status:	Running
VFD Frequency:	60Hz

Monitoring System
- Immediate notification of alarms and shutdowns



P. Tubing:	170psi
P. Casing:	0psi

Gather wellsite data to provide entire picture of the well's performance

Reservoir Pressure (P-Res):	3802psi
Oil Formation (Bo):	1.2stb/rb
Water Formation (Bw):	1.002stb/rb
Bottom Hole Temp:	179F
Gas Compressibility Factor (Z):	0.85
Gas Specific Gravity (gg):	0.85
Oil Specific Gravity (go):	0.85
Water Specific Gravity (gw):	1.02
Water Oil Ratio (WOR):	1
Gas Oil Ration (GOR):	0scf/stb
Solution Gas Oil Ratio (Rs):	0scf/stb
Productivity Index (J):	1.35stb/d/psi

Well Testing	
Oil:	2000bpd
Gas:	200Mscf
Water:	1500bpd

Downhole data for optimizing the ESP systems run life, performance and production

P. Intake:	642.6psi
P. Discharge:	2817.3psi
P. Inflow:	2646psi
T. Intake:	157.4F
Motor Temp:	254.3F
Volts.Avg:	48.4A
Vibration:	0.1g

Pump Model:	538/Flex47/Centurion – 120stages
Gas Sep:	538 GSVHV
Seal:	Centrilift 513 GSB3 H6
Motor:	562SP (175HP/3180V/34A)
Cable:	Centrilift #1 CEBER 5KV RD Monel
Sensor:	WellLift H Stainless Steel

Create a well-equipment model to compare real-world performance versus ideal performance

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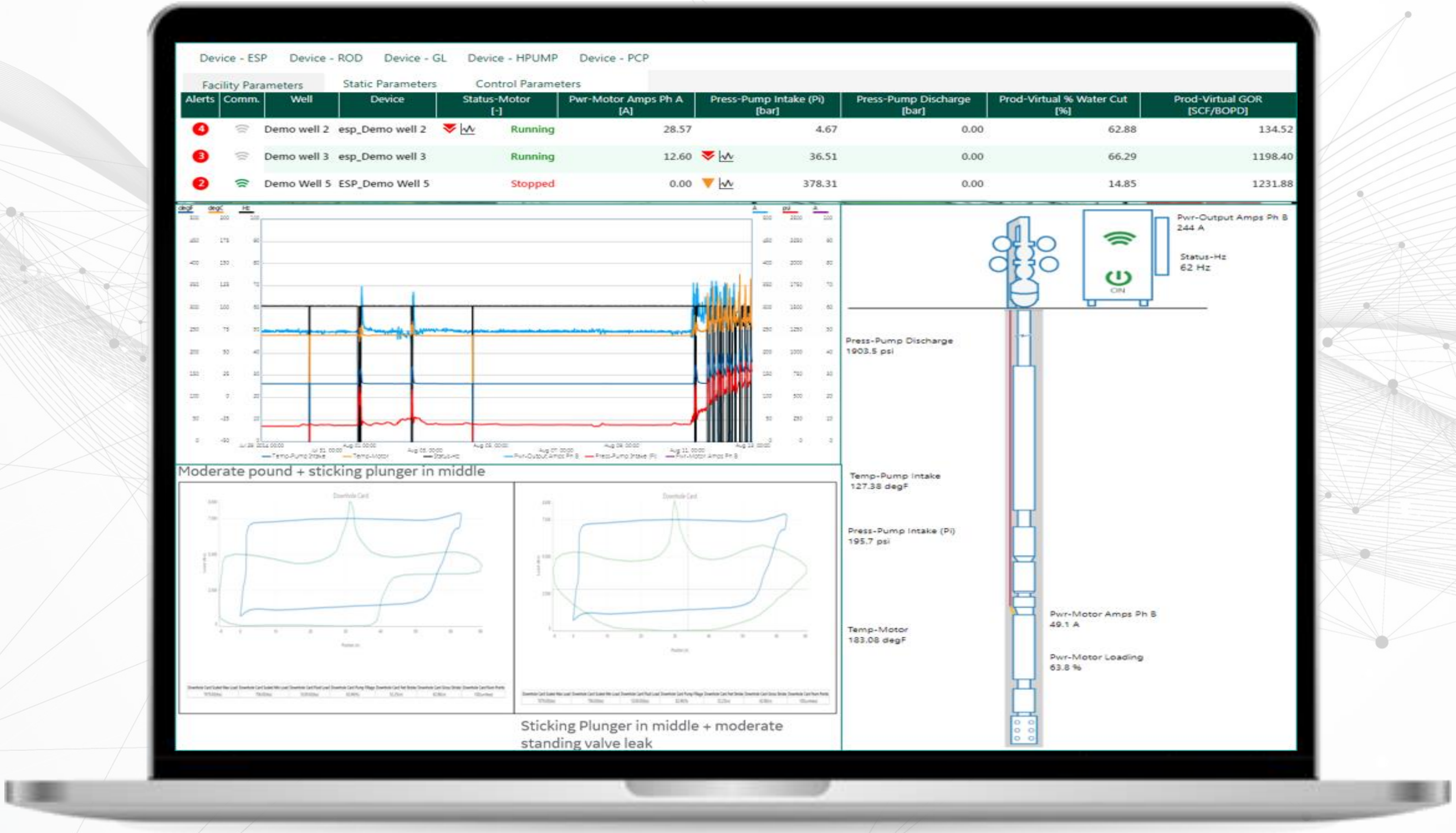
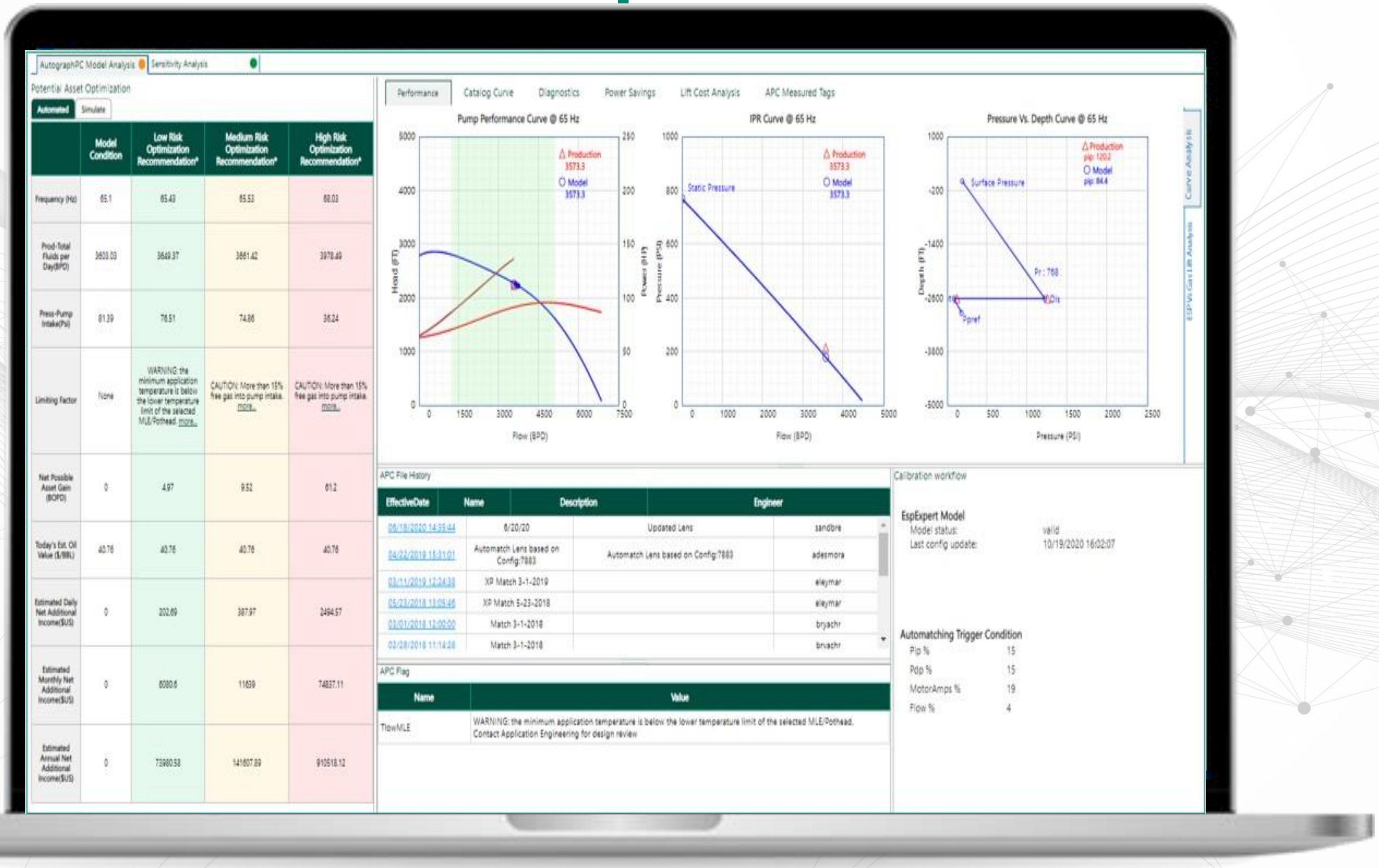
Monitoring and surveillance



Integrated solution to monitor the health of artificial lift systems, stay ahead of potential problems, and maximize recovery from artificial lift operations

- Predictive and diagnostic suite of analytics enable easy and immediate identification of trends, patterns, and anomalies to diagnose downhole conditions for quick decision making
- Integrated case management with automated reporting system

Workflow and optimization

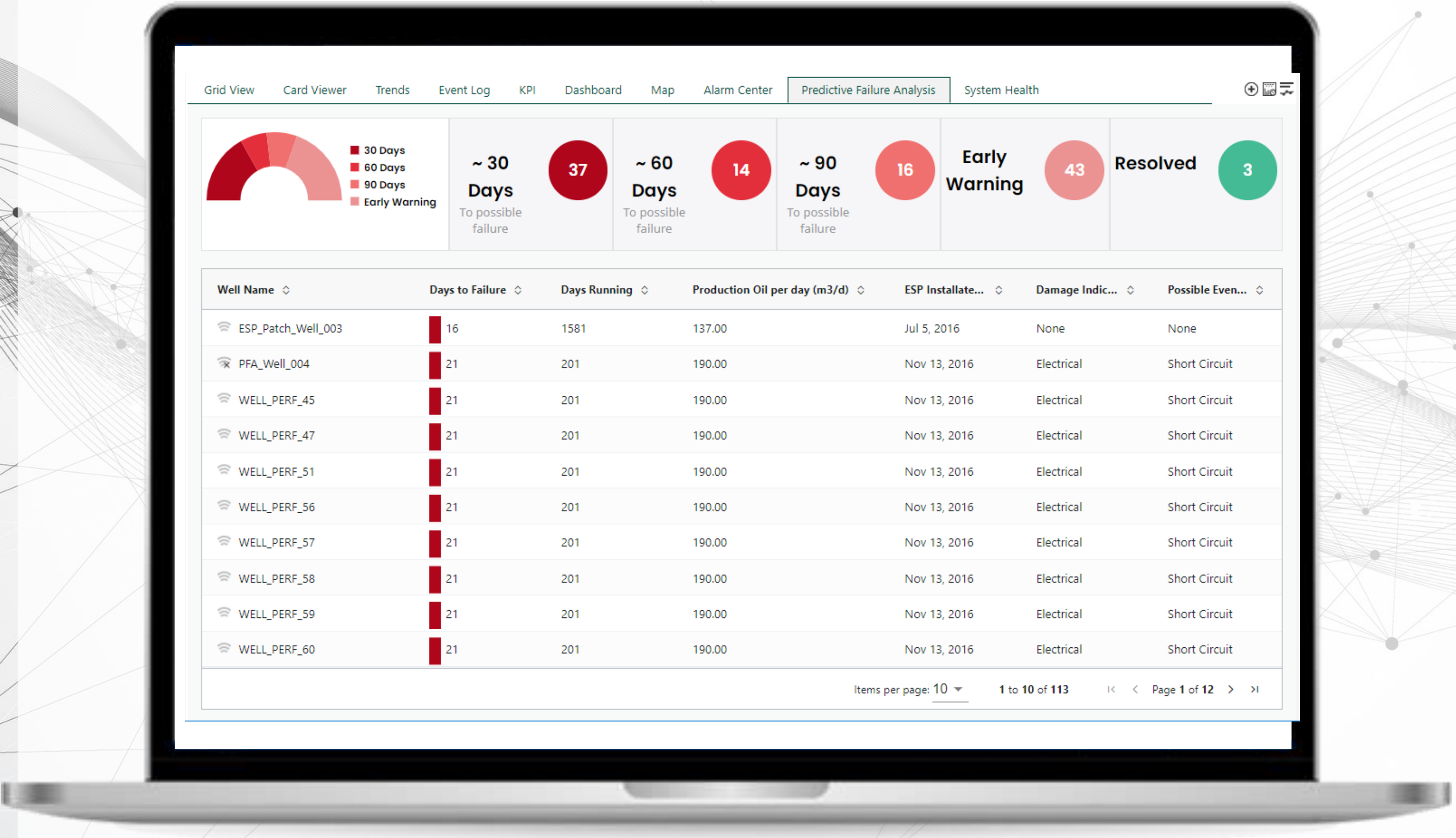


Real-time monitoring, control, and analytics service for artificial lift systems that avoids nonproductive time and maximizes production

- Asset, field, well, and device level optimization with customization for zone, pad and area
- Real time performance curves, IPR curves and pressure vs depth curve using digital twin model
- Multi-well optimization with constraints
- Lift cost analysis
- Real time model calibration

PRODUCTIONLINK ANALYTICS

ESP predictive failure analytics



Digital solution to leverage state-of-the-art artificial intelligence/machine learning and physics-based models to detect operational events and anomalies in your ESP system early—before a costly failure

- Predict ESP failures ahead of time to plan for workover
- Predict damage events, possible cause of failure to take remedial action to extend ESP life
- Predict remaining useful life (RUL) based on field average and AI driven failure prediction

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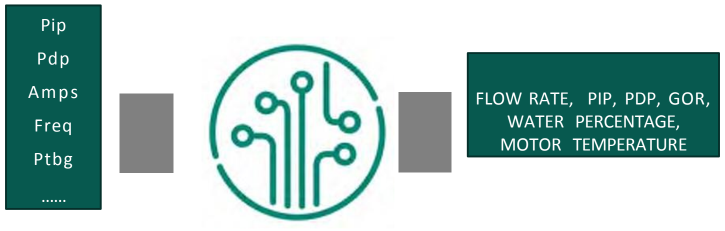
Virtual Flow calculates **Total Fluids Production (BFPD)** using a Phsyics and Neural Network based Model.

Virtual Flow reduce **Production Test required, saving OPEX and providing an estimated Flow Rate in Real Time**

- Virtual Gauge Meter can be used as a virtual sensor when the sensor signal is lost.

Physics Based Model



Machine Learning

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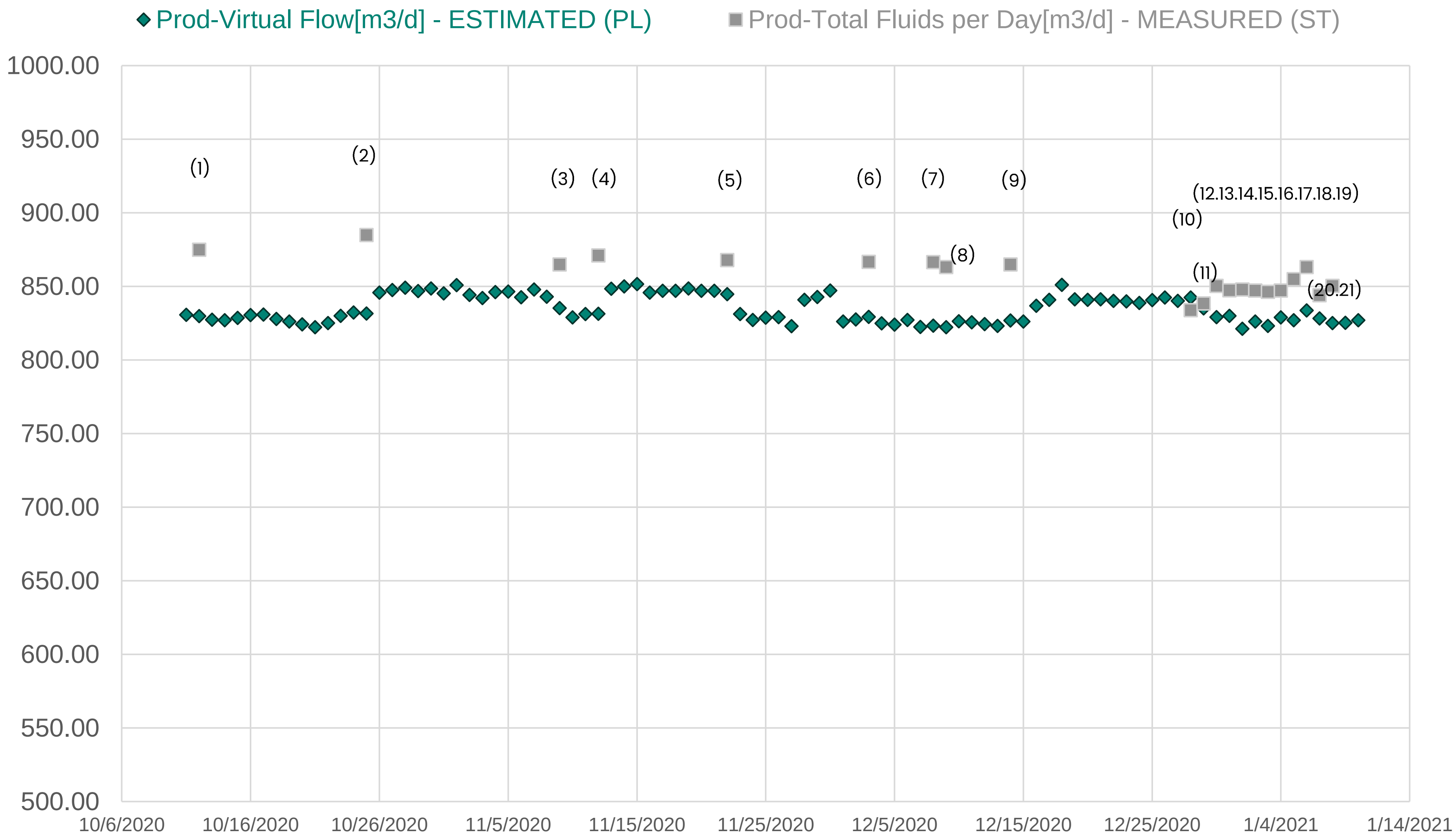
Flow
Estimated VS Measured



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Flow

Estimated VS Measured

ProductionLink estimates from 3 % to 6 % less than the measured value

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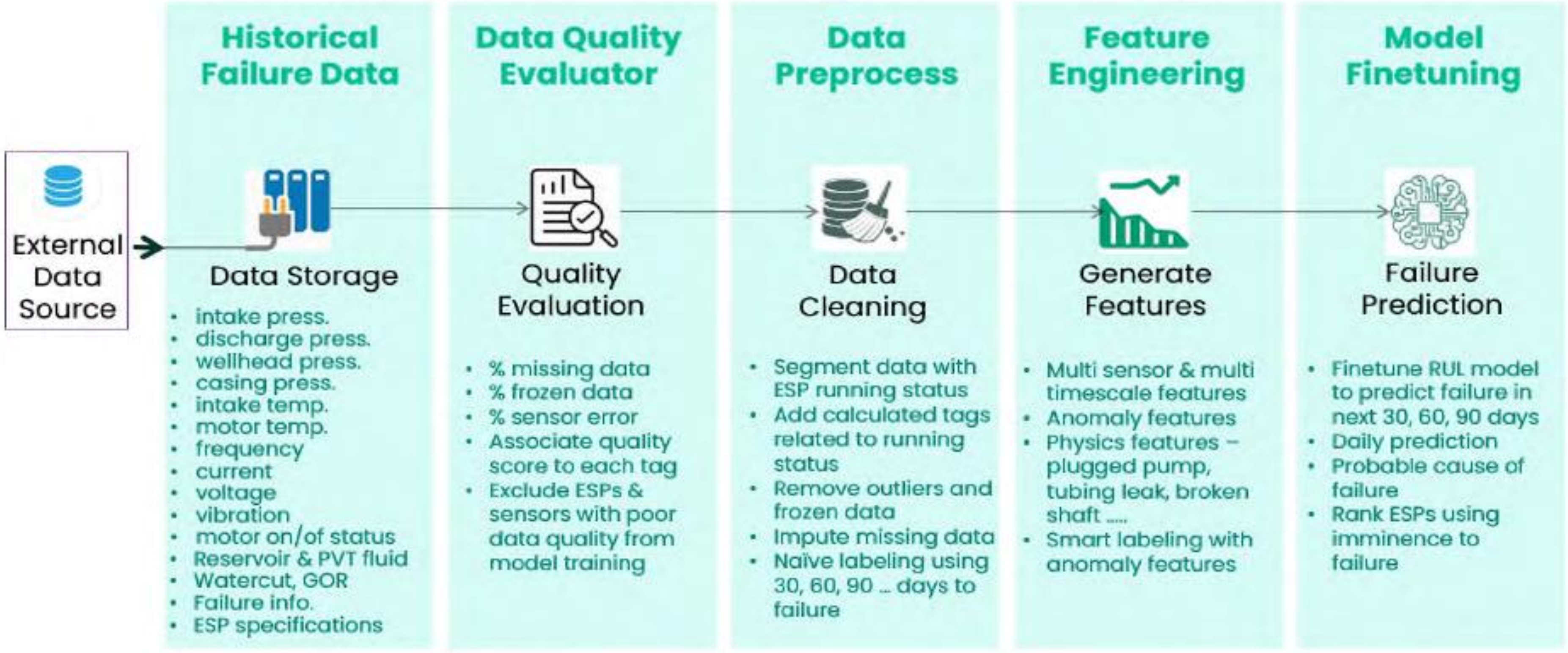
Predict ESP Failure Probability Using Machine Learning

PFA Model Finetuning with New Customer Data



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ML & AI Predictive Failure Analytics

1 Data collection and failure types:

- 96 ESP data collected – 25 running & 71 failed
- Running ESP have better data quality than failed ESP
- 50 ESP (25 running, 25 failed) selected for the POC based on data quality
- 21 ESP used to fine-tune PFA, 29 ESP to evaluate PFA
- Events/ failure causes: broken shaft/bearing, short-circuit, high current, motor overheating, scale deposition

2 Data Quality Assessment:

Tag Name	Average Missing Data% 11 running ESPs	Average Missing Data% 18 failed ESPs
Drive Frequency	5%	14%
Current	5%	14%
Volts	5%	14%
Current Leakage	5%	14%
Wellhead P	10%	25%
Intake P	12%	35%
Discharge P	5%	14%
Intake T	5%	14%
Motor T	6%	14%
Vibration X	5%	14%
Vibration Y	15%	19%

3 KPI of 3 PFA models on 29 ESP

KPI for Failed ESPs	Performance
Precision: (asset level KPI) correct alarms / correct alarms + false alarms (%)	80-100% ↑
Recall: (asset level KPI) correct alarms / total # of failed ESPs (%)	44-56% ↑

Among **18** historically failed ESPs, the best model has -
8 correctly predicted ESP failures (correct alarms)
0 False Alarms
10 missed ESP failures (no alarms)

KPI for Running ESPs	Performance
True Negative Rate: (asset level KPI) no alarms / total # of running ESPs (%)	81-100% ↑
False Alarm Rate: (asset level KPI) false alarms/ total # of running ESPs (%)	0-18% ↓

Among **11** running ESPs, the best model has -
11 ESPs with no alarms/ early warnings
0 false alarms

KPI for Damage Events/ Failure Cause Detection	# of Historical Events/ Failures	Detected by PFA	Accuracy
Broken Shaft/ Broken Bearing Failure	8	5	62%
Short Circuit/ High Current/ Electrical Failure	8	5	62%
Scale/ Deposition	5	4	80%

4 Potential cost savings by reducing deferred production:

Deferred production costs caused by ESP failure	1 ESP (well)	8 ESP failures correctly predicted
Average downtime due to rig availability	4-6 weeks	**$ 8.9 M**
Reduced Downtime using PLink PFA	2 weeks	
Average daily oil production (bbl/d)	2,000	
Oil price	$40	
Total savings from PLink PFA	**$ 1.1 M**	

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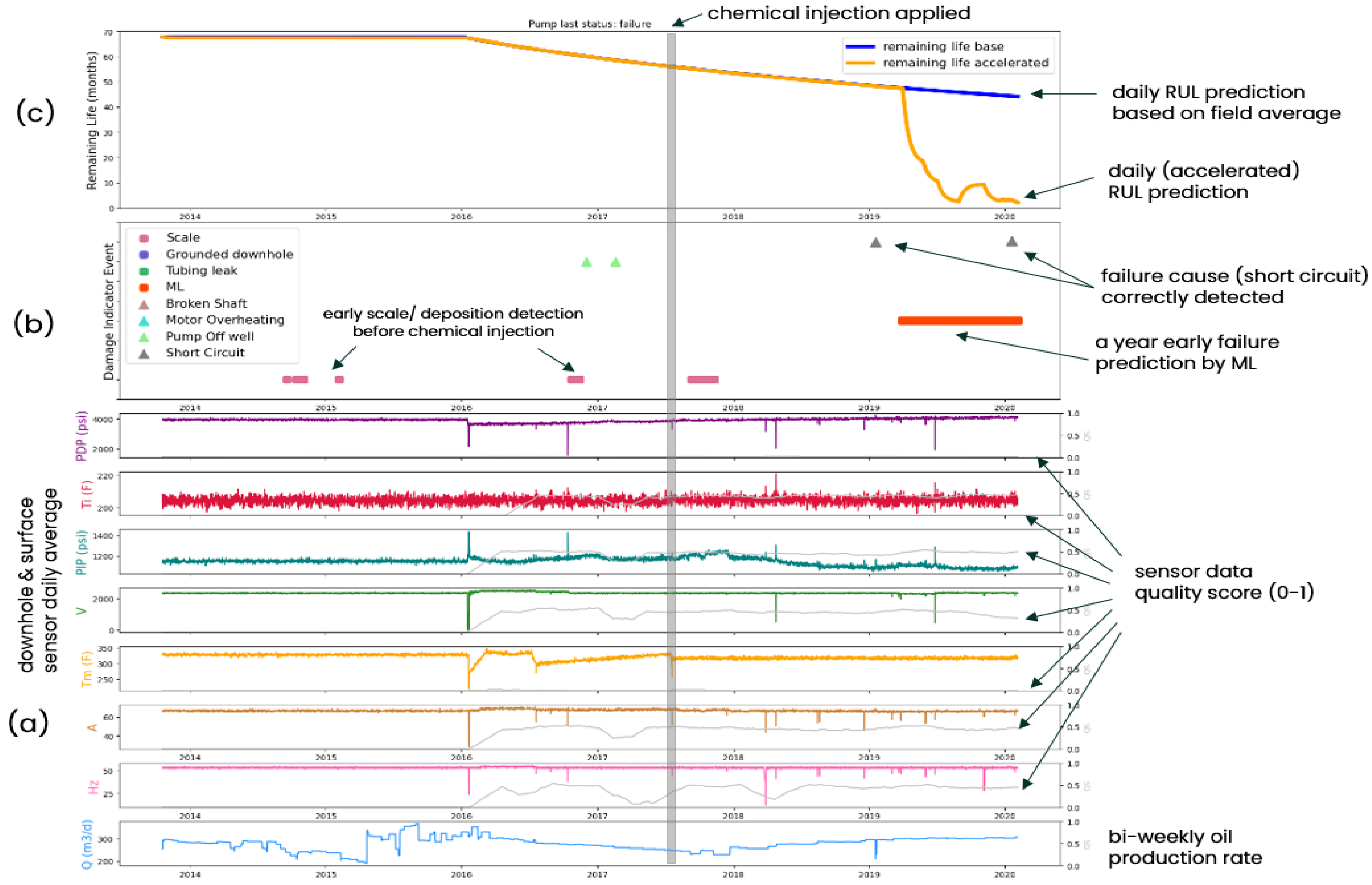
Failed ESP | Correct Alarm | Electrical Failure | Scale/ Deposition



Well 1, Run life - Oct. 2013 – Feb. 2020

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Figure - (c) shows 2 daily remaining useful life predictions, one (blue curve) based on average run life in the field and the final RUL prediction (orange curve) based on the damage events the ESP has encountered so far. When the ESP is new and has no issues, the blue and orange curve shows the same RUL. As the damage events are detected over time (b), the orange curve starts deviating from blue, indicating accelerated decline in RUL. For this ESP, PFA correctly showed less than 3-months RUL, close to its failure.

Figure - (b) shows outputs from 8 PFA damage indicators. Scale/ depositions was detected Oct. 2014 to Feb 2015, ~ 3 years prior to the chemical injection, as well as on Nov. 2016, 8 months prior to the chemical injection. Due to poor sensor data quality, initial scale detections are less reliable. Instead, scale/ deposition detection on Nov. 2016 is more reliable and can be used to apply chemical treatment at least ~ 8 months early to prevent significant drop in production.
Moreover, as showed in Figure - (b), machine learning (ML) raised failure alarm ~ a year before the actual failure, and short circuit was detected twice before the ESP failed due to electrical failure. Operators can use these alarms to take remedial actions to prevent failure.

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Services

INCREASE WELL PRODUCTION + **ENHANCE EQUIPMENT RUN LIFE** + **OPTIMIZE OPERATING COST**

INCREASE WELL PRODUCTION	ENHANCE EQUIPMENT RUN LIFE	OPTIMIZE OPERATING COST
Improving wellbore flow performance	Reducing lift design and operational complexity	Managing field services and surface facilities cost

MAXIMUM LIFT PERFORMANCE

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