ICDA Wet Gas & Oil Predictive Modeling

TECHNICAL TOOLBOXES

By Joe Pikas

Flow Modeling Decisions

- Predict IC locations
- Predict corrosion severity
- Predict cleaning pig frequency
- Predict ILI frequency
- Establish mitigation strategies
- Selection of flow and corrosion models to control IC
- Demonstration Using Multi Phase Flow Modeling

Aqueous Corrosive Phase

- Flow rates
- Acid gas content
  - CO_2
  - H_2S
  - O_2
- Type of products such as crude oil
- Sand, solids, bacteria
- Temperature/Pressure

Predictive Model Questions

- IC a threat?
- Where is IC likely to occur?
- When will IC occur?
- What is the corrosion mechanism?
- Which operating parameters need to be monitored?
- How are predictions validated?

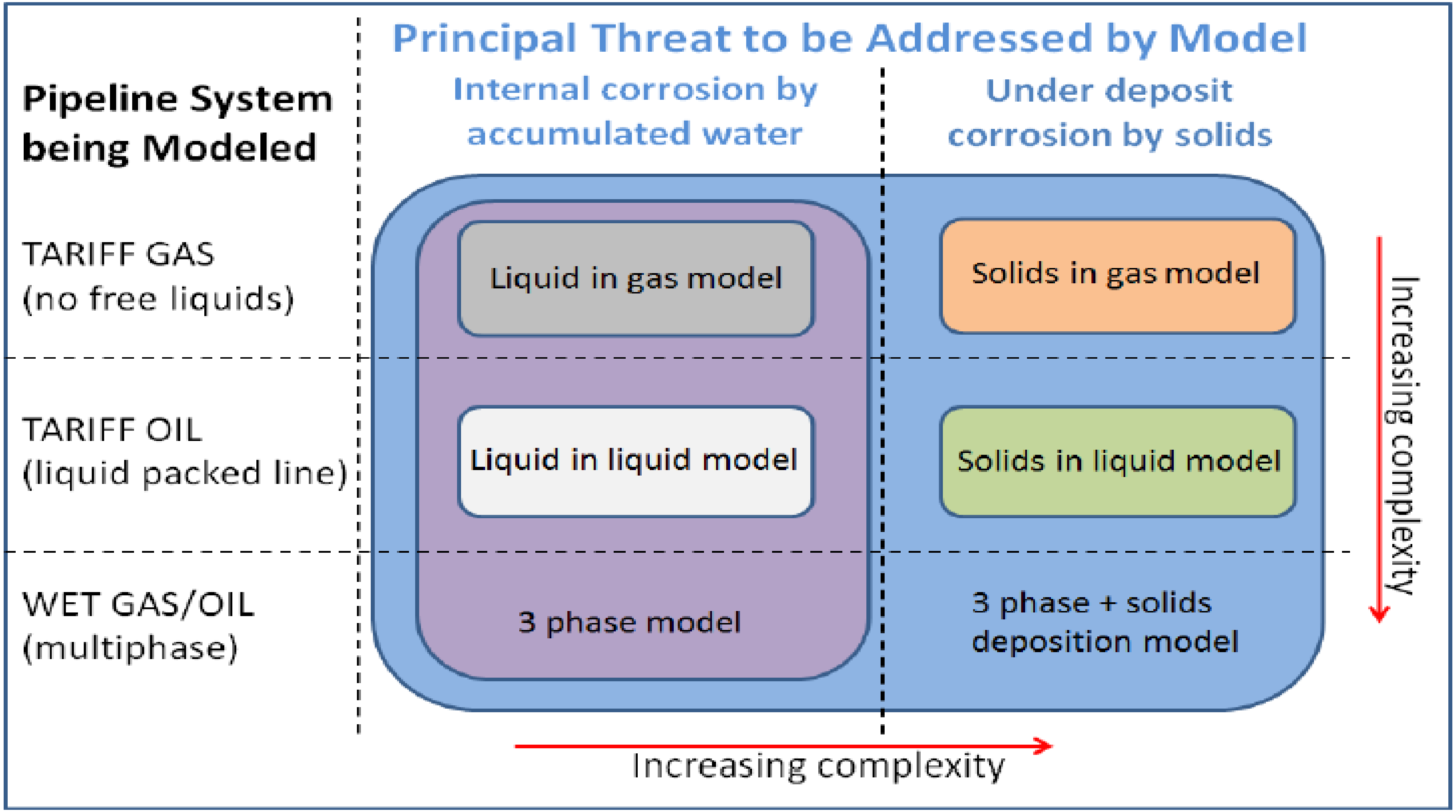
IC a Threat?

- Is there water and how high or low is the content?
  - Oil transmission lines with 0.5% volume and basic sediment and water (BS&W)
  - Production lines 10% volume
- Where will corrosion occur?
  - Water & BS&W in low lying regions where solids accumulate
  - Impingement
    - Bottom of Line (BOL)
    - Top of Line (TOL)
    - Over bends

Model Validation

- Models are developed based on the following:
  - Lab Tests (Short duration tests)
  - Analysis of Field Experience
    - Mitigation, monitoring, maintenance & other integrity activities
  - Computer Simulation (Assumptions formulated)
  - Scientific principles
  - Physical and chemical boundary conditions are within the capabilities of the model
  - All of the above

IC Model Threats



Corrosion Types (Flow Rate & Sand Level)

Flow Rate \ Sand Level	None	Small	Medium	Large
Very high	Liquid impingment erosion	Dispersed sand (solid) flow Liquid/solid impingment erosion	Dispersed sand flow Solid(sand) /liquid impingment erosion	Dispersed sand flow Solid/sand impingment erosion
High	Flow induced localized corrosion	Dispersed sand/solid flow Corrosion influenced erosion	Scouring sand flow Corrosion influenced erosion	Scouring sand/solid flow Corrosion influenced erosion
Medium	Flow assisted pitting corrosion	Scouring sand/solid flow Erosion influenced corrosion	Sand dunes Erosion influenced corrosion	Sand/solid dunes Erosion influenced corrosion
Low	General and pitting corrosion	Sand /solid dunes Pitting corrosion	Sand/solid deposits Pitting corrosion	Sand/solid deposits Underdeposit corrosion

Flow Model Selection

- Determine or estimate amount of pressure required to transport product(s).
- Pressure drops with distance downstream of pumps (liquid) or compressors (gas).
  - Static pressure is difference in elevation between upstream and downstream locations
  - Dynamic pressure is the energy loss due to flow of liquid(s)
    - Based on type of phases (oil, gas and water)
- Prediction of water accumulation, liquid holdup and flow regimes

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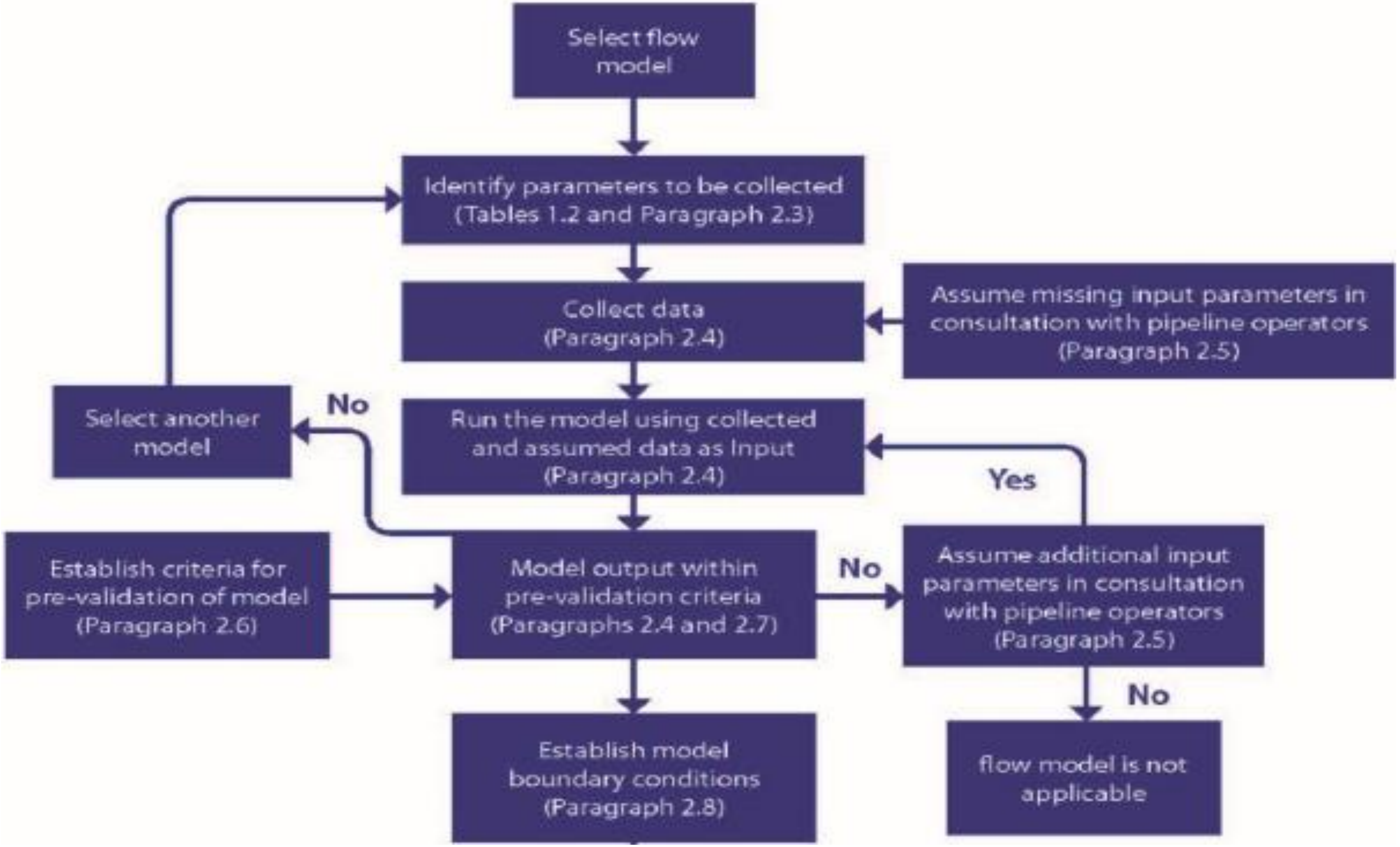
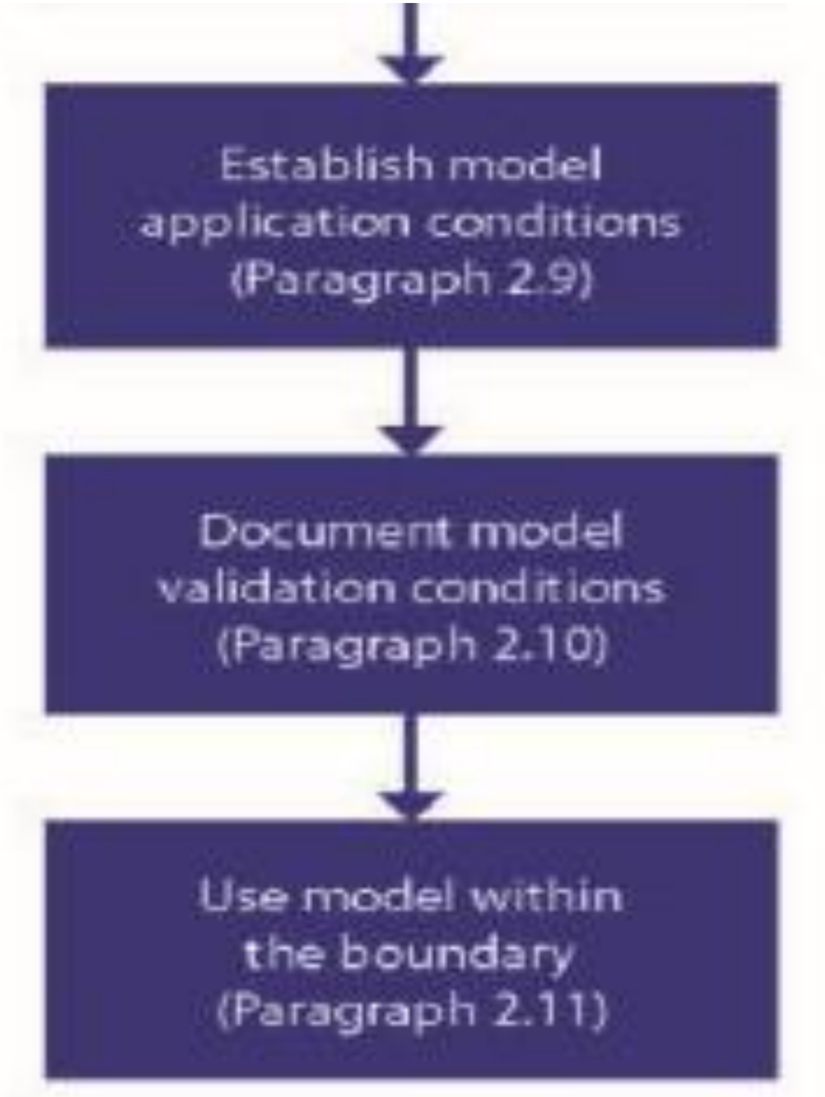
Validation Flow Model



Validation Flow Model



Input Parameters for Flow Model			**Output Parameters Obtained from Flow Model**	**Corrosion Control Output from Flow Model**
Construction	**Measurement**	**Assumption**		
Pipe features with inclination Accessories Elevation profile Diameter Wall thickness Inputs/outputs Internal (flow) coatings	Defined length Volume/amount of oil Volume/amount of gas Volume/amount of water Volume/amount of solid Pressure Temperature Hydrocarbon characterization (density and viscosity) Gas composition Water phase characterization (density and viscosity)	Compressibility factor[(B)] Effect of pig cleaning	Flow regime Flow rate Superficial liquid velocity Superficial gas velocity Liquid hold-up Water wetting Pressure drop along the pipe Temperature variation along the pipeline Particle impingement Location of solid settling	Locations for water accumulation

Validation of IC Model

- Historical locations of corrosion due to water
- ILI and other field monitoring data
- Tolerances and limits between model and field data
- Pressure profile to predicted model
  - Momentum
  - Mass transfer
  - Corrosion
- Compare, document and adjust model to tolerances established to a specific operating range

Corrosion Rate Model

- Different models vary based on the method for factors affecting corrosion rates.
- Corrosion models estimate the corrosiveness of an environment.
- Corrosion rates vary with time:
  - Corrosion rates change even if operating conditions stay the same
  - Corrosion rates change as feature depth changes
  - Corrosion parameters do not all outside the limits of the model

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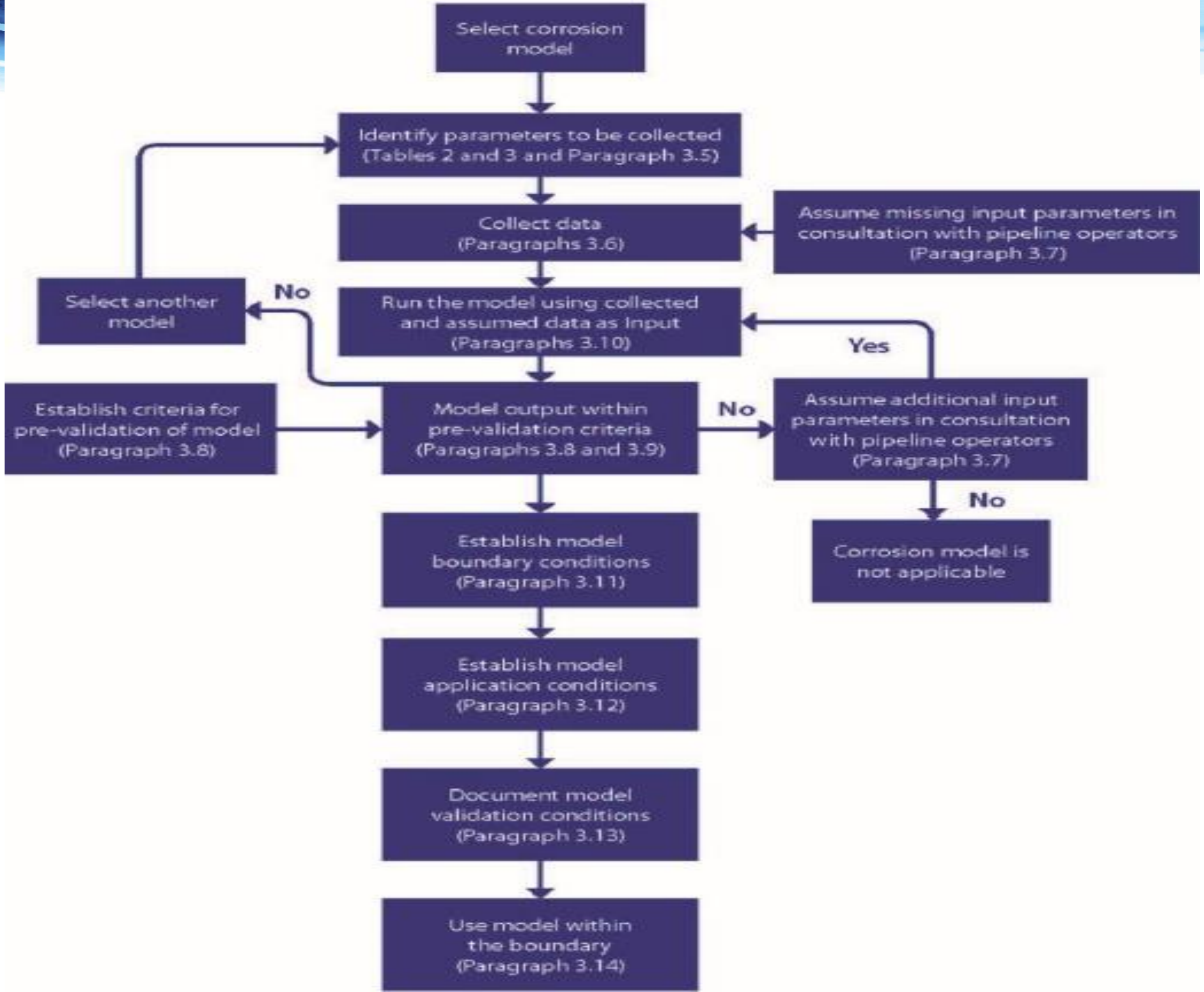


Select corrosion model
Identify parameters to be collected (Tables 2 and 3 and Paragraph 3.5)
Collect data (Paragraphs 3.6)
Assume missing input parameters in consultation with pipeline operators (Paragraph 3.7)
Run the model using collected and assumed data as Input (Paragraphs 3.10)
No
Select another model
Yes
Establish criteria for pre-validation of model (Paragraph 3.8)
Model output within pre-validation criteria (Paragraphs 3.8 and 3.9)
No
Assume additional input parameters in consultation with pipeline operators (Paragraph 3.7)
No
Corrosion model is not applicable
Establish model boundary conditions (Paragraph 3.11)
Establish model application conditions (Paragraph 3.12)
Document model validation conditions (Paragraph 3.13)
Use model within the boundary (Paragraph 3.14)

Parameters Involved in Corrosion Models[A]

Input Parameters Obtained From:			Corrosion Model Output
Flow model	**Measurement**	**Assumption**	**Calculation**
Type (Single phase, two-phase, multiphase)	Volume/amount of oil	The most recent measured parameters or weighted average of these parameters are representative for the entire duration of pipeline operation	Corrosion rate, along with uncertainty in prediction
	Volume/amount of gas		
Locations for water accumulation[B]	Volume/amount of water		
	Volume/amount of solid	Inhibitor efficiency	
Flow rate			
	Hydrocarbon characterization (density, viscosity, and composition)	Pigging efficiency	
Flow regime			
		Biocide efficiency	
Superficial water velocity	Gas composition (including acid gases)		
	Water phase characterization (density, viscosity, and composition)		
Superficial gas velocity			
	Solid characterization (density, viscosity, and composition)		
Superficial gas velocity			
	Microbial species characterization		
Liquid hold-up			
Pressure drop along the pipe			
Temperature variation along the pipeline			
Water chemistry			

Corrosion Models

- Most corrosion models are point models whereas they predict over a pipeline sub-region.
- To predict of the entire length, the sum of sub-regions are added together.
- Models predict both water wetting and accumulation
- Assumptions must be recorded and errors must be evaluated.
- Due to variations in production rates and operating conditions, modeling is done over discrete time intervals or layers.

Key Parameters Known to Cause Internal Corrosion

Parameters	Remarks
Water	Provides conductive phase for electrochemical corrosion to take place.
Oil	Oil phase, being a non-conductor, generally decreases corrosion rate taking place under pipeline operating conditions. ASTM[1] G205 provides guidelines to evaluate the effect of oil phase under pipeline operating conditions.[9]
Gas (CO_2)	Dissolution of CO_2 in the aqueous phase increases the corrosiveness.
Gas (H_2S)	Dissolution of H_2S in the aqueous phase changes the corrosiveness.
Oxygen	Dissolved oxygen increases corrosiveness. Oxygen is not normally present in the pipeline operating environment unless leaking valves lets atmospheric air into the pipelines or the ingredients came in contact with air prior to entering the pipeline environment.
Solids	Presence of solids facilitates UDC and MIC.
Temperature	Generally, an increase of temperature increases corrosion rate.
Pressure	Change of pressure changes corrosiveness.
Sulfate ion	Changes corrosion rate.
Bicarbonate ion	Generally, decreases corrosion rate, as a result of increase in pH.
Organic acids (e.g., formic and acetic acid)	Increases corrosion rate and accelerates TOL corrosion.
Chloride ion	Changes corrosion rate.
Microbes	Sulfate reducing bacteria, acid producing bacteria, iron-reducing bacteria, and iron-oxidizing bacteria are involved in corrosion. Deposit accumulation and formation of biofilm facilitates localized pitting corrosion.

Summary

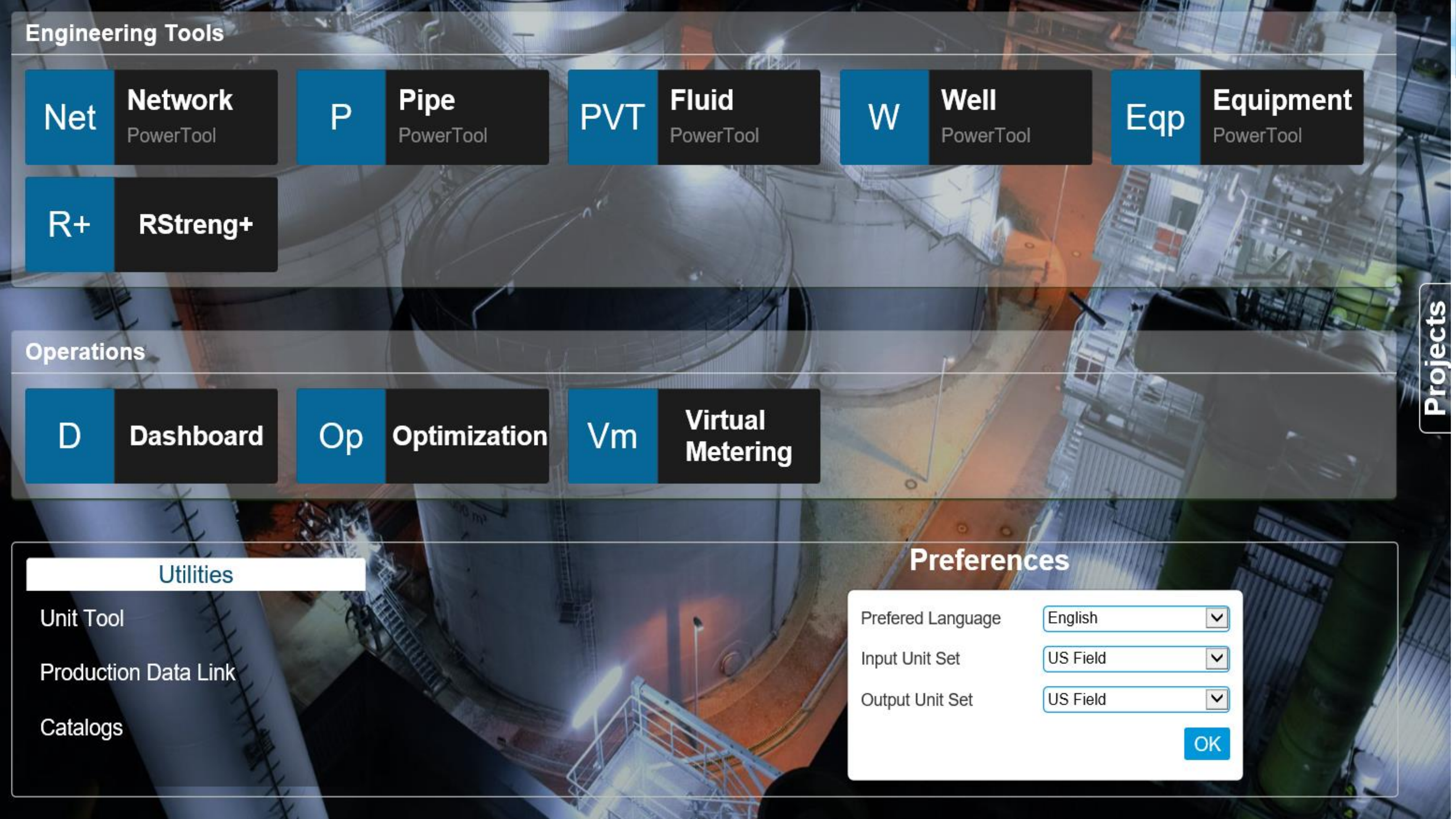
- IC modeling provides the corrosion rate and uncertainty of the rate.
- Model output and field corrosion rates must be within the tolerance limits established.
- Modifications to model must be made until field data agreements is reached.
- Must be run within the applicable range.
- Conditions of the model must be validated and documented.

Summary

- Validated model is then used to predict susceptible to water in contact with steel surface boundaries.
  - Does not need to be run where water does not contact steel surfaces
- Models can be integrated so all calculations are carried out simultaneously.
- Models can be used to establishing ILI if applicable and other integrity, mitigation and risk management programs

Demonstration of ICDA TT's Model

- ICDA Network Power Tool
  - Performs Integrated Analysis of Multiphase Flow Network Pipelines
  - Rigorous Hydraulics
  - Heat Transfer
  - PVT Analysis
  - Identification of Corrosive Gas, Liquids and other products i.e. solids
- ICD Toolbox
  - Secure Cloud Based System
  - Sharing


Engineering Tools
Net
Network
PowerTool
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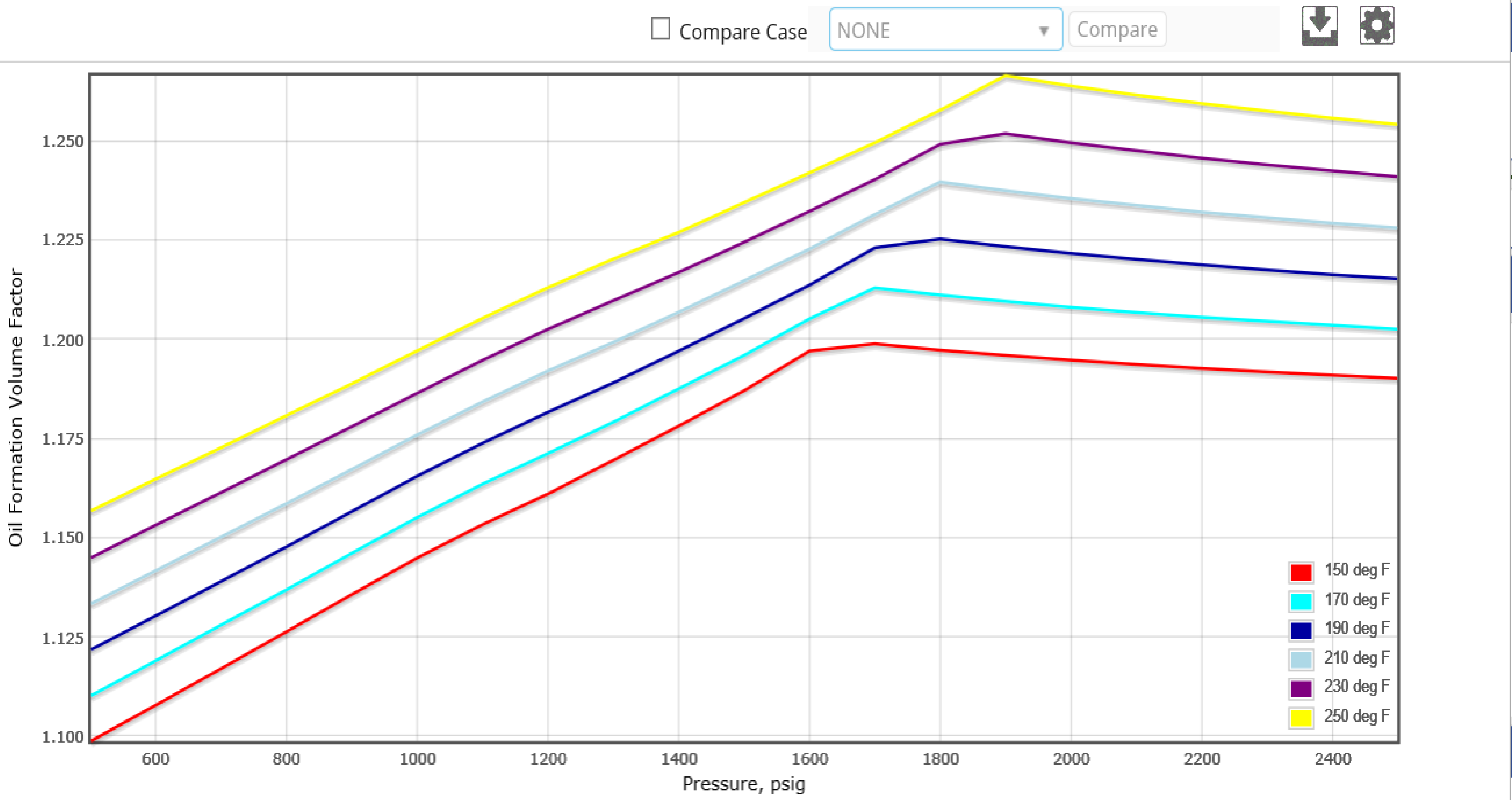
Pipe
PowerTool
PVT
Fluid
PowerTool
W
Well
PowerTool
Eqp
Equipment
PowerTool
R+
RStreng+
Operations
D
Dashboard
Op
Optimization
Vm
Virtual Metering
Projects
Utilities
Unit Tool
Production Data Link
Catalogs
Preferences
Prefered Language
English
Input Unit Set
US Field
Output Unit Set
US Field
OK

Oil Formation Volume Factor (Lasater) plot



Profile

Compare Case NONE Compare

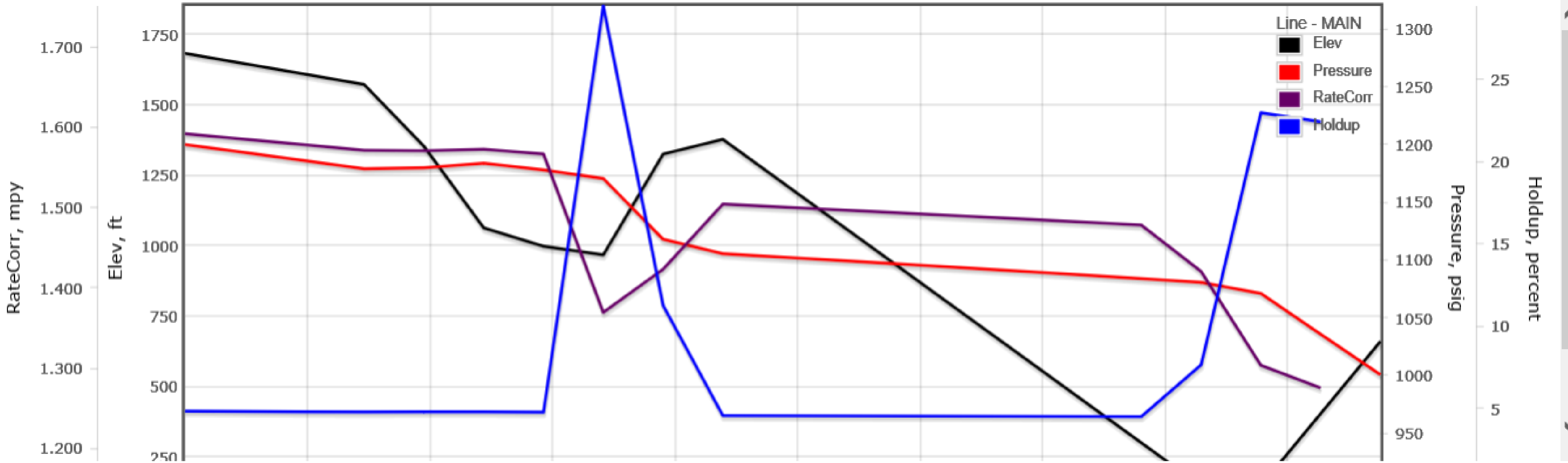
Wall Thickness	0.277 inch	Inside Diameter	8.071 inch	Total Length	24400.0 ft	Net Elevation Rise	-1023.0 ft
Average Roughness	0.00180 inch	Heat Transfer	0.10 Btu/hr-ft2-F	Segments	20	Vertical Flow	Beggs&Brill(P)
Horizontal Flow	Beggs & Brill	Ambient Temp	72.0 deg F	Inlet Pressure	1200 psig	Outlet Pressure	1000 psig
Liquid Rate	1574.7 BPD	Oil Rate	1495.9 BPD	Inlet Gas Rate	62988.693 MCFD	Water Rate	78.7 BPD
Total Mass Rate	140042.9 lb/hr	Inlet Temp	120.0 deg F	Outlet Temp	117.5 deg F	Gross Liq Inventory	126.0 bbl
Gas Inventory	610.5 MCF	Oil Inventory	105.4 bbl	Water Inventory	6.3 bbl	Average Holdup	8.16 percent

X ft

Y Elev ft Pressure psig

RateCorr mpy Holdup percent

Line MAIN



Profile

Compare Case NONE Compare

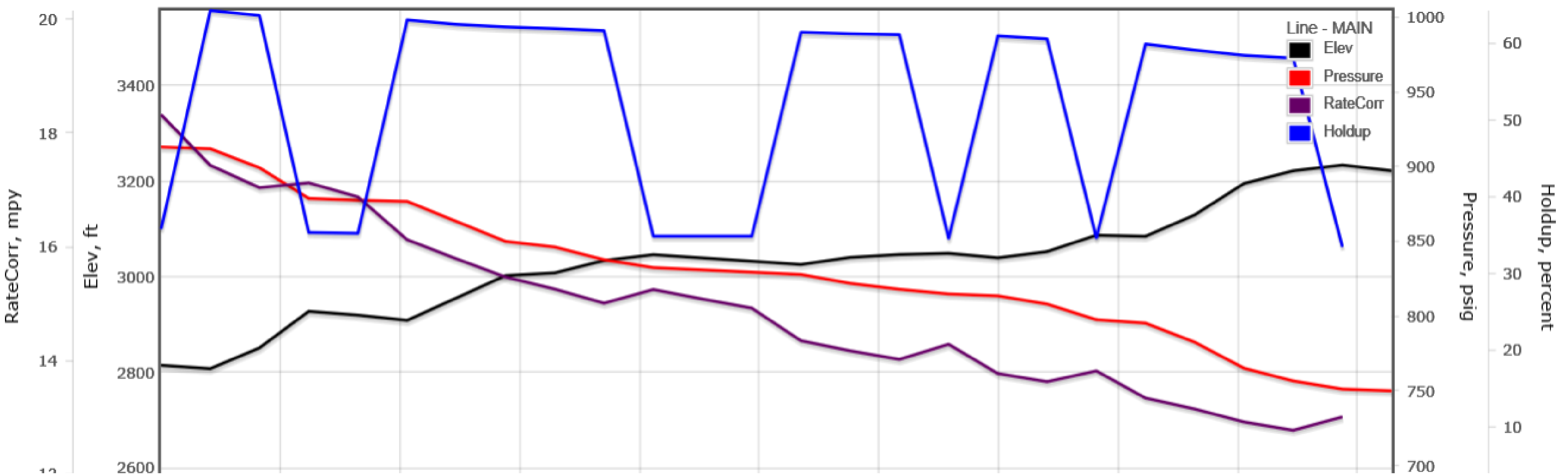
Wall Thickness	0.500 inch	Inside Diameter	7.625 inch	Total Length	20570.9 ft	Net Elevation Rise	406.8 ft
Average Roughness	0.00180 inch	Heat Transfer	3.50 Btu/hr-ft2-F	Segments	25	Vertical Flow	Beggs&Brill(P)
Horizontal Flow	Beggs & Brill	Ambient Temp	73.0 deg F	Inlet Pressure	913 psig	Outlet Pressure	749 psig
Liquid Rate	14076.4 BPD	Oil Rate	12345.0 BPD	Inlet Gas Rate	5537.592 MCFD	Water Rate	1731.4 BPD
Total Mass Rate	192593.3 lb/hr	Inlet Temp	106.0 deg F	Outlet Temp	80.8 deg F	Gross Liq Inventory	600.3 bbl
Gas Inventory	187.0 MCF	Oil Inventory	476.7 bbl	Water Inventory	73.7 bbl	Average Holdup	51.67 percent

X ft

Y Elev ft | Pressure psig

RateCorr mpy | Holdup percent

Line MAIN



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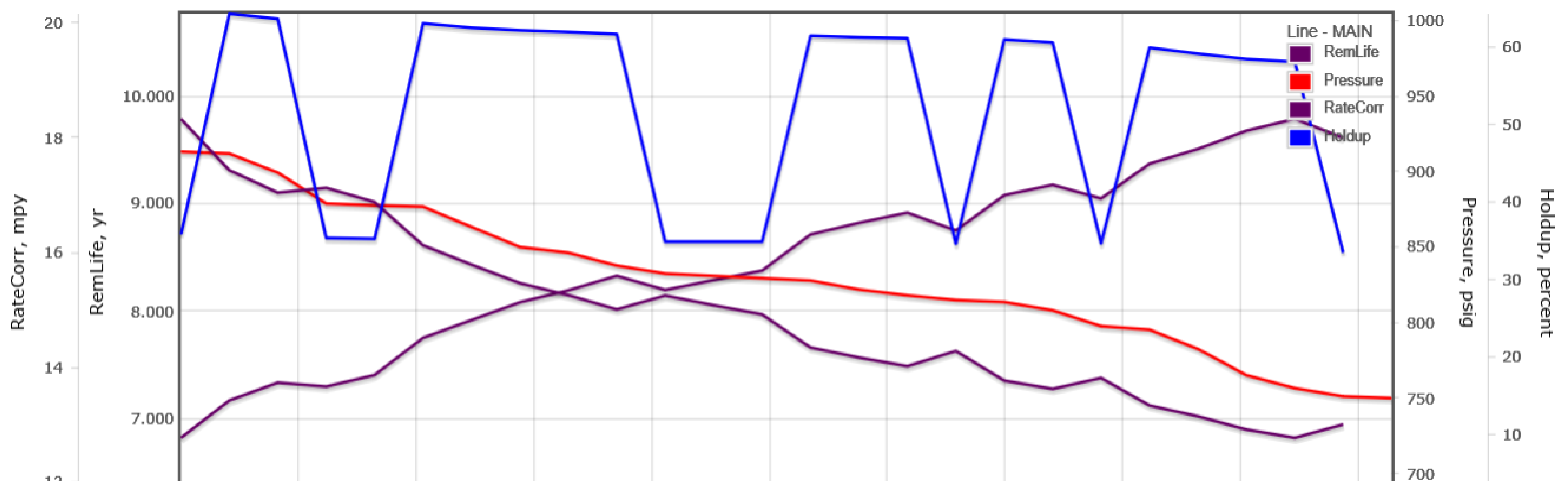
X ft

Y RemLife yr Pressure psig

RateCorr mpy Holdup percent

Line MAIN



Thank You

- Presentation based from NACE “**Selection of Pipeline Flow and Internal Corrosion Models”.**
- ICDA Multi-Phase Flow Modeling Graphs and Calculations – Technical Toolboxes (www.technicaltoolboxes.com)
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