Design of a Subsea Production Field

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ABBREVIATIONS

APIG	American Petroleum Institute Gravity
BBL	Barrel (unit)
BOPD	Barrels Oil per Day
BTU	British Thermal Unit
Ck	Choke (PIPESIM Nomenclature)
CRA	Corrosion Resistant Alloy
cP	Centipoise
Fl	Flow Line (PIPESIM Nomenclature)
FPSO	Floating Production Storage and Offloading
GL	Ground Level
GLR	Gas to Liquid Ratio
GOR	Gas to Oil Ratio
GPM	Gallons per Minute
ID	Internal Diameter
MD	Measured Depth
MMscfd	Million Standard Cubic Feet per Day
MUX	Multiplex
PLC	Programmable Logic Controller
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gauge
Rsr	Riser (PIPESIM Nomenclature)
SG	Specific Gravity
Sk	Sink (PIPESIM Nomenclature)
Src	Source (PIPESIM Nomenclature)
TVD	Total Vertical Depth
UPS	Uninterruptible Power Source
UTA	Umbilical Termination Assembly
WAT	Wax Appearance Temperature

1. Executive Summary

The subsea field is located on a slight downward sloping plain beginning at 1,050 meters depth at the shallowest point to 1,300 meters depth at the deepest. Five production wells are being produced with four water injection wells located around the periphery of the field used to sustain down-hole pressure of the production wells. The FPSO is located approximately in the center of the field and receives production from two risers while simultaneously supplying water for injection purposes down one riser. Two umbilicals are also used to deliver corrosion inhibitor and methanol to all five production wells.

The philosophy of the field layout concentrated on locating fluid handling equipment in a centralized area to facilitate ease of operation for the FPSO. When deciding on an optimized flow line and manifold arrangement, consideration was given to maximizing arrival temperature, keeping flow velocity below erosional limits, limiting flow line length, and limiting slugging while achieving the required minimum top-side arrival pressure of 190 psig. This led to an optimized solution that sought to minimize down-hill flow and utilize proper flow line diameters to avoid excessive velocity. Comingling was used in two flow loops. An initial design goal was to comingle similarly performing wells to limit the amount of required choking for the manifold arrival pressure (therefore minimizing reduced production). However, it was also necessary to maintain flow line and riser temperatures above the wax formation temperature of 70°F, which became a problem for the lower flow-rate wells. This led to a design compromise in which wells P1 and P2 were manifolded together, with wells P3, P4, and P5 forming the second flow loop. Wells P1 and P2 are very similar in production performance and were optimized with little difficulty. Wells P3 and P4 are the least performing production wells and were therefore manifolded together along with P5. Well P5 was included to provide thermal support to the comingled fluid to avoid solids formation in the riser. Production flow from well P4, due to its low flow rate performance, drops below the wax and hydrate formation temperature even before reaching the wellhead very early in its production life. This could have been countered by making the production tubular prohibitively small. However, minimizing diameter would tend to increase fluid velocity as well as pressure drop to unacceptable levels. It was therefore decided to select a suitable tubular to provide adequate flow and also add to the life-cycle plan injection of methanol down-hole in well 4 at the deepest point of solids formation to counter the risk. A further anomaly was encountered with the P3, P4, and P5 loop in which backflow was encountered into P4 when attempting to comingle pressure at the manifold. This was experienced in mid and late-life conditions and made the task of commingling the wells together and arriving at a properly converged solution in PIPESIM very difficult. The model was successfully converged by optimizing gas lift in P4 to create a suitable production fluid density which would create the desired forward flow for all production well within the flow loop. Wells P3 and P5 were compensated for this by varying their gas rate injection. Line sizes were chosen to avoid excessive fluid velocities and minimize pressure loss. Line choices are summarized in Table 1, as well as the resulting separator arrival pressure for early, mid, and late, life conditions. The use of gas lift and production chokes was utilized to comingle pressures at the manifold and achieve sufficient topside pressure.

The ultimate production field plan led to very favorable results as well as manageable flow assurance issues. The required topside pressure of 190 psig was met for all life stages. The erosional velocity predicted by API 14E was not exceeded at any point (assuming an empirical “C” value of 200, per project specifications). Slugging is encountered in the system but will be managed by sufficient separator sizing as well as a topside slug catcher. Low temperature issues were encountered in the P3, P4, P5 production loop but are managed by thermal insulation as well as methanol injection (methanol injection occurs down-hole for P4).

Well	Production Tubular ID (in)	Flowline ID (in)	Riser ID (in)	Arrival Pressure Early (psia)	Arrival Pressure Mid (psia)	Arrival Pressure Late (psia)
P1	7	7	9.5	219.62	208.42	228.2
P2	7	7	9.5			
P3	6	6	7.5	213.2	219.9	205.3
P4	4	6	7.5			
P5	6	6	7.5			

Table 1: Line sizes for flow loop 1 (P1 and P2), and flow loop 2 (P3, P4, P5). Arrival pressures also included for early, mid, and late-life.

A summary of the gas lift usage through all stages of life is included below in Table 2.

GAS LIFT USAGE (MMSCF/D)						
	Early	Mid	Late	Total Lift Early	Total Lift Mid	Total Lift Late
P1	1.95	0.8	0.62	13.451	4.66	2.91
P2	2.85	0.86	0.74			
P3	1.4	0.71	0.48			
P4	0.251	0.29	0.26			
P5	7	2	0.81			

Table 2: Gas-lift usage throughout all stages of production life.

The maximum gas lift rate allowed for the project was given as 65 MMscfd. The greatest amount of gas lift was required in early life, and only amounted to 13.451MMscfd, well below the maximum allotment. A general trend of reduced amounts of gas lift was observed as the field aged. This was attributed to lower flow-rates and fluid velocity within the system which had the effect of reducing the head loss and subsequent need for gas lift.

In addition to the production well study, the design team was tasked to optimize a water injection system. Throughout the life of the production field the flow rate and the pressure goes down for each production well. So in order to mitigate this effect water injection is necessary. The optimized solution involves a single 9” ID riser supplying a subsea manifold. Flow lines then run to the left and right of the manifold to deliver water to respective PLEM’s. The left flowline running to the PLEM is 6” ID. From the PLEM, a 6” flowline supplies injection well 1 and a 1.5” line supplies injection well 2. The flowline running to the right PLEM is an 8” line. From the PLEM, a 6” line supplies injection well 3 and a 5” line supplies injection well 4. Production tubulars are sized to 6”, 4”, 6”, and 5”, for injection wells 1, 2, 3, and 4, respectively. This data is summarized in Table 4, below. Water is injected with injectivity index of 50. A design requirement was not to exceed the maximum well head pressure of 3,000 psi. The topside discharge pump pressure was found to be 10 psi for Early-Life, 400 psi for mid-life, and 600 psi for late life. The piping sizes were optimized to satisfy these requirements for early, mid and late life.

The field development also included deployment of a corrosion inhibitor and methanol injection plan. Chemical delivery is accomplished via a single umbilical (one for each chemical), which runs subsea to an Umbilical Termination Assembly. The umbilical interfaces with a junction plate, which delivers the injected chemical to five separate flow lines. These flow lines run to their respective production wells. In the case of well 4, methanol is injected down hole in order to account for low temperatures experienced in the production tubular. PIPESIM was utilized to effectively size the umbilical and separate flow lines to ensure that chemical arrival pressure exceeded flowing wellhead pressure, ensuring positive injection. Required topside pump pressure was determined for both chemical and corrosion inhibitor injection pumps for all stages of life.

2. Field Architecture and Flow Assurance Strategy

2.1 Field Architecture

The field deployment plan includes the use of two manifolds and two risers. The philosophy of the field architecture was to minimize flowline distance while positioning the manifold units near to each other to facilitate both risers running to the FPSO in close proximity (for ease of top-side handling). Two production manifolds (M1 and M2) are utilized in the field. M2 is positioned closer to well P4 in order to reduce the flowline distance between the wellhead and manifold in order to minimize temperature loss. Production wells P1 and P2 use steel flow lines to connect their respective production trees to M1. Productions wells P3, P4, and P5 also use steel flow lines to connect to M2. M1 and M2 are located approximately 200 meters away from each other to position themselves close to the riser base location. To deliver produced fluids to the riser base, each manifold utilizes a steel flowline to connect to a PLET at the riser base location. At this point, two risers are run to the FPSO nearly side-by-side. This orientation is detailed Figure 1. The FPSO receives the two risers in a forward-mounted turret. Table 3 details the production field specifications, including tubular ID as well as horizontal distance and elevation change.

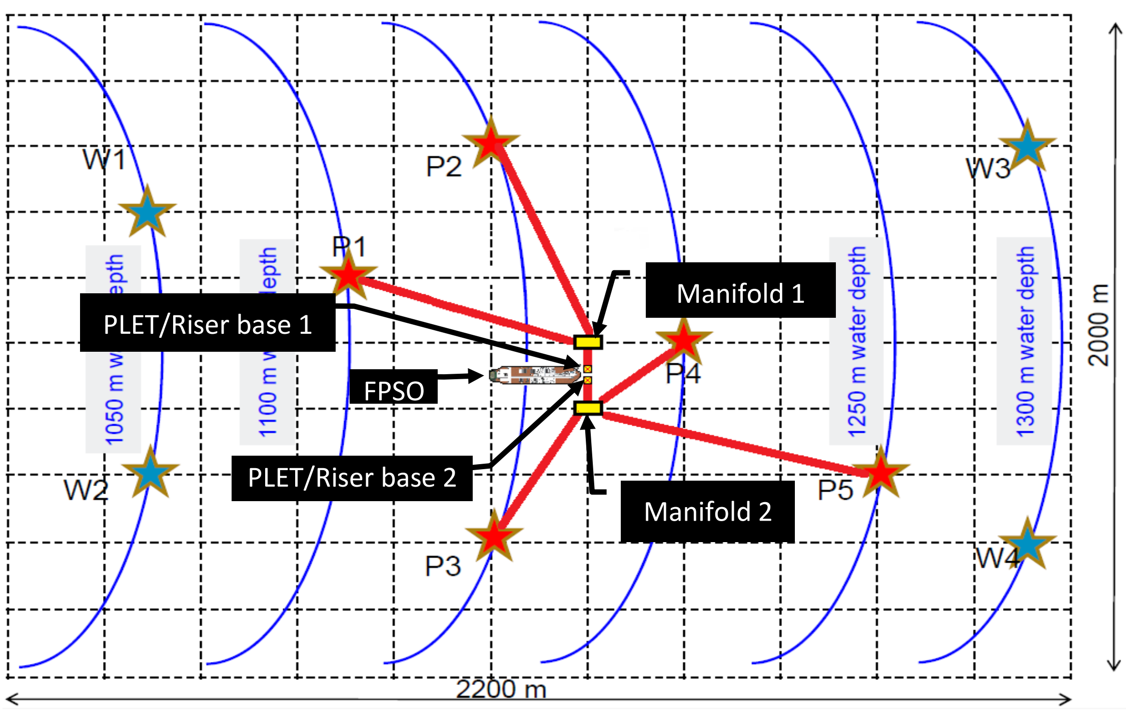

Figure 1: Production field layout. Flowline represented in red.

PRODUCTION SPECIFICATIONS					
Well	**Production Tubular ID (in)**	**Flowline ID (in)**	**Riser ID (in)**	**Horizontal Distance (m)**	**Elevation Change (m)**
P1	7	7	9.5	538.52	-70
P2	7	7	9.5	632.45	-20
Manifold connected to riser base with 7" line running 100 meters with no elevation change.					
P3	6	6	7.5	447.2	-20
P4	4	6	7.5	282.84	30
P5	6	6	7.5	632.45	80
Manifold connected to riser base with 7.5" line running 100 meters with no elevation change.					

Table 3: Specifications for all production tubulars.

There are an additional four water injection wells located around the periphery of the field that are used to sustain down-hole pressure throughout the field life. The design philosophy centered on the use of a single manifold that supplies two PLEMs, which then in turn supply their respective injection wells. From the top down, a single riser is used to inject water to a manifold located to the right of the riser base area. The flow is then split with one flowline running to the left of the field in between the production risers and the other line running to the right. These flowlines are used to avoid pipe clutter near the production wells. Each flowline supplies a PLEM. From the PLEM, separate flowlines supply water to the injection wells. Table 4 details the tubular specifications for the water injection system. Figure 2 demonstrates the water injection network.

WATER INJECTION SPECIFICATIONS								
	Production Tubular (in)	**Flowline (in)**	**Flowline Distance (m)**	**Elevation Change (m)**	**Manifold Connection Line ID (in)**	**Riser (in)**	**Manifold Connection Length**	**Manifold Connection Elevation Change**
W1	**6**	**6**	**538.5**	**20**	**6**	**9**	**700**	**105**
W2	**4**	**1.5**	**360.5**	**20**	**6**	**9**		
W3	**6**	**6**	**707**	**-25**	**8**	**9**	**800**	**-100**
W4	**5**	**5**	**510**	**-25**	**8**	**9**		

Table 4: Water injection tubular specifications.

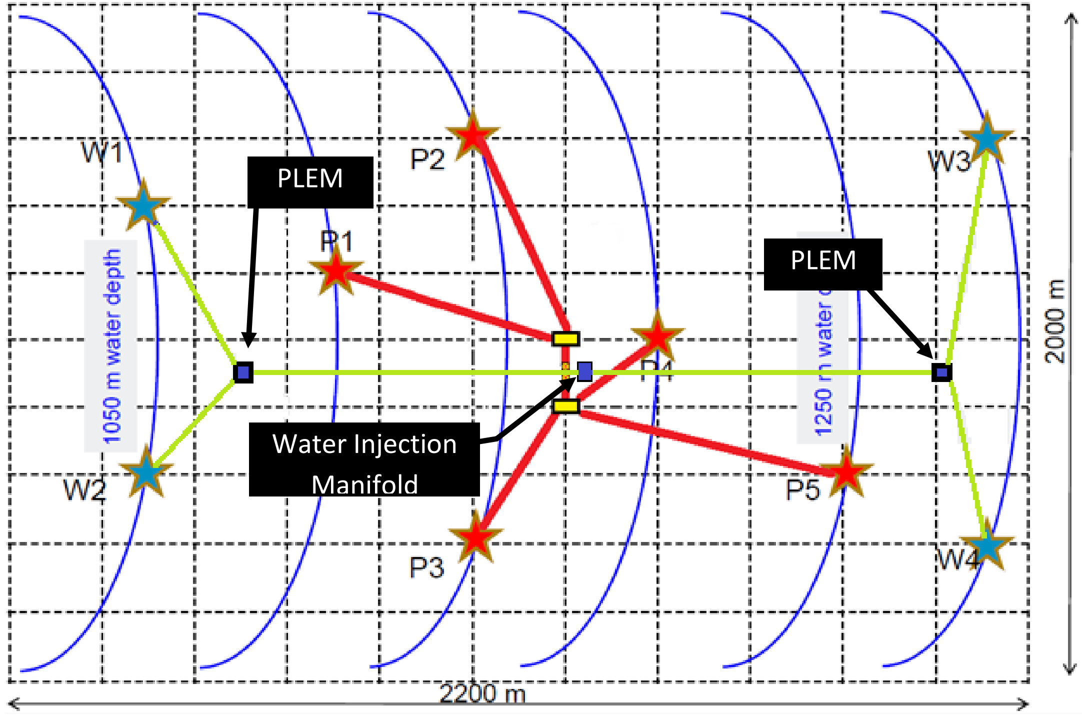

Figure 2: Water injection field layout. Injection lines detailed in green.

Chemical injection includes two umbilicals run from the forward section of the FPSO to the seabed at a location slightly offset to the left of the riser PLET units. An umbilical termination assembly is located at this location which receives the two umbilicals from the topside and distributes flow through a junction plate and into separate flow lines. These flow lines carry chemicals to their respective wells.

2.1.1 PIPESIM Field Orientation

Figure 3-7 demonstrate the production and injection well layouts as they were evaluated in PIPESIM.

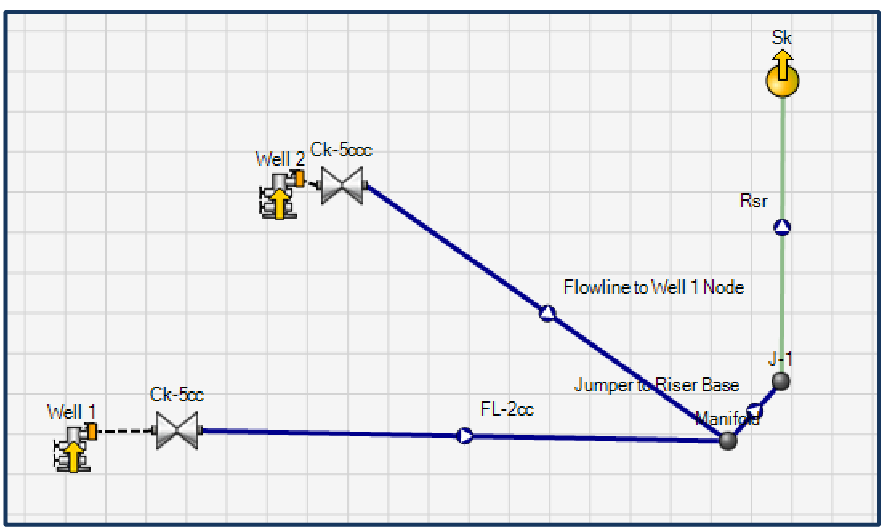

Figure 3: PIPESIM layout of production wells P1 and P2

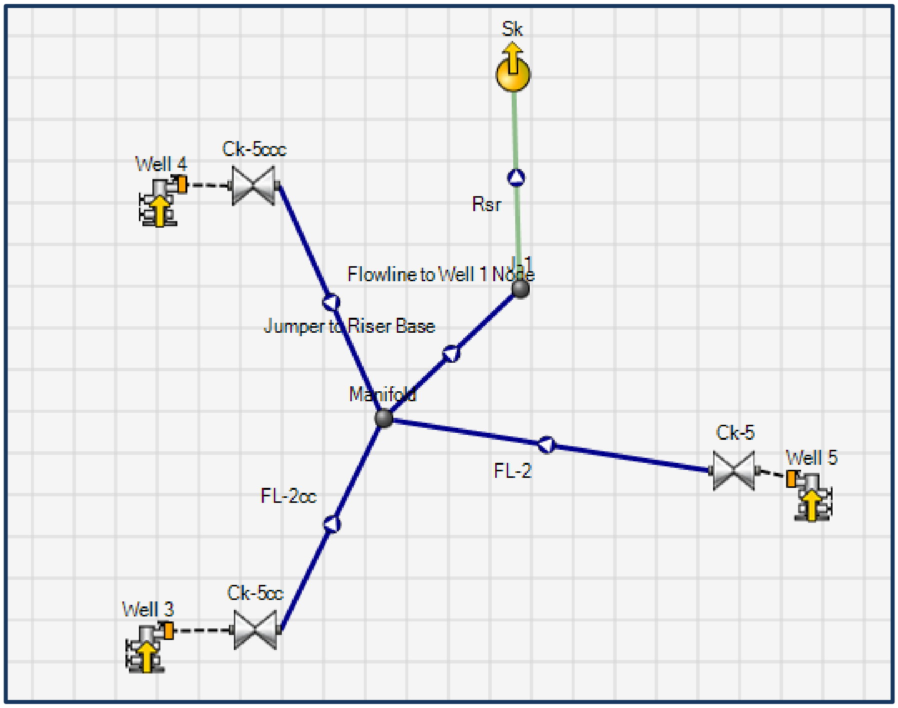

Figure 4: PIPESIM layout of production wells P3, P4, and P5.

Figure 5: PIPESIM water injection layout.

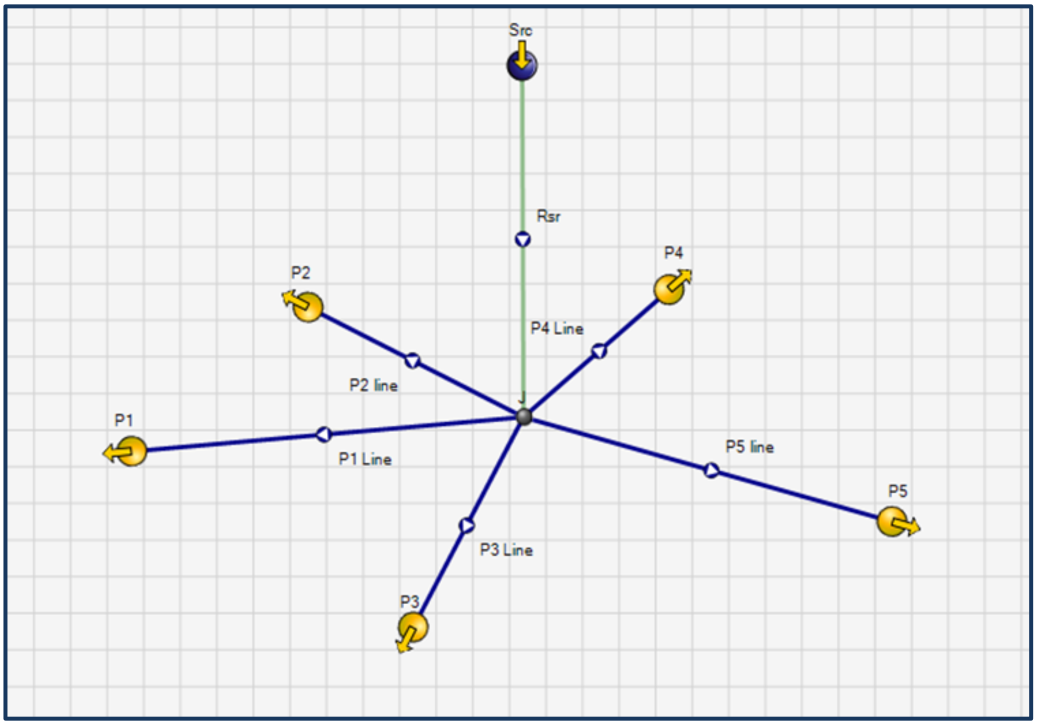

Figure 6: PIPESIM corrosion inhibitor injection layout.

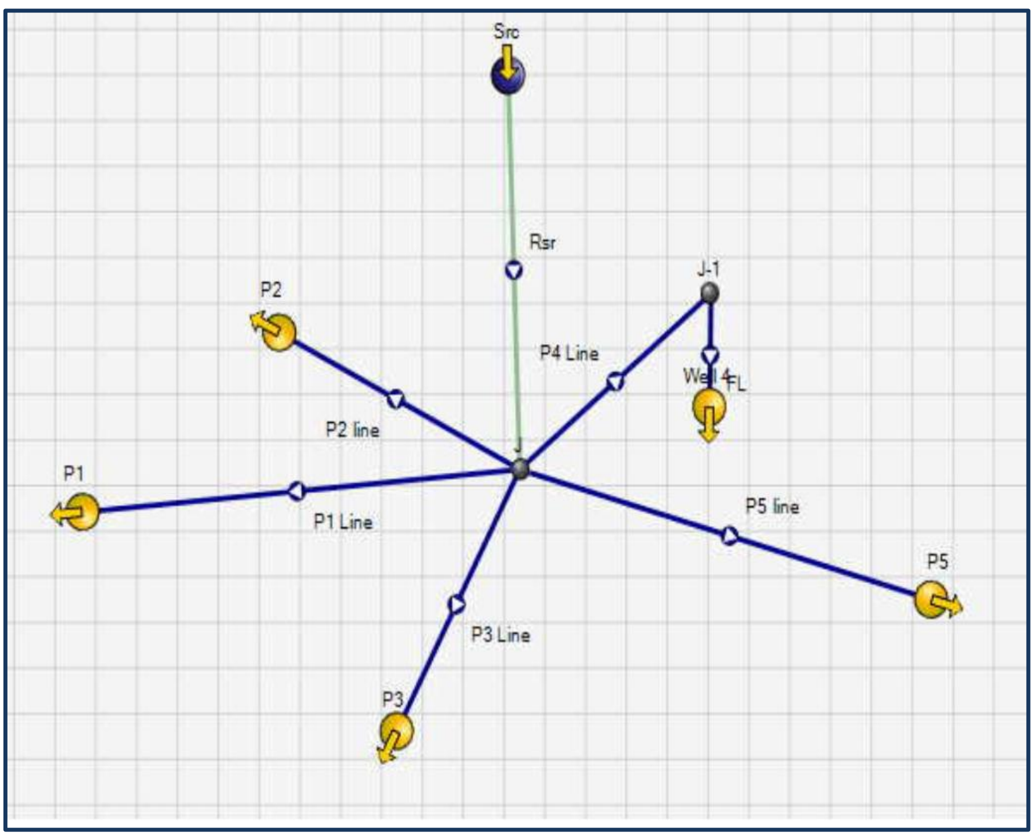

Figure 7: PIPESIM methanol injection layout. Note down-hole section of well 4.

2.2 Flow Assurance Strategy

2.2.1 Slugging

Slugging is encountered at all stages of life in both risers. It is planned to conduct a separate study to evaluate the slugging frequency and intensity. This data will then be used to properly size a topside slug catcher of adequate volume to contend with all slug contingencies. It is also planned to utilize a pigging network to remove entrained water. Topside receiving facilities are equipped with chokes that will be used to safely process slugs. FlowManager™ will be used to actively monitor the network to alert topside personnel of incoming slugs.

2.2.2 Erosion

Erosion is not a concern in this system. All lines have been adequately sized to keep production velocities well below erosional limits at all stages of life. This assumes an API 14E "C" value of 200, per the project parameters. PIPESIM assumes a default value of 100 for "C" which cannot be changed within the program. Therefore, the given erosional velocity output by PIPESIM can be multiplied by two to obtain the actual erosional velocity. All results which satisfy the erosional velocity constraint assuming a "C" value of 100 can therefore be considered extremely conservative. The flow loop containing wells P1 and P2 satisfy the erosional constraints assuming a "C" value of 100. Results in the respective section are therefore presented assuming this value. The flow loop containing wells P2, P3, and P4 satisfy the erosional constraints assuming a "C" value of 200. Results in the respective section are therefore presented assuming this value. Figure 8 relates an excerpt from the PIPESIM user's manual which explains the employed formula and chosen value for the empirical constant.

$$V = \frac{C}{\sqrt{\rho_m}}$$

Where r_m is the fluid mean density and C is an empirical constant. C has dimensions of (mass/(length*time^2))$^{0.5}$. Its default value in engineering units is 100, which corresponds to 122 in SI units.

Figure 8: Erosional velocity formula and explanation taken from the PIPESIM user's manual (Schlumberger, 2013).

2.2.3 Solids Formation

Temperature issues are encountered in well 4 early-life (in the production tubular) and well 5 late-life (in the flowline). Well 4 production fluid drops below 70°F approximately 2,000 feet below the wellhead. It is planned to inject wax inhibition chemicals at this depth along with methanol to combat hydrates. Methanol and corrosion inhibitor is injected at the production tree for all other wells. A strategy adopted by the design team was to commingle the flow from P5 to wells P3 and P4 to raise the production fluid temperature in the riser above 70 degrees for all stages of life. This was proved to be an effective decision and resulted in no issues concerning low temperature in the respective riser. A pigging network is in development to allow pigging of all flowline in addition to each riser. An initial design is detailed in

Figure 9. With this concept, a separate accessory umbilical will be run subsea to each manifold and interface with a subsea pig launcher mounted on the manifold. The flowline to be pigged will be shut in and blown down. With this concept, a separate accessory umbilical of approximately 6" ID will be run subsea to each manifold and interface with a subsea pig launcher mounted on the manifold. The flowline to be pigged will be shut in and blown down. Hot oil is pumped through the accessory umbilical and will push the pig through the target flowline network. The pig will travel down the main flowline from the manifold to the production tree and then back to the manifold through the pig return line. The pig can either be directed back to the pig launcher or be directed up the riser. A variable ID pig must be used. The feasibility study will include determination of required pigging frequency.

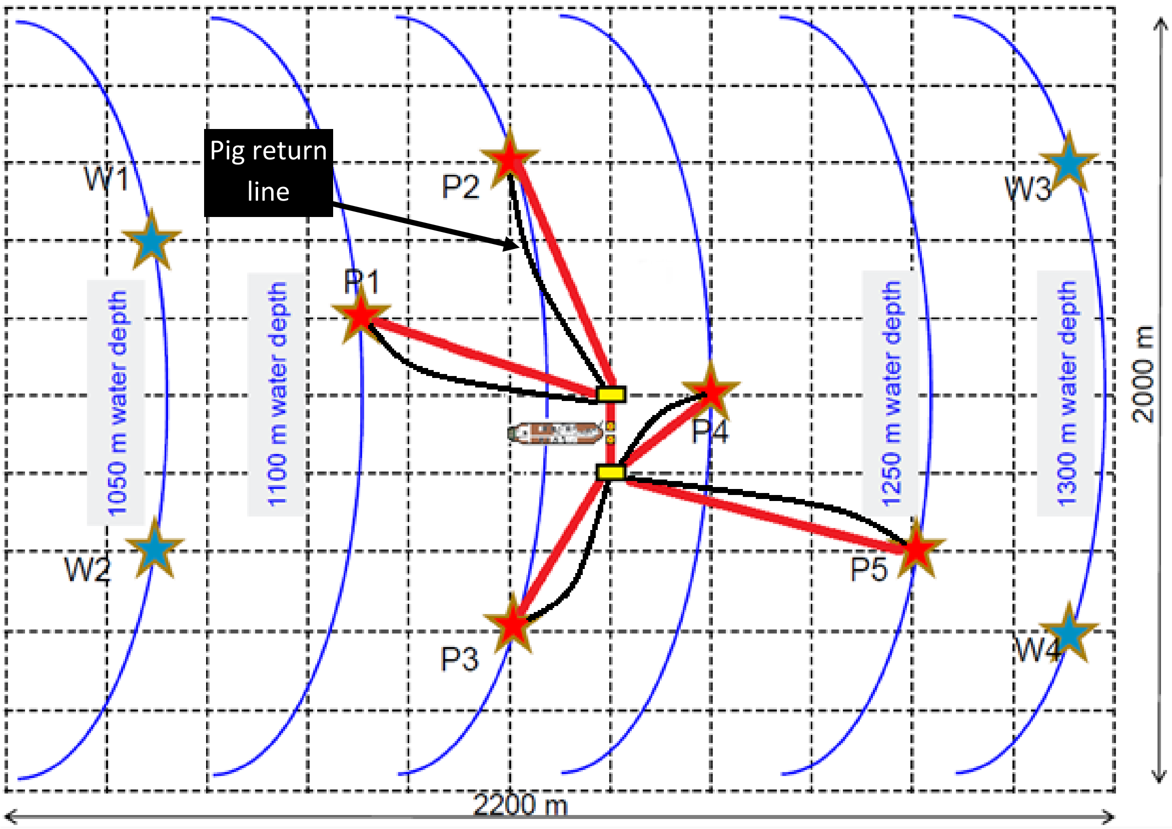

Figure 9: Field layout including pig-return lines detailed in black.

3 Input Data and Assumptions

3.1 Reservoir and Fluids

Each well was assumed identical in terms of construction and artificial lift placement. Essentially, each well profile can be described as a deviated well with a production tubular that runs to 7,200 feet MD with casing running to 11,320 feet MD. The packer is installed at 7,100 feet, with vertical completions at 7,200 feet (perforation point). A gas lift injection point comes into the production tubular above the packer at 7,050 feet. This profile is demonstrated below in Figure 10 as it was modeled in PIPESIM. Note also the well profile input for the deviation survey.

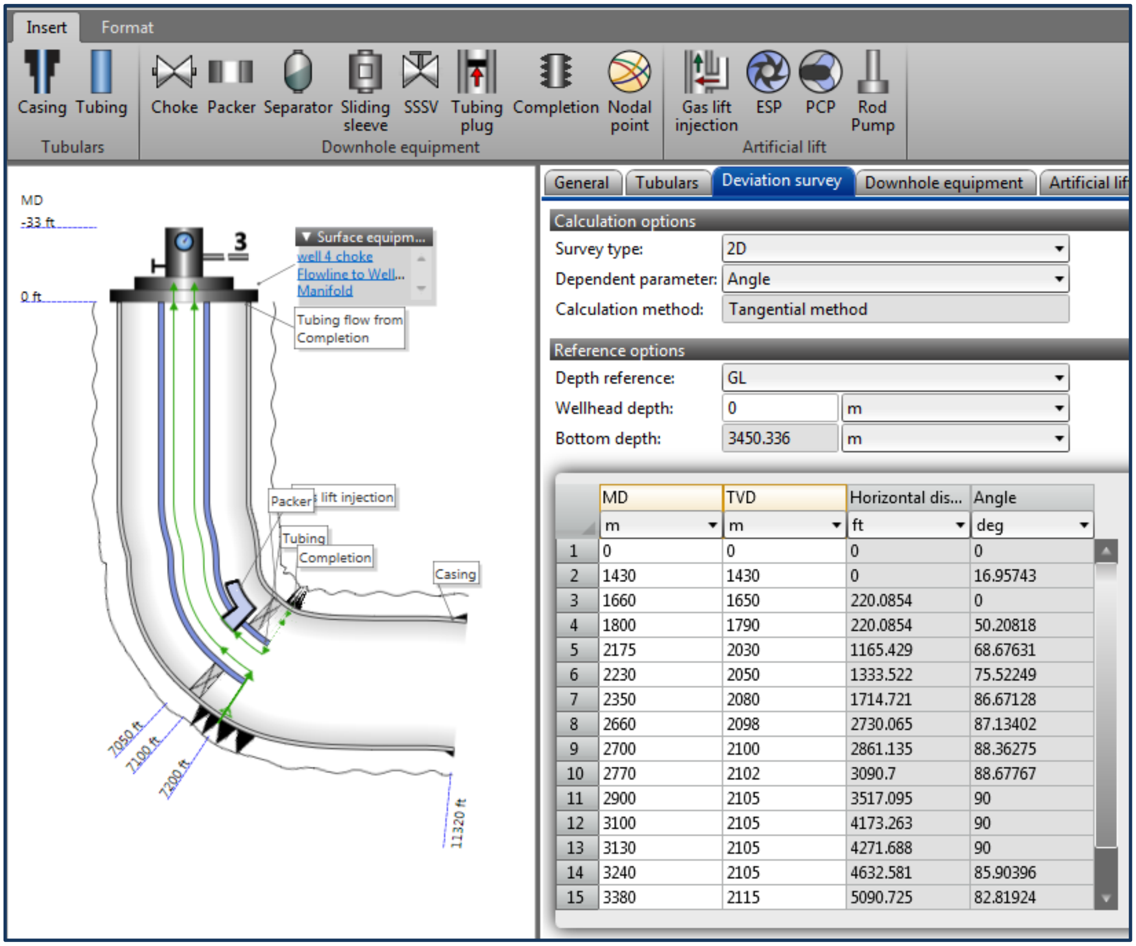

Figure 10: Well profile cross section.

Oil viscosity was correlated to Beggs and Robinson. .0075 mole fraction of H_2S was assumed. When detailing the fluid model for the production fluid, a gas specific gravity of 0.8 was assumed (as well as for gas lift). Reservoir pressure was calculated per the equation:

Productivity Index = Q / (Reservoir Pressure – FBHP)

The results of this calculation are included below in Table 5.

	Early-life Production Rate (bopd)	Pressure, early life (psi)	Mid-Life Production Rate (bopd)	Reservoir Pressure, mid life (psi)	Late-life Production Rate (bopd)	Reservoir Pressure, late life (psi)
P1	12300	3815	4500	3425	1200	3260
P2	14600	3930	4000	3400	2000	3300
P3	6300	3515	1700	3285	800	3240
P4	780	3239	200	3210	110	3205.5
P5	15000	3950	7000	3550	2500	3325

Table 5: Production rate and reservoir pressures for all production wells.

It was assumed that water cut percentages progress from 10% for early-life, to 40% at mid-life, and 90% for late-life**.** Tables 6 and 7 detail the assumed fluid and reservoir characteristics used for modeling. Tables 8 and 9 detail parameters assumed for the water injection study.

Parameter	Unit	Value
Downhole pressure	psia	3200
Depth of downhole sensor	ft	7200
Productivity Index of the reservoir	stb/d/psi	20
Reservoir temperature	°F	120
Oil API	-	19
Sea bed temperature	°F	40
Soil temperature profile	-	Linear interpolation from reservoir temperature to sea bed tempearture
Saturation pressure	psia	2800
Live oil viscosity at downhole P/T	cP	14
Solution GOR	scf/stb	340
Solution GLR	scf/stb	650
Dead oil viscosity @ 104 °F	cP	130
Sulphur content (weight percent)	%	0.75
Wax content	%	3
Wax appearance temperature	°F	70
Pour point	°F	-20
Asphaltene content	%	2

Table 6: Fluid and reservoir data.

Criteria	Specification
Erosion	API 14E C-Factor of 200
Total drawdown limit	800 psi
Maximum Shut-in wellhead pressure	2500 psia
Hydrate temperature corresponding to Shut-in pressure	65 °F
Maximum wellhead temperature	130 °F
Gas lift injection pressure (surface)	3000 psig
Topsides separator pressure	190 psig
Topsides temperature	70 °F

Table 7: Production well assumptions for modeling.

3.2 Water Injection

The following data was assumed for water injection modeling.

Parameter	Unit	Value
Maximum wellhead pressure	psig	3000
Injectivity Index	stb/d/psi	50
Design capacity	bbl/day	150,000
Maximum WI pump discharge pressure	psia	2500
FPSO discharge temperature	°F	80
Injection water viscosity	cP	0.85
Injection water specific gravity	-	1.02

Table 8: Parameters assumed for the water injection study.

Oil Production rate (bopd) from each well			
Well	**Early-Life**	**Mid-Life**	**Late-Life**
W1	7000	21500	23000
W2	400	1700	2000
W3	17500	34000	36000
W4	5000	10000	20000

Table 9: Injection rates assumed for water injection wells.

3.3 Gas Lift and Chemical Injection

To boost the delivery pressure of the production wells, gas lift was used bottom hole on all wells. Gas lift occurred slightly above the packer. Table 10 below lists the assumptions used when modeling gas lift.

Parameter	Unit	Value
Maximum gas lift rate	MMscfd	65
Compressor discharge temperature	°F	80
Compressor discharge pressure	psia	3000
Specific gravity of gas	-	0.8

Table 10: Gas lift properties.

Dosage rate, specific gravity, and viscosity were specified in the project input parameters for the corrosion inhibitor as well as methanol. These are included below in Table 11.

Chemical	Specific gravity	Viscosity	Dosage rate (gpm)
Corrosion Inhibitor	0.9	18 cP @ 4.4 °C 4 cP @ 21.1 °C	1
Methanol	0.8	1.2 cP @ 68 °F	3

Table 11: Chemical injection properties.

When specifying a fluid model for chemical injection, an LGR value of 99,999 was assumed to specify the fluid as gas free. Gas SG was kept as the default. The API value for each chemical was calculated per the following formula:

$$API = 141.5/SG - 131.5$$

4 Modeling and Analysis Approach/Methodology

4.1 Production Well Modeling

A key design goal for the project was to create two comingled circuits, with the impetus that this would allow greater optimization potential when attempting to avoid common flow assurance issues such as solids formation and erosion. The design team decided from the inception of the project to adopt insulated flow lines and riser as it was recognized early on that low temperature issues would be encountered as the field aged. The default PIPESIM value of 0.2 was assumed for all flow lines and risers.

4.1.1 Early Design iterations

An initial analysis involved comingling P1, P2, and P5 together as one circuit and commingling P3 and P4 together as a second circuit. This strategy was chosen as a way to commingle similarly performing wells (in terms of flow rate and reservoir pressure) in an attempt to avoid having to choke excessive flow. However, it soon became apparent that this configuration created undue challenges. The high-performance P1, P2, and P5 circuit created excessive flow velocities in the riser, necessitating a rather large riser selection which would have severely burdened the project budget. The P3, P4 circuit developed temperature issues early in life. This was mainly due to P4, which is a weak well offering comparatively little flow rate. As a consequence, the production temperature dropped below the solids formation temperature while still in the production tubular. This problem further manifested itself after comingling with P3, as the cooled flow from P4 brought the comingled flow temperature down, leading to a drop below wax formation temperature in the riser.

In order to solve these problems, the field orientation was changed to the current configuration. P5 was taken out of the P1, P2 loop and added to the P3, P4 loop. The effects were very positive. The new P1 and P2 loop now necessitated a 9.5” riser as opposed to a 10.5” riser. In the P3, P4, and P5 loop, no temperature issues were encountered in the riser for early, mid, or late-life. This limited the flow assurance issue to the P4 tubular/flowline branch, which will be managed throughout its life with down-hole methanol injection.

4.1.2 Modeling Approach

The design team adopted a bottoms-up strategy when modeling the field orientation. This began with choosing tubular and flowline sizes for each well and modeling the manifold arrival pressure. Tubular/flowline choice was driven by the need to limit pressure drop as well as provide a manifold delivery pressure that could be comingled easily with minimum gas lift. Once the tubular and flow lines were chosen, design efforts then focused on riser diameter specification. Essentially, this was accomplished by evaluating the top side delivery pressure assuming a commingled pressure as well as a specific riser ID. The first step for this analysis involved assuming a comingled pressure at the manifold and then evaluating the topside delivery pressure for several different riser IDs. Gas lift and production chokes were used to bring the manifold arrival pressure as close as possible for each well. Once a suitable comingled pressure was obtained, the flow rate of each well was modeled. The flow rates for each well in their perspective circuits were then combined and used as the input to the "Sink" node when conducting a network analysis ("Sink" of course symbolizing the topside separator). If the required delivery pressure could not be met with feasible riser ID choices, the comingled pressure was changed and the analysis repeated. These iterations continued until a suitable comingled pressure and riser ID were found.

Comingle manifold at 1000 PSI				
	Gas Injection	Choke Bean	Pressure at Manifold	Flow Rate at Manifold
Well 1	1.95	Open	1000.82	12298
Well 2	2.85	Open	999.1	14599.7
Riser ID	COMINGLED TOPSIDE PRESSURE	Required topside pressure met with 9.5" Riser.		
7	60.54			
8	140.9			
9	198.4			
9.5	219.62			
Max EVR (9.5" riser):	0.726			
Lowest Temp (9.5" riser):	90.78			

Table 12: Iteration example assuming 1,000 psi comingled pressure.

Acceptance criteria included sufficient topside arrival pressure (205 psia minimum) as well as not exceeding erosional velocity. Again, comingling at the manifold was achieved by the use of down-hole gas lift injection. Injection occurred slightly above the packer. To maximize the accuracy of the manifold arrival pressure, production chokes were used at various stages of the field life. An example of the iteration process can be seen in Table 12. Note the various riser ID choices that were evaluated.

4.2 Water Injection Well Modeling

The intention of water injection is to mitigate the loss in reservoir pressure over the life of the production field. The design of water injection circuit includes the riser from FPSO down to a central manifold in which flow lines are connected. These flow lines then travel to respective PLEM's (one PLEM for flow lines to well 1 and 2 while another is for flow lines to well 3 and 4). The injection scheme assumes the water from injection wells 1 and 2 will stimulate production from production wells 1, 2 and 3 whereas water from injection wells 3 and 4 will be used for injecting water to production wells 4 and 5. The reservoir pressure for water well 1 and 2 is considered the maximum of production wells 1, 2 and 3. On basis of given flow rate, injectivity index and reservoir pressure bottom hole pressure for each water well is calculated. While modeling the injection wells the pressure at the bottom of each well profile is ensured to be greater than bottom hole pressure. The network consists of one pressure source with one riser, a centralized manifold, and two PLEM's (each distributing to two wells).

In order to optimize the flowline sizing, validate the network, the following criteria were ensured to be met:

- Pressure at well head should be less than given maximum allowed well head pressure.
- Pressure at completion should be less than bottom hole pressure
- Given flow rate should reach to each corresponding well

- Fluid mean velocity should be less than erosion velocity i.e EVR should be less than 1 (a conservative measure as PIPESIM assumes an empirical “C” value of 100, as opposed to the project specified value of 200).

4.3 Chemical Injection Modeling

The intent of this stage of the project was to design injection circuits for both a corrosion inhibitor as well as methanol. The final design choice involved a single umbilical for each chemical, ran from the forward section of the FPSO subsea to an umbilical termination assembly (UTA). Each umbilical supplies a junction plate in which five chemical lines are made up. These lines then run to respective production wells. The design parameters included a maximum topside injection pump pressure of 100 psi. The vertical methanol umbilical was sized to deliver a dosage rate of 15 gpm (3 gpm for each well), while the corrosion inhibitor umbilical was sized to deliver 5 gpm (1 gpm for each well). With these parameters, several iteration were conducted to isolate proper flow line sizes from the UTA to the production wells in order to provide a delivery pressure at the wellhead slightly greater than the flowing wellhead pressure. This is to ensure positive injection. Well 4 has the only down-hole methanol injection scheme to combat solids formation in the production tubular.

5 Analysis Results

5.1 Production Well Circuit 1 (Wells P1 and P2)

Simulations iterations of several pipe size combinations were conducted to optimize the production flow from P1 and P2 to the manifold. As these wells presented higher flow rates, a somewhat larger profile of tubular and flowline sizes were eventually chosen as smaller lines typically caused excessive fluid velocity in excess of the erosion allowance. The larger pipelines also offered decreased pressure losses due to pipe friction which allowed a reduced amount of required gas lift. Both wells utilize a 7” ID production tubular, 7” ID flowline, 7” ID jumper line from the manifold to the riser base, and a 9.5” riser. Both flow lines flow down-hill. It was decided to choose the PIPESIM default heat transfer coefficient of 0.2 in all cases for sea-bed lines and riser. Insulation was chosen to combat lower temperatures seen in mid and later life.

A summary of the flow line sizes, horizontal distance runs, and elevation changes are detailed in Table 13. Note: negative elevation changes indicate a downhill run.

Well	Production Tubular ID (in)	Flowline ID (in)	Riser ID (in)	Horizontal Distance (m)	Elevation Change (m)
P1	7	7	9.5	538.52	-70
P2	7	7	9.5	632.45	-20

Table 13: Production well circuit 1 tubular sizes, horizontal distances, and elevation changes.

This configuration was then used to evaluate the early, mid, and late-life reservoir conditions with the end goal of meeting the required minimum topside arrival pressure of 205 psia. The first priority was comingling both wells at the manifold at the same pressure. Several comingled pressures were evaluated until the optimized pressure was found which would deliver the required topside pressure. Gas lift was used to accomplish this.

5.1.1 Production Well Circuit 1 Early-life Evaluation

A summary of the comingled parameters is presented in Table 14. As can be seen, arrival pressure is 219.62 psia topsides utilizing 1.95 mmscf/d gas lift for well 1 and 2.85 mmscf/d for well 2. Production chokes remained open for this stage of life and the manifold arrival pressures have been comingled at 1,000 psi.

Iteration 1: Comingle manifold at 1000 PSI				
	Gas Injection (mmscf/d)	Choke Bean	Pressure at Manifold (psi)	Flow Rate at Manifold (STB/d)
Well 1	1.95	Open	1000.82	12298
Well 2	2.85	Open	999.1	14599.7
Riser ID	COMINGLED TOPSIDE PRESSURE	Required topside pressure met with 9.5" Riser.		
9.5	219.62			

Table 14: Production parameters for early-life (well circuit 1)

The following figures demonstrate production profiles for this flow circuit. Call-outs are also included in Figures 11, 12, and 13 to delineate the major equipment sections. Figure 11 shows the pressure profile vs. distance for wells 1 and 2, from reservoir to topside. Figure 12 relates the temperature profile of both wells from reservoir to topsides. The lowest temperature encountered in the system is 90.78°F (top of the riser). This is well above the 70 degree wax formation temperature. Figure 13 relates the EVR of the system from reservoir to topsides. The highest EVR is .72 at the top of riser, well below the maximum EVR value of 1(assuming the more conservative "C" value of 100). Table 15 includes the mean fluid velocity vs. the erosional velocity of each branch (well 1, well 2, and the riser jumper line plus riser).

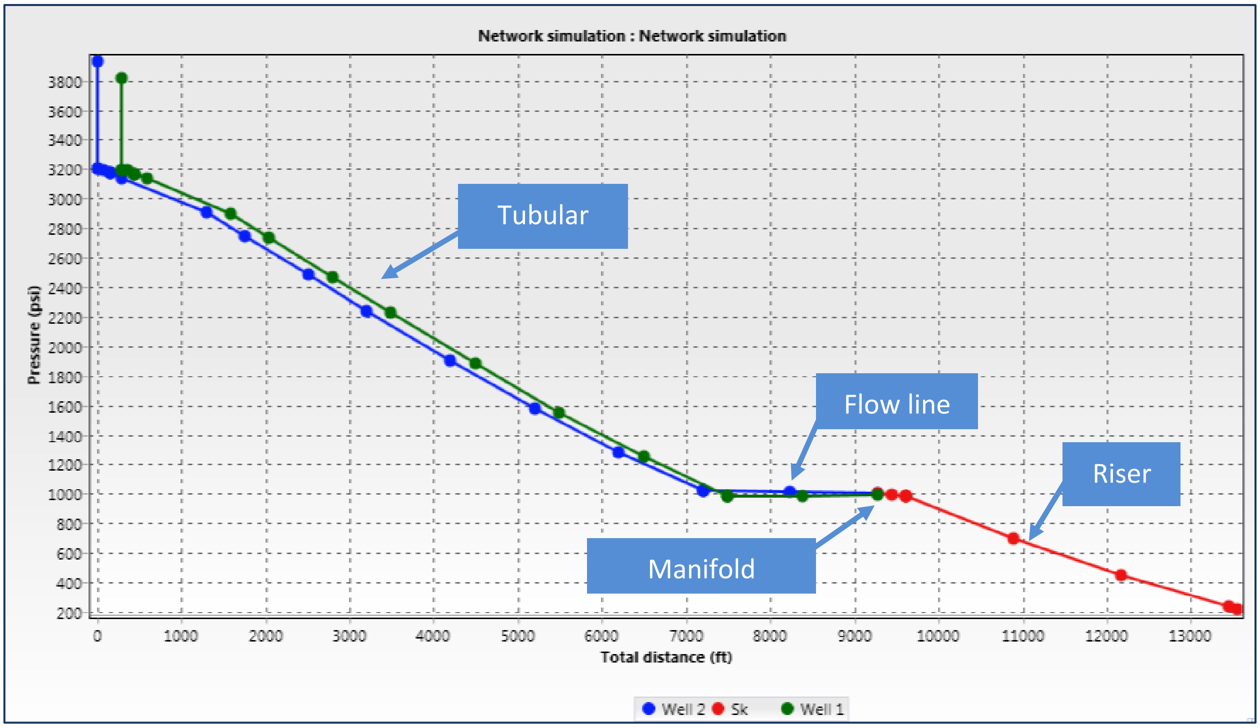

Figure 11: Pressure vs. distance for wells 1 and 2 flowlines as well as riser. Early-life.

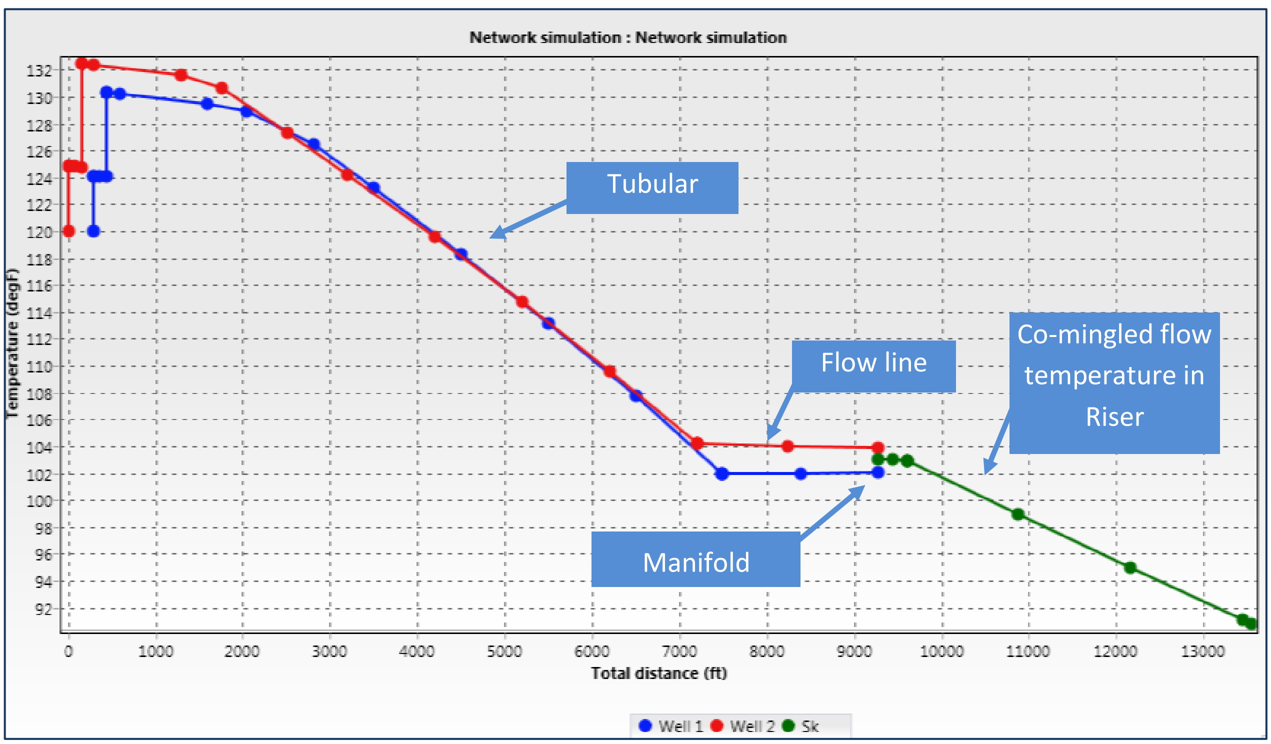

Figure 12: Temperature vs. distance, wells 1 and 2. Early-life.

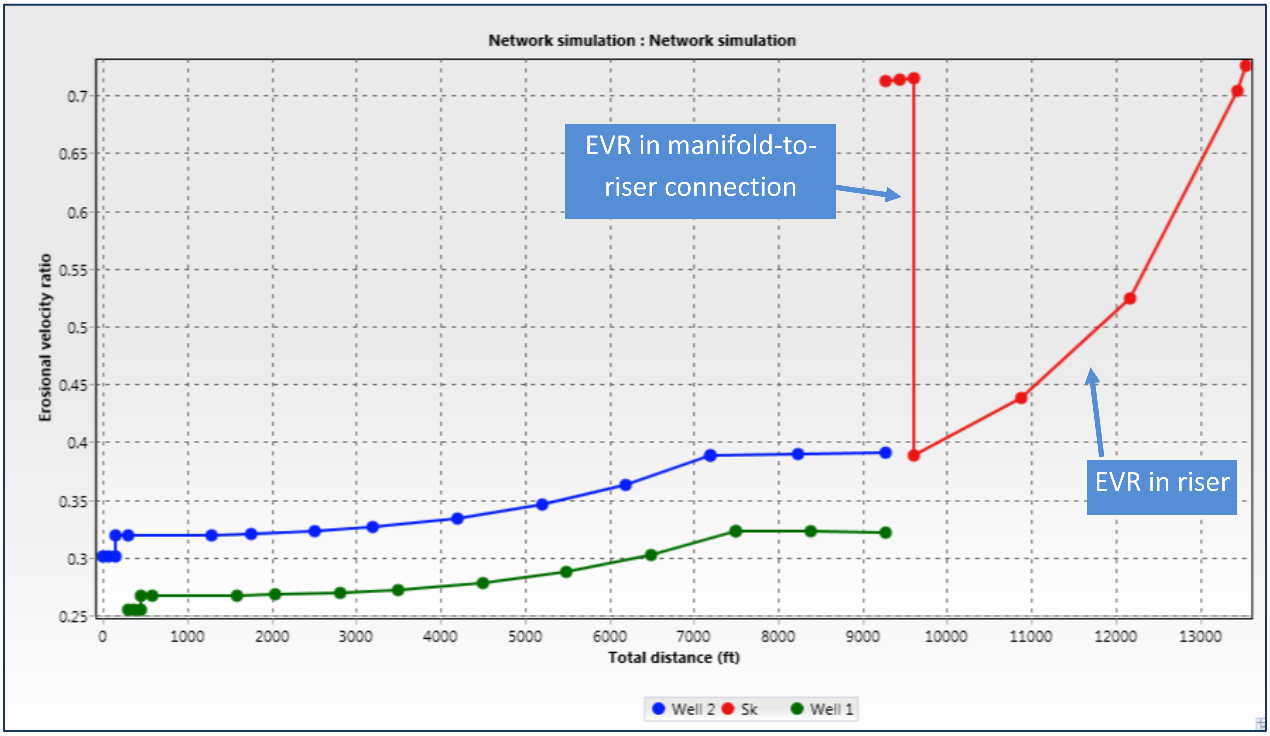

Figure 13: Erosional velocity ratio, wells 1 and 2 plus manifold-to-riser connection and riser. Early-life.

WELL 1			WELL 2			JUMPER + RISER		
Well 1 Distance	Well 1 Mean Fluid Velocity	Well 1 Erosional Velocity	Well 2 Distance	Well 2 Mean Fluid Velocity	Well 2 Erosional Velocity	Riser Distance	Riser Mean Fluid Velocity	Riser Erosional Velocity
0	COMPLETIONS	COMPLETION	0	COMPLETIONS	COMPLETION	0	12.0196	16.88402
0	COMPLETIONS	COMPLETION	0	COMPLETIONS	COMPLETION	164.0488	12.0733	16.9217
0	3.460177	13.58276	0	4.08407	13.58498	328.0976	12.12788	16.9599
64.2	3.460255	13.58291	64.2	4.084163	13.58513	328.0976	NODE	NODE
150	3.460456	13.58331	150	4.084403	13.58553	328.0976	6.585799	16.96136
150	GAS LIFT	GAS LIFT	150	GAS LIFT	GAS LIFT	1607.598	8.37209	19.12376
150	3.706622	13.86866	150	4.448715	13.94289	2887.198	11.9913	22.88704
294.5	3.707319	13.86996	294.5	4.449693	13.94442	4166.698	21.61055	30.72482
1294.5	3.712295	13.87926	1294.5	4.456793	13.95554	4266.698	23.01209	31.70549
1753.8	3.716544	13.88721	1753.8	4.47592	13.98546			
2508.4	3.759138	13.96656	2508.4	4.554015	14.10694			
3200	3.839255	14.1146	3200	4.657175	14.26582			
4200	4.012353	14.42928	4200	4.876436	14.59778			
5200	4.290384	14.92084	5200	5.220566	15.10408			
6200	4.732052	15.67004	6200	5.754537	15.85772			
7200	5.421226	16.77235	7200	6.568758	16.94248			
7200	CHOKE	CHOKE	7200	CHOKE	CHOKE			
7200	5.423426	16.77336	7200	6.571566	16.94368			
8089.727	5.397337	16.73297	8237.742	6.616802	17.0019			
8981.755	5.363338	16.68018	9276.141	6.649079	17.04332			

Table 15: Each branch detailing distance, mean fluid velocity, and erosional velocity. Early-life.

Table 15 above details the velocity profile of all branches. Note that fluid mean velocity does not surpass erosional velocity at any point.

5.1.2 Production Well Circuit 1 Mid-life Evaluation

A summary of the comingled parameters for mid-life conditions is presented in Table 16. As can be seen, arrival pressure is 208.42 psia topsides utilizing 0.8 mmscf/d gas lift for well 1 and 0.86 mmscf/d for well 2. The production choke remained open for well 1. A 2.5" choke bean was used on the well 2 production tree. Pressure was comingled at the manifold at 940 psi.

Iteration 1: Comingle manifold at 940 PSI				
	Gas Injection	Choke Bean	Pressure at Manidfold	Flow Rate at Manifold
Well 1	0.8	Open	940.6	4500.27
Well 2	0.86	2.5	940.528	3998.7
Riser ID	COMINGLED TOPSIDE PRESSURE	Topside pressure acceptable		
9.5	208.42			

Table 16: Production parameters for mid-life (well circuit 1).

The following figures demonstrate the production loop operational performance for mid-life conditions. Figure 14 demonstrates a delivery pressure of 208.42 psia. Figure 15 demonstrates the lowest temperature in the midlife system as 83.2°F topsides. Figure 16 demonstrate the max EVR as 0.2214. Table 17 shows the velocity profiles in each production branch. All velocities are much slower than early-life conditions and therefore substantially below the maximum erosion velocity.

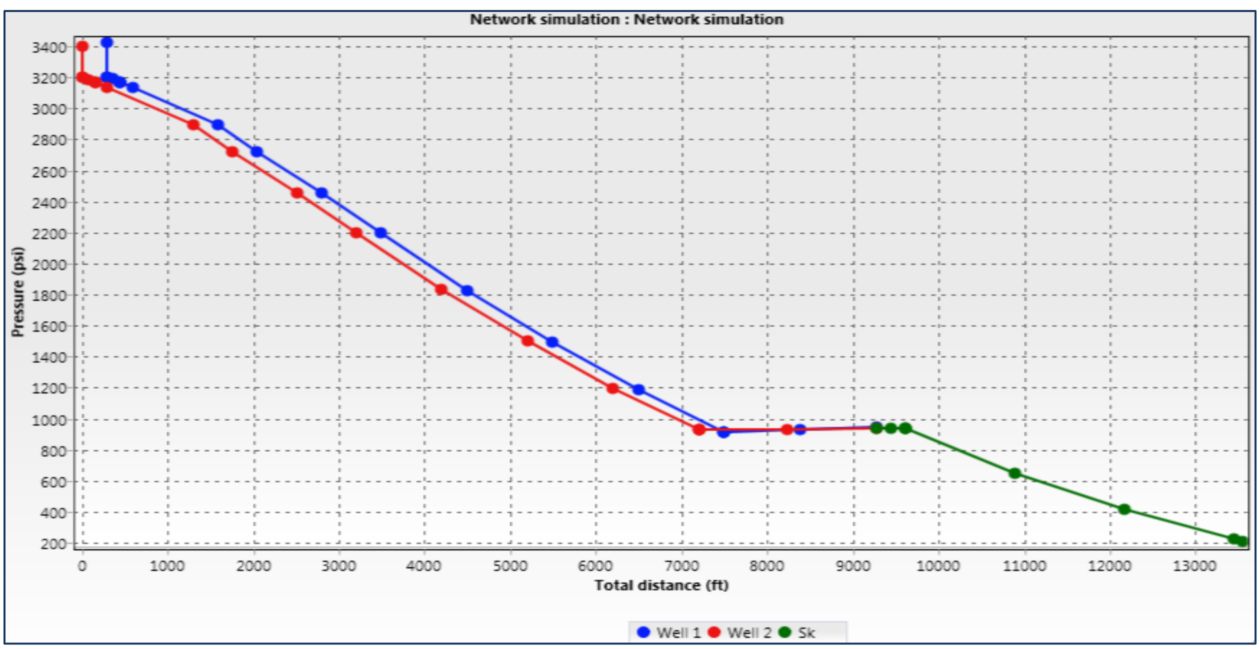

Figure 14: Pressure vs. distance for wells 1 and 2 flowlines as well as riser. Mid-life.

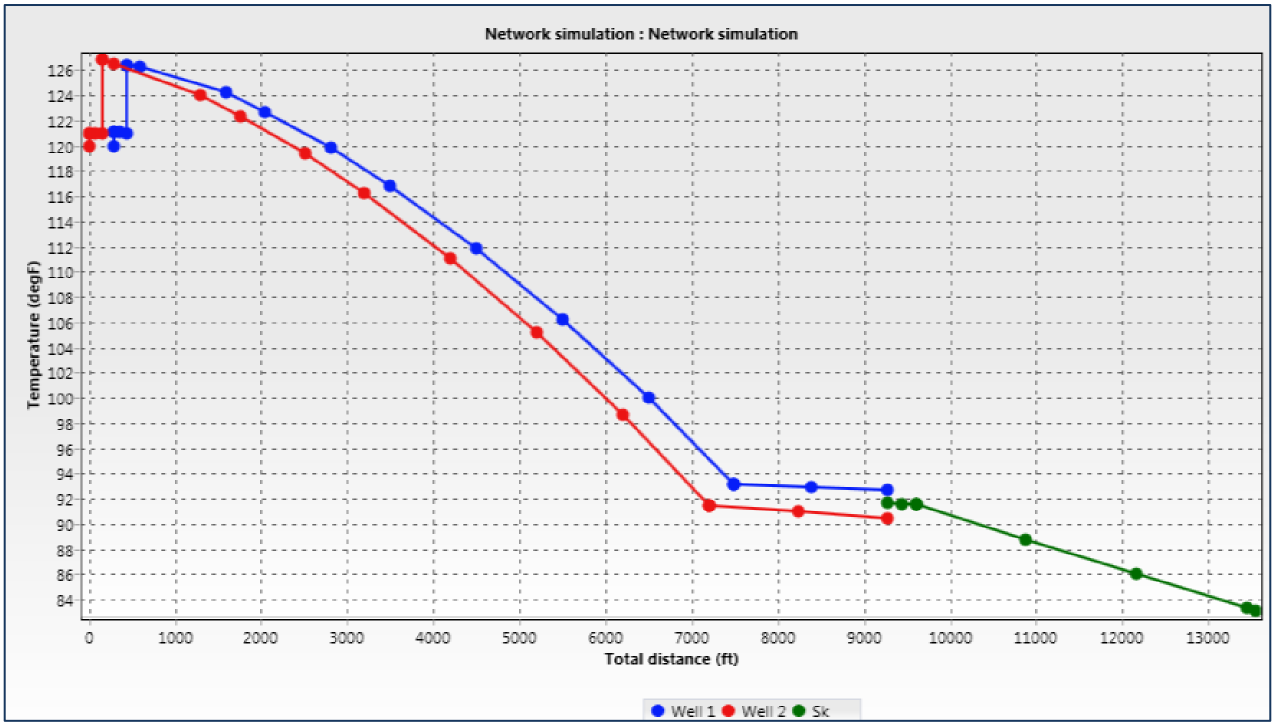

Figure 15: Temperature vs. distance, wells 1 and 2. Mid-life.

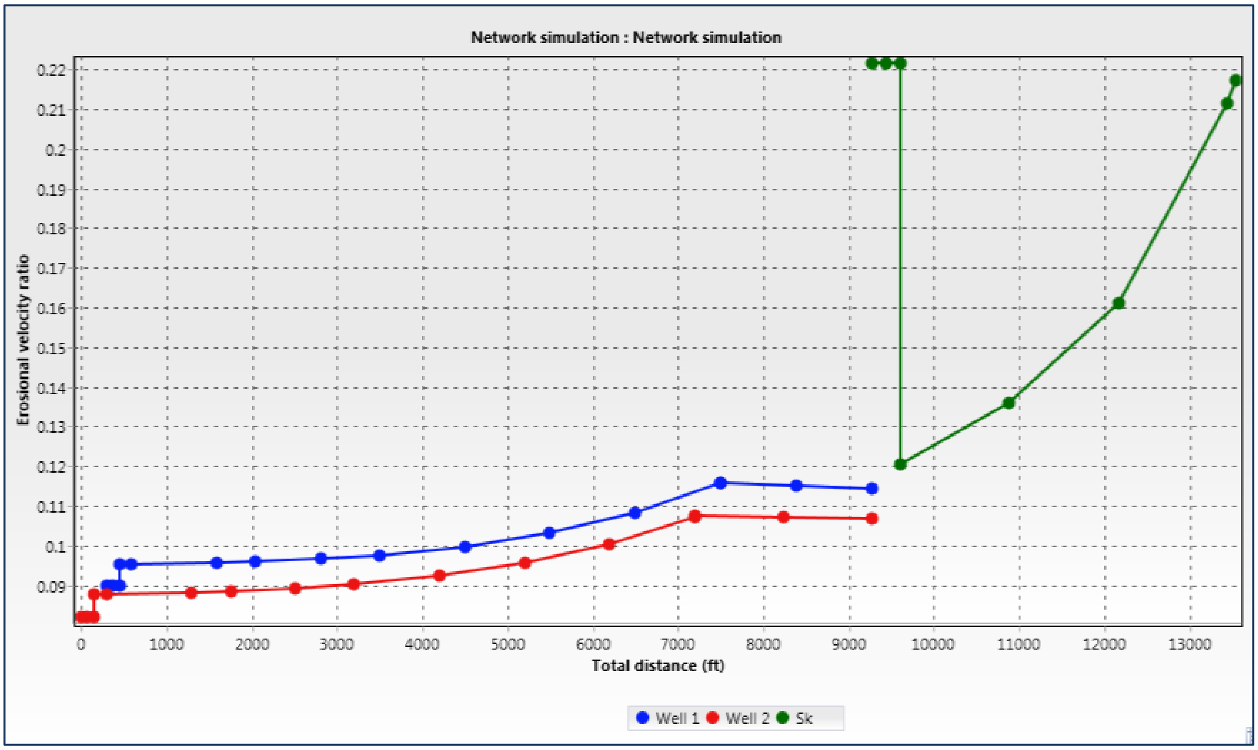

Figure 16: Erosional velocity ratio, wells 1 and 2 plus manifold-to-riser connection and riser. Mid-life.

WELL 1			WELL 2			JUMPER + RISER		
Well 1 Distance	Well 1 Mean Fluid Velocity	Well 1 Erosional Velocity	Well 2 Distance	Well 2 Mean Fluid Velocity	Well 2 Erosional Velocity	Riser Distance	Riser Mean Fluid Velocity	Riser Erosional Velocity
0	COMPLETIONS	COMPLETIONS	0	COMPLETIONS	COMPLETIONS	0	3.648327	16.47586
0	COMPLETIONS	COMPLETIONS	0	COMPLETIONS	COMLETIONS	164.0488	3.650804	16.48146
0	1.190392	13.23171	0	1.084708	13.23157	328.0976	3.651678	16.48343
64.2	1.190423	13.23188	64.2	1.084735	13.23174	328.0976	NODE	NODE
150	1.190499	13.2323	150	1.084803	13.23215	328.0976	1.982806	16.48416
150	GAS LIFT	GAS LIFT	150	GAS LIFT	GAS LIFT	1607.598	2.536517	18.64429
150	1.292429	13.57739	150	1.197544	13.65425	2887.198	3.558666	22.08363
294.5	1.292708	13.57886	294.5	1.198855	13.66172	4166.698	6.11958	28.95928
1294.5	1.300537	13.61991	1294.5	1.209409	13.72172	4266.698	6.474732	29.78776
1753.8	1.310417	13.67155	1753.8	1.219373	13.77813			
2508.4	1.330815	13.77754	2508.4	1.239758	13.89283			
3200	1.358332	13.91925	3200	1.266995	14.04461			
4200	1.419529	14.22935	4200	1.32685	14.37252			
5200	1.515294	14.70149	5200	1.421428	14.87594			
6200	1.667881	15.42395	6200	1.565413	15.61121			
7200	1.911218	16.5108	7200	1.789998	16.69354			
7200	CHOKE	CHOKE	7200	CHOKE	CHOKE			
7200	1.911915	16.51145	7200	1.793176	16.70596			
8089.727	1.891058	16.42114	8237.742	1.788182	16.68268			
8981.755	1.868189	16.32155	9276.141	1.778729	16.63853			

Table 17: Each branch detailing distance, mean fluid velocity, and erosional velocity. Mid-life.

Table 18 lists pressure and temperature effects of utilizing a 2.5” choke bean on well 2. Choking a wellhead arrival pressure of 933.12 psi down to 931.1 psi gave a manifold arrival pressure of 940.528 psi (which is the target comingle pressure). Temperature differences are also detailed.

Effects of Well 2 Production Choke				
Well 2 Wellhead Pressure	Pressure downstream of choke	Pressure at Manifold	Well 2 wellhead temperature	Temperature at Manifold
933.12	931.1	940.528	91.24	90.25

Table 18: Pressure and temperature effects of production choke on well 2.

5.1.3 Production Well Circuit 1 Late-life Evaluation

A summary of the comingled parameters for late-life conditions is presented in Table 19. As can be seen, arrival pressure is 228.2 psia topsides utilizing 0.62 mmscf/d gas lift for well 1 and 0.74 mmscf/d for well 2. Production chokes were utilized on both wells (1.15” bean size on well 1 and 1.5” on well 2). Pressure was comingled at the manifold at 785 psi.

Iteration 1: Comingle manifold at 785 PSI (USE CHOKES)				
	Gas Injection	Choke Bean	Pressure at Manifold	Flow Rate at Manifold
Well 1	0.62	1.15	785.77	1200
Well 2	0.74	1.5	785.56	1994.3
Riser ID	COMINGLED TOPSIDE PRESSURE	Topside Pressure Acceptable		
9.5	228.2			

Table 19: Production parameters for late-life (well circuit 1).

The following figures demonstrate the production loop operational performance for late-life conditions. Figure 17 demonstrates a delivery pressure of 228.24 psia. Figure 18 demonstrates the lowest temperature in the late-life system as 76.1°F topsides. Figure 19 demonstrate the max EVR as 0.097. Table 20 lists the velocity profiles in each production branch. All velocities are much slower than early-life conditions and therefore substantially below the maximum erosion velocity.

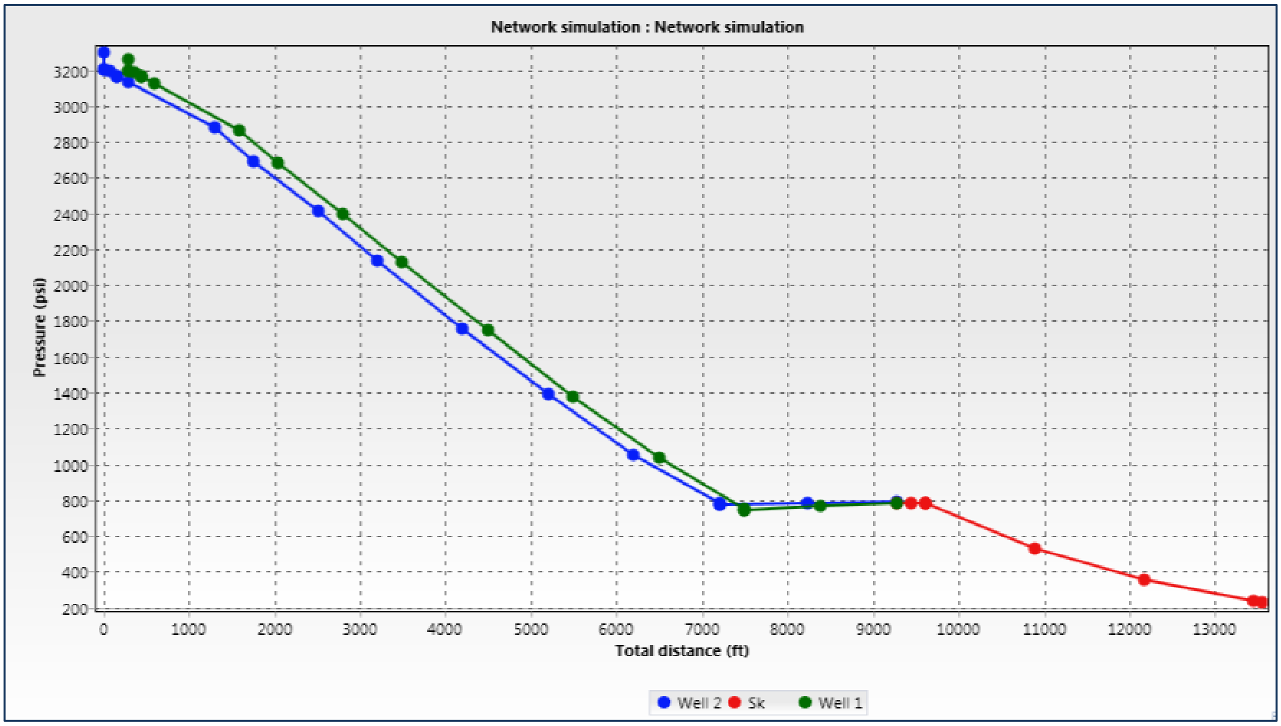

Figure 17: Pressure vs. distance, wells 1 and 2. Late-life.

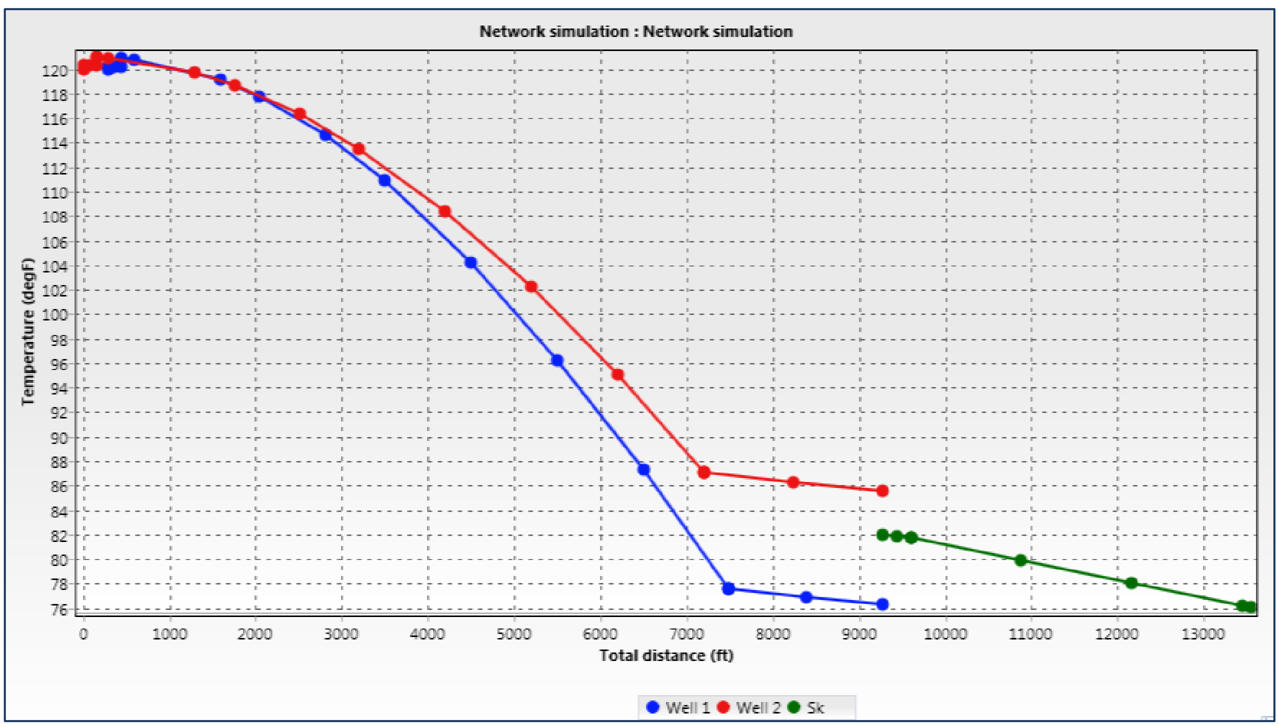

Figure 18: Temperature vs. distance wells 1 and 2. Late-life.

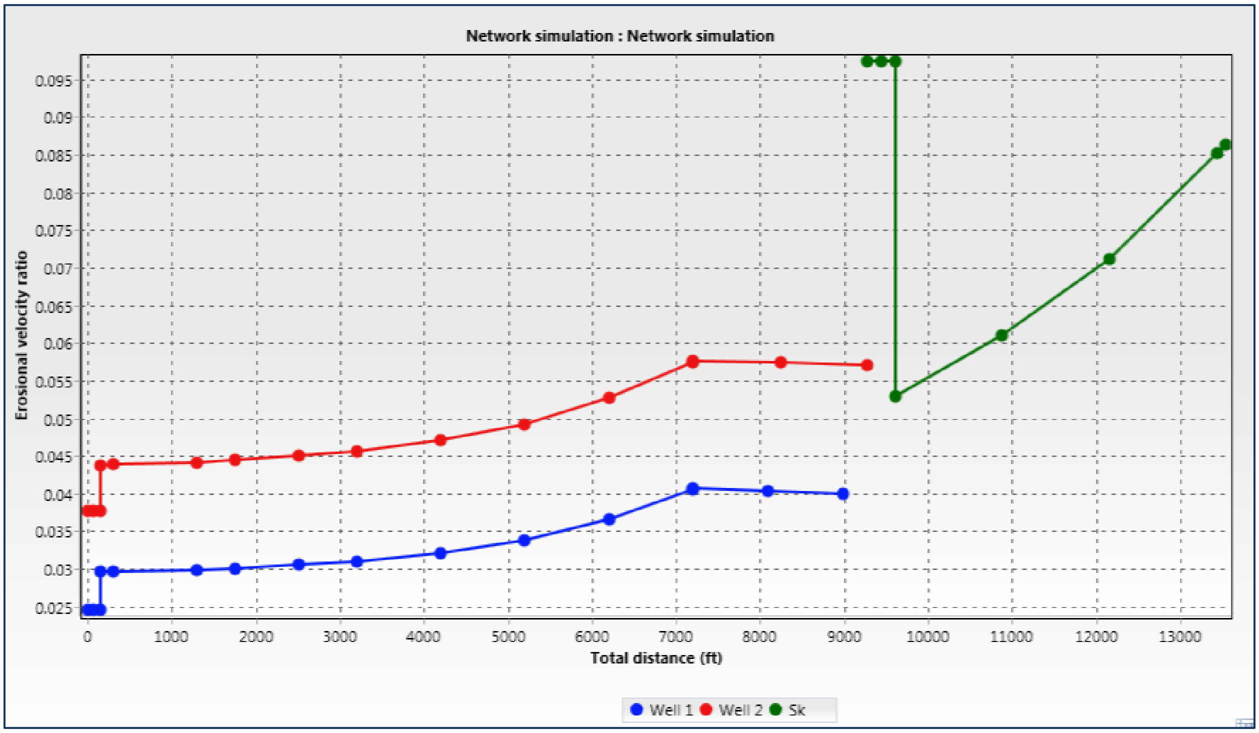

Figure 19: Erosional velocity ratio, wells 1 and 2 plus manifold-to-riser connection and riser. Late-life.

WELL 1			WELL 2			JUMPER + RISER		
Well 1 Distance	Well 1 Mean Fluid Velocity	Well 1 Erosional Velocity	Well 2 Distance	Well 2 Mean Fluid Velocity	Well 2 Erosional Velocity	Riser Distance	Riser Mean Fluid Velocity	Riser Erosional Velocity
0	COMPLETIONS	COMPLETION	0	COMPLETIONS	COMPLETIONS	0	1.790752	18.38795
0	COMPLETIONS	COMPLETION	0	COMPLETIONS	COMPLETIONS	164.0488	1.791393	18.39124
0	0.3107533	12.65049	0	0.4781083	12.65054	328.0976	1.790757	18.38797
64.2	0.3107632	12.65069	64.2	0.4781233	12.65074	328.0976	NODE	NODE
150	0.3107866	12.65116	150	0.478159	12.65121	328.0976	0.972373	18.38898
150	GAS LIFT	GAS LIFT	150	GAS LIFT	GAS LIFT	1607.598	1.290173	21.18191
150	0.4159076	14.05351	150	0.6028027	13.76092	2887.198	1.762048	24.75426
294.5	0.4168046	14.06865	294.5	0.6038799	13.77321	4166.698	2.519077	29.59797
1294.5	0.4236946	14.18446	1294.5	0.6122841	13.86871	4266.698	2.594856	30.03985
1753.8	0.4297767	14.2859	1753.8	0.6197876	13.95344			
2508.4	0.4416659	14.48216	2508.4	0.6346004	14.11919			
3200	0.457019	14.73172	3200	0.6537586	14.33073			
4200	0.4898568	15.25179	4200	0.694578	14.77135			
5200	0.5438978	16.07108	5200	0.7610085	15.4616			
6200	0.6351448	17.36691	6200	0.8711165	16.54237			
7200	0.7783711	19.22559	7200	1.03512	18.03246			
7200	CHOKE	CHOKE	7200	CHOKE	CHOKE			
7200	0.7839263	19.29132	7200	1.039679	18.06955			
8089.727	0.7706116	19.12679	8237.742	1.033761	18.01805			
8981.755	0.757152	18.95902	9276.141	1.02419	17.93444			

Table 20: Each branch detailing distance, mean fluid velocity, and erosional velocity. Late-life.

Table 21 lists pressure and temperature effects of utilizing a 1.15” choke bean on well 1 and a 1.5” choke bean on well 2. On well 1, the bean reduces the downstream pressure by 6.3 psi for a manifold arrival pressure of 785.7 psi. On well 2, the bean reduced the downstream pressure by 5 psi for a manifold arrival pressure of 785.5

	Effects of Well 1 and 2 Production Chokes				
	Wellhead Pressure	Pressure downstream of choke	Pressure at Manifold	Wellhead temperature	Temperature at Manifold
Well 1	759.4	753.1	785.7	76.5	75.2
Well 2	775.8	770.8	785.5	87.74	86.3

Table 21: Pressure and temperature effects of production choke on wells 1 and 2. Late-life.

5.2 Production Well Circuit 2 (Wells P3, P4 and P2)

The flow rate of wells 3 4 and 5 combined is low compared to wells 1 and 2 resulting in comparatively smaller tubing sizes. The circuit has been modeled for early-life and optimized for the later life periods. Among the 3 wells, well 5 has the highest flow rate followed by well 3 and well 4. As a result, it was decided to place the manifold near wells 3 and 4 (with a bias towards 4) to have the minimum pressure loses in their respective flow lines. Wells 3, 4 and 5 utilizes a tubing size of 6, 4 and 6 inches respectively.

A summary of the flow line sizes, horizontal distance runs, and elevation changes are detailed in Table 22. Note: negative elevation changes indicate a downhill run.

Well	Production Tubular (ID) (in)	Flowline ID (in)	Riser ID (in)	Horizontal distance from manifold (m)	Elevation Difference (m)
3	6	6	7.5	447.2	-20
4	4	6	7.5	282.84	30
5	6	6	7.5	632.45	80

Table 22: Production parameters for production well circuit 2 (P3, P4, and P5)

This configuration was then used to evaluate the early, mid, and late life reservoir conditions with the end goal of meeting the required minimum topside arrival pressure of 205 psia by varying gas-lift and choke values. Apart from the topsides pressure requirement, the model has been checked for temperature loss and EVR ratio.

5.2.1 Production Well Circuit 2 Early-Life Evaluation

A summary of the comingled parameters is presented in Table 23. The arrival pressure is 213.28 psia topsides utilizing 1.4 mmscf/d gas lift for well 3 and 0.251 mmscf/d for well 4 and 7 mmscf/d for well 5. Production chokes remained open for this stage of life, with attempts made to commingle the manifold arrival pressures at approximately 1,000 psi.

Comoingling manifold at 1083.83 psi				
	Gas injection	choke bean	Pressure at manifold (psi)	Flowrate at manifold (STB/d)
Well 3	1.4	open	1046.89	22057.75
Well 4	0.251	open	964.96	
Well 5	7	open	1067.061	
Riser ID	Comingled Topsides pressure		Required topsides pressure met with 7.5" Riser	
7.5	213.28 Psia			

Table 23: Production parameters for Early-Life (well circuit 2)

The following figures demonstrate production profiles for this flow circuit. Figure 20 shows the pressure profile vs. distance for wells 3, 4 and 5, from reservoir to topside. Figure 21 relates the temperature profile of both wells from reservoir to topsides. The lowest temperature encountered in the system is 45.6°F (at the manifold for well 4), which is below 70 degree wax formation temperature. Special treatment will be afforded this production branch in terms of down-hole chemical injection. Figure 22 relates the EVR of the system from reservoir to topsides. The highest EVR is 1.16 at the top of riser, well below the maximum EVR value of 2 (assuming an API C-factor of 200). Table 24 includes the mean fluid velocity vs. the erosional velocity of each branch (well 3, well 4, and 5 as well as the riser jumper line plus riser). The erosional velocity in this table has been corrected to assume a "C" constant value of 200 as opposed to the standard value of 100. It should be noted that the mean fluid velocity is below the erosional velocity at all points.

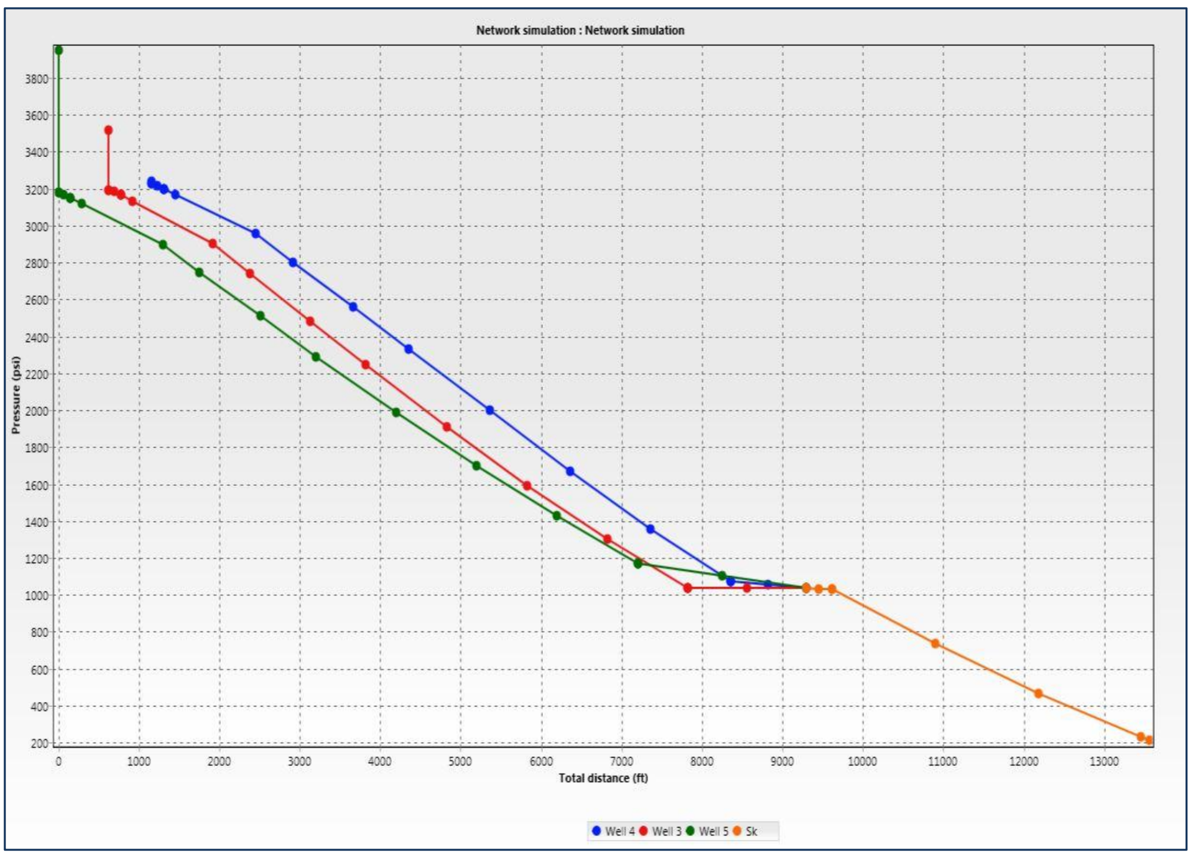

Figure 20: Pressure vs. distance. Early-Life.

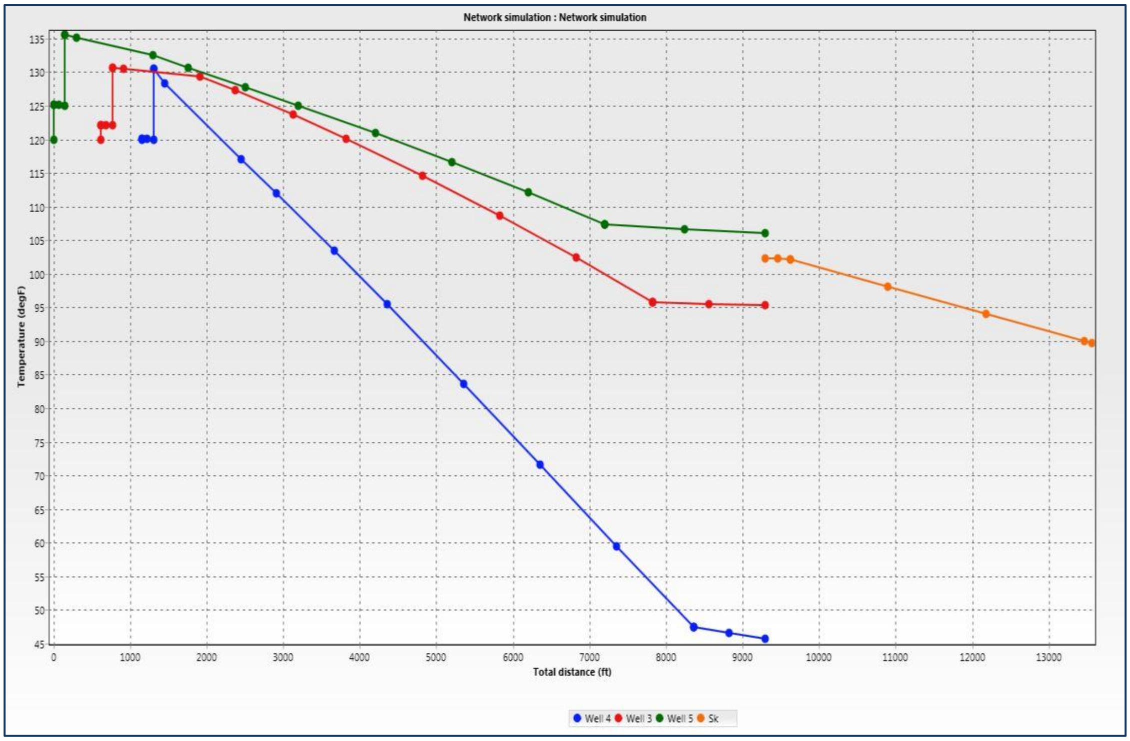

Figure 21: Temperature vs. Distance. Early-Life. It is observed that for well 4, temperature falls below 70°F).

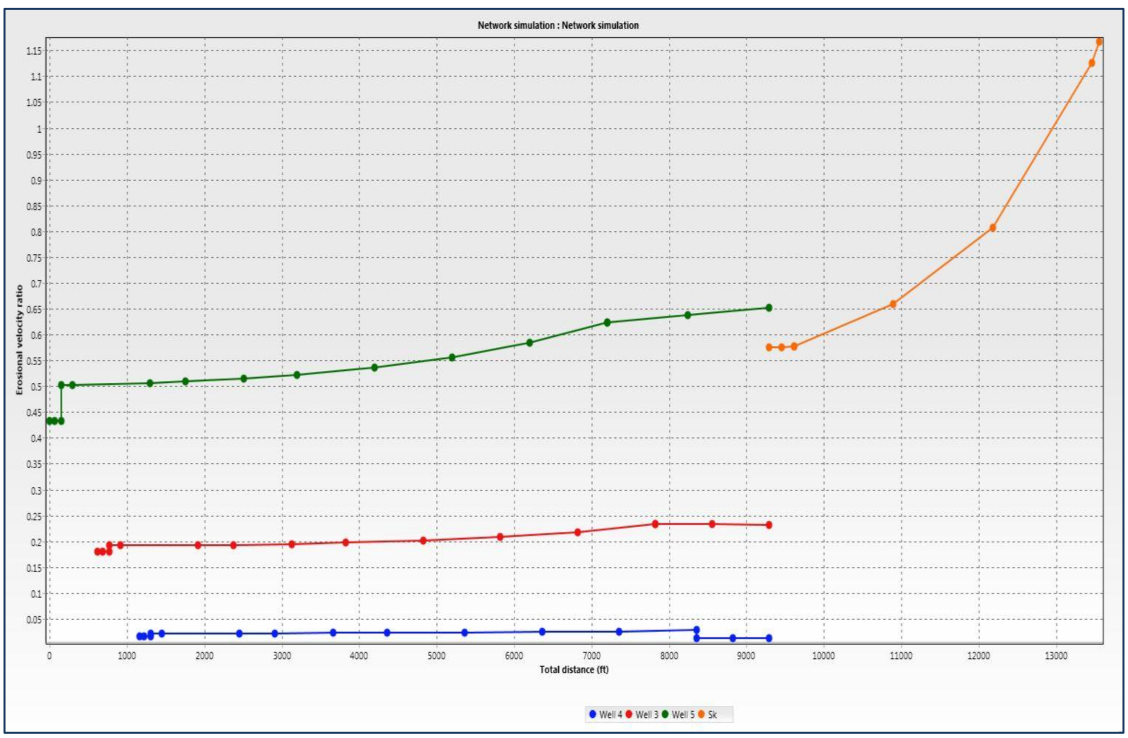

Figure 22: Erosional velocity ratio, wells 3, 4, and 5 plus manifold-to-riser connection and riser. Early-life. Erosion velocity ratio variation for API C factor 100. EVR must be less than 2 for API C factor 200.

To eliminate the wax and hydrate formation, it has to be ensured that the temperature is above 70°F. The present tubing sizes and gas lift values were used to simulate the temperature distribution for well 4 flowline by changing the heat transfer coefficient of "well 4 Flowline" in the layout to 0.15 BTU/ hr-ft2-F. This change in heat transfer coefficient was not able to reduce the heat loss much, as a major part of heat is lost in the tubing and not in the flowline.

Well 3				Well 4				Well 5				manifold to sink			
distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity
-	-	-	-	-	-	-	-	-	-	-	-	-	10.57916	0.5748716	36.80528
-	-	-	-	-	-	-	-	-	-	-	-	50.00208	10.61184	0.575759	36.8621
-	2.442431	0.1798991	27.15334	-	0.219494	0.0161753	27.13934	-	5.881694	0.4329128	27.17266	100.0042	10.64305	0.5766051	36.91626
19.56816	2.442487	0.1799012	27.15364	19.56816	0.219497	0.01617544	27.13956	19.56816	5.881854	0.4329187	27.17302	100.0042	10.64405	0.5766322	36.918
45.72	2.442628	0.1799064	27.15444	45.72	0.219503	0.01617565	27.13992	45.72	5.882239	0.4329329	27.1739	489.9958	13.90768	0.6591326	42.19996
45.72	-	-	-	45.72	-	-	-	45.72	-	-	-	880.0178	20.86513	0.8073389	51.68864
45.72	2.687229	0.1922572	27.95452	45.72	0.344252	0.021918	31.4127	45.72	7.312948	0.5014596	29.16664	1270.009	40.53019	1.125213	72.04004
89.7636	2.687796	0.1922775	27.95746	89.7636	0.344286	0.0219191	31.41428	89.7636	7.326353	0.501919	29.19336	1300.489	43.57119	1.166662	74.69376
394.5636	2.691762	0.1924193	27.97808	394.5636	0.3462	0.02197994	31.50148	394.5636	7.434141	0.5055977	29.40734	1300.489	sink	sink	sink
534.5582	2.71248	0.1931584	28.08556	534.5582	0.349667	0.02208972	31.65882	534.5582	7.526315	0.5087224	29.58908				
764.5603	2.759286	0.1948178	28.32684	764.5603	0.356321	0.02229891	31.95862	764.5603	7.706402	0.5147727	29.94098				
975.36	2.820335	0.1969612	28.63848	975.36	0.36512	0.02257254	32.35078	975.36	7.929641	0.5221754	30.37156				
1280.16	2.949064	0.201406	29.28478	1280.16	0.384199	0.02315479	33.18526	1280.16	8.370014	0.5364791	31.2035				
1584.96	3.149541	0.2081392	30.2638	1584.96	0.416385	0.02410517	34.54734	1584.96	8.99997	0.5563015	32.35644				
1889.76	3.458747	0.2181171	31.7146	1889.76	0.470341	0.02561942	36.71754	1889.76	9.901195	0.5834901	33.93784				
2194.56	3.930198	0.2325078	33.80702	2194.56	0.556209	0.02786004	39.92878	2194.56	11.2913	0.6231056	36.24202				
2194.56	-	-	-	2194.56	-	-	-	2194.56	-	-	-				
2194.56	3.93058	0.2325191	33.80866	2194.56	0.247231	0.01238293	39.931	2194.56	11.29623	0.6232416	36.24992				
2418.295	3.929618	0.2324906	33.80452	2336.929	0.250982	0.01247651	40.23278	2513.722	11.797	0.6369063	37.0447				
2642.232	3.922706	0.2322861	33.77478	2478.999	0.254205	0.01255636	40.49026	2832.088	12.34369	0.6514967	37.89334				

Table 24: Each branch detailing distance, mean fluid velocity, and erosional velocity. Early-life.

It has been ensured that fluid mean velocity is always less than erosion velocity i.e. EVR is always less than 2 when considering the corrected erosion velocity assuming API 14E C-factor 200.

5.2.2 Production Well Circuit 2 Mid-Life Evaluation

A summary of the comingled parameters for mid-life conditions is presented in Table 25. As can be seen, arrival pressure is 219.98 psia topsides utilizing 0.71 mmscf/d gas lift for well 3, 0.29mmscf/d for well 4 and 2mmscf/d gas lift for well 5. The production choke remained open for all the three wells.

Comoingling manifold at 1083.83 psi				
	Gas injection	choke bean	Pressure at manifold (psi)	Flowrate at manifold (STB/d)
Well 3	0.71	open	1002	8874.73
Well 4	0.29	open	1025	
Well 5	2	open	1002.89	
Riser ID	Comingled Topsides pressure		Required topsides pressure met with 7.5" Riser	
7.5	219.98			

Table 25: Production parameters for mid-life (P3,P4 and P5).

The following figures demonstrate the production loop operational performance for mid-life conditions. Figure 23 demonstrates a delivery pressure of 219.98 psia. Figure 24 demonstrates the lowest temperature in the midlife system as 50.75°F in well 4 flowline. This can be countered by chemical injection and electric heating of the well 4 branch flowline. Figure 25 demonstrates the max EVR as 0.41 (for API C-factor of 200 EVR must be less than 2). Table 26 shows the velocity profiles in each production branch.

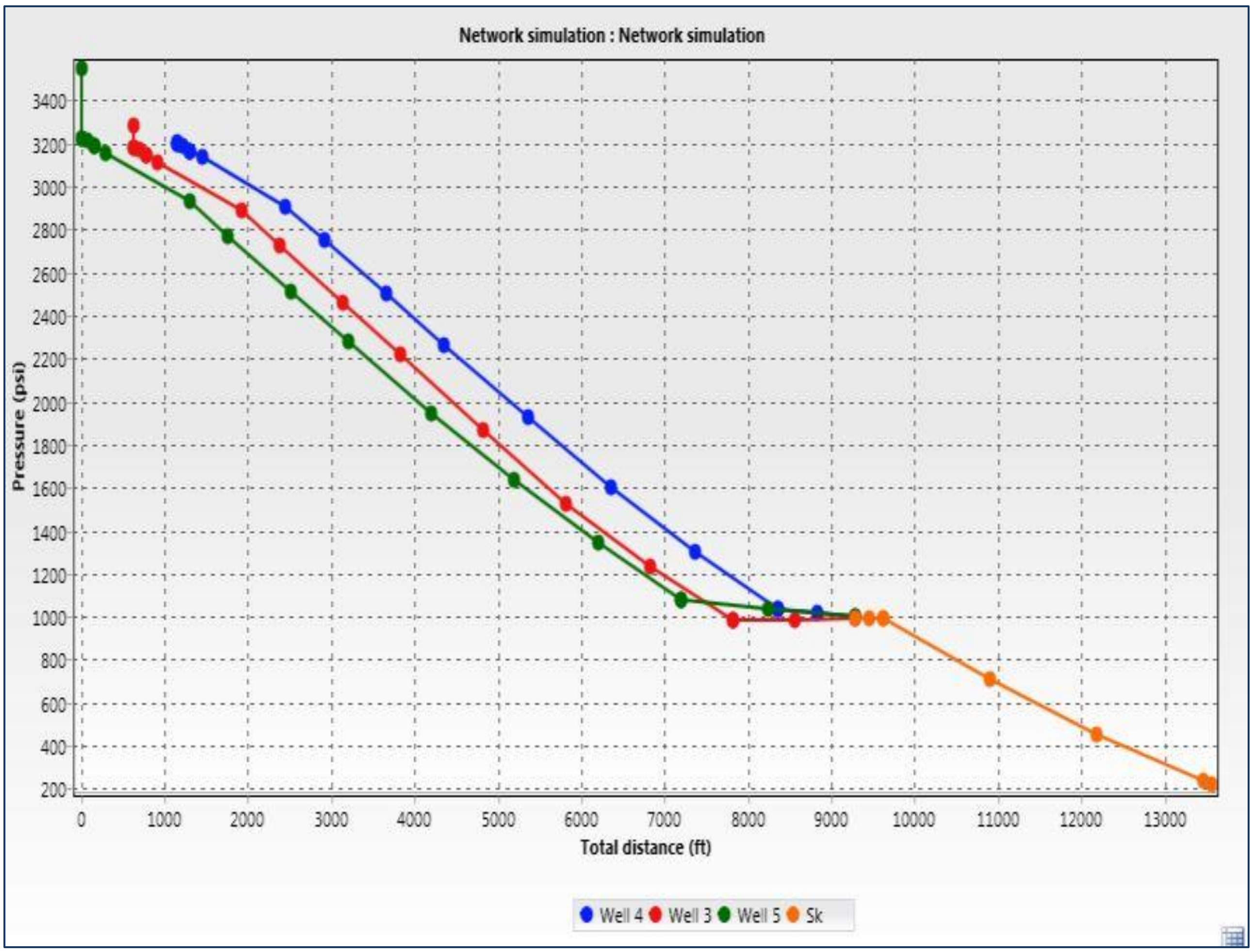

Figure 23: Pressure vs. distance. Mid-life.

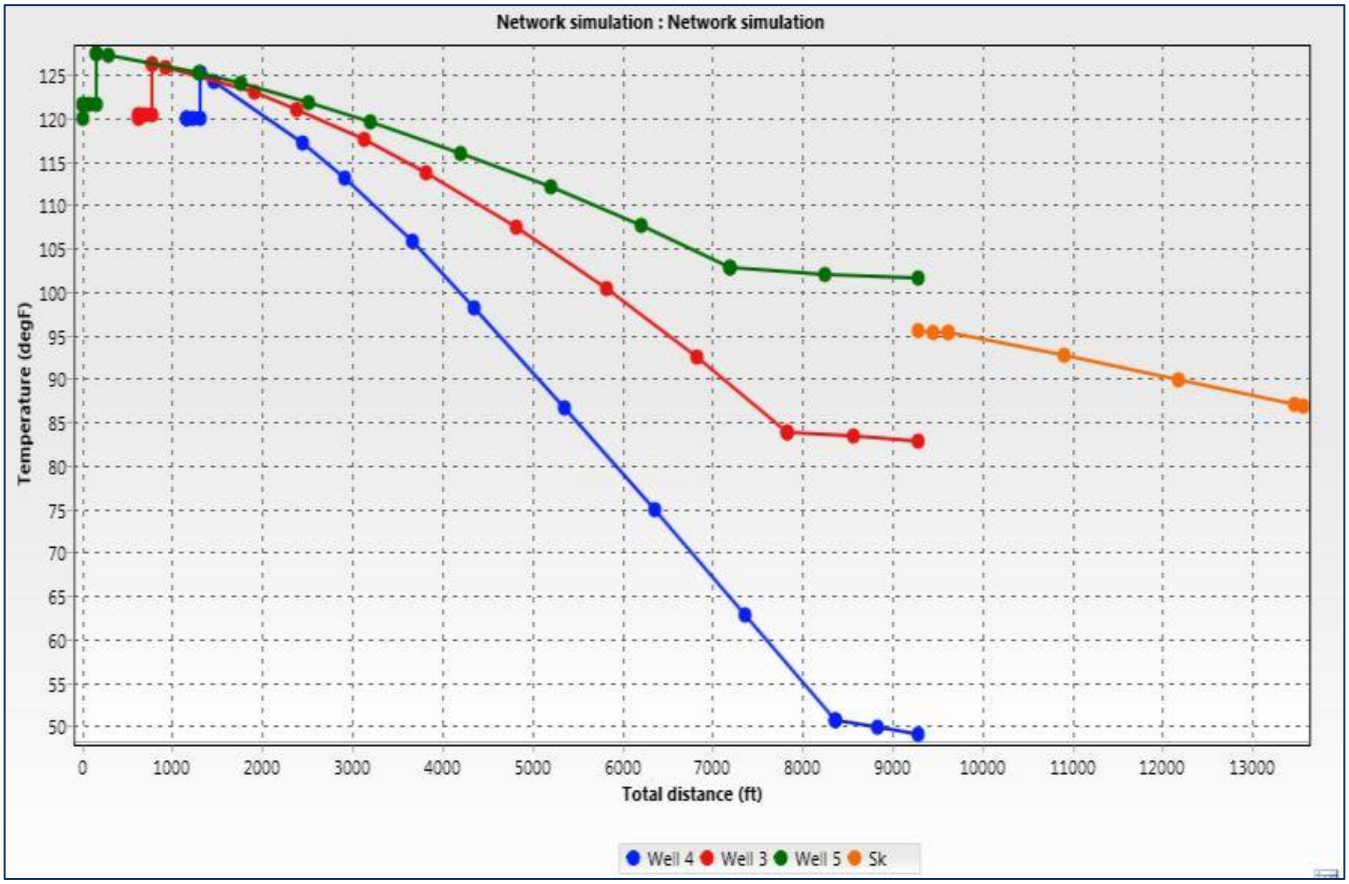

Figure 24: Temperature vs. distance. Mid-life.

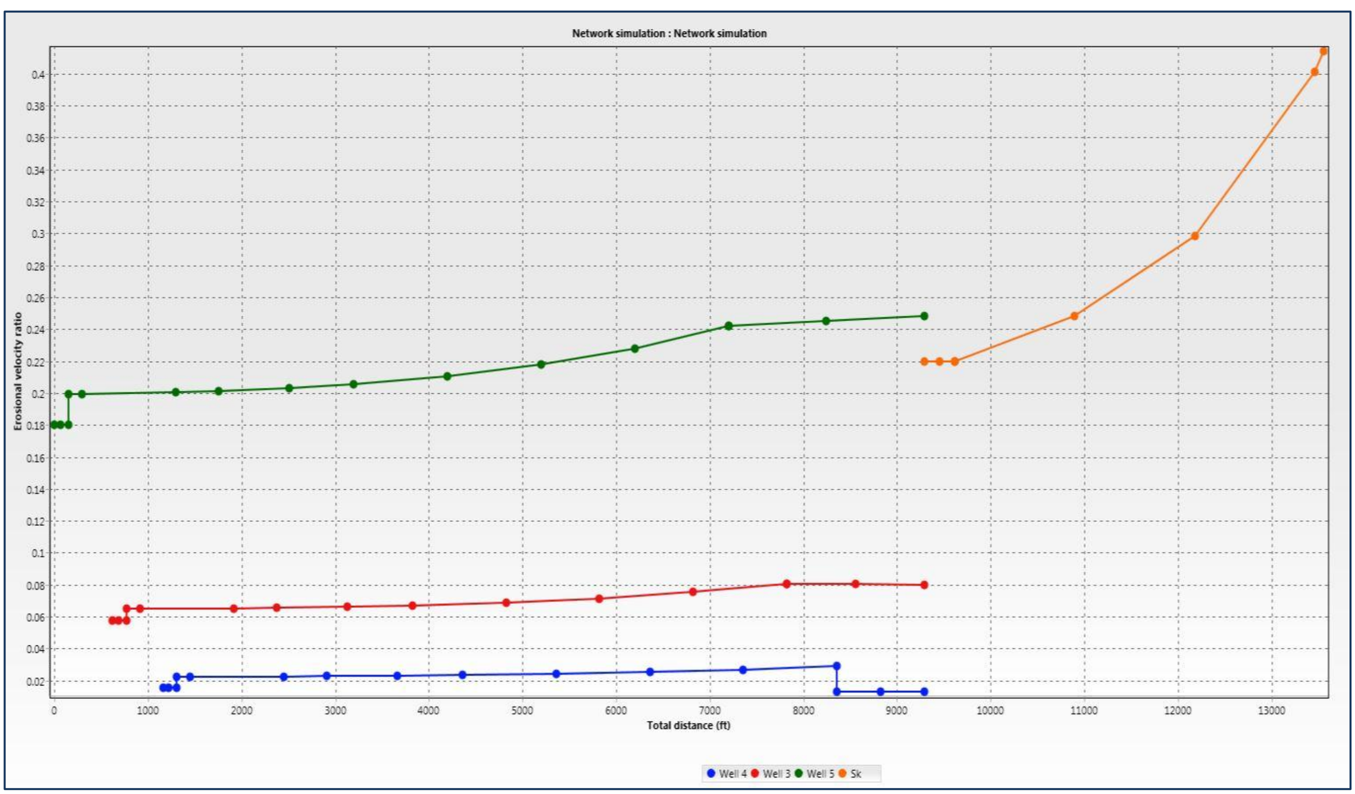

Figure 25: Erosional velocity ratio, wells 3, 4, and 5 plus manifold-to-riser connection and riser. Mid-life.

Well 3				Well 4				Well 5				manifold to sink			
distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity	distance (m)	fluid mean velocity (ft/sec)	EVR (must be less than 2)	Erosion Velocity
-	-	-	-	-	-	-	-	-	-	-	-	-	3.851069	0.2198684	35.03068
-	-	-	-	-	-	-	-	-	-	-	-	50.00208	3.853862	0.2199481	35.04338
-	0.764083	0.0577507	26.46144	-	0.204868	0.01548602	26.45844	-	2.380011	0.1798601	26.46514	100.0042	3.854993	0.2199804	35.04852
19.56816	0.764104	0.0577515	26.46178	19.56816	0.204873	0.0154862	26.45874	19.56816	2.380074	0.1798625	26.46548	100.0042	3.855294	0.2199889	35.04988
45.72	0.764152	0.0577533	26.46262	45.72	0.204882	0.01548655	26.45934	45.72	2.38023	0.1798684	26.46634	489.9958	4.91023	0.2482693	39.55568
45.72	-	-	-	45.72	-	-	-	45.72	-	-	-	880.0178	7.084728	0.2982179	47.51378
45.72	0.907472	0.0647545	28.02806	45.72	0.353125	0.02227957	31.69946	45.72	2.772302	0.1991969	27.8348	1270.009	12.82308	0.4012068	63.92256
89.7636	0.908745	0.0648	28.04772	89.7636	0.353805	0.022301	31.72994	89.7636	2.776097	0.1993331	27.85384	1300.489	13.65683	0.4140444	65.96792
394.5636	0.918682	0.0651533	28.20064	394.5636	0.359118	0.02246782	31.96732	394.5636	2.806587	0.2004248	28.00638	1300.489	-	-	-
534.5582	0.928167	0.0654887	28.34584	534.5582	0.364317	0.02262987	32.19788	534.5582	2.833951	0.2013995	28.14258				
764.5603	0.94703	0.0661509	28.63244	764.5603	0.373865	0.0229245	32.61708	764.5603	2.888324	0.2033224	28.41128				
975.36	0.971559	0.0670021	29.00086	975.36	0.386019	0.02329413	33.14298	975.36	2.957579	0.2057455	28.74988				
1280.16	1.023745	0.068778	29.76956	1280.16	0.41157	0.02405273	34.22232	1280.16	3.09912	0.2106111	29.42978				
1584.96	1.106553	0.0715055	30.95012	1584.96	0.451982	0.02520595	35.86314	1584.96	3.311149	0.2176966	30.41986				
1889.76	1.228238	0.0753347	32.6075	1889.76	0.515496	0.02691876	38.30012	1889.76	3.626539	0.2278287	31.83568				
2194.56	1.39608	0.0803172	34.76414	2194.56	0.611588	0.02932055	41.7174	2194.56	4.090311	0.2419582	33.81006				
2194.56	-	-	-	2194.56	-	-	-	2194.56	-	-	-				
2194.56	1.39618	0.0803201	34.7654	2194.56	0.271848	0.01303209	41.71974	2194.56	4.090837	0.2419738	33.81224				
2418.295	1.391318	0.0801801	34.7048	2336.929	0.276484	0.01314274	42.07396	2513.722	4.194623	0.245024	34.23846				
2642.232	1.38402	0.0799696	34.61366	2478.999	0.280455	0.01323679	42.37506	2832.088	4.293317	0.2478898	34.63892				

Table 26: Each branch detailing distance, mean fluid velocity, and erosional velocity. Mid-life.

5.2.3 Production Well Circuit 2 Late Life Evaluation

A summary of the parameters for late life conditions is presented in Table 27. As can be seen, arrival pressure is 205.29 psia topsides utilizing 0.48 mmscf/d gas lift for well 3 and 0.26 mmscf/d for well 4 and 0.81 mmscf/d gas lift for well 5.

<table>
<tr><td colspan="5"></td></tr>
<tr><td></td><td>Gas injection</td><td>choke bean</td><td>Pressure at manifold (psi)</td><td>Flowrate at manifold (STB/d)</td></tr>
<tr><td>Well 3</td><td>0.48</td><td>open</td><td>804.31</td><td rowspan="3">3406.23</td></tr>
<tr><td>Well 4</td><td>0.26</td><td>open</td><td>1025.72</td></tr>
<tr><td>Well 5</td><td>0.81</td><td>open</td><td>814.18</td></tr>
<tr><td>Riser ID</td><td colspan="2">Comingled Topsides pressure</td><td colspan="2" rowspan="2">Required topsides pressure met with 7.5" Riser</td></tr>
<tr><td>7.5</td><td colspan="2">205.29</td></tr>
</table>

Table 27: Production parameters for late life (P3,P4 and P5)

The following figures demonstrate the production loop operational performance for late-life conditions. Figure 26 demonstrates a delivery pressure of 205.29 psia. Figure 27 demonstrates the lowest temperature in the midlife system as 68°F at manifold in well 5 flowline. The heat loss in well 5 flow line has to be reduced by increasing insulation, insulating the flowline or electric heating of the flowline. Figure 28 demonstrates the max EVR as 0.147. Table 28 shows the velocity profiles in each production branch. All velocities are much slower than Early-Life conditions and therefore substantially below the maximum erosion velocity.

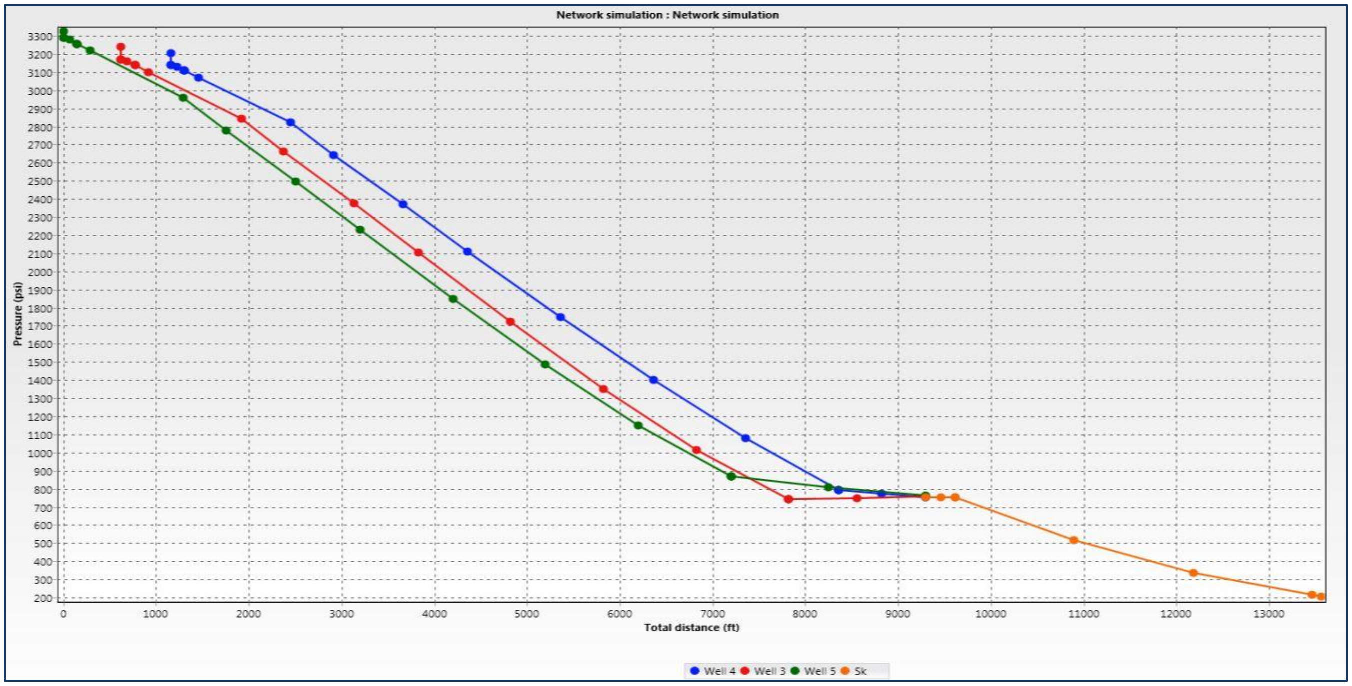

Figure 26: Pressure vs. distance. Late-life.

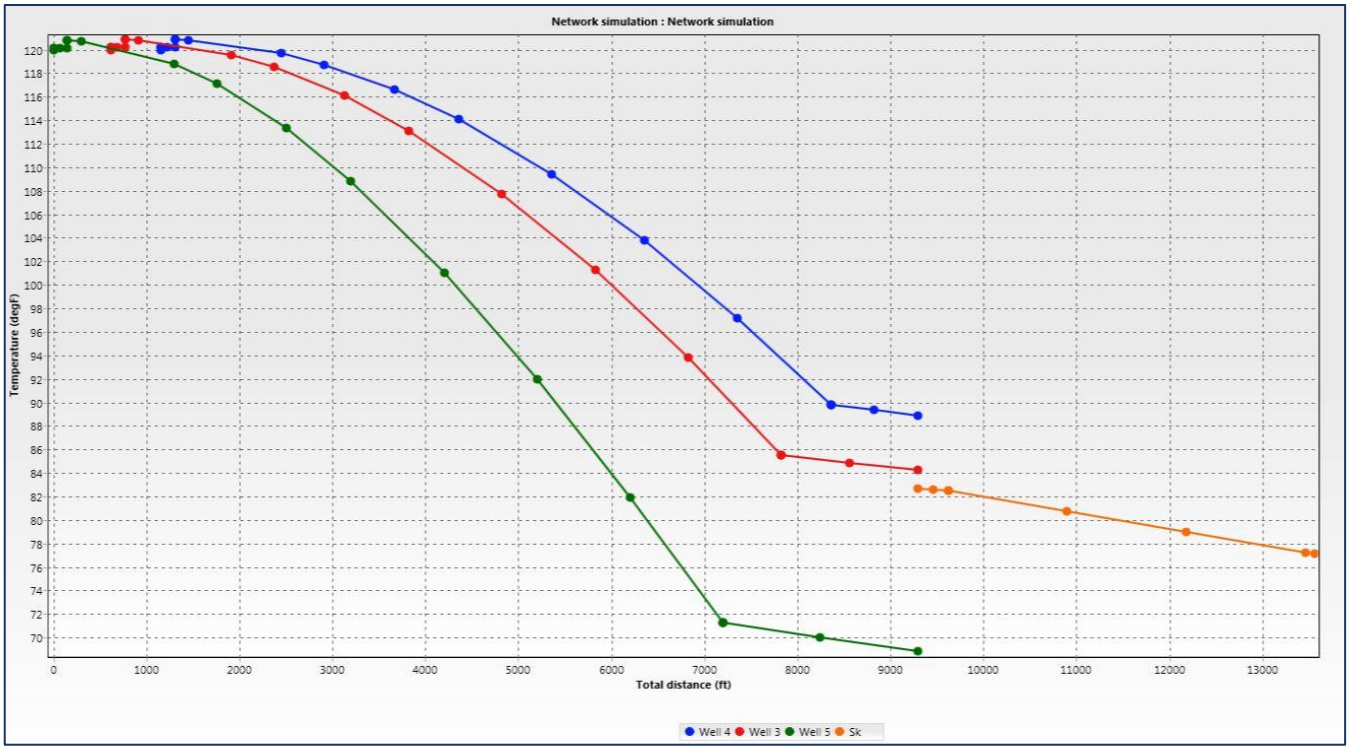

Figure 27: Temperature vs. distance. Late-life.

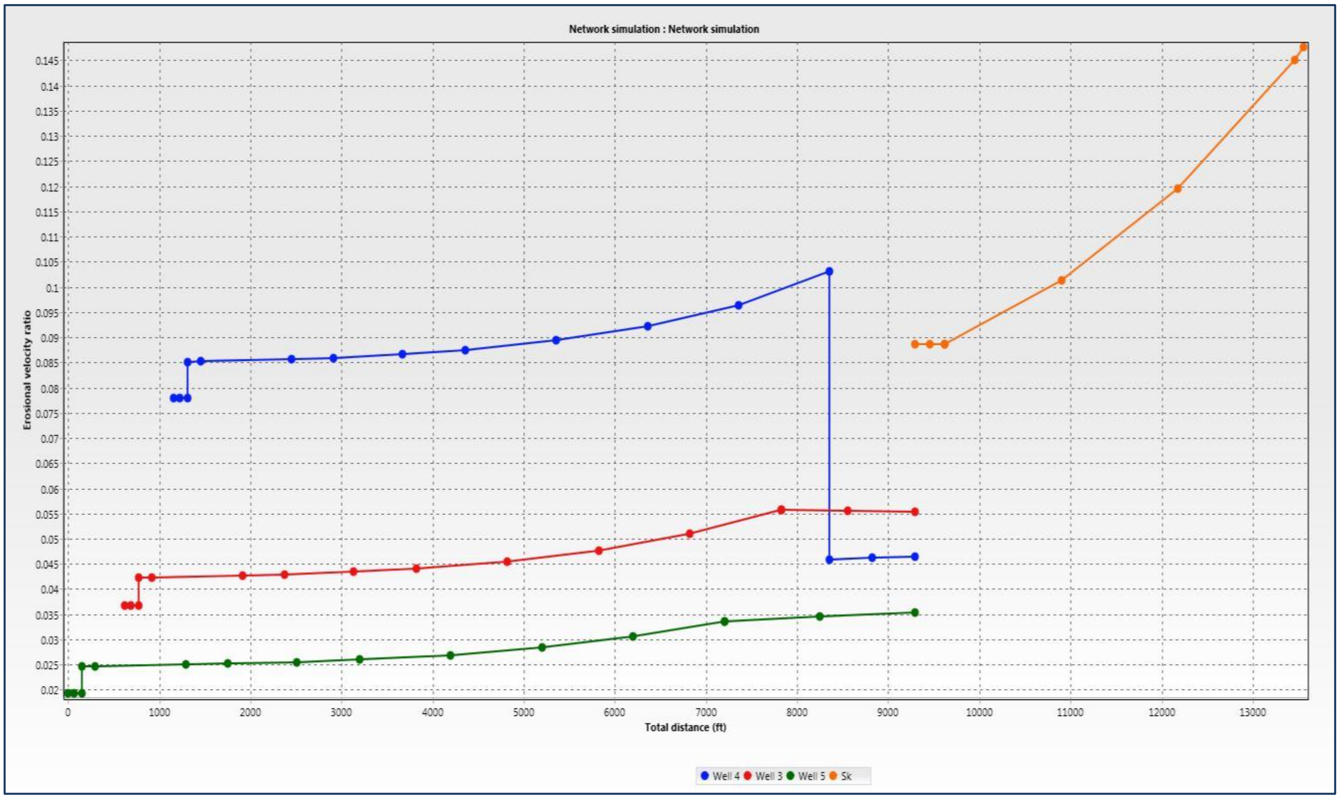

Figure 28: Erosional velocity ratio, wells 3, 4, and 5 plus manifold-to-riser connection and riser. Late-life.

Well 3				Well 4				Well 5				manifold to sink			
Distance (m)	Fluid mean velocity (ft/sec)	EVR	Erosion velocity	Distance (m)	Fluid mean velocity (ft/sec)	EVR	Erosion Velocity	Distance (m)	Fluid mean velocity (ft/sec)	EVR	Erosion Velocity	Distance (m)	Fluid mean velocity (ft/sec)	EVR	Erosion Velocity
-	-	-	0	-	-	-	0	-	-	-	0	0	1.604917	0.08857	36.24084
-	-	-	0	-	-	-	25.30336	-	-	-	0	50.00208	1.605508	0.088586	36.24752
0	0.4647773	0.0367	25.30214	0	0.984831	0.077842	25.30376	0	0.244061	0.019296	25.2969	100.0042	1.604884	0.088569	36.24048
19.56816	0.4647922	0.0367	25.30254	64.2	0.984862	0.077843	25.30472	19.56816	0.244069	0.019296	25.2973	100.0042	1.605031	0.088573	36.24214
45.72	0.4648275	0.0367	25.3035	150	0.984937	0.077846	0	45.72	0.244087	0.019297	25.29824	489.9958	2.099623	0.101305	41.45172
45.72			0	150			26.64882	45.72			0	880.0178	2.923301	0.119535	48.91124
45.72	0.5801509	0.0423	27.43066	150	1.134085	0.085113	26.66544	45.72	0.357846	0.024706	28.96868	1270.009	4.312269	0.145181	59.40526
89.7636	0.5811803	0.0423	27.45498	294.5	1.1355	0.085166	26.79386	89.7636	0.358723	0.024736	29.00418	1300.489	4.461104	0.147666	60.42174
394.5636	0.5891931	0.0426	27.6436	1294.5	1.146463	0.085577	26.9069	394.5636	0.365323	0.024962	29.26976	1300.489	sink	sink	sink
534.5582	0.5963938	0.0429	27.812	1753.8	1.156158	0.085938	27.1266	534.5582	0.371004	0.025156	29.49648				
764.5603	0.6106391	0.0434	28.1422	2508.4	1.175115	0.086639	27.40404	764.5603	0.381872	0.025522	29.92538				
975.36	0.629143	0.044	28.5654	3200	1.199274	0.087525	27.97266	975.36	0.395693	0.025979	30.46208				
1280.16	0.6688674	0.0454	29.45342	4200	1.249561	0.089342	28.84326	1280.16	0.424793	0.026918	31.56236				
1584.96	0.7343214	0.0476	30.86092	5200	1.32855	0.092122	30.19288	1584.96	0.471875	0.02837	33.26552				
1889.76	0.8440928	0.051	33.08726	6200	1.45579	0.096433	32.30234	1889.76	0.547462	0.030558	35.83088				
2194.56	1.00716	0.0557	36.14222	7200	1.666317	0.10317	0	2194.56	0.661617	0.033593	39.38984				
2194.56			0	7200			32.30394	2194.56			0				
2194.56	1.00725	0.0557	36.14386	7200	0.740659	0.045856	32.51744	2194.56	0.661702	0.033595	39.39236				
2418.295	1.001198	0.0556	36.0351	7667.089	0.750481	0.046159	32.70116	2513.722	0.696821	0.034475	40.4242				
2642.232	0.992817	0.0553	35.88396	8133.197	0.758986	0.046419	0	2832.088	0.730944	0.035309	41.40216				

Table 28: Each branch detailing distance, mean fluid velocity, and erosional velocity. Late-life.

5.3 Water Injection

The analytical result for water injection circuit is shown below in Table 29. The input table shown below, for each well, with the Injectivity Index=50. **Bottom-hole pressure is obtained** from **the following equation:**

$$\boldsymbol{P(bottom\ hole) = P(reservior) + (Q/Injectivity\ Index)}$$

Wells	Early			Mid			Late		
	Flow rate(bopd)	Pres(psi)	Pbh(psi)	Flow rate(bopd)	Pres(psi)	Pbh(psi)	Flow rate(b	Pres(psi)	Pbh(psi)
W1	7000	3930	4070	21500	3425	3855	23000	3300	3760
W2	400		3938	1700		3459	200		3304
W3	17500	3950	4300	34000	3550	4230	36000	3325	4045
W4	5000		4050	10000		3750	20000		3725

Table 29: Analytical results for the water injection circuit.

The discharge pump pressure for early, mid and late life is 10 psi, 450 psi and 600 psi, respectively. This is because the required injection rate increases with early, mid and late life. By iteration for early, mid and late life for pipe sizing, the optimum tubing sizes were found. These are detailed in Table 30 below:

All Life					
Tubular dia(inch)	Flowline(inch)	Riser(inch	PP(Early)	PP(Mid)	PP(Late)
6	5	9	10	450	600
4	1.5				
6	6				
5	5				
	5(FL left)				
	8(Fl Right)				

Table 30: Tubing and flowline sizes for the water injection system. Note "PP" stands for pump pressure.

As shown in tables below for early, mid and late life, pressure at well head is less than maximum well head pressure (i.e. 3000psi) and the pressure at the completions is greater than the bottom hole pressure in order to achieve positive water injection.

Early Life Pressure data at well head and completion			
	$P_{bottom\ hole}$	Well Head Pressure(Psi)	Completion Pressure(Psi)
W1	4070	1565.27	4370.755
W2	3938	1563.515	4534.662
W3	4300	1921.274	4476.201
W4	4050	1936.465	4800.742

Mid Life Pressure data at well head and completion			
	$P_{bottom\ hole}$	Well Head Pressure(Psi)	Completion Pressure(Psi)
W1	3855	1786.306	4038.899
W2	3459	1718.972	4658.15
W3	4230	2187.246	4207.041
W4	3750	2241.484	4957.747

Late Life Pressure data at well head and completion			
	$P_{bottom\ hole}$	Well Head Pressure(Psi)	Completion Pressure(Psi)
W1	3760	1945.008	4126.776
W2	3304	1841.224	4772.841
W3	4045	2341.168	4288.493
W4	3725	2374.272	4691.625

Table 31: Bottom hole, completion pressure, and wellhead pressure for water injection wells early, mid, and late life.

In order to positively inject water into the well completion, injection pressure should be higher than bottom-hole pressure which is demonstrated from above tables and following PIPESIM plots.

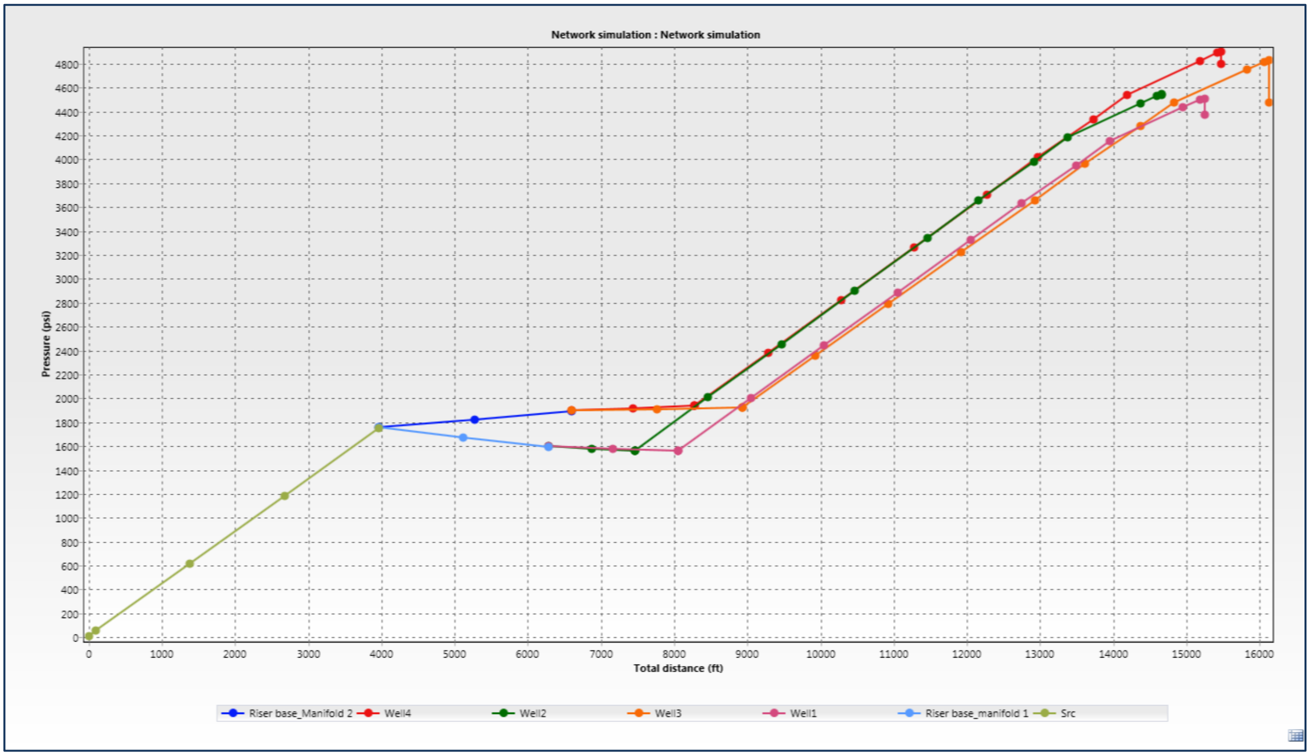

Figure 29: Pressure profile for water injection wells. Early-life.

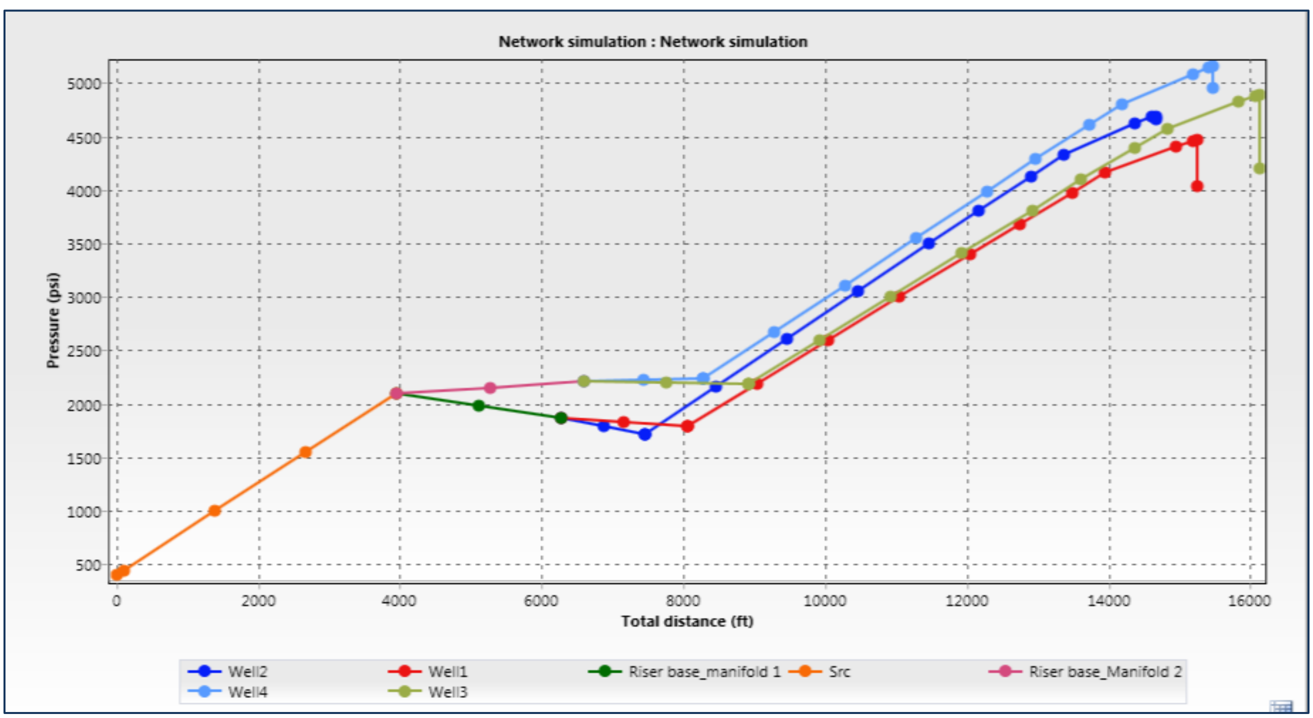

Figure 30: Pressure profile for water injection wells. Mid-life.

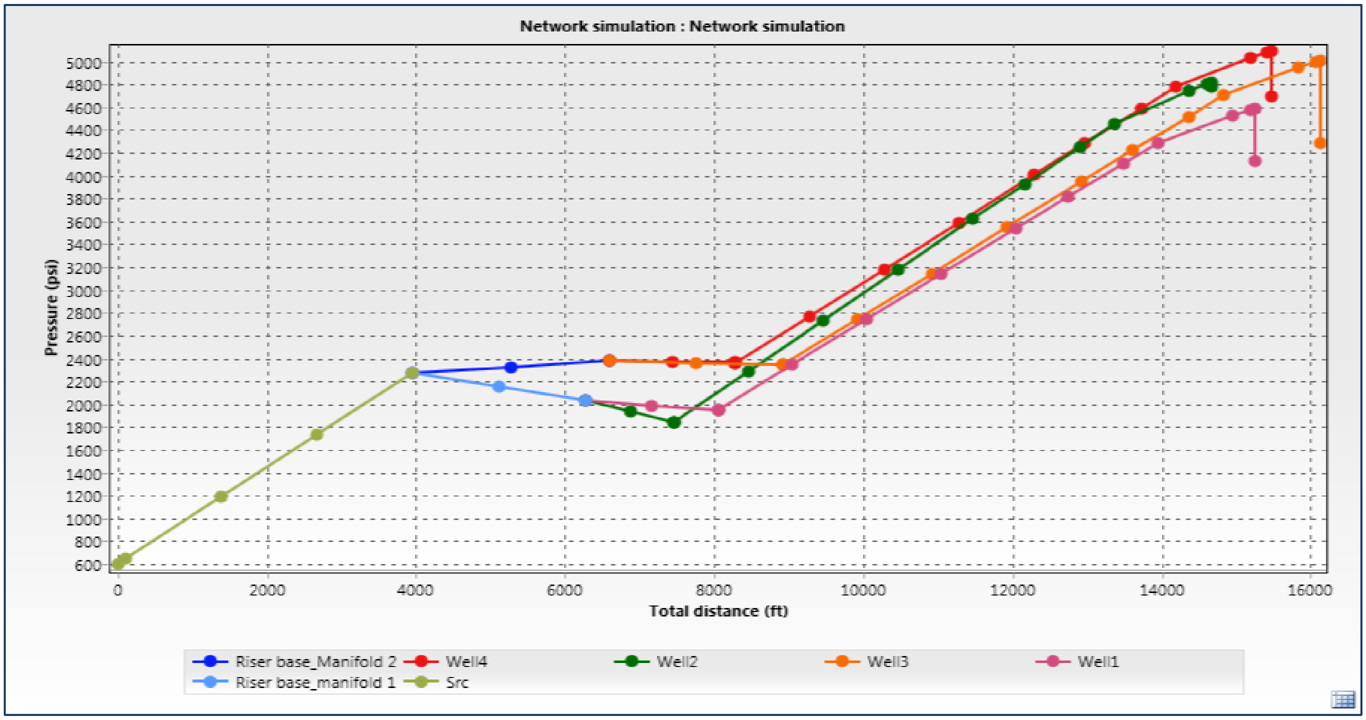

Figure 31: Pressure profile for water injection wells. Late-life.

The erosion velocity ratio (EVR) for riser to each well for early, mid and late life is shown in the following figures. It can be inferred from the plots that the EVR for each riser-well network for all life at every point is less than 1.

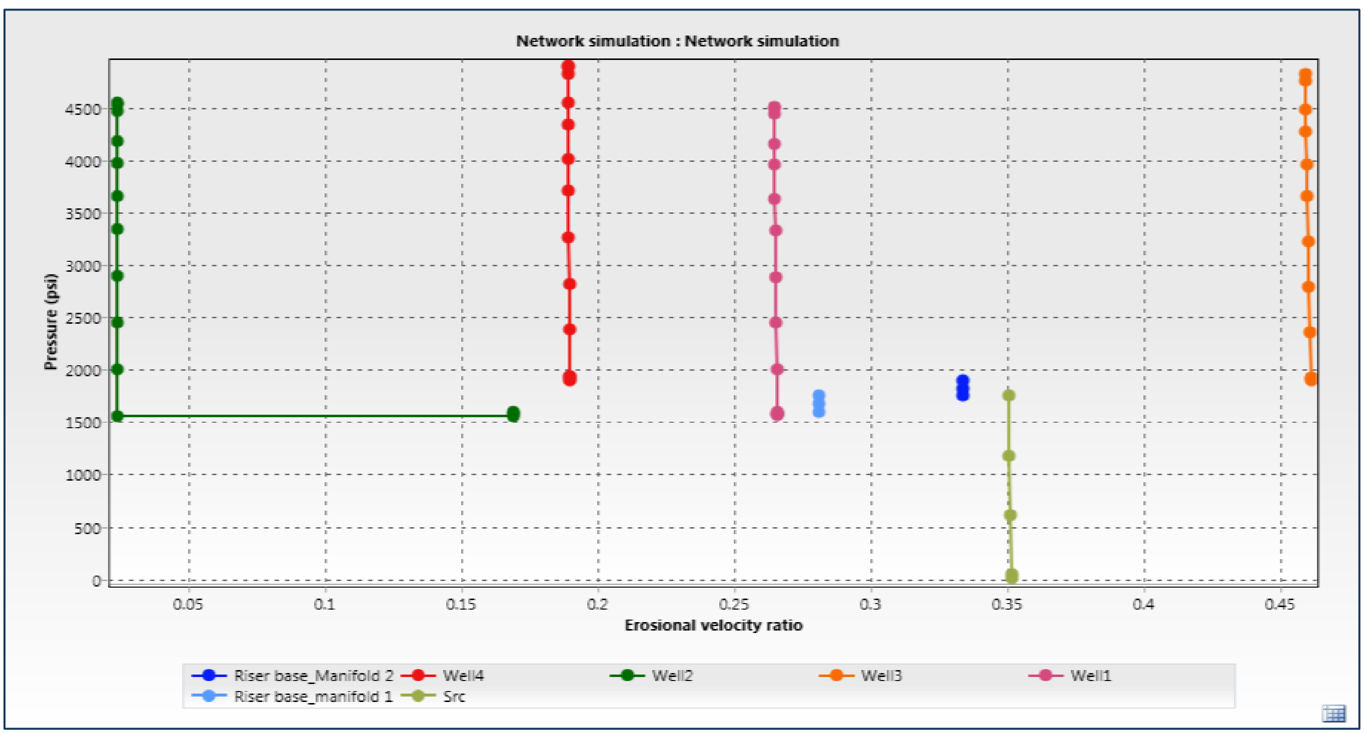

Figure 32 : EVR ratio profile of water injection system. Early-life.

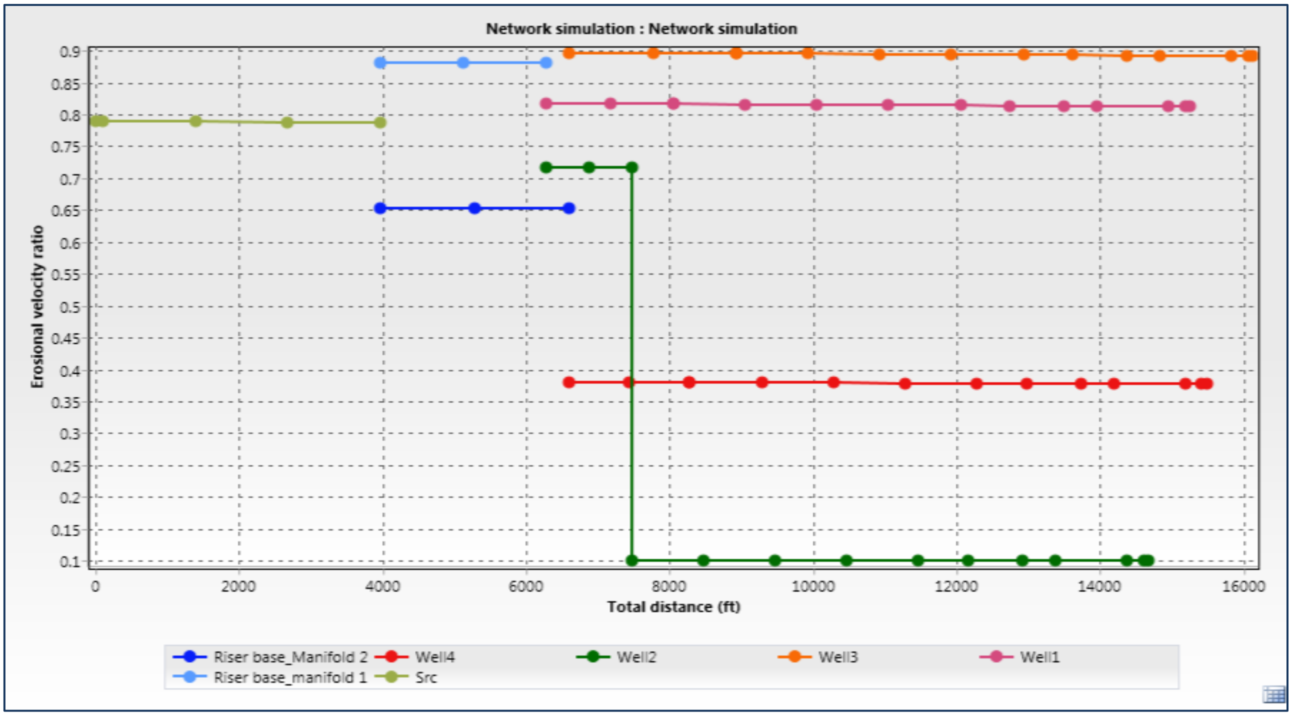

Figure 33: EVR ratio profile of water injection system. Mid-life.

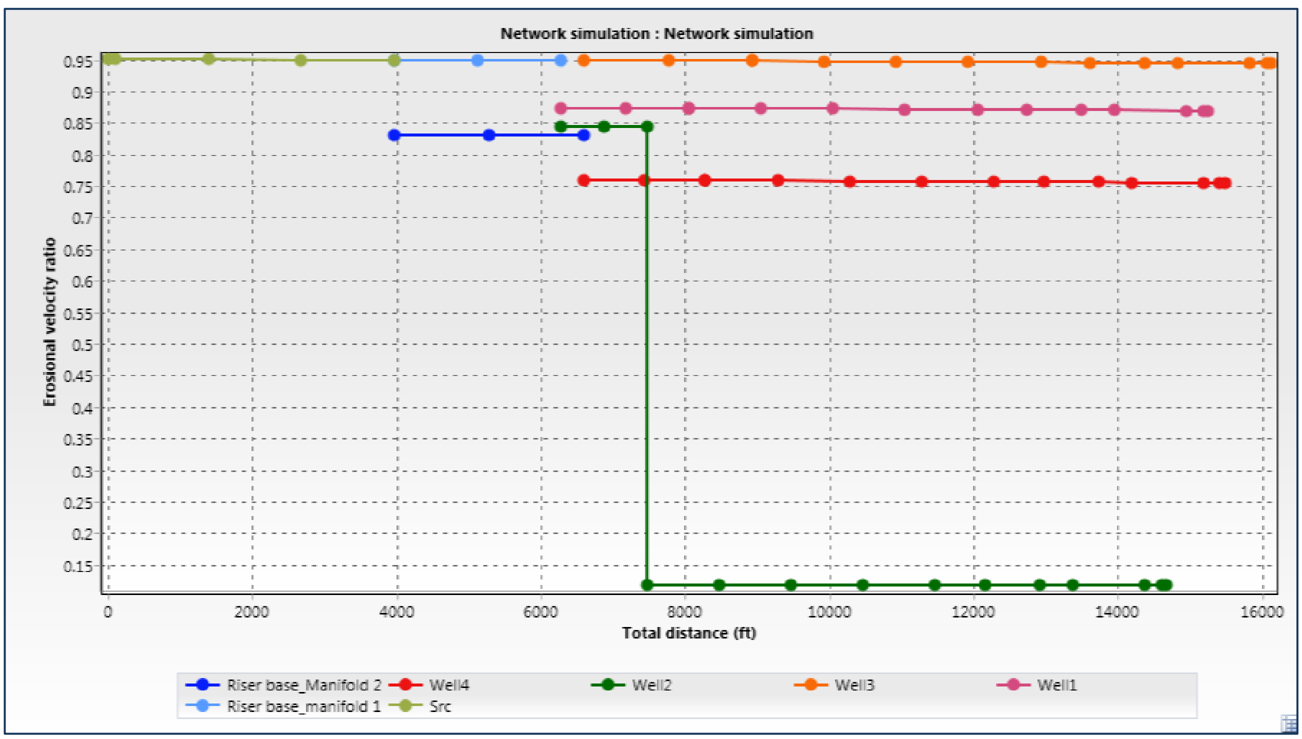

Figure 34: EVR ratio profile of water injection system. Late-life.

5.4 Methanol Injection

A methanol injection study was conducted assuming 3 gpm injection rate per well. A 1.5" umbilical delivers methanol to a subsea UTA which then distributes fluid through 5 flowlines to respective production trees. The flow lines were sized to ensure a chemical deliver pressure greater than the wellhead pressure. Methanol is injected down-hole at well four to compensate for low temperatures in the production tubular. Results are listed below in Table 32. A project goal was to limit the topside injection pump to a maximum 100 psi output. Lines were then sized accordingly. It can be seen below that 100 psi injection pressure is needed for early-life, 55 psi is needed for mid-life, and atmospheric pressure is needed for late-life.

Early				
Pump Pressure	Well	Pressure At Wellhead	Injection Pressure at wellhead	Diameter of Flow Line
100 psi	1	983.48	1002.261	0.5
	2	1018.1	1142.06	0.6
	3	1003.309	1063.1	0.5
	4 (downhole)	1669.769 (downhole)	1779.47	0.6
	5	1195.18	1223.461	0.65

Mid				
Pump Pressure	Well	Pressure At Wellhead	Injection Pressure at wellhead	Diameter of Flow Line
55 psi	1	906.66	941.12	0.5
	2	933.122	1081.26	0.6
	3	992.6	1001.959	0.5
	4 (downhole)	1603.724 (downhole)	1718.3	0.6
	5	1043.67	1162.632	0.65

Late				
Pump Pressure	Well	Pressure At Wellhead	Injection Pressure at wellhead	Diameter of Flow Line
1 psi (abs)	1	753.4	832.9	0.5
	2	780.2	973.8	0.6
	3	743.3	893.8	0.5
	4 (downhole)	1400.425 (downhole)	1610.2	0.6
	5	867.32	1055.197	0.65

Table 32: Early, mid and late, life pressure parameters and pump pressures.

Figures 35, 36, and 37 demonstrate chemical injection pressure vs. distance profiles for early, mid, and late-life, respectively. The initial pressure gain is due to the hydrostatic increase in the umbilical. The well 4 curve also shows a pressure increase beginning at the production tree as the line descends approximately 2,000 feet into the wellbore.

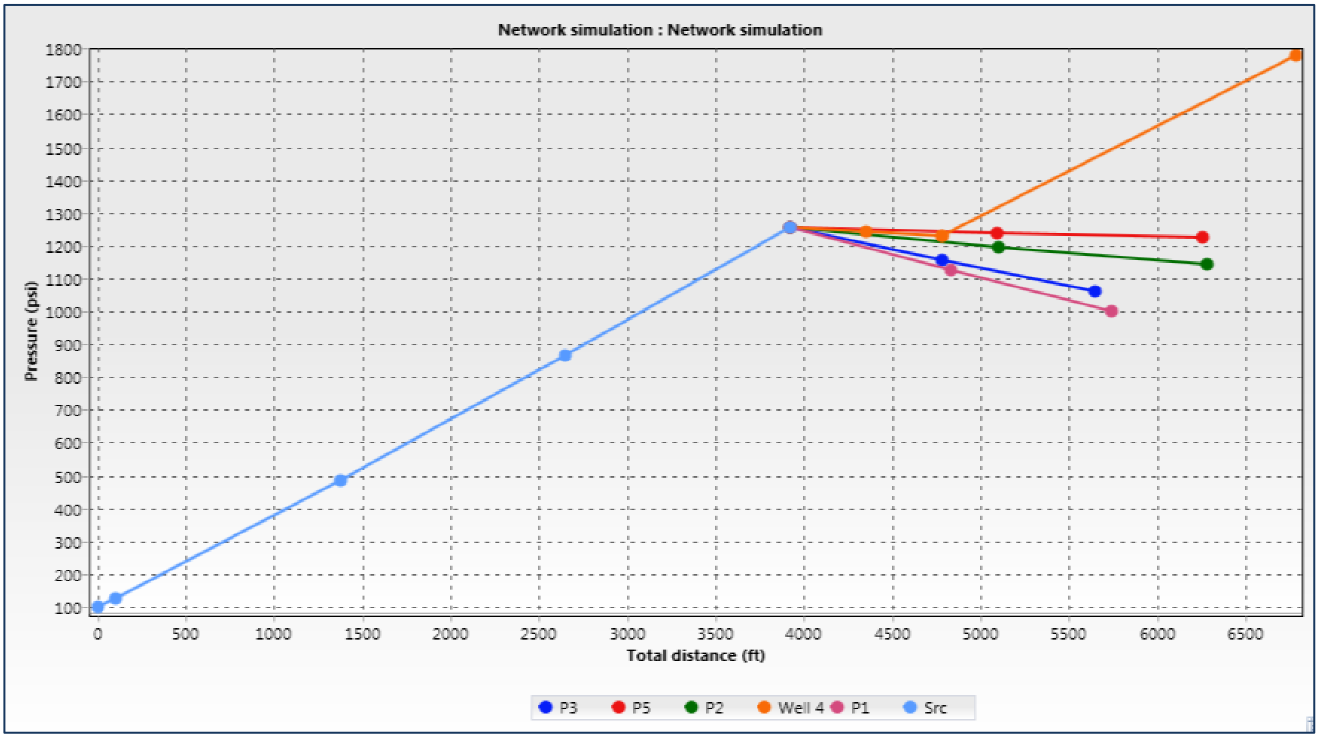

Figure 35: Pressure profile in the umbilical and five well injection lines. Early-life.

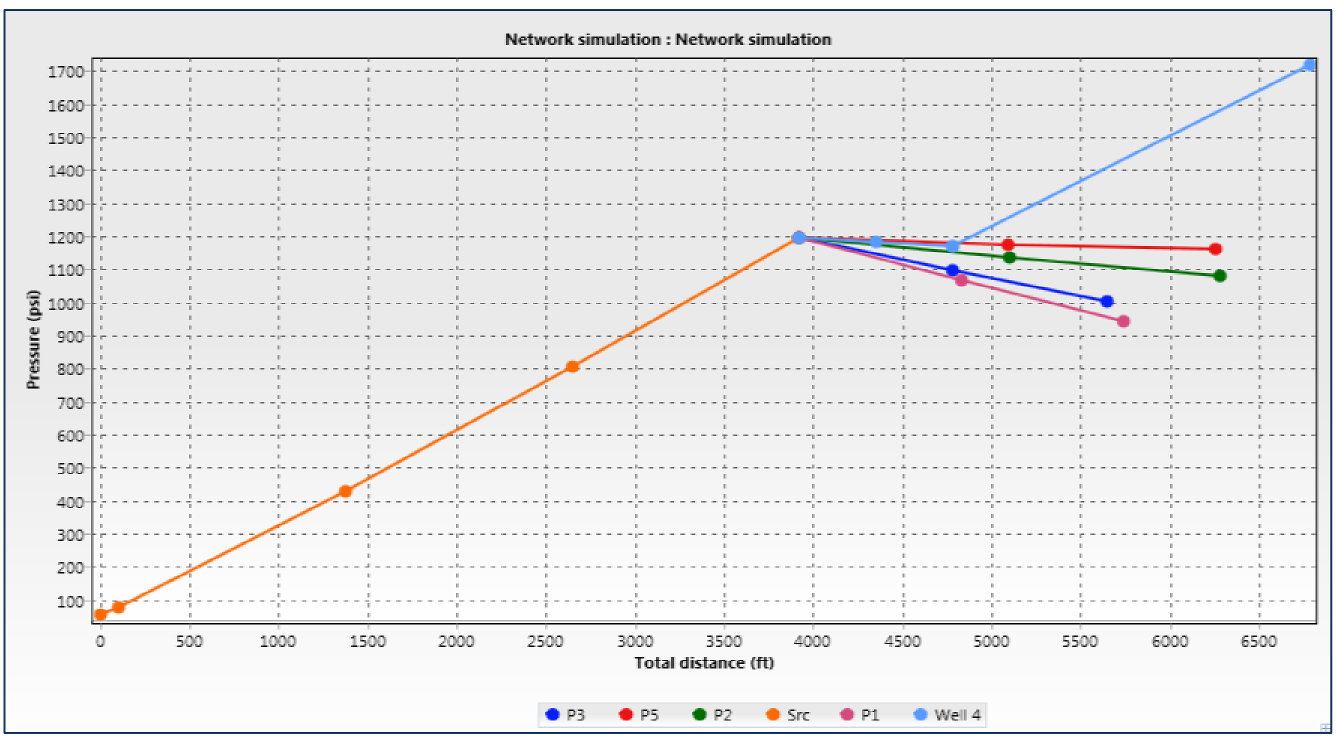

Figure 36: Pressure profile in the umbilical and five well injection lines. Mid-life.

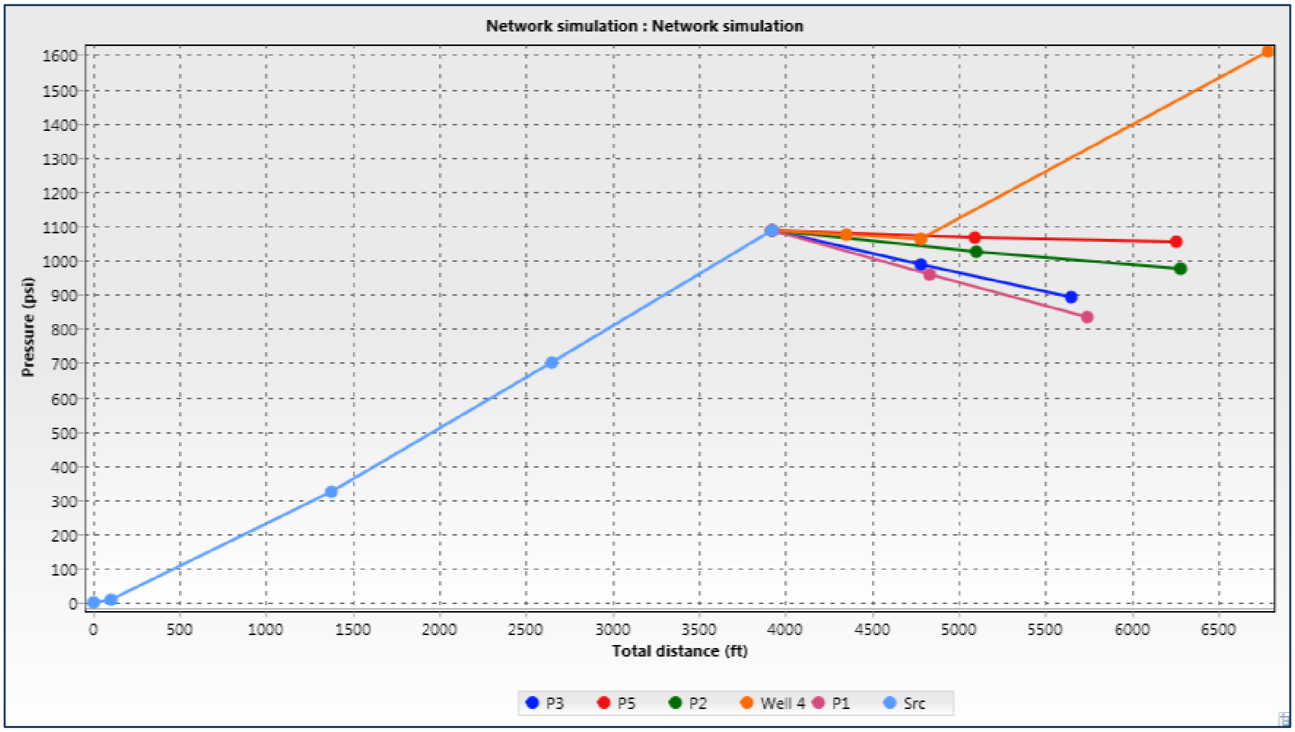

Figure 37: Pressure profile in the umbilical and five well injection lines. Late-life.

5.5 Corrosion Inhibitor

The corrosion inhibitor is injected at a rate of 1 gpm per well. It is delivered through an umbilical with ID of 0.65" to a UTA. The umbilical interfaces at a junction plate with five flow lines which each inject fluid at the production tree. The project goal was to inject corrosion inhibitor at a minimum discharge pressure to the well head at a pressure greater than the production well head pressure. The pump pressure would be varied with the life cycle of production well. In the below mentioned table the flow line diameter for each stage of life is given considering the well head pressure for each well without altering the flow-rate. The optimum diameter for each flow-line is 0.5" which would be run for the entire life cycle. The pressure profile is plotted for each life. The pressure increases due to gravity in umbilical and it increases or decreases as per ocean topography. It can be inferred that an increase in diameter of the umbilical or flowline has a much greater contribution for increase in well head pressure compared to an increase in pump pressure. Table 33 below shows the pressure results for each stage of production field life. Figures 38, 39 and 40 demonstrate the pressure profile for early, mid and late life

Early					
Pump Pressure	Well	Well head Pressure (Psi)	Injection Pressure at Well head(Psi)	Diameter of Flow line (inch)	Umbilical Diameter(inch)
45Psi	1	983.48	1084.275	0.5	0.65
	2	1018.1	1138.626	0.5	
	3	1003.309	1149.099	0.5	
	4	1044.79	1208.725	0.5	
	5	1195.18	1220.543	0.5	

Mid					
Pump Pressure	Well	Well head Pressure (Psi)	Injection Pressure at Well head(Psi)	Diameter of Flow line (inch)	Umbilical Diameter(inch)
Atmospheric Pressure	1	906.66	1033.77	0.5	0.65
	2	933.122	1088.09	0.5	
	3	992.6	1098.55	0.5	
	4	1064.15	1158.075	0.5	
	5	1043.67	1169.675	0.5	

Late					
Pump Pressure	Well	Well head Pressure (Psi)	Injection Pressure at Well head(Psi)	Diameter of Flow line (inch)	Umbilical Diameter(inch)
Atmospheric Pressure	1	753.4	1033.77	0.5	0.65
	2	780.2	1088.019	0.5	
	3	743.3	1098.525	0.5	
	4	792.88	1158.075	0.5	
	5	867.32	1169.675	0.5	

Table 33: Pressure results for each stage of production field life, including pump pressure and flowline diameter.

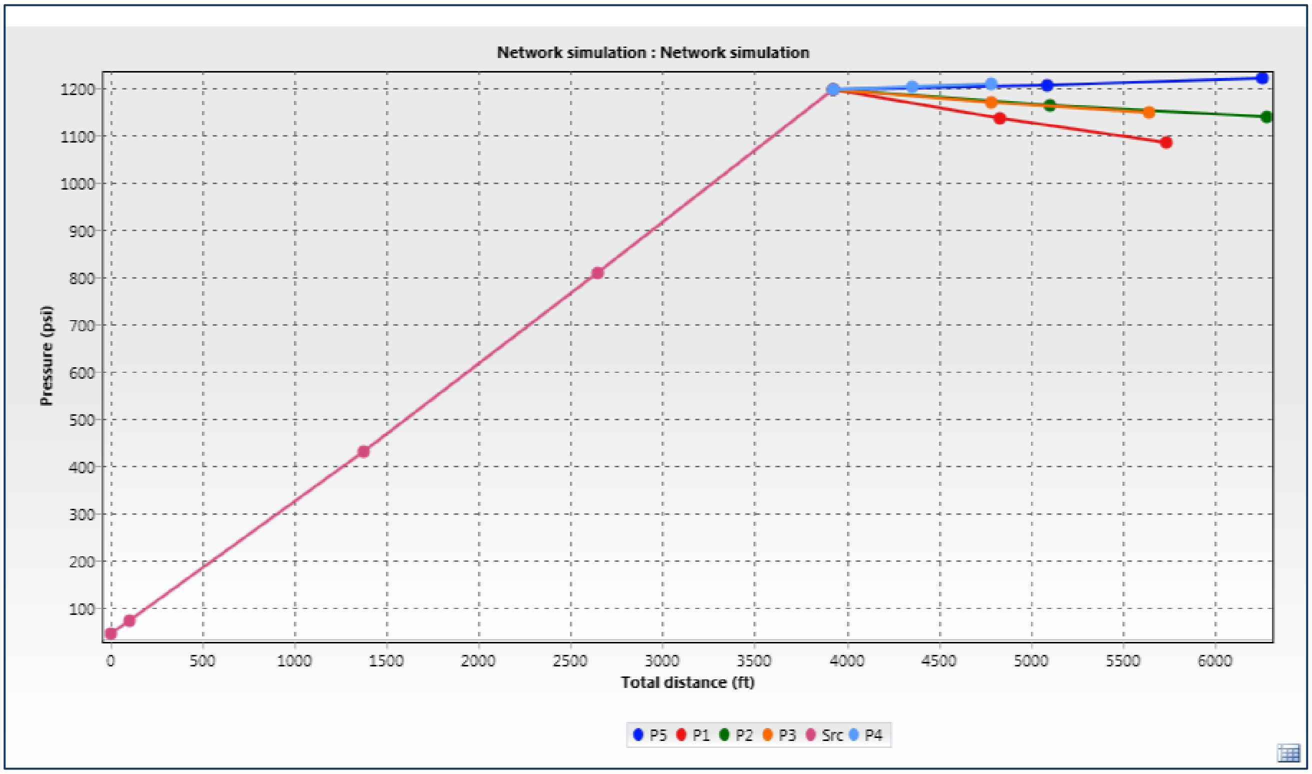

Figure 38: Corrosion inhibitor injection pressure profile. Early-life.

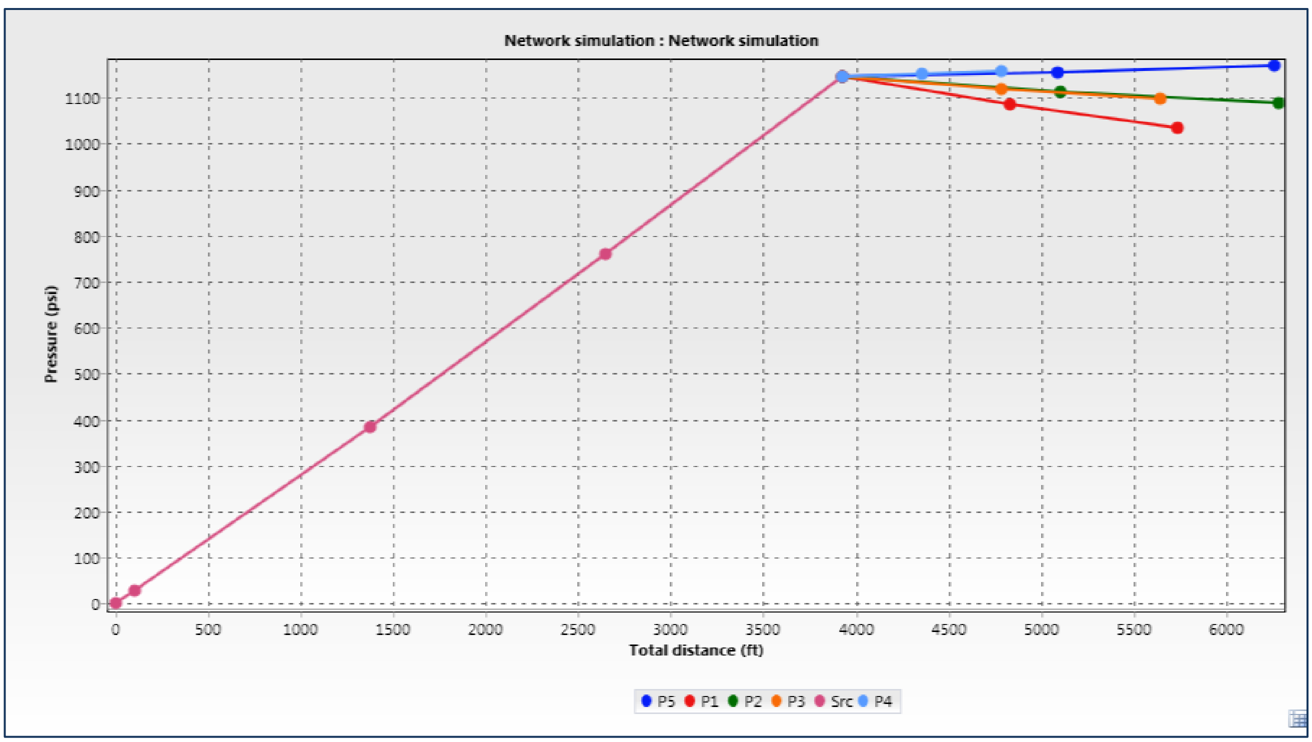

Figure 39: Corrosion inhibitor injection pressure profile. Mid and late life.

6 Recommendations

Though the project team was able to overcome many flow assurance issues through field design, several concerns still exist that must be effectively handled throughout the life of the field. To more effectively manage subsea equipment due to the depth of the field, the design team recommends utilizing a MUX-based control system as opposed to hydraulic. This will allow instantaneous activation of subsea valves/chokes. Control panels located on the FPSO should have fully redundant power sources as well as redundant PLC processing cards. Dual UPS units shall be available to allow continued subsea control in the event of a “black ship” in which all electrical power is lost. UPS units should be located in a “safe zone” away from volatile operations.

6.1 Slugging

Slugging is experienced in all phases of field life. The solution therefore falls to mitigation. The project team recommends evaluating the use of gas lift in the riser to reduce the slug volume. A gas delivery method would be a string ran internally in the riser. An additional mitigation option is pigging to remove liquids. As described previously, a pigging network is in development. The team recommends full development and implementation of the system. A primary mitigation strategy will be design of topside equipment to adequately handle all slugging profiles, including a slug catcher. The slug catcher should have the ability to be bypassed during normal operation and brought back online quickly to deal with incoming slugs. An active monitoring system, such as the FlowManger™ software platform, is recommended to predict incoming slugs. Topside chokes should also be available to more effectively handle slugs. Chokes should have the ability to be remotely controlled.

6.2 Solids Formation

As described previously, temperature issues are encountered in well 4 early-life (in the production tubular) and well 5 late-life (in the flowline). Well 4 production fluid drops below 70°F approximately 2,000 feet below the wellhead. It is recommended to inject wax inhibitors at these points continuously. For combatting hydrate formation, methanol should be injected continually throughout the entire system to maximize no touch time in case of a shut down. Low-dosage kinetic hydrate inhibitors should be applied to well 4, with anti-agglomerate chemicals used until the production water-cut percentages exceed 50%. An effective plan should also be established for line depressurization when attempting to mitigate hydrate plugs. An official procedure will maximize safety for all involved personnel.

Implementation of a pigging network is also highly recommended. The project team also recommends the use of electrical heating for cooler portions of the production system, such as the flowline from production tree 4 to the manifold. For combating asphaltenes and scale in the reservoir, the project team recommends utilizing chemical “squeeze” injection treatments to ensure the completions section remains fully operational. Solvents can also be injected into the flowline to combat asphaltene deposition. In general, a SARA analysis must be conducted from fluid samples throughout the field. From this, an effective solids control strategy can be developed(2).

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6.3 Material Selection

There are several parameters that must be considered when choosing the correct alloys for subsea pipelines, trees, wellheads, manifold and other equipment in order to match the technical requirements. Moreover, the cost of each has to be considered to meet economic limitations. Due to corrosion and erosion issues, sometimes we need to implement regular replacement periods for equipment parts and/or regular maintenance services including coatings to avoid catastrophic failures and shut downs which can cause significant expense. For instance, due to the relative low cost of 410 alloy, among other CRAs, and its relative high strength, this type of CRA (Corrosion Resistant Alloy) is a popular material choice for trees, manifolds, and the wellhead equipment.

6.4 Inhibitor Injection Considerations

There are a few instructions for the type of inhibitor that we select to inject, where to inject it, and the way to do so. It must be considered that the use of many inhibitors in their neat form may not improve the pipeline corrosive resistivity and can in fact be deteriorative. Another critical point to consider is that the quality of our inhibition injection relies on its injection location and the quality of its distribution and dispersion throughout the pipeline. The chemical must make an inner layer-like coating in the entire area of the pipeline or else the un-inhibited or not well-inhibited areas will be prone to corrosion.

Below are the figures that explain inhibitor injection considerations graphically[3].

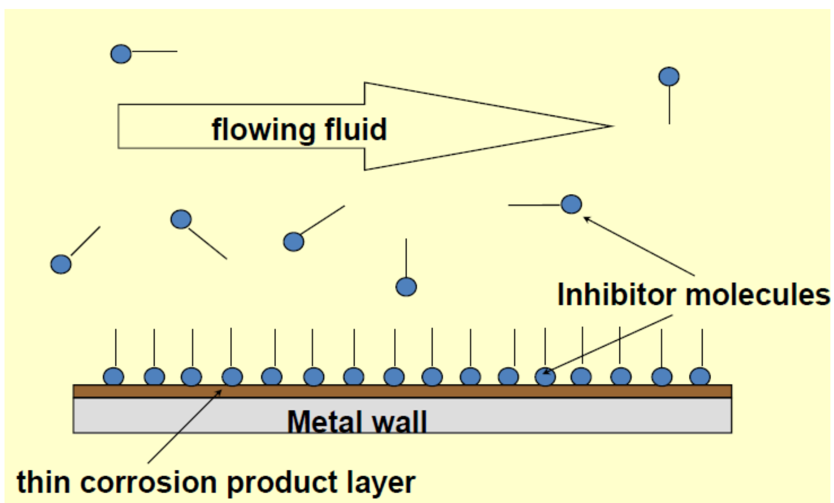

Figure 40: How corrosion inhibitor must be injected

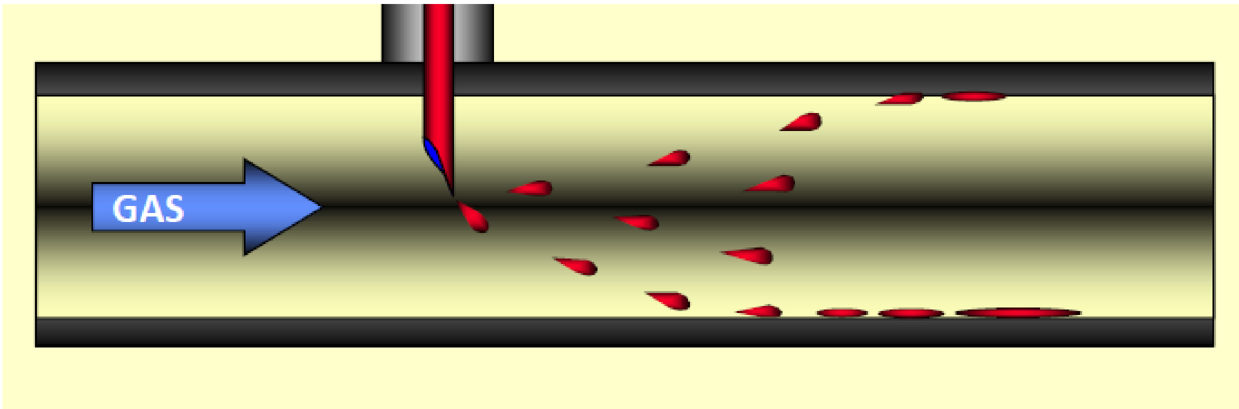

Figure 41: How corrosion inhibitor must be injected

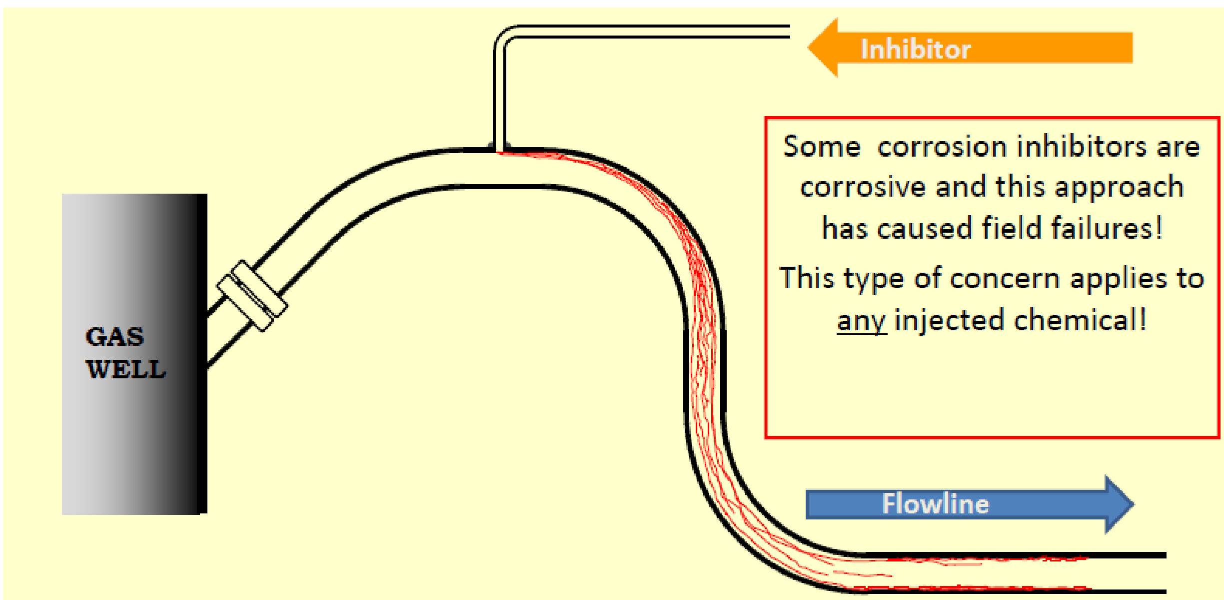

Figure 42: Where corrosion inhibitor must be injected

As it is shown in the above figures the inhibitor must be injected far enough upstream to protect the maximum length of the pipeline. The best place to inject inhibitors are at the trees. Our production field design employs this concept.

References

1. PIPESIM Online Help. Schlumberger, 2013.

2. Design Guidelines for Subsea Oil Systems. Lorimer, Ellison. Shell Deepwater Development.

3. "Corrosion Fundamentals". SUBS 6360 Subsea Materials and Corrosion course material. Fall 2014.