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Critical Gas Flow Rate Analysis for Mitigating Liquid Loading in the MnaziBay Gas Field, Tanzania

[1]Lazaro Isaac lazaro | [2]Mohammed Kauli Makame | [3]Omary Bakari Salehe | [4]Gregory Paul Mella

[1,2,3,4]Department of marine Engineering, Dar es salaam Maritime Institute (DMI)

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Abstract:

Liquid loading is a prevalent production challenge in mature gas wells, occurring when declining reservoir pressure prevents sufficient gas flow from lifting co-produced liquids, leading to accumulation, increased backpressure, and potential well shut-in. This study investigates the minimum critical gas flow rate required to prevent liquid loading in the Mnazi Bay Gas Field, Mtwara, Tanzania, using Well MB#01 as a case study. Three approaches were employed: the empirical Turner et al. (1969) method, nodal analysis via PIPESIM, and wellbore-centric modeling with PROSPER. Turner's model estimated a critical flow rate of approximately 14.96 MMSCFD, while PIPESIM predicted a minimum threshold of 3.8 MMSCFD, and PROSPER highlighted potential loading risks below 9 MMSCFPD. Current production levels indicate that MB#01 operates safely above these thresholds; however, ongoing reservoir pressure decline may increase the risk of liquid loading. Mitigation strategies, including surface compression, gas velocity strings, and multiple completions, are recommended to maintain safe flow rates and prolong well life. The study demonstrates that integrating empirical methods with simulation-based modeling provides a more accurate and practical framework for predicting critical flow rates and managing liquid loading in mature gas wells. These findings offer valuable insights for field operators in Tanzania and other Sub-Saharan gas-producing regions facing similar challenges.

Key words: Liquid loading, critical flow rate, Turner model, PIPESIM, PROSPER, MnaziBay Gas Field, nodal analysis.

1.0 Introduction:

The MnaziBay Gas Field, located in southern Tanzania within the onshore Ruvuma Basin, was first discovered by AGIP in 1982 but remained undeveloped due to the absence of a domestic gas market. Development resumed in 2004 under Artumas (now Wentworth Resources) through the Mtwara Energy Project, with gas production commencing in 2006–2007 [6] [8].

The field, currently operated by Maurel & Prom in partnership with the Tanzania Petroleum Development Corporation (TPDC), comprises five wells (MB-1, MB-2, MB-3, MB-4, and MS-1X) and spans approximately 756 km². Production has progressively increased, reaching over 110 MMscf/day in recent years following the commissioning of the Madimba Gas Processing Plant.

Geologically, MnaziBay is part of the Ruvuma Basin, formed during the rifting of Gondwana in the Permian–Jurassic periods. The reservoirs are predominantly clastic with minor mid-Jurassic carbonates. Like many mature gas fields, MnaziBay faces liquid loading, where declining reservoir pressures hinder the lift of co-produced liquids such as water and condensate. Accumulated liquids increase backpressure, restrict gas flow, and can lead to premature well shut-in [7].

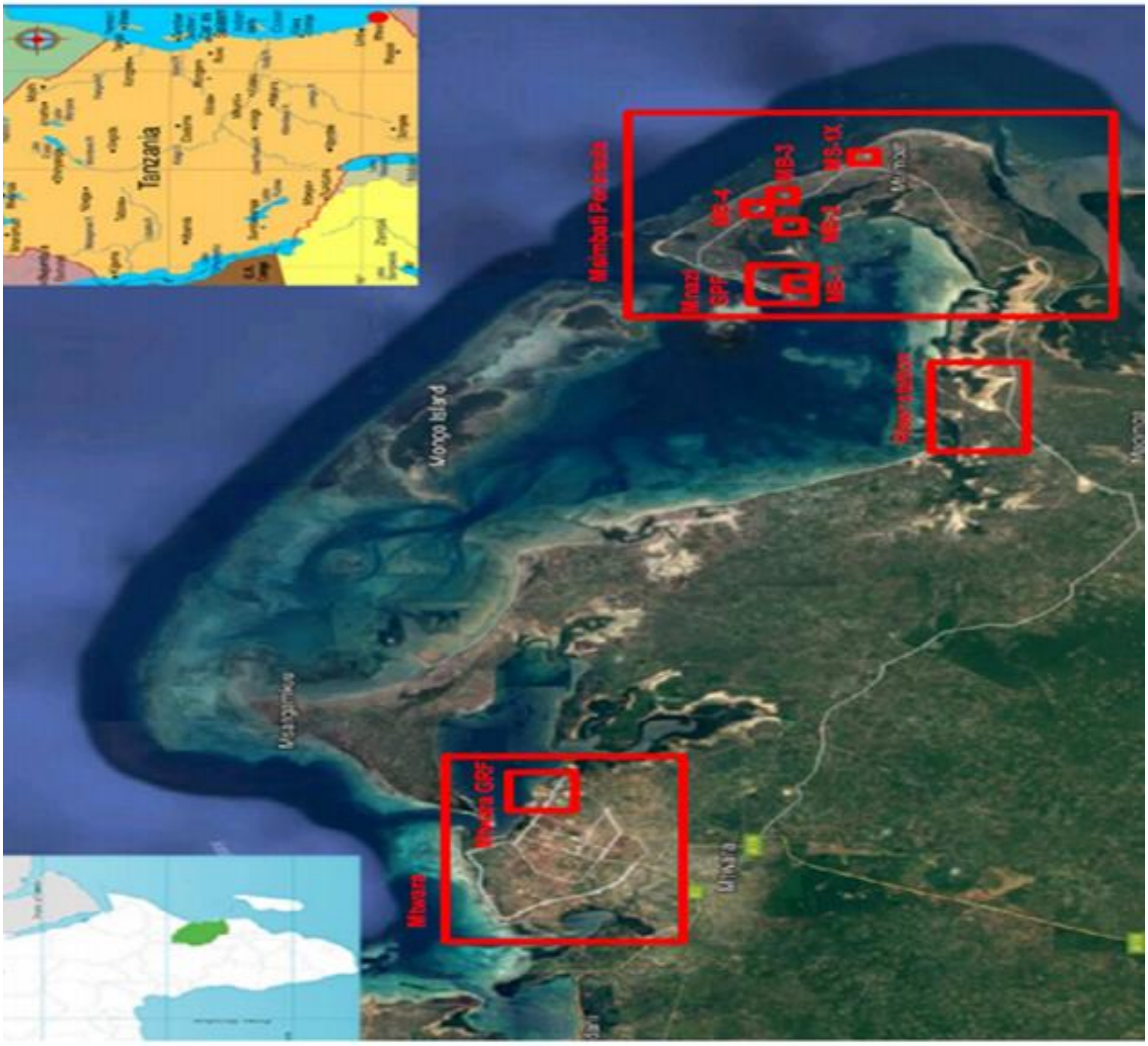

Figure 1. show five wells of MnaziBay Gas Field. (Source: Weatherill, 2019)

The MnaziBay reservoirs have been penetrated by five wells;

Table 1. Briefly background of MnaziBay Wells

WELL NAME	DRILLED BY	YEAR DRILLED
MNAZI BAY1 (MB1)	AGIP	1982
MNAZI BAY2 (MB2)	Artumas	2006
MNAZI BAY3 (MB3)	Artumas	2006
MNAZI BAY4 (MB4)	Maurel et Prom	2015
MS-1X	Artumas	2007

2.0 Literature Review:

Liquid loading is a common challenge in gas wells, occurring when the existing gas flow rate is insufficient to lift co-produced liquids, such as formation water or condensate, to the surface [1] (Shekhar, Kelkar, Hearn, & Hain, 2017). This accumulation of liquids increases backpressure, reduces gas production, and may ultimately result in well shut-in. Over the years, several correlations and models have been developed to predict the onset of liquid loading. Among these, the Turner et al. (1969) correlation is the most widely cited. The Turner model estimates the minimum gas velocity required to lift liquid droplets vertically using the concept of entrained droplets [2]. However, it has notable limitations: it does not account for wellbore diameter, inclination, or dynamic pressure variations, and some of its physical assumptions may not accurately reflect the true onset of liquid loading, particularly in deviated or complex well geometries. These shortcomings have motivated the development of more advanced predictive techniques, including mechanistic models and simulation-based approaches, such as nodal analysis using PIPESIM and wellbore-centric modeling with PROSPER. These methods incorporate well-specific parameters, fluid properties, and operational conditions, providing more reliable estimates of critical gas flow rates for preventing liquid loading.

Liquid loading is defined as the accumulation of liquids in the wellbore, which can lead to a reduction in natural gas production or even complete cessation of flow [3] (Adesina Fadairo, 2015). Various well completion and predictive methods have been developed to anticipate liquid loading; however, these approaches often show discrepancies and can be challenging to apply due to the difficulties in accurately predicting bottomhole pressures in multiphase flow conditions. Turner et al. (1969) developed the first liquid loading model based on the concept of critical gas velocity, providing a foundational framework for predicting the onset of liquid loading. More recent modifications, such as those proposed by Guo et al. (2005), have attempted to improve upon Turner's model, but they still do not account for liquid accumulation and kinetic effects, which can significantly influence liquid loading behavior in gas wells [4].

The minimum gas flow rate required to lift accumulated liquids from a gas well has been widely studied, particularly in mature fields experiencing declining reservoir pressures [5] (Sankar & Arul Karthi, 2019). Liquid accumulation in low-pressure gas well tubing can significantly reduce production and, in extreme cases, lead to early well abandonment, undermining the well's economic viability. Several correlations exist to predict the critical gas flow rate necessary to prevent liquid loading; however, these models often yield differing estimates, particularly at low wellhead pressures, highlighting the challenges in accurately forecasting conditions for effective de-liquification.

3.0 Methodology

Under this study investigation of liquid loading at MB#01 done through three approaches;

i. Turner et al Equation.
ii. PROSPER
iii. PIPESIM

3.1 Data collection.

The following are the primary data which are obtained direct from MnaziBay Field.

Table 2. MB#01 well parameter for investigation of liquid loading.

PARAMETERS	VALUE
Gas gravity($ps.gravity$)	0.65
Separator pressure(psi)	200

Water to gas ratio($STB/MMscf$)	100
Water salinity(ppm)	0.0000001
Condensate gravity (API)	50
Condensate to gas ratio($STB/MMscf$)	0.9
Compressibility factor	0.9
Gas density(kg/M^3)	0.65
Liquid density(lb/ft^3)	64.5
Tubing flowing pressure (KPa)	Zone G: 13000 and Zone D/E: 13460

Secondary data sources help validate, calibrate, and enhance the analysis of the liquid loading inquiry in the MnaziBay gas well (MB#01) utilizing PIPESIM, PROSPER, and the Turner et al. equation. These resources aid in the better interpretation of raw data and the development of well-behaved models.

Table 3. MB#01 well parameter for investigation of liquid loading

PARAMETERS	VALUES
Reservoir Permeability(md)	25
Reservoir porosity	0.16
Perforation interval (inch)	6462-6542 and 6380-6420
Well depth (ft)	6300
Tubing size (inch)	3-1/2
Reservoir pressure(psi)	2000
Reservoir thickness(ft)	419
Connate water saturation	0.25
Wall thickness(inch)	0.261
Packer size (inch)	2-3/8
Reservoir Temperature(k)	353.15
Wellbore Radius(feet)	0.354
Time since production (2016-2023)	2555days

Table 4. show natural gas composition of MB#1

Data (Composition)	Percentage Unit	Value
Methane	%	98.00298
Nitrogen	%	0.17885
Carbon-dioxide	%	0.29361
Ethane	%	0.901463
Propane	%	0.26494
Water	%	0.91400000
Hydrogen-sulphide	%	0.00000
Hydrogen	%	0.00000
Carbon monoxide	%	0.00000
Oxygen	%	0.00000
i-Butane	%	0.04413
n-Butane	%	0.05346
i-Pentane	%	0.01358
n-Pentane	%	0.00915
n-Hexane	%	0.02469

3.2 Data analysis.

3.2.1 Applying Turner Model to Predict the Liquid Loading.

The Turner model allowed critical velocity and critical flow rates to be predicted. Since the Turner model served as the basis for all other models and it made sense to start there given the necessary modifications, Turner et al. investigated two physical model liquid droplets entrained in flowing gas cores and liquid film movement along the walls of the production string in order to ascertain the minimum velocity. The liquid droplet model, which was previously described, will be used because it better fits the field data than the liquid film model.

Below the critical velocity, the droplet falls and liquids Equation 1 gives the formulae for critical velocity, equation 2 for critical flow rate based on droplet model:

$$V_{gc} = \frac{K}{\rho_g^{1/2}}\sigma^{\frac{1}{4}}(\rho_L - \rho_g)^{1/4} \text{ ... ...Equation 1}$$

$$Q_{gc} = \frac{PA}{(T+460)Z}3.06V_{gc} \text{ ... ...Equation 2}$$

The following formula provides the minimal gas flow velocity required to eliminate a liquid drop.

$$V_{crit-T} = \frac{1.92}{\rho_g^{1/2}}\sigma^{1/4}(\rho_l - \rho_g)^{1/4} \text{.Equation 3}$$

$$Q_{crt-T} = \frac{306}{TZ}PAV_{crit-T} \text{ ... ...Equation 4}$$

Turner critical rate model. Turner's critical model based on the assumption that the droplet is a sphere and will remains spherical all through the entire wellbore,

$$V_{crit-T} = \frac{1.593}{\rho_g^{1/2}}\sigma^{1/4}(\rho_l - \rho_g)^{1/4} \text{..Equation 5}$$

Li's critical rate model. Li's model above was developed based on the assumption that the liquid droplets are flat in shape and remains same all through the wellbore.

$$V_{crit-T} = \frac{0.7241}{\rho_g^{1/2}}\sigma^{1/4}(\rho_l - \rho_g)^{1/4} \text{.Equation 6}$$

Due to the fact that droplet deformation was not considered when the models were being developed, Turner's model and Li's model would not be able to accurately forecast the critical rate needed to lift a droplet that is neither spherical nor flat.

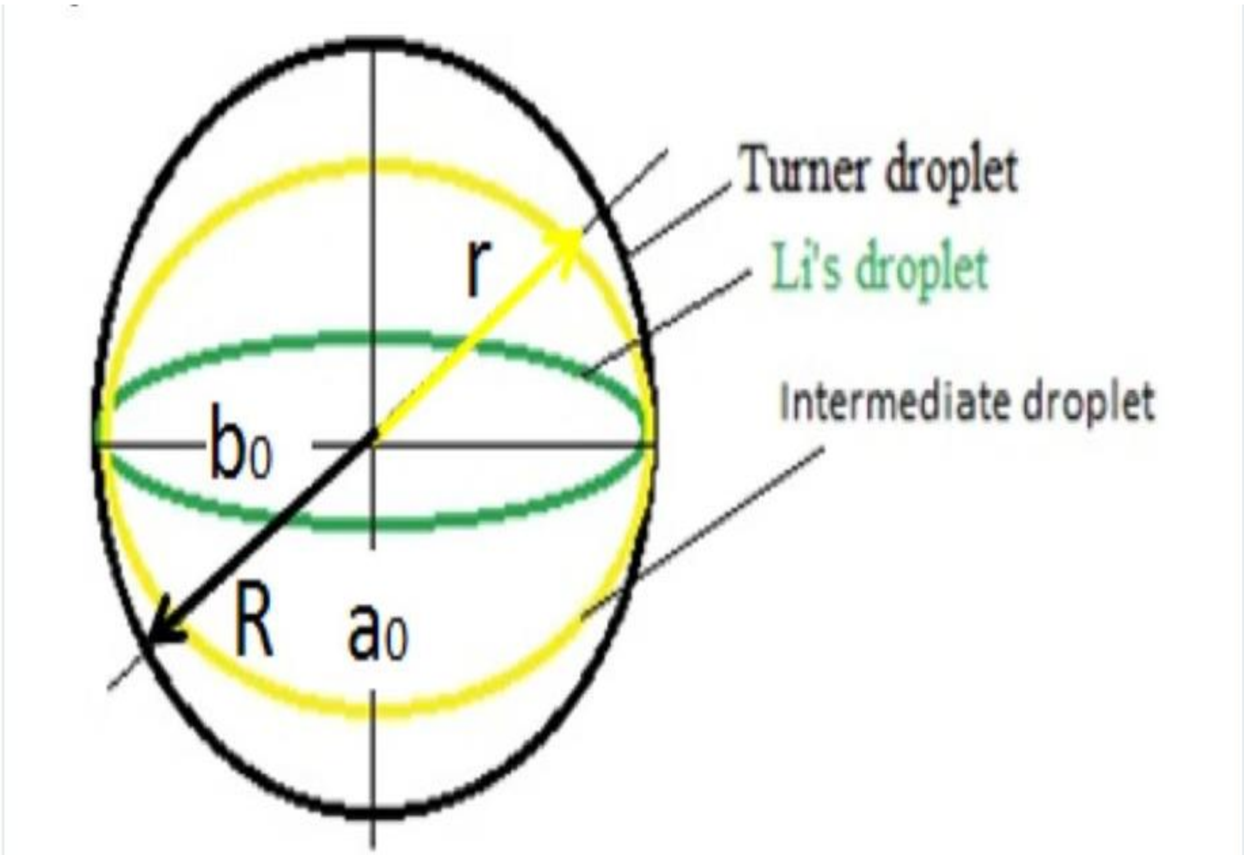

Figure 2. Droplet Shapes (Li, Sun, & Li, 2001)

To account for the deformation of the liquid droplet along the wellbore and, consequently, accurately forecast the critical rate when the droplet transitions from a spherical to a flat shape, a deformation coefficient C is included to the new model.

New model development

$$\begin{aligned} &New\ critical\ velocity\ \ model \\ &= \ Li\text{'}s\ critical\ velocity\ model \\ &+ \ Deformation\ coefficient \\ &\times (Turner\ critical\ velocity\ model \\ &- Li\text{'}s\ critical\ velocity\ model) \end{aligned}$$

$$C = 2.261921523$$

$V_{crit-new} = V_{crit-L} + 2.261921523 \times (V_{crit-T} - V_{crit-L})$ … … … … ….Equation 7

$New\ critical\ gas\ flow\ rate\ = \frac{3.060PVnewcrit \times A}{TZ}$ … … ….Equation 8

Equation (05) was modified to provide an accurate critical velocity prediction. In order to compare the predicted rate with the actual gas rates, a 20% modification was also made. Liquids are continually taken from the well; there is no liquid loading if the production rate is higher than the critical rate. Liquid loading happens inside the well if the production rate falls below the critical rate.

By using turner et al equation to describe critical gas velocity

$V_{crit-T} = \frac{1.593}{\rho_g^{1/2}} \sigma^{1/4} (\rho_l - \rho_g)^{1/4}$..Equation 9

$\sigma = 15 + 0.91(\rho_l - \rho_g)$ … … . ..Equation 10

$q_{crit-T} \frac{3.060PAV_{crit-T}}{TZ}$ … … … … ….Equation 11

Where;

ρ_l: Density of liquid

ρ_g: Density of gas

A: Cross-sectional area of conduit, ft2

Z: Gas compressibility factor

T: Temperature, °R

C: Deformation coefficient

3.2.2 Multiphase Flow Modeling using PIPESIM.

PIPESIM is a crucial tool for simulating intricate multiphase flow in the wellbore, according to Ghalambor. It determines the critical gas velocity required to move liquid upward using models such as the Turner droplet model. Liquid loading is expected if the predicted gas velocity drops below this level.

Testing and Optimizing Scenarios

Engineers may evaluate interventions like changing the size of tubing, adjusting choke settings, or installing artificial lift systems (gas lift, plunger lift, velocity strings) using PIPESIM's scenario modeling. This makes it possible to assess how each strategy can stop VLP from crossing the IPR at loading-indicating rates.

3.2.3 Nodal Analysis (A Software Assisted Approach – PIPESIM).

PIPESIM is a highly sophisticated and versatile software tool used in pipeline engineering, specifically designed for the modeling, simulation, and optimization of oil and gas production systems. Developed by Schlumberger, PIPESIM has become an industry-standard application for engineers looking to solve complex flow-related challenges in well, pipeline, and process facilities.

Step-by-step in PIPESIM:

Create Well Model:

A. Create a new well model in PIPESIM.

B. Describe the geometry and trajectory of the well (from perforation to wellhead).

C. Sizes of input tube and casing at the proper depths

Input Fluid Properties:

- Input the gas composition using the EOS.
- Run fluid characterization (calculate PVT tables
- Setup Reservoir Node:
- Define permeability, skin, pressure, and temperature

D. Setup Vertical Lift Performance (VLP).

- Use multiphase flow correlations (for these case Beggs & Brill is selected)
- selects tubing and casing flow paths.
- Set flow correlation suitable for your well (For this case vertical well is selected)

E. Run Nodal Analysis:

- Run the nodal analysis (Inflow vs. Outflow curve).
- Find the operating point (intersection of IPR and VLP).

Identification of liquid loading Use Turner's critical velocity or Coleman correlation in PIPESIM and Compare actual gas Flowrate vs. critical Flowrate. If gas Flowrate < critical Flowrate → liquid loading risk

4 Results and Discussion:

4.1 Results

The results are linked to workable mitigation techniques in the concluding discussion. Since the present rate for MB#01 is higher than the critical limit, no immediate action is necessary; however, if the flow ever approaches the loading threshold, it is advised to take surface compression, tube modifications, or artificial lift design.

4.1.1 Turner et al Result.

By using turner et al equation to describe critical gas velocity and flowrate.

From equation 09 and 10;

$$V_{crit-T} = \frac{1.593}{\rho_g^{\frac{1}{2}}} \sigma^{\frac{1}{4}} (\rho_l - \rho_g)^{\frac{1}{4}}$$

$$\sigma = 15 + 0.91(\rho_l - \rho_g)$$

$$\sigma = 15 + 0.91(64.5 - 0.65)$$

$$\sigma = 73.92 dyne/cm$$

$$V_{crit-T} = \frac{1.593}{0.651^{1/2}} 73.92^{\frac{1}{4}} (64.5 - 0.65)^{\frac{1}{4}}$$

$$V_{crit-T} = 16.4 ft/sec$$

From equation

$$q_{crit-T} = \frac{3.060 P A V_{crit-T}}{T Z}$$

$$A = \frac{\pi D^2}{4}$$

$$A = \frac{\pi}{4} \times 0.088 \times 0.088$$

$$A = 0.0062 m^2$$

$$q_{crit-T} = \frac{3.060 \times 1948 \times 0.0062 \times 16.4}{0.9 \times 45}$$

$$q_{crit-T} = 14.96 MMscf/d$$

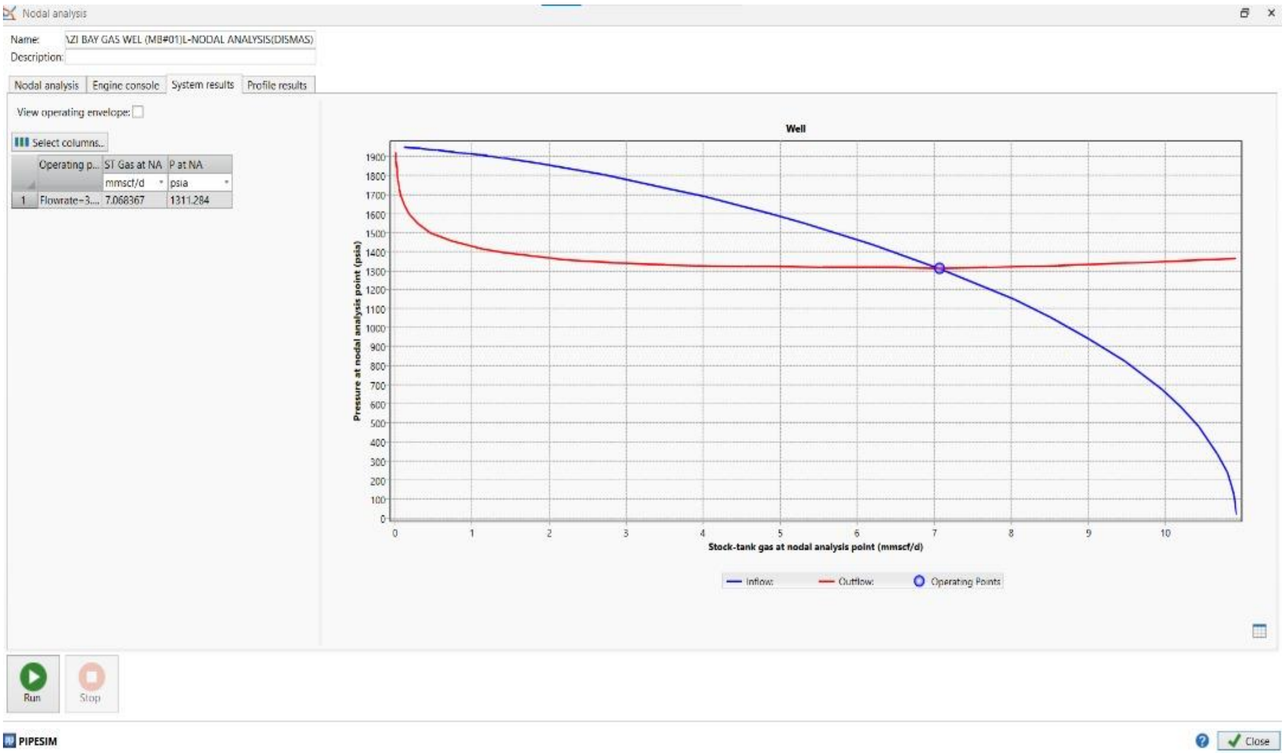

Fig 3; Simulated Result Base on PIPESIM.

Figure 3. show operating point which represent the intersection of Inflow and Outflow of MB#01 In a Nodal Analysis plot, the operational point of a natural gas well is the point where the outflow (VLP or TPR) and inflow performance relationship (IPR) curves connect. The well's current production rate (7.068MMscf/d) and bottomhole pressure (1311psi) are represented by this point.

VLP-Vertical Lift Performance; Describe how much pressure required by the reservoir to deliver gas flowrate to the surface. IPR-Inflow Performance Relationship; Describes how much gas the reservoir can supply to the wellbore at various bottomhole pressures. It depends on the reservoir pressure, permeability, skin factor, and fluid properties.

TPR-Tubing Pressure Relationship; but it more specifically refers to the pressure drop in the tubing as gas/liquid flows upward.

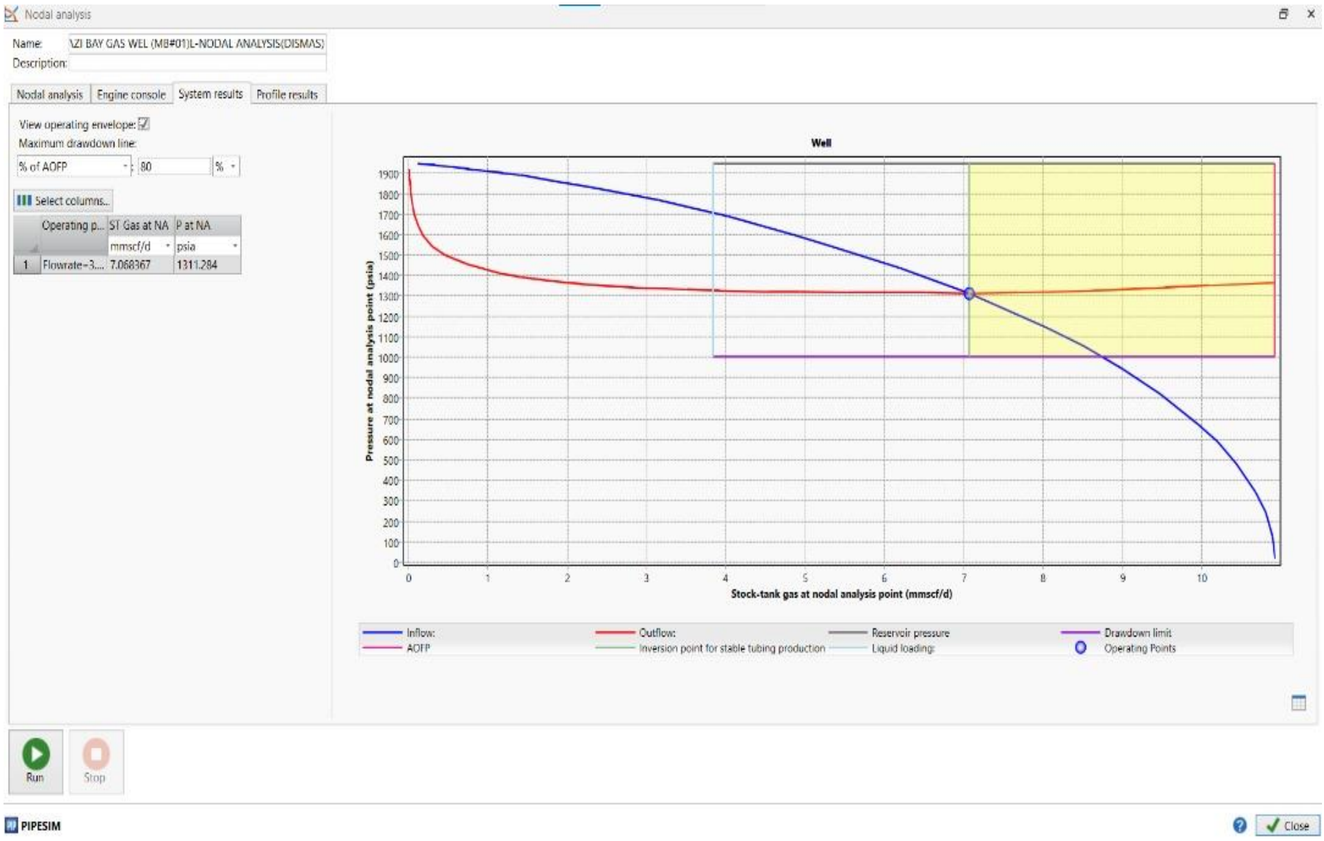

Figure 4. Show Minimum Critical flowrate for gas to avoid liquid loading(3.8MMscf/d).

Table 5. Result data from the figure 4

Row	Inflow Rate $(MMscf/d)$	Inflow Pressure $(psia)$	Outflow Rate $(MMscf/d)$	Outflow Pressure $(psia)$
1	10.191459	1946.375	10.191459	1361.47
2	9.308537	1777.706	7.068367	1311.284 (Operating Point)
3	8.491748	946.5026	2.838896	1341.096
4	7.649057	1214.007	2.374087	1321.064
5	6.893031	675.8783	4.152764	1322.791
6	6.109385	1486.542	3.759183	1297.075
7	5.347582	1546.951	3.011387	1309.098

8	4.526026	1444.091	0.001839	1590.842
9	3.892654	1366.591	0.003891	1578.168
10	3.274408	1241.415	0.006996	1575.12
11	2.716843	1801.162	0.008292	1375.128
12	2.201964	1460.63	0.009981	1575.182
13	1.745952	1804.696	0.005986	1395.892
14	1.365699	1771.472	0.003282	1371.892
15	1.042597	1641.518	0.001779	1370.804
16	0.783303	1833.773	0.000972	1330.447
17	0.576655	1827.065	0.000551	1315.11
18	0.422305	1833.77	0.000325	1315.117
19	0.311265	1219.541	0.000193	1343.722
20	0.238903	121.594	0.000115	1351.798
21	0.182465	920.854	0.000068	1359.822
22	0.139342	586.846	3.91772	1326.601
23	0.101672	1923.719	0.01265439	1642.791

4.1.2 PROSPER Result.

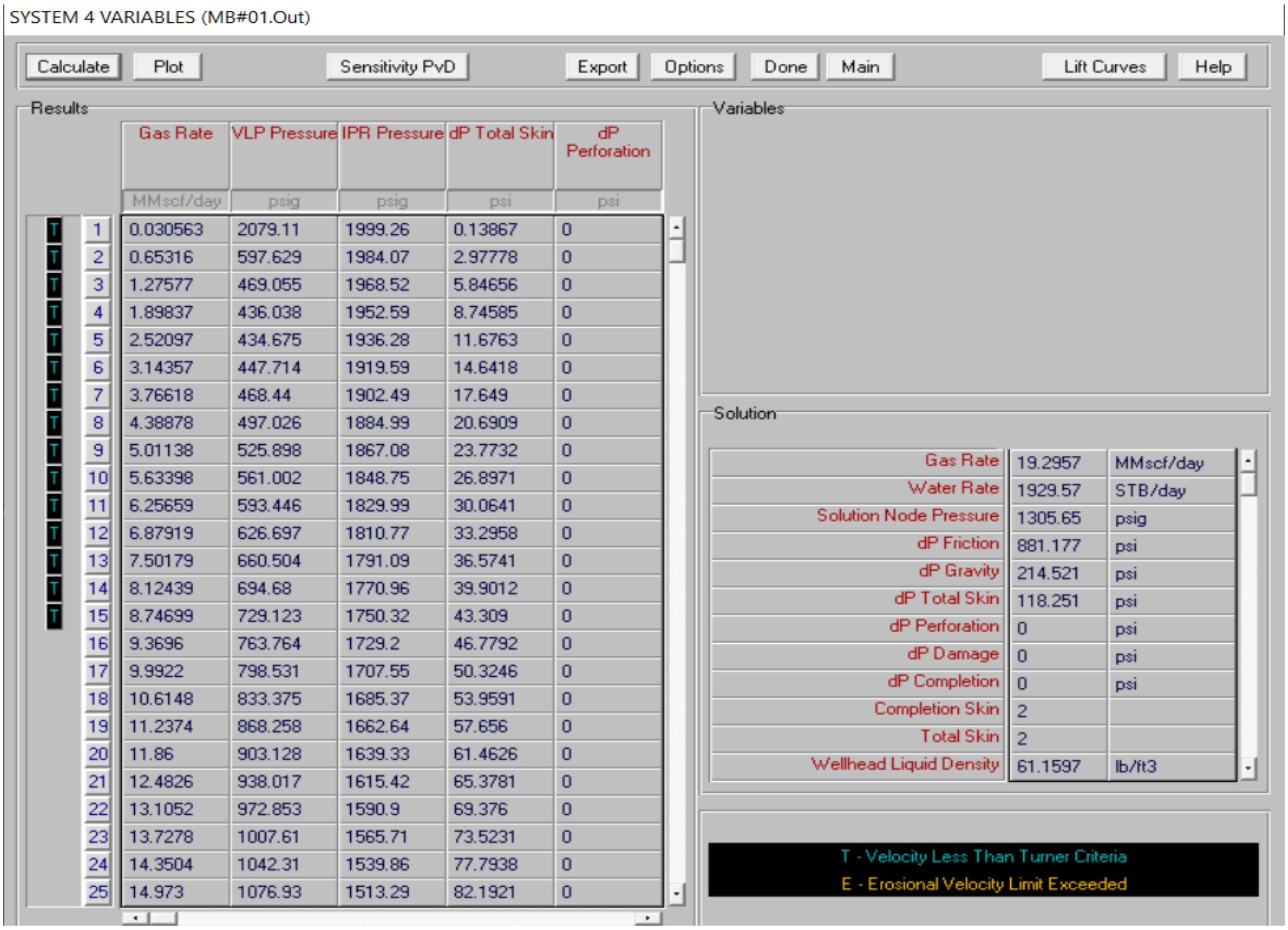

Figure 5. Flowrate of gas under Velocity less than Turner Criteria indicated by "T".

Table 6. flowrate of gas under Velocity less than Turner Criteria indicated by "T".

	No.	Gas Rate ($MMscf/day$)	VLP Pressure ($psig$)	IPR Pressure ($psig$)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.030563	2079.11	1999.26	0.13867	0
T	2	0.65316	597.629	1984.07	2.97778	0
T	3	1.27577	469.055	1968.52	5.84655	0
T	4	1.89837	436.038	1952.58	8.74585	0
T	5	2.52097	434.675	1936.28	11.6763	0
T	6	3.14357	447.714	1919.5	14.631	0
T	7	3.76618	468.44	1902.49	17.649	0
T	8	4.38878	497.026	1884.99	20.6692	0
T	9	5.01138	525.898	1867.08	23.7732	0
T	10	5.63398	561.002	1848.75	26.8971	0
T	11	6.25659	593.446	1829.99	30.0501	0
T	12	6.87919	626.697	1810.77	33.2958	0
T	13	7.50179	660.504	1791.09	36.5741	0
T	14	8.12439	694.68	1770.95	39.902	0
T	15	8.74699	729.123	1750.32	43.309	0
T	16	9.3696	763.764	1729.2	46.7729	0
T	17	9.9922	798.531	1707.55	50.3246	0
T	18	10.6148	833.375	1685.37	53.9591	0
T	19	11.2374	868.256	1662.84	57.6566	0
T	20	11.86	903.198	1639.36	61.4626	0
T	21	12.4826	938.017	1615.42	65.3781	0
T	22	13.1052	972.953	1590.9	69.4071	0
T	23	13.7278	1007.61	1565.71	73.5381	0
T	24	14.3504	1042.31	1539.86	77.7938	0

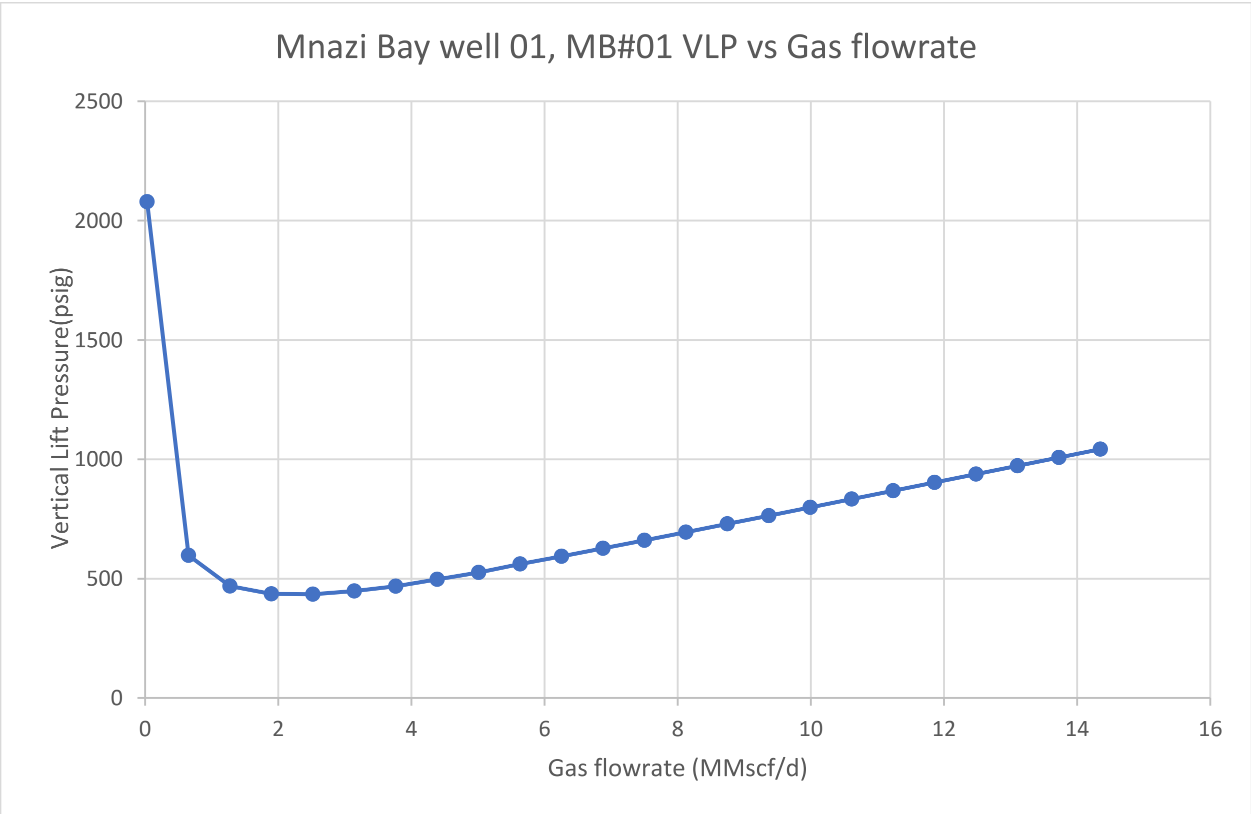

Figure 6. VLP against gas flowrate, result from PROSPER

Results

		Gas Rate	VLP Pressure	IPR Pressure	dP Total Skin	dP Perforation
		MMscf/day	psig	psig	psi	psi
	26	15.5956	1112.56	1485.98	86.7653	0
	27	16.2182	1147.07	1457.87	91.5106	0
	28	16.8408	1171.1	1428.93	96.4496	0
	29	17.4634	1205.34	1399.11	101.611	0
	30	18.086	1239.49	1368.36	106.987	0
	31	18.7086	1273.58	1336.6	112.637	0
	32	19.3312	1307.59	1303.77	118.597	0
	33	19.9538	1341.53	1269.78	124.911	0
	34	20.5764	1375.37	1234.54	131.586	0
	35	21.199	1409.15	1197.96	138.697	0
	36	21.8216	1442.86	1159.87	146.336	0
	37	22.4442	1476.49	1120.16	154.559	0
	38	23.0669	1510.06	1078.64	163.448	0
	39	23.6895	1543.55	1035.09	173.167	0
	40	24.3121	1576.97	989.208	183.903	0
	41	24.9347	1610.32	940.672	195.851	0
	42	25.5573	1643.57	889.07	209.285	0
	43	26.1799	1676.77	833.8	224.626	0
E	44	26.8025	1704.58	774.083	242.469	0
E	45	27.4251	1737.65	708.784	263.678	0
E	46	28.0477	1770.67	636.138	289.691	0
E	47	28.6703	1803.63	553.287	322.973	0
E	48	29.2929	1836.54	454.508	368.733	0
E	49	29.9155	1869.39	325.567	440.44	0
E	50	30.5381	1902.18	63.4794	640.049	0

Figure 7. show flowrate of gas when Erosional Velocity exceed the limit indicated "E".

Erosional Velocity; Erosional Velocity in natural gas production refers to the maximum velocity at which gas (or gas and liquid mixtures) can flow through a pipeline or production tubing without causing excessive erosion of the pipe wall. Exceeding this velocity can lead to mechanical wear, thinning, or even failure of the pipe over time due to the impact of solid particles or high-velocity fluids.

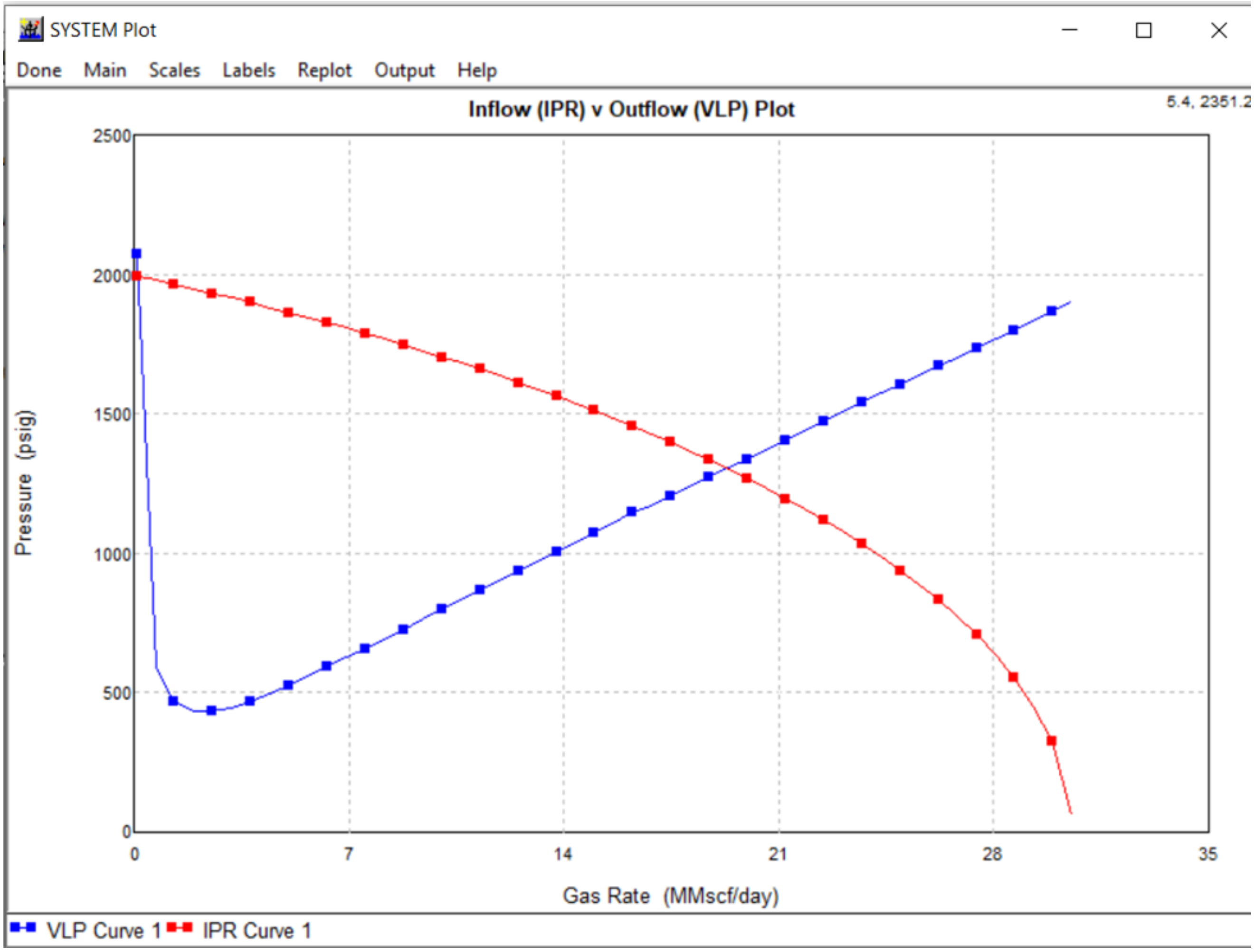

Figure 8. VLP and IPR in relationship with pressure and gas flowrate. Intersection represent Operating point (19.2MMscf/d, 1310psig) result from PROSPER.

Well parameters on critical flow rate gas.

From table 05. Row 2 and beyond: Despite a respectable inflow pressure, the outflow rate rapidly decreases (For example., rows 3–7). Very little or no outflow combined with high pressures (such as rows 8–18) → indicates that liquid is building up and blocking the passage of gas.

From table 06. 1. Low Gas Flow in Row 1 with Hi gh IPR Pressure:
0.03 $MMscf/d$ is the gas rate. Despite the high Operating Point.

Where the IPR and VLP curves intersect defines the only stable flow condition for the well under current reservoir and tubing conditions;

Below the intersection; The well cannot produce at that higher flow rate if the outflow curve (VLP) requires more pressure than the reservoir can provide (IPR) because gas cannot compensate for the whole lift and friction losses.

reservoir e, IPR = 1999 $psig$ is significantly greater than $VLP = 2079\,psig$, suggesting that liquids may be obstructing flow.

High VLP at Low Rates of Flow the VLP stays high ($\sim 400 - 600\,psig$) for low gas flows (For example., $< 2\,MMscf/d$). Generally, low flow rates ought to provide less hydrostatic head and friction. High pressure implies extra pressure needed to lift liquids, consistent with slug flow or hydraulic head buildup

Above the intersection; If the reservoir can supply more gas than the tubing can lift (VLP too restrictive), excess gas stays downhole, and flow cannot increase until tubing friction or backpressure is reduced.

4.2 Discussion.

4.2.1Turner et al. Approach

The critical velocity idea was first presented by Turner et al. (1969) using the entrained droplet model, presuming spherical droplets and vertical well conditions. Although it is quick and popular in field diagnostics, it has limita tions.

Assumes steady-state, single point analysis; does not completely account for inclination, liquid accumulation, or complex flow regimes.

According to the Turner technique approach critical flow for MB#01 at around 14.8 MMSCFD.

Strengths of the Approach

- Simplicity.
- Requires minimal input data.
- Useful for screening.

Limitations:

- Less accurate for deviated/horizontal wells.
- Ignores changing flow regimes and pressure gradients.

4.2.2 PIPESIM Approach.

PIPESIM uses detailed nodal analysis combining inflow performance (IPR) and vertical lift performance (VLP). It models multiphase flow behavior using mechanistic or empirical correlations (e.g.,Beggs & Brill).

For MB#01, the PIPESIM model showed an actual flow rate of 7.068 MMSCFD and a critical rate of 3.8 MMSCFD, confirming the well is above the loading threshold.

Simulated data captured backpressure build-up, liquid holdup, and operating point clearly.

Strengths of the Approach.

- Handles full geometry and fluid behavior.
- Visualizes IPR-VLP intersection.
- Predicts dynamic multiphase flow behavior.

Limitations of the Approach.

- Requires comprehensive data.
- Steeper learning curve

4.2.3 PROSPER Approach.

PROSPER also uses nodal analysis but is tailored more toward wellbore-centric optimization. It allows direct integration of real-time production data, artificial lift design, and erosional velocity constraints.

For MB#01, PROSPER indicated the operating point at 19.2 MMSCFD with BHP at 1310 psi, suggesting no immediate risk of loading.

It identified flow below Turner's threshold (tagged "T" flow $below\ 9.3696 MMscf/d$) and erosional velocity limit (tagged "E").

Strengths of the approach.

- Best for detailed well-level diagnostics.
- ports sensitivity analysis and optimization.
- Allows artificial lift scenario modeling.

Limitations of the approach.

Limited pipeline network analysis compared to PIPESIM. is primarily designed for wellbore-centric nodal analysis and is not suited for modeling pipeline networks, cannot model surface pipelines, multiple well interactions, or downstream facility effects.

Mitigation Strategies Based on Results and Well Parameters.

There is no need for quick action because MB#01 is producing above the critical flow rate (7.068 > 3.8 MMSCFD). However, mitigation will be required as pressure trends decline.

Recommended Strategies

Gas Velocity Strings: Reduce tubing diameter to increase gas velocity if flow approaches the critical threshold.

Compression: Surface compressors can reduce backpressure and boost flow rate above critical.

Tubing Change or Dual Completion: Optimize geometry for better lift performance.

Decision Basis:

From Turner, flow rate must remain >3.8 MMSCFD.

From PIPESIM, the nodal curve intersection confirms safe operation but nearing threshold.

From PROSPER, further flowrate increase may hit erosional limits, so aggressive artificial lift must be balanced.

5 Conclusions and Recommendation.

5.1 Conclusion.

The essential gas flow rate needed to reduce liquid loading in the Mnazi Bay MB#01 gas well was effectively determined and confirmed by the study. By combining software-based simulation techniques (PIPESIM and PROSPER) with theoretical modeling (Turner et al.), it was determined that the current well performance is safely over the crucial flow rate threshold, reducing immediate risk. Also, the study emphasizes how dynamic gas well operations are and how rapidly well conditions might change toward loading risk due to decreasing reservoir pressure.

While PIPESIM and PROSPER supplied comprehensive and accurate depictions of multiphase flow behavior and well performance, the Turner model presented a straightforward and useful starting estimate. When combined, these instruments demonstrated that proactive management practices such as compression and tubing adjustment. All things considered, this study advances the more general goal of maximizing gas recovery and guaranteeing long-term operations in established fields such as MnaziBay.

5.2 Recommendation.

The research's conclusions lead to the following important recommendations to improve gas production efficiency and avoid early liquid loading in mature wells like MB#01 at the MnaziBay Gas Field; Continuous Monitoring of Critical Flow Rates: To make sure that gas flow rates continuously surpass the critical threshold (e.g., 3.8 MMSCFD as determined), real-time monitoring of gas flow rates is advised. This makes it possible to identify and lessen loading occurrences early.

Artificial Lift Optimization: To lower bottomhole pressure and maintain gas production above essential thresholds, particularly in older wells, assess the viability of putting in surface compressors or artificial lift systems.

Regular Re-evaluation of Well Parameters: Because operating and reservoir conditions change over time, key flow rates should be periodically recalculated using programs like PROSPER and PIPESIM.

Use of Velocity Strings: If output starts to fall toward critical rates, using smaller-diameter tubing (velocity strings) can help boost gas velocity and guarantee that liquids are transported higher.

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