REPUBLIQUE ALGERIENNE DEMOCRATIQUE ET POPULAIRE
Ministère de l'Enseignement Supérieur et de la Recherche Scientifique

N° Série : ………. /2020

Université Kasdi Merbah Ouargla

Faculté des hydrocarbures energies renouvelables et science de la terre et de l'univers

Département de production des hydrocarbures

MEMOIRE

Pour obtenir le Diplôme de Master

Option : Production académique

Présenté Par :

AUGEIX Mohammed, ZEGHIB Mabrouk

-THÈME-

Integrated production system modelling and optimization - Application of the new technology Surface Jet Pump in Hassi Messaoud.

Soutenue le : .../09/2020 devant la commission d'examen

Jury :

Encadreur : Dr. DJEBBAS Fayçal Univ. Ouargla

Président : Univ. Ouargla

Examinateurs : Univ. Ouargla

Année universitaire : 2019/2020

PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA
Ministry of Higher Education and Scientific Research

Serial number: ………. /2020

Kasdi Merbah Ouargla University

Faculty of Hydrocarbons, Renewable Energies and Science of the Earth and the Universe

Hydrocarbon production department

THESIS

To obtain the Master's degree

Option: Academic production

Presented by:

Mohammed Augeix, Mabrouk Zeghib

- THEME -

Integrated production system modelling and optimization - Application of the new technology Surface Jet Pump in Hassi Messaoud.

Presented on: .../09/2020 In front of the exam board

Jury:

Framed: Dr. Faycal Djebbas	Univ. Ouargla
President:	Univ. Ouargla
Examiners:	Univ. Ouargla

University year: 2019/2020

Abstract:

Due to the complexity of Hassi Messaoud oil field, the production engineers are facing many exploitation problems (depletion, backpressure, network management …) that unfavorably affecting the wells' production.

Towards solving such problems, solutions have been brought different techniques and "Surface Jet Pump" is one the latest innovation in the industry in order to fix problems such as backpressure. To predict the outcome, integrated production systems modelling is employed to analyze and optimize the influencing parameters on the sequential production chain, our study focuses on:

- ✓ Establish an integrated well-network model and run sensitivities via PROSPER
- ✓ Analyzing the result of simulating the SJP's addition and benefit occurred with GAP

The key words: Integrated production system, PROSPER and GAP, Surface Jet Pump, optimization, depletion, backpressure.

Résumé:

Due à la complexité de gisement de Hassi Messaoud, les ingénieurs de production sont confrontés à de nombreux problèmes d'exploitation (déplétion, contre-pression, gestion du réseau ...) qui ont affecté défavorablement la production des puits.

Afin d'affronter ces problèmes, des solutions ont été amenés par différentes techniques et la "Surface Jet Pump" est l'une des dernières innovations dans l'industrie pour résoudre des problèmes comme contre-pression. Pour prédire le résultat, la modélisation de système de production intégrés est employée pour analyser et optimiser les paramètres influenceurs sur la chaîne de production séquentielle, notre étude est axée sur :

- ✓ Établir un modèle puits-réseau intégré fiable et lancer des sensitivités via PROSPER
- ✓ Analyser le résultat de simulation de l'ajout du SJP le bénéfice obtenu par GAP

Les mots clés : Système de production intégré, PROSPER, GAP, Surface Jet Pump, optimisation, déplétion, contre-pression.

ملخص:

نظرًا لتعقيدات حقل حاسي مسعود النفطي ، يواجه مهندسو الإنتاج العديد من مشكلات الاستغلال (الإستنفاذ ، الضغط المقابل ، إدارة الشبكة ...) التي أثرت بشكل سلبي على إنتاج الآبار.

من أجل حل مثل هذه المشكلات ، جلبت الحلول تقنيات مختلفة وتعتبر " مضخة النافثة على السطح " واحدة من أحدث الابتكارات في الصناعة من أجل إصلاح مشاكل شبكة التجميع منها الضغط المقابل . لتوقع فعالية التدخل ، تم اقتراح نمذجة أنظمة الإنتاج المتكاملة واستخدامها كأداة لتحليل وتحسين العوامل المؤثرة في سلسلة الإنتاج المتعاقبة ، ترتكز دراستنا على:

- ✓ إنشاء نموذج بئر-شبكة المتكامل من خلال سير عمل منتظم وتشغيل الحساسيات عبر "بروسبار"
- ✓ تحليل نتائج محاكاة إضافة "م ن س" في دراسة حالة مختارة و الاستفادة المتحصل عليها باستخدام "ڤاب"

الكلمات المفتاحية : نظام الإنتاج المتكامل، بروسبار و ڤاب ، مضخة النافثة على السطح ،التحسين، استنفاذ، الضغط المقابل.

Table of Contents

Acknowledgements

Dedications

Abstract

List of Figures

List of Tables

Nomenclature and Abbreviations

Introduction …………………………………………………………………… 1

Chapter 1: Production Systems Analysis

1.1 Introduction …………………………………………………………………… 3

1.2 Nodal Analysis ………………………………………………………………… 3

1.3 Reservoir inflow performance relationship (IPR) ………………………… 4

1.3.1 Productivity Index ……………………………………………………… 5

1.3.2 IPR curve in undersaturated reservoirs ………………………………… 6

1.3.3 IPR curve in saturated reservoirs ……………………………………… 6

1.3.4 Factors affecting IPR …………………………………………………… 7

1.4 Vertical lift performance ……………………………………………………… 10

1.4.1 Pressure drop calculations ……………………………………………… 10

1.4.2 Tubing outflow curve …………………………………………………… 11

1.4.3 Factors affecting the VLP curve ………………………………………… 11

1.5 Multiphase Flow ……………………………………………………………… 13

1.5.1 Flow regimes …………………………………………………………… 13

1.5.2 Superficial velocity and flow regimes maps …………………………… 14

1.5.3 Slip Effect ………………………………………………………………… 16

1.5.4 Flow regime through choke ……………………………………………… 17

Chapter 2: Surface Jet Pump

2.1 Introduction …………………………………………………………………… 19

2.2 Jet Pump Operation …………………………………………………………… 19

2.3 Application of Jet Pump ……………………………………………………… 21

2.3.1 Downhole ………………………………………………………………… 21

2.3.2 Gas Production …………………………………………………………………. 21
a) Noise Control ………………………………………………………………. 22
b) Temperature Effect ………………………………………………………. 23
2.3.3 Oil Production – Multiphase Applications of SJP ……………………………. 23
a) Compact Separator (I-SEP) in conjunction with SJPS ……………………. 24
2.4 Performance of the System and Key Components ……………………………. 25
2.5 Field Applications …………………………………………………………………. 29
2.5.1 Gas Production …………………………………………………………………. 29
2.5.2 Oil Production Applications …………………………………………………. 31
2.5.3 HP sources as Motive Fluid for SJP …………………………………………. 34
a) Typical HP Gas Sources …………………………………………………. 34
b) Typical HP Liquid Sources ………………………………………………. 34
2.5.4 HP Candidate well Selection for SJP ………………………………………. 35
2.5.5 LP Candidate well Selection for SJP ………………………………………. 35
2.6 Effect of variations to the operating conditions ……………………………. 35
2.7 The Best Location for SJP …………………………………………………. 36
2.8 Control, Instrumentation, Material selection and codes ……………………. 37
2.9 Commercial Benefits ………………………………………………………. 38

Chapter 3: Well Modelling and Optimization

3.1 Introduction ……………………………………………………………………. 39
3.2 Well presentation ……………………………………………………………. 39
3.2.1 Background …………………………………………………………………. 39
3.2.2 Localization …………………………………………………………………. 39
3.2.3 Performed Well tests ………………………………………………………. 40
3.3 Input Data ……………………………………………………………………. 41
3.3.1 PVT Data ……………………………………………………………………. 41
3.3.2 Well Data ……………………………………………………………………. 42
3.3.3 Reservoir Data ………………………………………………………………. 42
3.3.4 Well test Data ………………………………………………………………. 43
3.4 Setting up the Well model in PROSPER ……………………………………. 43
3.4.1 Workflow ……………………………………………………………………. 44
3.4.2 Options summary ……………………………………………………………. 44
3.4.3 PVT Data Input and Matching ………………………………………………. 45

3.4.4 Equipment Data Input 47
3.4.4.1 Deviation Survey 47
3.4.4.2 Surface Equipment 48
3.4.4.3 Downhole equipment 49
3.4.4.4 Geothermal gradient 50
3.4.4.5 Average heat capacities 50
3.4.5 IPR Data Input 51
3.4.6 VLP/IPR match procedures 51
Estimate U-value 51
Correlation comparison 52
VLP matching 53
IPR/VLP matching 53
3.4.7 Update to current condition (Latest test) 54
Calculate recent Bottom Hole Pressure 55
Update IPR 55
3.5 Sensitivities and results discussion 57
3.5.1 Sensitivity analysis on Reservoir pressure 57
3.5.2 Sensitivity analysis on skin factor 57
3.5.3 Sensitivity analysis on Wellhead pressure 58
3.5.4 Sensitivity analysis on GOR 59
3.6 Conclusion 59

Chapter 4: Network Modelling and Optimization

4.1 Introduction 60
4.2 System description 60
Problems statement 60
Wells description 60
4.3 Surface network modelling 61
4.3.1 Defining system options 61
4.3.2 Drawing system schematic 62
4.3.3 Generate & validate well IPRs and VLPs 63
Attach well models to GAP model 63
Define well types in GAP 64
Generate IPRs 65

Input VLP …………………………………………………………………… 65
4.3.4 Choke data …………………………………………………………………… 66
4.3.5 Pipe data …………………………………………………………………… 66
4.3.6 Matching pipelines data …………………………………………………… 67
4.3.7 Run GAP …………………………………………………………………… 68
4.4 Results from the GAP model ……………………………………………… 69
4.5 Sensitivities …………………………………………………………………… 70
4.5.1 Optimization by SJP ………………………………………………………… 70
Base case …………………………………………………………………… 70
Simulation results with implementing SJP ………………………………… 70
4.6 Conclusion …………………………………………………………………… 72

Conclusion …………………………………………………………………… 73

Recommendations …………………………………………………………… 75

References

List of Figures

Figure	Title	Page
Chapter 1: Production Systems Analysis		
Figure 1.1	*System Nodal Analysis*	4
Figure 1.2	*Typical reservoir IPR curve*	5
Figure 1.3	*Straight IPR (undersaturated reservoir)*	6
Figure 1.4	*Combined IPR curve for saturated and undersatured reservoir*	7
Figure 1.5	*Effect of oil viscosity on the IPR: Oil A is more viscous than Oil B*	8
Figure 1.6	*Effect of reservoir pressure to the IPR: Pressure is lowered from right to left*	9
Figure 1.7	*Effect of skin factor on the IPR: Skin factor is decreasing from left to the right*	9
Figure 1.8	*Typical tubing performance curve*	11
Figure 1.9	*Effect of increasing tubing diameter on the VLP: Diameter is increasing from left to right*	12
Figure 1.10	*Effect of increasing water cut on the VLP: Water is increasing from right to left*	13
Figure 1.11	*A generic two-phase vertical flow map*	15
Figure 1.12	*A generic two-phase horizontal flow map*	15
Figure 1.13	*Flow regimes through a choke in Hassi Messaoud Field*	18
Chapter 2: Surface Jet Pump		
Figure 2.1	*Key components of the Surface Jet Pump*	19
Figure 2.2	*Surface Jet Pump Internal Flow Dynamics*	20
Figure 2.3	*Performance Curves for Surface Jet Pumps-Gas production application homogeneous*	21
Figure 2.4	*In-line Silencers*	22
Figure 2.5	*In-line acoustic silencers*	23
Figure 2.6	*General Configuration of WELLCOM System for Oil Production*	24
Figure 2.7	*I-SEP Compact Separator*	25
Figure 2.8	*WELLCOM Jet Pump Performing for different GVF of the LP flow*	27
Figure 2.9	*Typical Efficiency Curve of WELLCOM Jet Pump in Liquid/Multiphase Operation*	28
Figure 2.10	*Effect of Free Gas in the Motive (HP) Liquid Phase*	28
Figure 2.11	*Effect of Liquid Present in the (LP) Gas Phase*	29
Figure 2.12	*High Pressure Well Driving Low Pressure Well using a Gas-Gas Jet Pump*	30
Figure 2.13	*Compressed Gas Used as Motive Flow to Boost Low Pressure Wells*	30
Figure 2.14	*Using HP Gas to Boost LP Production with a Gas Jet Pump*	31
Figure 2.15	*Using HP Wells to Drive LP wells with a WELLCOM System*	32
Figure 2.16	*The Effect of WELLCOM System to Increases LP Production for Two Wells with Different Production Characteristics*	32
Figure 2.17	*Example - Using a Jet Pump and Booster Pump for Deepwater Applications*	33

Figure 2.18	*Example - Using a Jet Pump and Booster Pump to Boost LP Oil and Gas Production*	34
Figure 2.19	*Surface Jet Pump*	36
Figure 2.20	*Typical Instrumentation for a Jet Pump*	37
Chapter 3: Well Modelling and Optimization		
Figure 3.1	*Well location of OMM202*	40
Figure 3.2	*PVT Input data section*	45
Figure 3.3	*PVT Match data screen*	46
Figure 3.4	*Correlation matching regression screen*	47
Figure 3.5	*Matching parameters 1 and 2 for all black oil correlations*	47
Figure 3.6	*Well's trajectory description*	48
Figure 3.7	*Profile of the well. On the x axis is the cumulative displacement while on the y axis is the measured depth*	48
Figure 3.8	*Downhole Equipment data input screen*	49
Figure 3.9	*Simple schematic of the downhole equipment*	50
Figure 3.10	*Geothermal Gradient data input screen*	50
Figure 3.11	*IPR data input main screen*	51
Figure 3.12	*Estimated U-value for well test (BU 2016)*	52
Figure 3.13	*Correlation comparison plot: All correlations plotted (Blue squared point corresponds to the well test 1 point)*	52
Figure 3.14	*Matched parameters for all tubing correlations*	53
Figure 3.15	*VLP/IPR Matching of OMM202 (05/01/2016)*	54
Figure 3.16	*Calculate BHP from WHP from latest gauging test*	55
Figure 3.17	*Reservoir pressure prediction*	55
Figure 3.18	*IPR section is updated to recent condition*	56
Figure 3.19	*VLP/IPR Matching (10/02/2020)*	56
Figure 3.20	*Sensitivity on reservoir pressure*	57
Figure 3.21	*Sensitivity on skin factor*	58
Figure 3.22	*Sensitivities on WHP*	58
Figure 3.23	*Sensitivities on GOR*	59
Chapter 4: Network Modelling and Optimization		
Figure 4.1	*SJP selected wells candidates on Map*	61
Figure 4.2	*GAP options*	62
Figure 4.3	*Insert production separator*	62
Figure 4.4	GAP model structure of base case study	63
Figure 4.5	*Generating the lift curves in PROSPER*	63
Figure 4.6	*Inputting the generated IPR file from PROSPER into GAP*	64
Figure 4.7	*Leave well type as oil producer (no Lift) for well OMM202*	64
Figure 4.8	*Get ready to generate IPR curves for all wells*	65
Figure 4.9	*VLP file name import field in GAP for wells*	65
Figure 4.10	*Input choke size for well OMM202 - 09mm*	66
Figure 4.11	*Input environmental parameters for pipeline*	66
Figure 4.12	*Dialogue for pipeline data input for well OMM202*	67
Figure 4.13	*Unit change dialogue*	68
Figure 4.14	*Solving the network in GAP*	68

Figure 4.15	*Input for separator pressure*	69
Figure 4.16	GAP model structure with SJP for case study	70
Figure 4.17	*Input for SJP parameter*	71
Figure 4.18	*LP-HP wells production Sm^3/day at different flow line pressure on HP side*	71
Figure 4.19	*Total production from LP-HP wells Sm^3/day at different flow line pressure on HP side*	72

List of Tables

Table	Title	Page
Table 3.1	*Performed Well tests*	40
Table 3.2	*Fluid PVT properties*	41
Table 3.3	*Effect of pressure on Bo, Rs and Oil viscosity*	41
Table 3.4	*Basic Reservoir characteristics*	42
Table 3.5	*Well test data*	43
Table 4.1	*Flowline specification of wells candidates for SJP case study*	61
Table 4.2	*Pipeline data*	67

Nomenclature et Abbreviations

A (in CH3): Drainage Area, m^2

A (in CH1): Cross-sectional flow area of the pipe, m^2

A_{gas}: pipe area occupied by gas, m^2

A_{liquid}: pipe area occupied by liquid, m^2

ANSI: American National Standards Institute

AOF: Absolute Open Flow m^3/hour

API: American Petroleum Institute

ASME: American Society of Mechanical Engineers

BHP: Bottom Hole Pressure, kg/cm^2_g

BU: Build Up

Bo: FVF, formation volume factor, bbl/stb

D: Pipe Diameter, inches

Dp: difference between the discharge and the LP pressure, kg/cm^2_g

DST: Drill stem Test

E: Estimated Error, %

EOR: Enhanced oil recovery

ESP: Electrical Submersible Pump

f: The Moody friction factor

FLP: Flowline Pressure, Bars

g: Acceleration due to gravity, m/s

GAP: General Allocation Program

GL: Gas Lift

GLR: Gas Liquid Ratio, Sm^3/Sm^3

GOR: Gas Oil Ratio, Sm^3/Sm^3

GVF: gas volume fraction

h: Reservoir thickness, ft

HI-SEP: High inline separator

HMD: Hassi Messaoud

HP: High Pressure

ID: Inside Diameter, inches

IOR: improved oil recovery

IPM: Integrated Production Modelling

IPR: Inflow Performance Relationship

I-SEP: inline separator

J: PI or IP productivity index, stb/day/psi

K: Permeability, md

L: the length of the pipe, m

LCP: Liner Cemented Perforated

LP: Low Pressure

MD: Measured Depth, m

MEG: mono-ethylene glycol

Mv: volumetric flow ratio

N: pressure ratio

η: efficiency

OD: Outside Diameter, inches

Pb: Bubble point, kg/cm^2_g

PETEX: Petroleum Experts

Pf: Downhole Pressure, kg/cm^2_g

PFD: Dynamic Downhole flowing pressure, kg/cm^2_g

PFS: Static Downhole flowing pressure, kg/cm^2_g

P_{node}: Node pressure, kg/cm^2_g

P_p: Pipeline pressure, kg/cm^2_g

P_R: P_g, Reservoir pressure, kg/cm^2_g

PR: Pressure Ratio

PROSPER: Production System Performance

P_{sep}: Separator pressure, kg/cm^2_g

PVT: Pressure, Volume, Temperature

Pwf: Downhole flowing pressure, kg/cm^2_g

P_{wh}: P_t, Wellhead pressure, kg/cm^2_g

Q: liquid rate, m^3/hour

Q_{max}: AOF, m^3/hour

Q_o: Oil flow rate, m^3/hour

r_e: external drainage radius, ft

RR: Recoverable reserves

R_s: Gas solubility at Saturation pressure, Sm^3/ Sm^3

r_w: wellbore radius, ft

S: Skin factor, dimensionless

SJP: Surface Jet Pump

SSSV: SubSurface Safety Valve

TVD: True Vertical Depth, m

U: overall heat transfer coefficient, BTU/h/ft^2/F

u: Velocity, m/s

VLP: Vertical Lift Performance

VM: Master Valve

$V_{s, gas}$: superficial gas velocity, m/s

$V_{s, liq}$: superficial liquid velocity, m/s

WC: Water Cut, %

ΔP_f: Pressure drop due to frictional forces, kg/cm^2_g

ΔP_g: Pressure drop due to gravitational energy change, kg/cm^2_g

ΔP_k: Pressure drop due to kinetic energy changes, kg/cm^2_g

ΔP: pressure differences between WHP and FLP, kg/cm^2_g

ε: roughness, inches

θ : the angle between horizontal and the direction of flow, degrees

λ_{gas}: Gas void fraction

λ_{liquid}: Liquid Hold-up

μ: viscosity, cp

μ_{oil}: oil viscosity, cp

ρ : the density of the fluid, kg/m^3 , API

Introduction

Introduction

The most important problems that petroleum production engineers try to find solutions for it are in manifold system, traditionally, choke valves are used to drop the pressure of high pressure (HP) wells and to combine the production from LP and HP wells. The use of choke valves in this way is a waste of energy. Also, in most applications, the production from LP wells is restricted so that their operating pressure meets the pipeline pressure. These problems demand solutions to maintain production and to enable the total recovery from the field to improve before the field is abandoned. Without the use of systems or solutions to maintain production, total recovery from the field may be limited to only 35 % (world average) of the total recoverable reserves (RR), or lower values.

Many fields rely heavily on IOR (improved oil recovery) and EOR (enhanced oil recovery) solutions. There are, however, methods to improve production without the need for major capital investment. Surface jet pump systems (SJPs) are among the least costly, value added, solutions to extend the life of many LP wells. Field applications have shown that the recovery of the capital spent in installing Surface Jet Pumps is generally achieved within a few weeks to a few months which use a high pressure (HP) fluid as the motive force to boost the pressure of produced gas and liquid phases. The system enables the flowing wellhead pressure (FWHP) to be reduced in order to increase production, whilst meeting the downstream production pressure requirements. A high-pressure fluid is needed as the source of energy or motive flow.

The integrated production system modelling approach consists of a focussed team of surface and subsurface staff working together to identify opportunities based on existing field constraints and limits. To explain in further detail, using IPM allowed petroleum engineering to understand the behaviour of fluids through the production system and the interactions between its different segments for possible optimizations and improvements in the performance of an oil field.

In order to achieve our goals, the thesis’ chapters are as follows:

- Chapter 01: Production Systems Analysis
- Chapter 02: Surface Jet Pump
- Chapter 03: Well Modelling and Optimization

- Chapter 04: Network Modelling and Optimization

The objective of this thesis work is to maximise the oil production rates by using the new technology SJP for two (HP is OMM412 - LP is OMM202) producing wells to optimize the network of Hassi Messaoud field, especially in W1F sub-manifold. The thesis work had been performed by the application of PROSPER and GAP software. In the result two well models had been prepared in this thesis work. Finally, a complete production network had been developed by combining all well models. By running a simulation results with implementing SJP program in GAP, optimized oil rate had been determined for LP well system and the maximum oil production rate had been achieved for the whole production system.

Chapter 1

Production Systems Analysis

1.1 Introduction

The well performance is defined by its capacity to deliver oil or gas to the surface. In petroleum engineering, the determination of the relationship of the combination of reservoir inflow and outflow performance in order to analyze the production's systems. The main purpose of this analysis is to predict the achievable fluid production of the reservoir through the tubing string, the very commonly used technique in petroleum engineering is called ‘’Nodal Analysis’’.

1.2 Nodal Analysis

Nodal Analysis have been applied for many years to analyze the performance of systems composed of interacting components. Its application to well producing systems was first proposed by Gilbert in 1954 and Mach, Proano, and Brown in 1979 further developed the concept **[1]**.

In Nodal Analysis, a specific point in the system is chosen (node) and the system is divided in two parts. All of the components upstream of the node comprise the inflow section and all components downstream of the node comprise the outflow section. The inflow and outflow curves are illustrated in **Figure 1.1**. Each component behavior in the system is directly related to flow rates and pressure drop. The flow rate through the whole system can be determined once the following requirements are satisfied:

1. Flow into the node equals flow out of the node.
2. Only one pressure can exist at a node.

Further, at any time, the pressure at the end points of the system {separator (P_{sep}) and reservoir pressure (P_R)} are both fixed. Thus:

$$P_R \text{- (Pressure loss upstream components)} = P_{\text{node}} \quad \text{Eq 1.1}$$

$$P_{\text{sep}} + \text{(Pressure loss downstream components)} = P_{\text{node}} \quad \text{Eq 1.2}$$

The Nodal Analysis method uses single or multiphase flow correlations and correlations or theoretical models developed for the various components of reservoir, well completion, and surface equipment systems to calculate the pressure loss associated with each component in the system. This information is then used to evaluate well performance under a wide variety of conditions, which will lead to optimum single well completion and production practices **[2]**.

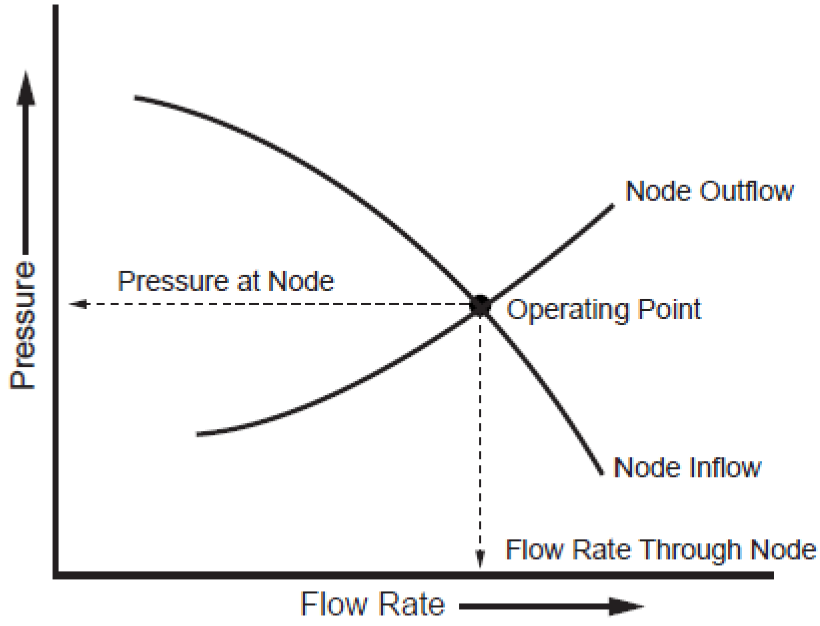


Figure 1.1: System Nodal Analysis **[3]**

1.3 Reservoir inflow performance relationship (IPR)

For a well to flow, there must be a pressure differential from the reservoir to the wellbore at the reservoir depth. If the wellbore pressure is equal to the reservoir pressure, there can be no inflow. If the wellbore pressure at the pay zone is zero, the inflow would be the maximum possible: The Absolute Open Flow (AOF). For intermediate wellbore pressures, the inflow will vary. For each reservoir, there will be a unique relationship between the inflow rate and wellbore pressure **[2]**

Figure 1.2 shows the form of a typical oil/gas well IPR curve. It is the deliverability curve, or "inflow performance relationship."

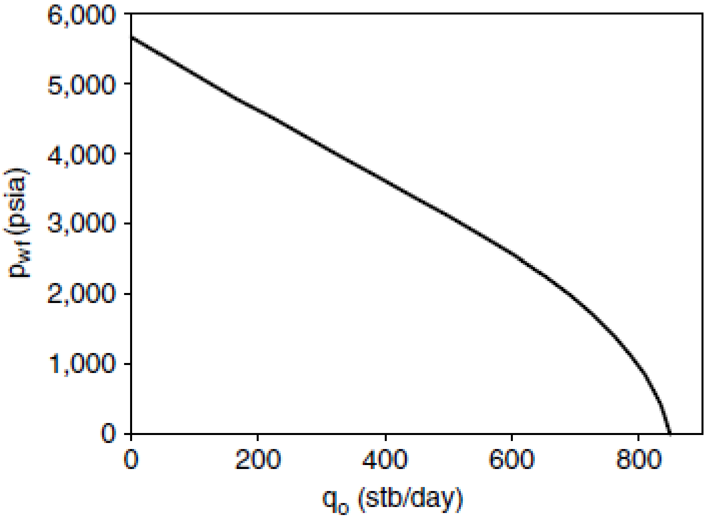


Figure 1.2: Typical reservoir IPR curve [4]

1.3.1 Productivity Index

The productivity index (PI) is the measure of the ability of the well to produce fluids. It is derived by the Darcy's equation for radial semi-steady state flow and it is the ratio of liquid flow rate to the pressure drawdown. It can be applied only in single phase flow, hence in the case of an undersaturated reservoir [5].

$$J = \frac{q}{\overline{P_R} - P_{wf}} = \frac{2\pi kh}{\mu Bo \ln(\frac{r_e}{r_w}) - 3/4 + S} \qquad \text{Eq 1.3}$$

Where q: liquid rate, stb/day

J: productivity index, stb/day/psi

$\overline{P_R}$: average reservoir pressure (static pressure), psi

P_{wf}: downhole flowing pressure, psi

r_w: wellbore radius, ft

r_e: External drainage radius, ft

S: Skin factor, dimensionless

h: Reservoir thickness, ft

μ: viscosity, cp

Bo: formation volume factor, bbl/stb

The productivity index is proved to be a very useful tool in Petroleum Engineering in order to predict future performance of wells, since, during the well's lifespan, flow regimes are approximating the pseudo steady-state ones. It should be underlined that unexpected declines in the value of J can be concrete indications for a series of well issues such as damages due to workover, completion, mechanical problems etc. [1].

1.3.2 IPR curve in undersaturated reservoirs

It is the linear relationship between the liquid flow rate and the pressure drawdown, for a single constant value of productivity index, as seen below:

$$q = J(\overline{P_R} - P_{wf}) \qquad \text{Eq 1.4}$$

Graphically, it is represented by a straight line with a slope equal to −1/J (**Fig. 1.3**). Note that the above methodology can only be applied to reservoirs with pressures above the bubble point pressure. When P_{wf} is equal to the average reservoir pressure, no flow is observed due to zero pressure drawdown value. On the other hand, maximum liquid rate occurs when P_{wf} is zero and it is called absolute open flow (AOF) [1].

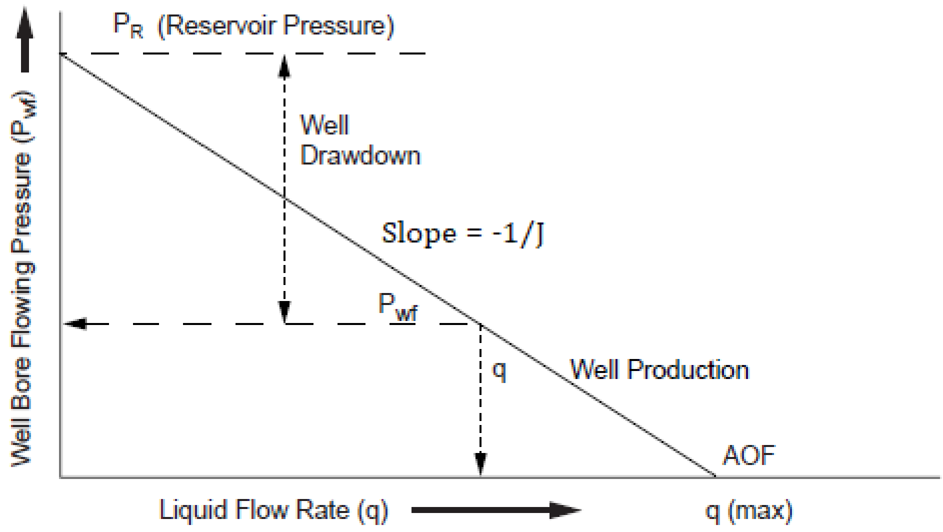


Figure 1.3: Straight IPR (undersaturated reservoir) [5]

1.3.3 IPR curve in saturated reservoirs

Muskat and Evinger [6] (1942) and Vogel [7] (1968) observed that when the pressure drops below the bubble-point pressure, the IPR deviates from that of the simple straight-line relationship as shown in **Figure 1.4** (curve C), it is proposed the following equation for predicting a well’s inflow performance under a solution gas drive (two phase flow) conditions based on a large number of well performance simulations.

$$\frac{q}{q_{max}} = 1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2 \qquad \text{Eq 1.5}$$

Where q_{max} : Absolute Open Flow (AOF), bbl/day

The combination of the straight and Vogel's curved IPR can fully describe the inflow performance at any pressure. Above Pb, the IPR is a straight line, while below Pb it is curved. In **Figure 1.4**, the area created between A and C represents the occurrence of two phase flow.

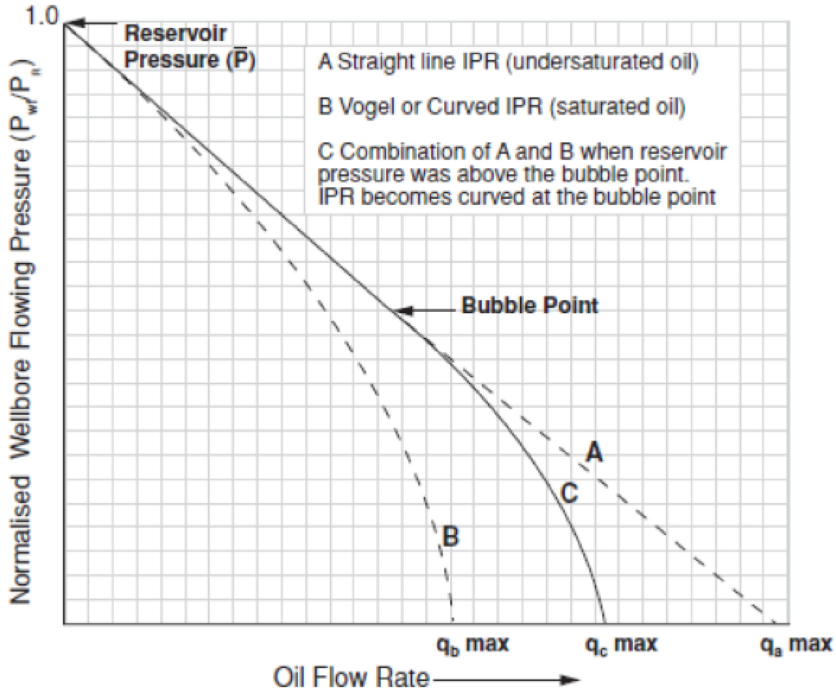


Figure 1.4: Combined IPR curve for saturated and undersatured reservoir [3]

1.3.4 Factors affecting IPR

IPR is influenced by parameters related to the reservoir. The bottomhole flowing pressure is the solution node that separate the two systems and effectively determine which components related to reservoir and those related to the flow in the tubing lift to surface. The most notable components affecting an IPR curve are the following:

- Rock Properties
- Fluid Properties

- Reservoir Pressure
- Well Geometry
- Well Flowing pressure

Examples demonstrate different values of some components potentially affect the IPR, in **Figure 1.5,** illustrates the effect of the viscosity, increasing oil viscosity affects the mobility of the oil through the porous media and leads to a lower productivity index, and **Figure 1.6** shows the effect of reservoir depletion to the IPR **[1]**.

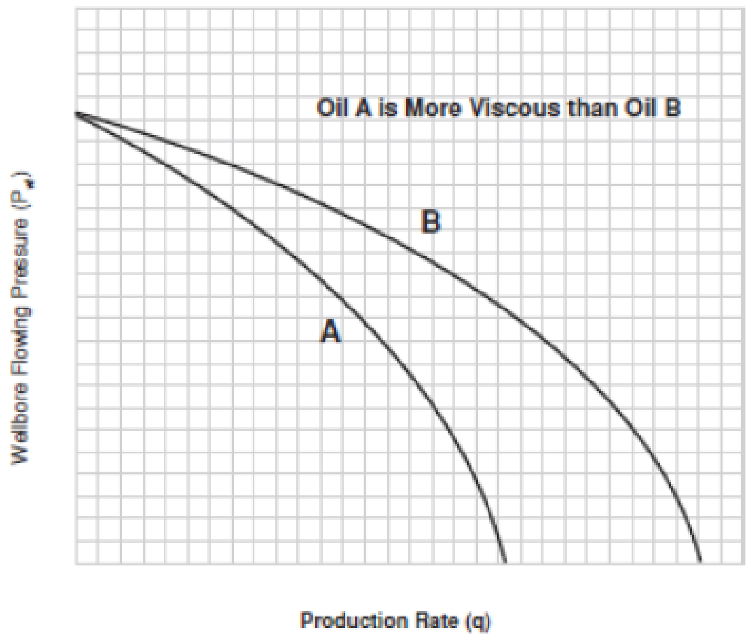


Figure 1.5: Effect of oil viscosity on the IPR: Oil A is more viscous than Oil B **[3]**

A decrease in the skin factor increases the deliverability of a system up to a point. **Figure 1.7** shows the effect of well stimulation techniques, such as fracturing or acidizing, on the inflow performance. When skin factor is further reduced, productivity of the system is unaffected.

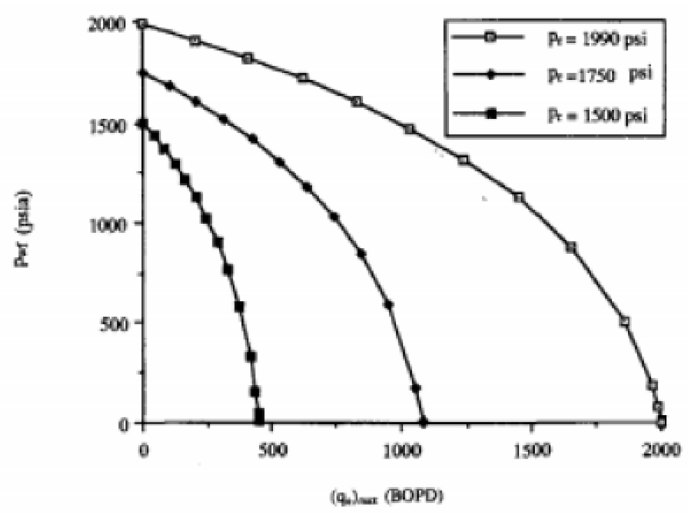


Figure 1.6: Effect of reservoir pressure to the IPR: Pressure is lowered from right to left [1]

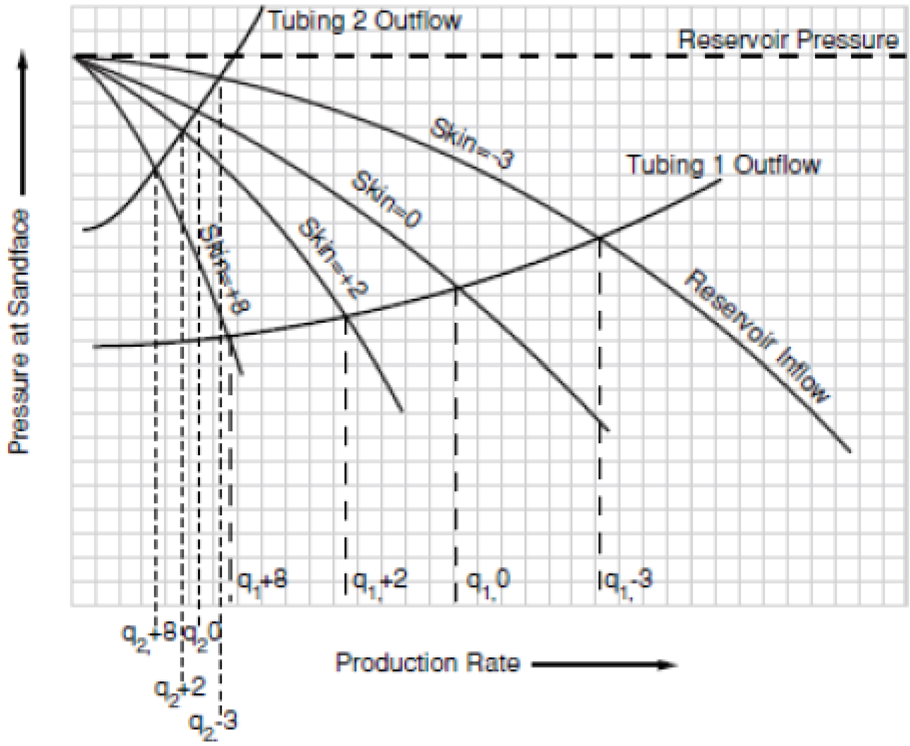


Figure 1.7: Effect of skin factor on the IPR: Skin factor is decreasing from left to the right [3]

1.4 Vertical lift performance

One of the most important components in the production system is the tubing string. As much as 80 percent of the total pressure loss in an oil well can occur in moving the fluids from the bottom of the hole to the surface **[8].** Vertical lift performance expresses the bottomhole flowing pressure as a function of liquid rate in the wellbore during the production of reservoir fluids. the outflow performance depends on several factors; liquid rate, fluid type (gas-liquid ratio, water cut), fluid properties and tubing size **[9].**

1.4.1 Pressure drop calculations

Generally, the total pressure drop in a well is the summation of the pressure drop due to frictional forces (ΔP_f), gravitational energy change (ΔP_g) and kinetic energy changes (ΔP_k), with the last one to be omitted as its value is usually negligible compared to the previous two sources

$$\Delta \mathrm{P} = \Delta P_f + \Delta P_g + \Delta P_k \qquad \text{Eq 1.6}$$

Pressure drop due to potential energy change:

$$\Delta P_g = g\rho L \sin\theta \qquad \text{Eq 1.7}$$

where g: the acceleration due to gravity,

ρ : the density of the fluid,

L: the length of the pipe

θ : the angle between horizontal and the direction of flow

Pressure drop due to kinetic energy change:

$$\Delta P_k = \rho\,(u_2^2 - u_1^2) \qquad \text{Eq 1.8}$$

Pressure drop due to frictional forces:

$$\Delta P_f = \frac{f\rho u^2 L}{2gD} \qquad \text{Eq 1.9}$$

Where f: The Moody friction factor

Estimation of the friction factor during turbulent flow is more complicated and other methods are used for its calculation. The most common is the use of the Moody chart which requires the knowledge of the roughness (ε) of the examined pipe.

Specialized software can perform all these complex calculations of pressure drop in pipelines. To do so, the pipelines are split in a set of many small segments and pressure drop calculations are held for each segment individually. The splitting is done adaptively so that are exhibiting big contribution to the total pressure loss are simulated with small segments, while in others of minor interest the software uses larger segments **[1].**

1.4.2 Tubing outflow curve

The outflow performance is also necessary to estimate the bottomhole flowing pressure P_{wf} And it's done by using the following method. For various flowrates and for a fixed wellhead pressure, the total pressure loss can be calculated using the Equation 1-6 for the whole length of the production tubing. The outcome of this approach is the Tubing Performance curve (or else known as VLP curve) and its importance lies on the fact that it captures the required flowing bottomhole pressure needed for various liquid rates. The VLP depends on many factors including PVT properties, well depth, tubing size, surface pressure, water cut and GOR **[1]**

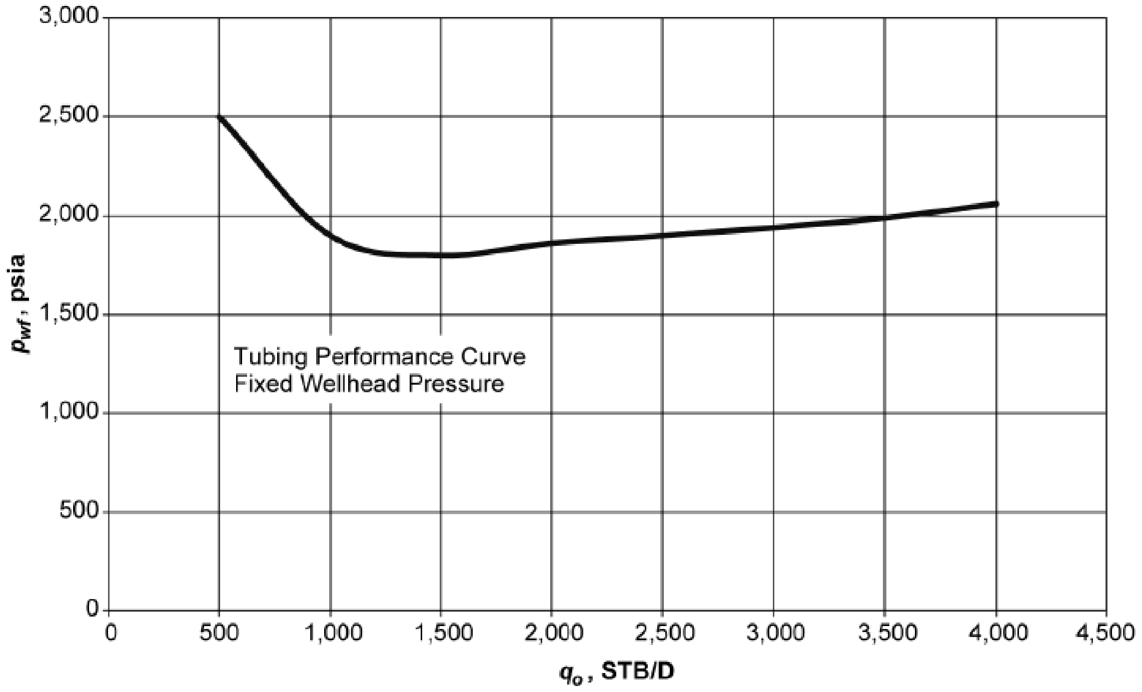


Figure 1.8: Typical tubing performance curve **[10]**

1.4.3 Factors affecting the VLP curve

Some of the factors affecting the vertical lift performance of the well are:

- Production Rate

- Well Depth
- GOR/GLR
- Tubing Diameter
- Water cut
- Restrictions (Scale, waxes, SSSV etc.)

Figure 1.9 showcases the different flowing rates in changing the tubing's diameter, although, it'll be discussed later that very large tubing size results in the large decrease of the upward gas flow velocity that it is no longer sufficient to efficiently lift the liquid to the surface.

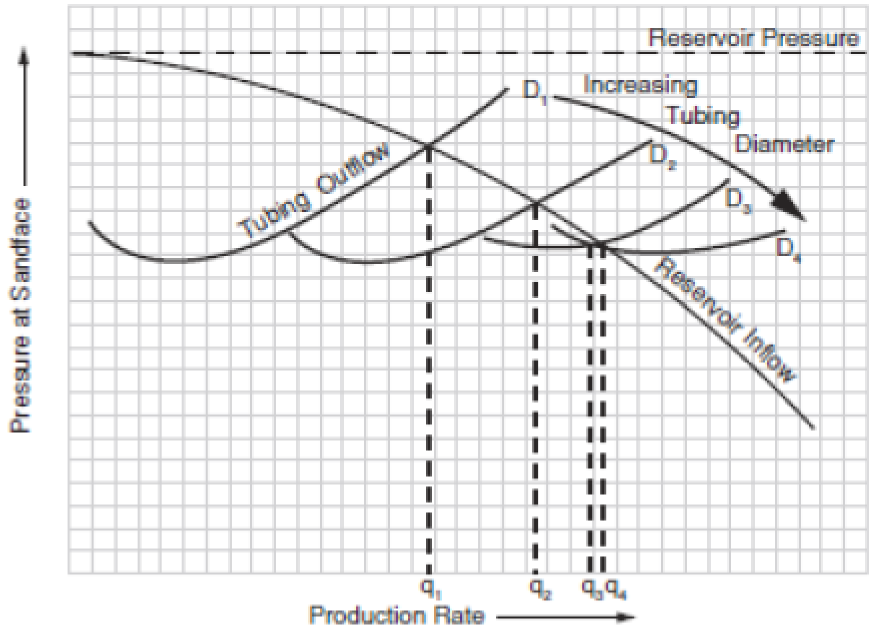


Figure 1.9: Effect of increasing tubing diameter on the VLP: Diameter is increasing from left to right **[3]**

Water cut is also an important parameter that must be taken into consideration. An increasing water cut reduces the gas-liquid ratio. Less oil means that less gas will be evolved from it, and in combination with the greater density of the water in respect to that of the oil, the average density of the fluid will be greater than initially was. This eventually leads to an increase of the hydrostatic head between the reservoir and the surface (**Fig. 1.10**). Heavier flowing fluid requires more pressure from the reservoir to be lifted up to the surface **[1].**

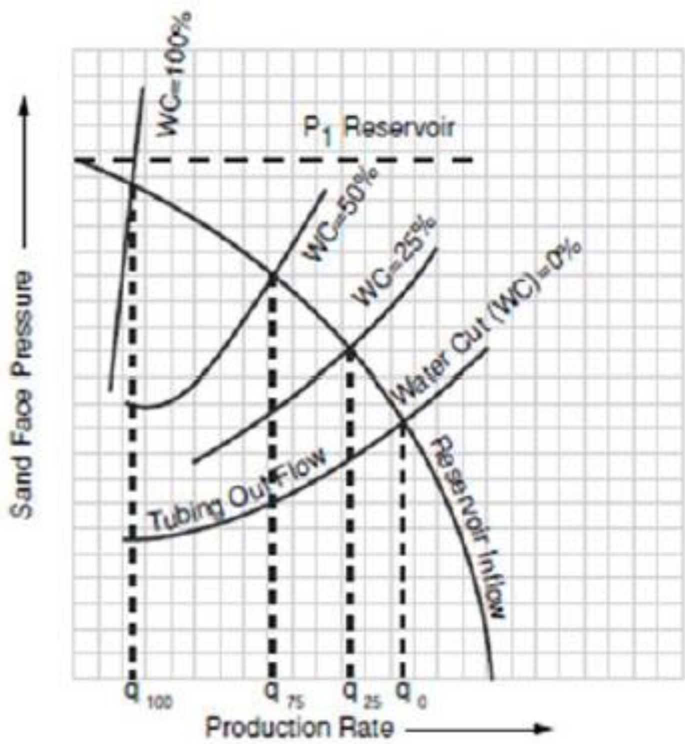


Figure 1.10: Effect of increasing water cut on the VLP: Water is increasing from right to left **[3]**

1.5 Multiphase Flow

1.5.1 Flow regimes

In oil and gas production, multiphase flow often occurs in wells and pipelines because the wells produce gas and oil simultaneously. This is called two-phase flow. In addition to gas and oil, water is also often produced at the same time. This is called three-phase flow. The calculations of pressure drop along the production tubing become more complex than the ones described in previous section. Common single-phase characteristics are thus inappropriate for describing the nature of such flows. The flow structures are classified in flow regimes, whose characteristics depend on a number of parameters such as operating conditions, fluid properties, flow rates and the orientation and geometry of the pipe through which the fluids flow. The distribution of the fluid phases in space and time differs for the various flow regimes, and is usually not under the control of the designer or operator **[11].**

All flow regimes however, can be grouped into dispersed flow, separated flow, intermittent flow or a combination of these:

- Dispersed flow: Bubble and mist flow are characteristic examples of this category. The main characteristic of this type of flow is the uniform distribution of phases in both radial and axial directions.
- Separated flow is characterized by a non-continuous phase distribution in the radial direction and a continuous phase distribution in the axial direction. Examples of such flows are stratified and annular.
- The intermittent flow regime is characterized by discontinuity in liquid and vapor flow. In this flow regime, vapor slugs or plugs are formed, surrounded by a thin liquid coating on the periphery and blocked by a liquid slug between successive vapor bubbles **[12].**

1.5.2 Superficial velocity and flow regime maps

The term superficial velocity is often used on the axes of flow regime maps. Flow regime maps are a qualitative tool used to define the type of flow, when superficial velocities are known. The velocity of a single phase vapor or a liquid (through vessels, pipes, etc.) is equal to the volumetric flow rate divided by the cross-sectional flow area of the pipe ‘‘A’’ **[1].**

$$V_{s,gas} = \frac{q_{gas}}{A} \qquad \text{Eq 1.10}$$

$$V_{s,liquid} = \frac{q_{liq}}{A} \qquad \text{Eq 1.11}$$

Where: $V_{s,gas}$,$V_{s,liq}$: superficial gas velocity and superficial liquid velocity respectively (m/s)

In **Figure 1.11**, we illustrated the dependency of the flow regime by the superficial gas and liquid velocities in vertical flow. In horizontal flows as well, the flow regime transitions depend upon many factors such as gas-liquid velocities, fluid properties, orientation of conduit, tube diameter (D) and operating conditions **[13]**. The following map (**Fig. 1.12**) shows qualitatively, how flow regime transitions are dependent on superficial gas and liquid velocities in horizontal multiphase flow. A map like this will only be valid for a specific pipe, pressure and a specific multiphase fluid.

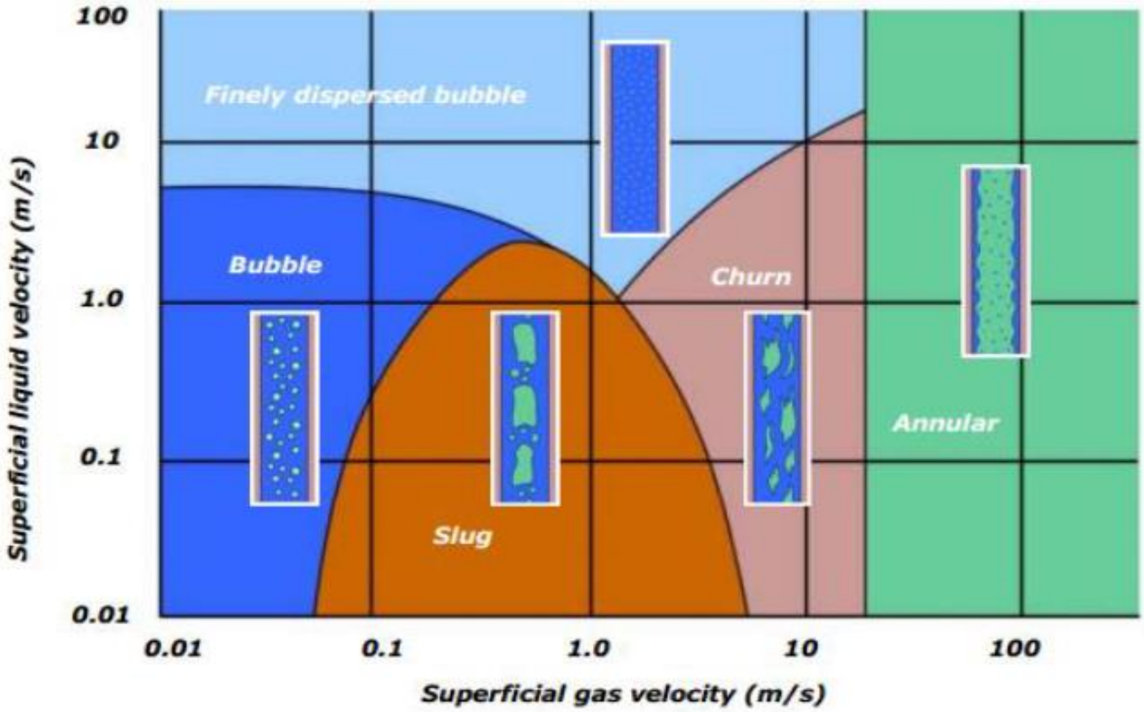


Figure 1.11: A generic two-phase vertical flow map [11]

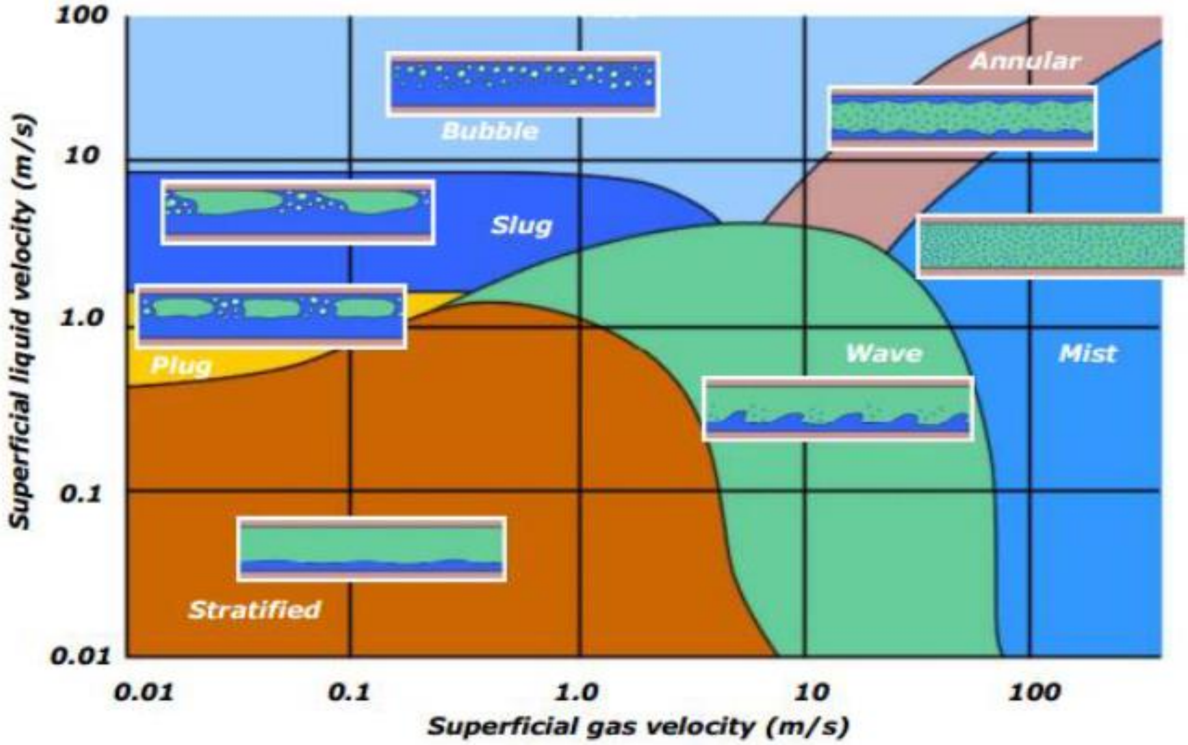


Figure 1.12: A generic two-phase horizontal flow map [11]

1.5.3 Slip effect

Experiments have shown that one fundamental phenomenon occurring in inclined multiphase flow (oil-gas, water-oil, etc.) is the concept of slip and hold-up. These phenomena are most important for the gas/liquid case since the density differences are greatest: Slip refers to the ability of the less dense ("lighter") phase to flow at a greater velocity than the denser ("heavier") phase. Hold-up is a consequence of slip - the volume fraction of the pipe occupied by the denser phase is greater than would be expected from the (relative) in – and outflow of the two phases - since its flow velocity is slower than that for the light phase **[3]**. This is something which severely affects calculations of pressure drop in a pipe. When more gas is present in a pipe segment, friction is the main factor of pressure loss due to its increased actual velocity. On the other hand, pipe segments almost full of liquid, exhibit pressure losses due to the increased gravity term **[8].**

The phase velocities are the real velocities of the flowing phases. They may represent velocities in a local scale in the pipe cross section or a velocity of a cross sectional average of the pipe. They are defined by:

$$V_{gas} = \frac{q_{gas}}{A_{gas}} \qquad \text{Eq 1.12}$$

$$V_{liquid} = \frac{q_{liquid}}{A_{liquid}} \qquad \text{Eq 1.13}$$

where A_{liquid} and A_{gas} are the pipe areas occupied by the liquid and gas respectively. Gas and liquid will flow at different phase velocities within the pipe. The relative phase velocity or slip velocity is defined by:

$$V_s = |V_{gas} - V_{liquid}| \qquad \text{Eq 1.14}$$

Liquid hold – up and gas void fraction are defined as the ratio of the area occupied by each phase (liquid or gas) to the total cross sectional area of the pipe.

$$\lambda_{liquid} = \frac{A_{liquid}}{A_{pipe}} \qquad \text{Liquid holdup} \qquad \text{Eq 1.15}$$

$$\lambda_{gas} = \frac{A_{gas}}{A_{pipe}} \qquad \text{Gas void fraction} \qquad \text{Eq 1.16}$$

$$\lambda_{gas} + \lambda_{liquid} = 1 \qquad \text{Eq 1-17}$$

Only under no-slip conditions is the gas void fraction equal to the gas volume fraction, and the Liquid Hold-up is equal to the Liquid Volume Fraction. The flow in this case is homogeneous and the two phases travel at equal velocities. In reality, however, the Liquid Hold-up will be larger than the Liquid Volume Fraction and, consequently, the gas void fraction will be smaller than the gas volume fraction.

Multiphase flow correlations are used to predict the liquid holdup and frictional pressure gradient. Depending on the particular correlation, flow regimes are identified and specialized holdup and friction gradient calculations are applied for each flow regime. The density difference between gas and either water and oil is far greater than the density difference between oil and water. The multi-phase flow correlations lump oil and water together as liquid and calculations are based on liquid/gas interactions. Such flow correlations are more accurately described as two-phase methods. The calculation errors resulting from lumping the water and oil together have been found to be insignificant for the majority of oil well pressure calculations. The primary purpose of a flow correlation is to estimate the liquid holdup (and hence the flowing mixture density) and the frictional pressure gradient **[1].**

Some of the correlations most widely accepted for oil wells are:

- Duns and Ros
- Hagedorn and Brown
- Orkiszewski
- Beggs and Brill

1.5.4 Flow regime through choke

The choke has an important role in the production cycle, allow to control the flow via adjusting the wellhead pressure, with taking consideration to reservoir-well-network constraints:

- Water coning
- The vertical flow regime through the tubing
- Surface installations available to handle the production

We use multiphase flow formulas through choke in order to calculate the flow, the equations attach coefficients that differ from a field (Hassi Messaoud in our case) to another depending on the report of pipeline pressure to wellhead pressure.

In **Figure 1.13**, we distinguish the three types of flow regimes across a choke, we obtain the critical regime when Pp/P_{wh} is inferior 0.5, the flow, pressure are constants despite modifying the pressures (**zone III**).

The estimated interval for transient regime is between the values 0.5 to 0.75 (**zone II**)

When the report Pp/P_{wh} is superior to 0.75, the flow is dependable to the variation of the pipeline and wellhead pressure and the flow is not stable in the non critical flow regime (**zone I**)

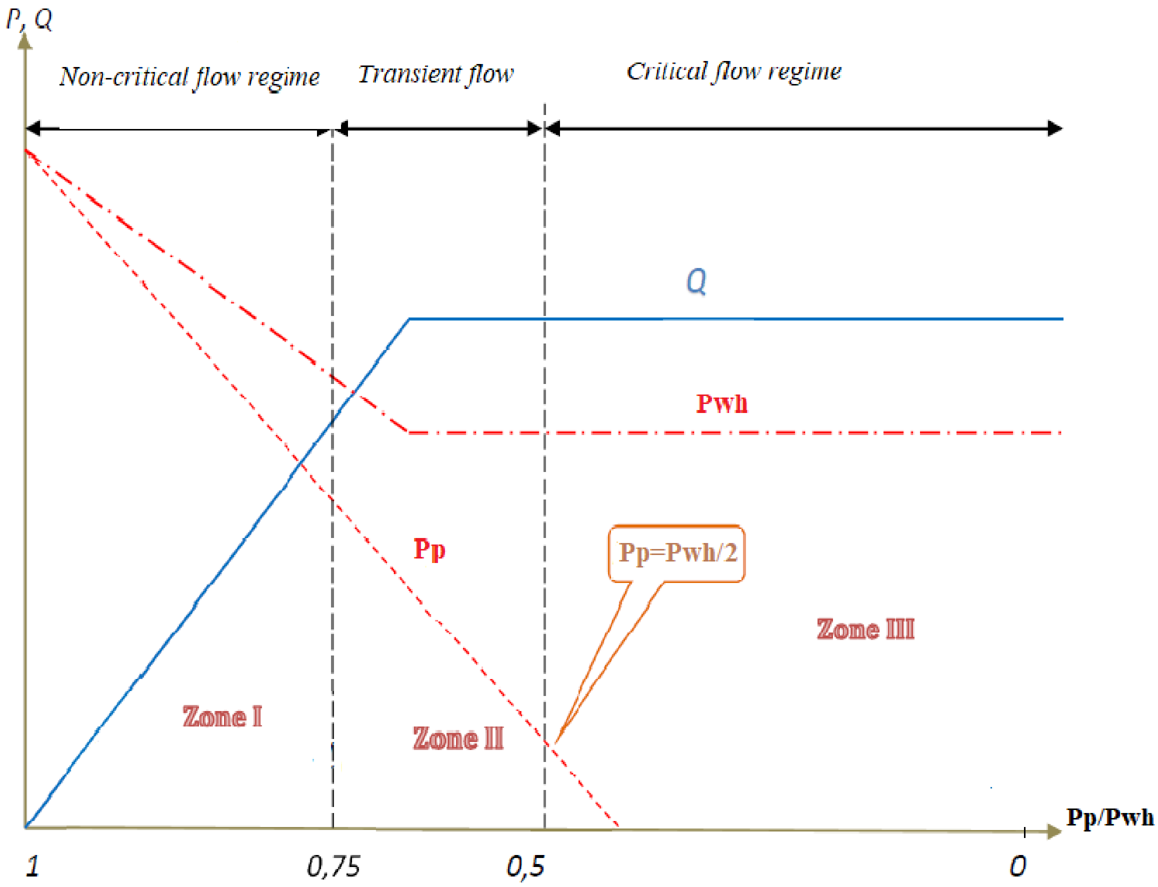


Figure 1.13: Flow regimes through a choke in Hassi Messaoud Field **[14]**

Chapter 2

Surface Jet Pump

2.1 Introduction

Jet pump technology dates back to 18th century! The early applications were, however, limited to combining two streams of steam at different pressures and, in some cases, jet pumps were used to combine two liquids of different pressure for mixing purposes.

In a manifold system, traditionally, choke valves are used to drop the pressure of high pressure (HP) wells and to combine the production from LP and HP wells. The use of choke valves in this way is a waste of energy. Also, in most applications, the production from LP wells is restricted so that their operating pressure meets the pipeline pressure.

Jet pump is a simple and reliable system to use some of the energy from high pressure wells to boost the production pressure and flow rate of LP wells.

2.2 Jet Pump operation

Jet pumps are also known as educators, ejectors or gas jet compressors, depending on their application in various industries. In oil and gas production applications, onshore or offshore, it is preferred to refer to them as surface jet pump or “SJP” for short, and use this abbreviation for simplicity. **Figure 2.1** shows the general configuration of the jet pump and key components of the system.

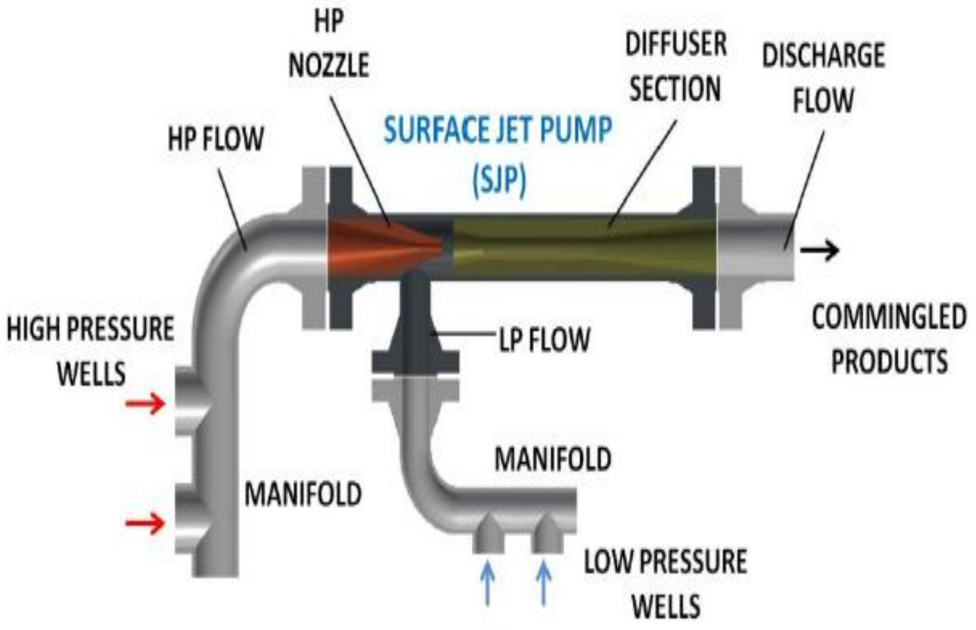


Figure 2.1: Key components of the Surface Jet Pump [16]

The HP fluid passes through the nozzle of the surface jet pump (SJP) where part of potential energy (pressure) is converted to kinetic energy (high velocity). As a result, the pressure of the HP fluid drops in front of the nozzle. It is at this point where the LP flow is introduced. The mixture then passes through the mixing tube where transfer of energy and momentum takes place between the HP and LP fluids. The mixture finally passes through the diffuser where the velocity of fluids is gradually reduced and further recovery of pressure takes place. The pressure at the outlet of the jet pump will be at an intermediate value between the pressure of the HP and LP fluids.

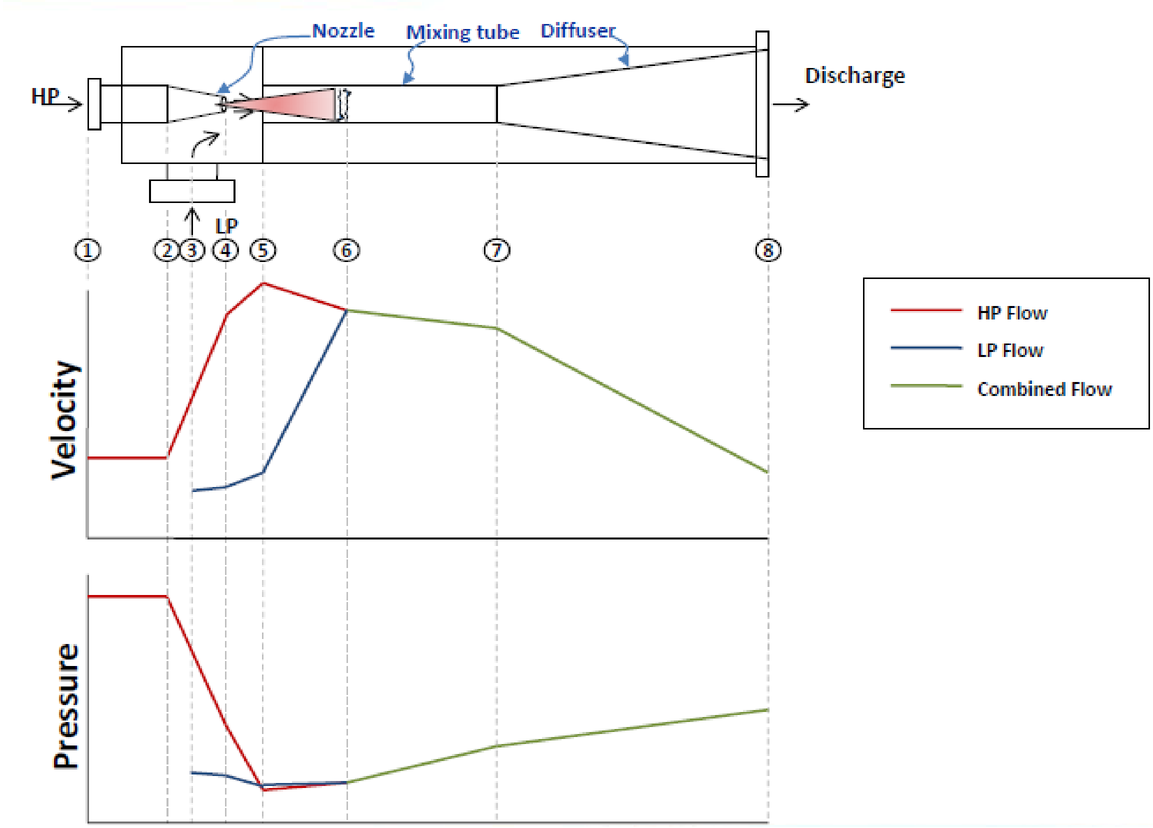


Figure 2.2: Surface Jet Pump internal flow dynamics **[17]**

The level of boost in the pressure of the LP fluids depends on a number of factors which include:

- HP/LP flow ratio and pressure ratio
- Density or molecular weight of the HP and LP fluids

There are also secondary factors such as the operating temperature and whether the jet pump is operating under its optimum design conditions. **Figure 2.3** shows the performance of the SJP in gas production applications at different HP/LP pressure ratios. **[18]**

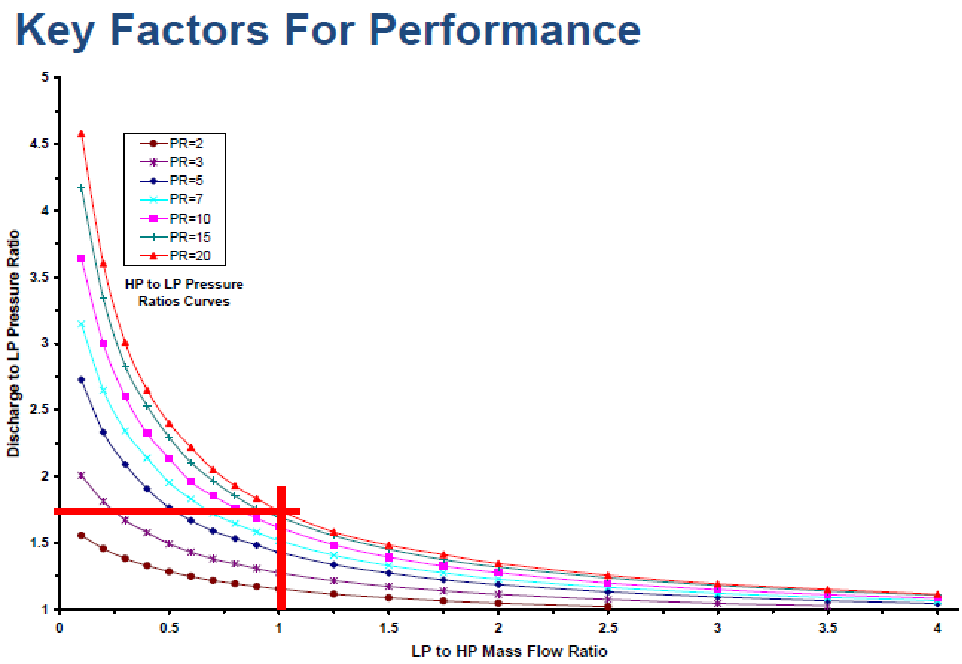


Figure 2.3: Performance curves for Surface Jet Pumps-gas production application homogeneous [18]

2.3 Application of Jet Pumps

2.3.1 Downhole

Jet pumps have applications in both gas and oil production. They can be used downhole, offshore and onshore. One of the first applications of the jet pump in the oil and gas industry has been downhole for well kick-off or for increasing production from low pressure oil wells. A specially designed and slim-line unit is installed downhole close to the production zone. A motive fluid (oil or water) is injected via a dedicated pipe or through the annulus. This allows the production from the well to be increased because of the said pressure drop generated by the jet pump in its suction side. It is further possible to introduce additives or diluents to the motive flow to improve the properties of the produced oil (e.g. viscosity).

Jet pumps can also be used downhole for gas production in cases where the reservoir pressure is low and liquid in form of condensate or water is also produced and causes the seizure of production from such low-pressure wells. High pressure gas could be the motive flow in this application. The economics of this method of recovery is dependent on the availability of high-pressure gas or compressors to provide the motive flow. [15]

2.3.2 Gas production

In the case of gas production, both HP and LP fluids are primarily gas. Presence of liquids (condensate, oil or water) in the LP flow can be tolerated so long as the volumetric flow rate of liquids is below 1% to 2% of the volumetric flow rate of the LP gas at the operating pressure and temperature. Beyond these values, the effect on the achieved dp (discharge pressure – LP pressure) could be significant, requiring the LP liquids to be separated upstream of the SJP and be boosted separately.

Alternatively, the LP liquids can be sent to a part of the process system which operates at a lower pressure, if such a source is available. Presence of liquids in the HP gas also has a similar limitation, beyond which the liquids need to be separated upstream of the SJP. The main reason in this case is that the performance and sizing of the nozzle is affected based on whether the HP flow is liquid or gas phase. A further point is that if the HP flow is multiphase (a mixture of gas and liquids) the fluctuating flow regime associated with multiphase flow reduces further the efficiency of the SJP significantly as the mixture is not usually. **[18]**

a) Noise control

As the flow of gas through the nozzle of the jet pump could reach and exceed the sonic level, noise generated by the SJP could exceed 85 dBA, which is generally the acceptable level onshore and offshore.. The level of noise depends on a number of factors including the pressure and flow ratios of HP and LP gas, the wall thickness of the pipeline and installation support details. **[15]**

Silencers are therefore needed to prevent noise travelling beyond the SJP along these lines. Silencers are flanged spool pieces which are installed at the LP inlet and the discharge line of the SJP. In some cases, the noise emitting through the body of the SJP may be beyond the permitted limit. In this case the body of the SJP can be acoustically lagged. In-line acoustic silencers can be designed to limit the noise to lower than the quoted 85 dBA in cases where the SJP is close to populated onshore areas. **[18]**

Figure 2.4: In-line silencers **[20]**

Figure 2.5: In-line acoustic silencers **[20]**

b) Temperature effect

A significant drop in the HP gas pressure at the outlet of the nozzle of the SJP could cause a drop in the temperature of gas at the outlet of the SJP. This is a complex phenomenon beyond that expected under pure Joule-Thomson cooling principle, as immediately after the nozzle, LP gas is combined with HP gas, and further recovery of the pressure takes place. There is also the generation of shock waves within the SJP in most cases, which affect the resultant temperature. Analytical tools are available to predict the temperature at the outlet of the SJP at each stage of operation, including the start up.

In general, the temperature of the gas at the outlet of the SJP is well above that calculated by considering only the Joule- Thomson cooling effect as a result of HP pressure dropping to the LP pressure in front of the nozzle. In exceptional cases where the temperature at the outlet of the SJP is expected to be within the hydrate formation band, introduction of hydrate suppressant such as Glycol or MEG, or equivalent will be advised upstream of the SJP. Presence of liquids in the HP or LP gas also reduces the cooling effect.

In oil production application cases where HP liquid is the motive flow, neither noise, nor temperature, poses any problems. Silencers are therefore not required in such cases. **[18]**

2.3.3 Oil production - multiphase applications of SJPs

Production of oil involves multiphase flow, a mixture of gas and liquid phases. This often involves fluctuations in the flow and flow regimes such as the slug flow in both HP and LP lines. In order to optimise the performance of the jet pump, gas is separated from the HP mixture and only the liquid phase is used as the motive flow entering the jet pump. The entire LP mixture, in this case, enters the suction side of the jet pump. **Figure 2.4** shows the general configuration of the System for oil production, the system has been given the trade name "WELLCOM", short for a Well Commingling System. WELLCOM consists of a compact inline separator (I-SEP), a specially designed multiphase jet pump and a commingler. The commingler enables the separated HP gas to be combined efficiently with the flow from the outlet of the jet pump. [15]

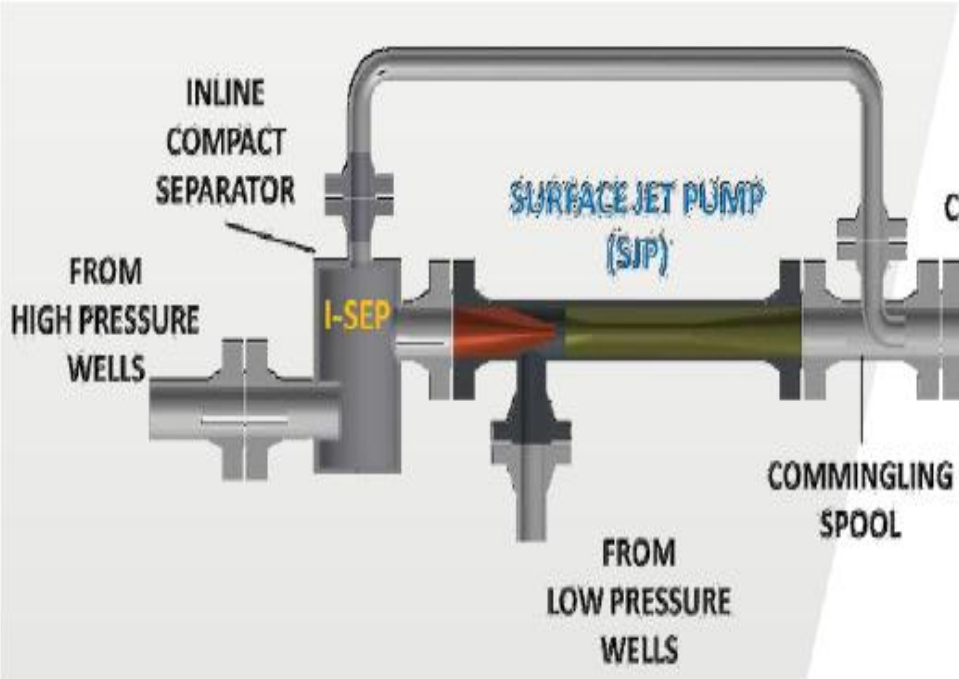


Figure 2.6: General configuration of WELLCOM system for oil production [19]

It is difficult to produce general performance curves **(fig 2.3),** for the WELLCOM system, as in addition to HP/LP pressure ratio and flow ratio, other factors such as temperature, flow rate of LP gas and liquids also affect the performance of the system.

Software is however developed and fully validated to predict the performance of the system in oil production applications. [18]

a) Compact separator (I-SEP) in conjunction with SJPs

When either HP or LP flow is multiphase, a mixture of gas and liquids, separation of gas and liquids is required. Gravity separators can be used to achieve the desired separation of gas and liquids. Gravity separators are however bulky and have limitations in their design pressure. Ideally, a compact unit is required so that the total system occupies minimum space and the system is easy to operate.

A compact separator under the trade name of I-SEP, developed and patented by Caltec, is available to perform the desired separation duties. I-SEP is a cyclonic passive device which requires no active level or pressure control. In applications where a high degree of separation efficiency is desired, a combination of I-SEP and HI-SEP (knock-out pot) can be used. These units are compact with a foot print which is a fraction of those for gravity separators. **[18]**

I-SEP has been used for a variety of applications including:

- Phase splitting including gas - liquid separation
- Sand separation
- Oil - water separation
- Compact multiphase well testing using conventional meters **[17]**

Figure 2.7: I-SEP compact separator **[17]**

2.4 Performance of the system and key components

The performance of I-SEP in this application is assessed by its efficiency in separating gas from the multiphase HP fluids. The purity of the separated liquid phase (free of gas) is of particular importance in this application as the separated liquid phase is the motive flow and excessive free gas carried into this phase affects the efficiency of the jet pump.

The performance of the jet pump, the key component of the system, is presented by two dimensionless terms - *N*, pressure ratio and the efficiency η as follows:

$$N = \frac{P_3 - P_2}{P_1 - P_3} \qquad \text{Eq 2.1}$$

$$\eta = \frac{Q_{l(LP)}\,(P_3 - P_2) + P_2\,Q_{g(LP)}\ln(P_3/P_2)}{Q_{l(HP)}\,(P_1 - P_3)} \qquad \text{Eq 2.2}$$

where:

P_3 is the discharge pressure

P_2 is the LP pressure

P_1 is the HP pressure

Mv the volumetric flow ratio of LP tb HP fluids, is defined by:

$$Mv = \frac{Q_{l(LP)} + Q_{g(LP)}}{Q_{l(HP)}} \qquad \text{Eq: 2.3}$$

Where:

Ql and Qg are the volumetric flow rates of the liquid and gas phases at the operating temperatures and pressures.

The term gas volume fraction (GVF) is used as the ratio of the volumetric flow rate of gas at the operating pressure to the total volumetric flow rate of gas and liquid phase in each stream under the operating conditions:

$$GVF = \frac{Q_{g(LP)}}{Q_{g(LP)} + Q_{l(LP)}} \qquad \text{Eq:2.4}$$

The above terms are used to define and demonstrate the performance of the jet pump and the total System.

The performance of I-SEP affected by the flow regime generated in the production/test lines. Slug flow was experienced in most test cases, this was caused by the configuration of the piping system upstream of the separator and the gas and liquid velocities in the line. Presence of slug flow resulted in a small percentage of free gas to enter the liquid outlet line of the separator. The values varied depending on the gas volume fraction of the mixture and by the set position of the gas outlet valve. This valve controls the back pressure on the gas outlet line and also controls the optimum flow rate of the liquid phase through the liquid outlet line. Its position also affects the level of liquid carried over into the gas phase.

It is important to note that I-SEP can be designed and set to minimise the liquid carry-over or gas carry-over in each application. It is also worth noting that so long as the gas carried into the separated liquid phase is kept to below 5%, its effect on the performance of the jet pump is negligible **[15]**

In general, the jet pump performance is dominated by the total volumetric flow rate of LP fluids and the GVF of the LP flow. **Figure 2.8** shows the variations in performance presented by dimensionless value N against the various ratios of LP to HP flow. The results show that as the GVF of the LP flow is increased, the LP liquid flow rate which the jet pump can handle under a given discharge pressure is reduced so as the LP flow rate increases, more energy is required to boost its pressure and, as a result, the pressure ratio N is reduced. In this case also includes the volumetric flow rate of gas in the LP fluid mixture.

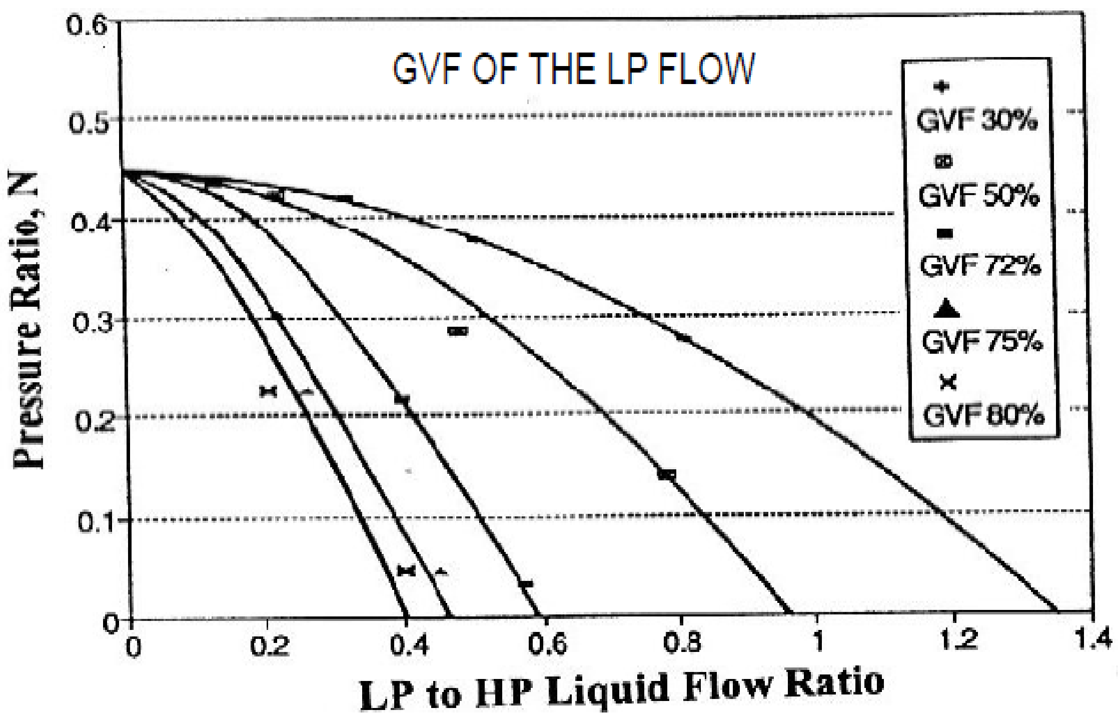


Figure 2.8: WELLCOM Jet Pump performing for different GVF of the LP flow [20]

Figure 2.9 shows the efficiency of the jet pump under different LP to HP flow ratios (Mv). The maximum efficiency relates to a specified value for each system design. The relatively flat efficiency curve, however, confirms that the efficiency does not drop significantly under a wide range of production conditions.

Figure 2.10 shows the effect of free gas in the motive liquid phase. The values confirm that presence of a few percent of gas in the motive liquid phase does not affect the performance of the jet pump significantly. For higher volumes of the gas in the motive liquid phase, the jet pump performance drops, but it still operates safely and in a stable manner.

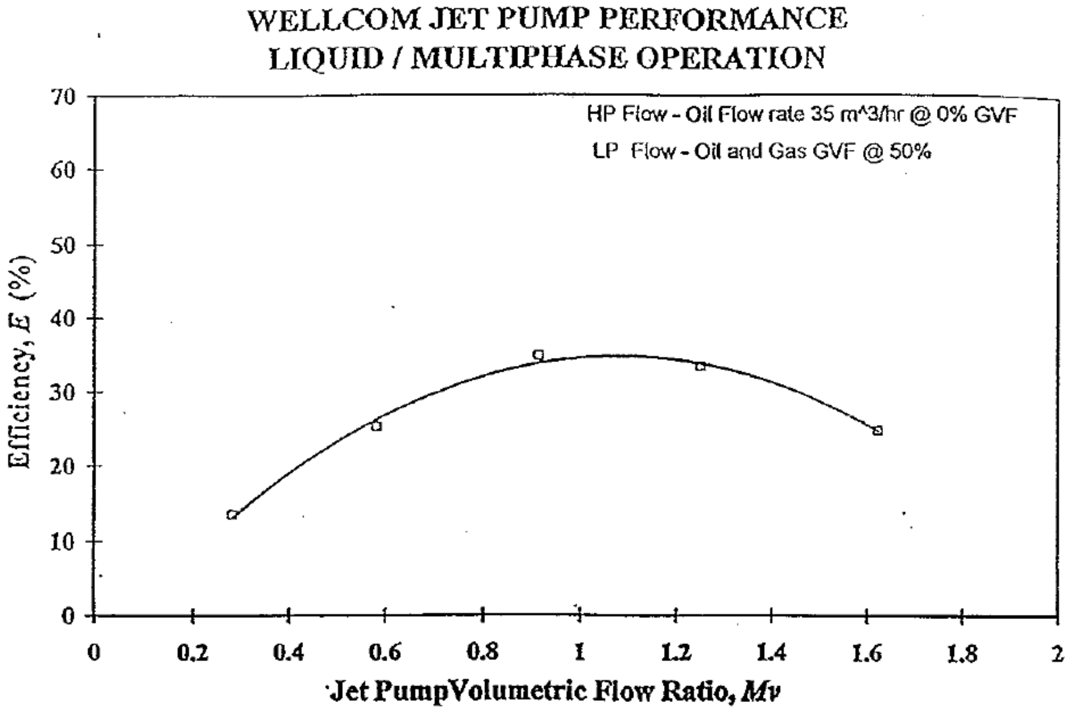


Figure 2.9: Typical efficiency curve of WELLCOM Jet Pump in liquid/multiphase operation [15]

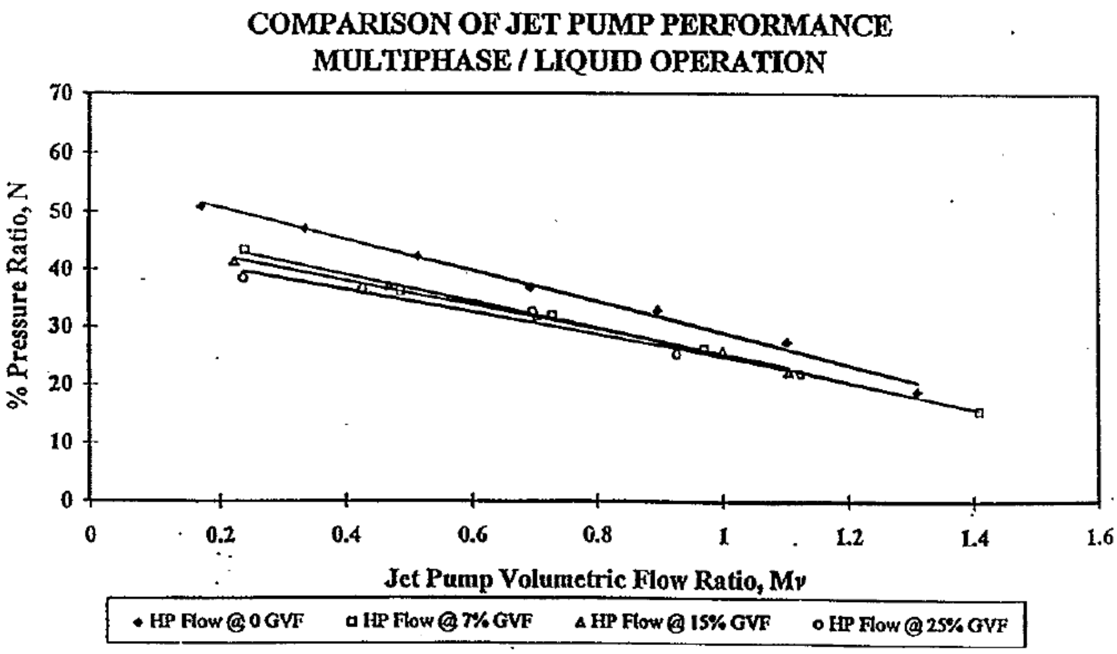


Figure 2.10: Effect of free gas in the motive (HP) liquid phase [15]

In the other way **Figure 2.11** shows the effect of liquid in the motive gas phase. The values confirm that presence of a few percent of liquid in the motive gas phase does not affect the performance of the jet pump significantly. For higher volumes of the liquid in the motive gas phase, the jet pump performance drops, but it still operates safely and in a stable manner. [15]

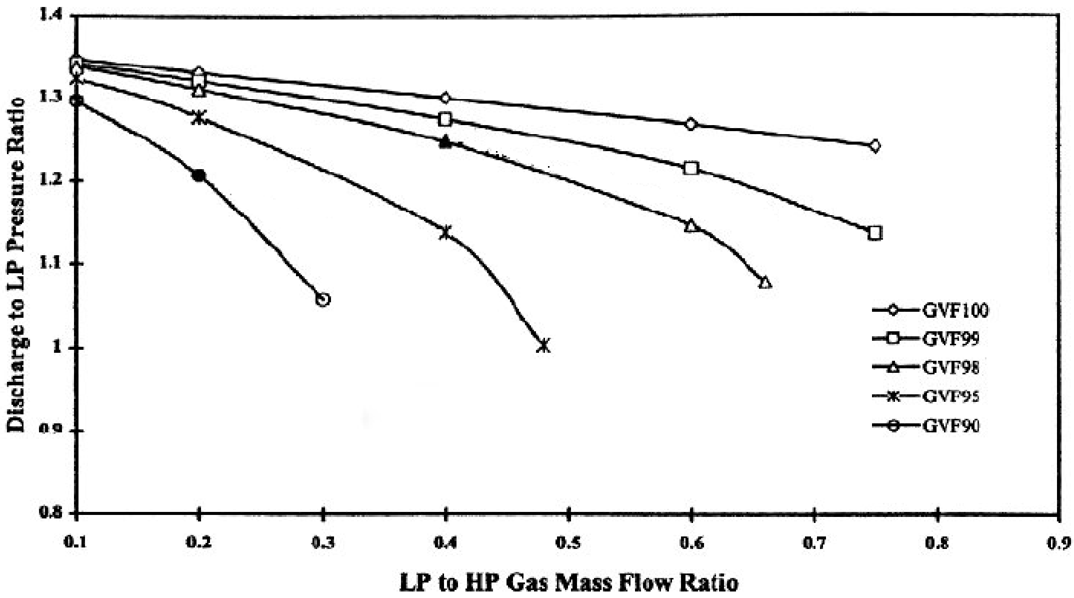


Figure 2.11: Effect of liquid present in the (LP) gas phase [20]

The performance of the SJP is assessed simply by noting the dP, the difference between the discharge and the LP pressure of the SJP. The discharge pressure is not controlled by the SJP and is mainly dictated by the downstream pipeline and production system. The SJP, however, responds to changes in the parameters which affect its performance by adjusting the LP pressure which it generates. [18]

2.5 Field applications

A review on the installation of WELLCOM system on typical field production scenarios has helped to identify the following main applications:

2.5.1 Gas production

The main applications are:

- High pressure wells drive the low-pressure wells and boost their production. **(Fig 2.12).**

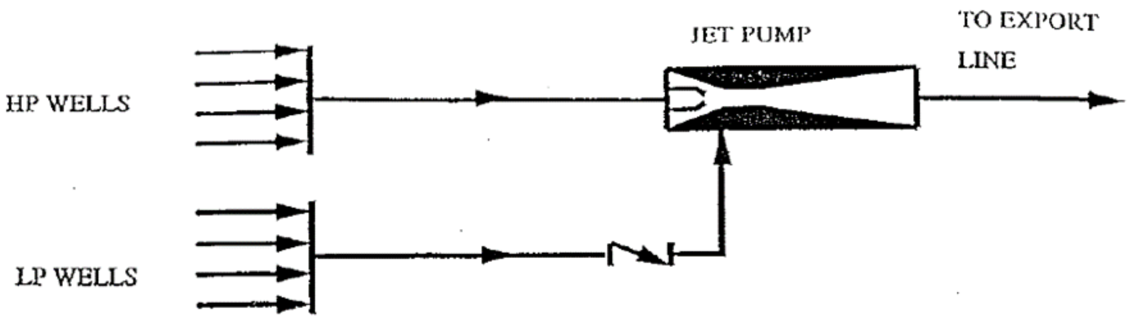


Figure 2.12: High pressure well driving low pressure well using a gas-gas Jet Pump [15]

- Use high pressure gas from downstream of compressors as the motive flow to boost the production of LP wells or LP gas from the process System. This concept will be economically viable if the existing compressors have the spare capacity to provide and handle the additional gas. **(Fig 2.13).**

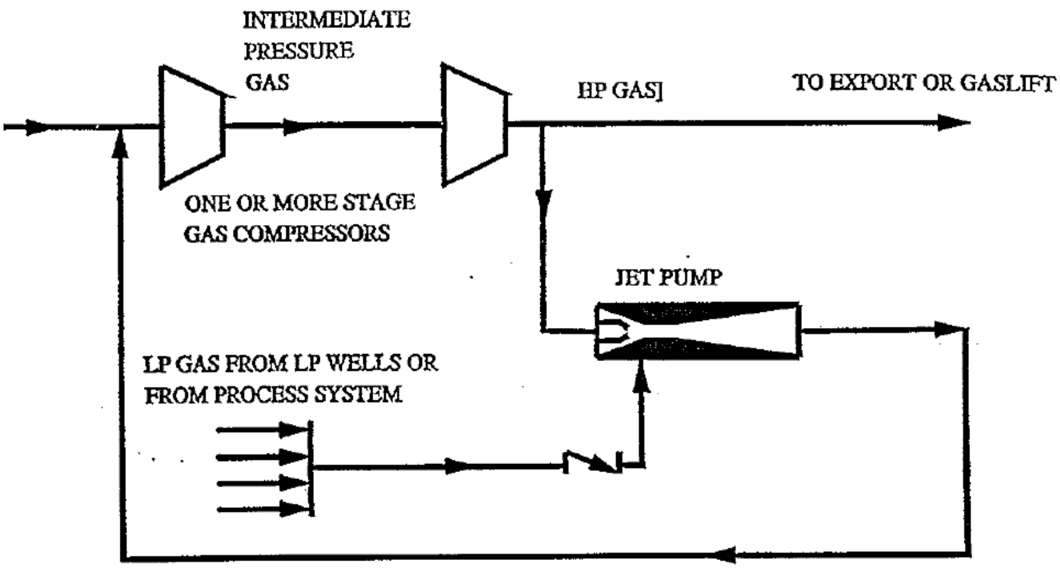


Figure 2.13: Compressed gas used as motive flow to boost low pressure wells [15]

- Use high pressure gas from a high-pressure process stream to boost the pressure of LP gas from the second LP stream. This solution enables the elimination of a compressor on the platform as shown in (**Fig 2.14)**

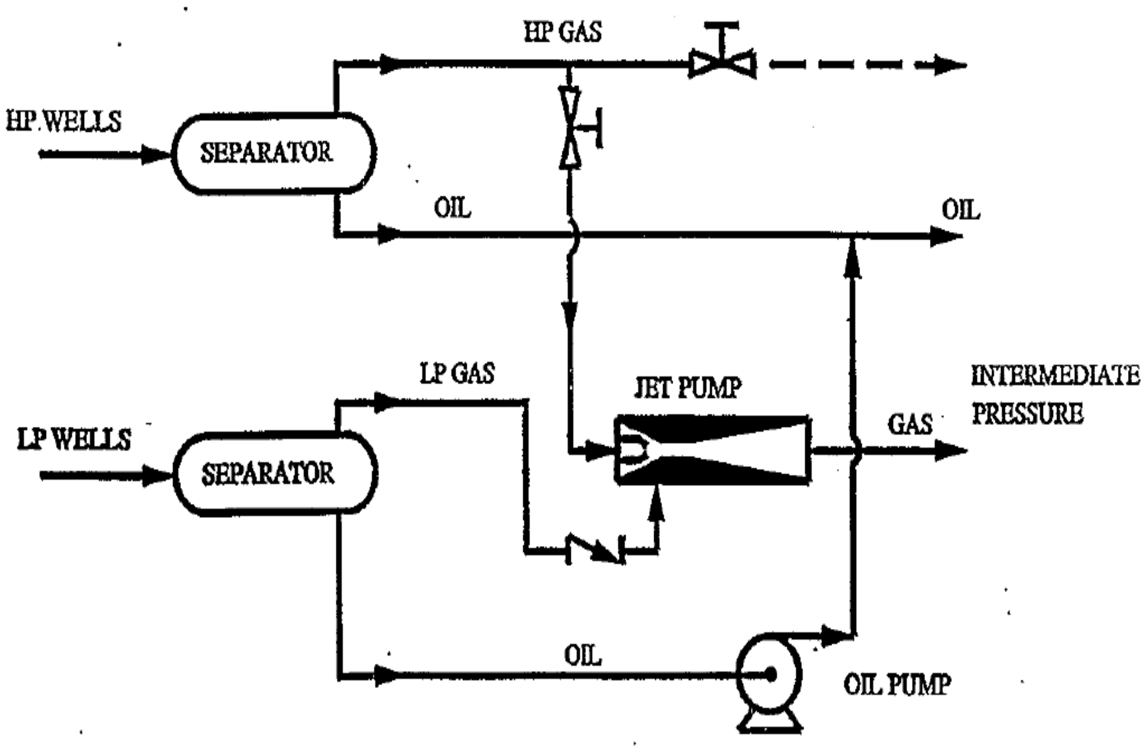


Figure 2.14: Using HP gas to boost LP production with a gas Jet Pump [15]

There are a number of scenarios where using a jet pump may eliminate the need for additional compressors or may prevent flaring the LP gas. Each application should be reviewed to assess the viability of the concept which depends on the pressure and volumetric flowrates of LP and HP gas and other details of the platform facilities which are specific to each field. [15]

2.5.2 Oil production applications

Typical applications of the WELLCOM system and jet pump technology in oil production are as follows:

- High pressure wells drive low pressure wells **(Fig 2.15)**. **Figure 2.16** shows how the WELLCOM system increases the production and meets the pipeline pressure. The shaded area in **Fig 2.16** is use additional production achieved by using the jet pump. In this example, the increase in production is shown for two wells with different production characteristics.

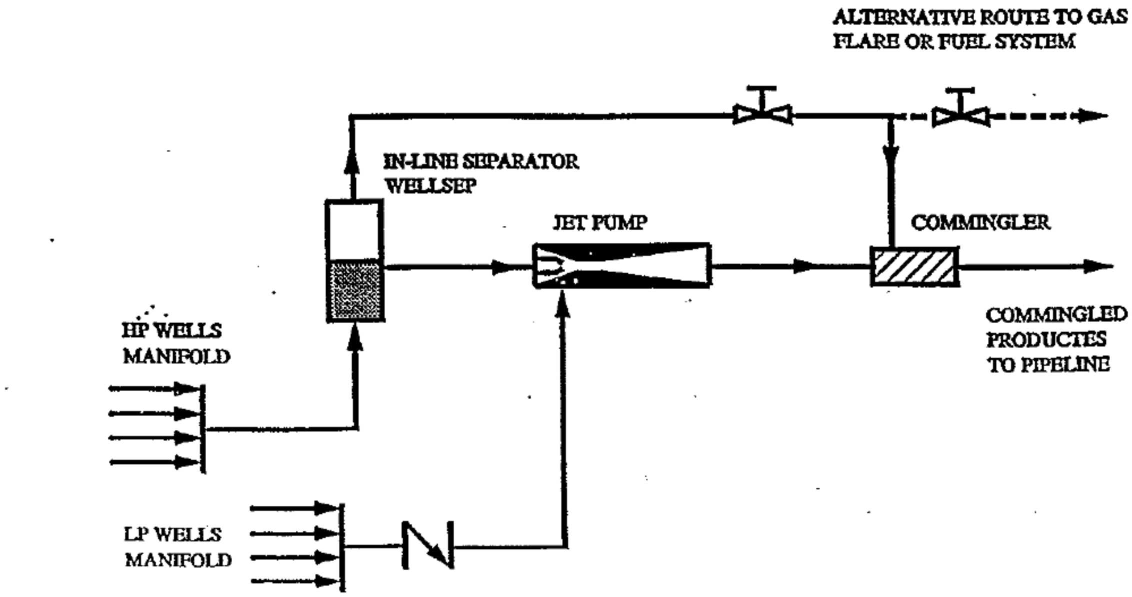


Figure 2.15: Using HP wells to drive LP wells with a WELLCOM system **[15]**

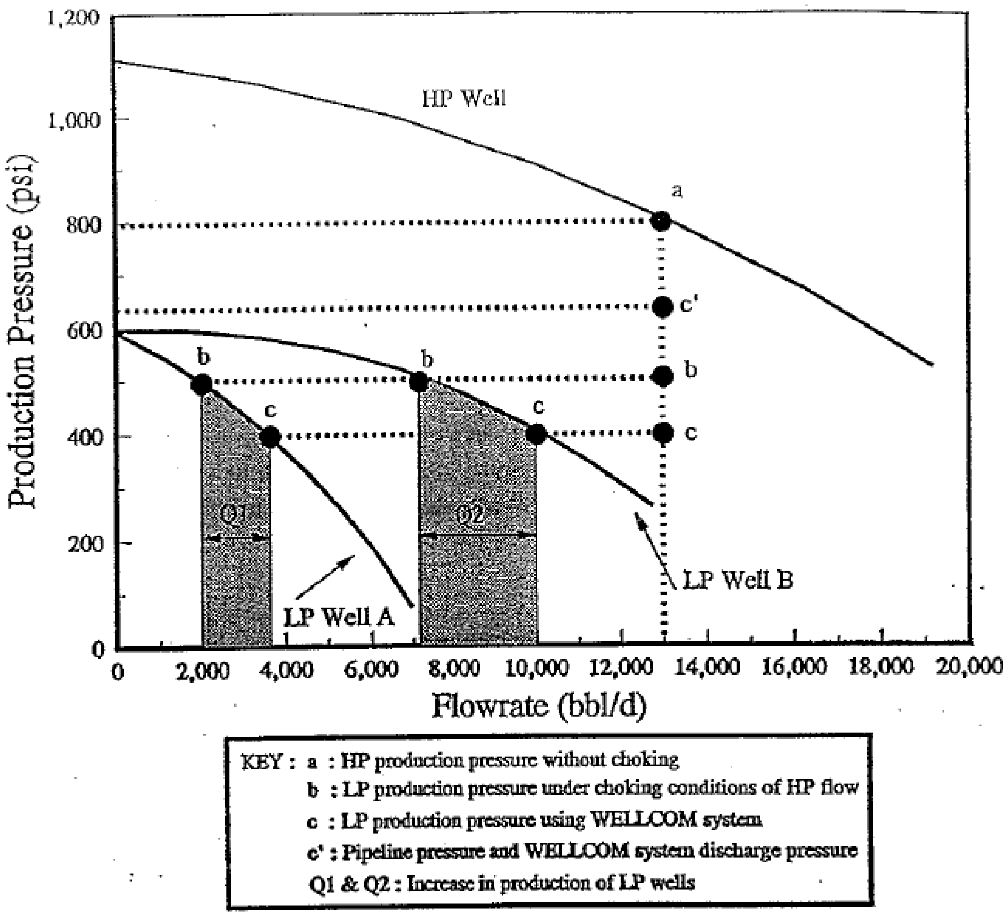


Figure 2.16: The effect of WELLCOM system to increases LP production for two wells with different production characteristics **[15]**

- In applications where high pressure wells do not exist, motive fluid can be supplied via a booster pump. This application is particularly suitable for deep-water production where the hydrostatic head of produced oil restricts production from LP wells. In this case the reliable jet pump is the only component of the System subsea, as shown in **(Fig 2.17).**The motive flow, in this case, can be dosed with Chemicals or additives which may be required to prevent formation of hydrates, to reduce the viscosity of produced oil (for heavy oils) or for suppressing wax deposition in the line.

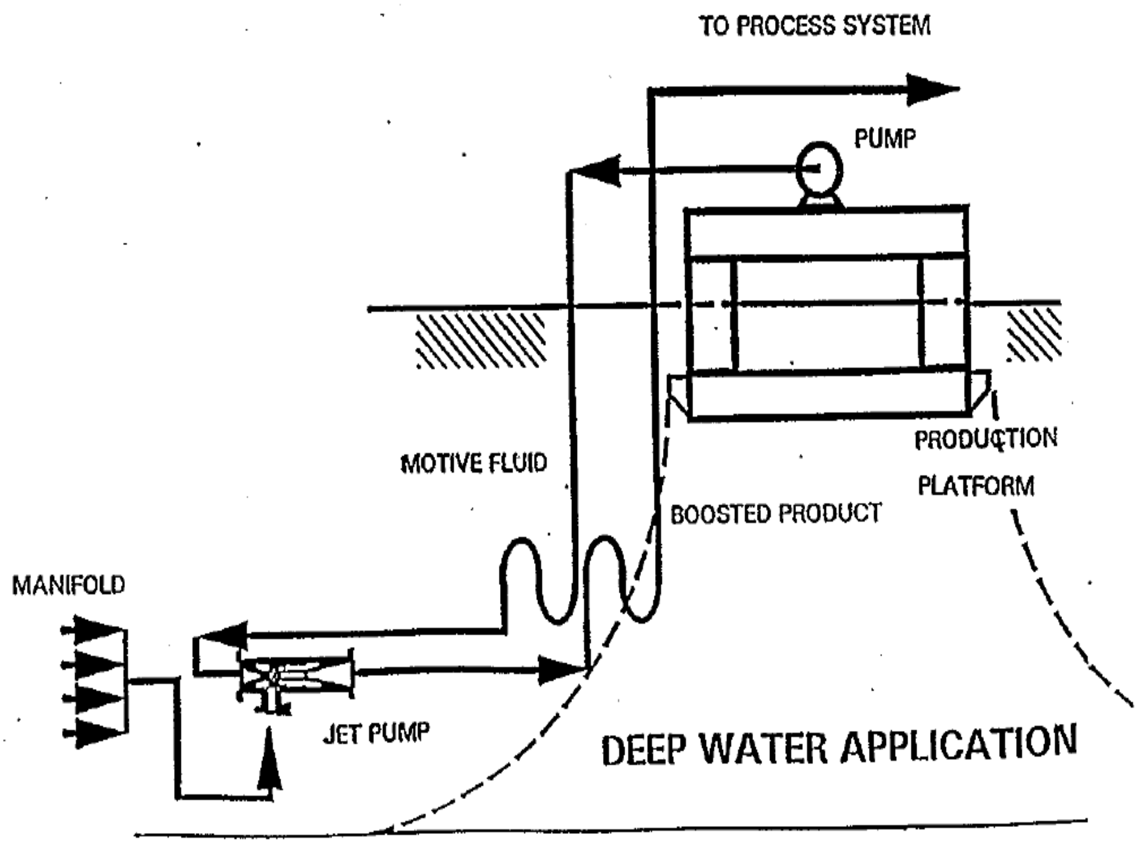


Figure 2.17: Example - using a Jet Pump and Booster Pump for deep-water applications [15]

- In particular applications where the use of compressors is avoided for economic reasons, a booster pump can be used to supply (HP) the motive flow to the jet pump and to enable low pressure wells to produce at pressures below that of the 1st stage separator. The separator pressure is, in this case, dictated by the minimum pressure required for transportation of gas by pipeline without the aid of a compressor **(Fig 2.18).**

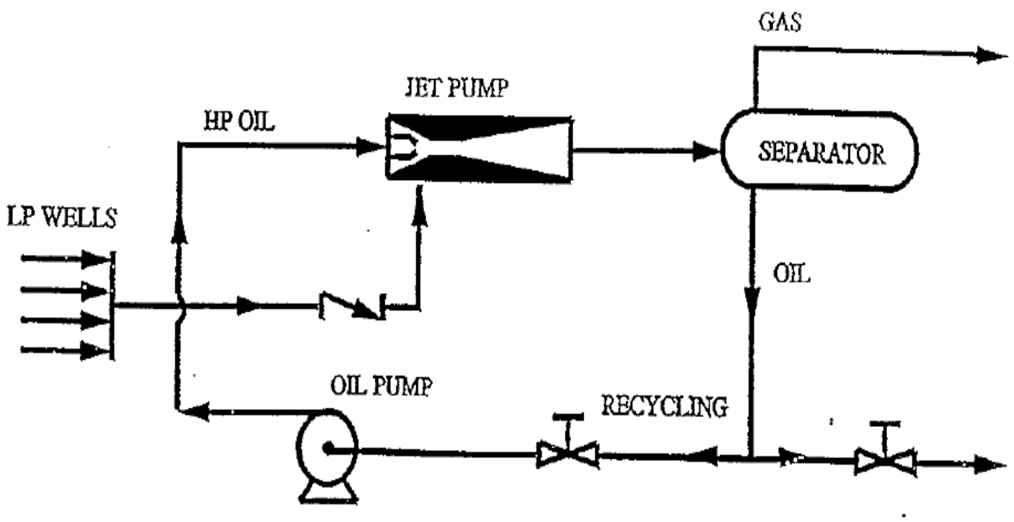


Figure 2.18: Example - using a Jet Pump and Booster Pump to boost LP oil and gas production [15]

2.5.3 HP sources as motive flow for the SJP

The HP fluid provides the power (motive force) for the SJP to do its work (i.e. to lower the FWHP of the LP well etc):

a) Typical HP Gas Sources

- HP gas wells
- HP gas from process system
- HP gas from HP production or test separator
- Gas lift or injection gas
- Compressor re-cycled gas
- N2 or C02 injection as HP gas

b) Typical HP liquid sources

- HP oil well
- Injection water pump
- HP export oil pump
- ESP boosted production as HP
- Oil or water flow from a HP production or test separator
- Spare booster pump to further boost the pressure of the available liquid phase. [19]

2.5.4 HP candidate well selection for SJP

- Review HP well production history for sustainability
- Ensure stability of well production
- Ensure it will be able to maintain its pressure and flowrate for a longer duration
- Confirm its flow rates (via flowmeter, test separator etc.)
- Confirm It will be able to deliver the flow and pressure required by the SJP
- If, for some reason, all HP flow is not needed, a by-pass with a globe valve & isolation valves should be provided to by-pass the excess HP flow. Isolation valves should also be provided around the SJP. **[19]**

2.5.5 LP candidate selection for SJP

- Select well which will respond to lowering of FWHP
- Choose wells with Higher PI (Productivity Index)
- For LP Oil wells, choose wells with low water cut
- Check reservoir related issues (previous slide)
- Review production history of the LP wells
- If LP well has been shut in, check the reasons why
- Choose wells with low/zero sand production
- Review stability of flow through LP wells
- Review condensate/water content (for gas wells)
- As a first choice Use a Test separator (if available) to test the wells & record production at reduced FWHP (predicted by Caltec) to validate the production gain.
- Preferable location of SJP is at the manifold where the HP and LP wells meet, in order to minimise pipework
- For loaded LP wells, severity of loading may lead to the need for an initial AL solution.

LP well Candidate Selection: for best results & minimising costs **[19]**

2.6 Effect of variations to the operating conditions

The operating conditions of both the HP and LP sources may change during the service life of the SJP. The SJP system is initially designed for a base case agreed with the client. This condition often relates to the operating conditions within the initial life of the SJP. The SJPs supplied can be of universal type with the internals (the nozzle and the mixing tube) replaceable if needed. **Figure 2.19** shows the key features of the replaceable internals. If the HP pressure or flow rate changes significantly, only the nozzle of the SJP needs changing.

If, however, the total HP and LP flow rate changes beyond 20% to 25%, a change of the mixing tube may become necessary to optimise the performance of the system. Change-out of the internals is a relatively simple operation and can be carried out by platform crew within a matter of a few hours. Detailed procedures are available for change-out operation. It is worth noting that in practically all cases experienced so far, the cost of replacing the internals has been recovered over a few weeks from the enhanced production achieved by optimising the design of the SJP. [18]

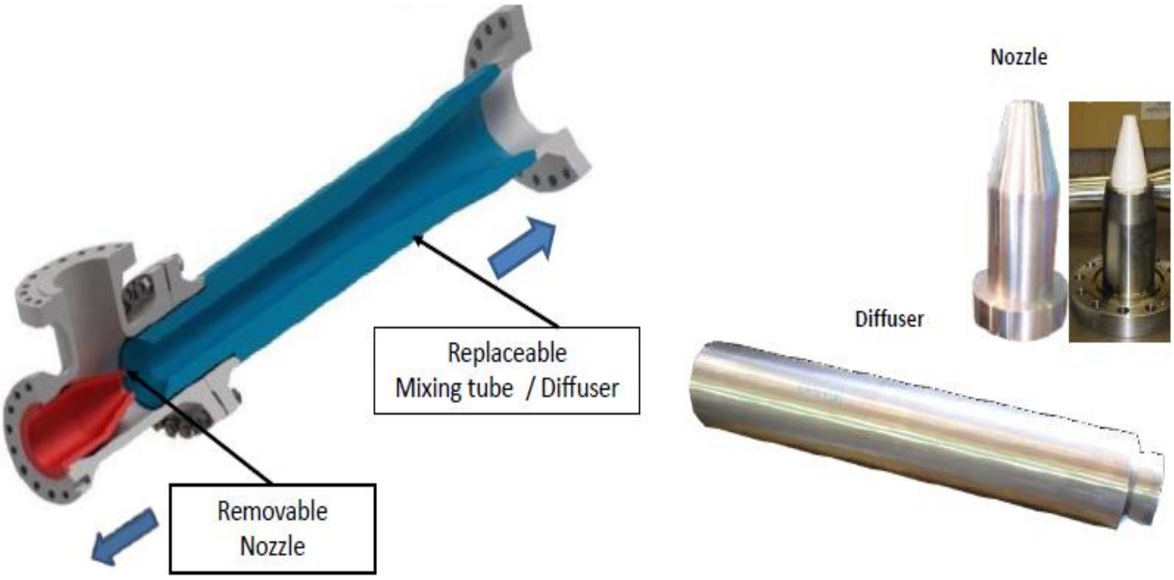


Figure 2.19: Surface Jet Pump [20]

2.7 The best location for the SJP

Location in most cases dictated by the site conditions:

- At the wellhead
- At the manifold
- At the transportation line
- At pipes connections (e.g. Tee)
- At the by-pass line
- Upstream, inlet of a separator

- Downstream, at the outlets of a separator (production/Test)
- Upstream of compressor suction line
- From the re-cycle line of compressor
- Downstream of compressor
- Between compressor stages
- Upstream of a pump [20]

The best location for the SJP is dictated by the details of the production system and where the sources of HP and LP fluids are located. In most cases the aim is to minimise the interconnecting pipe work. This rule applies to both onshore and offshore applications. [18]

2.8 Control, instrumentation, material selection and codes

Jet pumps are passive devices with no moving parts and are simple to operate. They do not usually need any control system. There are exceptional cases that some type of control may be required in order to ensure that the SJP operates safely under all expected operating conditions.

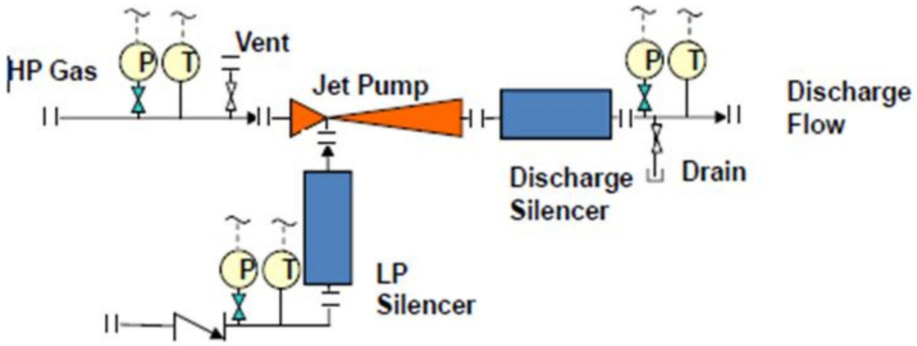


Figure 2.20 Typical instrumentation for a Jet Pump

The jet pump can be supplied in a variety of materials as required by the specific applications. The materials covering pipework and fittings normally meet the standards of the oil and gas industry such as ASME/ANSI codes. The selected materials need to meet two basic requirements:

- Suitability based on the nature and composition of produced fluids
- Compatibility with the existing equipment and pipe work on the platform or fields.

The selected materials could therefore range from simple carbon steel to high grade duplex. In case of sand production, parts of the internals which are subject to high velocities and erosion, such as the nozzle or the mixing tube, can be coated with hard wearing materials such as tungsten carbide, or ceramic lining is added which has the highest level of resistance to erosion. The modularization of the jet pumps allows easy modification and the change-out of the key components or internals.

2.9 Commercial benefits

- Extend the life and productivity of oil and gas fields
- Pay back in days to months
- Easy to deploy
- Near zero maintenance
- Low risk equipment
- Boost production rates (usually 20%-40%)
- Lower the unit cost of production **[17]**

Chapter 3

Well Modelling and Optimization

3.1 Introduction

The main objective of well modelling and optimization is to construct a computerized and representative model of the well OMM202 in order to achieve to the optimization purpose which is to maximize the production and define the various components limiting upstream flow (GOR, pressures …).

Establishing the model is essential towards the integration of the well model into the network model by using one of PETEX programs “PROSPER” as we take well 202 as setting up well model example for chapter 3.

Our job is divided in two tasks:

- Collecting well data required to build the model
- Well modelling and analyze the sensitivities on the different parameters

3.2 Well presentation

3.2.1 Background

OMM202 is a vertical well located in zone 1A-Complexe, drilled on 12/10/81 and completed on slotted liner. The well was side tracked on 08/07/05 and completed as LCP.

3.2.2 Localization

Zone: 1A

Perimeter: HMD Central area.

Coordinated:

X: 791699.375

Y: 130351.141

Manifold: W1C

Sub / Manifold: W1F

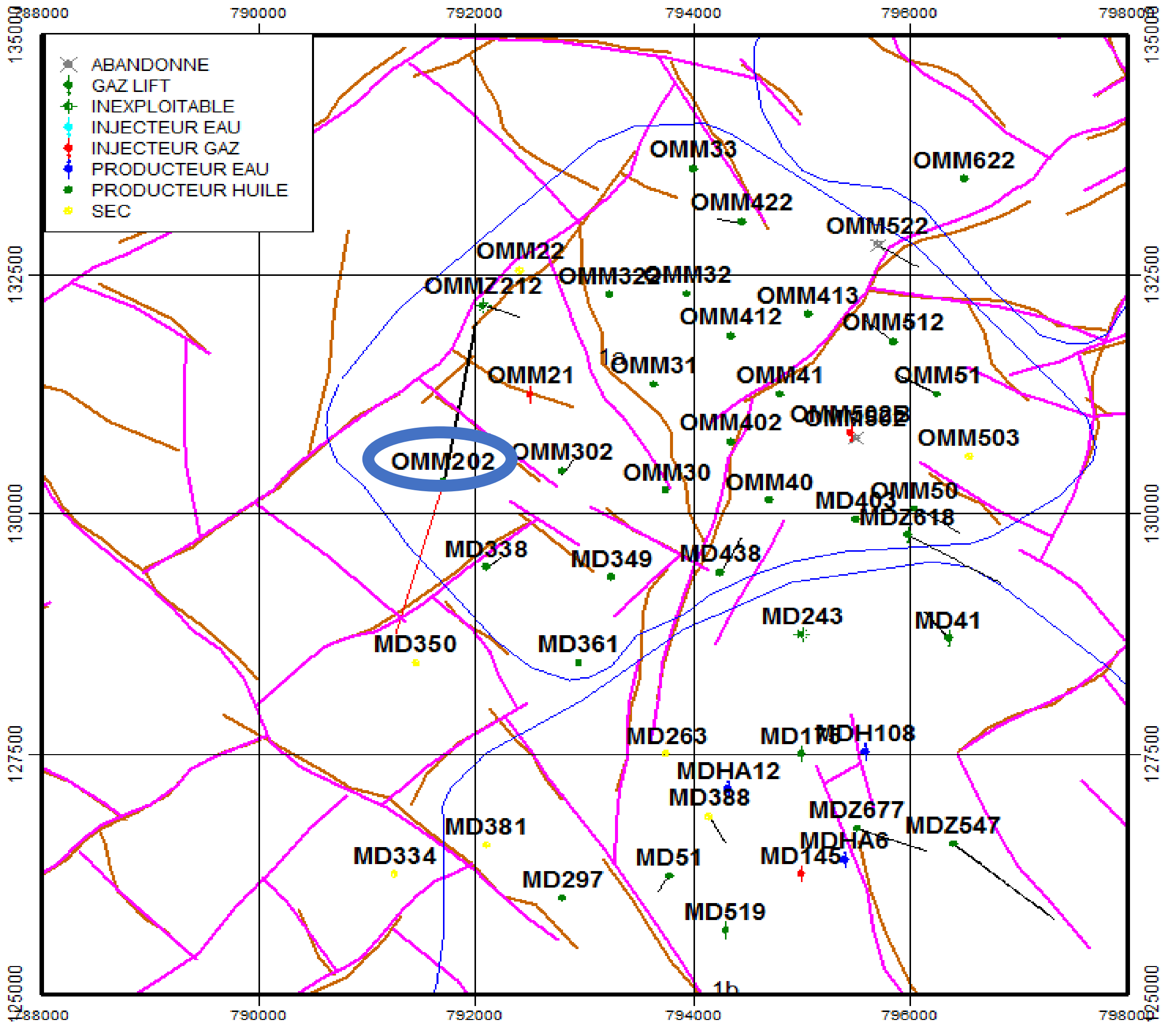


Figure 3.1: Well location of OMM202

3.2.3 Performed Well tests: (Table 3.1)

Test	Date	PG (kg/ cm^2)	PFD (kg/ cm^2)	PT (kg/ cm^2)	Oil Rate (m/h)	IP	HKP	HKL (Hw* Kyz)	Skin	Choke	Remarks
DST	25/10/1981	348	267.03	53	6.35	0.085	116	-	0.14	9.5	-
EP BU	12/01/1982	352.2	214.72	33	3.12	0.026	101.5	-	11.6	9.5	EP
PFS	29/08/2009	260.87	--	--	--	--	--	--	--	--	PFS
BU	05/01/2016	297.29	143.62	33.5	6.5	0.044	--	98.9	1.94	12.5	PFD at -3122.18m

3.3 Input Data

OMM202 has a low well head pressure and back-pressure problems. Hence, one of the suggested solutions is to implement surface jet pump to optimize the production. OMM202 was selected along with OMM412 to install the innovative technology in Algeria. The available data is separated into various categories and it will be presented in this chapter and extracted from various data source in SONATRACH data bank, Cahier du Courbe and interpreted PVT, reservoir and many information and knowledges from the company's engineers. Each data category will be modeled separately and subsequently all of them will be joint in a unified model. When this model is tuned to real field data, PROSPER can confidently predict the well's performance under various scenarios. In the further sections we'll be showcasing a detailed explanation of the role of each data category will be analyzed along with the way it is introduced to the software.

3.3.1 PVT Data

Table 3.2: Fluid PVT properties

Oil API Gravity	45	API
Oil Specific Gravity	0.8017	
Gas Specific Gravity	0.836	0.793
Water Salinity	350,000	ppm
Water Gravity	1.2748	
RS at Saturation Pressure	**190.0359**	Sm3/Sm3
Fluid Model	Black Oil	
Laboratory Data		
Saturation Pressure	**153.966**	kg/cm2_g
Temperature	118	^{O}C

Table 3.3: Effect of pressure on Bo, Rs and Oil viscosity

Pressure	**Bo**	**Rs**	**Oil viscosity**
kg/cm2 (gauge)	**m3/Sm3**	**Sm3/Sm3**	**cp**
153.9668	1.715	190.0359	0.245

138.9668	1.65	176.1066	0.263
118.9668	1.58	155.2126	0.288
78.9668	1.4	108.4498	0.334
58.9668	1.3	83.576	0.36
18.9668	1.11	29.8486	0.407

3.3.2 Well Data

The well was sidetracked on 07/08/05 where the deviation point is at 3347.5 m. The target inclination degree is 5º and TVD is 3450.6 m. the wellbore diameter is 0.354ft.

The production casing diameter is 7'' and the is completed as LCP with a $4^{1/2}$, no available measurements of a subsurface safety valve (SSSV). According to Prosper manual in case of oil producing wells the overall heat transfer coefficient is estimated at 8 to 9 BTU/hr/ft²/F **[21]**.

3.3.3 Reservoir Data

A general description of the reservoir data is presented in **Table 3.4**. From a well test conducted and after the correction, the estimated skin value is 2.75 and the Dietz shape factor is calculated at 10.853, a value that corresponds to the shape of the drainage area which is approximately a rectangle and the well is placed in the upper center.

Table 3.4: Basic Reservoir characteristics

Property	Value	Units
Reservoir pressure	306.14	Kg/cm2
k	4.49	md
A (drainage area)	614300	m2
h (thickness)	22.32	m
S	2.75	Dimensionless
Dietz shape factor	10.853	Dimensionless

3.3.4 Well test Data

Bottom hole pressure and temperature were measured using gages at the seating nipple, above the perforations. So, the pressure and temperature values of the static and dynamic must be corrected, taking into account the gradient of pressure and temperature.

The gauge depth is subsea and to be corrected 3122.18+147.82=3270m (master valve VM)

To correct these measures and the values submitted in the modelling procedures, we proceed as follows:

$$\text{Pf } \mathbf{(}\text{Perfos}\mathbf{)} = \text{Pf } \mathbf{(}\text{gauge}\mathbf{)} + [\text{pressure gradient} * \mathbf{(}\text{perfos depth} - \text{gauge depth}\mathbf{)}] \quad \text{Eq 3.1}$$

Where the value of pressure's gradient in Hassi Messaoud field is 0.06. Further in the following section, a quality check for well test is performed in order to be corrected.

Table 3.5: Well test data

	Tubing Head Pressure	Tubing Head Temperature	Liquid Rate	Gauge Depth	Gauge Pressure (measured)	Water Cut	Reservoir Pressure
	(kg/cm2)	(degC)	(m3/hour)	(m)	(kg/cm2)	(%)	(kg/cm2)
Test point	33.5	37	6.51	3276	143.62	0	306.14

We have to point out that some parameters may are not representable or missing so, some correction and conclusion of their value to latest update we'll be explained in further sections of the chapter.

3.4 Setting up the Well model in PROSPER

The main objective is to generate a mathematical model, tuned against real field data that can describe as accurately as possible the well's behavior under various future production scenarios. Each category of data will be modeled separately and the developed sub-models will be joined to develop a complete model capable of predicting both the inflow and outflow performance of the well.

3.4.1 Workflow

The general workflow starts with the introduction of the basic information about the examined well in the summary section. After that, PVT data is entered and the appropriate fluid PVT property correlations are selected. The system is described in terms of downhole and surface equipment and trajectory of the well. As the temperature plays an important role to pressure drop calculations, the geothermal gradient (i.e. rate of increasing temperature of the surrounding formation with respect to increasing depth) and average heat capacities (ratio of the amount of heat energy transferred to oil, water or gas over the resulting increase in their temperature) are also take into consideration. In the IPR section, the available data on reservoir properties is used to generate the IPR curve for the current reservoir pressure. Then, a quality control of the well test data is run in the VLP section to discard unrealistic measurements. Subsequently, the correlation that best describes the multiphase flow in the tubing is matched against the measured data. After completing all the above tasks, nodal analysis (see **Section 1.2**) and investigation of future production scenarios is possible.

3.4.2 Options summary

Recall that it is a single branch producing well, with a cased hole, no sand control, while production fluids travel through the production tubing. In this section, the main characteristics of the well are entered as the following options:

- Fluid: Oil and Water
- Method: Black Oil
- Separator: Single-Stage Separator
- Emulsions: No
- Water Viscosity: Use default correlation
- Viscosity Model: Newtonian Fluid

- Flow Type: Tubing Flow
- Well Type: Producer
- Artificial Lift Method: None
- Predict: Pressure and Temperature (on land)
- Temperature Model: Rough Approximation
- Range: Full System
- Well Completion: Cased hole
- Sand Control: None
- Inflow Type: Single Branch
- Gas Coning: No

3.4.3 PVT Data Input and Matching

The surface PVT data given, such as Solution GOR (equal to Rs in this case because reservoir pressure is above Pb), API gravity, gas gravity and water salinity are used as input as seen in **Figure 3.2**

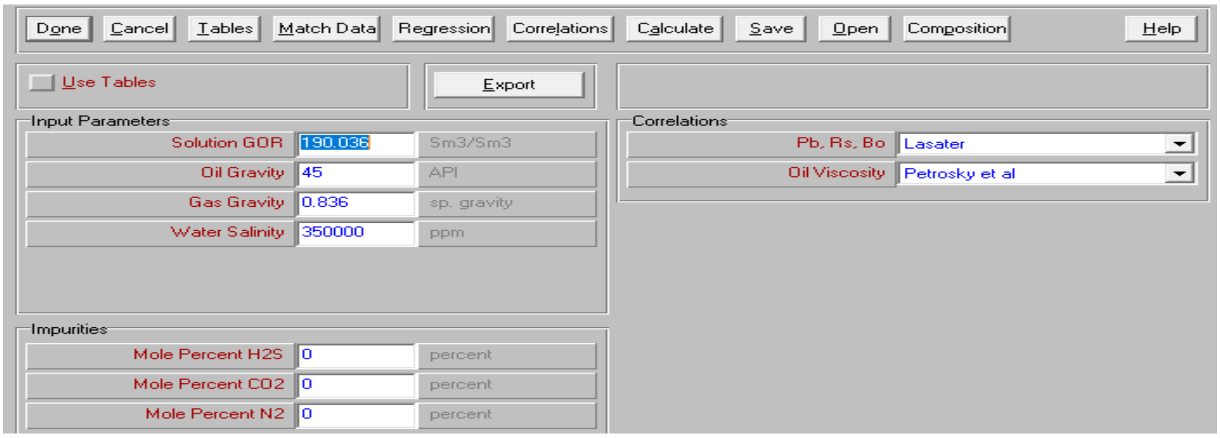


Figure 3.2: PVT Input data section

PVT Laboratory analysis carried out on the produced fluid which that it has a bubble point pressure of 153.97 Kg/cm²_g and solution GOR at this pressure is 190.0366. **Figure 3.3** is introducing the variations of Bo, GOR, μ_{oil} versus pressure in the PVT match data screen.

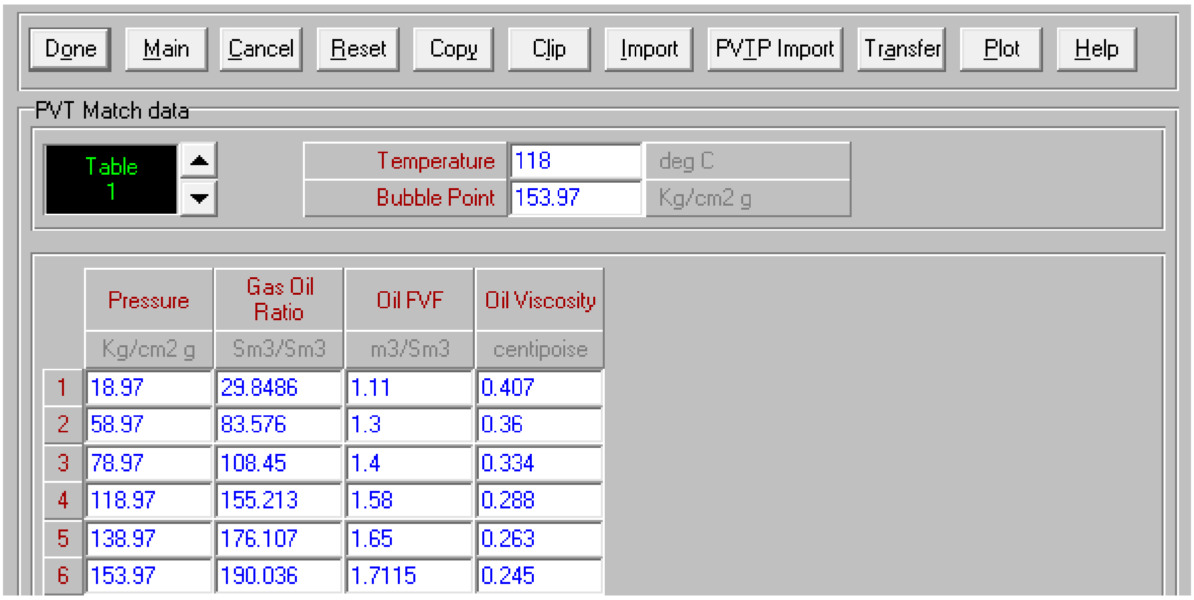


Figure 3.3: PVT Match data screen

PROSPER supports several built-in correlations to predict the Pb, Bo, GOR, μ_{oil} based on experimental data of various crude oil/natural gas mixtures. More specifically, for the calculation of Pb, Bo, GOR.

PROSPER was used to model the reservoir fluid. This is done by matching the PVT data obtained from laboratory analysis to the available correlations. The match is performed through nonlinear regression, adjusting the correlations to best fit laboratory measured PVT data. It applies a multiplier (parameter 1) and a shift (parameter 2) to each of the correlations. The correlation that best matched the fluid is one which required the least correction. The standard deviation represents the overall closeness of the fit. The lower the standard deviation, the better the fit.

As it is mentioned in the Chapter 1 that the main cause of pressure drop in the tubulars is the gravity and the corresponding hydrostatic term. The density of gas and liquid phase at various pressures and temperatures, as well as the knowledge of the proportion of the pipe occupied by liquid (holdup) and it is affected by different parameters and are closely related with the PVT data. Thus, a consistent PVT model is essential.

Lasater's correlation for Pb, oil FVF and solution GOR is selected while Petrosky's correlation is selected to model the oil viscosity as the values of Parameters 1 and 2 lie closer to 1 and 0 respectively compared to any other correlation. PVT data at every any pressure and temperature can now be predicted with the adjusted black oil correlations.

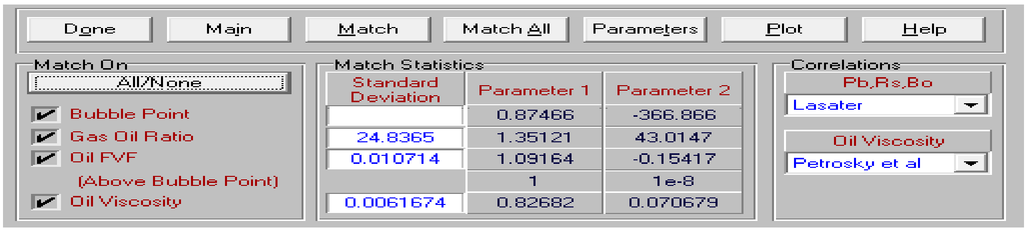


Figure 3.4: Correlation matching regression screen

An overview of the matching parameters for all black oil correlations is given in **Figure 3.5**.

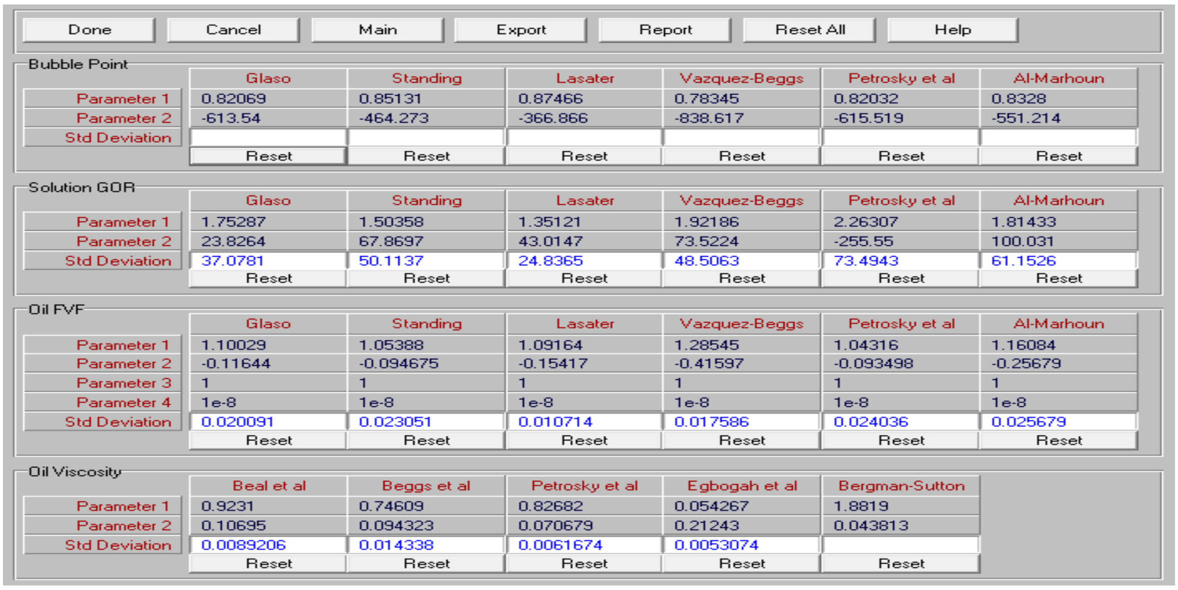


Figure 3.5: Matching parameters 1 and 2 for all black oil correlations

3.4.4 Equipment Data Input

In this section of PROSPER, a detailed description of the well's trajectory, surface and downhole equipment, geothermal gradient and average heat capacities is given

3.4.4.1 Deviation Survey

A consistent deviation survey is necessary to obtain accurate calculations in the VLP section. TVD of the well is essential for the calculation of the pressure drop due to gravity (or vertical elevation) since it only depends on the change in elevation and the density of the fluid. On the other hand, the very sensitive issue of pressure loss due to friction and the generation of the corresponding temperature profile are intimately related to accurate values of MD. All equipment placed in the production tubing is always described in terms of MD.

As we introduced in Section 3.4.2, OMM202 is a vertical well and then it was side tracked afterwards. That means that, it is vertical down to a certain point. Below this point, an inclination angle is built and determined 5 degrees to the verticality. In **Figures 3.6** and **3.7** the description of the well and the profile of the well are illustrated respectively.

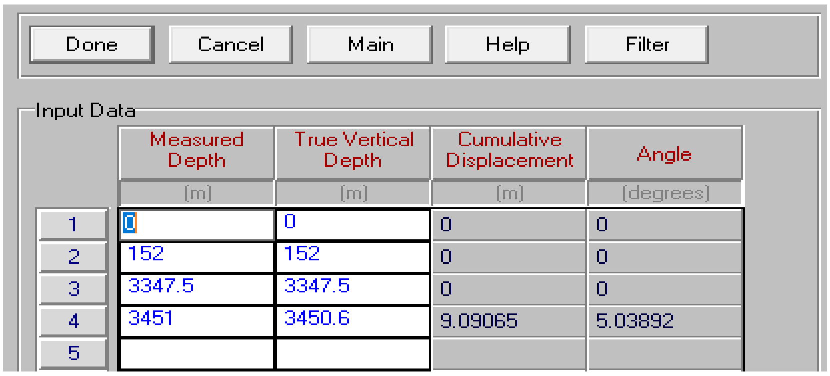


Figure 3.6: Well's trajectory description

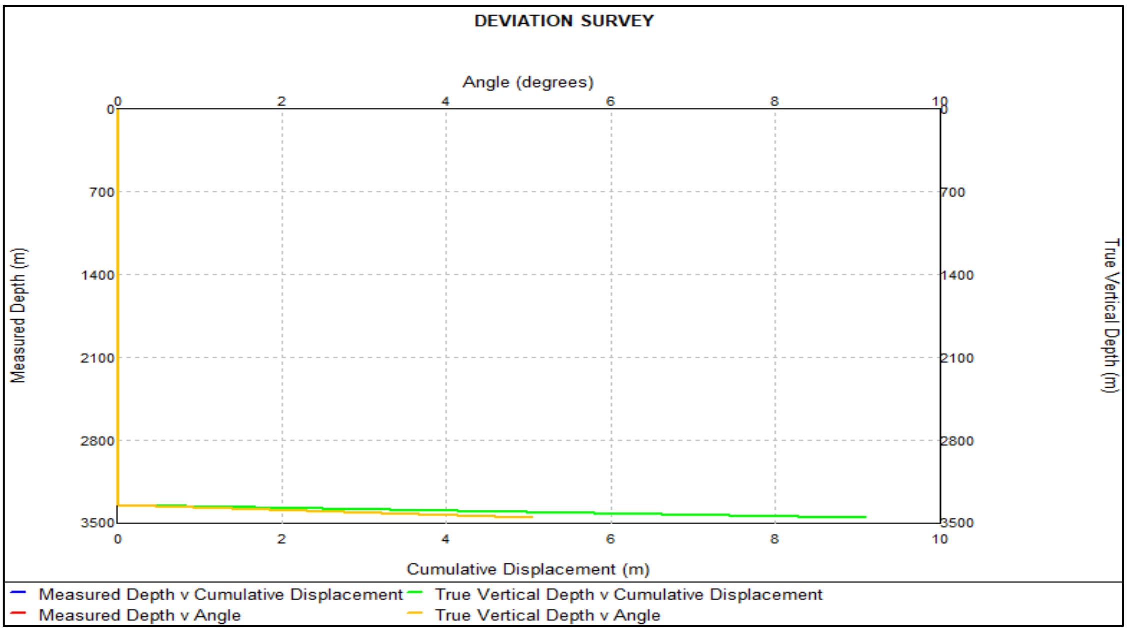


Figure 3.7: Profile of the well. On the x axis is the cumulative displacement while on the y axis is the measured depth

3.4.4.2 Surface Equipment

As the wellhead pressure was provided in the well tests, it was decided, for the Nodal analysis calculations, the set top node at the wellhead. For this reason, the manifold TVD was set at 0' TVD. The only values set in this form are the ambient temperature at 15°C and the overall heat transfer coefficient at 8 BTU/h/ft²/°F.

3.4.4.3 Downhole equipment

As similar to the deviation survey, the description of the well's equipment is necessary to calculate the VLP of the well and the pressure and temperature gradients. the calculations performed by the "Rough Approximation" model depends on the tubing ID. Tubing's ID and inside roughness are also used to estimate frictional pressure losses during production.

The Downhole Equipment screen (**Fig. 3.8**) enables the downhole completion data to be entered. Working with the available data, the production packers are set at 3280 m MD. The production tubing ends a few feet deeper at 3321 m. The production casing runs from the surface and reaches bottomhole at 3437m.

The rate multiplier at the right hand side of the screen in **Figure 3.8** is related to the calculation of pressure losses due to friction in dual completion wells. Due to the fact that the well is a single branch one, the value of this variable was set to its default value of 1.

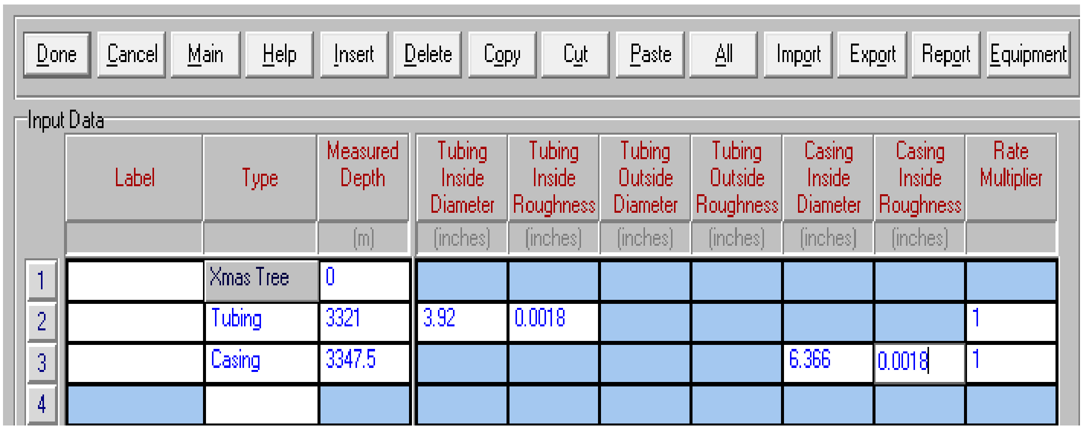


Figure 3.8: Downhole Equipment data input screen

A schematic representation of the downhole equipment, as obtained by PROSPER, is presented below (**Fig. 3.9**):

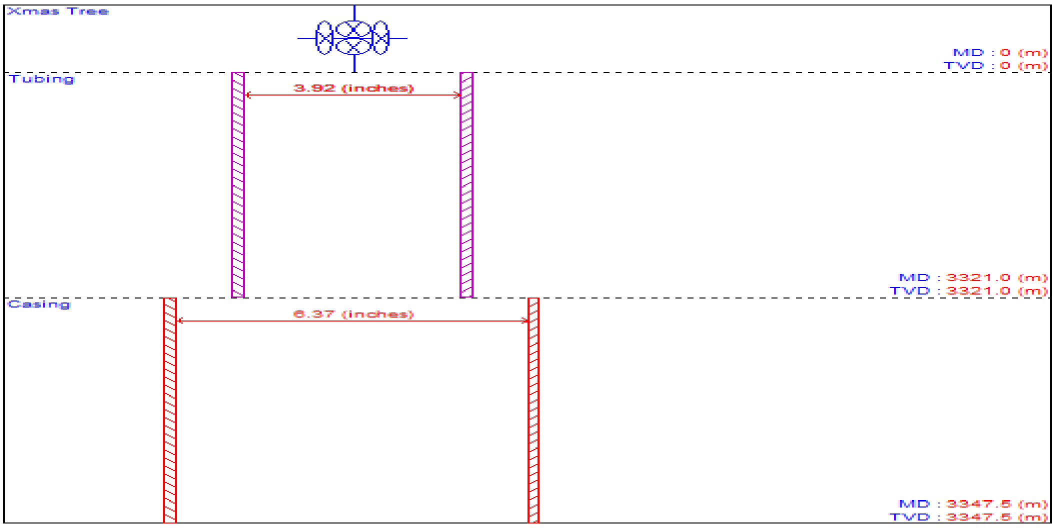


Figure 3.9: Simple schematic of the downhole equipment

3.4.4.4 Geothermal gradient

The formation temperature at any depth can be computed by PROSPER by the means of the geothermal gradient. A rough approximation of the temperature profile can be achieved by introducing the known values of temperature at the surface and at the reservoir. Because of the linear interpolation by PROSPER at least two data points must be introduced. geothermal gradient and overall heat transfer coefficient are also introduced as take part in predicting the temperature fluids at any given point for the sake to investigate the hydrates formation (flow assurance).

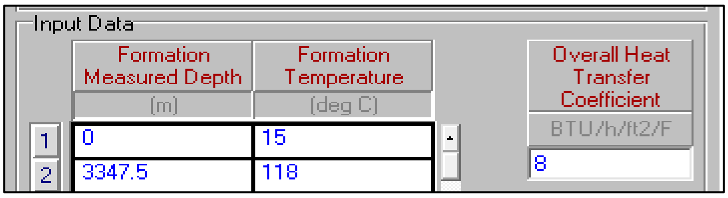


Figure 3.10: Geothermal Gradient data input screen

3.4.4.5 Average heat capacities

The average heat capacities of water, oil and gas are used in the "Rough Approximation" temperature model (in addition geothermal gradient and heat transfer coefficient) to calculate the dissipated heat when the fluid changes temperature. A good approximation can be given by using the default values of Cp of oil, water and gas. it should be noted that, Cp for oil and gas is not a constant value since their composition changes and thus their properties change along depth.

3.4.5 IPR Data Input

This section defines the Reservoir Inflow Performance curve. Calculating an IPR curve results in a relationship between the bottomhole pressure and the flow rate passing in the well. In this case the "Darcy" model is used entering skin by hand option. The software uses the Darcy's equation above the bubble point and the Vogel's model below the bubble point. The Vogel's model applies by the time when the flowing pressure at the bottom node (Pwf) becomes equal to the bubble point and hydrocarbon two phase flow takes place. The IPR curve derivation and its role on Nodal analysis were well-discussed in **Chapter 1**. The main screen of the IPR section is offered in **Figures 3.11**.

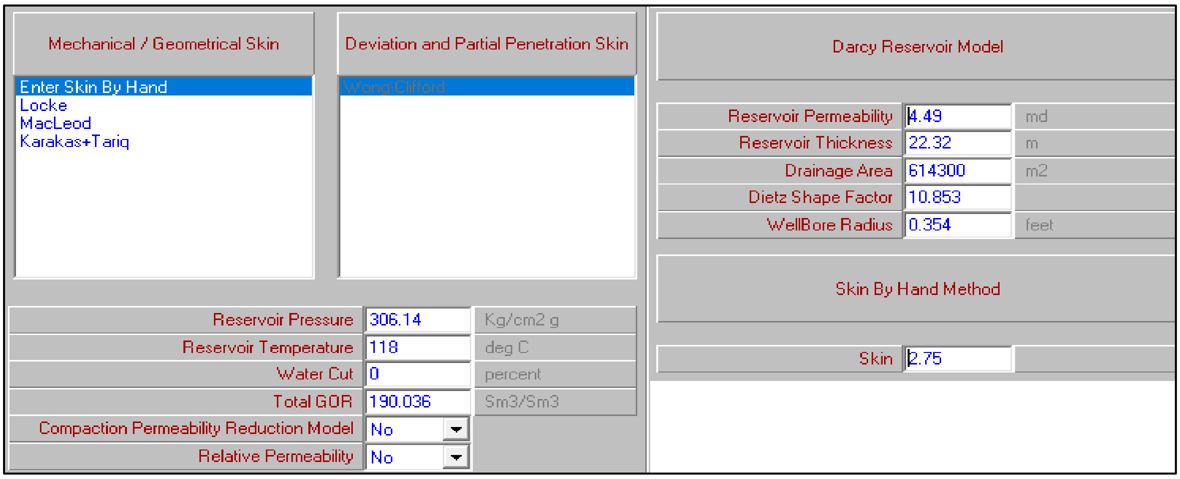


Figure 3.11: IPR data input main screen

3.4.6 VLP/IPR match procedures

The general procedure in this section implies, first of all, the introduction of the well test data to the main screen. Afterwards, the procedure of processing the data is done by following 4 steps in sequence.

Estimate U-value

PROSPER estimates the overall heat transfer coefficient that matches the wellhead temperature of the well test. The calculations for temperature prediction along the wellbore can be more accurate with the revised U-value. The value should be close to the interval 8 to 9 BTU/h/ft2/F as mentioned in Section 3.4.2. The optimized value will replace the initial one in all successive calculations.

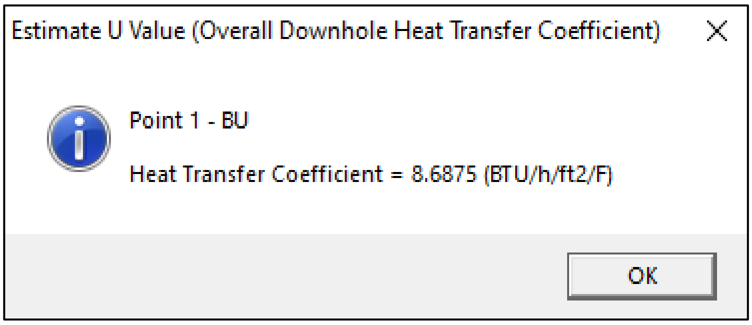


Figure 3.12: Estimated U-value for well test (BU 2016)

Correlation comparison

The selection of the most appropriate correlation to describe pressure drop in the tubing consists in comparing correlations with gauge pressure and depth measured from well test. The determination of the correlation to be used to simulate the OUTFLOW curves of the wells, this is due to the complexity of the multiphase flow in the tubing.

Choosing the correlation for the vertical two-phase flow is a very important step for the rest of the calculations. This then determines the accuracy of the predictions of pressure drops in the tubing and towards an effective analysis. The correlation to which the plotted measurement of pressure is closer to the gradient curves is valid for match (**Fig. 3.13**). It is clear that the correlations that match best with the test point is Hagedorn and Brown's correlation.

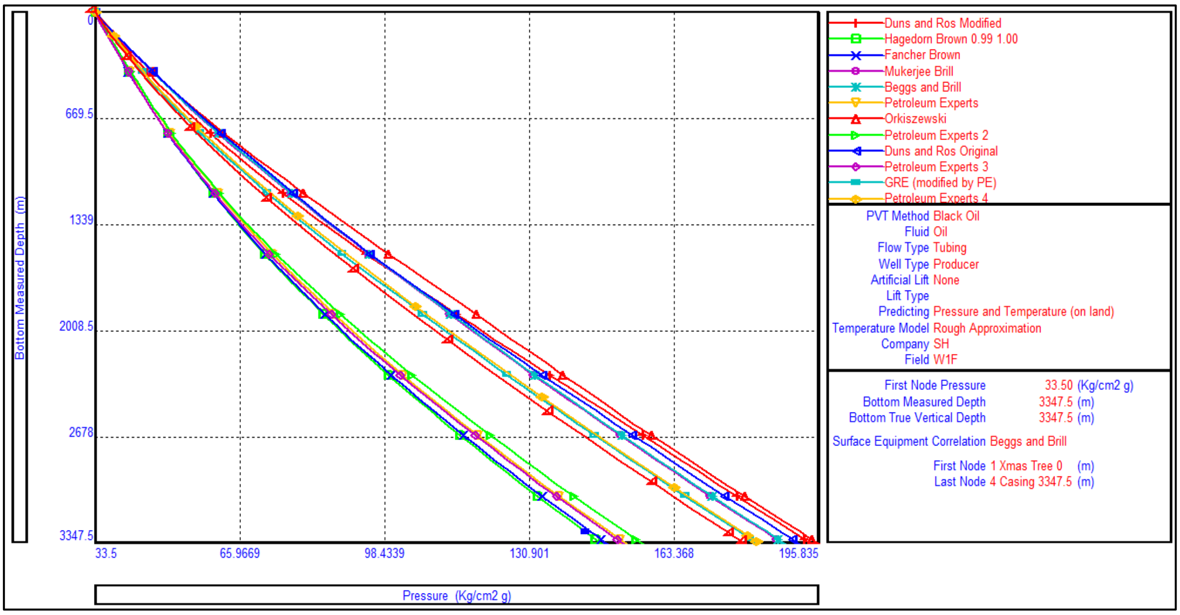


Figure 3.13: Correlation comparison plot: All correlations plotted (Blue squared point corresponds to the well test 1 point)

VLP matching

Once the most representative correlation has been selected, a match is carried out so that the gauge pressure calculated exactly matches the measured pressure.

This is done by applying a multiplier to both the gravity pressure drop term (parameter 1) and the friction pressure term (parameter 2) **[21].** The selected correlation's parameter 1 and 2 values should be the closest to 1. In **Figure 3.14**, we could validate the selected correlation from the correlations' comparison which the value of the two parameters are closest to 1 ''Hagedorn Brown''

		Correlation	Parameter 1	Parameter 2	Standard Deviation
1	Reset	Duns and Ros Modified	1.01404	1	0.00012207
2	Reset	Hagedorn Brown	1.01047	1	0.00012207
3	Reset	Fancher Brown	1.01539	1	0.00012207
4	Reset	Mukerjee Brill	1.01404	1	0
5	Reset	Beggs and Brill	0.79555	1	0.00036621
6	Reset	Petroleum Experts	0.99315	1	0.00048828
7	Reset	Orkiszewski	0.74165	1	0.00085449
8	Reset	Petroleum Experts 2	0.97505	1	0.00012207
9	Reset	Duns and Ros Original	0.79465	1	0.00024414
10	Reset	Petroleum Experts 3	0.99969	1	0.00024414
11	Reset	GRE (modified by PE)	0.84025	1	0.66248
12	Reset	Petroleum Experts 4	0.83158	1	0.00012207
13	Reset	Hydro-3P	0.86248	1	0
14	Reset	Petroleum Experts 5	0.8667	1	0.00061035
15	Reset	OLGAS 2P	0.2286	0.2286	0.00073242
16	Reset	OLGAS 3P	0.2286	0.2286	0.00073242
17	Reset	OLGAS3P EXT	0.2286	0.2286	0.00073242

Figure 3.14: Matched parameters for all tubing correlations

IPR/VLP matching

Now we arrive to the final step of setting up the well model which is match IPR/VLP. Since the VLP is matched and trusted as seen in the previous section. We must verify the intersection of VLP curve with the inflow relationship performance and whether the Liquid Rate and the BHP that meet the operating point (discussed in Chapter 1). The calculations indicate that the differences between measured and calculated liquid rate and BHP are negligible and we can valid these values and the matching of VLP/IPR as it is shown in **Figure 3.16**. for liquid rate the difference was -1.96% and the difference between BHP measured and calculated was 0.0074153%. if the differences were not negligible, the steps we can take is to modify either the reservoir pressure or skin factor as they affect the IPR curve. we may after this step valid the values of parameters related to the tubing curve performance and those are affecting IPR.

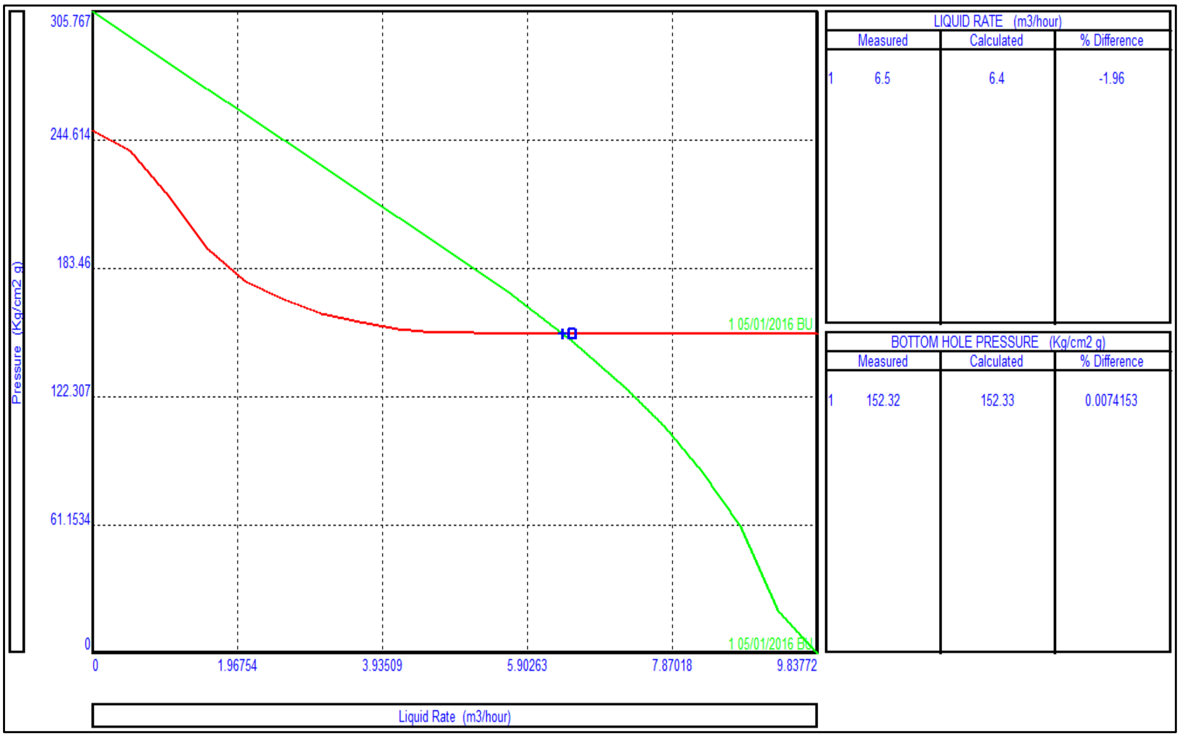


Figure 3.15: VLP/IPR Matching of OMM202 (05/01/2016)

3.4.7 Update to current condition (Latest test)

Our task is not accomplished yet in terms of establishing a representable system performance model for OMM202 for its current condition as we need to update it according to the latest gauging test dated 10/02/2020.notice that the steps are reduced from the previous section as we need to update IPR and VLP and match reproduce the new system performance curve and then we shall perform our typical analysis on our selected well.

One of the principal purposes of the previous step is to choose the correlation the most representable (both gravity and friction related pressure parameters are closest to 1) in order to predict new BHP for the new well conditions like different reservoir pressure, skin, Liquid rate…etc.

Calculate recent Bottom Hole Pressure

The new BHFP is calculated using the selected correlation ‘’Hagedorn Brown” like we confirm is the correlation that represent our well i.e. using latest gauging test 10/02/2020 through ‘’BHP from WHP’’ feature in ‘’Analysis Summary”. In **Figure 3.17** we present latest gauging test numbers in order to calculate new BHFP.

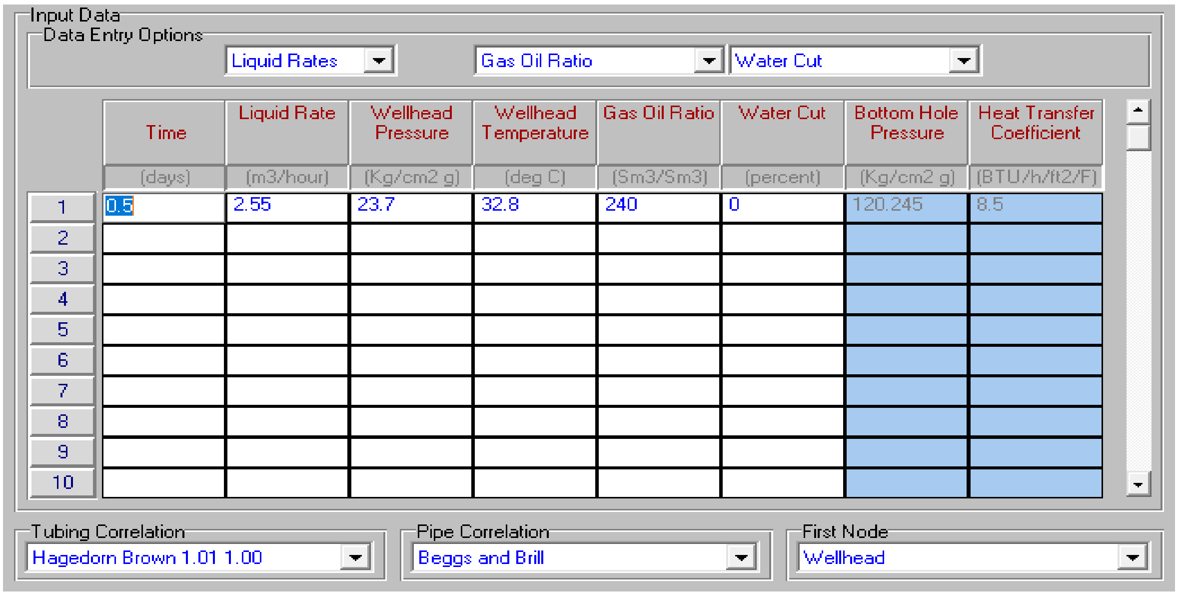


Figure 3.16: Calculate BHP from WHP from latest gauging test

Update IPR

After we obtain new reference point (Liquid rate vs BHP), we shall update our IPR to 10/02/2020 condition. Two parameters to adjust are skin factor and reservoir pressure. First, we predict the reservoir pressure and this is may contain a certain amount of error the reason is we use extrapolation and some considerations like near Water flooding/injector wells. **Figure 3.17** shows the graph of predicting the reservoir pressure via extrapolation using OMM202 reservoir pressure’s history. We can assume it is approximately 250 kg/cm²_g.

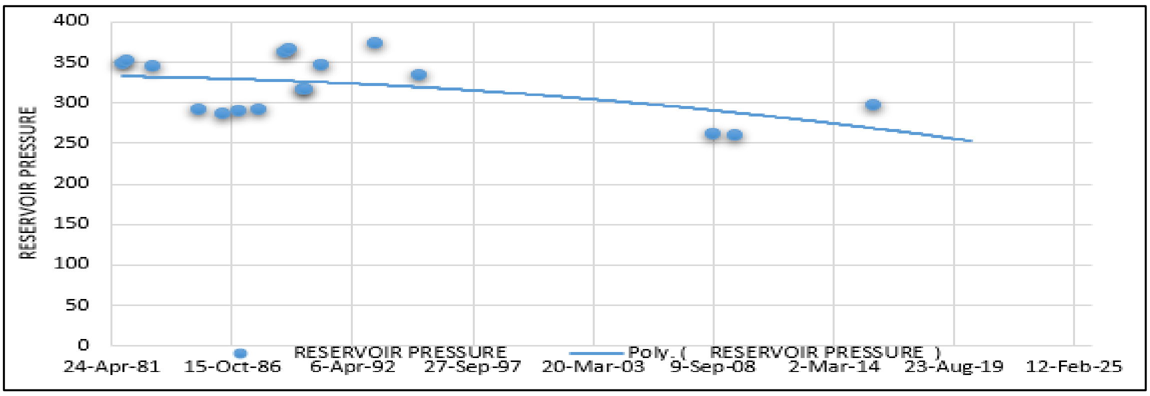


Figure 3.17: Reservoir pressure prediction

Secondly, we adjust the skin factor value according to the predicted reservoir pressure and our reference point which is 2.55 m^3/hour and 120.245 kg/cm^2_g. In **Figure 3.18**, we introduce our updated IPR with predicted skin factor assumed by PROSPER by 14.3,

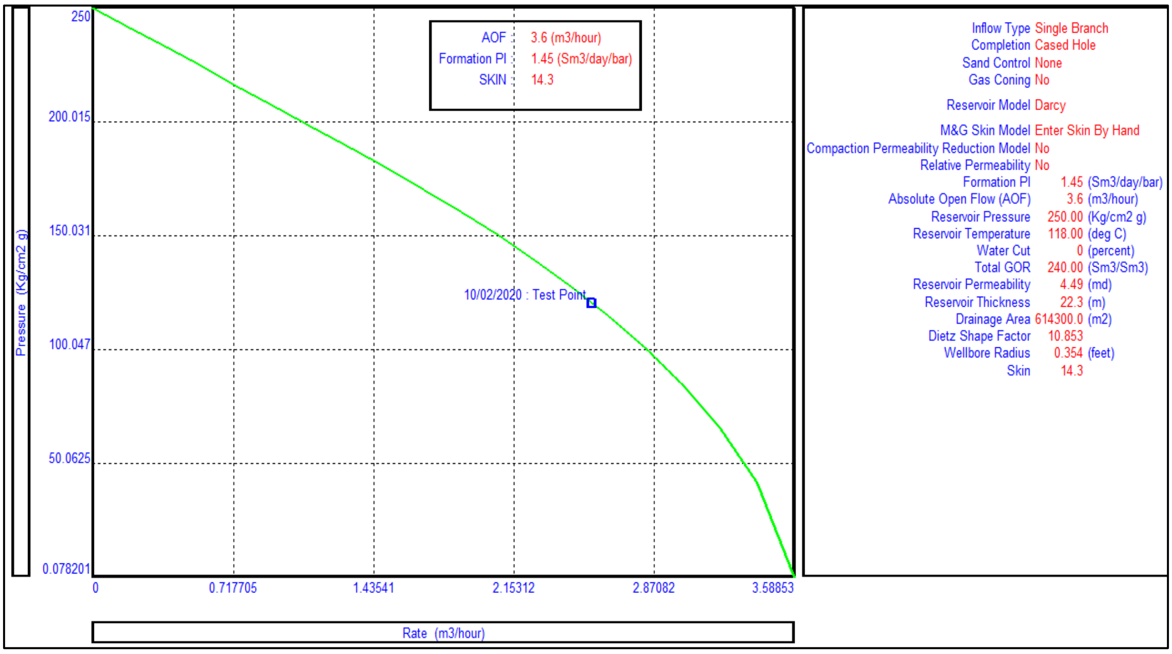


Figure 3.18: IPR section is updated to recent condition

Finally, system VLP/IPR is matched with model calculated oil rate and from gauging with differences close to null as it is shown in **Figure 3.19** with the system performance curve in the recent condition.

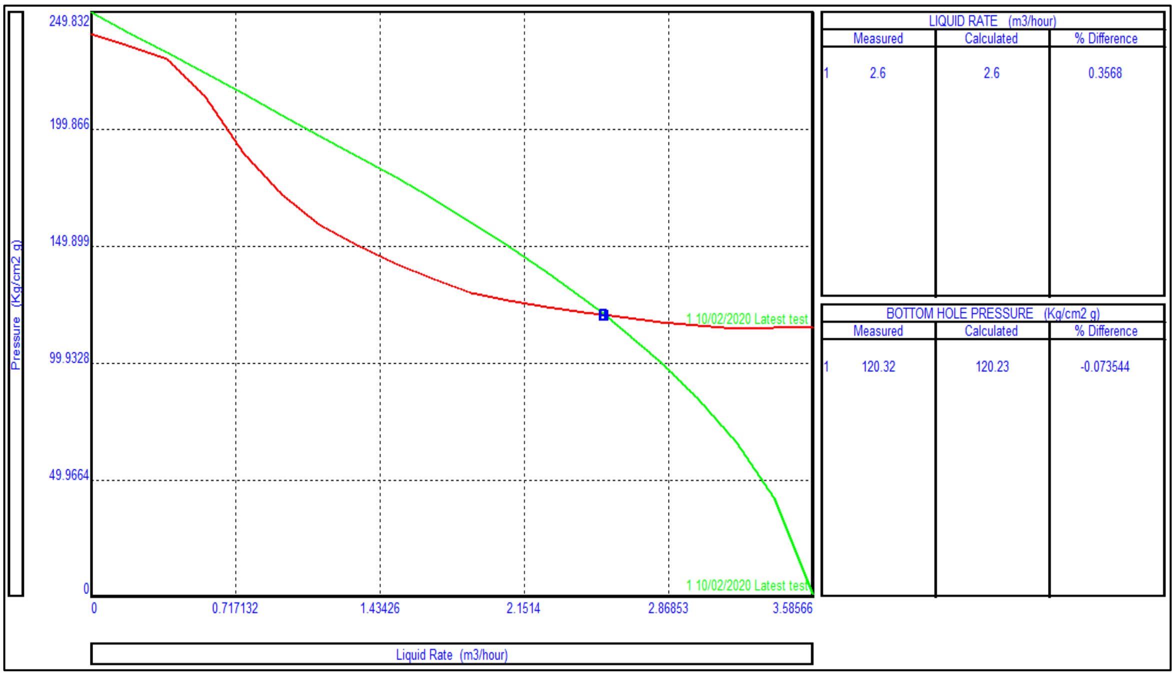


Figure 3.19: VLP/IPR Matching (10/02/2020)

3.5 Sensitivities and results discussion

Our analysis is based on the interpretation of results obtained by sensitivities on different factors/parameters affecting the inflow performance relationship from one hand and the tubing curve performance on the other hand (discussed in Chapter 1). Notice that some parameters could affect both. We have selected reservoir pressure, skin, WHP and GOR to be spotted on to observe the different IPR and VLP produced from the sensitivities on them.

3.5.1 Sensitivity analysis on Reservoir pressure

Our first scenario is variating of reservoir pressure to observe the change of oil rates through the sensitivity case and mark our interpretation on the results obtained that indicated and shown in **Figure 3.20.**

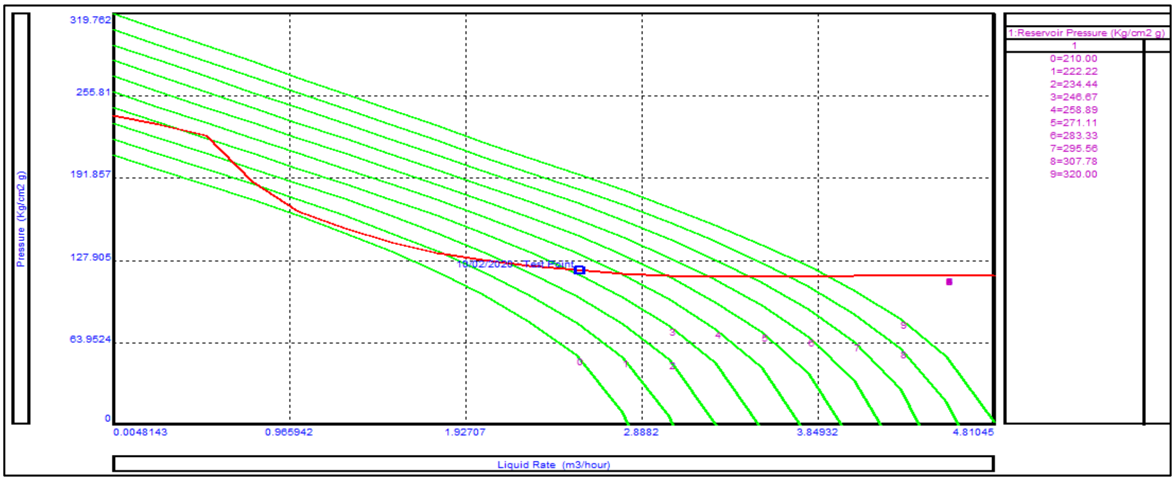


Figure 3.20: Sensitivity on reservoir pressure

<u>**Results**</u>

Based on the results obtained that OMM202 won't produce naturally below P_R=222 kg/cm²_g so it is important to maintain the pressure using the second method of oil recovery through gas flooding or water flooding as they're available for the use in Hassi Messaoud.

3.5.2 Sensitivity analysis on skin factor

The second scenario is projecting the effect of reducing the damage factor as we would see in **Figure 3.21** and predicting the IPR curves resulted by it.

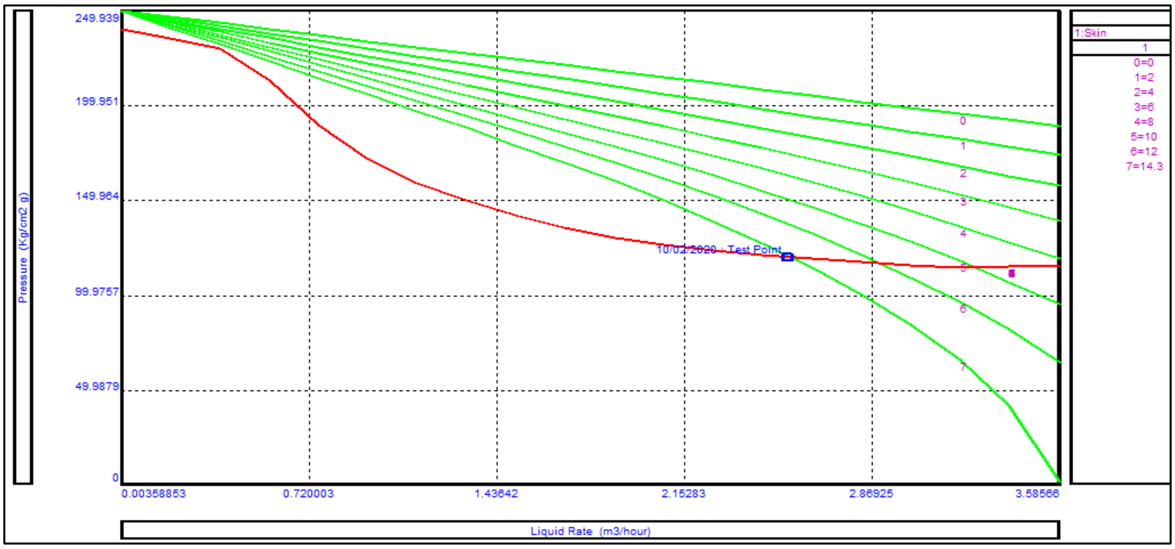


Figure 3.21: Sensitivity on skin factor

<u>**Results**</u>

OMM202 needs well intervention and stimulation in order in reduce the skin factor in the sake of a predicted increase in oil rates.

3.5.3 Sensitivity analysis on Wellhead pressure

Next scenario is the trying different WHP values and named by PROSPER by ‘’first node pressure’’ and its impact on the oil rate, resulting VLP curves as shown in **Figure 3.22.**

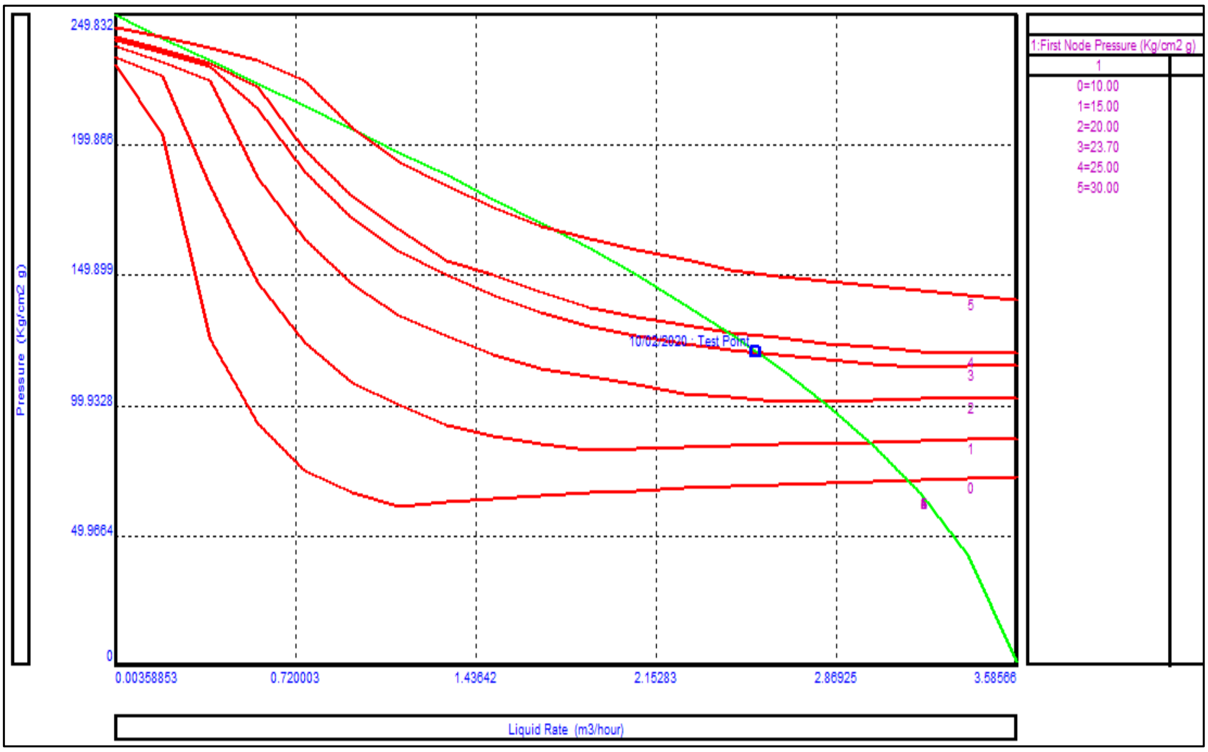


Figure 3.22: Sensitivities on WHP

Results

We remark that the oil rate increases when the WHP is reduced and it indicates to OMM202 very sensitive towards the variation of the wellhead pressure.

3.5.4 Sensitivity analysis on GOR

Last scenario is the implementation of different Gas Oil Ratio values and the action on OMM202 to whether consider the artificial lift solution. And the results are as shown in **Figure 3.23.**

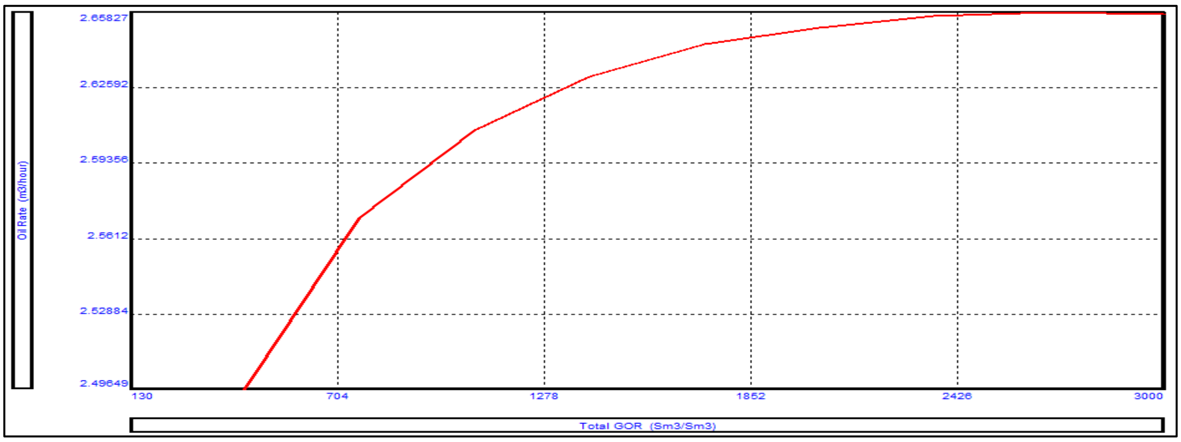


Figure 3.23: Sensitivities on GOR

Results

The observation on the sensitivity is the oil rate increases alongside the increase of GOR but the increase is barely notable with 0.1 m^3/hour.

3.6 Conclusion

We have completed an important phase into the optimization of the performance of OMM202 after we established the well modelling workflow via PROSPER platform and the update to its recent condition the well is producing under, we carried a group of cases of sensitivities on skin, GOR, reservoir pressure and wellhead pressure as they have an important role into the increase of oil rate and precede to the network modelling and optimization phase so we could integrate the wells models of OMM202 and OMM412 to complete our work.

Chapter 4

Network Modelling and Optimization

4.1 Introduction

Making designs and optimisations for wells, and surface facilities without taking into account the network, may result in production losses or investing in the wrong area.

In this chapter, the evaluation of production enhancement by using the new technology SJP for two (HP-LP) producing wells had been performed using GAP software, and print screens of well OMM202 had been used as representative samples in this section.

4.2 System description

The wells OMM412 & OMM202 were selected to be respectively motive well, and motivated well for surface jet pump, based on these criteria:

- Motive well: should have high well head pressure, in OMM412 case WHP = 67.4 Bars and FLP = 46.7 Bars.
- Motivated well: should have low well head pressure, in OMM202 case WHP = 23.7 Bars and FLP = 15.6 Bars.
- Low differential pressure across the choke for LP well, ΔP = 8 Bars.
- Flow line pressure too high for HP well, FLP = 46.7 Bars.

Problems statement:

- Since 2016, OMM202 has faced a sharp decline in production, from 6.5 Sm^3/h to 2.62 Sm^3/h (currently).
- OMM202 required an artificial lifting.
- Due to OMM202 location, it will be costly to extend gas lift network (the nearer manifold of GL is MD403 which is 3 km away).
- ESP isn't an option due to the absence of electricity in the area plus, flow assurance issues.

Wells description:

In our case study, the location of wells candidate for SJP is given in **Figure 4.1** (HP well is OMM 412 and LP well is OMM 202), and **Table 4.1** represents their flowline specification.

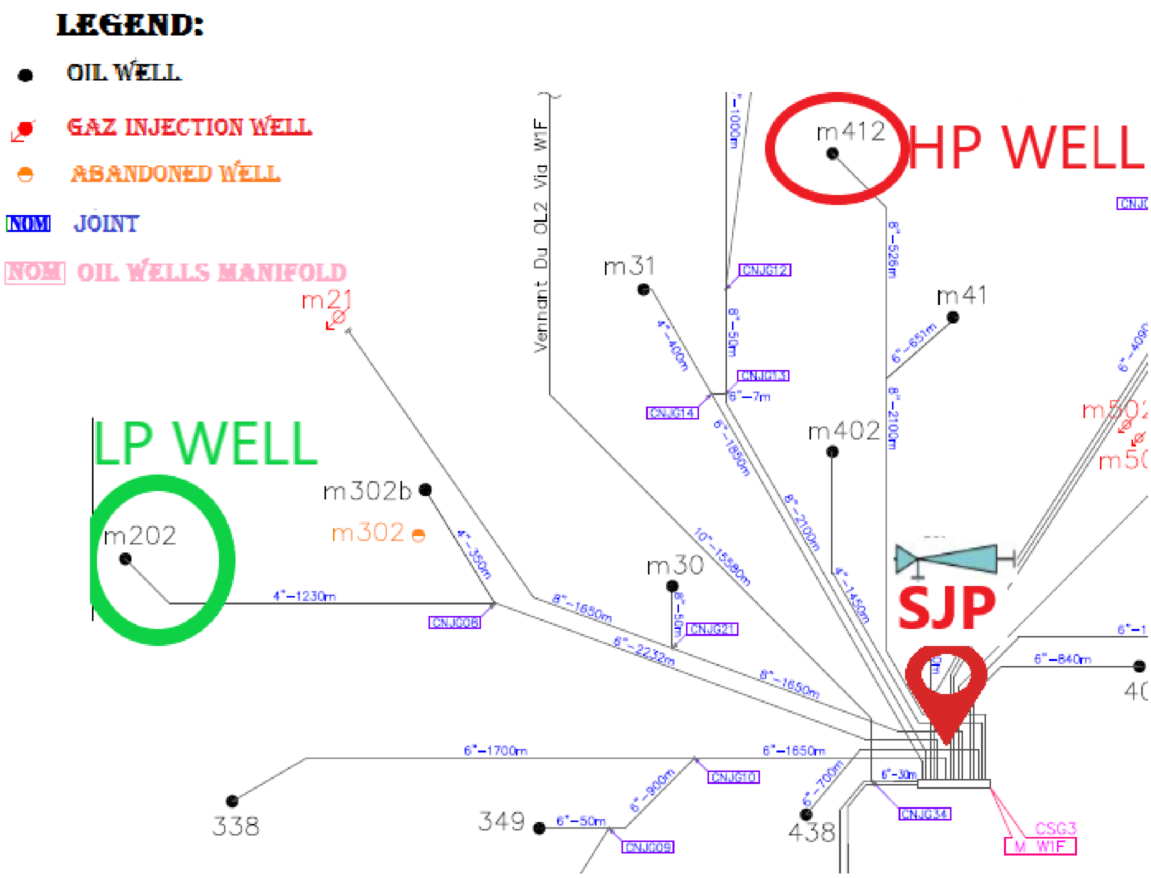


Figure 4.1: SJP selected wells candidates

Table 4.1: Flowline specification of wells candidates for SJP case study

Well name	Sub-manifold name	Manifold name	Nominal diameter (Inch)	Flowline length (Meter)	Design pressure (Bars)	Design temperature (°C)	Material
OMM 412	W1F	W1C	8	2626	90	-10 / +125	API 5L GRADE B
OMM 202	W1F	W1C	4	1230			
			6	2232			

4.3 Surface network modelling

4.3.1 Defining system options

This option allows setting up overall system parameters. The following system options had been defined for this GAP model.

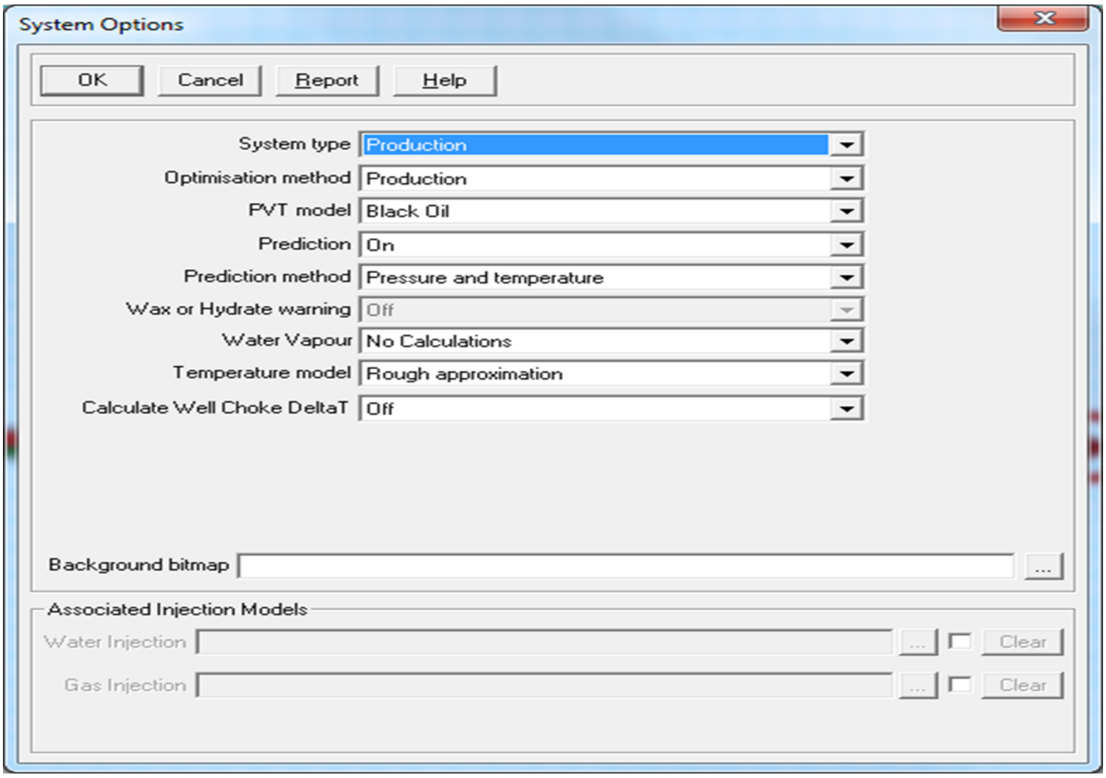


Figure 4.2: GAP options

Other options can be set for the suitable applications.

4.3.2 Drawing system schematic

The system drawing in **Figure 4.4** had been prepared according to the production network of wells candidate for SJP in WIF sub-manifold of Hassi Messouad Field **(Figure 4.1)**

First, define end point for production fluids by adding a separator:

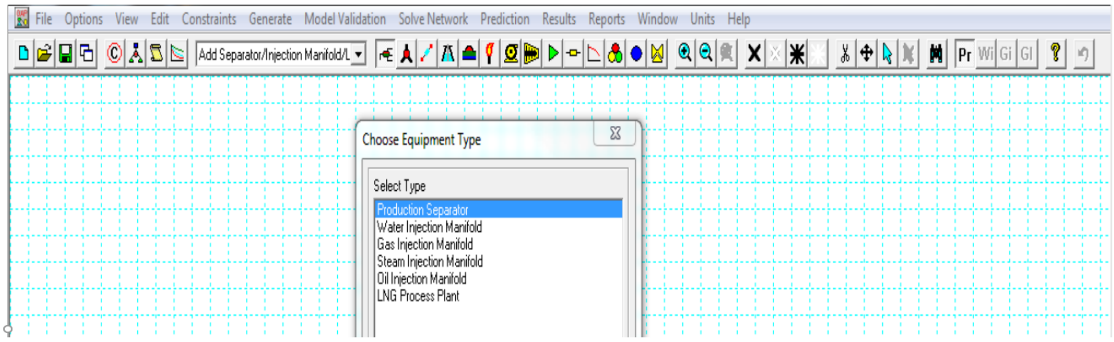


Figure 4.3: Insert production separator

In our thesis work, there are only two wells, two chokes, two pipe line segments and a separator.

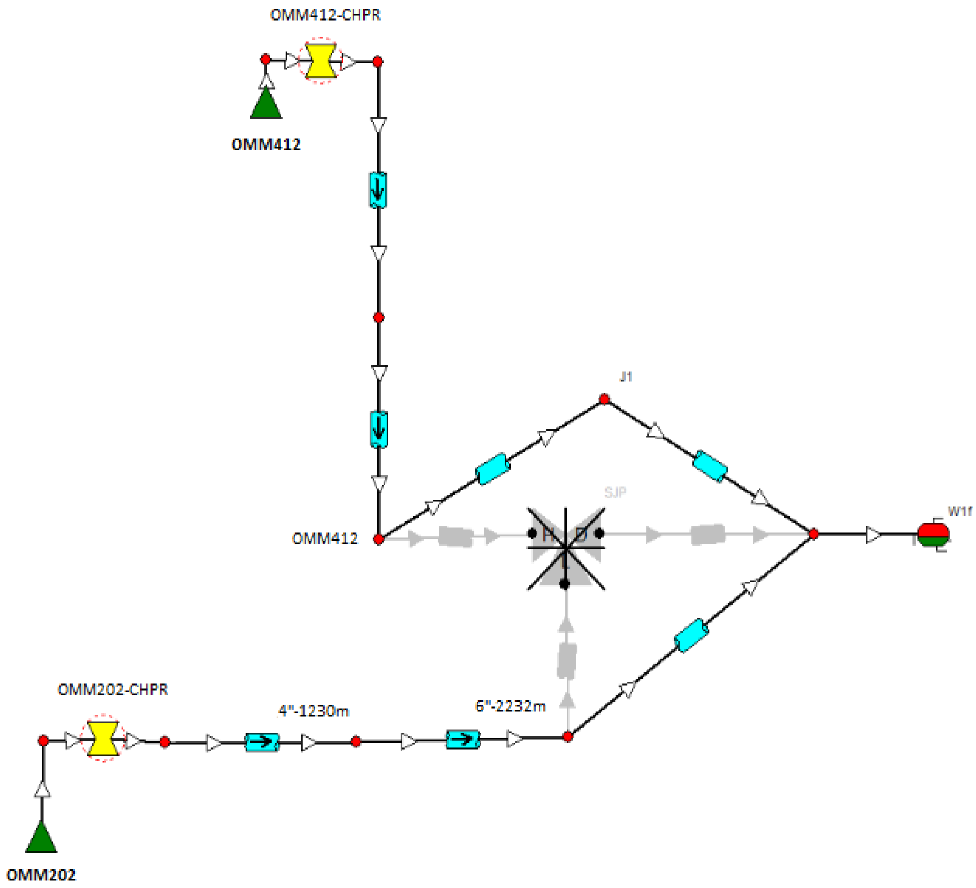


Figure 4.4: A complete GAP model structure of our base case study

It's a good idea to save GAP model often especially during the initial model construction stages.

4.3.3 Generate & validate well IPRs and VLPs

- **Attach well models to GAP model**

To attach a previously prepared well model to GAP, a well model must be created, properly calibrated, checked for consistency, and VLP table generated.

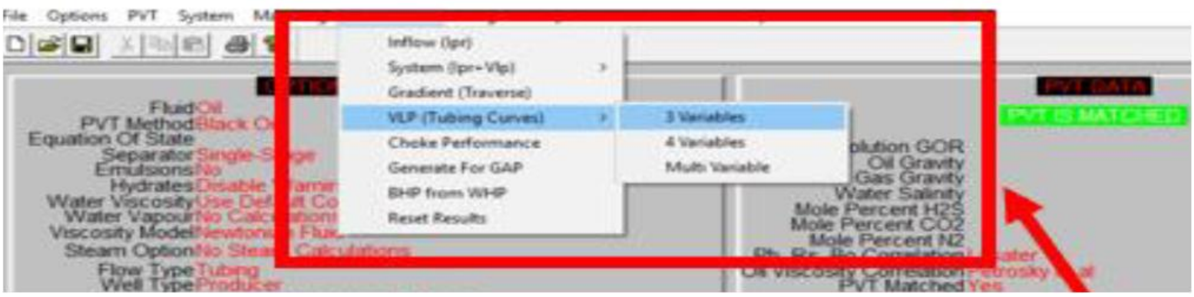


Figure 4.5: Generating the lift curves in PROSPER

For describing the input data for individual well in GAP program, print screens of well OMM202 had been used as representative samples in this section. The well OMM412 can be done in a similar manner.

In GAP main panel, double click on Well to bring up well dialogue and click Browse Icon next to PROSPER File Field to select well model to be inserted to well in GAP.

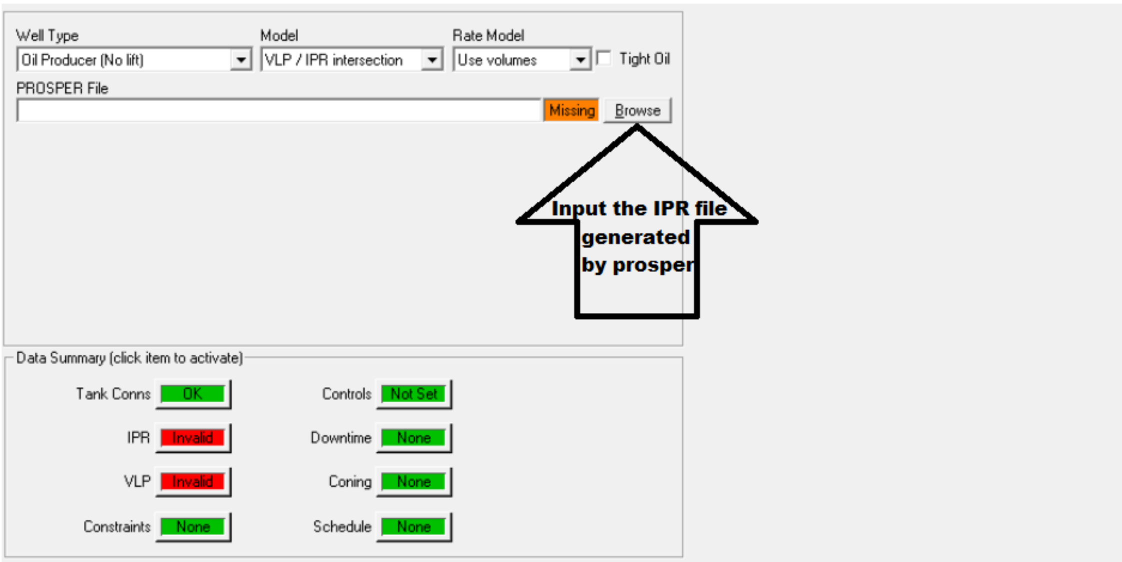


Figure 4.6: Inputting the generated IPR file from PROSPER into GAP

- **Define well types in GAP**

The wells OMM202 and OMM412 keep the default setting for natural flowing well.

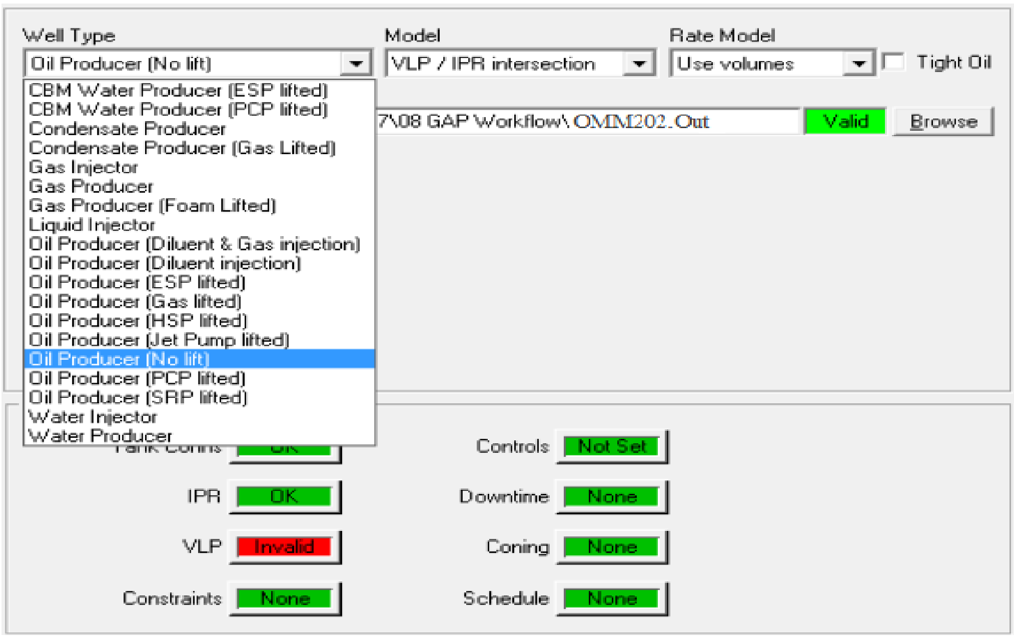


Figure 4.7: Leave well type as oil producer (no Lift) for well OMM202

- **Generate IPRs**

IPRs generate for all the wells by follow these steps: Generate -> Generate IPR from Prosper Models

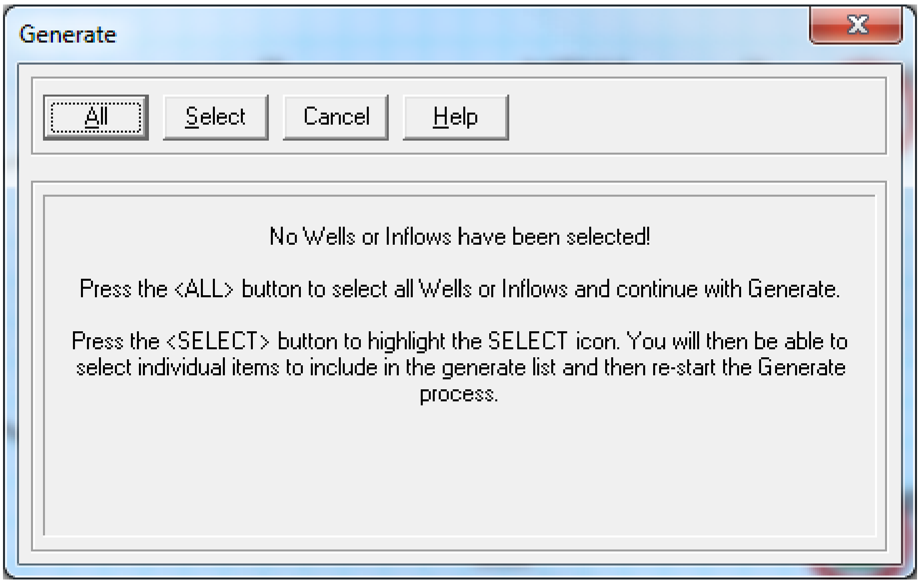


Figure 4.8: Get ready to generate IPR curves for all wells

- **Input VLP**

To import VLP table for well, double click on Well Icon in GAP work space. Then, select VLP table file by click Browse Icon next VLP Table Field.

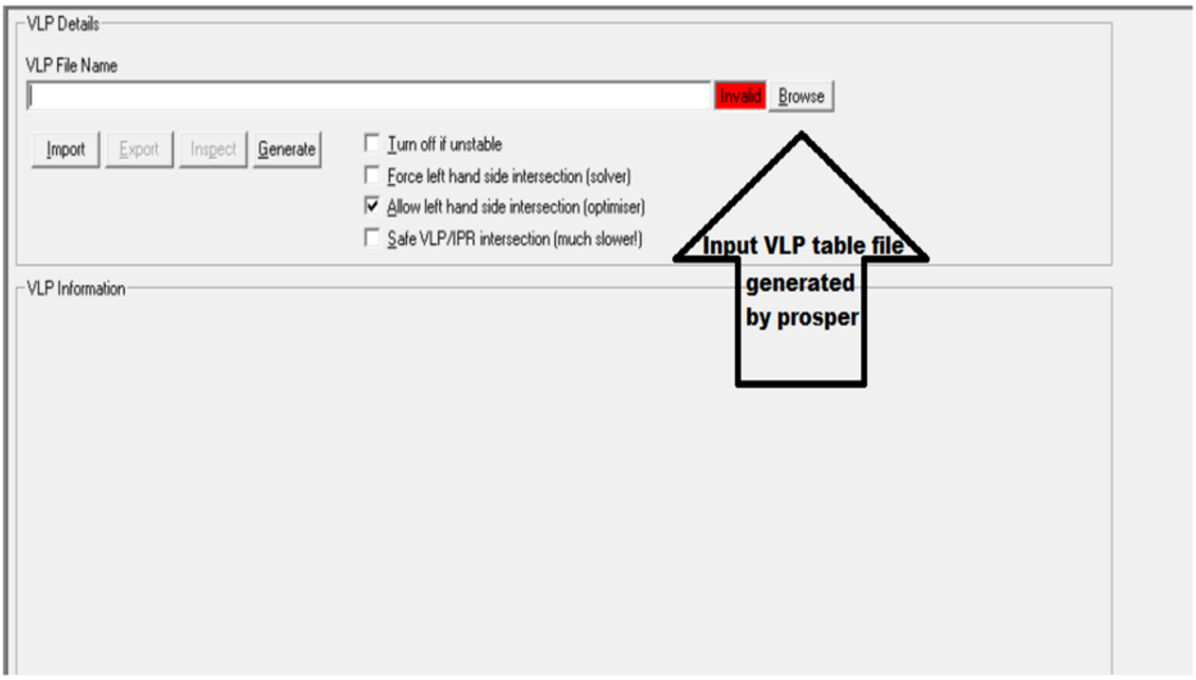


Figure 4.9: VLP file name import field in GAP for wells

4.3.4 Choke data

To add data for choke, double click on Choke Icon.

Insert choke size for well OMM202 - 09mm.

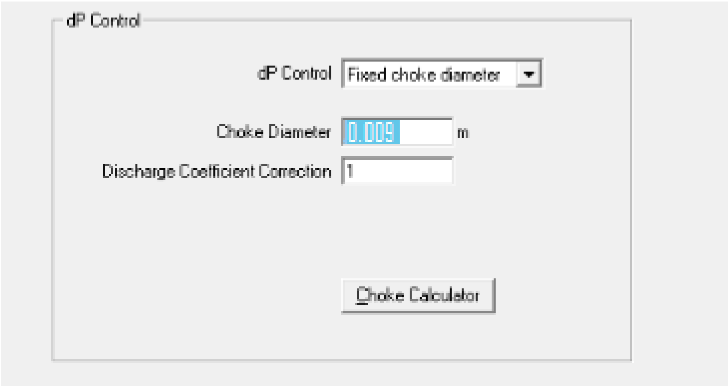


Figure 4.10: Input choke size for well OMM202 - 09mm

Note the color change for choke of OMM202.

4.3.5 Pipe data

To add pipeline data to GAP model, double click Pipeline Icon on a pipe in the GAP model. The pipeline data dialogue will show up as shown below.

Input 30C, it is the actual temperature value for surrounding of the pipeline.

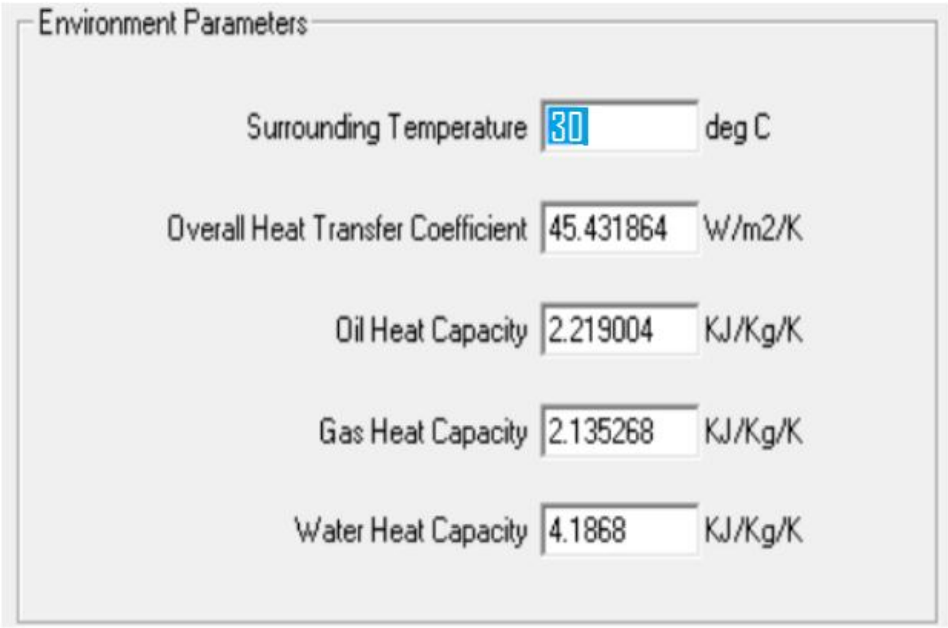


Figure 4.11: Input environmental parameters for pipeline

- **Description**

A general description of the pipeline data for HP-LP wells is given in **Table 4.2**.

Table 4.2: Pipeline data

Well	Nominal diameter (Inch)	Inside diameter (Inch)	Length (Meter)	Elevation (Meter)	Roughness (Millimeter)
OMM412	8	7.981	2626	1.52	0.0018
OMM202	4	4.026	1230	2.17	0.0018
	6	6.065	2232	1.94	0.0018

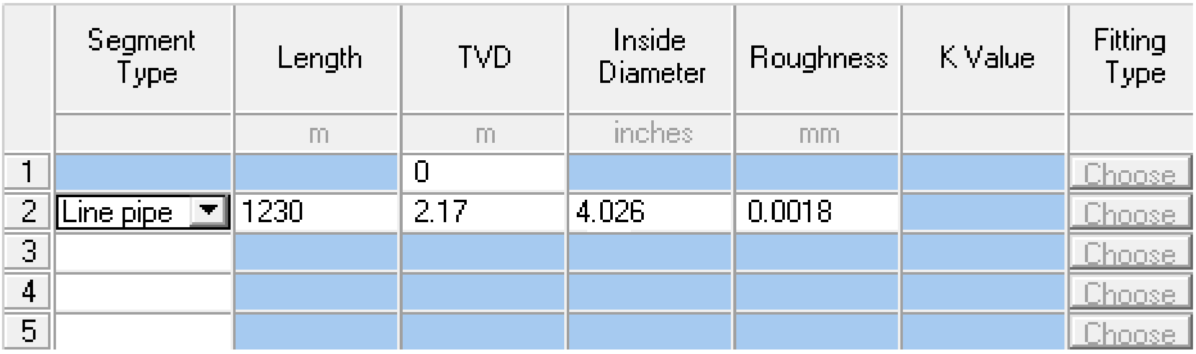


Figure 4.12: Dialogue for pipeline data input for well OMM202

Note that more pipe segments can be entered similarly.

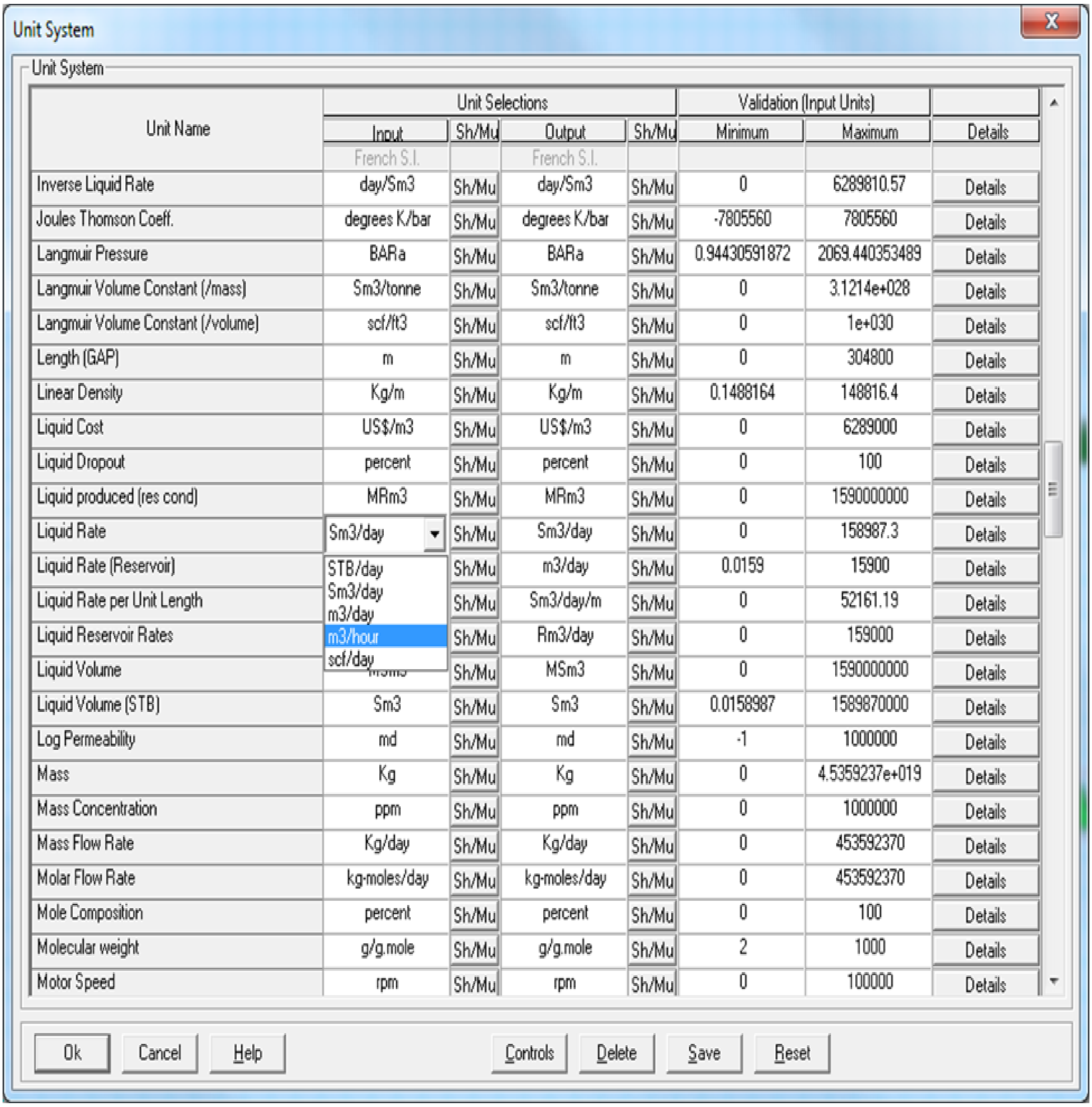
Once all pipeline data are entered, the GAP model is fully defined.

4.3.6 Matching our pipe lines data

Input the test data, then we will click on the Match button and choose the correlation that best fits. Petroleum Expert 2 is the correlation that best represents the behaviour of the fluid through surface installations. Parameter 1 (gravity coefficient) was found 1.00 and Parameter 2 (friction coefficient) was found 1.14, which showed very close to unity.

While suitable unit system can be selected, some specific units may need to be changed to meet the customary preferences. For example, oil rate is commonly reported as Sm^3/h in Hassi Messaoud.

To change a specific unit, click on Units => Edit Units to bring up Units Editing Dialogue as shown below to make the desired changes.



Unit Name	Unit Selections: Input (French S.I.)	Sh/Mu	Output (French S.I.)	Sh/Mu	Validation (Input Units): Minimum	Maximum	Details
Inverse Liquid Rate	day/Sm3	Sh/Mu	day/Sm3	Sh/Mu	0	6289810.57	Details
Joules Thomson Coeff.	degrees K/bar	Sh/Mu	degrees K/bar	Sh/Mu	-7805560	7805560	Details
Langmuir Pressure	BARa	Sh/Mu	BARa	Sh/Mu	0.94430591872	2069.440353489	Details
Langmuir Volume Constant (/mass)	Sm3/tonne	Sh/Mu	Sm3/tonne	Sh/Mu	0	3.1214e+028	Details
Langmuir Volume Constant (/volume)	scf/ft3	Sh/Mu	scf/ft3	Sh/Mu	0	1e+030	Details
Length (GAP)	m	Sh/Mu	m	Sh/Mu	0	304800	Details
Linear Density	Kg/m	Sh/Mu	Kg/m	Sh/Mu	0.1488164	148816.4	Details
Liquid Cost	US$/m3	Sh/Mu	US$/m3	Sh/Mu	0	6289000	Details
Liquid Dropout	percent	Sh/Mu	percent	Sh/Mu	0	100	Details
Liquid produced (res cond)	MRm3	Sh/Mu	MRm3	Sh/Mu	0	1590000000	Details
Liquid Rate	Sm3/day	Sh/Mu	Sm3/day	Sh/Mu	0	158987.3	Details
Liquid Rate (Reservoir)		Sh/Mu	m3/day	Sh/Mu	0.0159	15900	Details
Liquid Rate per Unit Length		Sh/Mu	Sm3/day/m	Sh/Mu	0	52161.19	Details
Liquid Reservoir Rates		Sh/Mu	Rm3/day	Sh/Mu	0	159000	Details
Liquid Volume		Sh/Mu	MSm3	Sh/Mu	0	1590000000	Details
Liquid Volume (STB)	Sm3	Sh/Mu	Sm3	Sh/Mu	0.0158987	1589870000	Details
Log Permeability	md	Sh/Mu	md	Sh/Mu	-1	1000000	Details
Mass	Kg	Sh/Mu	Kg	Sh/Mu	0	4.5359237e+019	Details
Mass Concentration	ppm	Sh/Mu	ppm	Sh/Mu	0	1000000	Details
Mass Flow Rate	Kg/day	Sh/Mu	Kg/day	Sh/Mu	0	453592370	Details
Molar Flow Rate	kg-moles/day	Sh/Mu	kg-moles/day	Sh/Mu	0	453592370	Details
Mole Composition	percent	Sh/Mu	percent	Sh/Mu	0	100	Details
Molecular weight	g/g.mole	Sh/Mu	g/g.mole	Sh/Mu	2	1000	Details
Motor Speed	rpm	Sh/Mu	rpm	Sh/Mu	0	100000	Details

Figure 4.13: Unit change dialogue

4.3.7 Run GAP

To run GAP model, click Run Network Solver Icon as shown below:

Figure 4.14: Solving the network in GAP

Nest, a dialogue will appear to accommodate input for the separator pressure.

Insert separator pressure for manifold W1F – 9 Bars.

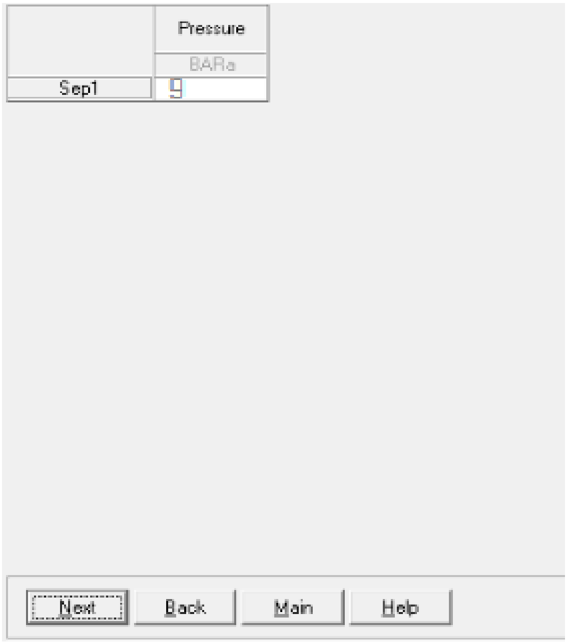


Figure 4.15: Input for separator pressure

Now, GAP model is ready to run. There are a few modes to run GAP models for different situations. Select the mode "No Optimization" for simulation run.

4.4 Results from the GAP model

One can examine the simulation results by placing cursor on any element in the GAP model. These results can also be exported as needed.

Well oil rate for OMM202 from GAP simulation is 2.46 Sm^3/h – very close to the oil rate of 2.63 Sm^3/h reported in gauging test.

In addition, well oil rate for OMM412 from GAP simulation is 4.02 Sm^3/h – very close to the oil rate of 4.16 Sm^3/h reported in gauging test.

We have to calculate the error percentage, to check if our model is reliable.

Error estimate:

$$E = \frac{(\text{measured parameter} - \text{calculated parameter})}{\text{calculated parameter}} * 100$$

The actual total rate: 6.79 Sm^3/h.

The calculated total rate: 6.48 Sm^3/h.

The error from the model and the actual total rate is of 4.7%, which is acceptable.

4.5 Sensitivities

Once the model is matched, it can be used to evaluate impacts from different operating conditions. Here is impact of SJP in total production from LP-HP wells.

4.5.1 Optimisation by SJP

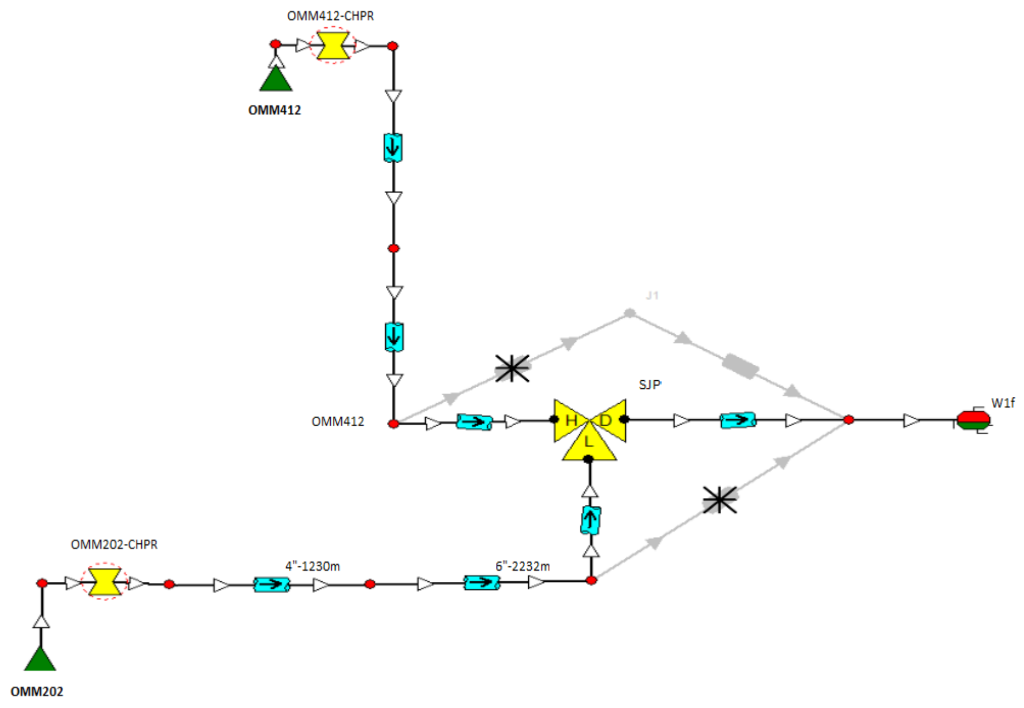


Figure 4.16: A complete GAP model structure with SJP for our case study

Base case:

- OMM412 produce 100 Sm3/day, with WHP = 67.4 Bars and FLP = 46.7 Bars.
- OMM202 produce 63 Sm3/day, with WHP = 23.7 Bars and FLP = 15.6 Bars.

Simulation results with implementing SJP:

- Fixed the HP well oil rate and observe the incremental from the LP well at different flow line pressure on HP side / Inlet pressure for SJP.
- Operating pressure limited to 50 Bars in the flow line. It realized the 45 Bars is good enough to boost OMM202 production up to 11 Sm^3/day and maintain stable production.
- Expected drop is around 9 Bars on OMM202 well head pressure.

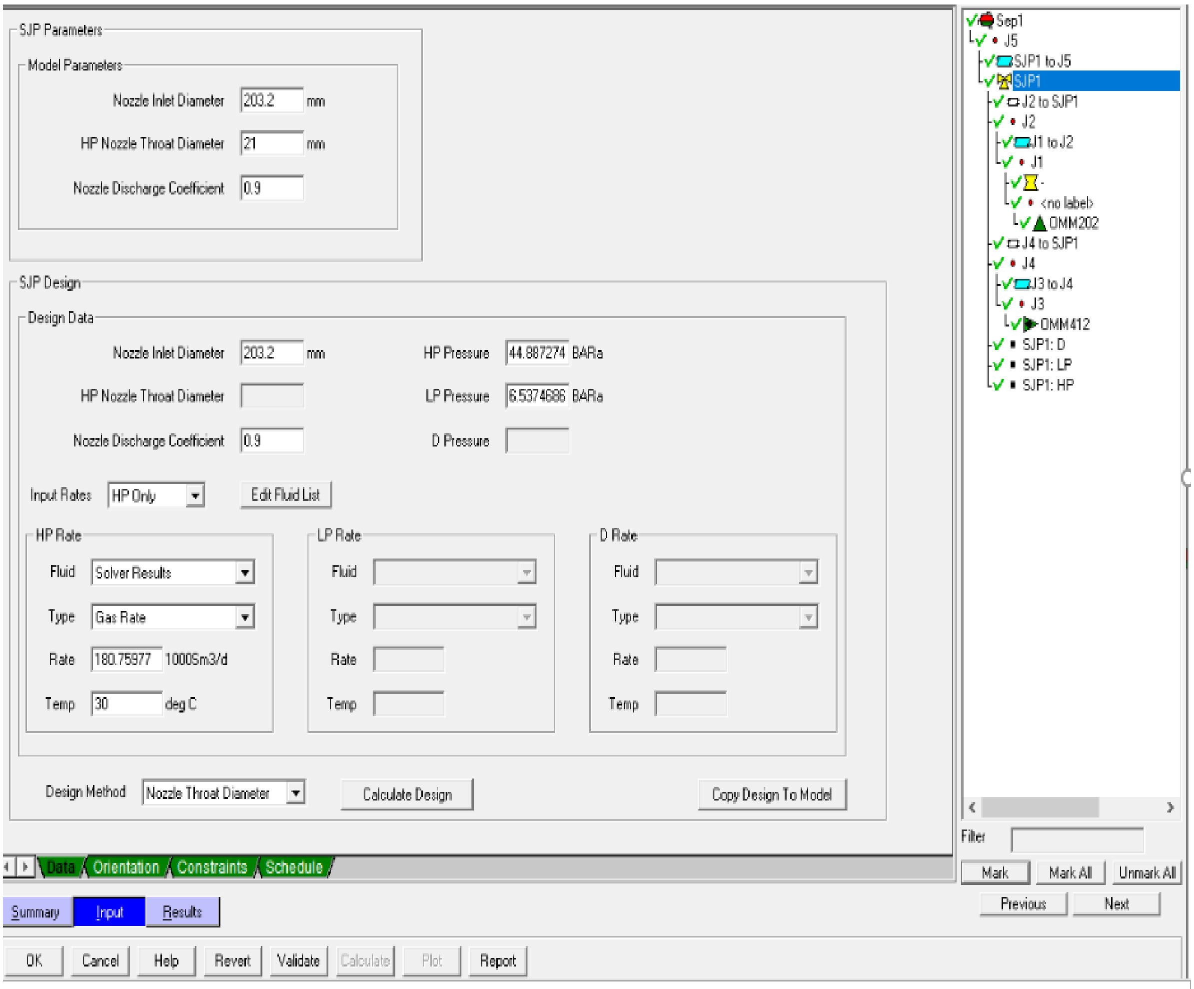


Figure 4.17: Input for SJP parameter

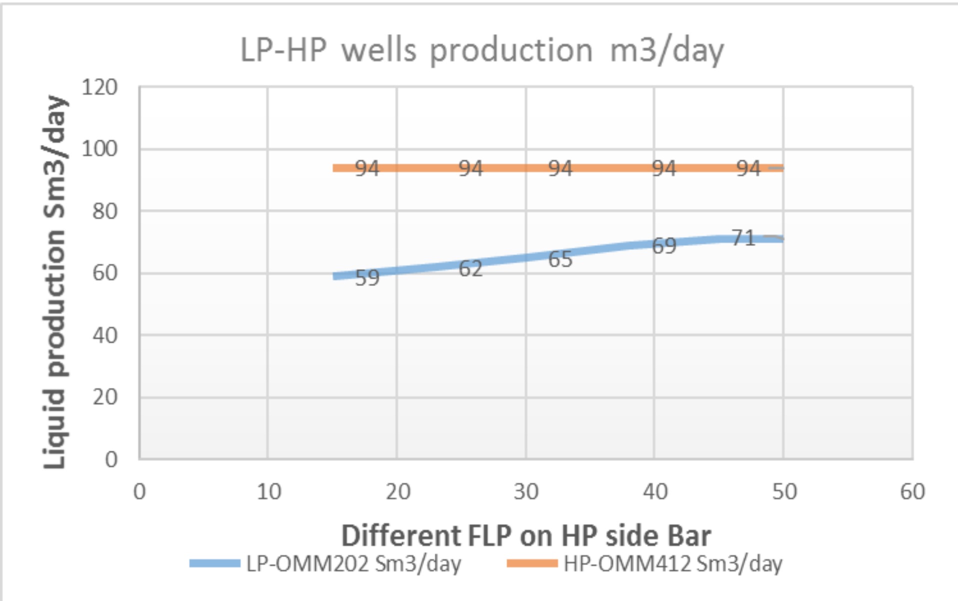


Figure 4.18: LP-HP wells production Sm^3/day at different flow line pressure on HP side

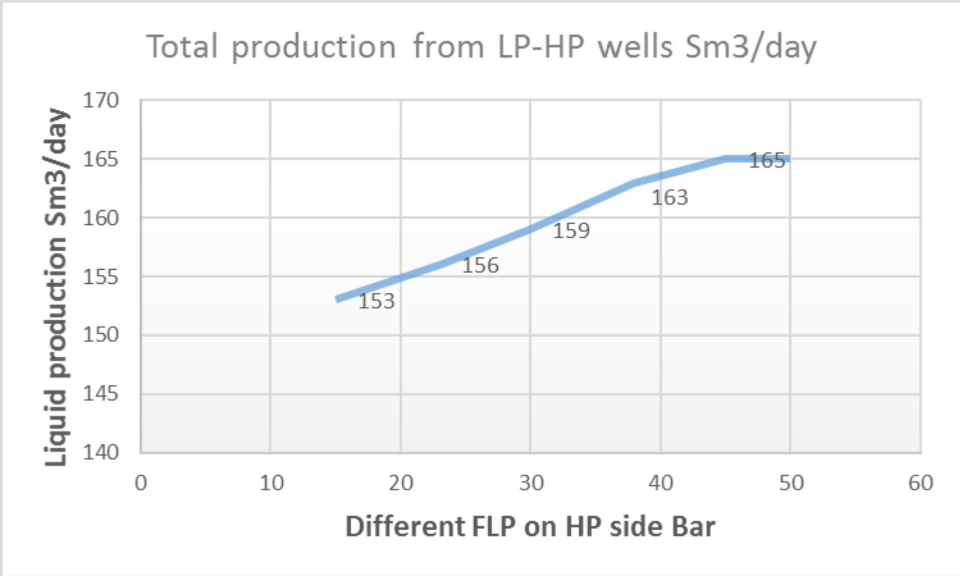


Figure 4.19: Total production from LP-HP wells Sm^3/day at different flow line pressure on HP side

4.6 Conclusion

Any investment or changes should take into account the effect on the network, most of the investment on the network for the wells with gas lift injection is likely to increase the production.

Due to OMM202 location, it will be costly to extend gas lift network but with the aid of SJP, LP well can get benefits utilizing energy of HP well.

Finally, SJP will help to unlock the high-pressure wells production potential without negatively impacts the low-pressure wells in the network, where you can recognize the maximum return of investment.

Conclusion and Recommendation

General Conclusion and Recommendation

General Conclusion

Petroleum Engineering need a powerful tool to achieve many important tasks, for example: PROSPER software assists the production or reservoir engineer to predict tubing and pipeline hydraulics and temperature with accuracy and speed, in addition, GAP software is very general and has many functions for production and injection systems.

Data necessary to model the wells and the network is gathered, wells and network model are generated and matched, sensitivities are run to evaluate and optimise the existing system. On field trips took place to confirm the results. Discussions were conducted with the people responsible to learn the real limitation and to be able to propose realisable and non-costly solutions.

Surface Jet Pumps (SJPs) are simple, low cost, passive devices which use a high pressure (HP) fluid as the motive force to boost the pressure of produced gas and liquid phases. The performance of the SJP is assessed simply by noting the dP, the difference between the discharge and the LP pressure of the SJP. The discharge pressure is not controlled by the SJP and is mainly dictated by the downstream pipeline and production system. The SJP, however, responds to changes in the parameters which affect its performance by adjusting the LP pressure which it generates.

Obtaining the optimum oil rate is important but any investment or changes should take into account the effect on the network, may result in production losses and increases operation cost. To obtain the optimum oil production rate in our case study, all wells had been modelled properly. Flash data of recombined reservoir fluid had been used for PVT matching. Lasater’s and Petrosky’s correlations were found best-fit correlation for PVT matching.

Since the reservoir parameter is continuously changing from inception of production, current well test data was the focus for quality checking of well test data. In this work, it was found that current well test data for all wells had been matched with calculated data in Prosper. For correlation comparison of VLP, Hagedorn and Brown’s correlation was found very close to well test data for all well tests. Parameter 1 and 2 was close to unity. Thus, HB correlation had been used for VLP matching in Prosper. While matching surface flow line in Gap program, Petroleum Expert 2 was found the best-fit correlation for production and test flow line. Calculated manifold pressure was compared with the measured wellhead pressure and found very close results.

General Conclusion and Recommendation

Presently average total oil production rate of HP-LP wells is around 163 Sm3/day. From simulation result of GAP program, maximum oil production rate was achieved 172 Sm3/day at operating pressure limited to 50 Bars in the flow line. It realized the 45 Bars is good enough to boost OMM202 production up to 11 Sm3/day and maintain stable production when we fixed the HP well oil rate and observe the incremental from the LP well at different flow line pressure on HP side / Inlet pressure for SJP Production.

Finally, SJP will help to unlock the high-pressure wells production potential without negatively impacts the low-pressure wells in the network, where you can recognize the maximum return of investment.

Recommendation

- Typical (minimum) HP to LP pressure ratio should be 2 or higher
- Typical HP flowrate should be equal to or more than the LP flow
- For installation of SJP a by-pass line is recommended for both HP and LP sources
- Preferable location of SJP is at the manifold where the HP and LP wells meet, in order to minimise pipework
- LP well candidate selection for best results & minimising costs:
  - Select well which will respond to lowering of WHP
  - choose wells with low water cut
  - Review production history of the LP wells
- HP Candidate well Selection-General:
  - The HP well provides the power (motive force) for the SJP to do its work (i.e. to lower the FWHP of the LP well)
  - The SJP does not sacrifice any of the flow from the HP well. It is normally designed to utilise the maximum HP flow and pressure available
  - Even if the flow from the HP well has to be reduced slightly for operational reasons, this is differed production and is not lost production
- The prerequisites for GAP models are:
  - The well models were created and matched to the most recent jageages for these wells
  - The vertical lift performance (VLP) tables have been generated in Prosper for these wells
  - The well models and pipeline data for these wells will be used to create a GAP model
- operating pressure limited to 50 Bars in the flow line

General Conclusion and Recommendation

- It realized the 45 Bars is good enough to boost OMM202 production up to 11 Sm3/day and maintain stable production when we fixed the HP well oil rate and observe the incremental from the LP well at different flow line pressure on HP side / Inlet pressure for SJP Production.

References

References

[1] Tetoros E. Ioannis. (2015). Design of a continuous gas lift system to initiate production in a dead well. MSc Thesis. Technical university of Crete, School of mineral resources engineering

[2] James Lea, Henry V. Nickens, Michael wells. (2011). Gas well deliquification: solutions to gas well loading problems.

[3] (2011). Production Technology Heriot Watt University. Institute of Petroleum Engineering.

[4] Boyun, G. (2007). Petroleum Production Engineering. A Computer-Assisted Approach, 1st Edition

[5] Ahmed, T. (2010). Reservoir Engineering Handbook Reservoir Engineering Handbook

[6] Evinger, H.H. and Muskat, M. (1942). Calculation of Theoretical Productivity Factor Trans., AIME 146, 126.

[7] Vogel, J.V. (1968). Inflow Performance Relationships for Solution-Gas Drive Wells. J. Pet.

[8] Beggs H. (2008), Production Optimization Using Nodal Analysis. Oil & Gas Consultants, 2nd edition.

[9] Golan, M., & Whitson, C. H. (1991). Well performance. Englewood Cliffs. N.J: Prentice Hall.

[10] PetroWiki, (2015). Wellbore flow performance. http://petrowiki.org/Wellbore_flow_performance,

[11] (2005). Handbook of Multiphase Flow Metering. Norwegian Society for Oil and Gas Measurement (NFOGM).

[12] Gaurav, N. (2008). Flow regime transitions during condensation in microchannels. MSc thesis. Georgia Institute of Technology

References

[13] Ali F., (2009). Two phase flow in large diameter vertical riser. Phd Thesis. Cranfied University, School of Engineering

[14] BERRAHAL Sara. (2017). Modélisation & optimisation (puits, réseau collecte) du champ RAMA. Induction Final Project. SONATRACH Society.

[15] M. M. (Sacha) SARSHAR (CALTEC), M. VILLA, F. PAONE (AGIP SPA) W.L.LOH, N. A. BEG (CALTEC). (1997). Field Testing and Applications of WELLCOM System Using Jet Pump Technology (pp. 1-15). Papers presented at the 8th International Conference on Multiphase *97, organized and sponsored by BHR Group limited. Held in Cannes, France on 18-20 June 1997.

[16] SONATRACH-HALLIBURTON. (2020). FMIS Surface Jet Pump Pilot & Prosper Analyses (pp. 3). Held in Hassi Messaoud, Ouargla, Algeria on 3 January 2020.

[17] Dr Najam Beg. (February 2019). Enhancing Oil & Gas Production with Surface Jet Pump (SJP) (pp. 3-42). CALTEC's Surface Jet Pump (SJP) Patented Technology.

[18] Syed M Peeran, Dr Najam Beg & Sacha Sarshar (CALTEC Ltd UK). (2013). SPE 164256 Novel Examples of the use of Surface Jet Pumps (SJPS) To Enhance Production & Processing: Case Studies and Lessons Learned (pp. 1-8). Society of Petroleum Engineers Copyright. Paper was prepared for presentation at the SPE Middle East Oil and Gas Show and Conference. Held in Manama, Bahrain. On 10–13 March 2013.

[19] Dr Najam Beg & Syed Peeran. (March 2019). Well Candidate Selection Guidelines (pp. 9-12). CALTEC's Surface Jet Pump (SJP) Patented Technology.

[20] Dr Najam Beg. The Applications of Surface Jet Pump Technology to Increase Oil and Gas Production (pp. 11-44). On 27 September 2011.

[21] Petroleum Experts, *Prosper User Manual*, Single Well Systems Analysis, Version 13.0, June 2014.