Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Natural Sciences
Department of Chemical Engineering

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Jet Pump Technology for Enhanced Oil Production

Master's thesis in Chemical Engineering and Biotechnology
Supervisor: Magne Hillestad
June 2019

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Abstract

Maturing oil fields often experience production depletion of oil wells due to decreasing pressure, increasing water cut and depletion of the reservoir. Ula oil field have been in operation since 1986 and have several wells that are challenging to operate. The present aid to help these wells is a gas lift solution. This requires pressurized gas which is an energy demanding supply source. Jet pump technology is proposed as an alternative boosting solution. It utilizes a high pressure fluid and the Venturi effect to lower backpressure in a low pressure well and thus boost production rates.

In this report, investigations on the performance and potential production boost of different jet pump solutions were done. Three different high pressure fluid sources were considered, injection gas, injection water and high pressure well fluid. Performance data of different cases were developed in cooperation with Caltec Production Solutions. Production boost was estimated using well performance curves.

An injection water rate of 6402 bbl/d gave an estimated oil production boost of 627 bbl/d in total when routing all four low pressure wells to the jet pump. The required amount of injection water is a portion of the water which is in excess from water injection pumps and thus a power source which would otherwise go to waste.

A jet pump solution driven by injection gas must include in-line separation of the suction fluid. The required amount of injection gas to get the same production increase of 627 bbl/d was estimated to 6248 Mscf/d.

The final solution utilize energy in liquids from high pressure wells, a power source which is usually wasted. The estimated production boost was 620 bbl/d of oil when using one well to lower the backpressure of two low pressure wells to 7 barg.

A simplified safety analysis of the different solutions were conducted. Using injection water or gas as driving source were found to require an addition of pressure safety barriers, hereunder a pressure safety valve. The use of high pressure wells to drive the jet pump implicated no requirements of new safety devices.

Sammendrag

Aldrende oljefelt opplever ofte fallende produksjon i enkelte brønner som følge av lavere trykk, økende vannmengder og endrede reservoaregenskaper. Ula-platformen har vært i drift siden 1986 og har flere slike brønner. Metoden som brukes på Ula i dag for å hjelpe på produksjonen er gassløft-teknologien. Denne løsningen bruker komprimert gass, noe som gjør det til en energikrevende løsning. En jetpumpe ble foreslått som en alternativ løsning for å øke produksjon og forlenge levetiden til oljefeltet. Den benytter en væske- eller gasstrøm og Venturi-effekten til å senke mottrykket i en lavtrykksbrønn og dermed øke produksjonen.

Denne masteroppgaven tok for seg ulike jetpumpeløsninger og undersøkte ytelse og potensiell produksjonsøkning ved ulik anvendelse av jetpumpene. Tre ulike kilder til drivstrøm ble vurdert, injeksjonsgass, injeksjonsvann og væske fra høytrykksbrønner. Det ble inngått et samarbeid med Caltec Production Solutions for å beregne ytelse. Produksjonskurver for de enkelte brønnene ble brukt for å estimere økt produksjon med jetpumpen.

En strøm injeksjonsvann på 6402 bbl/d ga en estimert produksjonsøkning på totalt 627 bbl/d når alle fire lavtrykksbrønner ble ledet til jetpumpen. Injeksjonsvannet er i overskudd når begge vanninjeksjonspumpene er i drift og er dermed en energikilde som ellers ville gå tapt.

Et arrangement med jetpumpe drevet med injeksjonsgass må inkludere "in-line" separasjon av lavtrykksstrømmen slik at kun gass ledes inn i jetpumpen. Den nødvendige mengden injeksjonsgass for å få samme produksjonsøkning på 627 bbl/d ble estimert til 6248 Mscf/d.

Det siste jetpumpearrangementet bruker energien i væskestrømmen fra høytrykksbrønner, en energikilde som vanligvis går til spille ved at trykket i brønnstrømmen reduseres over choke-ventilen. Den estimerte produksjonsøkningen i det tilfellet hvor en høytrykksbrønn ble bruk til å redusere mottrykket i en lavtrykksbrønn til 7 barg var 620 bbl/d olje.

En forenklet sikkerhetsanalyse ble gjort for de ulike løsningene. Den viste at nye sikkerhetsbarrierer, blant annet en trykksikkerhetsventil, var nødvendig dersom injeksjonsgass eller injeksjonsvann var drivkilden. For løsningen med brønnstrøm som drivkilde var ikke nytt utstyr påkrevd.

Acknowledgements

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I would like to express my gratitude to my supervisor at IKP, Professor Magne Hillestad, for patience, valuable advise and support during the semester.

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Finally, Jet pump Technology vendor and supplier Endúr Energy Solutions and Caltec Production Solutions have provided technical data for the work in this thesis. I would like to thank them for allowing me to use their data and especially Dr. Najam Beg, Technology Director at Caltec for providing a lot of advice and insight on Jet Pump Technology.

Emilie Wattø Larsen Trondheim, 19/6 - 2019

Emilie Wattø Larsen Place, Date

Contents

List of Figures

List of Tables

List of Abbreviations

BHP	Bottom hole pressure
GLR	Gas liquid ratio
GOR	Gas oil ratio
GVF	Gas volume fraction
HP	High pressure
LP	Low pressure
MAWP	Maximum allowable working pressure
MP	Medium pressure
PRD	Pressure relief device
PST	Pressure safety transmitter
PSV	Pressure safety valve
SAC	Safety analysis checklist
SAT	Safety analysis table
TST	Temperature safety transmiter
WAG	Water alternating gas
WHP	Wellhead pressure

List of Symbols

Table 0.0.1: List of symbols.

Symbol	Unit	Description
P/p	barg	Pressure
T	$^\circ C$	Temperature
v	m/s	Velocity
g	-	gravitational acceleration
z	m	Elevation
ρ	kg/m^3	Density
f_f	-	Fanning friction factor
L	m	Tubing length
u	m/s	Fluid velocity
D	m	Tubing inner diameter
R	-	Area ratio
A_j	m^2	Cross-sectional area of nozzle
A_t	m^2	Cross-sectional area of throat
q	misc.	Flow rate
M	-	Flow ratio
H	-	Pressure head
η_p	%	Jet pump efficiency
GVF	-	Gas volume fraction
GLR	scf/bbl	Gas liquid ratio
GOR	scf/bbl	Gas oil ratio
μ	cP	Viscosity
c	kJ/kg-C	Heat capacity

1 Introduction

After years with oil prices well above $100 a barrel, prices decreased drastically summer of 2014. The oil price continued to drop and dipped below $35 in early 2016. It stayed below 60 $ for almost two years. Many companies had invested in projects with a much higher break-even price. Following this, large parts of the oil industry went into deep economical crisis. As Statistics Norway reported, over 20 000 jobs were cut over a three year period [27]. Oil prices have now increased, but is not forecasted to reach 2014-levels before 2040 [25].

The petroleum industry now has to adjust in order to profit of of their new projects and prolong the lifetime of already operating and aging assets. This means implementing technology which increases recovery and lower operating costs. Mature fields are therefore being redeveloped to reach higher recovery rates than earlier. These types of projects are known as brownfields. Payback time of such investments play a key role when companies decide on new investments.

The Norwegian Petroleum Directorate has estimated that only 45 % of the total recoverable oil reserves on the Norwegian Continental shelf has been retrieved [15]. A lot of the remaining reserves will however be much harder to retrieve than previous. This demands for better drilling technology as well as producing more of the retrievable resources.

Another motivation for increasing reservoir recovery rate, and perhaps more important from a holistic and global point of view is the fact that there is a limited amount of fossil fuels in the world. The world's energy consumption is continuously growing at the same time. The U.S. Energy Information Administration estimated a 28 % growth from 2015 to 2040 [24]. Strong economic growth in Asian Non-OECD countries, which includes China and India, is expected to contribute to more than half of the energy growth.

Large investments are put into expanding the renewable energy marked. However, the increase is not large enough to meet the needs of tomorrow and the demand for energy from fossil fuels will thus stay high in the foreseeable future. Investing in brownfields that contributes to decrease climate footprint of petroleum production should be a priority for the entire industry.

1.1 Ula Oil Field

The Ula oil field is located in the southern part of the North Sea and started production in 1986. Water depth at Ula is 70 meters and the reservoir is located 3500 meters below sea level [2]. Oil and gas from the reservoir are brought up the surface wellhead on the drilling platform, Ula D, and processed on Ula P. Produced fluids from the satellite fields Blane, Tambar and Oda are transported to and processed at the Ula platform. The produced oil is exported to Ekofisk and further to Teesside in the UK. Produced gas and water are reinjected into the reservoir to maintain reservoir pressure and thus increase oil recovery.

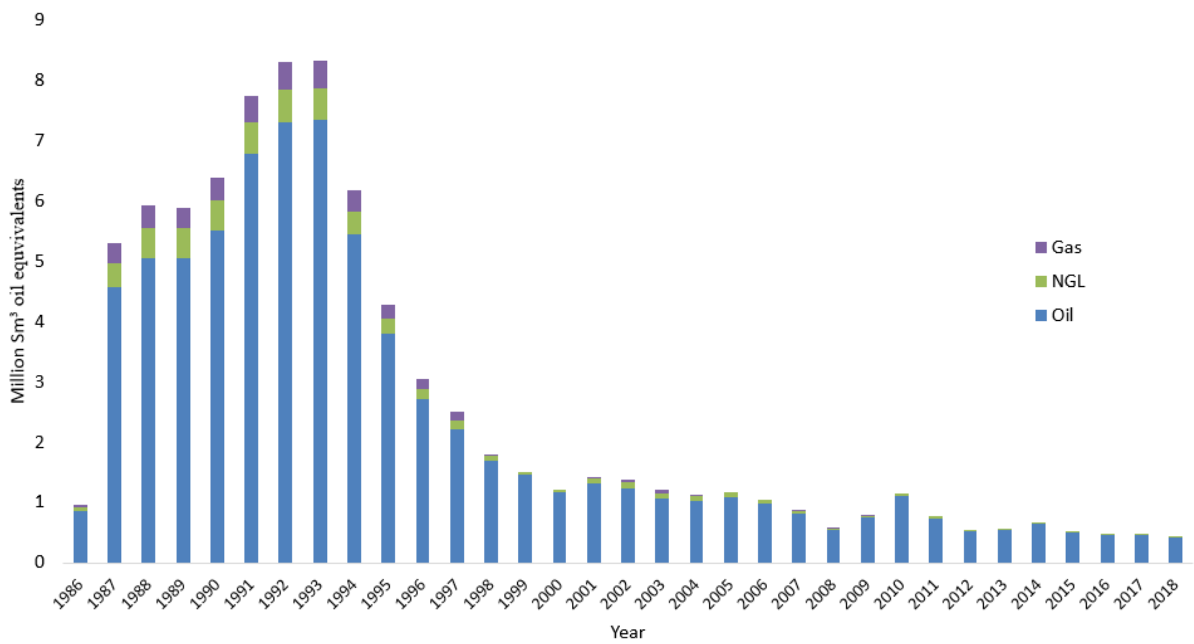

Figure 1.1.1: Historical production data for Ula and satellite fields retrieved from the Norwegian Petroleum Directorate [14].

Figure 1.1.1 displays Ula's historical production data where it can be seen that a large part of the production happened in the late 1980's and 90's. In the current century, production is slowly decreasing, and last year's production was 0.43 million Sm^3 oil equivalents. According to the Norwegian Petroleum Directorate there is about 7.5 million Sm^3 oil remaining of the total 82.9 million Sm^3 in the reserve. In addition are tie-in of satellite fields, self operated and third party, contributing to maintaining production at Ula. Until recently, Ula was expected to be shut down in the near future. However, it was decided to prolong the life time of the platform, and the vision is now to operate until the 2040's [2]. New technologies and investments are needed in order to retrieve as much as possible of the reserve's remaining 9 % of recoverable oil [14].

1.2 Thesis objectives

A well proven brownfield project is the change of production wells into injection wells where water, gas or a combination of both are injected into the bottom of the reservoir. This raises reservoir pressure, enabling higher petroleum production and recovery.

Despite extensive injection of water and gas, well pressure in many oil wells will eventually decrease to a level where production stops because pressure in surface processing equipment is higher than the well's pressure. A well known solution to ease the production of low pressure wells is to install a gas lift system where pressurized gas are injected into the lower part of the production tube.

An alternative to gas lift is a jet pump, also known as an ejector, eductor or velocity spool, installed down hole or at surface. It has shown to be a promising solution for production boosting in petroleum applications. Jet pumps utilize pressure in high pressure fluids, such as fluids from high pressure wells. This represent a source of energy which is otherwise wasted over the wellhead choke.

This thesis will investigate whether a solution utilizing a jet pump would be feasible for boosting production and possibly prolonging the lifetime of one of Aker BP's maturest oil fields, the Ula field.

Details on oil well performance and physical properties of wells in the reservoir forms the basis for the investigations. Data is retrieved from Aker BP's production reports, process system descriptions and Unisim simulation files. The scope of the thesis is limited to the wells connected to the Ula reservoir. Satellite fields Blane, Tambar and newly started Oda are not investigated. Blane and Tambar's production rates are taken into account in some calculations and process descriptions. Oda satellite field started production spring of 2019 and is therefore not included in any of the work for this report.

Open access performance data of jet pumps are very limited and often not comparative to the cases in this report. A cooperation with a contractor of jet pumps, Endúr, was therefore formed to obtain realistic performance data. Endúr's supplier of jet pumps is Caltec. Calculations were performed by engineers at Endúr and Caltec, and their findings will be used to further investigate possible production increase.

Different installations utilizing the jet pump technology were chosen after a literature review and preliminary discussions with engineers from Aker BP and Endúr. The goal is to establish the potential production gain for each case. The effect of the different solutions on the rest of the process will also be briefly assessed.

Process safety and control related to the jet pump solutions will be investigated based on the standard ISO 10418. Research on undesirable events related to jet pump operation and recommended process safety instrumentation are included in this work.

2 Basic Principles

2.1 Petroleum Production

Oil and gas located in the North Sea were formed from organic material trapped under layers of sand and other sediments 150 million years ago. Formed hydrocarbons migrated from the source rock upwards into porous geological formations below ground called reservoirs [10]. Wells are drilled into the reservoir to retrieve the hydrocarbons, often located several thousand meters under the sea bed. The amount of hydrocarbons retrieved from a well at a given time is regarded as the production rate. This quantity is, as stated by Guo et. al., dependent of the wellhead pressure, the reservoir production characteristics and flow performance of the production string [10].

The pressure difference in a tube of length L containing fluid flowing between two points, 1 and 2, is described by the right hand side of equation 2.1.1 [10].

$$\Delta P = P_1 - P_2 = g\rho\Delta z + \frac{\rho}{2}\Delta u^2 + \frac{f_F \rho u^2 L}{2D} \tag{2.1.1}$$

The first part describes the contribution from the difference in potential energy, the second part reflects the change in kinetic energy, while the third part describes energy loss due to friction.

In early stages of production the reservoir has enough energy to drive hydrocarbons to the surface without external interference. A choke valve is the main unit for controlling wellhead pressure (WHP). The choke is placed where the flow line is connected to the processing plant, called a Christmas tree. If needed, fluid pressure is reduced over the choke valve to match the operating pressure of downstream equipment

The pressure in the reservoir, the bottom hole pressure (BHP) is defined as a the sum of wellhead pressure and hydrostatic pressure.

$$\text{Bottom hole pressure} = \text{Wellhead pressure} + \text{Hydrostatic pressure} \tag{2.1.2}$$

It declines over time as hydrocarbons are released from the reservoir. To maintain the pressure at a high enough level, water or gas are injected through special injection wells. The Ula platform injects water and gas in injection wells, called *Water Alternating Gas* (WAG) injection. A portion of the injected water escapes into production wells rising the water cut which in turn increases the density of the liquid column in the production tube. This heavy coulumn rises the hydrostatic pressure and slows down production.

2.2 Ula Process Plant

It is necessary to have knowledge of the Ula topside processing plant in order to evaluate the effects of installing new equipment. A simplified block diagram of the process was made from a process flow sheet of the processing plant, and is shown in figure 2.2.1. Perfect separation is assumed for all separators for simplicity, although it should be noted that this is a rough assumption. The process can be explained from information from a collection of system description reports made by Aker BP.

Well fluids from each well at Ula are sent to the production manifold. The fluids are led to the high pressure (HP) separator where oil, water and gas are separated. If needed, wells can be routed to the test separator via the test manifold. Production from Tambar is normally routed to test separator, but could also go to production separator. Blane's production is separated in its own separator before the oil phase flows to the MP separator.

The oil stream from test and production separator is also led into the MP separator. Lower pressure and temperature results in further separation of gas and water from the oil phase. Oil flows to booster pumps where pressure is increased before it gets exported in pipes to the Ekofisk platform.

Separated water from each separator is led to the produced water system. Six hydrocyclones separate oil from water before gas is removed in a degassing tank. Water is either dumped in the sea or pressurized by two water injection pumps and injected back into the reservoir, either at Ula or Blane. The injection pumps compresses more water than needed when both are in operation, and excess HP water is dumped to sea.

Gas from the MP separator is treated in the MP gas train. Collected gas from HP, Test and Blane separator and MP gas train is treated either at the HP or UGU gas facility. HP gas facility treats a constant amount of gas, while the newer UGU gas train is suited for treating varying gas rates and is operated accordingly and often not in use at all if gas rates are small. The split between UGU and HP gas trains will therefore vary but is assumed to be 50/50 for the work in this report.

UGU gas facility compresses gas to injection pressure. Some gas are retrieved from an intermediate level to be used for gas lift or fuel gas. Gas treated in HP gas train can go to the fuel gas system or be routed further to WAG gas facility. Here, further compression is done to reach injection pressure levels.

It is possible to lead production from certain wells directly to the MP separator if wellhead pressure is very low. However, all wells are assumed to produce to HP separator in this report.

Table 2.2.1: Flow rates of every stream displayed in figure 2.2.1. Values are average production from a report of historical production data. Perfect separation is assumed.

System	Stream	Flow rate
Blane separator		
	Gas outlet	8.0 t/h
	Oil outlet	3000 bbl/d
	Water outlet	2600 bbl/d
Tambar separator		
	Gas outlet	8.5 t/h
	Oil outlet	7000 bbl/d
	Water outlet	430 bbl/d
HP separator		
	Gas outlet	41.6 t/h
	Oil outlet	7900 bbl/d
	Water outlet	56400 bbl/d
MP separator		
	Gas outlet	3.0 t/h
	Oil outlet	17900 bbl/d
	Water outlet	1600 bbl/d
Water treatment		
	Inlet	61030 bbl/d
	Dump to sea	0 bbl/d
	Water injection	61030 bbl/d
Crude oil treatment		
	Inlet	17900 bbl/d
	Oil export	17900 bbl/d
MP gas facility		
	Inlet	3 t/h
	To HP/UGU facility	3 t/h
HP gas facility		
	Inlet	30.55 t/h
	Fuel gas	4.0 t/h
	To WAG	26.55 t/h
UGU gas facility		
	Inlet	30.55 t/h
	Gas lift	8.15 t/h
	Gas injection	22.4 t/h
WAG gas facility		
	Inlet	26.55 t/h
	Gas injection	22.4 t/h
	Gas lift	4.15 t/h

Table 2.2.2: Description of pressure and temperature of the main streams on the platform.

System	Stream	Pressure [barg]	Temperature [°C]
Production manifold		21-23	130
Test manifold		21-23	130
Blane separator		20-22	125
HP separator		20-22	125
MP separator		8-16	50
Test separator		20-22	127
Crude oil treatment			
	Oil inlet	18	60
	Oil export	30	60
UGU gas facility		20	90
	HP comp. suction	20	20
	HP comp. discharge	70	105
	1st comp. suction	70	12
	1st comp. discharge	200	110
	2nd comp. suction	200	30
	2nd comp. discharge	420	88
MP gas facility			
	MP comp. suction	10	20
	MP comp. discharge	20	85
HP gas facility			
	HP comp. suction	20	20
	HP comp. discharge	60	130
WAG gas facility			
	1st comp. suction	60	15
	1st comp. discharge	140	95
	2nd comp. suction	140	35
	2nd comp. discharge	350	110
Water treatment			
	Water injection	250	35

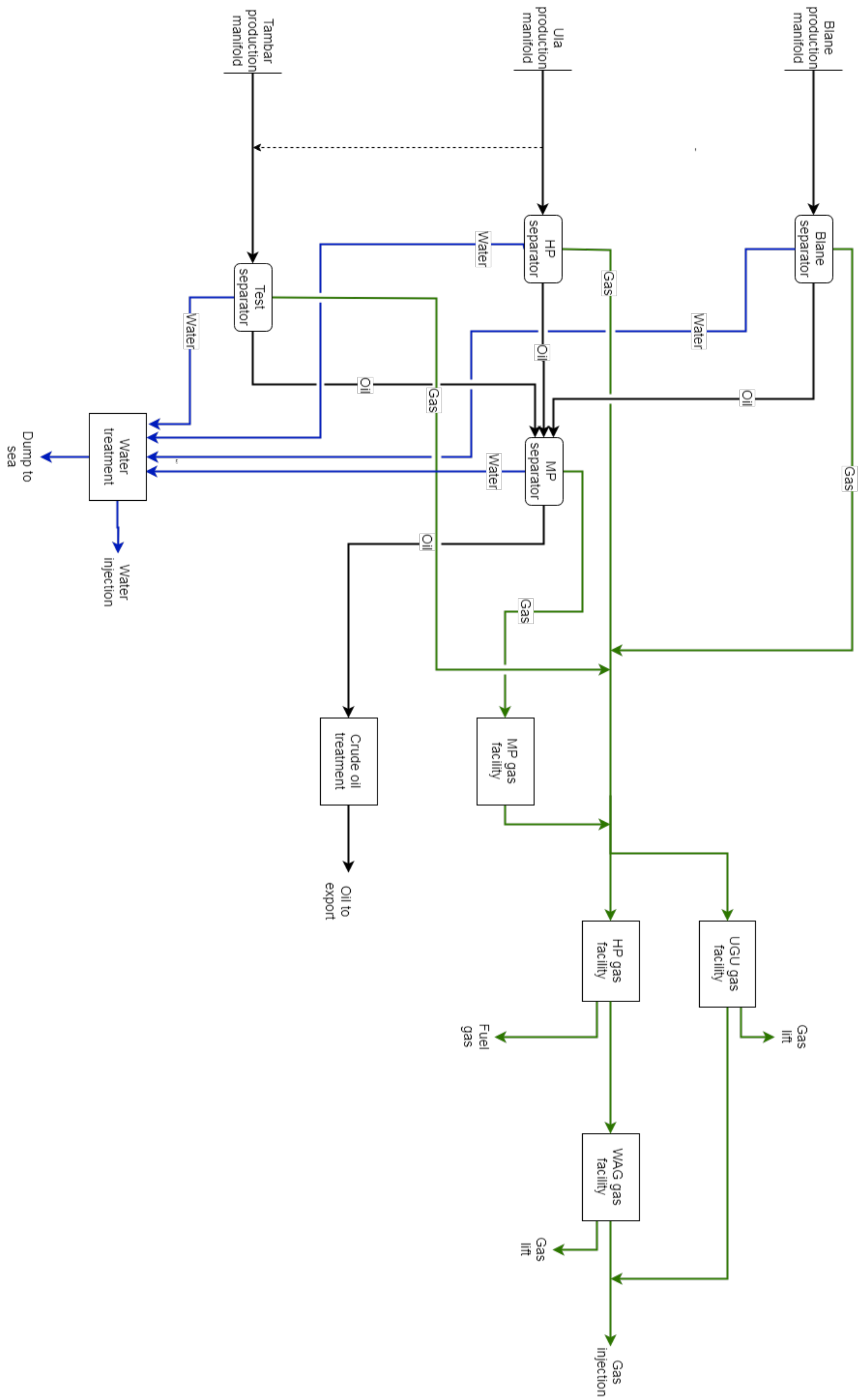

Figure 2.2.1: Schematic of the processing plant at Ula.

2.2.1 Production with Gas Lift

Gas lift is used to help start up production from a well or during production of low pressure wells. As explained by Guo, compressed gas are injected into the lower section of a production tube [10]. Gas mixes with oil, lowering the effective density of the fluid. Following equation 2.1.1 the pressure difference between bottom hole and wellhead decreases and production becomes possible. The injected gas bubbles also pushes the surrounding liquid giving an extra lifting effect.

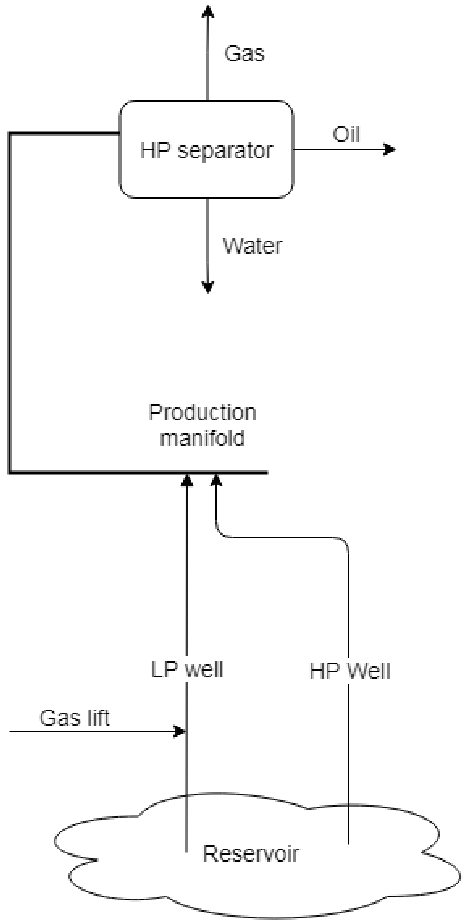

Figure 2.2.2: Simple schematic of the gas lift arrangement easing the production of a LP well

A sketch of the system is displayed in figure 2.2.2. This solution demands a portion of the capacity in the gas compression facility, which otherwise could be utilized for injection or export gas production.

2.3 Jet Pumps for Production Boosting

The first use of jet pump technology was for steam locomotives in the 19th century where it was utilized to pump feed water into the boiler using the boiler's own steam as motive fluid. Today, it is used in chemical, pharmaceutical, petroleum and food industry, among others [8]. Applications range from refrigeration and air-conditioning systems to gas recovery.

The technology utilizes the Venturi effect, which is based on Bernoulli's principle. It states that the total mechanical energy of a fluid remains constant [9]. The principle is explained by the following equation,

$$\frac{v^2}{2} + gz + \frac{p}{\rho} = constant, \tag{2.3.1}$$

when the fluid is assumed in-compressible and non-viscous. The first part reflects kinetic energy, the second represents potential energy and the last part is due to the gravitational potential energy of the fluid. A jet pump uses this principle to transfer energy between two fluid streams. In this case the streams in question differs in pressure. High pressure fluid transfers energy to fluids with lower pressure (LP) .

The ejector consist of separate inlets for HP and LP streams, a nozzle, a mixing tube and a diffuser. The equipment and its different parts are displayed in figure 2.3.1. There are no moving parts in the jet pump which makes it less exposed to malfunctions. The fact that it does not require any external energy sources results in an emission free machine without operating costs. The amount of training needed to operate it is very limited due to the simple, static operation. Gou explained that one of the limits of a jet pump is the low efficiency, usually around 20-30 % [10]. Villa et. al. showed that the efficiency dropped with increasing GVF [26]. However, jet pump efficiency is not as significant if the source of driving stream is cost free.

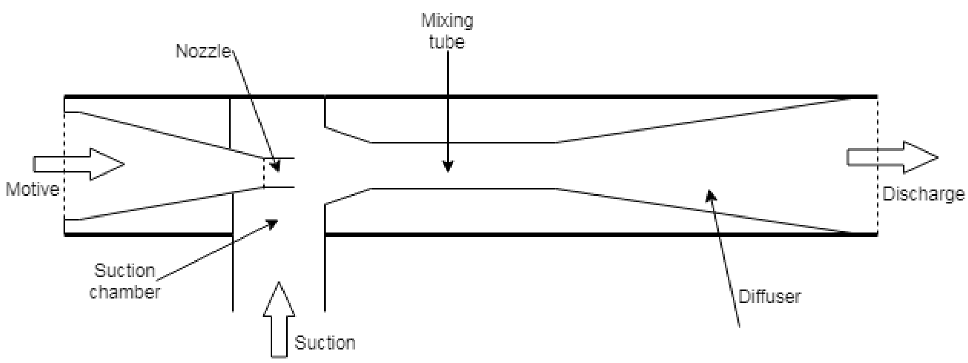

Figure 2.3.1: Schematic of the main parts of a jet pump.

Motive fluid of high pressure enters the jet pump and moves trough a nozzle which accelerates the fluid, often to supersonic levels. Due to Bernoulli's principle, equation 2.3.1, pressure decreases over the nozzle when velocity increases [26].

Low pressure, or suction, fluids, are introduced in a chamber right where motive fluid leaves the nozzle. The pressure in this chamber is lower than the suction fluid's pressure and thus creates a suction in the inlet pipe. It is this effect that enables the production boost since the suction stream experiences a lower back-pressure than the pressure downstream of the jet pump. The two streams mixes in the mixing tube section where the fluids obtain a homogeneous pressure by transfer of energy before reaching the diffuser. There, the velocity decreases while pressure rises due to the increasing diameter, again following Bernoulli's principle. The resulting outlet pressure is below the starting pressure of the motive stream and above the inlet pressure of the suction stream [22]. Figure 2.3.2 gives a graphical presentation of the explained changes in pressure and velocity for the motive fluid.

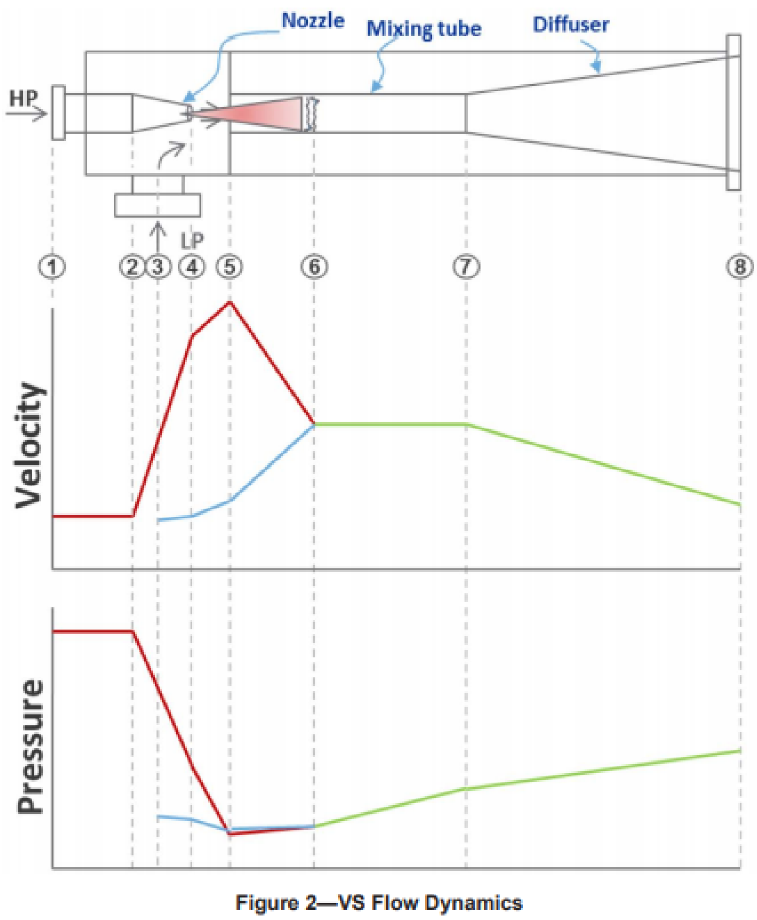

Figure 2.3.2: Schematic of the pressure and velocity through a jet pump retrieved from Caltecs' Jet Pump Handbook [5].

2.4 Performance Factors

The boosting effect of the LP stream depends on a number of factors explained by e.g. Agena et. al., Peeran et. al. and Villa et. al., [1] [17], [26]. Performance is dependent on the geometry of the jet pump it self as well as the properties of the streams entering it.

The area ratio, R, is the ratio of the nozzle area, A_j to total throat area, A_t [1].

$$R = \frac{A_j}{A_t} \tag{2.4.1}$$

The flow ratio of suction fluid rate, q_2, to motive fluid rate, q_1, is

$$M = \frac{q_2}{q_1} \tag{2.4.2}$$

Equation 2.4.3 show the equation for pressure head, H, deduced from the velocity head. Lorenz's mixing-loss model is used for the conversion [19].

$$H = \frac{P_3 - P_2}{P_1 - P_3} \tag{2.4.3}$$

where P_1 is motive pressure, visualized as a red line in the pressure graph in figure 2.3.2, P_2 is suction pressure, seen as a blue line in figure 2.3.2 and P_3 is discharge pressure, showed in figure 2.3.2 by a green line. The equation shows that a large pressure difference between HP an LP streams yields a large pressure ratio. Caltec recommends a pressure ratio between P_1 and P_2 of 2 or more to achieve adequate pressure boost [5].

The efficiency is defined by Petrie as the ratio of energy, or work, added to the discharge fluid, defined by equation 2.4.4, to energy lost by the motive fluid, defined by equation 2.4.5, [19]. Notice that these equations are valid for liquid streams. Isothermal conditions are assumed, which is evaluated to be a valid assumption due to the fluids high velocities and short travel distances. The unit of these equations is Js^{-1} or W.

$$w_2 = q_2(P_3 - P_2) \tag{2.4.4}$$

$$w_1 = q_1(P_1 - P_3) \tag{2.4.5}$$

Jet pump efficiency can then be found by dividing equations 2.4.4 and 2.4.5.

$$\eta_p = \frac{q_2}{q_1} \cdot \frac{P_3 - P_2}{P_1 - P_3} \tag{2.4.6}$$

or

$$\eta_p = MH \tag{2.4.7}$$

A modification of equation 2.4.4 is necessary for multiphase suction streams. Sarshar et. al. defined efficiency for jet pumps handling liquid driving streams and multiphase suction streams as

$$\eta = \frac{q_{l,2}(P_3 - P_2) + P_2 q_{g,2} ln(P_3/P_2)}{q_{l,1}(P_1 - P_3)} \tag{2.4.8}$$

where $q_{l,2}$, $q_{l,1}$ and $q_{g,2}$ denotes volumetric flow rates of the liquid fractions of the LP and HP streams and the vapour fraction of the LP stream [21]. This differs from equation 2.4.6 by regarding the gas flow of q_2 as compressible [11].

Equation 2.4.8 could be modified to give efficiency for jet pumps driven by gas streams under isothermal conditions.

$$\eta = \frac{P_2 q_{g,2} ln(P_3/P_2)}{P_1 q_{g,1} ln(P_3/P_1)} \tag{2.4.9}$$

where $q_{g,1}$ denotes volumetric flow rates of the vapour fraction of the HP stream.

The gas volume fraction, GVF, of any stream is defined as

$$GVF = \frac{q_g}{q_g + q_l} \tag{2.4.10}$$

where q_g and q_l are volumetric flow rates of gas and liquid under operating conditions. Other parameters often used when linking stream composition to performance are GOR and GLR, explained in equation 2.4.11 and 2.4.12. The units of GOR and GLR are both scf/bbl, where gas rates are given at standard conditions.

$$GOR = \frac{q_{gas}}{q_{oil}} \frac{[scf/hr]}{[bbl/hr]} \tag{2.4.11}$$

$$GLR = \frac{q_{gas}}{q_{oil} + q_{water}} \frac{[scf/hr]}{[bbl/hr]} \tag{2.4.12}$$

GOR, GLR or GVF have a direct affect on the jet pump performance.

Villa et. al. reviewed the installation and performance of a surface liquid - multiphase ejector at Villafortuna oil facility in Italy in 1996 [26]. An important discovery from laboratory testing was a relationship between the mixing tube length and GVF of the suction stream. If the GVF was lower than 0.9, a short mixing tube was advised.

The physical dimensions of the parts in a jet pump are designed to suit each specific case [8]. Operating conditions will often vary over time. A significant change in process conditions will result in a drop in efficiency, and the parts of the jet pump will have to be replaced. Having easily changeable parts to suit new operating conditions is important to minimize downtime related to this maintenance. Caltec, a large provider of jet pump solutions, states that changing internal parts of their jet pumps can be completed in one shift [5].

For equipment handling liquids, cavitation is a source of concern. It is defined by Arnd as the formation of the vapour phase in a liquid [4]. It occurs when pressure in a liquid drops below the vapour pressure. In a jet pump, cavitation can occur when suction fluid is introduced. The result is bubbles which collapses when pressure increases above vapour pressure in the mixing tube and diffuser. The bubbles creates shock waves when they break that can cause severe damage to the equipment [1]. Other effects of cavitation are efficiency drop, noise and vibration. For the jet pump applications discussed in this report where well fluids and injection water are considered, pressures are most likely to stay well above water vapour pressure levels. Cavitation is therefore not considered further.

2.5 Motive and suction fluids

The motive or driving fluid can be any stream in liquid phase (L), gas phase (G) or multiphase (M). The choice of motive fluid depends on the type of suction fluid. In cases of liquid or multiphase suction stream, preferred motive fluid is liquid and can to some extent be multiphase. Both liquid and gas HP streams are applicable to drive gas suction streams.

As stated in a 1997 conference paper by Caltec, the streams in an mulitphase jet pump are preferred to be as close to single phase as possible [21]. Villa et. al. drew the same conclusion and recommended separation when GOR of the driving fluid was high [26]. Correspondence with Caltec's Technology Director further elaborated on the recommended limits. The tolerated amount of liquids in a gas motive stream is 1-2 %, while 15 % is the upper recommended level of gas in a liquid motive stream.

The source of motive fluid does not have to be a high pressure well. Injection water could be utilized for either LL or LM jet pumps, and injection gas can be used as the driving fluid in a gas-gas type jet pump. In cases of low production where pumps and compressors run with a significant amount of recycle, jet pumps can utilize this energy.

2.6 Process implementation

Jet pump technology is implemented in different ways. A common arrangement was described by Lea et. al. [12], and is known as a down hole pump. It is integrated in the production tube and is operated by a power fluid, often diesel or water, which is pumped from the surface.

Surface mounted jet pumps represent another type of solution. Piping of relevant fluid streams are rearranged to the production boosting jet pump and the discharge pipe is then led to the production manifold. Flare gas recovery is another example where jet pumps can be used. The technology has also been implemented in compressor trains to de-bottleneck 1st stage compressors.

The jet pump is compact compared to other alternatives for top side production boost such as mechanical pumps or compressors. A surface installation requires available areas topside and will on many offshore platforms represent an issue since they are built without much excess space. The Ula drilling platform however, does not have significant area shortage, and will have area available for a jet pump arrangement.

3 Proposed Solutions

After preliminary investigations on how jet pump technology could be implemented, sketches of different applications were developed for further evaluation. HP well liquids, injection gas and injection water were investigated as driving fluids. Suggested implementations are explained in sections 3.1 - 3.3. The installation's physical locations are surface mounted in bypass of the choke valve and upstream the production and test manifold.

The desired result is boosted production of the low pressure well and possibly a decreased need for gas lift.

3.1 Jet Pump Driven by Well Fluids

3.1.1 Multiphase Well Fluid

The simplest solution is a single jet pump without any preprocessing of entering streams also known as a multiphase-multiphase (MM) jet pump. A simplified sketch of the system is showed in figure 3.1.1. This is a space saving alternative to any solutions with in-line separation explained in section 3.1.2. Estimation of performance is however difficult due to the complexity of multiphase flow and development of data models describing it.

This solution puts strict requirements on the compositions of the entering streams. As explained in section 2.3 the motive stream should not have more than 1-2 % liquids in a gas stream and 15 % gas in a liquid motive stream. MM jet pumps are not expected to be effective devices above these limits. Separation of gas and liquids were recommended by Villa et. al. when the driving stream has high GOR values. [26].

Further work showed that the HP wells which could potentially be driving streams for a MM jet pump have high GOR and GVF values. From the literature review, it was found that the effect of a MM ejector would be poor [26]. Further investigations regarding performance of this configuration were therefore not conducted.

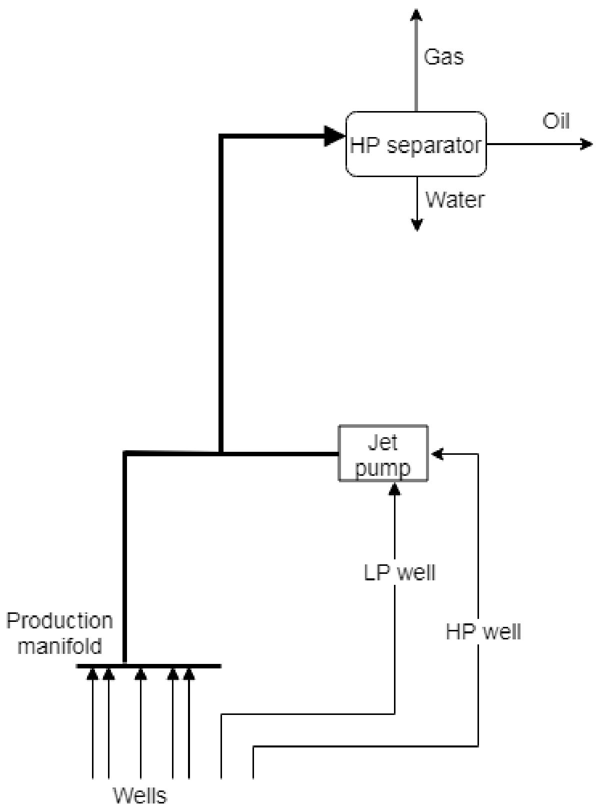

Figure 3.1.1: Simplified sketch showing a MM jet pump.

3.1.2 In-line Separated Well Fluids

A jet pump combined with in-line separation has previously been explained in a series of articles and conference papers, see [21], [17], [18] and [22]. Jet pump technology supplier Caltec have an in-line separator unit called I-SEP. It is a compact cyclonic separator, removing gas from the combined oil and water phase and operates at process pressure [23]. Including an in-line separator of this kind previous to the HP inlet allows for the use of HP wells to reduce backpressure of multiphase LP wells.

The proposed solution is sketched in figure 3.1.2. Well fluids from the HP well are directed into the in-line separator which divides liquid and gas stream. High pressure liquid stream is then directed into the jet pump which creates a lower pressure at the suction fluid inlet, making this a liquid-multiphase (LM) jet pump. Streams from the jet pump and separated HP gas are combined by a commingling spool and led to the manifold. It is assumed that the in-line separator is of the same type as the Caltec separator.

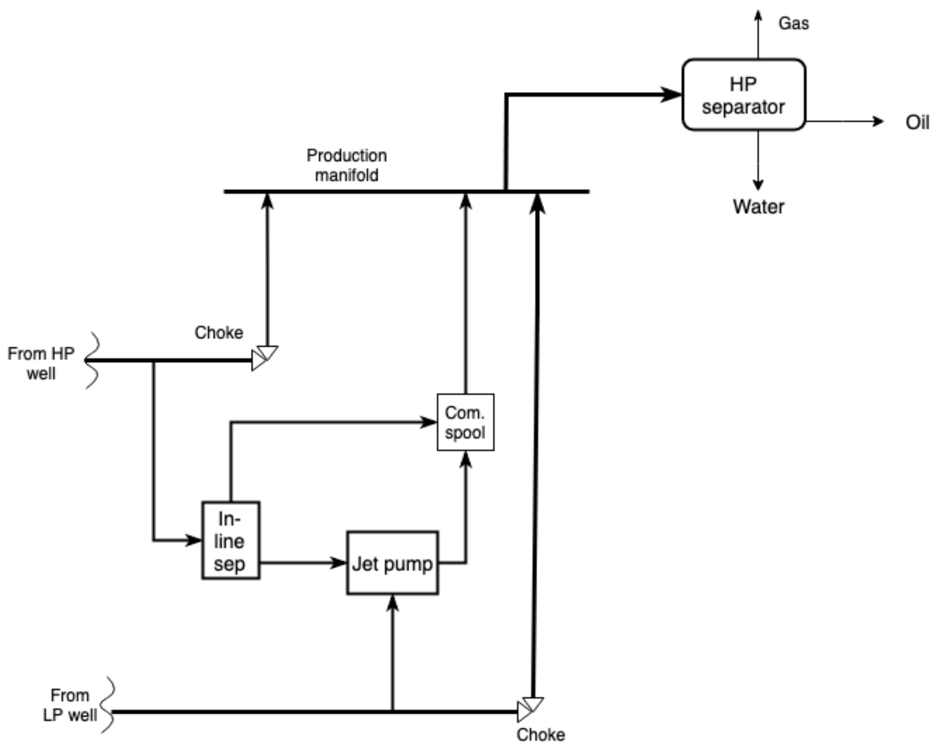

Figure 3.1.2: Schematic of the LM jet pump with upstream in-line separation of the motive stream.

3.2 Jet Pump Driven by Injection Water

An alternative to HP well fluids as driving fluid is excess water from water injection pumps. Figure 3.2.1 shows how HP water could be utilized as jet pump driving fluid. No separation of the driving or suction stream is necessary.

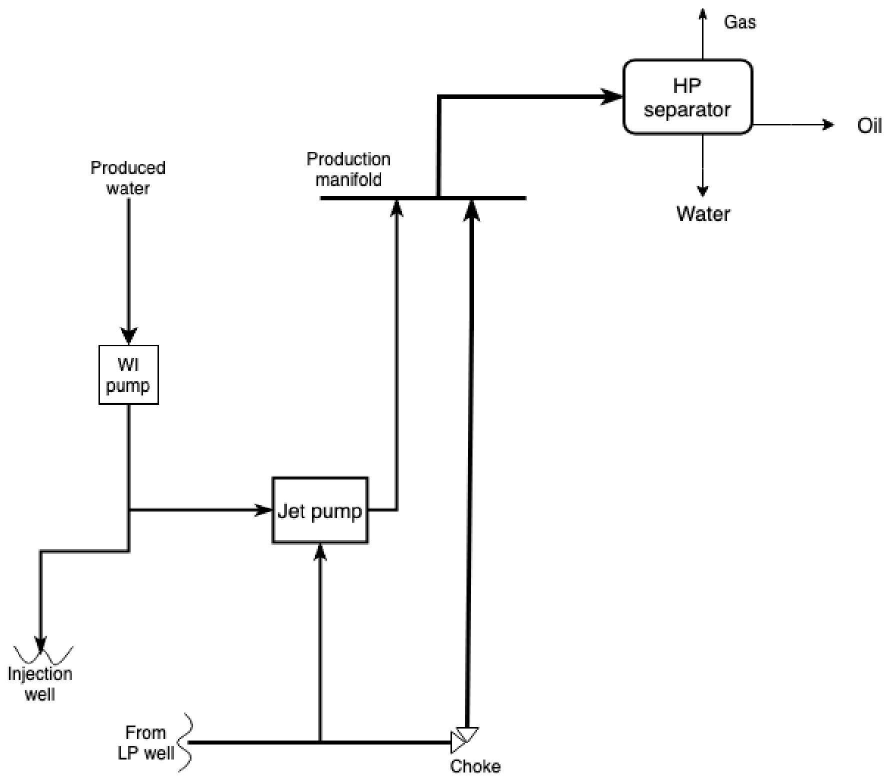

Figure 3.2.1: Schematic of a LM jet pump with high pressure water as driving stream.

3.3 Jet Pump Driven by Injection Gas

Another alternative motive fluid is high pressure gas for reservoir injection. The suction fluid would also need to be in gas phase so an in-line separation of the LP well stream is necessary. The LP well liquid phase would most likely have a lower pressure than the discharge pressure of the jet pump. The liquid stream pressure would therefore need to be increased by a pump to meet the discharge pressure of the jet pump.

The need for a pump could possibly be eliminated if the LP well liquid phase was routed to the test manifold and further to test or MP separatorwith lower operating pressure. GG jet pump discharge could then be sent to production manifold and HP separator together with the fluids from HP wells. This could also allow for a possible increase in HP separator pressure. It is this solution that is regarded in the rest of the work. Figure 3.3.1 shows a sketch of the possible arrangement.

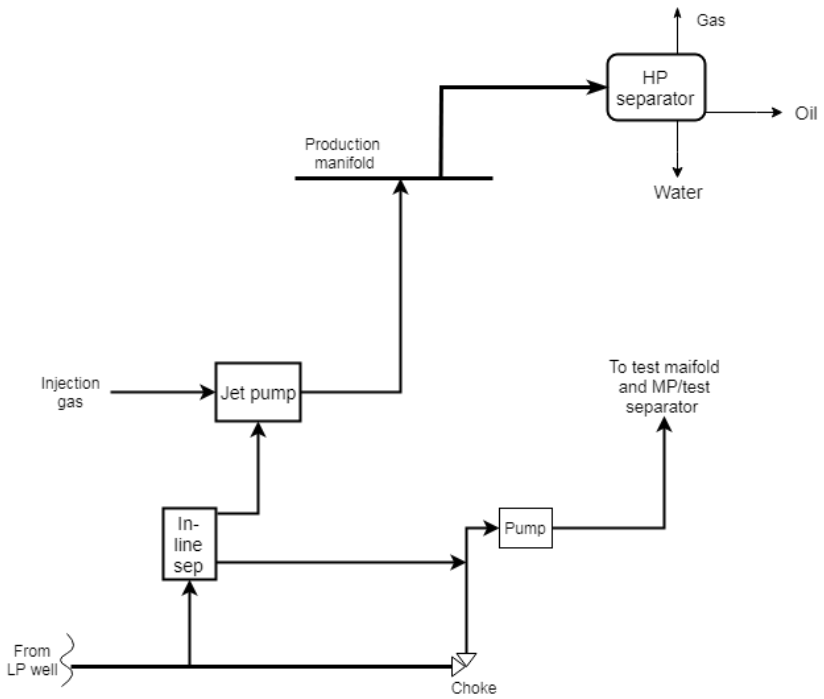

Figure 3.3.1: Schematic of a GG jet pump driven by injection gas.

4 Evaluation of Jet Pump Solutions

Jet pump performance can be estimated using performance data from similar jet pumps. In a conference paper written by Peeran&Beg for Caltec, performance data of a jet pump using gas streams as motive and suction fluid were presented [17]. Figure 4.0.1 shows the performance curves which reflects the statements of section 2.4. Small suction to motive mass flow ratios and high motive to suction pressure ratios yield the highest discharge to suction pressure ratios.

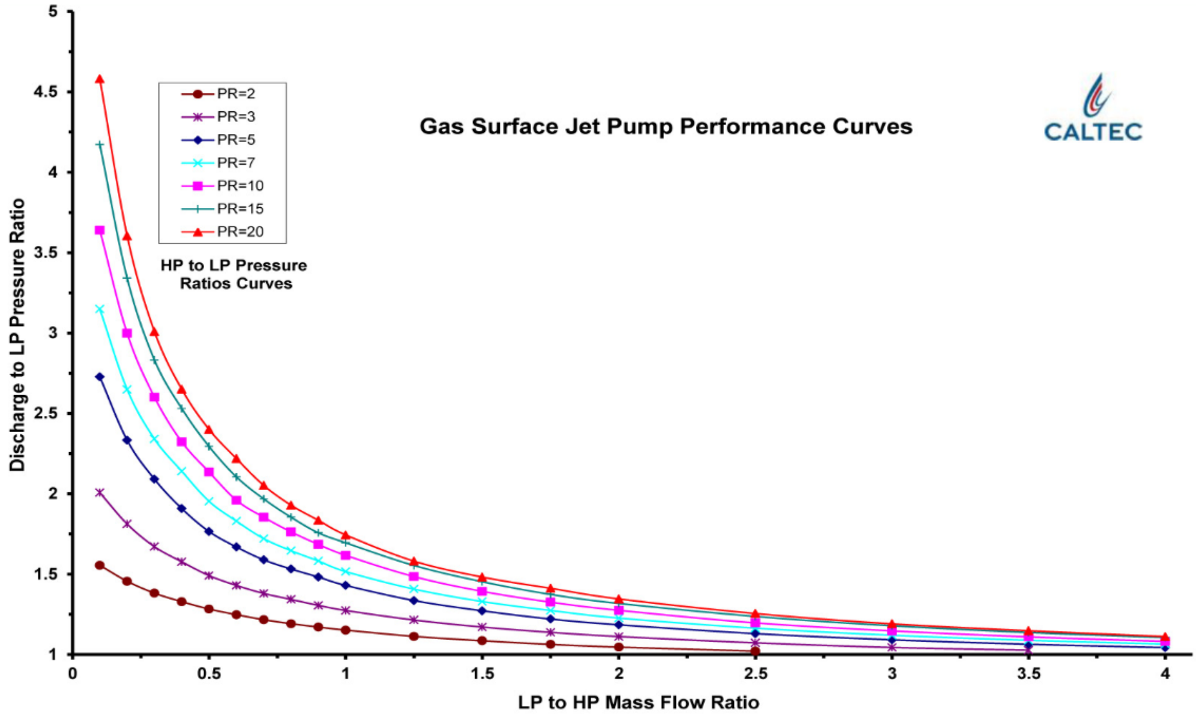

Figure 4.0.1: Graph displaying performance curves for a gas-gas jet pump, retrieved from Peeran et. al. [17].

Corresponding curves for jet pumps with liquid or multiphase streams are available in much less degree. Some performance data are available in papers such as Sarshar et. al [21]. However, the jet pumps that the performance data were based on operated under conditions that differed significantly from the conditions at Ula. Using this data would therefore represent a large source of uncertainty and it was decided that these performance curves were not applicable for the LM jet pumps in this report.

To establish reliable estimates for liquid driven jet pumps it would be necessary to cooperate with a vendor. It was therefore decided together with Aker BP to initiate a cooperation with Endùr, a vendor of Caltecs' jet pump technology. In cooperation with their engineers, the proposed solutions in section 3 were evaluated.

4.1 Basis for Calculation

The performance estimations are based up on calculations from real production data from the Ula platform. Production rates tend to vary greatly over time, especially for HP wells, so the production of each well over a time period of a year, March of 2018 to March of 2019, were used to determine maximum, minimum and average production. Tables 4.1.1 and 4.1.2 displays this information as well as water cut, GLR, GOR and GVF. Endùr received the same information and used the average values to conduct their simulations.

Table 4.1.1: Production data from high pressure wells. Conversion between units were conducted using table A.0.2. Actual gas densities were retrieved from Unisim. Watercut, GLR, GOR and GVF were calculated using average values.

	Well 09	Well 12	Well 18
Pressure (WHP), (barg)	50-60	25-45	60-90
Temperature, (°C)	134	120	140
Gas flow rate, min-max, (t/h)	2.5/50.3	2.5/35.2	0.75/18.3
Gas flow rate, average, (t/h)	18	12.4	4.7
Actual gas density, (kg/m^3)	40-49	20-38	48-74
Actual gas flow, min-max (m^3/h)	62.2-1026.5	124.4-936.2	15.6-247.3
Actual gas flow, avg (m^3/h)	404.5	432.1	77.2
Oil flow rate, min-max (bbl/d)	400-4500	300-4000	50-1700
Oil flow rate, avg (bbl/d)	1760	2500	500
Oil flow rate, min-max (m^3/h)	2.7-29.8	2.0-26.5	0.3-11.3
Water flow rate, min-max (bbl/d)	2000-50000	2000-24000	2500/38000
Water flow rate, avg (bbl/d	29000	16200	18000
Water flow rate, min-max (m^3/h)	13.3-331.2	13.3-159.0	16.6-251.7
Total liquids, avg (bbl/d)	30760	18700	18500
Total liquids, avg (m^3/h)	203.8	123.9	122.6
Water cut, (%)	94.3	86.6	97.3
GLR, (scf/bbl)	465	526	200
GOR, (scf/bbl)	8136	3940	7400
GVF	0.77	0.86	0.48

Alternative to high pressure wells as motive fluid are pressurized gas and water. Discussions with Aker BP's engineers established an estimate of the available excess water to be 160 m^3/h. 6250 Sm^3/h of compressed gas was estimated to be available. However, this is a conservative estimate and may be increased. Table 4.1.3 displays the size, pressure and temperature of these streams. Endúr was also given access to this data.

Total production from Ula reservoir is displayed in table 4.1.4.

Since the platform also receives well fluids from satellite fields, production data from these

Table 4.1.2: Production data from low pressure wells. Conversion between units were conducted using table A.0.2. Actual gas densities were retrieved from Unisim. Watercut, GLR, GOR and GVF were calculated using average values.

	W02	W03	W08	W10
Pressure (WHP), (barg)	20-25 (with GL)	25	10-20	20-25
Temperature, (°C)	45	35	55	80
Gas lift rate, (t/h)	4.0	2.5	-	-
Gas flow rate, min-max (t/h)	0.5-2.9	0.1-1.0	1.9-5.7	3.8-10.7
Gas flow rate, avg (t/h)	0.9	0.4	3.8	7.9
Actual gas density, (kg/m^3)	20.8-26.6	28.0	9.6-19.9	18.1-23.0
Actual gas flow, min-max (m^3/h)	24.1-108.45	4.5-35.9	197.4-283.8	208.0-464.7
Actual gas flow, avg (m^3/h)	38.6	15.9	260.1	384.0
Oil flow rate, min-max (bbl/d)	100-640	100-1500	500-1600	900-2000
Oil flow rate, avg (bbl/d)	264	724	1210	1550
Oil flow rate, min-max (m^3/h)	0.7-4.2	0.7-9.9	3.3-10.6	6.0-13.3
Water flow rate, min-max (bbl/d)	100-1300	5-50	10-150	100-400
Water flow rate, avg (bbl/d	560	18	40	230
Water flow rate, min-max (m^3/h)	0.7-8.6	0.03-0.3	0.1-1.0	0.7-2.7
Total liquids, avg (bbl/d)	824	742	1250	1780
Total liquids, avg (m^3/h)	5.5	4.9	8.3	11.8
Water cut, (%)	68.0	2.4	3.2	12.9
GLR, (scf/bbl)	886	477	2440	3528
GOR, (scf/bbl)	2769	489	2521	4052
GVF	0.88	0.76	0.97	0.97

Table 4.1.3: Description of alternative motive fluids.

Variable	HP Gas	HP Water
Pressure, (barg)	320	250
Temperature, (°C)	40	35
Flow rate	6250 Sm^3/h	160 m^3/h
	5297 MScf/d	24144 bbl/d

Table 4.1.4: Average production from Ula reservoir

Field	Oil [bbl/d]	Water [bbl/d]	Gas [t/h]	Gas lift [t/h]
Ula	8508	64048	48.1	6.5

wells are also included. Table 4.1.5 displays the produced values. Oda satellite field started production spring of 2019 and are not included in the calculations.

Further, relevant properties of the gas needed by Caltec for performance estimations where found in a laboratory report from HP separator gas outlet testing, conducted in September of 2017. Corresponding test of water and oil did not exist, so the Unisim simulation file of

Table 4.1.5: Average production from Blane and Tambar reservoir.

Field	Oil [bbl/d]	Water [bbl/d]	Gas [t/h]
Blane	3000	2600	8
Tambar	10047	1353	11

the platform were used to obtain relevant properties for these fluids. Table 4.1.6 summarizes the information.

Table 4.1.6: Relevant properties of gas, oil and water phases

Property	Gas	Oil	Water
Mass density, (kg/m^3)	1.07	763.1	959.3
Viscosity, (cP)	-	1.26	0.32
Cp/C_v	1.25	-	-
Mass heat capacity (kJ/kg-C)	2.21	-	-
Z factor	0.995	-	-

The number of possible combinations of HP wells, injection water and gas to the different LP wells to evaluate are high and were reduced in cooperation with the vendor. The next sections gives details on the chosen cases for each jet pump installation proposed in section 3. The requirement for discharge pressure (MP) of the jet pump was set by Caltec to be either 25 or 20 barg. Results from the performance investigations are reported in section 5.

4.2 Jet Pump Driven by Injection Gas

Table 4.2.1 display the cases used to evaluate the performance of the GG jet pump driven by injection gas. Two cases with all four wells and two cases with two wells where chosen. Each combination were simulated with and with out production gain.

Table 4.2.1: Description of cases utilizing injection gas to lower separator pressure.

Case	Suction streams	Discharge pressure, barg	Comment
GG 1	W02+W03+W08+W10	20	-
GG 1A	W02+W03+W08+W10	20	Assumed incremental production gain of 20%
GG 1B	W08+W10	20	-
GG 1C	W08+W10	20	Assumed incremental production gain of 20%

The available GG jet pump curve, figure 4.0.1, were also used to do performance calculations of the cases in table 4.2.1. The estimations were then compared to the calculations done by Endúr.

4.3 Jet Pump Driven by Water Injection

The available water amounts are large and of high pressure. It was therefore chosen to investigate the needed water rate to reduce LP pressure down to 15 barg for all LP wells combined. Case LM 2A also included a production gain of 20 % in the calculation. The third case regarded the reduction of LP pressure of a single well, W03, to 10 barg. Table 4.3.1 summarizes the investigated cases.

Table 4.3.1: Description of cases utilizing injection water to lower manifold pressure.

Case	Suction streams	Discharge pressure, barg	Comment
LM 2	W02+W03+W08+W10	20	-
LM 2A	W02+W03+W08+W10	20	Assumed incremental production gain of 20% (both gas and liquids)
LM 2B	W03	25	-

4.4 Jet Pump Driven by HP Wells

A short preliminary investigation on which HP wells that would be most suitable to drive the jet pump was done. Table 4.4.1 displays the calculated pressure ratio between HP and LP wells. As explained in section 2.4 the pressure ratio should be above 2 to obtain an adequate boosting effect.

Table 4.4.1: Average pressure ratio of different combinations of wells.

HP Well	LP well	HP pressure, barg	LP pressure, barg	Pressure ratio
9	2	60.0	22.0	2.7
9	3	60.0	25.0	2.4
9	8	60.0	15.0	4.0
9	10	60.0	22.0	2.7
12	2	35.0	22.0	1.6
12	3	35.0	25.0	1.4
12	8	35.0	15.0	2.3
12	10	35.0	22 .0	1.6
18	2	75.0	22.0	3.4
18	3	75.0	25.0	3.0
18	8	75.0	15.0	5.0
18	10	75.0	22.0	3.4

Well 12 combined with either Well 2, 3 or 10 results in a average pressure ratio below 2.

Further investigations on jet pumps using well 12 as motive stream were therefore not conducted.

Three cases where decided for both W09 and W18. The first boosting two wells, the second boosting all four LP wells and the last case included a 10 % increase in LP production. The goal here was to establish the possible reduction on LP pressure since there were a restricted amount of HP flow. Table 4.4.2 summarizes the cases.

Table 4.4.2: Description of cases utilizing W09 and W18 to lower manifold pressure.

Case	Motive stream	Suction streams	Discharge pressure, barg	Comment
LM 3	W09	W02+W03	25	-
LM 3A	W09	W02+W03+W08+W10	25	-
LM 3B	W09	W02+W03+W08+W10	25	Assumed incremental production gain by 10% (both gas and liquids)
LM 4	W18	W02+W03	25	-
LM 4A	W18	W02+W03+W08+W10	25	-
LM 4B	W18	W02+W03+W08+W10	25	Assumed incremental production gain by 10% (both gas and liquids)

4.5 Estimation of Efficiency

Estimations on jet pump efficiency was done using equations 2.4.8 and 2.4.9. For cases including in-line separator, perfect separation was assumed.

Gas volume rates were adjusted to the temperature and pressure at suction and driving stream inlets using equation 4.5.1, where q^{act} is actual volume flow rate and q^{stp} is volume flow rate at standard conditions (15 °C and atmospheric pressure). Inlet pressures are given for each case and temperature was assumed to be the mean inlet temperature of the entering streams combined.

$$q^{act} = q^{stp} \frac{T_{act}}{T_{stp}} \cdot \frac{P_{stp}}{P_{act}} \tag{4.5.1}$$

4.6 Estimation of Production Boost

Ula well test reports gives an overview of well performance with different wellhead pressures. The well tests are conducted by producing one well at a time to the test separator. Pressure and choke position are held constant for several hours and flow rates of oil, water and gas are measured. This procedure is done for several pressures for each well.

Well performance curves are developed by reservoir engineers at Aker BP based on well tests and observation of daily production. Performance estimations are plotted with the corresponding trend line in figures 4.6.1 - 4.6.4. Also plotted is the results of the welltests.

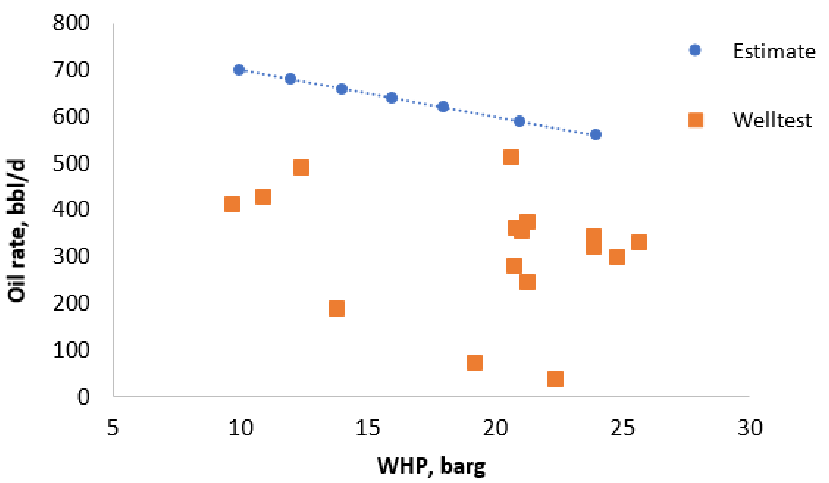

Figure 4.6.1: Graph displaying estimated oil production of well 02 as a function of WHP. Also plotted are results from welltests of the same well.

The original performance curve for well 03 is developed from bottom hole pressures. Since the behavior of the BHP is so close to linear it was decided after correspondence with Ula's reservoir engineer to assume that WHP could be calculated from equation 2.1.2. The hydrostatic pressure for well 03 is assumed to be ca. 100 barg. The data points were adjusted to fit wellhead pressures and are plotted in figure 4.6.2.

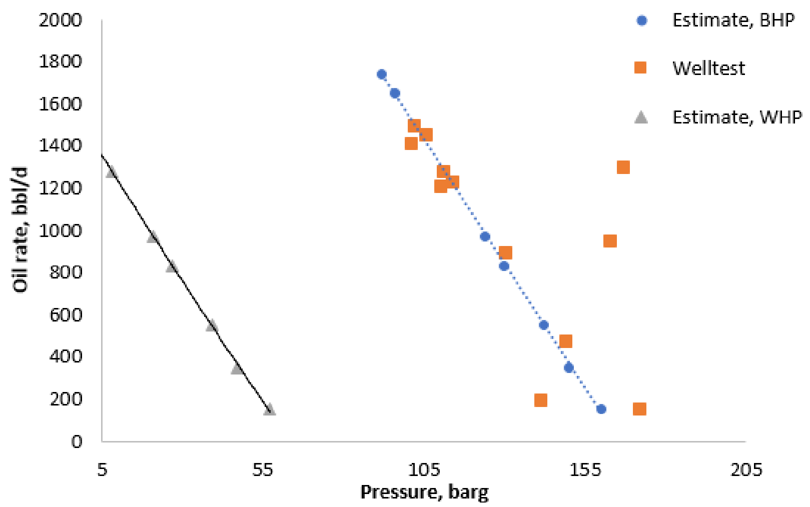

Figure 4.6.2: Graph displaying estimated oil production of well 03 as a function of BHP. Also plotted are results from welltests of the same well.

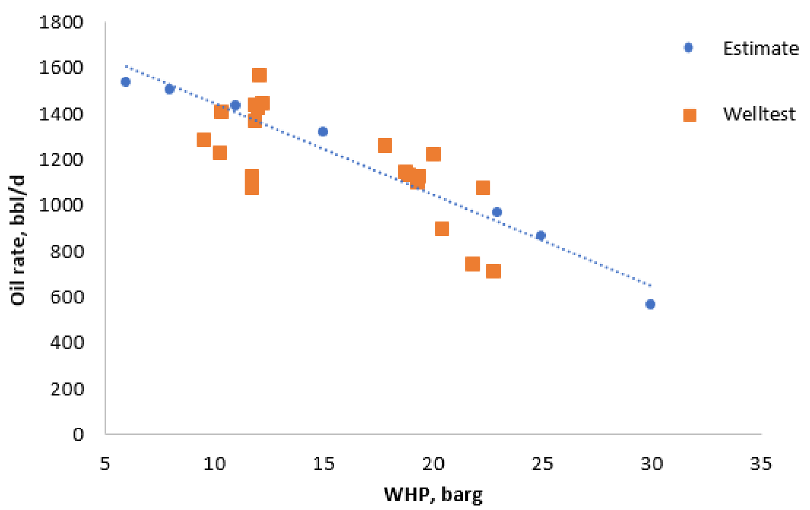

Figure 4.6.3: Graph displaying estimated oil production of well 08 as a function of WHP. Also plotted are results from welltests of the same well.

Visual inspection of figure 4.6.1 shows that the data points representing previous welltests does not coincide well with the estimation line for well 02. Corresponding plots for well 03, 08 and 10 show a better fit between welltests and theoretical estimations. This suggests that the performance of well 02 ay be more difficult to predict. This would make the production boost estimations for well 02 more uncertain.

Table 4.6.1 displays GOR and water cut as well as the mentioned trendline equations.

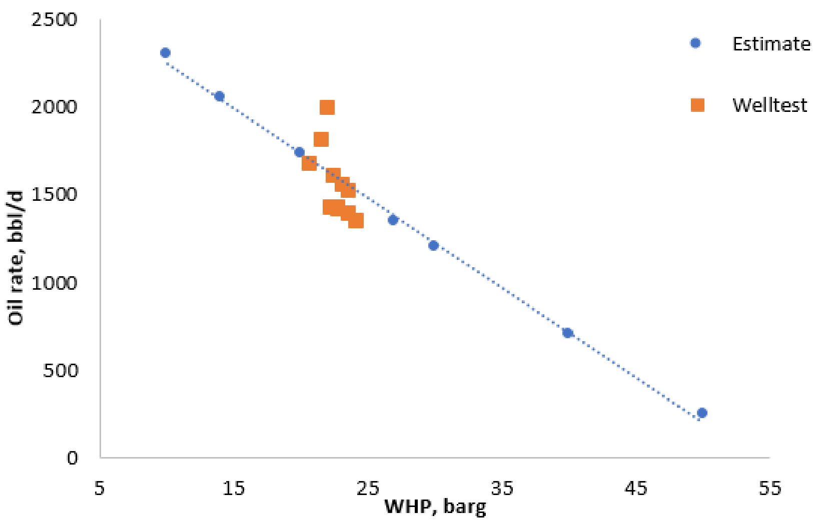

Figure 4.6.4: Graph displaying estimated oil production of well 10 as a function of WHP. Also plotted are results from welltests of the same well.

Table 4.6.1: Gas oil ratios and watercut of the LP wells. Also displayed are equations describing oil rate as a function of pressure, retrieved from figures 4.6.1 - 4.6.4

Well	GOR, (sfc/bbl)	Water cut (%)	Estimated oil production
W02	5300	53	y = -10x + 800
W03	490	3	$y = 0.019x^2 - 24.48x + 1475.30$
W08	2300	2	y = -39.84x + 1842.20
W10	3700	12	y = -51.10x + 2758.20

Oil production rates varies depending on if it is estimated using yearly average production, shown in table 4.1.2, or performance estimation curves displayed in table 4.6.1. The same difference is observed by comparing estimated GOR and water cut reported in table 4.6.1 to the values in table 4.1.2. The values in table 4.1.2 originates from average calculations and have not been adjusted for abnormal periods or other conditions. Well performance curves are developed with more insight into the behavior of each well and are therefore considered to be more reliable.

Investigations on performance boost will be done using data originating from table 4.6.1. Calculations using data from 4.1.2 will also be conducted and are given in appendix.

5 Results and Discussion

The main benefit of the jet pump is an increased oil production. This increase leads to a higher load on downstream systems. Figure 2.2.1 shows that increasing streams from the production manifold affect most downstream systems.

In cases where a jet pump would rise the total pressure of well fluids going to production manifold, HP separator pressure could be increased. A higher separator pressure would result in some compressor work reduction.

Compressor energy consumption is most dependent of if one or two injection compressor trains are in use, meaning that increasing the load on a single train is not as significant compared to starting a second train. Wells using gas lift to maintain production will potentially require less lift gas as a result of reduced backpressure. A decrease in gas lift consumption result in more gas available for other utilities such as injection gas to the reservoir. Since injection gas requires more compression, the total compressor work would increase but more so if it meant operating both compressor trains.

Produced water is routed to six hydrocyclones. Discussions with Ula's process engineer revealed that the total capacity today is at 80000 bbl/d of water. The planned installation of a new cyclone will increase the capacity to over 110000 bbl/d of water. However, until this installation is in place, there will be a restrain on production here. Increased water production could potentially challenge the capacity of the water treatment system.

5.1 Estimation of Jet Pump Performance

Jet pump performance were investigated by Endùr. The performance estimations reported in this section are based on simulation models owned by Endùr and Caltec.

5.1.1 Using HP wells

Table 5.1.1 displays the vendors resulting HP, LP and MP pressures and stream details. Table 4.4.2 describes each case.

Table 5.1.1: Display of calculated performance of the cases from table 4.4.2 utilizing W09 or W18 as driving streams.

Case #	HP			LP			MP		
	Pressure barg	Flow MMscf/d	Liquid bbl/d	Pressure barg	Flow MMscf/d	Liquid bbl/d	Pressure barg	Flow MMscf/d	Liquid bbl/d
LM3	60	14.3	30760	7	1.1	1566	25	15.4	32326
LM3A	60	14.3	30760	20.6	10.4	4596	25	24.7	35356
LM3B	60	14.3	30760	21.0	11.5	5056	25	25.8	35816
LM4	75	3.7	18500	7	1.1	1566	25	4.8	20066
LM4A	75	3.7	18500	21.4	10.4	4596	25	14.1	23096
LM4B	75	3.7	18500	21.6	11.5	5056	25	15.2	23556

The resulting reduction in LP pressure is highly dependent on the amount of LP fluid routed to the jet pump, from 7 barg for W02+W03 to 20.6 for W02+W03+W08+W10. Combining and routing all LP wells to a jet pump driven by either W09 or W18 does not give a significant reduction of backpressure, since operating pressure of the HP separator is between 20-22 barg. Case LM 3B and LM 4B considered an incremental increase in LP flow rate of 10 %. Having a fixed HP flow rate and MP pressure resulted in an increase in LP pressure of 1.9 and 0.9 % for cases LM 3B and LM 4B respectively.

HP wells is an energy source which is cost. There will be a need for an in-line separator and commingling spool which represents additions to equipment cost and associated piping.

5.1.2 Using HP Injection Water

The results from simulating case LM 2, LM 2A and LM 2B, described in table 4.3.1, are displayed in table 5.1.2.

6300 bbl/d of injection water is needed to give a pressure on suction side of 15 barg for all LP wells combined. This amount is 26 % of the total available injection water. A 20 % incremental production gain resulted in a 2.4 % increase in required injection water rate to give the same reduction in backpressure.

Table 5.1.2: Display of calculated performance of the cases from table 4.3.1 utilizing injection water as driving stream.

Case #	HP			LP			MP		
	Pressure barg	Flow MMscf/d	Liquid bbl/d	Pressure barg	Flow MMscf/d	Liquid bbl/d	Pressure barg	Flow MMscf/d	Liquid bbl/d
LM2	250	0	6300	15	10.4	4596	20	10.4	10896
LM2A	250	0	6450	15	12.5	5515	20	12.5	11965
LM2B	250	0	1100	10	0.35	742	25	0.35	1842

The injection water is a fluid source which would otherwise be dumped, assumed that both injection pumps are in operation. It does not require separation prior to use which limit purchase cost of the jet pump system. However, the extra water being introduced back into the system will increase the load on the water treatment facility. The water handling capacity must therefore be evaluated. Compatibility of the possible mix of produced water and seawater must also be assessed.

5.1.3 Using HP Injection Gas

The required amount of HP gas to reduce backpressure of LP wells to 15 barg with a discharge pressure of 20 barg were estimated and the results are showed in table 5.1.3. A 20 % increase of LP fluids in cases GG 1A and GG 1C resulted in an increase of required HP gas of 20 and 14.3 % respectively.

For the cases where pressurized gas where used the estimated available gas rate were 6250 Mscf/d, which was a conservative estimate. The required gas rates are close to or above the available rate, suggesting that more gas have to be made available. If the jet pump reduced the need for gas lift, this could be utilized for driving fluid instead.

Table 5.1.3: Display of calculated performance of the cases from table 4.2.1 utilizing injection gas as driving stream.

Case #	HP			MP			MP		
	Pressure barg	Flow Mscf/d	Liquid bbl/d	Pressure barg	Flow Mscf/d	Liquid bbl/d	Pressure barg	Flow Mscf/d	Liquid bbl/d
GG 1	320	5500	0	15	10414	0	20	15914	0
GG 1A	320	6600	0	15	12497	0	20	19097	0
GG 1B	320	4900	0	15	9330	0	20	14230	0
GG 1C	320	5600	0	15	11196	0	20	16796	0

This solution requires the purchase of an in-line separator and commingling spool. A pump drive the separated LP well liquid to downstream separators would possibly also be required. Using injection gas to drive a jet pump result in more compressor work to maintain the gas rate going to reservoir injection. Similar to utilizing injection water, using injection gas increases the gas flow to the separator and downstream compressor trains.

5.1.4 Validation of Vendor Calculations

Alternative estimations were conducted on the jet pump driven by injection gas based on figure 2.3.2. Table 5.1.4 displays the found discharge pressure for each case when perfect gas-liquid separation in the upstream separator is assumed.

Table 5.1.4: Performance estimations on the gas-gas jet pump based on performance curves from [17].

HP Well	HP pressure, barg	LP pressure, barg	Pressure ratio	HP flow Mscf/d	LP flow Mscf/d	LP to HP flow ratio	Discharge to LP pressure ratio	Discharge pressure, barg
GG 1	320	15	21.3	5207	10414	2.0	1.3	20
GG 1A	320	15	21.3	6248	12497	2.0	1.3	20
GG 1B	320	15	21.3	4665	9330	2.0	1.3	20
GG 1C	320	15	21.3	5598	11196	2.0	1.3	20

Comparing the calculated HP flow rates to the estimations made by Endúr show a very good fit between the calculation, giving good indications that the performance estimations are realistic. The calculations were based on a graph originally made by Caltec, [17], which also provided estimations for Endúr. Possible additional validation should be done using independent models.

5.2 Jet Pump Efficiency

Theoretical jet pump efficiency in each case were calculated using equations 2.4.8 and 2.4.9. Figure 5.2.1 displays the results. Calculation details are displayed in table B.0.1 in appendix.

Overall, the estimated values for LM jet pumps are equal to or above what is reported in literature, such as Guo or Villa et. al, [10] and [26].

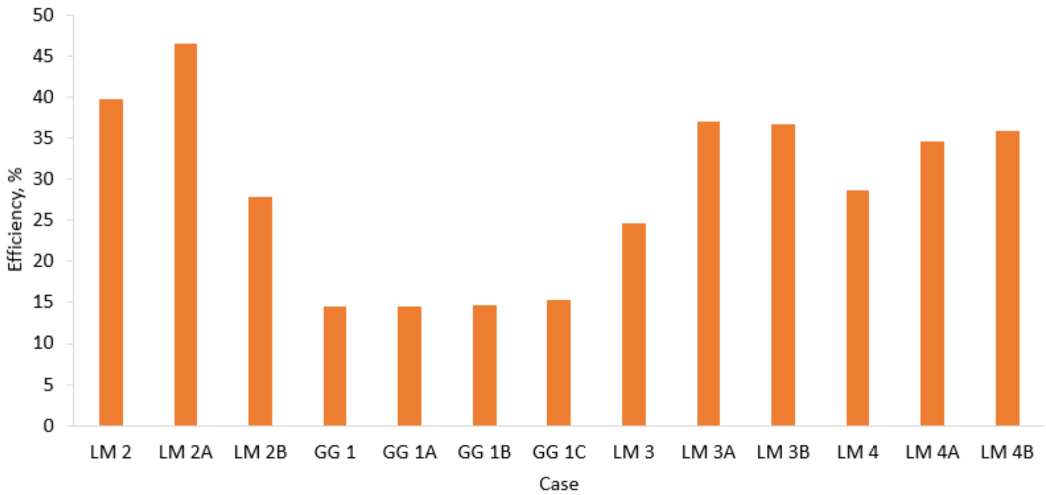

Figure 5.2.1: Presentation of the calculated efficiencies of the different cases based on equations 2.4.8 and 2.4.9.

The gas-gas jet pumps have estimated efficiency of 15 %, which were expected following investigations by Villa et. al. which stated that the efficiency declined with increasing GVF.

Perfect separation in the upstream in-line separator of cases GG1-1B and LM3-4B were assumed. In reality, this will not be the case and so the real efficiency will probably be smaller as a driving stream with a higher GVF negatively affects the performance of the jet pump. The calculated efficiency is valid for what is considered to be the peak performance of each case, meaning that fluctuating operating conditions will affect the efficiency.

What should also be considered is the efficiency of the treatment of the driving fluid, when it is needed. This suggests that the total efficiency of cases LM2-2B and GG 1-1C are lower than stated in figure 5.2.1 since the driving fluids require processing.

5.3 Increased Production from Low Pressure Wells

Potential production gain were estimated based on well performance curves developed by Aker BP. The curves for well 02, 03 and 10 where made with a minimum WHP of 10 barg. It was assumed that the estimations were valid also for lower pressures. Due to the assumption of constant GOR and water cut, gas and water production follows the increase in oil production.

The cases GG 1A, GG 1C and LM 2A were not included in these calculations because LP pressure were unchanged from their corresponding case. Note that the production increase reported in this section does only regard LP wells and excludes the added HP fluid.

5.3.1 Well 02

Table 5.3.2 displays the calculated production boost from well 02. A large gain in oil production from the well is observed for all cases. The highest production increases are found in case LM 3 and LM 4, since HP fluids are used to boost W02 and W03 alone and pressure on suction side is reduced to 7 barg. As suggested in section 4.6 the predictions based on the well performance curve for W02 may be more uncertain than the predictions for the other wells.

Table 5.3.1: Estimated new oil, gas and water production rate and gain from well 02.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, MScf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	650	8.3	3445	8.3	733	8.3
GG 1	15	650	8.3	3445	8.3	733	8.3
LM 3	7	730	32.7	3869	32.7	823	32.7
LM 3A	20.6	594	8.0	3148	8.0	670	8.0
LM 3B	21	590	7.3	3127	7.3	665	7.3
LM 4	7	730	32.7	3869	32.7	823	32.7
LM 4A	21.4	586	6.5	3106	6.5	661	6.5
LM 4B	21.6	584	6.2	3095	6.2	659	6.2

5.3.2 Well 03

Table 5.3.2 displays the calculated production boost from well 03. Well 02 and 03 are represented in the same cases, except for case LM 2B where W03 is the only LP source. The response in production for well 03 when being boosted by a jet pump is slightly larger than well 02. This is because of a steeper performance curve slope.

Table 5.3.2: Estimated new oil, gas and water production rate and gain from well 03.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, MScf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	1109	12.4	543	12.4	34	12.4
LM 2B	10	1231	42.4	603	42.4	38	42.4
GG 1	15	1109	12.4	543	12.4	34	12.4
LM 3	7	1304	50.8	639	50.8	40	50.8
LM 3A	20.6	972	12.4	476	12.4	30	12.4
LM 3B	21	962	11.3	471	11.3	30	11.3
LM 4	7	1304	50.8	639	50.8	40	50.8
LM 4A	21.4	952	10.2	467	10.2	29	10.2
LM 4B	21.6	947	9.6	464	9.6	29	9.6

5.3.3 Well 08

Table 5.3.3 displays the calculated production boost from well 08. This well has an estimated performance curve with the steepest slope, resulting in the largest increase in production per barg reduction in LP pressure.

Table 5.3.3: Estimated new oil, gas and water production rate and gain from well 08.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, MScf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15.0	1245	19.1	2863	19.1	25	19.1
GG 1	15.0	1245	19.1	2863	19.1	25	19.1
GG 1B	15.0	1245	19.1	2863	19.1	25	19.1
LM 3A	20.6	1022	20.7	2350	20.7	21	20.7
LM 3B	21.0	1006	18.8	2313	18.8	21	18.8
LM 4A	21.4	990	16.9	2276	16.9	20	16.9
LM 4B	21.6	982	16.0	2258	16.0	20	16.0

5.3.4 Well 10

Table 5.3.4 displays the calculated production boost from well 10. The jet pumps investigated gave a boost in production above 10 % in all cases.

Table 5.3.4: Estimated new oil, gas and water production rate and gain from well 10.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, MScf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15.0	1992	14.7	7369	14.7	272	14.7
GG 1	15.0	1992	14.7	7369	14.7	272	14.7
GG 1B	15.0	1992	14.7	7369	14.7	272	14.7
LM 3A	20.6	1706	15.2	6311	15.2	233	15.2
LM 3B	21.0	1685	13.8	6235	13.8	230	13.8
LM 4A	21.4	1665	12.4	6159	12.4	227	12.4
LM 4B	21.6	1654	11.7	6121	11.7	226	11.7

5.4 An Overview

Figure 5.4.1 summarizes the findings by comparing increased production for all wells in the different cases.

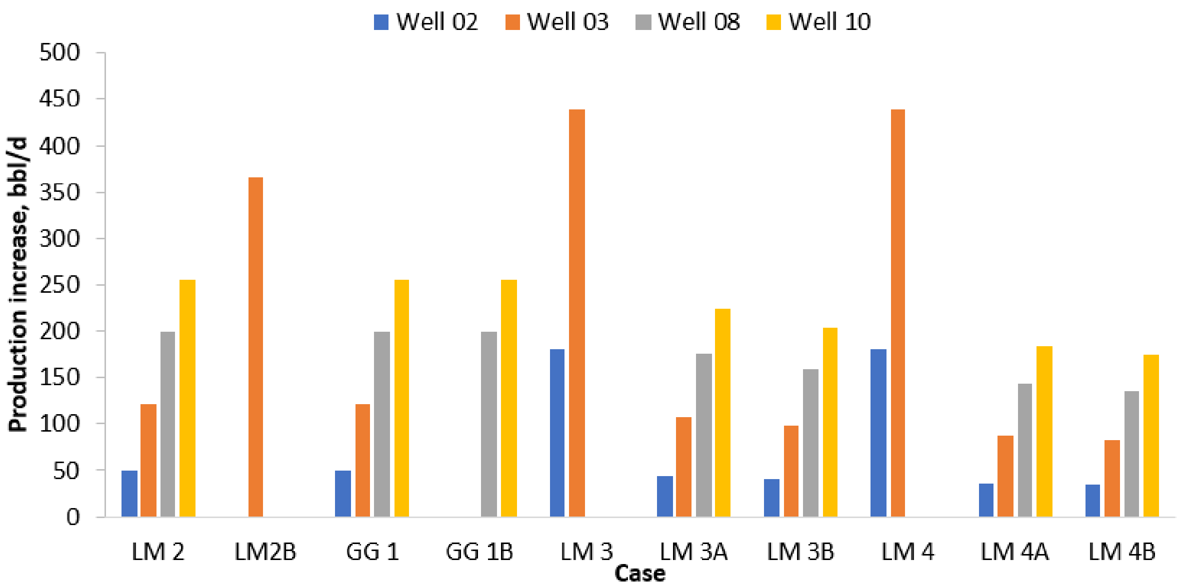

Figure 5.4.1: Graphical presentation of oil production gain for each case and LP well.

Case LM 2A estimated the needed amount of HP water if production were increased by 20 % from case LM 2. Estimated values from performance curves, tables 5.3.2-5.3.4, show that only well 08 have close to 20 % production increase, and 13.6 % as average increase for all LP wells. As a result, the required HP fluid will be between 6300 and 6450 bbl/d, and 6402 bbl/d exactly if assuming that the increase in required water is linear. The same result can be found from Case GG 1/1A were required HP gas will be between 5500 and 6600 Mscf/d, and 6248 Mscf/d assuming linear increase.

LM 3A/3B and LM 4A/4B compared the change in LP pressure when assuming 10 % production increase. Tables 5.3.2-5.3.4 show that the actual production increase are 14.0 and 11.5 % for LM 3A and LM 4A respectively. The expected LP pressure considering the increased production will therefore be higher than estimated, suggesting that the real production increase will be lower than estimated.

Table 5.4.1 summarizes the total expected gained oil production per case together with the needed addition of gas or water to the system. Cases LM3-4B utilizes HP well fluid which is already present in system and does therefore not add any fluids. It would require purchase and installation of an in-line separator. The jet pump has a high estimated efficiency and when used to boost wells 02 and 03, an increase in production of 620 bbl/d is expected.

Cases LM 2 and LM 2A and GG 1 and GG 1A results in the largest gain in oil production. HP gas would take up compressor capacity, as well as require an in-line separator and possibly a pump. Gas-gas jet pumps are therefore considered to be the least feasible option for production boosting at Ula.

A jet pump solution driven by injection water utilizes high pressure water which would otherwise be dumped. Large production gains are estimated for this solution but it implies adding more water to the process. Additional investigations are needed to ensure that the water treatment capacity is not exceeded in the time before the extra hydrocyclone becomes installed.

Table 5.4.1: Added gas or water compared with increased total oil production and estimated revenues for each case.

Case	Added water, bbl/d	Added gas, Mscf/d	Added oil prod. bbl/d	Est. revenues NOK per year
LM 2	6300	0	627	121 144 000
LM 2A	6450	0	if 20 % increase	-
LM 2B	1100	0	366	70 783 000
GG 1	0	5500	627	121 144 000
GG 1A	0	6600	if 20 % increase	-
GG 1B	0	4900	455	87 885 000
GG 1C	0	5600	if 20 % increase	-
LM 3	0	0	620	119 753 000
LM 3A	0	0	551	106 590 000
LM 3B	0	0	501	96 899 000
LM 4	0	0	620	119 753 000
LM 4A	0	0	451	87 209 000
LM 4B	0	0	426	82 364 000

A price of $ 60.87 per barrel crude oil retrieved from OPEC's website June 3. 2019 were used to make an estimation of the value of the increased production, displayed in table 5.4.1. After correspondence with the vendor and engineers at Aker BP an assumption of a cost range was made. The equipment is likely to have a cost of 5-10 mill. NOK, depending on the required equipment and safety arrangement. However, the largest costs are related to required downtime for installation and rearrangements of piping. The total cost is roughly assumed to be 30 mill. NOK. This gives a payback time of three months using case LM2 or LM 3.

6 Process Safety and Control

Health, safety and environment are important and the implications of installation of new equipment on HSE must be evaluated. By identifying and analyzing risk factors, necessary barriers can be installed to limit these risks. Conducting risk assessments is therefore a key element of safe operation.

There exists a range of international standards which states the functional requirements and guidelines for analysis, design and testing of safety systems in different types of installations [6]. The European standard often used for basic surface processing safety systems in offshore oil and gas industry is the ISO 10418 standard. The following investigations will be conducted using the following standards as basis:

- ISO 10418 (similar to API 14C)
- P-002
- API STD 521

The Ula platform is built and operates according to ISO 10418 standard for offshore installations. The possible installation of a jet pump will have to comply with the requirements of this standard. The jet pump will utilize one or several high and low pressure fluid sources from well lines routed bypass the choke valve or water/gas injection lines. The discharge stream is connected to the production or test manifold and further led to the separators.

To conduct a full safety analysis on the proposed jet pump solutions would be very comprehensive and not in scope of this report. This section will determine undesirable events related to an operating jet pump and connecting equipment up- and downstream, defined from the production flowlines and injection lines to the separator. Recommended safety devices are found from ISO 10418 and will be compared to existing instrumentation. Further, a brief description of process control philosophy will be presented.

Two different configurations of jet pump technology will be investigated, one being the same as proposed in section 3.1.2 and the other when the source of HP fluid is either injection gas or water, showed in sections 3.2 and 3.3.

6.1 Undesirable Events

A number of undesirable events are listed in annex B.2 of ISO 10418 [6]. Marvin Rausand defined it as the first event in a series that leads to an undesired consequence if not adverted [20]. It is therefore sometimes called an accident initiator. ISO 10418 contains safety analysis tables (SAT) for a range of process equipment. SATs states undesirable events that can affect the equipment and possible causes of them. It also states how undesirable events can be detected. Safety analysis checklists (SAC) follows the SATs and states required safety instrumentation. Together with each safety device is a set of conditions, or exemptions, which eliminate the requirement for that safety device.

There are no specific SAT available for jet pumps. It was therefore decided to use the SAT for a header since previous safety analysis work conducted for jet pumps at another of Aker BP's assets, Valhall, made this assumption. SAT B.5 in ISO 10418, showed in table 6.1.1, states that the following events are the most relevant for a jet pump.

Table 6.1.1: SAT table for jet pump [6].

Undesirable event	Cause	Detectable condition at component
Overpressure	Blocked or restricted outlet Hydrate plug Upstream flow control failure Excess inflow	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure Fire or Gas accumulation
Excess temperature	High fluid temperature Gas pressure drop	High temperature Low temperature

Upstream flow control failure listed as a cause of overpressure can be illustrated by a specific scenario known as choke inadverted valve opening. At normal start-up of a well the choke is opened gradually after opening of the wing valve closest to the well. As explained by engineers in Aker BP, a choke inadverted valve opening occurs if the choke valve is fully open at start-up of a high pressure well so fluids flows unrestricted to downstream equipment. This specific cause is a highly unlikely scenario but can potentially cause serious damage to downstream equipment. A proposed solution is installing a second choke valve. Until this solution is in place, an awareness of this possible scenario is necessary.

6.2 Safe Operating Limits

Processing equipment are constructed to fit a site's specific process conditions. Figure 6.2.1 illustrates the philosophy of different operating envelopes, which are defined for all relevant process variables, such as pressure, temperature or flow rate.

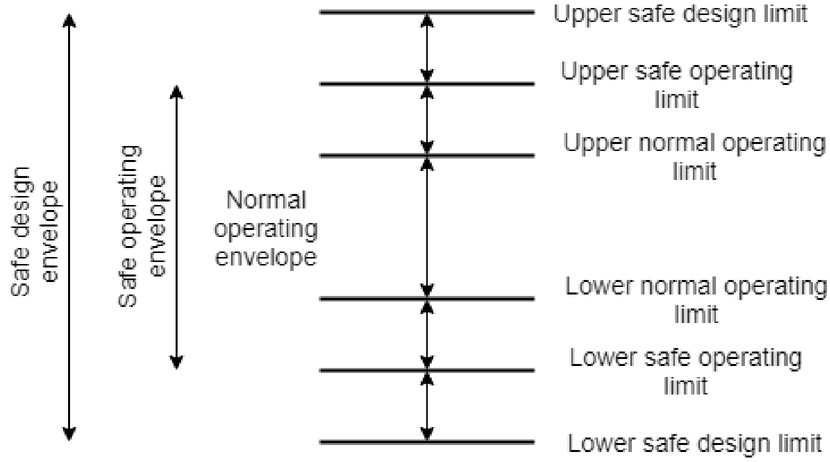

Figure 6.2.1: Graphical presentation of safe operating limits envelopes [13].

Tables D.0.1, D.0.2 and D.0.3 in appendix displays safe operating limits for flowlines, injection lines, manifolds and separators. Most relevant for the preliminary safety analysis in this work are the safe operating and design limits. The pressure design limit is determined by the design rules of the specific pressure design code of a component, as defined by API STD 521. Another relevant property is maximum allowable working pressure (MAWP), defined as the maximum gauge pressure permissible at the top of a completed vessel in its normal operating position at the designated coincident temperature specified for that pressure. Design pressure is equal to or less than the MAWP, (MWAP = design pressure if MWAP is unknown)[3].

6.3 Safety Instrumentation

Investigations of Piping&Instrument-diagrams (P&IDs) from the specified areas showed the existing safety instrumentation system. A schematic of the findings are displayed in figure 6.3.1. "ST" in "XST" denotes safety transmitter, and "X" denotes the detectable condition, such as pressure, temperature or flow. The safety devices are in compliance with the ISO 10418 standard.

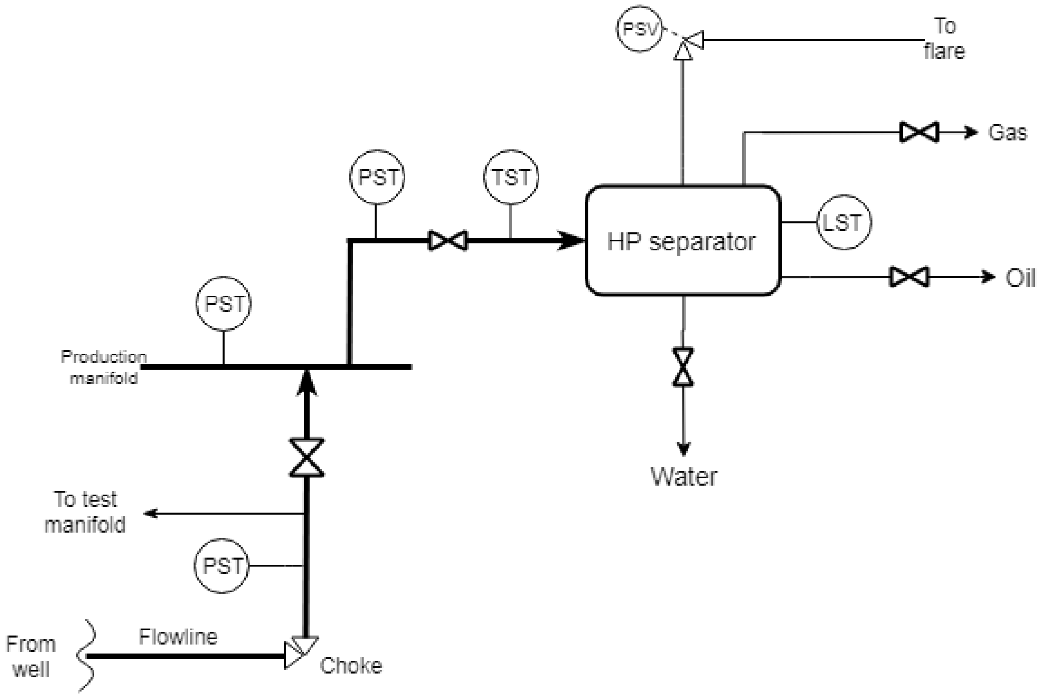

Figure 6.3.1: Schematic of the main safety instrumentation. The three PSVs on the HP separator are illustrated as one for simplicity.

The illustration in figure 6.3.1 displays only the production manifold and HP separator. The flowlines from the wells at Ula could also be routed to the test manifold and test separator. It was decided to exclude this route for simplicity.

From the SOL tables, it can be found that the design pressure of the manifold is 226 barg and the production lines have design pressures in the range of 226-380 barg. The maximum shut-in pressure of the HP wells has previously been tested and found to be 305 barg. The production manifolds design pressure is lower than this, but after investigations and pressure testing, it was decided that the equipment could withstand max. shut-in pressure, and did not require a PSV. The jet pump solution, including possible in-line separator and commingling spool, is assumed to have the same design pressure as the highest inlet source.

The upper design pressure of the HP separator is 31 barg. There is a valve on the inlet of the HP separator which closes of if necessary.

There are check valves placed on every line which prevent fluid flow in the opposite direction, and thus hinder back flow. The lines also have pressure safety transmitters (PST) with an alarm that is activated if the measured pressure exceeds a set limit, usually set at upper safe operating limit [13], and closes of the high pressure source (here the production lines).

The main characteristic for performance of a PST is the response time from the alarm goes off to the relevant valves are closed. There is usually an extra pressure transmitter set at upper normal operating limit which notifies the operators and give them time to act and possibly prevent the automatic shut-down. The PST is the first barrier in the safety system against overpressure. The second barrier is a Pressure relief device (PRD), here represented by a pressure safety valve (PSV), which is mechanical and inhibit further pressure increase.

The HP separator has three PSV's, illustrated as a single PSV in figure 6.3.1. As explained by Crowl&Tipler, the PSV opens at a specified pressure to release mass from the system [7]. The maximum mass flow through a PSV is the main characteristic of its performance. The set pressure is normally set at upper design limit [13]. The PSV closes when pressure is reduced below set pressure. There is, however, limited capacity on the relief rate of these PSVs. Following a jet pump installation, production rates are expected to increase and could exceed PSV capacity. Specific scenarios, such as start-up where HP well pressures are expected to be extra high, should be investigated in detail.

Level safety transmitters are installed on the HP separator which sets of an alarm if the liquid level is either too high or too low. Very high liquid levels can lead to liquid flow into the gas outlet, also known as liquid overflow. Too low liquid levels can result in gas being routed to the liquid outlets, also known as gas blowby.

6.3.1 Jet Pump Specific Safety Instrumentation

The requirements for the safety arrangement for a jet pump are stated in SAC B.6 in ISO 10418 [6]. Table 6.3.1 summarizes the findings.

Table 6.3.1: Required safety devices for a jet pump as stated in SAC table B.6 in ISO 10418 [6].

Undesirable event	Protection	
	Primary	Secondary
Overpressure	PST, high alarm	PSV
Leak	PST, low alarm	Fire and gas detection
Excess temperature	TST	

Following the listed exceptions in the SAC, PST with high alarm already installed at the manifold is an adequate primary overpressure protection, showed in figure 6.3.2. A PSV is not necessary since the jet pump is built to withstand the max. shut-in pressure (Entry c.2 in SAC table B.6.).

An adequate fire and gas detection system already in place removes the requirement of a PST with low pressure alarm. The temperature design limit of the flowlines and header are -6/200 °C (Table D.0.2). Fluid temperatures will not exceed these limits so temperature safety transmitters are not necessary according to table B.6, remark e.2 in ISO 10418.

Figure 6.3.2 displays a possible arrangement of the safety devices when the jet pump is installed. Note that a potential in-line separator is not included in this arrangement. Jet pump discharge can either be routed directly to the manifold as displayed or be connected to the production flowline upstream the manifold.

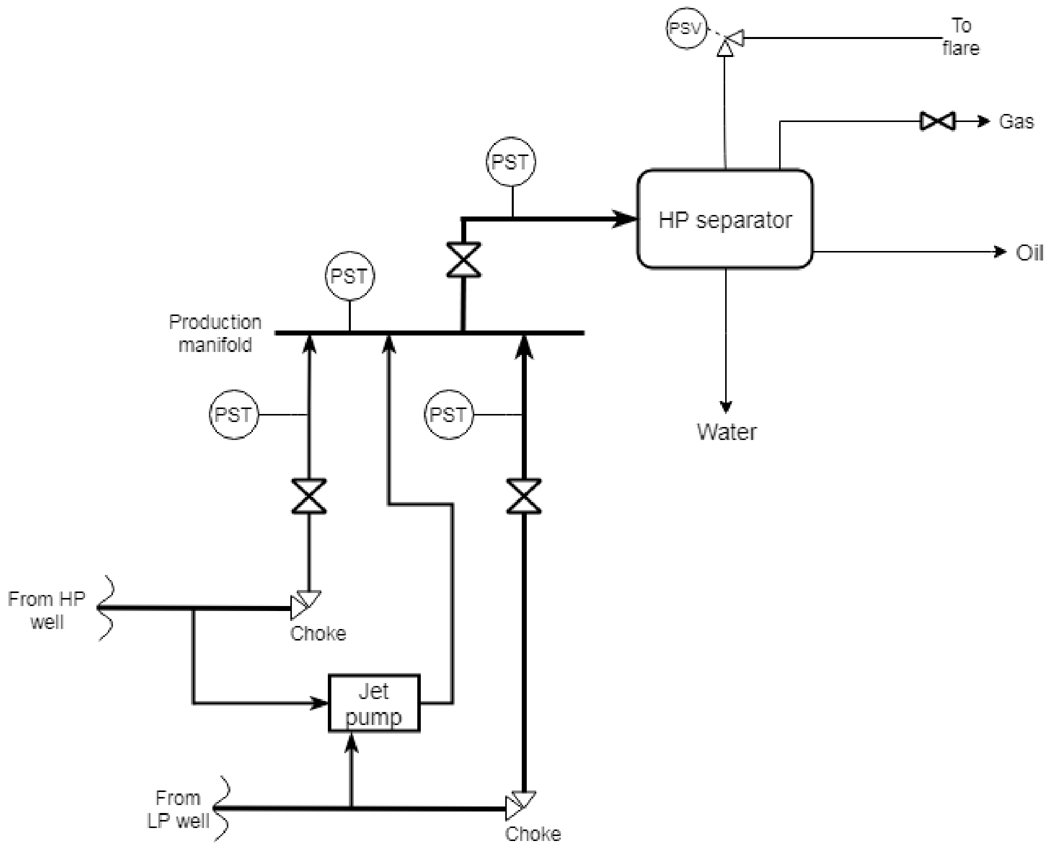

Figure 6.3.2: Schematic of the main safety instrumentation when a jet pump is installed. The three PSV's on the HP separator are illustrated as one for simplicity.

6.3.2 Jet Pump with In-line Separator

For the boosting solution in section 3.1.2 and 3.3 an in-line separator are included in the installation. In a safety analysis the compact in-line separator would be regarded as a flowline segment as long as it is built in a standard pipe code dimension. Section B.3 of ISO 10418 describes the requirements for this type of equipment [6]. Overpressure, leakage and excess temperature are listed as possible undesirable events. Following the same argument as for the jet pump, excess temperature in the system is not a problem. Suitable protection is already in place for detection of leakage. If liquid overflows to gas outlet or gas goes to liquid outlet, it would only affect the performance of the jet pump and not be a safety issue.

Safety transmitters to detect high pressure are required upstream the inlet. Entry a2 in SAC table B.2 states that a PST would not be necessary if the working pressure is not set higher than the max. shut-in pressure and is protected by a downstream PST. It is assumed that the in-line separator will have a working pressure that matches the upstream segments and that the PST at the manifold is regarded as adequate protection. Following this, there is not a requirement for a PSV as well, listed as exemption c2 in the SAC table.

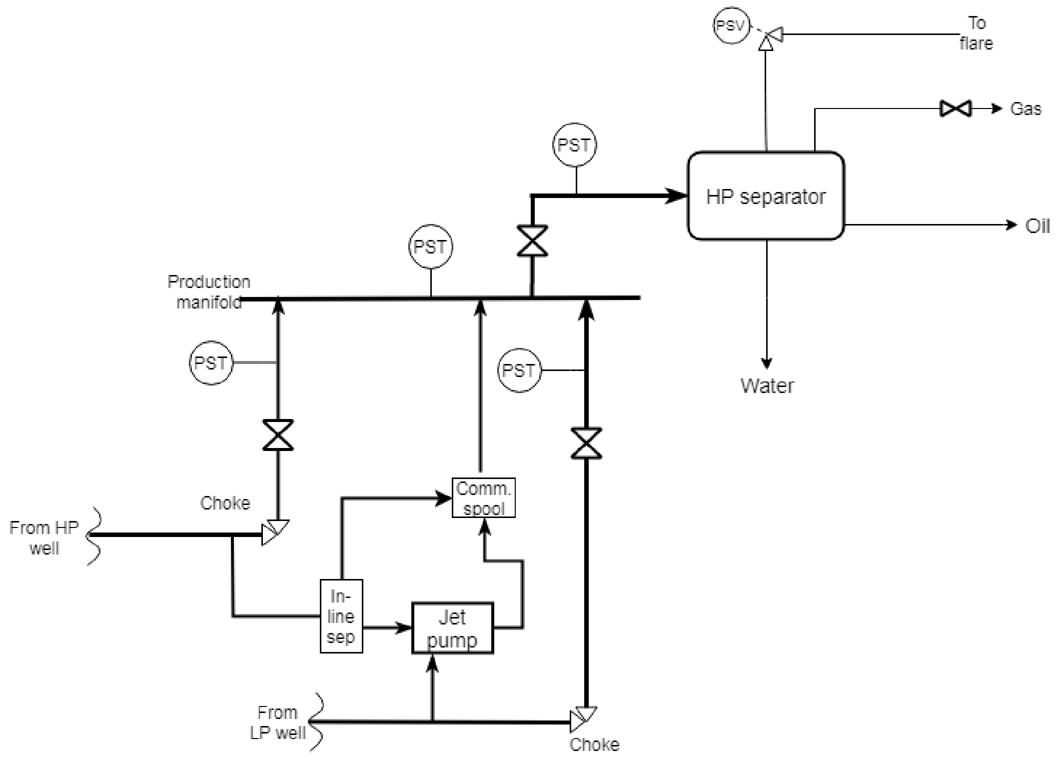

Figure 6.3.3: Schematic of the main safety instrumentation when a jet pump system with in-line separation of HP well stream is installed. The three PSV's on the HP separator are illustrated as one for simplicity.

6.3.3 Using Injection Water/Gas as Driving Fluid

The gas-gas jet pump solution includes an in-line separator which is left out in this section. The previous section evaluates a solution with an in-line separator and so this segment is considered to be covered there.

This arrangement is similar to the solution in section 6.3.1 but the driving stream source is an injection line with a design pressure of 551 barg (table D.0.1). Water and gas injection streams have a pressure of 250 and 320 barg respectively. A new review of the required safety devices is needed.

As in the previous solutions the gas detection system is capable of detecting leaks, so a PST with low pressure alarm is not required. Fluid temperatures are not expected to exceed design limits which eliminates the requirement of a TST.

Two strategies for securing the jet pump against overpressure is proposed. The first assumes that the jet pump is built with the same design pressure as the upstream well flowlines. This implies the installation of a control and safety structure on the water/gas injection line to prevent inflow of too high pressure to the jet pump. PST, control valve and a PSV set at the upper design limit for the jet pump is then needed, showed in figure 6.3.4. A possible reduction of driving fluid pressure prior to the jet pump will negatively affect jet pump performance.

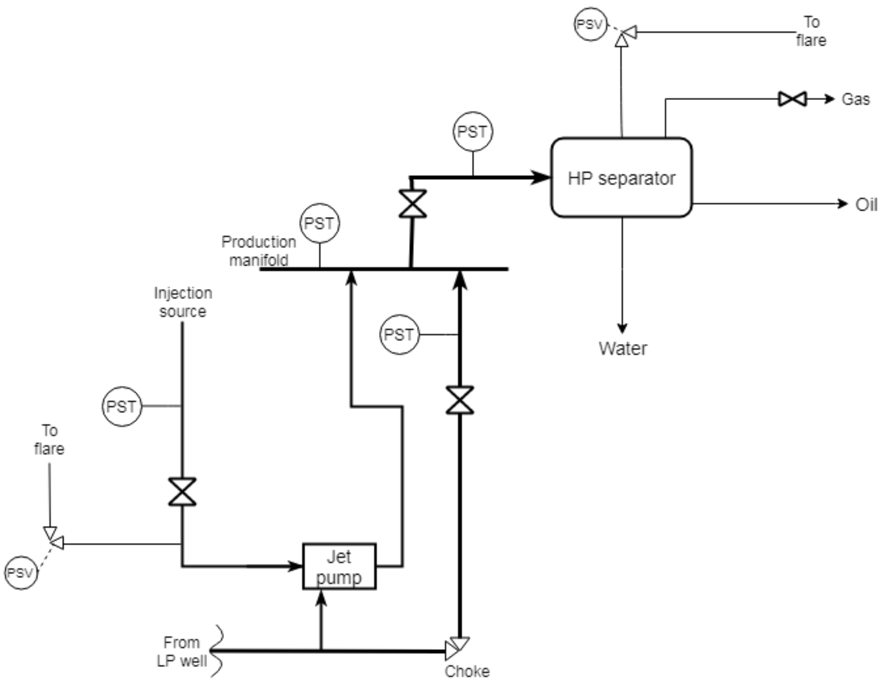

Figure 6.3.4: Schematic of the main safety instrumentation when a jet pump system driven by fluids from an injection line is installed and the jet pump is built to match design pressure of well lines.

The second arrangement is the result if the jet pump were to be built to match injection line pressure design code. The jet pump discharge line would then need a safety arrangement including PST, control valve and a PSV adjusted to protect the production manifold. The arrangement is displayed in figure 6.3.5.

Both arrangement implies the installment of a PSV, which includes piping to connect with the flare system and represent a significant cost.

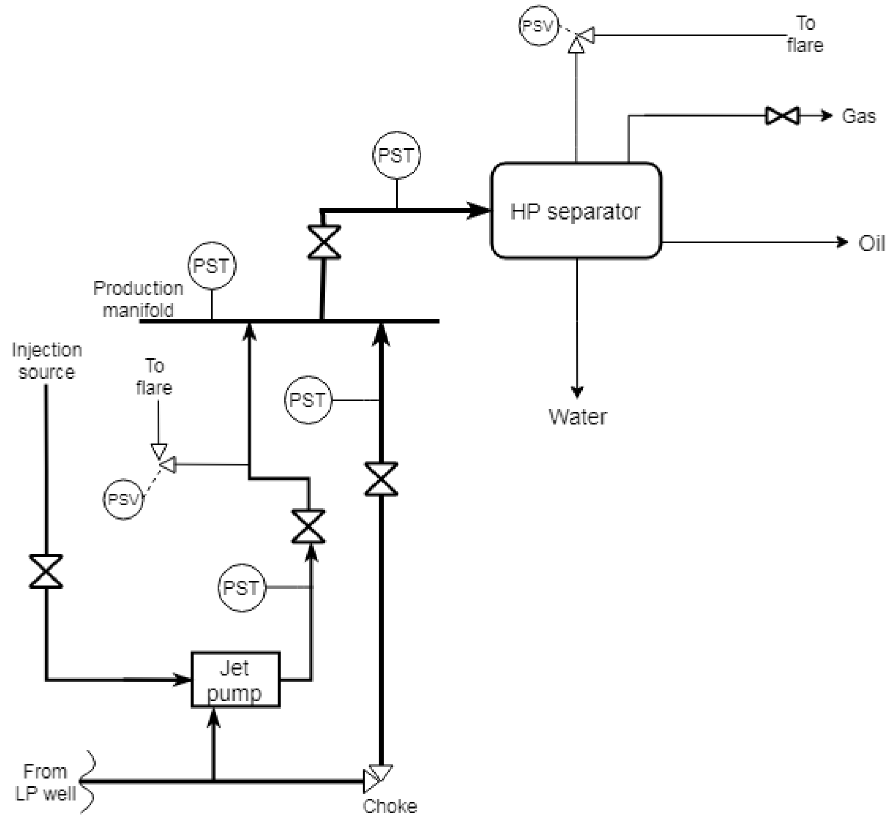

Figure 6.3.5: Schematic of the main safety instrumentation when a jet pump system driven by fluids from an injection line is installed and the jet pump is built in the same pressure grade as the injection line.

6.4 Control Instrumentation

In addition to safety instrumentation, conducting measurements of pressure and flow rate allow for process regulation. However, according to the developers at Caltec, no active control is needed for boosting applications [5]. The proposed control structure is therefore optional.

Different control structures are available and figure 6.4.1 displays one type of arrangement. Pressure and flow transmitters are installed at each inlet. Valves are located at each inlet and on the recycle line. When the jet pump is installed in bypass of the choke valve, switching between jet pump and normal production is uncomplicated.

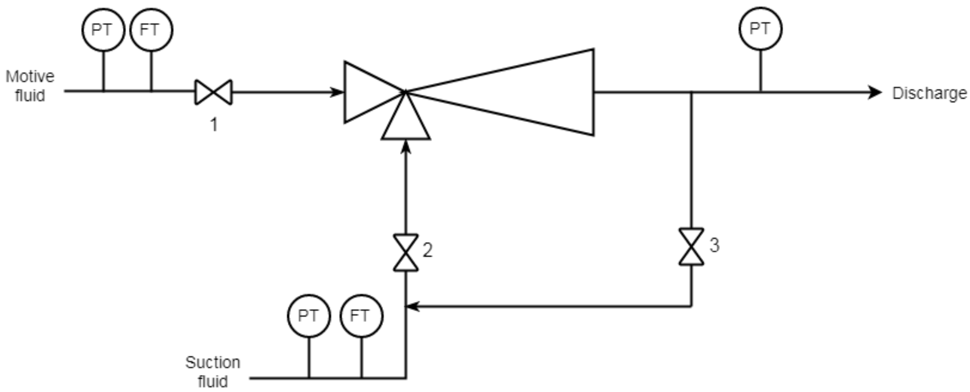

Figure 6.4.1: Suggested control arrangement for a jet pump.

The combination of flow and pressure measurements at HP inlet could be used to indicate wear of the HP nozzle if HP flow increase with constant HP pressure [5]. In the cases where an in-line separator is used, the recycle line can be used to control the LP pressure, and thus the pressure in the in-line separator.

Start-up and shutdown routines varies with different applications and conditions at the field.

7 Conclusion

Investigations were conducted on how jet pump technology could be utilized for production boosting at the Ula platform operated by Aker BP. Three suggested solutions were presented, utilizing high pressure wells W09 or W18, injection gas or injection water. Evaluation of jet pump performance were conducted in cooperation with a vendor of jet pump technology, Endúr, and its supplier, Caltec. Simulation models developed by Caltec were used to estimate the amount of backpressure reduction on low pressure wells and the needed amount of driving fluid to do so.

HP well fluid are traditionally relieved of excess pressure over the choke valve. Utilizing this energy in a jet pump for production boosting of LP wells have the potential to prolong the lifetime of these wells without operating costs or extra emissions. Well 09 and 18 have an assumed average pressure of 60 and 75 barg respectively. Estimated oil production gain is 620 bbl/d when boosting Well 02 and 03 together and 551 bbl/d when boosting all four wells. It is therefore more beneficial for a jet pump driven by a HP well to boost a fewer number of wells.

Injection water with a pressure of 250 barg was found able to lower backpressure of all four low pressure wells to 15 barg. The estimated oil production increase is 627 bbl/d using 6402 bbl/d of injection water. Injection water are in excess in the process, and so utilizing this as a driving fluid improves energy utilization at Ula.

Injection gas having a pressure of 320 barg where estimated to give an increased oil rate of 627 bbl/d when reducing backpressure to 15 barg. The required amount of gas are 6248 Mscf/d, which is equal to the estimated available gas. If more gas were to be needed it would put restrictions on the compressors also treating gas for reservoir injection. This solution is therefore considered to be less suitable compared to the other driving sources.

Research on process safety and control related to the different jet pump solutions were also done. Safety analysis tables from ISO 10418 were used to investigate the need for additional safety instrumentation. Recommended instrumentation not already installed were PST with high alarm, control valve and PSV when the source of driving fluid was HP water og gas. No new instrumentation were found to be required when HP wells were driving fluid.

A brief economical evaluation was conducted. The estimated yearly revenues were estimated to 121.1 mill. NOK for cases LM2 and GG 1 and 119.9 mill. NOK for cases LM 3 and LM 4. Assuming total cost of the installed jet pump solution to be 30 mill. NOK results in an investment payback time of three months.

8 Suggestions for Further Work

The basis of the jet pump performance estimations were based on properties retrieved from Unisim and average production rates from the last year. A more accurate estimation could have been reached if the full production data set as well as future estimations were used.

Investigations on additional cases for the solutions using injection water and HP wells are needed before being able to conclude on the optimal combination of HP and LP streams. Also, conducting independent calculations of the vendor's given performances is advised for validation purposes.

Estimations on increased production were based on real well test reports. The number of test were very limited for some wells and several of the tests where reported with deviations resulting in uncertain calculations of production boost. To improve the estimations, reservoir modeling software such as GAP or Prosper could be used to better estimate well response to changes in backpressure. The same models could be used to investigate possible reduced gas lift need.

The wells investigated in this report were limited to the wells at Ula. Preliminary investigations on Tambar satellite field revealed two low pressure and one high pressure well which could be well suited for a jet pump application. Investigations into the possibility of using jet pump technology at Tambar should therefore be considered in the future.

A comprehensive safety analysis, e.g. a HAZOP study, of the installation will have to be conducted in cooperation with the jet pump supplier.

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A Relevant units and conversions

Table A.0.1: Common units in oil and gas production [16]

Unit	Description
Sm^3 o.e.	Standard cubic oil equivalent
Sm^3	Standard cubic meter
Scf	Standard cubic foot
Mscf/d	Thousand standard cubic feet per day
STB/bbl	Stock tank barrel/barrel

Table A.0.2: Conversion of quantities in oil& gas production [16]

Quantinty		Conversion factor	Description
1 Sm^3	=	6.2898 bbl	STB /barrel
1 Sm^3	=	35.315 sfc	Standard cubic foot
1 scf	=	0.028317 Sm^3	Standard cubic meter
1 Mscf/d	=	0.001256 t/h	Tonnes per hour
1 Sm^3 oil	=	1 Sm^3 o.e.	Standard cubic oil equivalent
1000 Sm^3 gas	=	1 Sm^3 o.e.	Standard cubic oil equivalent

B Calculation of efficiency

Table B.0.1: Calculation details based on equation 2.4.8 for LM jet pumps and equation 2.4.9 for GG jet pumps.

Case	Numerator	Denumerator	Efficiency, %
LM 2	91468	230391	39.70
LM 2A	109763	235877	46.53
LM 2B	10989	39353	27.92
GG 1	87814	602266	14.58
GG 1A	105378	722719	14.58
GG 1B	78673	536564	14.66
GG 1C	94408	613216	15.40
LM 3	42232	171179	24.67
LM 3A	63328	171179	36.99
LM 3B	62795	171179	36.68
LM 4	42232	147075	28.71
LM 4A	50996	147075	34.67
LM 4B	52749	147075	35.87

C Calcualtion of Production Boost using Average Production Data

Table C.0.1: Estimated new oil, gas and water production rate and gain from well 02 based on average production data from table 4.1.2.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, Mscf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	650	146.5	1800	146.5	1381	146.5
GG 1	15	650	146.5	1800	146.5	1381	146.5
LM 3	7	730	176.8	2021	176.8	1551	176.9
LM 3A	20.6	594	125.3	1644	125.3	1262	125.3
LM 3B	21	590	123.8	1633	123.8	1253	123.8
LM 4	7	730	176.8	2021	176.8	1551	176.9
LM 4A	21.4	586	122.2	1622	122.2	1245	122.3
LM 4B	21.6	584	121.5	1617	121.5	1240	121.5

Table C.0.2: Estimated new oil, gas and water production rate and gain from well 03 based on average production data from table 4.1.2.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, Mscf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	1109	53.1	542	53.1	28	53.4
LM 2B	10	1231	70.0	602	70.0	31	70.3
GG 1	15	1109	53.1	542	53.1	28	53.4
LM 3	7	1304	80.1	638	80.1	32	80.4
LM 3A	20.6	972	34.2	475	34.2	24	34.5
LM 3B	21	962	32.9	470	32.9	24	33.1
LM 4	7	1304	80.1	638	80.1	32	80.4
LM 4A	21.4	952	31.5	466	31.5	24	31.8
LM 4B	21.6	947	30.9	463	30.9	24	31.1

Table C.0.3: Estimated new oil, gas and water production rate and gain from well 08 based on average production data from table 4.1.2.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, Mscf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	1245	2.9	3137	2.9	41	2.9
GG 1	15	1245	2.9	3137	2.9	41	2.9
GG 1B	15	1245	2.9	3137	2.9	41	2.9
LM 3A	20.6	1022	-15.6	2575	-15.6	34	-15.6
LM 3B	21	1006	-16.9	2535	-16.9	33	-16.9
LM 4A	21.4	990	-18.2	2495	-18.2	33	-18.2
LM 4B	21.6	982	-18.9	2475	-18.9	32	-18.9

Table C.0.4: Estimated new oil, gas and water production rate and gain from well 10 based on average production data from table 4.1.2.

Case	WHP w/ jp	Oil rate, bbl/d	Increase, %	Gas rate, Mscf/d	Increase, %	Water rate, bbl/d	Increase, %
LM 2	15	1992	28.5	8070	28.5	296	28.5
GG 1	15	1992	28.5	8070	28.5	296	28.5
GG 1B	15	1992	28.5	8070	28.5	296	28.5
LM 3A	20.6	1706	10.0	6910	10.0	253	10.0
LM 3B	21	1685	8.7	6827	8.7	250	8.7
LM 4A	21.4	1665	7.4	6745	7.4	247	7.4
LM 4B	21.6	1654	6.7	6703	6.7	245	6.7

D Safe operating limits

Table D.0.1: Safe operating limits for pressure in production lines, injection lines and manifolds.

Equipment/line	Pressure [barg]			
	Normal operating set point	Normal operating limit	Safe operating limits	Safe design limits
Flowline W02 USC	22	23/160	NA	-1/269
Flowline W02 DSC	22	NA/50	NA/65	-1/226
Flowline W03 USC	34	22/110	NA	-1/344
Flowline W03 DSC	34	NA	NA/65	-1/228
Flowline W08 USC	12	NA/60	NA	-1/269
Flowline W08 DSC	12	NA/50	NA/65	-1/269
Flowline W09 USC	110	97/226	NA	-1/345
Flowline W09 DSC	33	NA/75	NA/80	-1/345
Flowline W10 USC	25	23/47	NA	-1/269
Flowline W10 DSC	30	NA/50	NA/65	-1/226
Flowline W12 USC	59	NA/119	NA	-1/380
Flowline W12 DSC	21	NA/47	NA/65	-1/345
Flowline W18 USC	65	NA/185	NA	-1/381.4
Flowline W18 DSC		NA/47	NA/65	-1/228
Test manifold	30	NA	6/NA	-1/226
Prod. manifold	30	NA	10/NA	-1/226
Flowline WAG inj. W01	NA	300/500	0/551	0/551
Flowline WAG inj. W11	345	300/500	0/551	0/551
Flowline WAG inj. W13	375	300/500	0/551	0/551
Flowline WAG inj. W14	375	300/500	0/551	0/551
Flowline WAG inj. W15	365	300/500	0/551	0/551

Table D.0.2: Safe operating limits for temperatures in flow lines connected to production manifold

Equipment/line	Temperature [C]			
	Normal operating set point	Normal operating limits	Safe operating limits	Safe design limits
Flowline W02 USC	150	35/NA	NA	-6/121
Flowline W02 DSC	150	35/NA	NA	-6/121
Flowline W03 USC	80	30/NA	NA	-6/120
Flowline W03 DSC	80	30/NA	NA	-6/120
Flowline W08 USC	150	89/NA	NA	-6/121
Flowline W08 DSC	150	89/NA	NA	-6/121
Flowline W09 USC	120	75/NA	NA	-7/121
Flowline W09 DSC	120	75/NA	NA	-7/121
Flowline W10 USC	150	75/NA	NA	-6/121
Flowline W10 DSC	150	75/NA	NA	-6/121
Flowline W12 USC	140	75/NA	NA	-7/121
Flowline W12 DSC	140	75/NA	NA	-7/121
Flowline W18 USC	130	90/NA	NA	-46/121
Flowline W18 DSC	130	90/NA	NA	-46/121
Test manifold	150	NA	NA	-6/200
Prod. manifold	150	NA	NA	-6/200
Flowline WAG inj. W01	80	NA	NA/140	-46/140
Flowline WAG inj. W11	80	NA	NA/140	-46/140
Flowline WAG inj. W13	80	NA	NA/140	-46/140
Flowline WAG inj. W14	80	NA	NA/140	-46/140
Flowline WAG inj. W15	80	NA	NA/140	-46/140

Table D.0.3: Safe operating limits for MP and HP separators.

		HP separator	MP separator
Pressure [barg]	Normal operating set point	17	9
	Normal operating limit	16.5/24	7.6/17.3
	Safe operating limits	10/25	6/19.7
	Safe design limits	0/31	0/21.5
Temperature [C]	Normal operating set point	135	99.8
	Normal operating limits	20/NA	NA
	Safe operating limits	5/NA	NA
	Safe design limits	-6/142	-6/134
Flow (gas) [t/hr]	Normal operating set point	70	0.2
	Normal operating limits	NA	NA
	Safe operating limits	NA/87	NA/20
	Safe design limits	NA/97	NA/22.2
Flow (oil) [Sm3/hr]	Normal operating set point	30	NA
	Normal operating limits	NA	NA
	Safe operating limits	NA/82.5	NA/284.5
	Safe design limits	NA/92	NA/316.1
Flow (water) [m3/hr]	Normal operating set point	270	17
	Normal operating limits	NA	NA

Table D.0.3: Safe operating limits for MP and HP separators.

		HP separator	MP separator
	Safe operating limits	NA/450	NA/43
	Safe design limits	NA/500	NA/48.1
	Normal operating set point	47	48
Level (oil) [%]	Normal operating limits	35/62	42/64
	Safe operating limits	4/100	0/100
	Safe design limits	0/100	0/100
	Normal operating set point	88	80
Level (water) [%]	Normal operating limits	67/94	70/95
	Safe operating limits	12.4/100	0/100
	Safe design limits	0/NA	0/NA

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