Production technology designed for heavy oil recovery of a marginal field offshore Vietnam

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ABSTRACT

Production technology application in heavy oil production has been widely developed in industry over past decades in an effort to improve the ultimate recovery of this "difficult" hydrocarbon. Apart from thermal method, pumping technology makes remarkable advance by enlarging the draw-down created over the conventional gas-lift in several heavy oil projects. This paper presents the production technology design set out in the Field Development Plan (FDP) to enhance the wellbore lifting efficiency of a marginal heavy oil field offshore Vietnam. The finding of 20^0API viscous oil in Cuu Long Basin is weird to the geologist and its considerable large reserve challenges operator in thinking of a suitable development strategy to efficiently and economically extract this reserve. In so doing,a series of systematic technical studies has been purposely planned from the first encounter of heavy oil in wildcat well to the modelling study and asset design to accommodate the viscous fluid whilst optimizing the economic yield over the field life. Among them, the application of Electric Submersible Pump (ESP) was finally decided as the key driver to reinforce the well performance. As a result, the facility design at the surface such as surface electrical system coupledwith gas-lift back-up, sand control, chemical injection and so on, all integrated in one to boost production and prolong well life.

Key words*: *Electric Submersible Pump, heavy oil, recovery, combination, back-up

1. INTRODUCTION

The application of the ESP has been well-known in the industry but still quite low in Vietnam. Whilst a neighbour field employed it since early two thousands as an alternative in the event gas-lift system unavailability, the application in this project is to enhance artificial lift efficiency in heavy oil production. It's a long progress from the very first few days when encountered viscous oil in the well testing to the concept selection, equipment sizing, deployment considerationand economic aspect. This paper introduces a systematic approach todesign an efficient artificial lift system to enhance production of the heavy oil reservoir, Tay Do field from the field development planning to execution phase.

Background

The Tay Do field was found commercially via threewildcat wells with wide range of formation and fluid properties. Its development concept is depicted in **Figure 1** in which heavy oil producers in Platform B will be the candidate for artificial lift optimization.

Three pay zones were discovered in the Middle Miocene Upper-Lower Con Son formations (BII.2.20, BII.2.30 and BII.1.10) in wildcat wellsA, B and C as stacked channel sandstones trapped. Each gross sandstone package is about 30-40m thick, capped above by 10-30m ofshale/clay stones. The vertical cross section over the wildcat wells is illustrated in figure 2.

The diverse in fluid properties (20.5^{0}API to 35^{0}API) posed difficulty in selecting production technology method to enhance wellbore lifting efficiency.

Question was raised during the FDP in how to develop them concurrently with regards to reservoir management perspective. Drilling highly deviated well with single completion string and artificial lift to produce from only one formation is a preferable concept in this marginal field development.

2. PRODUCTION TECHNOLOGY SCREENING

Contribution to the complexity includesvarious production technologies forenhanced recovery of a marginal field andthe existence ofthe corrosion agents in the well stream. The screening exercise aimed at the following purposes.

- Improve the overall lifting efficiency of the wells.
- Gas-lift becomes fairly inefficient with heavy oil.
- Accelerate production by applying more aggressive pressure drawdown.
- High fluid production rate compensates oil reduction as a result of water cut increasing.
- Available deployment technologies and economic/technical comparison.
- Reservoir development and production forecasts.

The reservoir data shown in **Table 1** coupled with detailed pros/cons of each artificial lift method outlined in **Table 2** provide a snapshot for consideration. A quick check between ESP and gas-lift was carried out in reservoir simulationgiven the same operating condition. It turned out that ESP outperformed gas-lift in lowering bottom-hole flowing pressure which resulted in about 30% incremental recovery.

Viscous fluid with almost no solution gas and shallow depth best suits to the ESP or Progressive Cavity Pump (PCP). The major concern in those options is the solid production as a nature of shallow and unconsolidated reservoir which will definitely lead to the shortage of run life. Therefore, a rigorous geomechanic and sand production study were performed beforehand to ensure sand-free fluid flow in the wellbore. Besides, high production rate and the population in the area make ESP a bit advance than its counterpart.

After due consideration, the ESP is selected to proceed to detailed engineering studywith facility team and pump vendors.

2.1 ESP Design Consideration

The optimization scheme to account for reservoir parameter changes, involve the selection of pump curve type that would have less impact with the potential changes in these parameters. In addition, the number of stages is selected to have enough to absorb the total change in total dynamic head.

In the first step, a model for a typical Well X was built and validated with the existing gas-lift data as shown in **Figure 4**. The design for Well X was based these following assumptions:

- Static Bottom Hole Pressure: 2061 psi @ 1490 mTVD
- Anticipated Productivity Index: 3.3 bbls/psi (from Pressure Build Up interpretation)
- Anticipated Reservoir Temperature: 171^0F
- Pump degraded 5%-15% with the increasing of viscosity and impurity gas H_2S which was found quite substantial in the well testing.

The GOR of the candidate wells is quite low (approx. 10scf/stb) and the intake pressure into the ESPs are far above the bubble point (approx. 100 psi). Therefore, intake gas separation is not recommended here. In reality, due to lots of limitation, only one compromised solution which give the best efficiency with respect to wide range of well performance, is considered.

According to the designed operating conditions, the ESP system has been designed to be operating with a pump intake pressure of 1,396 psig. 0% of free gas will enter the pump, allowing operation without the installation of a gas separator.

Selection of the ESP system was based on surfacefacilityconstraint on 65 KW power consumption and production rate 1,500 BLPD. Other variables were assumed when not given and all of these conditions should be analysed again when final data is available in order to ensure proper equipment selection.

The pump designed for Well X is summarized in **Table 3.** The total power consumption is 66 KVA or 56 KW, including loss through downhole cable.All of the selected equipments will utilize Abrasion Resistant (AR) components and Corrosive Resistance material. The 3 chambers seal, L/2BP, which contains 3 mechanical seals have been chosen. The pump curve and inflow/outflow performance are shown in **Figure 6** and **Figure 7**respectively.

The optimized configuration recommended in this operating condition is thecompletion illustrated in **Figure 5** – Conventional ESP without tailpipe.

Since the pump will have the full clearance within the 9-5/8” casing it is comfortablewith the installation and operation under these conditions. The clearance is sufficient toconsider shrouds on these two wells to ensure the pump motors are sufficiently cooled.

2.2 ESP Deployment Methods

The jointed pipe ESPs are the industry standard in ESP completion whilst a recently developed technology, so-called "spoolable completion", refers to a method where the string can be run and/or pulledrapidly without need for a rig.Generallydeployed via coiled tubing (CT), these configurations can provide operational savings due to their speed of workover and elimination of rig costs in favour of CT units. **Table 4** outlines the two ESP completion methods where the jointed pipe completion is split to rig and Hydraulic Workover Unit-based.

In evaluating spoolable completions for use on the specifics of the wells andplatform itself must also be reviewed:

- Platform B on which the candidate wellheads are located has very little additional room for equipment. At minimum, during a CT workover, space would be required for the CT unit, reel, and power pack. In addition, there is a limitation on the crane and its capability to handle such kit.

- The preferred option available would be to perform all operations from a barge. This has been done previously on other projects overseas, however, safety precautions would need to be taken to ensure that disconnect could be executed in the event of torrential weather.

- The disadvantages of thattechnique including well control issues at the surface andconcern regarding security of the cable; it provides even less production due to the associated friction losses ofannular flow between the CT and casing.

- The other issue with this method is that it does not provide access to the producing zones below the ESP and gas-lift backup.

The industry standard method does require a rig or HWU to workover the well should the ESP malfunction.It is costly operation but enjoy the simple completion scheme and low CAPEX. Alternatively, it is highly recommended to install contingency gas lift mandrels (**Figure 8**) which could be used to continue production whilst awaiting mobilization.

An economic analysis is also performed to further evaluate CT ESPs vs.Jointed Pipe ESPs with rig support as well as HWU support.

A summary table (**Table 5**) lists the various options withtheir simulated incremental oil (vs. current gas lift). This includes any differences due tolead time for equipment, lead times for rig and CT unit mobilization but not the production from gas-lift when the pump failure.

Aside from the above technical comparison, this economic analysis does show that CT deployed ESP does provide the best net undiscounted return vs. the jointed pipeESPs($12.7 MM). The main differences are the incremental oil attributed to less workover time, the service rate and original CAPEX. Technically the CT deployed ESP required extensive platform upgrade which will impact to overall project schedule and hidden cost during construction.

Based on the analysis contained herein (both technical and economic) we haverecommended to install an ESP on jointed pipe below a retrievable packer. Above the

ESP would be installed gas lift mandrels as a contingency lift method should there be arequirement to retrieve and replace the pump. The concept considers a primary system such as ESP combined with gas-lift as secondary system.

The application of combined artificial lift systems yields improved production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. The combination provides a wide operating range reaching the optimal technical and economical performance. The long-term benefits are a reduction in production downtime.

The analysis clearly leads to recommend jointed pipe as the choice forthis project. It has benefits in its simplicity, economic efficiency and ability to withstand thewell profile. The other methods described herein have strong advantages but are simplycompromised technically due to critical project schedule.

2.3 Challenging

Pilot application always comes with risk and uncertainty regarding installation, maintenance and performance optimization in long run. Key remarks include:

- Performance Data Availability: ESP calibration based on gas-lift data.

- Offshore people expertise and skill shortage.

- Power source stability

- Full bypass for wireline and hydraulic access below ESP.

- Chemical injection for continuous H_2S scavenger/viscosity reduction below the pump.

3. CONCLUSION

Marginal fields requires cost-effective and high efficiency concepts to maximize revenues and make the project economics.

- Studying reservoir performance is essential to understand the specifics of the flow dynamics to assist concept selection.

- Potential changes in ESP design parameters and consequences of reservoir performance effect during production.

- Conventional ESP deployment with rig support is the robust option with the option of starting Gas-lift during pump failure.

- Dedicated system approach and good project management to overcome the challenges.

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Công nghệ khai thác nâng cao hệ số thu hồi dầu nặng mỏ cận biên ngoài khơi Việt Nam

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Công ty điều hành chung Lam Sơn

TÓM TẮT

Ứng dụng công nghệ khai thác dầu nặng đã và đang được phát triển rộng rãi trong hàng thập kỉ qua, nhằm nâng cao hiệu suất thu hồi của loại hydrocarbon khá hóc búa này. Ngoài phương pháp nhiệt, công nghệ bơm điện chìm đánh đấu bước phát triển vược bậc trong thu hồi dầu nặng, do tạo ra độ chênh áp lớn giữa vỉa và đáy. Nếu so sánh với phương pháp gas lift truyền thống, thì độ chênh áp lớn do bơm điện chìm tạo ra ưu việt hơn hẳn.

Bài báo đề cập đến thiết kế công nghệ khai thác cho kế hoạch phát triển mỏ nhằm nâng cao hiệu quả khai thác đặc biệt cho mỏ nhỏ ngoài khơi Việt Nam. Ví dụ như ở vùng bồn trũng Cửu Long, với trữ lượng đáng kể dầu khí được phát hiện với chỉ khoảng 20 API^0 gây không ít ngạc nhiên với các chuyên gia địa chất, từ đó thúc đẩy việc nghiên cứu để tìm ra giải pháp phát triển hiệu quả về mặt kĩ thuật cũng như kinh tế cho đối tượng này. Bài viết đề cập đến một chuỗi các nghiên cứu kĩ thuật từ mô hinh hóa tính khai thác của giếng thăm dò đầu tiên, cho đến thiết kế sơ bộ thiết bị để phù hợp với đặc tính dầu nặng. Với phương thức tiếp cận như vậy, bài toán kinh tế cho toàn bộ đời mỏ cũng được nghiên cứu để tối ưu hóa khai thác. Cuối *cùng, bài viết lựa chọn công nghệ bơm điện chìm (ESP) là phương án tối ưu nhất để tăng cường hiệu quả khai thác. Qua đó, các thiết bị bề mặt, hệ thống điện cũng như bộ thiết bị lòng giếng của bơm chìm kết hợp với phương pháp gas lift dự phòng, công nghệ ngăn cát và bơm hóa phẩm được tích hợp trong toàn bộ hệ thống nhằm nâng cao khả năng khai thác cũng như kéo dài đời mỏ.*

Từ khóa: *Bơm điện chìm, dầu nặng, thu hồi, kết hợp, dự phòng.*

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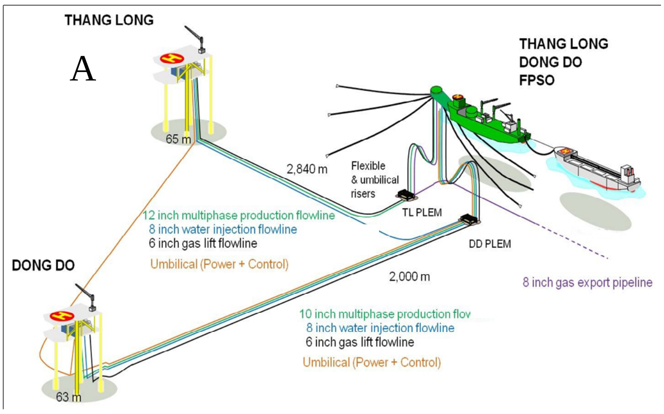

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Figure 1. Tay Do Field Layout

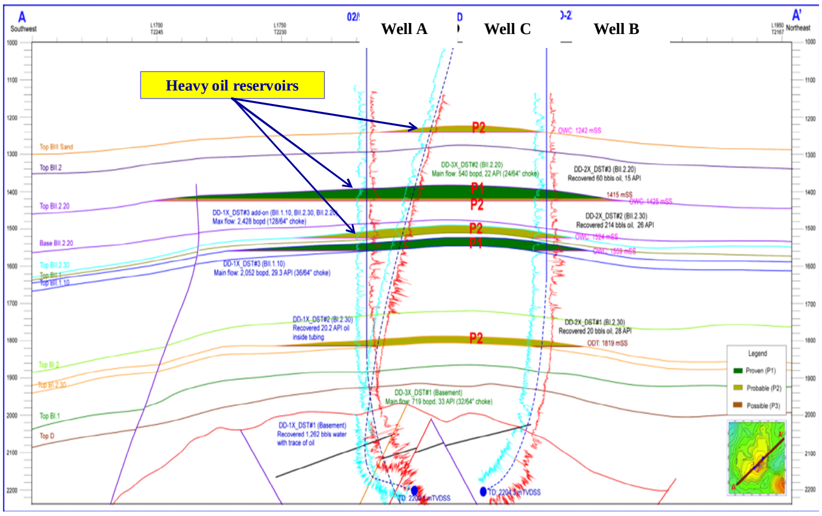


Figure 2. Reservoir Cross Section

Legend:

++	Very well suited for this situation
+	Well suited for this situation
+/-	May be OK, depending on details
-	Poorly suited for this situation
--	Very poorly suited for this situation

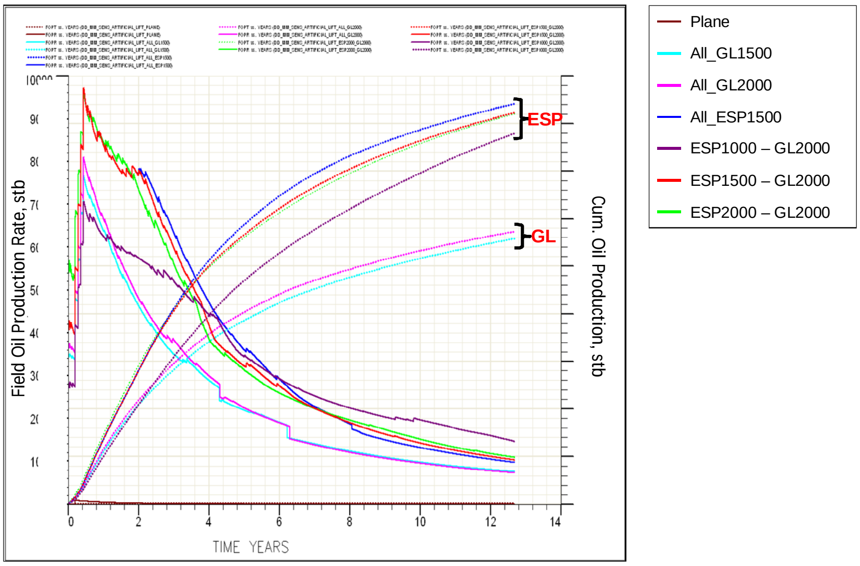


Figure 3. Production Forecast ESP vs. Gas-lift

Table 1. Pertinent Data Input

Parameter	Value
Reservoir Pressure	1946 – 2,192 psia
Reservoir Temperature	171 – 174, deg. F
Well Head Pressure	250 psia
Pump Measured Depth	4,406 – 4,987 ft
Max OD	6 in
Design Rate	1500 bbl/day
Gravity (API)	21
Viscosity	8.9 cp
PI	3-4 bbl/psi/d
Total GOR	5-10 scf/STB
Water Cut	0%-50%

Table 2. Artificial Lift Selection Matrix

Characteristic	ESP	PCP	Beam	Hydraulic	Gas-Lift
Well Conditions					
Deep	+	+/-	+/-	+/-	+/-
Shallow	+	+	+	+	+
Deviated	+/-	+/-	+/-	+/-	+
Small casing	-	+/-	+/-	-	+/-
Dual completion	--	-	-	-	+/-
Production Characteristics					
High production rate	++	+/-	-	+/-	+/-
Low production rate	-	+/-	+	+/-	+/-
High bottom-hole pressure	+	+	+	+	++
Low bottom-hole pressure	+/-	+/-	++	+/-	-
High GOR	-	+/-	--	-	++
Low GOR	+	+	+	+	-
Sandy	-	+/-	-	-	+/-
Sour	+/-	+/-	+/-	+/-	+/-
Viscous	-	+/-	-	-	-
Corrosive	-	-	-	-	+/-
Location					
Onshore	+	+	+	+	+
Offshore	+/-	+/-	-	-	++
Sub-sea	+/-	-	-	-	+/-
Developed	+/-	+/-	-	-	+/-
Remote	+/-	+/-	+/-	-	+/-
Access to Power					
Good electrical power	+	+	+	+	+/-
Poor electrical power	-	-	+/-	-	+
No access to electrical power	--	--	+/-	--	+

Access to Spare Parts					
Ready access to spare parts	+	+	+	+	+
Poor access to spare parts	+/-	-	-	-	-
Staff					
Trained engineers	+	+	+	+	+
No engineers	-	-	+/-	-	+/-
Trained operators	+	+	+	+	+
Untrained operators	-	-	+/-	-	+/-
Good access to service staff	+	+	+	+	+
Poor access to service staff	-	-	+/-	-	+/-
Budget Support					
Adequate capital budget	+	+	+	+	+
Limited capital budget	-	-	+/-	-	+/-
Adequate operating budget	+	+	+	+	+
Limited operating budget	-	-	+/-	-	+/-

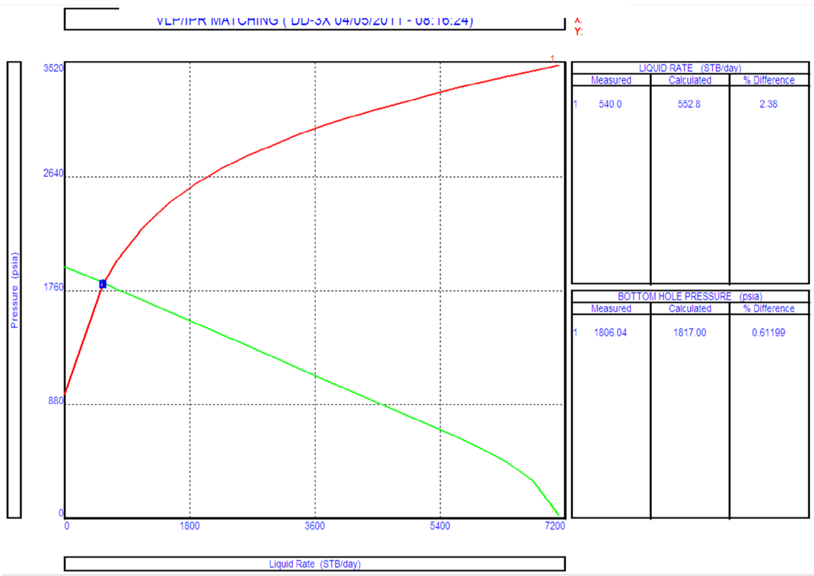


Figure 4. Gas-lift Calibration Point

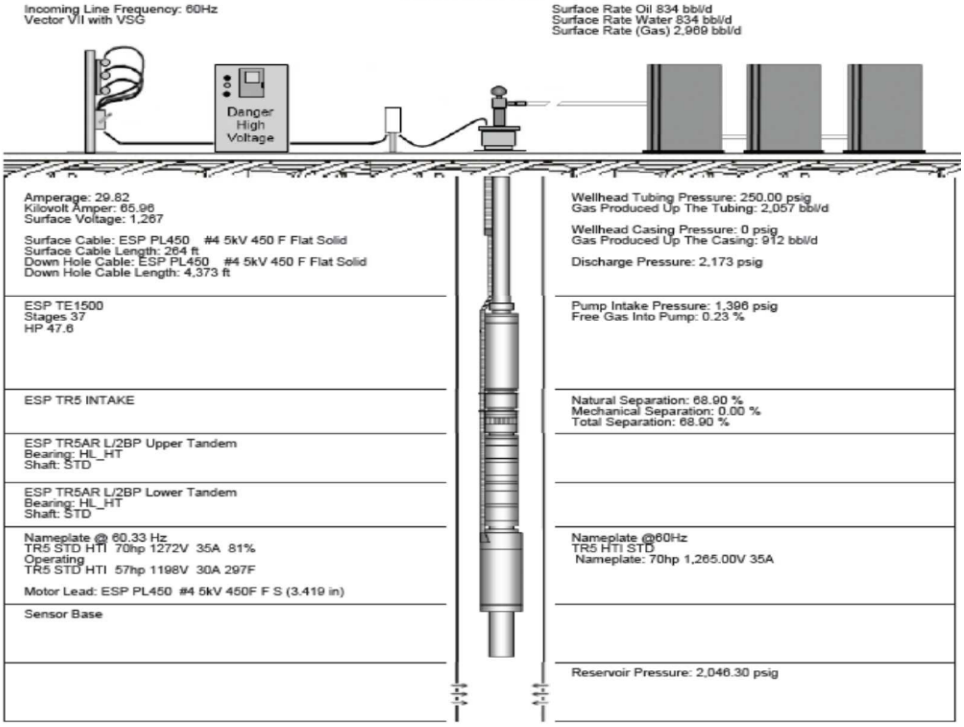


Figure 5. ESP System Configuration

Table 3. ESP Design Summary

Well X	
Pump	5.37 inches (800-2,250bbl/day)
No. Stages	37
Motor	70 HP\1905V\ 23A @ 60 Hz
Intake	No gas separator
Shroud	NONE
Cable	PL300 5KV LEAD GALV
Cable Configuration	ROUND

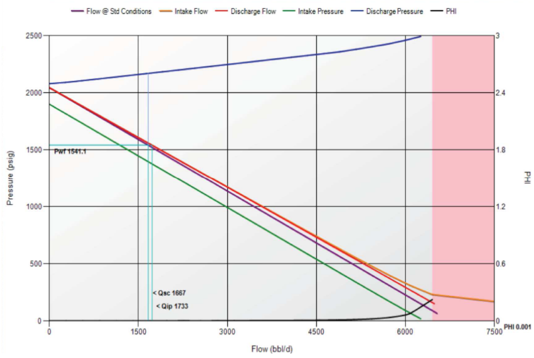


Figure 6. Inflow/Outflow Curve of the Selected Pump

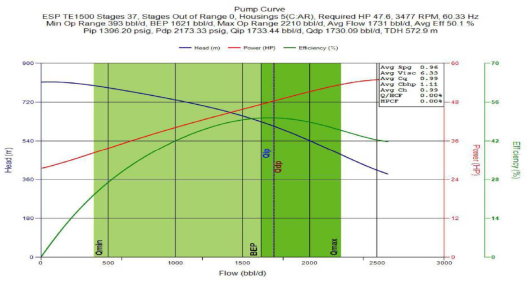


Figure 7. Pump Curve of the Selected Pump

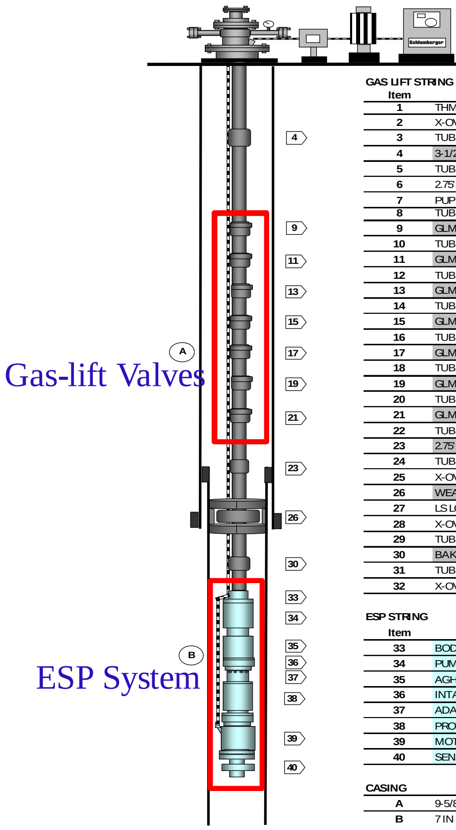
Table 4. ESP Deployment Methods

Description	Advantages	Disadvantages
Conventional jointed pipe with drilling rig support	• Conventional and simple method • Gas lift backup • Low CAPEX	• Long well work-over time • High work-over cost (OPEX)
Conventional jointed pipe with Hydraulic Work-over (HWO) Unit support	• A half of drilling rig rate • Gas lift backup • Some CAPEX to modify platform structure	• Longer well shut-in time than drilling rig • Increased completion complexity • Mob/demob issues • High work over cost (OPEX)
Coiled Tubing	• Rigless operation • Less well shut-in time • Low workover cost (OPEX)	• High CAPEX • Well control issue at surface • No gas lift backup • Mob/demob issues if run with large CT size

Table 5. Preliminary Economic Assessment Result

	Conventional jointed pipe ESP with drilling rig support	**Conventional jointed pipe ESP with Hydraulic Workover (HWO) Unit support**	**Coiled Tubing deploy ESP**	**Remark**
Waiting time till arrival of WO unit (day/well)	15	45	30	Analogue to Bokor field with minor adjustment to cope with VN market
WO time at no production (day/well)	15	25	10	
WO unit rental rate (USD/day)	130,000	55,000	30,000	Current VN market
Total WO unit rental cost for 6 wells - OPEX (USD)	11,700,000	8,250,000	1,800,000	
Number of WO cycles in 10yrs	3	3	3	
Total oil production of 6 ESP wells in 10yrs (stb)	13,942,500	13,465,833	13,823,333	Figures from Res. simulation
Total undiscounted loss due to WO (USD)	**21,450,000**	**50,050,000**	**28,600,000**	
Total number of ESP in 10yrs	12	12	12	6 new for 1st completion
Total cost for 1st ESPs completion - CAPEX (USD)	1,291,086	1,291,086	2,700,300	Analogue to Bokor field
Total cost for ESP maintenance in 10yrs - OPEX (USD)	1,291,086	1,291,086	2,700,300	6 replacements of 3 workovers
Cost for surface equipments and completion - CAPEX (USD)	1,566,072	1,566,072	5,473,584	Refer to Bokor Field
Total CAPEX (USD)	2,857,158	4,457,158	8,173,884	Including WHP Upgrading
Total OPEX (USD)	12,991,086	9,541,086	4,500,300	
Total undiscounted net (USD)	**15,848,244**	**13,998,244**	**12,674,184**	
Oil Price (USD/stb)	60	60	60	

(*) The calculation is done on the basis of only ESP system involved, disregard the other completion components CAPEX
(**) HWU is in analogue to KNOC and Halliburton



Client Name:
Well Name:
Field:

GAS LIFT STRING

Item	Description	OD (in)	ID (in)
1	THM	na	na
2	X-OVER 4'' 8RD PIN X 3-1/2'' VAM ACE PIN	3.50	2.99
3	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
4	3-1/2 '' TM(E) SSSV 2.812'' B PROFILE	3.50	2.81
5	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
6	2.75'' F-NIPPLE	3.50	2.75
7	PUP JOINT 3-1/2'' VAM ACE	3.50	2.99
8	TUBING 3-1/2'' VAM ACE BOX X PIN .	3.50	2.99
9	GLM #7	5.00	2.87
10	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
11	GLM #6	5.00	2.87
12	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
13	GLM #5	5.00	2.87
14	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
15	GLM #4	5.00	2.87
16	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
17	GLM #3	5.00	2.87
18	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
19	GLM #2	5.00	2.87
20	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
21	GLM #1	5.00	2.87
22	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
23	2.75'' R-NIPPLE 3-1/2'' VAM ACE BOX X 3-1/2'' VAM ACE PIN	5.00	2.87
24	TUBING 3-1/2'' VAM ACE BOX X PIN	3.50	2.99
25	X-OVER 3-1/2'' VAM ACE BOX X 2-3/8'' 8RD PIN	3.50	1.99
26	WEATHER HYDROW II-AP PACKER	7.00	2.38
27	LS LOWER EXTENSION	na	na
28	X-OVER 2-3/8'' 8RD PIN X BOX	2.38	1.99
29	TUBING 2-3/8'' 8RD BOX X PIN	2.38	1,99
30	BAKER SSD CMD 1.87'' F PROFILE	2.38	1.87
31	TUBING 2-3/8'' 8RD BOX X PIN	2.38	1.99
32	X-OVER 2-3/8'' 8RD BOX X 3-1/2'' 8RD PIN	3.50	1.99

ESP STRING

Item	Description	OD (in)	ID (in)
33	BOD	5.38	2.99
34	PUMP S538 - S8500 - 53STG	5.38	na
35	AGH S538 - S70-100	5.38	na
36	INTAKE S540 - BOI	5.13	na
37	ADAPTER S540.456	5.13	na
38	PROTECTOR S400/456 - BPBSL/BPBSL	4.56	na
39	MOTOR S456 - 180HP - 2682V - 43.1A	4.56	na
40	SENSOR - PHOENIX TYPE 0	3.37	na

CASING

A	9-5/8 IN X 53.5 PPF	9.63	8.53
B	7 IN X 29 PPF	7.00	6.18

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Figure 8. ESP System with Gas-lift backup