Field Development Power Demand Optimization Amidst Subsurface Uncertainties

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Abstract – Electrical Submersible Pump (ESP) power requirements are calculated based on the data extracted from observations or test wells which represents 5% of total wells that are developed for oil production. The calculations also consider additional factors and compensation to account for subsurface uncertainties, production decline due to water cut, cyclic nature of oil production, and outages etc. As such the calculated individual ESP power represents the peak operating conditions. This paper analyzes the variables of reservoir and provides a method to calculate a load factor that can be applied to establish the average power demand for all ESPs over the life cycle of oil producing field. As a result, the average overall power demand will be reduced by more than 50% of the calculated peak power demand and accordingly will allow to optimize the required electrical network. In case of offshore electrical network, this approach will further reduce the required shunt reactive compensation and thereby mitigate its associated technical issues.

Index Terms — Load factor, offshore network, reactive compensation, submarine cables, reservoir subsurface conditions, electrical submersible pumps, water cut.

I. INTRODUCTION

A. *Industry Practice for Power Demand Calculations:*

The initial power demand calculations for any new project involves various steps that are common in industry practice. First, through consultation with production and process engineers, an electrical load list along with its actual loading capacity, plant operational and maintenance requirements are prepared. The sum of power rating of all the electrical loads provides a total connected power demand. However, the actual power drawn from the source is always less than this connected power demand because of the following:

1) *Design factor:* Equipment have design margin to actual load. In addition, allowance for future load growth are also factored.
2) *Duty factor:* Equipment are continuous or intermittent or standby as required for operations and based on the sparing philosophy adapted.
3) *Demand factor:* Equipment are fully or partially loaded based on plant operating capacity or environmental conditions (between day and night, or between seasons). Also based on cyclic operational of certain group of equipment or multiple plants within a large industrial complex.

An overall load factor is calculated to account for all the above factors; this generally ranges from slightly less than 100% for continuous process plants, such as refineries and petrochemical plants, to as low as 40% for cyclic plants which mainly involves loading/unloading or batch operations.

B. *Challenges of AC Transmission for offshore:*

AC transmission for offshore load centers typically includes submarine cables which has high capacitance. The offshore load centers with power demand of more than 100MW and distances beyond 50km will require huge reactive compensation to avoid over voltage conditions at the load side due to Ferranti Effect that occurs when the cable is energized with light load or load disconnected. The reactive shunt reactors could range from 100 MVAr to 300 MVAr. Moreover, the reactive compensation needs to be variable in order to adjust the compensation according to variations in the overall loading. Switching of such large reactors and controlling as per variations in loads will pose other challenges and will require complex protection systems and cumbersome procedures to restore power outages.

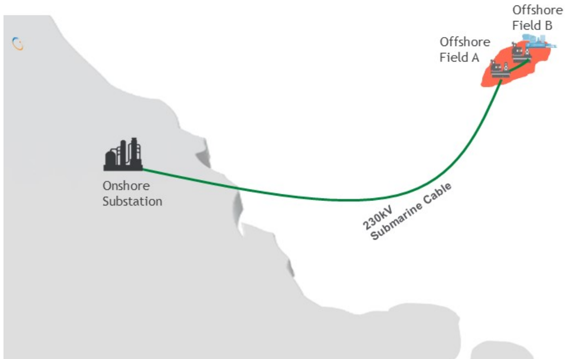

Figure 1: Submarine cable for power supply

C. Oil Fields and *Artificial Lift Methods – Overview:*

Generally, many of the oil fields are initially at high reservoir pressure which allows free flow of the oil to the surface. However, the reservoir pressure declines over the life cycle, and thereby oil production will also decrease. To maintain the oil production capacity, additional wells are drilled and or the two major artificial lift methods as briefly explained below are deployed.

1. *Electrical Submersible Pump (ESP):* An ESP consist of an integrated pump and motor which are installed inside the well tubing. The pump and motor are modular in design which are assembled as per the required flow and power rating. Electrical distribution network at medium voltage will be required throughout the field to provide power to different clusters of ESPs. The power is stepped down to low voltage and variable frequency drive (VFD) is provided to achieve the flow control and thereby production from each ESP. After the VFD, he power is stepped to medium voltage depending on the depth of the ESP from the subsurface. Typically, the required ESP power at initial stage is lower because the reservoir pressure is higher and the water cut is lower or zero in the case of a new field. However, as the field starts producing, the pressure declines and water cut increases over time and larger ESPs are required to produce the same flow to maintain the production. Typically, the ESP power rating ranges from 100kVA to 600kVA.

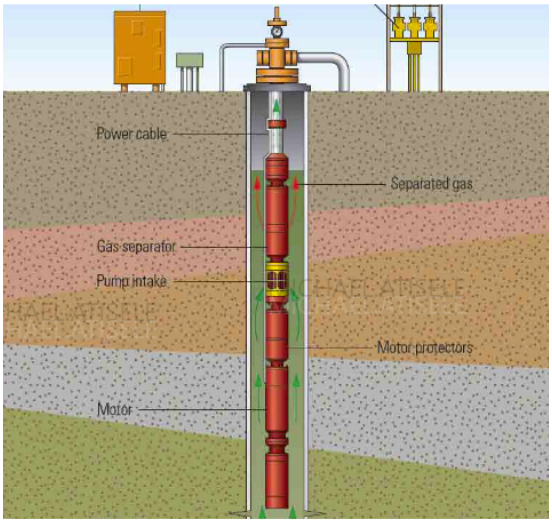

Figure 2: [4] Cross section of well with installed ESP

2. *Gas Lift:* Gas lift technology is a much older method and commonly used for reservoir where inherently the field has a higher Gas to Oil ratio (GOR) or the cost of power deployment to install ESPs does not make for viable economics. In this case, some of the associated gas produced from the reservoir along with the oil is separated at surface facilities and reinjected back to reservoir to maintain the pressure. However, at a later field life, the gas required for this purpose may be a challenge during a cold earth field re-start. This is because there may not be any free flowing well to provide the initial gas to start the wells that need gas lift. In certain fields, where available, a gas buy back from a source external to the field is used for this cold start up

D. *ESP – Power Demand Bases:*

The ESP power demand mainly depends and requires adjustments in accordance with two main factors as explained below.

The first factor is associated with subsurface variables that includes but not limited to, flowing wellhead pressure, flow rate, GOR, tubing diameter, ESP setting depth, well trajectory, productivity index, oil gravity, gas gravity and reservoir pressure. Typically, this data is extracted from the test or observation wells that are drilled at different locations of reservoir. These wells are usually 5% of the total wells that will be developed over the entire life of the reservoir. This 5% sample is driven by the practicality of time and costs to implement and process the data. For a field where limited deployment experience exists, the effect of some of these variables can only be fully known after the field is fully onstream and the reservoir fully delineated. As a result, due to limited data available from the test wells, the initial ESP power is always conservatively calculated based on the extreme conditions for these variables.

The second factor is associated with produced water. The associated water cut depends on the subsurface conditions, well placement, how fast water is coned and, for a field with water injection, how quickly water injection breakthrough occurs. All of these again are not fully known at the initial ESP deployment planning stage. An average water cut is typically established based on the assumed and expected minimum and maximum values of water cut. The average water cut is then used for calculating the additional wells required in later years to maintain the oil production. Water cut for a field is calculated as a percentage using the formula below.

$$W_c\,(\%) = \frac{Vw}{(V_w + V_o)} \qquad (1)$$

W_c = Water cut
V_w = Volume of Water produced
V_w = Volume of Oil produced

From the above it can be noted that for any increase in water cut, additional wells will be required to maintain the oil production.

Additionally, to compensate some of the wells that will be producing less or remain idle as required to allow for efficient sweep of the reservoir while meeting the field production commitments. Extra wells are also considered to account prolong periods of workover (maintenance) activities undertaken on wells. Moreover, margins are required to meet extra demand that is occasionally driven by global market conditions and OPEC mandates.

Considering all of the above factors, expected number of wells, ESP power and well performance for early (up to 8 years), mid (from 9 to 16 years) and late life (17 to 25 years) of the reservoirs are initially established which forms the design basis for all necessary systems which includes flowlines, main trunkline, electrical distribution and transmission network.

Petroleum Engineers continuously monitor the extracted data during completion of wells and subsequently during production. The data provides more clarity on the subsurface conditions and water cut prediction model and thereby establish and adjust the support systems including the ESP power requirements which are generally of optimum value than initially calculated value.

II. CASE STUDY

A. ESP Power Demand

The offshore field in this case study consists of two main reservoirs namely A which produces Arab Medium grade crude and B which produces Arab Heavy grade crude. Both reservoirs are spread over a large geographical area and overlap each other from a surface perspective. Presently A reservoir is producing oil by free flow, but artificial lift via cluster of ESPs that will be deployed in phases to capture the water cut increase and minimize production interruptions while managing capital deployment. B reservoir is a new crude increment and is slated to produce oil deploying artificial lift from the onset via ESPs. Below are the tables which indicates the reservoir characteristics, producing well design data and expected ESP power requirements at different stages of the reservoir.

TABLE 1

Initial Design Basis for Reservoir A

Data Description	Early Life	Mid Life	Late Life
Total Production Wells	200	250	300
Average liquid Production per well (kBD)	7	7	7
Average Water Cut expected (%)	10	20	35
Total Oil Production (kBD)	500	500	500
Calculated ESP Power of each well (kVA)	300	450	550
Total Connected Power Demand (MVA)	60	113	165

TABLE 2

Initial Design Basis for Reservoir B

Data Description	Early Life	Mid Life	Late Life
Total Production Wells	400	450	500
pAverage liquid production per well (kBD)	9.3	9.3	9.3
Average Water Cut expected (%)	20	35	45
Total Oil Production (kBD)	500	500	500
Calculated ESP Power of each well (kVA)	200	350	450
Total Connected Power Demand (MVA)	80	157	225

As seen from the above, the cumulative connected power demand for both reservoirs at early, mid and late life will be 140 MVA, 270 MVA and 395 MVA respectively.

Considering, the usual design basis for project life which is 25 years, the required electrical network that is required to be installed will have to meet the ultimate total power demand of 395MVA. However, the electrical network will be loaded at 50% of its capacity and therefore additional reactors will be required to compensate for the submarine cables.

B. Calculation of Actual Power Demand

The following factors are calculated to establish an overall load factor which is applied to the ultimate total power demand.

1. *Design Factor:* The ESP motor rating is 10% higher than the mechanical shaft power of the pump.
2. *Duty Factor:* For worst case scenario, it is considered that all ESPs will be operating continuously. However in that situation, some of ESP will be operating at reduced capacity so that overall production from all ESPs will not exceed the hydraulic and electrical design capacity.
3. *Demand Factor:* Pump capacity (flow) from each ESP, number of wells, ESP power, water cut values as tabulated in above Table 1 and 2 are utilized in calculating the demand factor as below.

   a) *Reservoir A at early life (500kBD oil and 10% Water cut)*

   - Using formula (1), the water production will for Reservoir A at early life conditions is

$$0.10\,(V_w + 500) = V_w$$

$$V_w = \frac{50}{0.9} = 56 \text{ kBD.}$$

- Total liquid production per well = 56 + 500

  = 556 kBD

- Designed liquid production rate of each ESP is 7 kBD, and total number of wells 200,

  Total liquid production will be 7 x 200
  = 1400 kBD

- Therefore, demand factor due to reduced production will be

$$= \frac{\text{actual liquid production}}{\text{total liquid production}}$$

$$= \frac{556}{1400} = 0.40$$

b) Reservoir A at mid life (500kBD and 20% water cut)

- Using the formula (1), the water production will be

$$0.20\,(V_w + 500) = V_w$$

$$V_w = \frac{100}{0.8} = 125 \text{ kBD.}$$

- Liquid production per well = 125 + 500
  = 625 kBD

- Designed liquid production rate of each ESP is 7 kBD, and total number of wells 250,

  Total liquid production will be 7 x 250
  = 1,750 kBD

- Therefore, demand factor due to reduced production will be

$$= \frac{\text{actual liquid production}}{\text{total liquid production}}$$

$$= \frac{625}{1750} = 0.36$$

c) Reservoir A at late life (500kBD and 35% water cut)

- Using the formula (1), the water production will be

$$0.35\,(V_w + 500) = V_w$$

$$V_w = \frac{175}{0.65} = 269 \text{ kBD.}$$

- Liquid production per well = 214 + 500
  = 714 kBD

- Designed liquid production rate of each ESP is 7 kBD, and total number of wells 300,

  Total liquid production will be 7 x 300
  = 2,100 kBD

- Therefore, demand factor due to reduced production will be

$$= \frac{\text{actual liquid production}}{\text{total liquid production}}$$

$$= \frac{769}{2100} = 0.37$$

d) Demand factors for Reservoir B:

In similar way the demand factors calculated for Field B will be as below:

- 0.20 – at early life
- 0.37 – at mid life
- 0.39 – at late life

C. Summary of Load Factors:

All the above factors as summarized in following table provides to establish the actual power demand for respective fields at different timeline.

TABLE 3

Calculated Actual Power for Reservoir A

Description	**Early Life**	**Mid Life**	**Late Life**
Design Factor (%)	10	10	10
Demand Factor (%)	40	36	37
Total Connected Power Demand (MVA)	60	113	165
Overall actual realistic power demand (MVA)	21	36	55

TABLE 4

Calculated Actual Power for Reservoir B

Description	**Early Life**	**Mid Life**	**Late Life**
Design Factor (%)	10	10	10
Demand Factor (%)	20	37	39
Total Connected Power Demand (MVA)	80	158	225
Overall actual realistic power demand (MVA)	15	52	80

Accordingly, the overall average power demand for both reservoirs at early, mid and late life will be 36 MVA, 88 MVA and 135 MVA respectively.

A graphical explanation of the gradual increment of power demand over the years compared with and without this optimal approach is shown in the chart below:

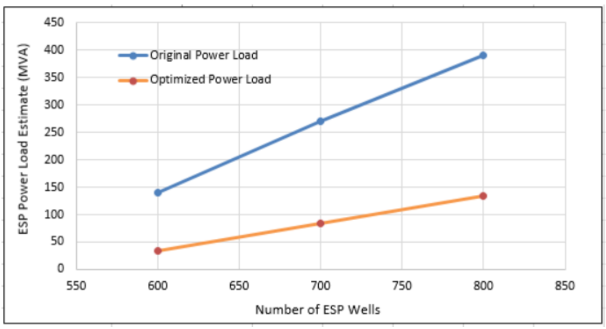

Figure 3 - Comparison of ESP Power Demand based on the use/non-use of a Load Factor

The chart shows that non-application of overall load factor will result in twice the actual power demand being designed for and therefore tripling of the required electrical power network and thereby the associated capital cost.

Below figure depicts a typical offshore substation configuration and power distribution network to ESP cluster platforms.

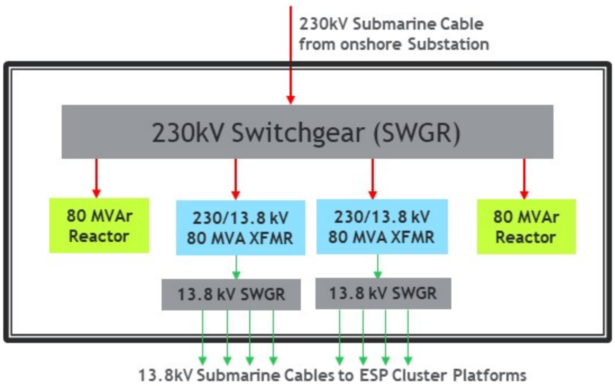

Figure 4: Offshore Substation Configuration (Typical)

Below table indicates the required major electrical equipment of the offshore electrical network before and after applying demand factor for the overall power demand.

TABLE 5

Major Electrical Scope (Preliminary Quantities)

Equipment	Without Load Factor	With Load Factor
Submarine Cables (Transmission)	180 km	60 km
Offshore Substations	3	1
Power Transformers	6 x 80 MVA	2 x 80 MVA
Shunt Reactors	6 x 100 MVAr	2 x 100 MVAr

Moreover, if the load factor is not applied, the realistic low power demand of 36 MVA during the initial stages would also pose technical challenges related to operation and control of the extra-large large reactors that needs to be switched and controlled according to different possible operating scenarios (multiple power sources, outages of groups of ESPs etc.).

To ensure field applicability, the calculated overall load factors was compared with other offshore fields that are deployed with ESP and the overall actual power demand was found to be in similar range.

In addition, the team ensured the electrical network will have space provisions to accommodate additional submarine cables and reactors for a scenario of increased ESP power demand in future because of changes in subsurface conditions given some uncertainties that would only be reduced with actual deployment experience and field delineation especially in the B reservoir. This monitoring and optimization can be achieved by close coordination with Petroleum Engineers who are monitoring the reservoir. If there is change in the characteristics that indicates a need for higher power requirement, then a future project at the appropriate time can be introduced to augment the capacity of the electrical system accordingly.

III. CONCLUSION

This paper has shown that a multi-disciplinary approach using a systems engineering methodology that accounts for a robust approach is required for optimally designing power network. The surface facilities engineers also need to design the system to allow for minimal investments to ensure future subsurface uncertainties that can be addressed as needed.

The application of load factors will optimize the capacity of ultimate power demand to be 135 MVA that will be adequate until the late life with normal reservoirs characteristics. On the contrary, providing the electrical system to meet the ESP peak power demand of 395 MVA as per initial study design input will result in tripling of the electrical power network and associated infrastructure. Besides the exorbitant multimillion-dollar capital outlay, there are technical challenges to operate and control the extra-large reactors during the initial stages when the ESP power demand is usually low. Additionally, the staged implementation of the required electrical power network will ensure meeting higher ESP power demand if ever needed due to subsurface uncertainties in future.

NOMENCLATURE

ESP	Electrical Submersible Pumps
GOR	Gas Oil Ratio
kBD	Kilo Barrel per Day
km	Kilo meter
kVA	Kilo Volt Ampere
MVA	Mega Volt Amperes (Active)
MVAr	Mega Voltage Amperes Reactive
VFD	Variable Frequency Drive

IV. ACKNOWLEDGEMENTS

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V. REFERENCES

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[4] Courtesy Schlumberger for typical well details

VI. VITA

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