Abstract - Rising development costs for new oil and gas facilities has led many operators to look to maximise the production capability from existing onshore and offshore plants. These projects often include a combination of brownfield and greenfield development – with the target of using as much of the existing infrastructure as possible. For example, as existing wells become depleted, production tails off, and new wells must be drilled for production, water injection or gas lift. Often this requires new wellhead platforms because existing well slots are fully utilised, or they are required to enable drilling to reach other untapped parts of the reservoir. These type of projects present many challenges, especially when the original facilities were designed and built in the mid 1990’s in a low oil price market, when the CRINE initiative was hatched. This typically led to minimising facility flexibility and stripping out any allowance for future expansion in order to reduce CAPEX. Many were originally designed for a limited lifetime, and now some of these facilities are the ones being extended and expanded to provide additional production throughput.

This paper examines some of the electrical power system challenges during the expansion of one such offshore facility in Denmark. A series of developments over the years had already seen the peak load increase beyond the rating of one of the 2 x 100% rated main generators. The latest plans involved significant changes to the gas compression system, including new compressor bundles, requiring new and larger rating of electric motors and gearboxes. Further additional loads and switchgear would also be added with two new wellhead platforms, one bridge linked and the other 2.5km away from the host platform. The paper considers the required motor starting constraints at the limits of the power system capability, switchgear very close to its maximum fault rating, and weight and space constraints. The methods used to evaluate and overcome some of these issues will be presented. This includes the use of detailed electrical power system modeling as a tool to simulate transient conditions of the existing and revised power distribution system, and actual transient power measurements to verify the model results. Details of the motor design requirements, with extremely constrained maximum starting currents, and modifications to the main generator AVR’s will be discussed. Finally, some feedback from the installation/commissioning phase of the project will be given as lessons learnt for the benefit of other similar brownfield projects.

Index Terms - Power generation, Induction motors, Load flow, Fault calculations Transient response, Motor starting.

I. INTRODUCTION

During the relatively low oil price era of the early to mid 1990’s, companies faced a real challenge making many new oil & gas facilities economic to develop. In the UK offshore sector, for example, designers had to come up with ideas to reduce CAPEX costs or projects simply remained on the drawing board. During this time the CRINE initiative was developed, with the general philosophy of removing everything possible, prioritising low equipment/materials cost, stripping out any consideration of future facilities growth, and in some cases reducing operational flexibility and performance.

Whilst today, even with relatively high oil prices, it can be argued this CAPEX consciousness is every bit as relevant. However, this should be tempered with the experiences of 15 years or so operating some of the lower-cost developments from the mid 1990’s.

This paper does not seek to comment on the economic success or otherwise of these developments, but using a case study discusses some of the technical challenges faced when trying to expand an existing facility designed with little thought for future growth. The case study is an offshore platform in the Danish sector, designed in the mid 1990’s and installed in 1998. There have been a number of relatively small additions and changes during the first 12 years of operation, including the installation of two additional seawater injection pumps. Even these facilities updates resulted in a change in the power generation operating philosophy, since the original design was based on 2 x 100% generators, but the increasing load meant that both generators now have to run in parallel to meet the peak loads. The most recent plans required 2 new wellhead platforms to drill additional wells to maintain production and reach parts of the reservoir until now undeveloped. In addition, the gas compression system needed to be up-rated, requiring 3 new compressor bundles, 2 new gearboxes and 2 larger motors. The designers faced several challenges, including expansion of existing switchgear, increasing fault levels on the power system, motor starting constraints and space limitations. The methods used to tackle these challenges, and the resulting outcomes, will be discussed.

II. EXPANDING THE FACILITIES

A. Methodology used

There were 3 main challenges with the proposed developments at the offshore installation:

1. Load Flow Studies
2. Motor Starting Constraints
3. Switchgear Space and Weight Constraints
• Power distribution for the facilities on the 2 new wellhead platforms.
• Design of the motors for the new gas compressor bundles.
• Impact on the existing platform power supply.

1) New wellhead power distribution: One new wellhead platform (WHPE) is to be bridge-linked with the existing platform and the other (WHPN) will be approximately 2.5km from these platforms. The wellhead platforms do not have much installed equipment, and the electrical load is relatively low (approx 200kW). However each requires a 50 Tonne crane to support drilling activities and general platform use.

For WHPE, with the relatively low loads it was decided to supply the platform from the existing main power system. This comprises 2 x 24MW gas turbine generators (GTG’s), originally intended as 2 x 100% generators but already the platform runs both generators in parallel as the load is above the rating of a single generator. Thus the addition of a relatively small load had little impact on the current power generation philosophy. For the remote wellhead platform WHPN, various options were considered. However, of prime concern was to minimise planned and unplanned visits to the platform to reduce potential for exposing personnel to a hazardous environment, and minimise helicopter operations. Thus a decision was taken not to have power generators on the platform, but to supply power via subsea cable from the existing platform. Similarly, in order to eliminate diesel storage completely, it was decided to select electro-hydraulic motor operated cranes for both wellhead platforms. This increased the load on each wellhead platform by approximately 400kW when the crane is operational. So a total peak load of approximately 1.2MW has been added to the existing power system.

Lack of space on the existing platform and limitations on the equipment fault ratings meant that it was not economic or technically feasible to expand the existing power generation system. A load shedding system was already in place to cater for the sudden failure of one of the main GTG’s, and the additional load for the wellhead platforms did not affect the operation of this system. Thus no changes or additions to the power generation system were foreseen. However, the next challenge was the distribution of power from the existing platform to the wellhead platforms. The existing power distribution comprises a single 11kV switchboard, with normally closed bus-tie and 1 main GTG connected to each side of the bus. The LV distribution system was designed for single transformer feeder supplying each switchboard, with the ability and capacity to cross feed if one transformer is out of service. However, the transformer loads were already close to the full load ratings, the LV switchgear had very little spare capacity for new feeders and it was not very practical to supply the wellhead platforms at low voltage from the main LV switchgear. The 11kV switchgear had space at one end for approximately 1.5 additional circuit breaker (VCB) cubicles. It was decided to install a new 11kV VCB at the end of the switchgear to supply a single 11kV feed over to the bridge-linked WHPE, and all further power distribution for both wellhead platforms would be distributed from WHPE. In addition, a 3-phase LV feeder from the existing platform emergency power distribution system, and 2 feeders from the existing UPS system would be installed to provide emergency/critical loads on WHPE.

2) Motor design for the new gas compressor bundles: The existing gas compression system comprises 3-stage, single train, motor driven LP, IP and HP gas compressors. The original design premise was that it should be possible to start up and run the gas compression system with only 1 main GTG available, and this philosophy was also appropriate for the new compressor arrangement.

The original motor ratings were 2.75MW (LP compressor), 5.25MW (IP compressor) and 7.65MW (HP compressor). All are 11kV motors, Ex p, T3, fixed speed and DOL start. Extensive modeling was carried out on the process design which resulted in the following requirements:
- LP compressor – existing motor rating adequate for new compressor bundle.
- IP compressor – increase in motor rating to 6.6MW (+26%) and new gearbox for new compressor bundle.
- HP compressor – increase in motor rating to 8.4MW (+10%) and new gearbox for new compressor bundle.

The existing motors were already a low-starting current design to achieve DOL starting from one GTG whilst maintaining minimum transient voltage of 80% at the 11kV motor terminals. In 2 known attempts to start the HP compressor motor with 1 GTG on line, only 1 start was successful. Clearly there was going to be a technical challenge starting a 10% larger motor rating from the same power system. In addition, another design requirement was that the new motors needed to be the same frame size, with exactly the same shaft height and interface locations as the original motors. Thus careful consideration had to be made of the cooling system to maintain the temperature class of the hazardous area rating. It was decided at an early stage to engage the original motor manufacturer in studies to examine all the possible options and the practical design limits of the original motor frame sizes. This was coupled with parallel studies with the compressor manufacturer and a specialist process design consultancy to determine the possible starting and operating conditions. Following this initial design work, it was clear an accurate model of the electrical power system was required to verify that the motors could be started, to examine the impact on fault levels, and to determine if any changes were required to the power system.

The original IP compressor motor had been controlled by a contactor (VC), but the new IP compressor motor current would be beyond the rating of a VC. It would therefore have to be controlled by a VCB, meaning 2 additional VCB tiers were required, one for the new wellhead platform feeder and one for the motor. With some careful manoeuvring of an existing distribution board, it was possible to create enough space to add 2 extra tiers to one end of the switchgear. However, the power system fault calculation studies indicated that under the worst case conditions it was possible the fault breaking rating of the switchgear could be exceeded. One possible contingency for overcoming this was to open the 11kV switchgear bus-tie whenever the crude export pumps were running. However, adding the new IP compressor motor VCB to the end of the switchgear meant that all the major loads were on one bus. In fact
this would have overloaded the generator supplying this bus if the bus-tie had been opened. Thus a more complex arrangement had to be planned, which involved moving 2 existing VC circuits from within the line-up to the end of the switchgear, and replacing them with the new VCB tier for the IP compressor motor. This was certainly a more practical challenge, and required detailed planning to execute during a tight offshore installation programme.

B. Power system studies

1) Electrical network model: When modifying any offshore platform power system, a model is needed to predict the behavior of the system with the new loads and to ensure that equipment ratings are not exceeded.

In this case study, the model contains the main generators and all individual consumers on the 11kV switchgear. On the 415V level, the main switchboards with the largest consumers are modeled, and all other loads are modeled as a single summation load.

The model is used for several types of calculations.

2) Load flow and voltage drop study: The basis for all simulations is that the power system is in a normal configuration without any faults. This is shown in the load flow normal scenario.

All consumers are running with normal load and checks are made to ensure that no generators, transformers, VCBs and cables etc. are overloaded. The voltage drop is also examined to ensure it remains within design limits, and generator voltage and transformer tapping are selected.

For the greenfield development, for reasons as previously discussed, the two new wellhead platforms have been designed with electrical motor driven cranes, each with 2x195 kW motors. This is by far the largest electrical load on WHPE and WHPN. The transformer on WHPN has no on-load tap changer and the tap setting is based on a maximum scenario with cranes on full load. Therefore a no-load scenario is calculated to check that the voltage is not rising above the maximum steady state limit under low load conditions.

3) Short circuit calculations: The results of the short circuit study are highly dependent on the standard used for the calculations. The main platform is a European installation and calculations are performed according to IEC60909-0 (2001). The preface to the standard states that it is not suitable for calculations on offshore installations, but according to normal practice in the North Sea, it is used anyway as there are no better alternatives.

Calculations according to IEC61363 can also be performed, but this standard only deals with symmetrical faults.

The maximum short circuit study is of special interest since the short circuit level was already close to the rating of 40kA 1s / 110kA peak on the main 11kV switchboard. It had to be checked that this rating was not exceeded with the new larger motors that were to be installed.

One of the main parameters when calculating the peak short circuit level is the X/R ratio for the generators, as it will affect the peak current and the time dependant decay of the current.

IEC60909 §3.6 specifies that we should use an \( R_{ol} = 0.07 \times X_0 \) equal to \( X/R = 14.3 \) for the generators when calculating I-peak. By using this X/R factor rather than the supplier data the decay of the AC component is included, and I-peak is a more realistic value. The associated note, however, specifies that for calculation of the decaying \( I_{dc} \) we have to use the supplier data, which in this case is X/R=52.

X/R values for large motors will also affect the results and, according to IEC60909 §3.8, HV motors above 500kW shall be calculated with X/R=10.

This is a relatively low value if we compare it with ANSI C37.010, for example, where X/R is up to 45 for the 8.4MW induction motor.

Calculations with the IEC60909 data gave a calculated peak current just below the rating of 110kA when the new motors are installed.

Another concern was the breaking capacity of 40kA. The data for the existing switchgear is not clear, but it is indicated that the VCBs can interrupt a current of 40kA with a content of 30% DC.

The calculated initial short circuit current with the new motors is almost 42kA with approximately 100% DC component. The total breaking current with both AC and DC decays to 40kA within 60ms and thus the selected approach is to delay the trip of each VCB until the breaking current is within the rating of the VCB.

4) Protective device coordination study: The new 11kV switchgear tiers are equipped with multifunction protection relays. The feeder circuits for the new motors are equipped with motor protection relays, and the feeder to WHPE has a line differential relay at each end with fibre optic communication between the two relays.

The existing 415V emergency switchboard is equipped with fuses and due to switchgear design limitations, it is very difficult to implement a MCCB solution in the new feeder for WHPE. The feeder is therefore equipped with a 315A fuse, which is the largest acceptable fuse, and the...
downstream MCCBs have to be limited in size in order to achieve discrimination.

5) **Transient studies:** When simulating the transient behaviour of a power system, the supplier data for generators and large motors are of vital importance, significantly affecting the study results.

The data for the GTGs were retrieved from the original supplier, who had models of the transfer functions for both the generator AVR and turbine governor. Generator saturation curves and system moment of inertia were also given.

![Fig 2: Model of GTG governor](image)

The data for the new compressors and motors are well known. The motor supplier could give accurate values for motor X, R and inertia, and the compressor supplier could give accurate load torque-speed curves and inertia values. The simulations of the new motors are considered to be very precise.

The data on old motors is, however, more insecure as the 15 year old data sheets do not include all the information required. Motor parameters were therefore estimated by software based on no-load and full-load data. Where possible, more load points were added so that the programme could give a full set of motor parameters, including tolerances.

![Fig 3: Motor parameter estimation](image)

### Estimated Motor Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotor Resistance</td>
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</tr>
<tr>
<td>Rotor Reactance</td>
<td>-0.2785</td>
</tr>
</tbody>
</table>

### Motor Impedances

<table>
<thead>
<tr>
<th>Impedance</th>
<th>Value (in %)</th>
<th>Value (in Ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator Resistance Rl</td>
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<td>0.0001</td>
</tr>
<tr>
<td>Stator Reactance Xl</td>
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<td>3.7093</td>
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<tr>
<td>Rotor Resistance R2</td>
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<tr>
<td>Rotor Reactance X2</td>
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<td>Magnetization Resistance RM</td>
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<td>7500.0405</td>
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<tr>
<td>Magnetization Reactance XM</td>
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<td>68.9930</td>
</tr>
</tbody>
</table>

**Root-Mean-Square Fitting Error (%):** 0.9930

### Field measurements

1) **Model validation:** As this is an existing installation it was possible to validate the model. A program was set-up with high speed measurements of electrical parameters during a restart of the process after a shutdown. During the measurements, a specific request was made for only one of the main GTGs to be on-line, which results in the highest voltage and frequency dip during motor start.

The utility load was approximately 2.7MVA when the gas compression train was restarted: First the 5.25MW IP-compressor was started followed by the 7.65MW HP-compressor and the 2.75MW LP-compressor. Starting of seawater lift pumps and water injection pumps was also monitored.

Parameters were tuned to achieve a close correlation between the measured and simulated values. When these were closely matched, it was then reasonable to assume that the simulated values for the future larger motors would be valid.

![Fig 4: Current during start of 7.65MW HP-compressor motor](image)

### D. Outcomes/Motor starting study

1) **Motor starting study:** With the new 6.6MW and 8.4MW motors in the model, the voltage and frequency response for a motor start was then examined.

The motor starting time was simulated to be approximately 33s. This calculation is based on the compressor being in bypass mode with a pressure of 20bar, resulting in a load of 58% of nominal torque. It is important that the motor is started in bypass as a higher load will increase the starting time which would be critical for the thermal impact on the rotor.
The simulated voltage during the initial start of the motor acceleration drops approximately 18% before the AVR begins to restore it, and rises to +12% rated voltage when nominal motor speed is reached and the starting current rapidly decays. This is a very high voltage drop and it was decided to boost the voltage by 5% just before the motor is started, and to reset it after 10s to avoid increasing the over-voltage at the end of the motor run up.

The function is only implemented for the two largest motors on 6.6MW and 8.4MW, and only when one main generator is supplying the grid. This is done to avoid exchange of large amounts of reactive power between the two generators, for example if the boost voltage control is not exactly matched.

The function requires coordination with the compressor control system as the boost voltage must be activated before the motor starts. This is done by implementing a 2s timer in the compressor control system which sends the voltage boost signal prior to sending the VCB close signal.

2) AVR modification: The starting current of the new HP-compressor motor is 1540A and the nominal current of one main generator is 1535A. As the HP-compressor is typically started when the IP-compressor is already running and there is a base load from sea water lift pumps etc., the generator will be heavily overloaded during motor acceleration. With the existing motors the operators had experienced generator trips several seconds after initial motor acceleration, and this challenge would only increase with larger motors.

The generator control has some protection systems, of which two were identified as requiring changes. The Stator current limiter was originally set to be unlimited up to 10s, but then limited to 1.05 nominal current, which was before the motor had run up to full speed. This was changed to allow a longer time for the overload to cover the motor starting period. Furthermore, the rotor excitation system also had to be modified. In the existing system the field forcing was limited to 4.271pu for 10s after which it was limited to 2.601pu. With the new larger motors this would cause the generator to trip during motor starting, so a third step of 3.2pu for 30s had to be introduced. This was offset by reducing the initial current limit to a maximum time of 5s. Since the total thermal effect on the rotor system is determined from $I^2t$, the overall thermal effect remained unchanged.
3) Transient stability study: A transient stability study is performed to evaluate voltage and frequency variations in different fault scenarios.

Motor trip during acceleration with high field forcing is simulated to find extreme voltage rise and determine the required withstand ability of the distribution system components.

Short circuits on high voltage and low voltage systems are simulated to find the power system response and check that the generators are still in synchronism when the fault is cleared. The delayed tripping of the VCBs described in section B3 will result in a loss of main power if a bolted short circuit is occurring on or close to the main 11kV switchboard.

Finally, the load shedding system on the existing platform is simulated by tripping one main generator during full load. This resulted in a power deficit and predicted frequency drop to 48.5Hz, whereby the 4 x 4.2MW water injection pumps will be tripped by under frequency relays, which will be sufficient to ensure the power system recovers from the disturbance.

E. Motor design

Revising motor design to provide increased performance without affecting the existing installation at site can be, and usually is, a major challenge. The task can be considered from two different perspectives. Firstly there is the actual electrical performance of the motors with regard to both existing motors, and potentially new replacement motors. Secondly there are the mechanical design limitations associated with site layout, as well as those imposed by the electrical design.

In an ideal world with good performance from the existing motors over many years of service, it would be nice to assume the motors could be re-used and simply upgrade the driven equipment (pump/compressor), and this is often possible. To give an example of smaller motors, end users may wish for a 17kW motor, but because they are standard, off the shelf products, they actually receive an 18.5kW motor, with rating plate identifying 17kW, to satisfy the requirements. Whilst typically large HV motor performance is not standard, it can initially be viewed in the same light. In the same way that the original data for the 17/18.5kW motor can be reviewed and a new nameplate supplied verifying higher output performance, by reviewing the original test data for the HV motors it is possible to determine if the existing motors have any margin for up-rating.

It can be seen from Table 1 that for this particular example various test data has to be considered when reviewing the possibilities of re-rating a motor. Simply increasing the nameplate rating might initially appear to be achievable whilst still maintaining a desired temperature rise, but other areas such as rotor temperature for temperature class such as T3 must also be evaluated.

![Fig 7: Field limitation system](image)

<table>
<thead>
<tr>
<th>OUTPUT (KW)</th>
<th>LINE I (A)</th>
<th>STATOR WINDING RISE BY R (K)</th>
<th>STATOR WINDING RISE BY ETD (K)</th>
<th>EST. ROTOR RISE (K)</th>
</tr>
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<td>77*</td>
<td>81*</td>
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<tr>
<td>8400</td>
<td>540</td>
<td>75</td>
<td>90</td>
<td>155</td>
</tr>
</tbody>
</table>

* Derived from tests at the OEM factory.

Table 1: Motor re-rating study

The information within Table 1 is an actual extract from a recent OEM re-rating study. It is listed to demonstrate that the existing design had been reviewed, and re-rating considered. It also makes clear that whilst a new design of motor could be achieved at 8.4MW, that pushing the envelope too far to 9.0MW was simply unacceptable unless relaxation on stator temperature rise and T3 limits could be granted by the end user. In this instance relaxation is not a desirable route to take given that thermal stability is of high importance when designing the motor from a safety aspect, and also when considering product durability.

Having concluded the existing capabilities of the motors concerned were not sufficient to meet the new up-rated design requirements with a satisfactory and appropriate thermal design, the electrical engineers still faced a challenge of providing increased kW performance without increasing the load on the supply such that it could not support the up-rating. The biggest design characteristic that can be fine tuned to reduce load on the supply system is motor starting current.

Motor starting current is typically 6 to 7 times the normal full load current (FLC) on a standard induction motor which places a tremendous demand on the supply during starting conditions. The 7.65MW example being examined in this case was already a vastly reduced starting current design of 2.9 x FLC. To achieve 8.4MW the normal running current has to increase, but this is still well below the short-term current capacity of the power...
system, already known to withstand 1440A drawn when starting the existing 7.65MW motors. Following guidance from the end user, the motor OEM had to consider the 1440A as a maximum starting current regardless of motor rating, and as such 2.66 x FLC became the desired maximum starting current for the 8.4MW motor.

The motor OEM can tailor the design and manufacture to meet such starting current restrictions, but there is always a corresponding trade-off between starting current and motor torque. Sufficient motor torque must still be available to start and run the driven equipment, and in this instance it was agreed that a maximum design limit of 2.85 x FLC, slightly over the 1440A, would be set. This was higher than the previous motors, but with some modifications to the generator AVR it was agreed this absolute value of current would be feasible, and ensured sufficient margin for the required motor starting torque. This is demonstrated in fig 8, Torque-Speed curve. It can also been seen that the actual recovery voltage profile has been used to give a more practical design, rather than assume that the voltage remains at 80% nominal for the duration of the motor start.

Mechanically it would be simple to just repeat the motor frame design to ensure interchangeability, but having to accommodate 400mm of extra active material in the middle to ensure the new design characteristics could be met meant entirely new frames with bespoke designs to ensure as many interfaces as possible could be maintained. Figures 9, 10 and 11 show the original motors, the new motors, and then the new motor overlaid on top of the old motor.

![Figure 9 Original Motor](image)

![Figure 10 New Motor](image)

For the electrical design department to meet such requirements, the electrical engineers concluded that a new build replacement motor was required. As such the mechanical design team needed to not only fit things in and around the existing design that had been running at site for over 12 years, but also to incorporate the increased levels of copper and electrical steel which had been specified in order for the new motors to meet the up-rated requirements.
Looking at the overlaid picture it is possible to see that many different aspects of the motor interchangeable need to be considered. Motor bolting down holes are just one aspect, shaft end dimensions and position need to match, plus cooler flange connection need to be aligned if possible. The oil lube pipe work could not be matched as the bearing housings simply could not be positioned in the same place. Terminal box positioning was considered and with close liaison between the motor OEM and the end user auxiliary boxes either stayed exactly as originally positioned or were moved closer to the incoming cable source. This allowed installation engineers to cut back and re-terminate the motor end of the existing cables. The purge system was no longer available to be supplied with up to date certification and as such a newer purge system was fitted with suitable ATEX certification to meet the requirements for Ex e px, IIC T3. This too had to be positioned to limit offshore installation work to the very minimum.

Figure 12 shows the larger of the motors being re-engineered and it is possible to see that the shaft end had to have an integral half coupling incorporated into it, this was to keep motor length down, but was fairly fundamental to ensure the non drive end foot fixings remained outside the motor body. Even with this modification extra long holding down bolts had to be designed to allow the non drive end foot fixings to be in a pocket within the base frame, rather than as the original design which were on the edge of the base.

In summary, the electrical limitation combined with the mechanical challenges come together to form a very bespoke motor design. Having performed detailed studies of the motor requirements, and with end user approval of the initial design concept study, the motor OEM was able to complete manufacture of the units in a relatively short period, and the electrical design exceeded the design criteria, achieving 2.55 x FLC, with the torque above the minimum specified design levels. The mechanical design was proven to be successful by achieving the motor change out within the tight offshore programme, and all units were commissioned offshore and production started up on time.

III. PROGRESS & FEEDBACK

The new compressor bundles, motors and switchgear/control system modifications were successfully installed and commissioned in 4 weeks of a 6 week platform shutdown during August/September 2011. Detailed planning ensured that no major problems were encountered, and the production was started up successfully at the first attempt. In order to gather data to verify the design studies, the platform operations team agreed to start up the facility on only one main generator to prove that the design criteria had been met. Measurements were recorded of the motor starts and compared to the predicted values from the power system studies.

During starting of the new 6.6MW and 8.4MW compressor motors the starting currents and voltage drops were found to be a few percent lower than calculated. This could possibly be attributed to the fact that the specified design motor starting currents were used in the studies, although during the motor factory tests lower starting currents had actually been measured (2.55 x FLC versus 2.85 x FLC). However, since the locked rotor current tests were at approximately 30% rated voltage, and there appears to be no standard for factoring any saturation affects at full voltage, the design limited starting currents are taken as the nominal.

The motor starting times were also significantly lower than calculated, although this was attributed to the gas
pressure conditions being much less onerous than the worst case design.

The recorded voltage curves indicated that the pre-start boost logic didn’t work, although the motor started successfully. Fault finding for this is outstanding due to continuous operation of the facilities, and is scheduled for next planned shutdown in Q3/Q4, 2012.

The new wellhead platforms are currently in the fabrication phase in Spain and will be towed to offshore Denmark, installed and commissioned during Q3/Q4 2012. Thus the performance of the power system with the loads from the wellhead platforms and the subsea cables is as yet unknown, although it is not anticipated that these will significantly affect the gas compressor/motor upgrade. However, other challenges will be presented when integrating the new installations into the existing power system!

IV. CONCLUSION

The main conclusion which can be drawn from this brownfield project is that with good cooperation, planning and teamwork between operations, design contractors and equipment suppliers, many significant challenges can be overcome when expanding existing installations. The ability to model the existing power system in detail, with actual equipment data, and to perform tests to verify the accuracy of those models, was invaluable for the upgrade of the gas compressors. This verification is something which isn’t available when similar studies are performed for greenfield installations. It also gave the confidence to understand, and design to, the power system limits to ensure maximum value is obtained from the asset.

This particular project also highlighted some of the challenges associated with modifying facilities which have been designed with little thought of future expansion. This is particularly true when equipment is very close to its maximum rated value (eg fault rating and starting current limitations in this case). Some discrepancies with the standards for key parameters have also been identified.

Amidst all the technical challenges, it is often the simpler, practical things such as weight and space limitations which can become the greatest obstacles. One such example was when it became apparent that 2 VC circuits from within the switchgear line-up would have to be removed and installed at the end of the switchgear and replaced with a new VCB tier. This was particularly challenging during a very constrained offshore installation programme and required very detailed planning to ensure the work was carried out without incident and on time. It didn’t help that the original assembly plant which manufactured the switchgear had long since closed, making it difficult to get manufacturing design drawings & data. However, this was eventually successfully overcome, and one positive advantage was that it did enable all of the original control cabling for the IP compressor to be re-used.

Finally, this project highlighted the importance of engaging key suppliers and contractors early in the conceptual design process to ensure the project scope could be achieved, and to determine the practical design limits imposed by project design constraints.

V. REFERENCES


VI. VITA

Graeme Peck graduated from Brunel University, West London. He has worked for 25 years on oil and gas development projects for BP, ConocoPhillips and Chevron. His experience includes all aspects of electrical power system design, installation, commissioning and operations for both onshore and offshore oil and gas facilities. He is currently senior electrical engineering advisor for US oil company Hess, covering various projects in Europe, North Africa and South East Asia. Graeme is a member of the Institution of Engineering and Technology (IET), and has been a PCIC Europe committee member for the past 2 years.

Preben Jakobsen received the B.Sc.E.E degree from the University of Southern Denmark in 1990, and since he has worked with UPS- and industrial LV and HV power systems. He entered the oil and gas business in 2001 and has been working as Senior Chief Consultant at Ramboll Oil & Gas since 2007. He has carried out concept, FEED and detailed design for power generation and distribution on several plants and performed power system studies for greenfield and brownfield projects.

Ed Snow first experienced the Oil and Gas industry in the mid 1990’s through educational projects linked to BP-Phillips and Shell, which in-turn lead to short term positions at Amoco and Shell. He graduated from Staffordshire University in 2003 with an Honours degree in Engineering. Now in his 9th year at Laurence Scott he has had the opportunity to work with OEMs, Contractors and End Users on numerous projects from early pre- FEED stage right through installation, commissioning, and his support extends through into the products service life.