SPE 112099

Applying Sand Management Process on the Lunskoye High Gas-Rate Platform Using Quantitative Risk Assessment

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This paper was prepared for presentation at the 2008 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 25–27 February 2008.

Abstract

This paper is a case study, which describes how Quantitative Risk Assessment (QRA) is applied to sand management in the specific case of Lunskoye, to minimise risk of failure, while maximising production, reducing cost, and safeguarding reserves. Lunskoye is a high-rate gas development offshore Sakhalin island. The key concern is safely producing gas at high velocity, while minimising the risk from sand production.

In order to develop a safe method of producing gas, an integrated multidisciplinary team was put together to address the key parameters to manage potential sand production, using QRA.

In particular, consequences, probabilities of occurrence and means of monitoring and control were addressed. The key aspects of this approach are using the right kind of technology to design a safe production system, and then using the appropriate data to monitor and manage the impact of sand production.

The "intelligent tool" that was used allows an experienced integrated team to focus on the practical aspects of managing sand production in a structured and systematic manner to quantify the residual risk to people, facilities, and the asset as a whole. That tool also allowed us to integrate the inputs from widely spaced geographical locations - the production system was designed in the Netherlands, and was being built in Korea, then relocated to Sakhalin island.

The QRA involved the operator (Sakhalin Energy) and technical advisor (Shell), combining input from the corporate knowledge base with that of the asset team. This delivered operational plans that provide the key guidance for safe operation, which was endorsed by the operator and its shareholders. Overall, the value of this work has significantly reduced the risk exposure to the project, while reducing well completion costs and safeguarding production in the long term.

Introduction

The Sakhalin Phase II development is an oil and gas project, comprising 2 new offshore platforms, one on the Lunskoye field and a second on the Piltun Field. The Phase II development also includes changing the existing Astokh platform to an all year round production operation. These platforms will be linked to an oil terminal and an LNG plant 800km away on the southern edge of Sakhalin Island. Over 90% of the gas for the LNG plant will be supplied by the Lunskoye field, and will result in production of 9.6 million tonnes of LNG p.a. or upto 1,635 MMSCF/D processed through two LNG trains (Fig 1).

The Lunskoye Field is an offshore field situated in 48m of water in the Sea of Okhotsk to the east of Sakhalin Island. The field comprises a north-south trending anticline, with 4-way dip closure (Ross et. al., 2006).

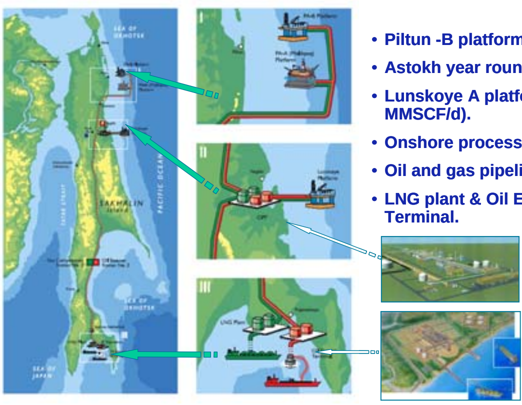


Figure 1. Sakhalin Phase II Development.

The anticline is approximately 20km long (N-S) and 8 km wide (E-W) at the gas-fluid contact, and at the crest comprises approximately 400m TVD thick gas filled sandstone, with 18.2 TCF GIIP. The anticlinal structure is sub-divided by six NE-SW oriented faults (Fig 2). The crest of the Lunskoye field occurs at depth of 1700 mTVSS. The reservoir sandstone has an average porosity of 25%, and permeabilities in the range 150 – 1,200 mD.

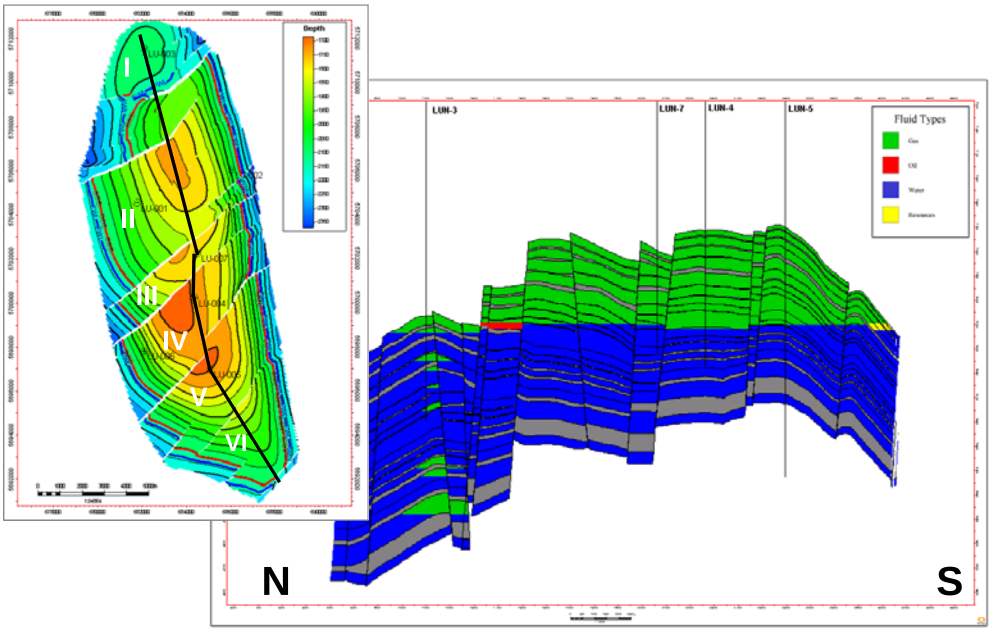


Figure 2. Top structure map and crestal x-section (N-S) of the Lunskoye field, offshore Sakhalin Island, Russian Federation.

The field is expected to be produced by depletion drive with the initial reservoir pressures of approximately 3,000 psi reducing to 500 psi over the expected 40 year production life of the field. Initial studies predicted that this depletion would lead to stress increases sufficient to cause sand production from these formations, as a result the platform facilities were designed for a lifetime of sand production at a rate of 0.5 lb/MMSCF, in line with Shell designs in other sand production prone regions.

The initial gas required to reach plateau production of 1,800 MMSCF/D will be produced through 6 big bore gas wells capable of producing in excess of 300 MMSCF/D/well. As depletion occurs more wells will be drilled in order to maintain the plateau.

The potential for sand production to disrupt the gas production and LNG delivery has been minimised in the design stage of the project. This paper describes a Quantitative Risk Analysis (QRA), based on the as-built Lunskoye-A facilities and upon updated well and completion designs, which aims to further reduce any residual risks by identifying and quantifying the critical failure modes and identifying the appropriate mitigating measures, through the use of a systematic, rigorous methodology, based on sound principles, which is able to provide implementable results; Failure Modes, Effects and Criticalities Analysis (FMECA) technique (Hother, 1999, 2002a, 2002b, 2006, Hother et al. 2001, 2003, 2005).

Completion Design and Predicted Sand Production

This Quantitative Risk Analysis of the Lunskoye-A wells and production facilities specifically focuses on the failure modes resulting from sand production. Sand production occurs when reservoir effective stresses exceed the strength of the sandstone resulting in rock failure and disaggregation, during which, sand grains become detached from the sandstone reservoir formations. The effective stress in a reservoir increases during depletion, causing the weaker sandstones to fail, followed by the failure of successively stronger formations as the depletion continues. If the disaggregated sand is transported to the facilities in the gas and liquid stream, it will result in erosion of the flowlines and settle in areas of low flow velocities leading to plugging. If the sand is not transported out of the wellbore and remains in the well, the completion interval will gradually "sand up", and production will decline, requiring a workover and a cleanout in order to restore productivity.

The completion design for the Lunskoye big bore gas wells is one of the primary risk reduction activities for managing sand production. In comparison with an openhole completion, the preferred "cased and perforated" completion will delay the onset of sand production and is expected to reduce the volumes of produced sands during field life. However, sand production is still predicted from a few thin layers early during the production period: The adoption of selective perforating ensures that these weaker layers are left unperforated, so delaying the onset of sand production further and reducing the volumes of sand production. Consequently, Selective perforation is the preferred sandface completion for the early Lunskoye-A wells.

Sand production predictions have been used to estimate the onset of sand failure and the potential volumes of sand which could accompany the depletion and production from the field, and produced to the facilities. Most of the failed sand is expected to be transported to the surface facilities, due to the high flow rates (300 MMSCF/D) and velocities in these big bore gas wells wells. The well completion comprises 8 ½" hole sections drilled through the reservoir, completed with a 7" cemented liner and a 9 5/8" x 7" production tubing, for the first three gas development wells: 9 5/8" monobore completions will be used in subsequent wells (Fig 3).

Each well will have its own characteristics for the onset of sand production and for the volumes which will be produced, depending upon the location of the well on the structure, the local reservoir mechanical properties, the pore pressure and stress evolution and the completion design. The magnitude of the expected sand volumes for the first production well, Lunskoye well 517, is used as an example (Figure 4); these estimates are based on the predicted sub-surface formation properties.

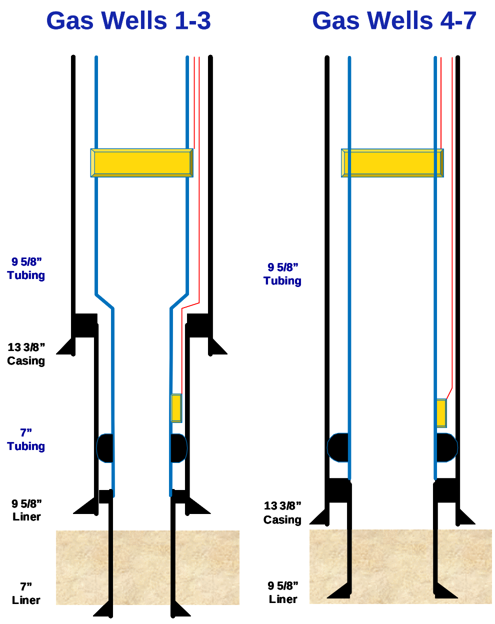
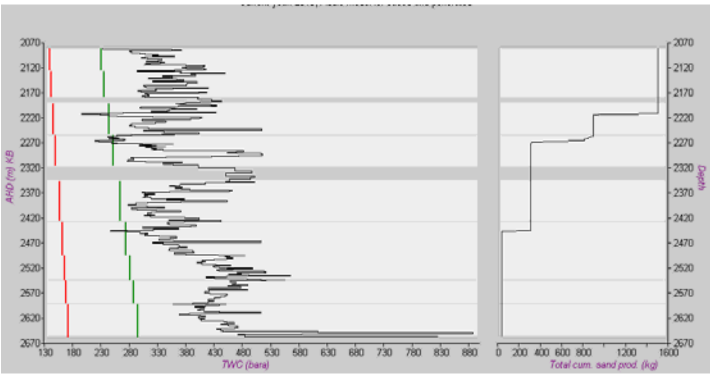
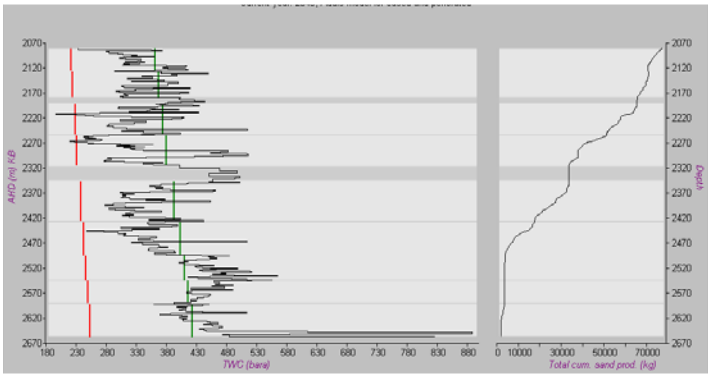


Figure 3. Completion designs for the initial Lunskoye field, big bore gas wells.

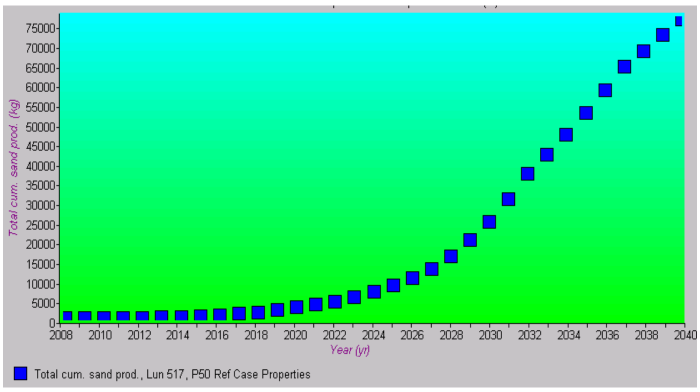
In the left hand plots of Figures 4a & b, the black line represents the calculated strength of the reservoir sandstone, which comprises 10 layers; the darker grey layers are considered non-productive. The green lines define the threshold strengths required to avoid sand production: if the calculated strength is lower than the green line sand failure is expected. The right hand plots in Figures 4a & b, show the estimated total cumulative sand produced in the wellbore up to that analysis date: "total cumulative sand production" indicates the cumulative sand produced and passing that depth since the start of production.



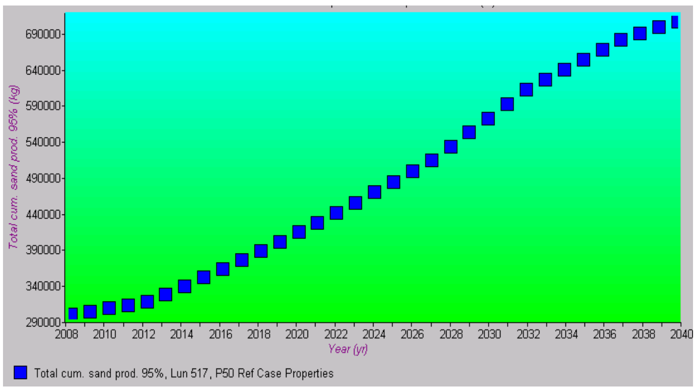
a) 2018



b) 2040



c)



d)

Figure 4. Predicted sand failure and sand volumes for Lunskoye-517, a) for 2018, b) for 2040 end of well life, c) P50 estimates and d) P95 estimates for cumulative sand volumes for the production life of the well.

The predictions in this example are based on a selective perforation scheme to ensure sand free production to 2017. Following the QRA study, it was agreed to delay sand production until 2025, without impacting gas deliverability.

At the end of field life approximately 75 tonnes of produced sand (P50) are predicted from such a well (Figure 4c). The worst case, P95 estimate, shows that the sand could be an order of magnitude higher, however, the predictions and calibrations performed to date indicate that the P50 is an appropriate basis for forward “blind” predictions.

QRA

Quantitative Risk Assessment (QRA) is one of the tools used to evaluate and quantify risks associated with an operation. QRA is generally used to address one, or more, of the following (Van de Graff, 2005):

- Assist in reducing risks: by identifying areas of high risk or identifying areas where risk can be further reduced
- Assist in option selection by ranking options in terms of risk
- Assess the cost-effectiveness of risk-reducing measures
- Assist in the demonstration and achievement of ALARP (As Low As Reasonably Practicable)
- Act as an aid to communication with the workforce and third parties regarding their impact on risk and their exposure to risk
- Indicate whether or not risks are tolerable
- Comply with legislation and company policy.

The QRA study of the Lunskoye wells and production facilities (up to the export line) was initiated to address most of these items, principally with the aim of identifying outstanding risks and methods to mitigate these risks. Specifically, the technical objectives of this QRA project included;

- Providing a systematic analysis of failure modes with mitigating measures and recommended actions identified;
- Formulating an action plan based on a cost/benefit view;
- Analysing the impact of alternative scenarios (sand-face completions and well-head de-sander);
- Formulating initial responses when excessive sand is detected;

QRA Approach for the Lunskoye Sand Management

The basis for QRA is that Risk = Probability of Occurrence x Severity of Failure: In order to assess the risks present in a system, an approach is required to identify potential failure modes, a method to assess the Probability of Occurrence of those failures and an assessment of the Severity of the Failures (Consequences), normally expressed in monetary terms. A Failure Modes, Effects and Criticalities Analysis (FMECA) technique was used as a basis for the QRA, in order to provide a systematic risk assessment, in a three-staged approach (Table 1):

Table 1. QRA/FMECA Format for failure mode analysis.

Stage 1							Stage 2
Components	Failure Mode	Effect	Severity Ranking	Cause	Probability of Occurrence	Risk	Recommended Action
AA	BBB	DDD	4	FFF	1		-
				GGG	5		-
	CCC	EEE	5	HHH	8		MMM
				JJJ	3		-
				KKK	2		-

In Stage I we established the baseline approach for the analysis;

- defining 8 different production phases of the operations, e.g. well clean-up & bean-up, plateau production prior to and following compression, and
- defining a system block diagram of the 16 major system components (e.g. 12” flowline, separator etc.) showing the flow configuration for each of those production phases (Figure 5).

For each of the operational phases, a failure mode analysis was performed, identifying failure modes, causes, effects and probabilities, using the format shown in Table 1 above. In advance, a set of ranking tables was established that facilitated the assignment of a ranking value for severity and probability of occurrence to each failure mode in a consistent manner.

The identified failure modes for the different components are assigned a probability of occurrence (of failure) and the consequence of such a failure. This is repeated for each production phase when sand can be produced and observed by the production facilities.

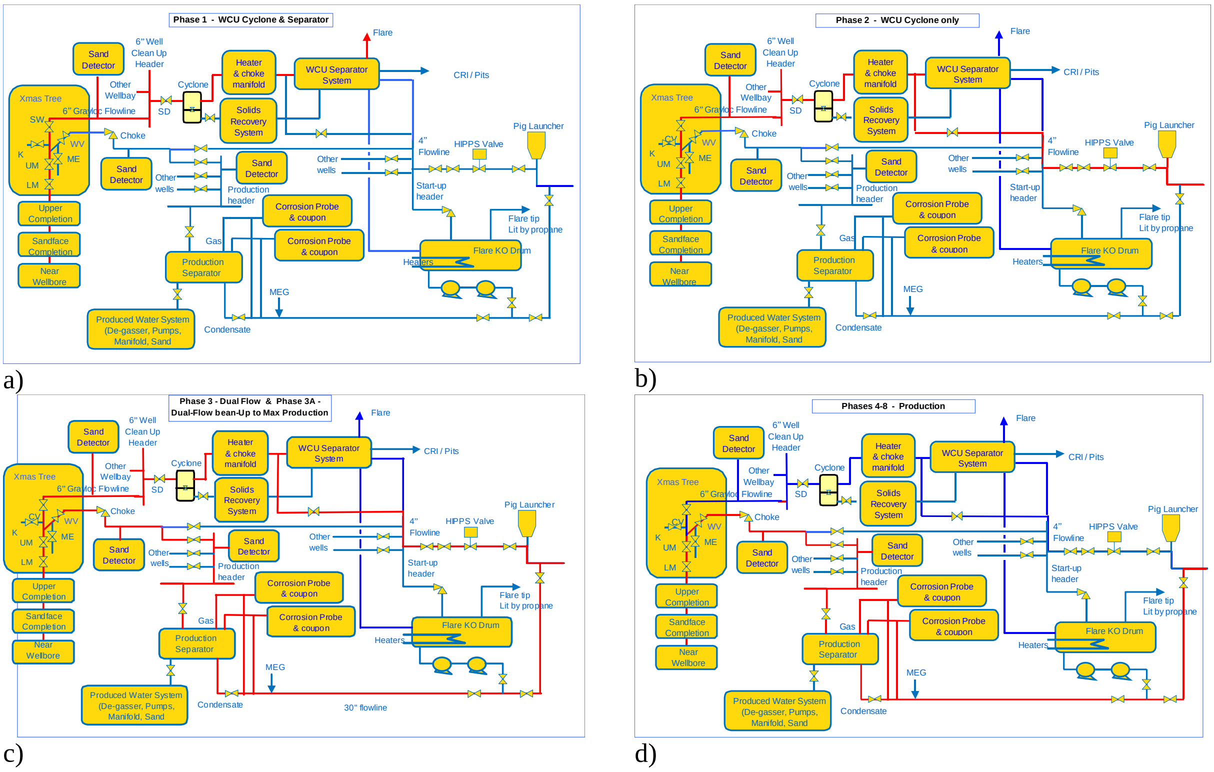


Figure 5. Different phases of production used to identify associated failure modes and assess risks: a) Clean-up, b) Clean-up with cyclone only, c) Bean-up to plateau with dual flow, d) Plateau production.

In Stage II, all the critical failure modes, were reviewed along with the first estimate of erosion risks. Mitigating measures and specific recommendations for action were identified for each critical failure mode.

In Stage III, the recommendations were examined in detail from a cost/benefit point of view, to provide a basis to decide which to adopt. Sensitivity analysis was then adopted by performing various ‘what-if’ scenarios’ and comparing the results.

Input to QRA: Probability of Occurrence (PoO)

The principal failure modes resulting from sand production include erosion, in the form of metal wall loss from tubulars, with the potential for a loss of containment of hydrocarbons, and / or deposition of sand and plugging of flowlines and equipment.

The probability of occurrence for these failure modes was based on the predicted P50 and P95 sand volumes and sand rates, based on sand quantification estimates: For the base case ‘cased and perforated’ 100% perforated completion, probability distribution curves were defined using a Weibull function for the production phases (Figure 6), and a triangular function for the start-up phases. The sand failure and sand volume predictions were based on the geological prognosis for the Lunskoye gas development wells from the ‘reference case’ static geological IRM model (Ross et al., 2006.)

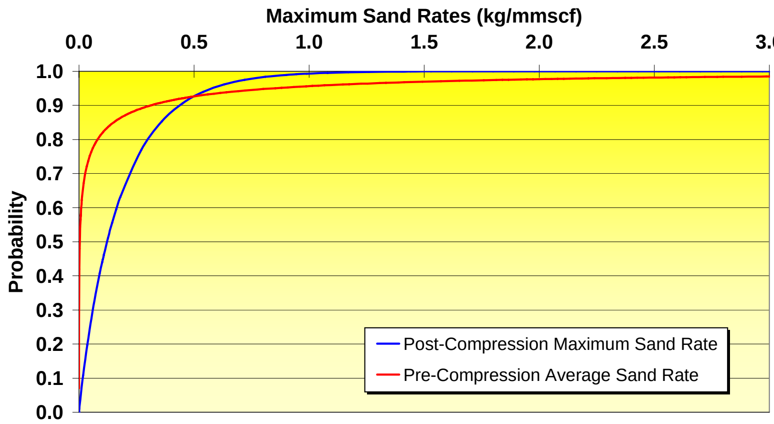


Figure 6. Estimated probability distributions for sand rates pre- and post- compression (2020) based on Lunskoye- 517 predictions for 100% perforated completion.

Estimating the probability of occurrence for erosional failures was achieved in two stages, summarised in the following diagram (Figure 7):

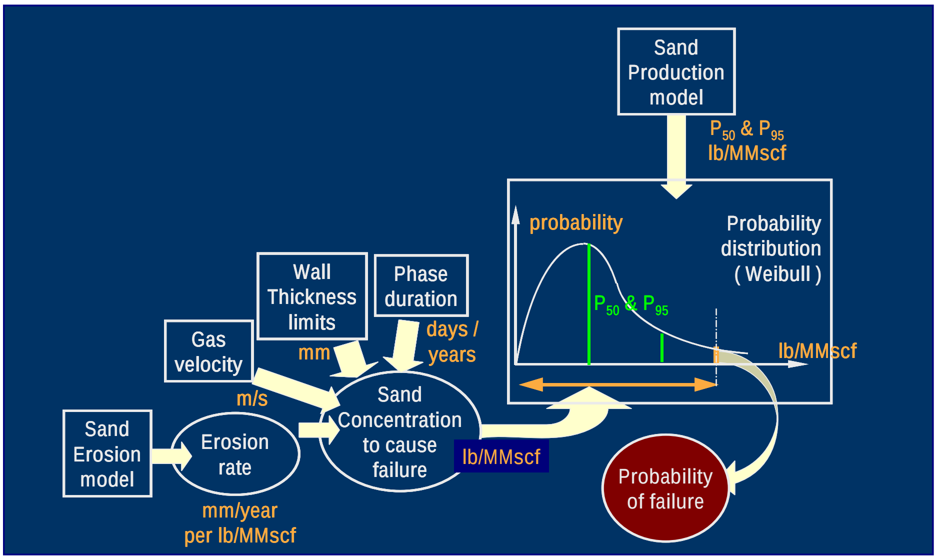
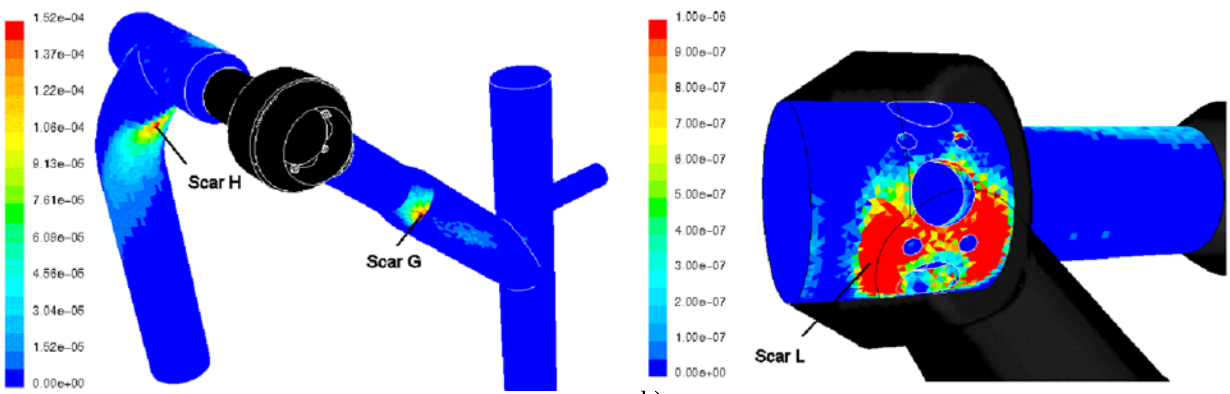


Figure 7. Estimating Probability of Occurrence of Erosional Failures

i) the critical sand concentration required to cause failure was determined for each component and for each production phase, which has a specific phase duration. This critical sand concentration was defined by the combination of gas velocity, allowable wall loss or wall thickness limit, duration of the operations phase and erosion rate. Gas velocities and erosion rates were based on the analysis of flowlines and bends using the Tulsa University Sand Erosion Model (Skogsberg et al. 2005) and for more complex components such as the choke or wellhead, from Computational Fluids Dynamics analysis (Barton, 2003), (Figure 8).

ii) use the probability distribution curve to find the probability of occurrence of the "critical" sand concentration which would cause the failure, during each phase of the operations.

These rates and sand volumes were used as input to erosion estimates for different system components, e.g. 12" flowline and choke.



a) b)

Figure 8. Erosion rates (mm/kg of d_{50}=100 μm sand) estimated using Computation Fluids Dynamics modeling of the a) Xmas Tree and 12" flowline, and b) the choke gate for Lunskoye-A big bore gas wells (290MMscf/d) (Barton, 2003).

The probability of occurrence of a failure was then ranked using a probability ranking table with 10 subdivisions. The ranking table probabilities ranged from the highest probability >1 in 2, to the lowest probability of occurrence < 1 in 1,500,000. The rankings for each failure mode was included in Table 1.

Input to QRA: Severity of Failure (SoF, or Consequence)
The consequences of the failure were defined in terms of costs, e.g. a day of lost rig time, a lost day of plateau production, etc. These costs were summarised in a severity ranking table (ranks 1-10), Table 1, with costs increasing by a factor of ten for each severity rank. Each failure mode (for which a probability of occurrence had already been assigned) for each phase of the operation was assigned a severity rank, with an associated 'order of magnitude' cost.

Using the Probability of Occurrence and the Severity of Failure rankings, a relative risk for the different failure modes was defined.

Relative Risk Assessment Results: Base Case Completion

The QRA analysis identified 154 potential failure modes for all the life-cycle phases. In addition, another 90 potential failure modes were identified for the alternative sand-face completions (Open Hole Gravel Pack, OHGP & Expandable Sand Screen, ESS). These potential failure modes are presented in the Risk Profile plot in Figure 9. An overview of these potential failure modes showed that the majority would have a low impact on the operation. Consequently, a Risk Ranking threshold was set below which the risked costs of the possible failure modes were low. The potential failure modes, which fall above the risk ranking threshold value (20), were focused upon, for the purpose of identifying risk mitigation measures.

For the base case 'cased and perforated' completion the locations, or components, which have potentially the highest relative risk for failure include the Xmas Tree valves, 12" flowline, 20" production header, all of which are susceptible to erosion.

Based on this, a number of recommendations were identified to reduce these residual risks. These risk mitigation measures are predominantly operational, but also include actions such as increasing the number of non-intrusive sand detectors, e.g. on the well clean up package.

When alternative sandface completions are considered as a replacement to the cased and perforated completion, additional risks are introduced into the production system, associated with OHGP and ESS screens eroding through, packers leaking, and OHGP ports leaking (Figure 9).

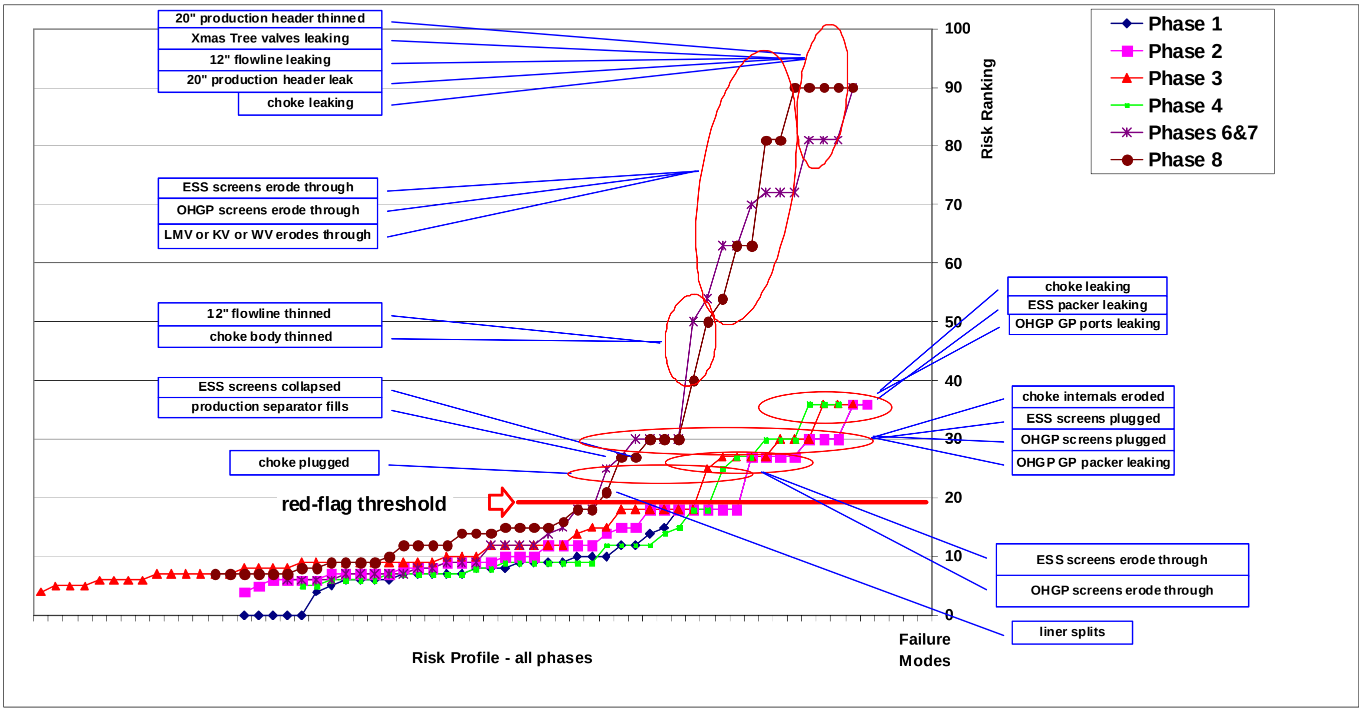


Figure 9. Risk Profile chart illustrating the risk ranked potential failure modes for the Lunskoye big bore gas wells and production system: Base case design and alternative completion scenarios.

Recommendations and Mitigation Measures: Base Case Completion
The following are some of the recommended actions, which would further reduce operational risk.

Choke body

- Carry out baseline in-situ Non-Destructive Testing (NDT) measurements on the choke body after installation, and mark on the outside of the body the reference points where subsequent measurements should be made;

- Open-up the choke periodically and measure wall thickness;
- Ensure that a spare choke will be onsite.

12-inch flow-line

- Apply Non-Destructive Testing (NDT) to the blind-tees composing the flowlines.

Applicable to all Key Components

- Maximise the volume of flow through the WCU Package;
- Follow strict bean-up procedure, ensuring sand rate drops to trace levels before bean-up to next step;
- Minimise the size of the bean-up steps;
- Ensure that the clamp-on sand detector equipment is working & calibrated;
- Prepare quantitative sand monitoring guidelines (in terms of frequency of measurement and specific mass/flow-rate scenarios) and compare all data with previous start-ups;
- Confirm optimum position of clamp-on detectors by consultation with contractor
- Collect in-line sand samples between the flow-line and the manifold (eg milli-pore filter) for grain-size analysis;
- Dedicated modelling must explore well decline rates and tubing-head pressures;
- Utilise NDT data from previous phases and accumulated experience (e.g. frequency of inspection / specific points of inspection);
- Regular, pre-defined flushing of the production separator to avoid the separator filling, leading to sand carry-over into the export pipeline.
- Define roles and responsibilities for monitoring, data acquisition and recording, and analysis (Sand Management Plan);
- Review the operational assumptions that were originally based on theoretical calculations and modelling to determine the impact of real historical data that is available in this phase;
- Undertake a design review of these critical components to identify modifications that would reduce the probability of failure;
- Undertake a review of the plan for replacing these components if / when they fail, and undertake the modifications indicated by the review to make the replacement practical.

Alternative Scenarios

The QRA process was repeated with 3 alternative sandface completions and with a wellhead de-sander option, examining the potential failure modes, quantifying the risks, and assessing the engineering implications and costs involved with each scenario.

Three alternative sandface completions were considered for these 55° inclined, 600m AHD long well intervals:

1) Selectively Perforated Completion: Decreased, or Conservatively, Perforated Interval.

   This option considered selectively perforating the completion interval in order to minimise sand production to 2025, rather than the previous 2017: this would mean perforating less of the interval and potentially impacting initial gas production.

2) Openhole Gravel Pack (OHGP): with shunt tubes

   This option was considered utilizing a one or two stage gravel pack, using gravel packing fluid systems, which would be compatible with the oil-based mud used to drill the open hole reservoir interval.

3) Expandable Sand Screen (ESS):

   The standard 5 ½” ESS system was considered as the preferred completion design for these wells, however the 7” system could be considered later in the development.

Prior to the Quantitative Risk Analysis being performed, a productivity comparison was performed for these alternative completions to ensure the initial productivity met the required 300MMSCF/D.

Relative Risk Assessment: Alternative Completions

The results of the failure mode analysis and risk assessment for the three alternative completions are presented in Figure 10.

The conservative “Decreased Perforating Interval” completion, delays sand production from 2017 to 2025 and the sand concentration shows an associated reduction. Risk of failure due to sand throughout the system in the production phases is consequently reduced by the later arrival of sand. Producing less sand from the perforations also reduces risk in the earlier phases. The failure mode analysis showed a reduction in the risk of failure of the completion itself during production post-compression (Phase 8) compared with the base case, with no significant difference in the earlier phases.

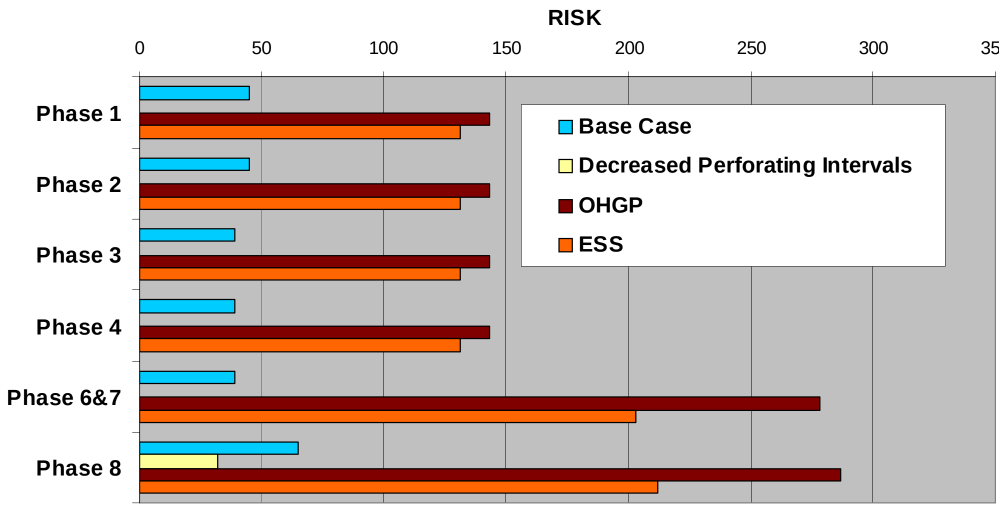


Figure 10 - Comparison of the risks associated with Alternative Sand-Face Completions

The failure mode analysis of the Openhole Gravel Pack (OHGP) showed roughly 5 times the risk of failure of the completion itself during production pre- and post-compression (i.e. Phases 7 & 8), compared with the base case, and roughly 3 times in the preceding phases. This is somewhat contrary to the general industry view, where sand control completions such as gravel packs, are used to reduce sand production, compared to openhole, or cased and perforated completions. However, this view and supporting observations (King et al. 2003) measure the success of sand control completions based on the observation of sand production as an indicator of its success. In such comparisons the cased and perforated completion commonly shows sand more often than the sand control options, as is expected, as this is not a sand control completion.

The Relative Risk considered here is not concerned with the observation of sand, but on the impact of failure of the completion and subsequent sand production on the overall production system reliability. It should be emphasised here that this is a Lunskoye specific assessment. Each development team should assess this for their specific field, completion and operational conditions.

The failure mode analysis of the Expandable Sand Screen (ESS) showed roughly 3 times the risk of failure of the completion itself during all phases, compared with the base case.

As a result of this QRA sensitivity analysis, in support of other completions studies, the preferred completion for the Lunskoye field big bore gas wells is a cased and perforated completion, selectively perforated to avoid sand production until 2025. If sand control or exclusion is required in the Lunskoye gas wells, the ESS is preferred to the OHGP as an alternative completion, due to ease of installation and similar, or lower, risk of failure.

Relative Risk Assessment: Wellhead Desander

Wellhead Desanders are normally installed at the wellhead to remove sand from the flowlines so reducing the exposure of equipment downstream of the Desander to sand erosion and deposition; reducing the sand-related failures of all downstream components. The failure mode analysis of this option showed no high-risk failure modes and only a small increase to the overall risk of the whole system due to failures from sand.

However, wellhead de-sanders currently available are not considered viable for the Lunskoye platform at this time, due to space restrictions in the wellbay area.

Remedial measures

Sand production is expected from the Lunskoye wells following 2025, based on the selectively perforating scheme, where any layers predicted to produce sand prior to 2025 will be left unperforated. Sand production may occur sooner than predicted for a number of reasons, including unexpected geological variations, or issues in the completion design, e.g. error in logs, depth errors, perforation of uncemented or partially cemented liners sections.

Remedial options are available for cases of unexpected excessive sand production (Farrow, 2001): Four main options for managing the risks associated with sand production, include;

- Do nothing – i.e. live with sand production with no major operating changes. Repair and replace equipment as it is damaged by sand. Continuous monitoring to detect damage due to sand (Flowline Acoustic Sand Detectors, Ultrasonic Testing/Non-Destructive Testing (UT/NDT), etc.).

- Bean back, or shut-in individual sand producing wells, so that minimal or no sand is produced: Establish the Sand Free Rate (SFR) or Acceptable Sand Rate (ASR).
    - Conditioning the well: This applies to Lunskoye wells as the sand production expected is transient sand production and can be achieved by a stepwise bean-up of the well followed by short flow periods at a higher than required drawdown, before reducing the drawdown to the required level for long term production: this is one step beyond establishing the sand free rate and is used to increase and impose a required sand free rate.
- Topsides solutions – install a desander/in-line separator to remove sand once it gets to the topsides.
- Downhole solutions – install downhole sand screens to prevent sand from reaching the topsides.
    - Shut-off sand producing zones. If the sand producing interval is known (e.g. from video camera, or logging suite), setting patches or plugs may shut-off sand and gas production from this layer.
    - Installation of downhole sand control. Various types of downhole sand control can be installed to reduce the level of produced sand, e.g. sand control screens, expandable sand screens, gravel packs or frac and packs. These options tend to reduce the productivity of the wells to an unacceptable level or introduce significant risk for future sand production as a result, the alternative would be a sidetrack with a new sandface completion.
    - Recompletion/sidetracking of the well to avoid sand production from the intervals using an alternative completion.

Production of excessive sand, above the design, or acceptable limits, for an extended period of time will result in erosion of the facilities and if the conditions are left to continue without intervention, to a loss of hydrocarbon containment. A generic response diagram is shown below in Figure 11.

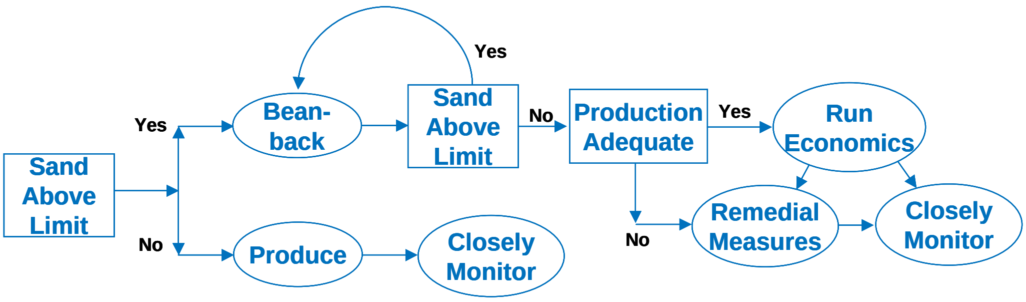


Figure 11. Generic decision tree in the event of an indication of excessive sand production

Once excessive sand production is observed, the required actions lead to closer monitoring prior to a subsequent decision or action, or to beaning back (conditioning) the well to an acceptable sand production level. If the gas production following bean-back is inadequate to meet the contracts, well intervention is required, either with a remedial option such as casing/liner patches or with sidetracking and an alternative completion. Following the drilling of the initial development wells required to meet plateau production, drilling will continue to ensure spare wells will be available to minimise gas deferment.

Discussion: Sand Management & QRA

Sand Management forms a strategy for a production operation when sand and/or fines are produced to the facilities and which require the well production to be optimised and platform down-time to be minimised. The Sand Management approach aims to reduce the impact on operations of solids production, through appropriate completion and facility designs, management of the operations, and appropriate monitoring and surveillance (Mathis, 2003, Acock et al. 2004).

The use of a sand management strategy for high rate gas wells and LNG production operations is well established, having been operational for decades in northern Netherlands, Groningen and satellite fields, and on the Goodwyn and surrounding fields on the NorthWest Shelf (NWS) of Australia. All of which use big bore well completions to ensure high production rates, upto 350 MMSCF/D.

Cased and perforated sandface completions are commonly selected for these big bore gas wells, though recent big bore wells in Ormen Lange utilise openhole gravel packs due to the extremely weak nature of the reservoir formation, and the sub-sea nature of the gas gathering and distribution operations. Also ESS have been used with success in these high rate wells on the North West Shelf. The benefits of cased and perforated completions, no downhole sand control, have been outlined by Farrow et al. (2004) for the NWS operations.

Sand Management is also used as a development strategy in other parts of the world with lower gas production rates, e.g. Southern North Sea (Selfridge et al. 2003, McPhee et al. 2007), Thailand (McPhee et al. 2000), Pakistan (McPhee and Enzendorfer, 2004).

Quantitative Risk Analysis of the Lunskoye-A completion and facilities has been used to assess residual risks to the operation due to sand production. Risk mitigation measures have been identified based on the analysis, and have been adopted within the Lunskoye-A Sand Management Plan. The formulation of the sand management plan for Lunskoye-A has drawn heavily from the experience of NAM in the Netherlands and Woodside and the NWS venture on the NWS Australia. However, this is the first time that QRA has been used as a basis to reduce risks due to sand production, and used as a basis to define an operational Sand Management plan, where sand production is expected during the life of the field.

The ability to perform QRA for sand management hinges on the ability to ascribe Probability of Occurrence to failure modes, which in turn has required two important technical developments; The first is the development of sand erosion models which account for sand properties, flow conditions and flow geometry in the erosion estimates, with reasonable accuracy. The development of these sand erosion models has been an ongoing research effort in several institutes, notably Tulsa University, AEA and DNV.

The second technical development relies on the ability to predict sand volumes and sand rates with reasonable confidence. Sand Quantification models, which predict the volumes of sand have only started appearing in the industry since 2002 (Willson et al. 2002, Van den Hoek and Geilikman 2003). Prior to this sand models focussed solely on predicting the onset of sand production, with little or no capability to estimate sand volumes. It is this ability to estimate sand volumes and rates, which has, in part, enabled QRA to be performed, and for the probabilities of failure to be estimated.

Reduction of risks associated with sand production will help secure the supply of gas to the LNG terminal, and the LNG cargoes to customers.

Conclusions

The Lunskoye field development is expected to produce sand during the life of the field. This results from the depletion of the field and the accompanying increase of stress on the weak to moderately strong sandstone formations. The surface production facilities on Lunskoye-A have been designed for this: The Basis of Design for the Lunskoye-A platform quotes 0.5 lbs of sand per million scf of gas, as one of the basis for the design of the production facilities.

The potential for this sand to be unmanageable, presents a potential risk to the operation and to the integrity of the facility. Risk reduction has been addressed primarily through the sandface completion design and the sand tolerant design of the Lunskoye-A facilities, which enable a sand management strategy to be followed. As a part of this sand management strategy the residual risks to the Lunskoye -A facilities has been assessed using Quantitative Risk Analysis (QRA), which aimed to further reduce any potential risks. The analysis, conclusions and recommendations from the QRA form an integral part of the Sand Management Plan for Lunskoye. The Sand Management Plan addresses designs and operational procedures which focus upon reducing the quantity and impact of sand observed in the facilities, as well as monitoring and inspection schemes which track the impact of any sand on the integrity of the facilities. Remedial and contingency options as well as operational procedures, which help manage any unexpected unmanageable sand production, have been identified and assessed, also using QRA.

Acknowledgements

The authors would like to thank Sakhalin Energy Investment Company (SEIC) and it's shareholders (Gazprom, Shell, Mitsui & Mitsubishi) for permission to publish this paper. The authors would also like to acknowledge the time and effort put in by the Lunskoye sub-surface and production operations staff who have contributed to the work presented in this paper, specifically, Bill Renwick, John Carminati, Russell Malmquist, Paul Raven, Phil Muir, Jim Wrathall, Rod Phillips, Gerrit Lemstra, Egbert Prins, Peter Ideler and the reviewers of this work from the SEIC partners Shell, Mitsui, Mitsubishi, and Prof N. Morita of Waseda University who acted as an external reviewer/consultant to the sand management effort.

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