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Drilling & Completion

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- Casing Accessories: ensure the integrity of the well construction and cementing operations.
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- Stimulation Chemicals: increase load recovery, hydrocarbon production, lower pumping friction and increase ROI.
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- Stimulator: improve penetration rate by inducing axial vibration in the drill string to reduce friction drag and sticking.
- Casing Accessories: ensure the integrity of the well construction and cementing operations.
- Artificial Lift: novel pump systems, reliable support to help lower cost, improve reliability and deliver more production.

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U$40 is the new US$70 – at least that’s the phrase that has been making the headlines recently. It wasn’t too long ago that US$70 was seen as a rough minimum required for US shale producers to make money. As the downturn wore on, that figure soon fell to US$60, then US$50 and now – if John Hart, CFO of Continental Resources is to be believed – US$40 could be the turning point.

According to Reuters, Hart stated that Continental would be prepared to increase Capex if US crude prices reach “the low- to mid-US$40s range”, effectively boosting 2017 production by at least 10%. Whiting Petroleum Corp, the biggest producer in the Bakken is currently on track to stop fracking of all new wells by the end of March, but CEO Jim Volker was quoted as saying that the company would “consider completing some of these wells” if oil made a return to the US$40 - 45 range.2

This sounds like good news for shale producers, but is such a rally likely in the short term? As I write this, Brent crude has spent more than a week sitting comfortably above US$35. Whilst that’s nothing spectacular, it’s certainly an improvement on the lows of US$27 that were reached just a few weeks earlier. The driving force behind this particular upswing appears to have been the recent announcements by several major oil and gas producers, Russia and Saudi Arabia included, that they would aim to negotiate a production freeze and cap output at levels seen in January. The news of this potential agreement brought a surge of optimism to the market and lifted oil prices. After all, a production freeze could be seen as the first step along the way to production cuts, a reduction of the supply glut, and a return to higher prices. Alexander Novak, Russia’s Energy Minister said the aim of the production freeze was to “stabilise the price of oil around US$50 - 60/bbl” .

It’s not all sunshine and rainbows, however. As tempting as it may be to buy into the possibility of a sudden upswing, Matthew Smith, Head of Commodity Research at ClipperData summed up the situation neatly, “Fundamentally, things are still extremely weak. It’s being driven more by hope.” All the factors that caused prices to fall in the first place are still in play. A freeze in production might seem like an admirable first step – an attempt to work towards cuts – but agreeing to freeze production at levels that outmatch demand seems of little practical use. The other spanner in the works is Iran; having finally emerged from sanctions earlier this year, the Iranian government is – I think understandably – more than reluctant to agree to the freeze and effectively start sanctioning itself.3

Despite these issues, oil prices will eventually recover – that much is certain. For one thing, the supply glut is unsustainable in the long term – major suppliers, such as Saudi Arabia, are burning through their cash reserves to make up the shortfalls in their budgets. In the meantime though, it’s encouraging to see the continued ingenuity and tenacity of the US shale industry, despite the hardship felt by many. The same drive that brought about the shale boom in the first place, and made the industry profitable at US$100/bbl, has led to the development of technologies and processes that allow companies to operate at less than half the price. It’s that kind of approach that will see the upstream industry make it through the downturn.4

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Production drilling commences on Johan Sverdrup

The *Deepsea Atlantic* drilling rig began the first of a total of 35 wells to be drilled in the initial phase of the Johan Sverdrup field development.

“The *Deepsea Atlantic* drilling rig is currently predrilling the first production well for the first phase of the Johan Sverdrup development. This is a central operation in a complex Johan Sverdrup puzzle. Predrilling allows the production capacity on the field to be utilised as efficiently as possible when Johan Sverdrup has come on stream late in 2019. This way, we maximise value from the field from day one,” said Kjetel Digre, senior vice president for the Johan Sverdrup project.

The rig is drilling the first production well through a predrilling template that was installed on the field in the summer of 2015. A total of eight wells will be drilled through the predrilling template, before the rig relocates to drill injection wells on three locations in the field.

In 2018 the permanent Johan Sverdrup drilling platform will be installed as the second of four platforms. The drilling platform is currently being constructed at Aibel’s yard in Haugesund, north of Stavanger, and in Thailand. When the drilling platform is installed and operational, the eight predrilled wells will be hooked up from the predrilling template. At this point *Deepsea Atlantic* will be drilling the injection wells providing reservoir pressure support to maintain high field production.

The operator (Statoil), the rig owner (Odfjell Drilling) and the drilling service provider (Baker Hughes) have co-operated closely to ensure safe and cost-effective deliveries. The Johan Sverdrup project introduces integrated drilling services as a new concept, which means that Baker Hughes will provide the main deliveries together with Odfjell Drilling.

JDR awarded IWOCS umbilical contracts

JDR has been awarded a contract for intervention, workover and control systems (IWOCS) by Aker Solutions Subsea Division. The project – which is scheduled for delivery in summer 2016 – will include the first deployment of JDR’s ‘Mark II Reeler’ concept.

The scope of supply includes two 1200 m umbilicals, which provide annulus circulation function to subsea systems. Both umbilicals will be supplied on the new Mark II Reeler technology. The new reeler is designed to provide customers with a significant reduction in size versus conventional reelers, saving valuable deck space, as well as a lower weight for lifting and handling. The reeler, which has no impact on umbilical capacity, will also lower costs due to reduced materials. In addition, the new design includes a number of key safety features such as improved operator access and compliance with DNV lifting requirements.

MEO secures investor for Cuban exploration

MEO Australia Limited has announced it has executed a private placement agreement with London listed Leni Gas Cuba Limited to raise US$1.4 million with funds to be used to advance MEO’s exploration programme on the company’s newly advanced 2380 km² onshore oil block, Block 9 in Cuba.

Under the placement agreement MEO will issue Leni Gas Cuba 140,716,573 shares at an issue price of AU$0.01 per share. The placement of shares to Leni Gas Cuba falls within MEO’s placement capacity and will make Leni Gas Cuba MEO’s single largest shareholder with a 15.8% interest in the company.

Cuba boasts exceptional oil and gas prospectivity. The Block 9 PSC area is in a proven hydrocarbon system with multiple discoveries within close proximity, including the multi-billion barrel Varadero oilfield. Block 9 contains the Motembo field, the first oilfield discovered in Cuba.

In brief

Northwest Europe

SeaBird Exploration Plc has announced that the company has signed an agreement to conduct a pre-funded 2D multi-client survey in North West Europe during this coming summer season. The project is due to commence during Q2 2016 and will run for approximately 2 - 3 weeks.

Ireland

Statoil has been awarded six licensing options offshore Ireland. The licensing options cover a total area of approximately 7700 km² in the Porcupine Basin in water depths ranging between 1100 and 3150 m. Statoil and ExxonMobil each hold 50% equity in all the licensing options.

Work programme commitments are limited to 2D and 3D seismic surveys to be acquired during 2016 and 2017. The analysis of that seismic data will then determine whether the company will seek to convert the licensing options into frontier exploration licenses, enabling possible exploration drilling at a later stage.

UK

Subsea 7 has announced it has secured a sizeable extension to the existing contract by BP Exploration Operating Company Limited, for the provision of subsea construction, inspection, repair and maintenance (IRM) services in the North Sea.

Under the terms of this agreement, Subsea 7 will provide BP with an additional two years of IRM delivery, extending the contract to 2019. This is the continuation of the long standing relationship between Subsea 7 and BP that has been in place since 1998.
Noreco sells Norwegian exploration activities

Noreco has announced that its fully owned subsidiary Noreco Norway AS has entered into a sale and purchase agreement (SPA) with Det norske oljeselskap ASA for the sale of its remaining exploration licenses, employees, and a cash balance of NOK45 million, to be adjusted for working capital.

Subject to completion, the proposed transaction, together with the previously announced Enoch transaction will constitute a ceasing of all Noreco Norway’s petroleum activities. Added to the proceeds from the Oseilvar sale this is expected to result in an estimated recovery of approximately 94.7% of the initial principal amount under the NOT06 bond issue.

The transaction entered into with Detnor is conditional on approval from NOR06 bondholders. Pertaining to this, Noreco has received pre-acceptance and voting commitments for the transaction from major bondholders holding a majority of the outstanding bonds. A summons to a bondholder meeting to formally approve the transaction is due to follow shortly.

Lion Energy upgrades Oseil energy reserves

Lion Energy Ltd has advised that the 31 December 2015 reserves report by US based engineering firm DeGolyer & MacNoughton estimates proven (1P) oil reserves at 4.88 million bbls (compared to 4.75 million bbls at the end 2014).

After taking into account 2015 production of 1.22 million bbls, the proven reserves estimate for the Oseil fields have effectively increased by 1.36 million bbls (or 28%).

Lion has a 2.5% interest in the Seram (Non-Bula) PSC (Seram PSC). Production from the Seram PSC remains strong at approximately 4200 bpd (105 bpd net to Lion) and the joint venture is implementing aggressive cost saving measures, including suspending future development drilling (such as the planned Oseil-23).

Commenting on the reserve report and Seram PSC activities, Lion CEO Kim Morrison said: “The increase in Oseil area reserves by DeGolyer & MacNoughton is a pleasing outcome and reflects the positive development drilling outcomes on the Oseil field in recent times.”

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Reports of the death of North Sea oil & gas ‘exaggerated’

An analysis by the technical engineering and workforce solutions provider Fircroft has found that prospects for the North Sea oil and gas industry are still positive in the long run, despite increasingly negative reports in the media.

This comes at a time when the government has announced a £20 million funding package to support the North Sea industry. Industry giants such as Royal Dutch Shell have also reiterated confidence in the region following its £35 billion acquisition of rival firm, BG Group, while the newly opened Laggan and Tormore gas fields off the Shetland Islands reportedly have the potential to provide gas for the whole of Scotland.

Johnathan Johnson, CEO of Fircroft, commented: “The past few months have clearly been a difficult time for the North Sea oil and gas industry but as a company that’s been heavily involved in the sector for over 45 years, it’s our strong view that the market is cyclical and it will only be a short time before business picks up once again. The market has obviously struggled to react to the fact that the value of our product has essentially been cut in half but the UK government, as well as a number of major firms, have invested huge amounts into the North Sea and they’re not going to allow these assets to go to waste. Reports suggest that there will be an estimated 22% reduction in the cost of operating existing assets by the end of 2016 and that, supported by the first annual production increase in over a decade, will improve the outlook for the region.”

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With our comprehensive tools and equipment, we can support your operation in any application. Make your operation faster, safer and better with a complete, cost-efficient solution from NOV.
Subsea 7 awarded contract offshore Egypt

Subsea 7 has announced the award of a major contract by BP, and partner DEA (Deutsche Erdol AG), for the development of the Giza, Fayoum and Raven subsea fields offshore Alexandria, Egypt. This is the second phase of the West Nile Delta project, where the field development will be at depths of up to approximately 800 m.

The contract scope includes engineering, procurement, installation and pre-commissioning of the subsea infrastructure from 12 wells, with 80 km of umbilicals and 220 km of pipelines. It also includes the installation of the export lines from the subsea location to the Iduku terminal.

Engineering and project management work will commence immediately and will be undertaken at Subsea 7’s Global Projects Centre in London. Offshore installation is to be conducted in two stages. The first stage, commencing in 2017, will comprise the landfall and shallow water pipelay, and the second stage, commencing in 2018, will involve the installation of deepwater pipelines and execution of the SURF scope. Subsea 7 vessels Seven Borealis and Seven Antares will be used for the pipelay, with the heavy construction vessel, Normand Oceanic, being used for the other construction activities.

Øeyvind Mikaelsen, Executive Vice President Southern Hemisphere and Global Projects said: “This major contract awarded by BP recognises our performance during the first phase of the West Nile Delta project and allows us to deliver synergies across multiple work packages. Our early engagement on this project has enabled BP and Subsea 7 together with DEA to develop an optimised solution for the development of the Giza, Fayoum and Raven fields and demonstrates the effective collaboration between us. We look forward to consolidating our presence in Egypt and building on our long and successful relationship with BP.”

Transserv Energy: Warro testing continues

Transserv Energy has announced that during the past week Warro-6 continued to flow gas naturally while Warro-5, which is presently being converted to natural flow, continued to clean up with the aid of a jet pump.

At Warro-6, the gas rate exhibited a slow decline to average 0.73 million ft³/d over the last 25 hours (from 0.85 million ft³/d). Importantly, the accompanying water rate decreased at a greater rate and has presently reduced to 310 boe/d from 425 boe/d.

Mechanical issues with surface pumps at Warro-5 meant that stabilised flow was not achieved until recently and this delayed the move to natural flow. The jet pump is presently being removed from the well. Prior to this, the well had stabilised at a gas rate of 0.61 million ft³/d while associated liquid rates continue to trend downwards.

Both wells will now be allowed to flow naturally for an extended period to establish their long term potential.

MoU for Badile exploration well

Sound Energy, the Mediterranean focused upstream oil and gas company has announced the signature of a memorandum of understanding (MOU) for the rig for the forthcoming Badile exploration well.

The company has signed an MOU with Pergemina SpA for the use of the 3000 HP EMSCO C3 No.29 rig, which is already in Italy. The rig will be available within four months of signature of the contract, which is now under discussion. The terms of the rig will result in a further €0.5 million reduction to the previously announced expected drilling costs and will include the payment of 23% of the service charges through the issue of new ordinary shares in the company with a value of approximately €1 million.

The company remains confident of a successful conclusion to the Badile permitting and has confirmed that it still expects to be in a position to drill Badile during 2016.

Dry well northwest of the Arena gas discovery

The well was drilled about 25 km northwest of the 7224/6-1 (Arenaria) discovery and about 240 km north of Hammerfest.

The well’s primary exploration target was to prove petroleum in Lower Triassic reservoir rocks (the Klappmyss formation).

The secondary exploration target for the well was to prove petroleum in Upper Triassic reservoir rocks (the Snadd formation).

Well 7224/2-1 did not encounter sandstones with reservoir quality in the Klappmyss formation, which nevertheless contains traces of petroleum. The well encountered two sandstone layers in the Snadd formation with thicknesses of roughly 45 and 15 m and with very good reservoir quality. Both layers are aquiferous.

The well encountered traces of petroleum in two thin sandstone layers in the Kobbe formation and in two thin sandstone layers with poor reservoir quality in the Havert formation. The well is classified as dry.

Update on jackup rig Noble Lloyd Noble

Noble Corporation has reported its newbuild jackup rig, Noble Lloyd Noble, sustained damage on February 28, 2016 following the collapse of a shipyard crane boom operating near the rig. The rig is in the late stages of construction at the Sembcorp Marine Jurong shipyard in Singapore. Damage appears to be confined to one area of the rig, including damage to one of the rig’s cranes. The incident resulted in minor injuries to certain shipyard personnel. The Singapore Ministry of Manpower has begun an investigation into the cause of the incident.

Construction on the Noble Lloyd Noble was expected to be completed during the second quarter of 2016. Following mobilisation of the rig to the North Sea, it was expected to begin a four year primary term contract with Statoil during Q3 2016, with the contract stipulating a start date of no later than 1 March, 2017.
In today’s challenging market, it’s important to get things right. Now, more than ever, Volant’s Casing Running Tool (CRT™/CRTe™) is the right tool when it comes to safety, efficiency and in these times, profitability. The Volant CRT is a 100% mechanical tool requiring no hydraulic equipment. It requires less maintenance, is run directly by the driller and needs less rig floor space. With more control, comes increased safety. The right tool. The right time.
OVERCOMING OBSTACLES
Russia’s share in the global oil market supports its strong position in the global energy industry. However, technological inferiority and institutional specificity mean that Russia is highly inefficient when it comes to oil production and processing. It follows then, that Russia’s oil industry faces numerous challenges, which are explained in this article.

Andrey V. Bystrov and Vadim D. Svirchevsky, Plekhanov Russian University of Economics, Russia, provide an overview of the challenges faced by the Russian oil and gas industry.
**Cost of oil production**

The high net cost of oil production in Russia can be attributed to a number of causes. Firstly, the difficult climate conditions in isolated oil extraction areas hinder the extraction process, as does the depth of the oilfields. On top of these high production costs there are hefty taxes and excise duties for the net cost of oil, combined with a strict governmental policy that heightens tensions between oil companies and the state.

**Low sustainability of oil production and processing**

The environmental impact of oil production is visible at all stages of extraction and processing, from fuel evaporations, to ground subsidence and emissions release during oil transportation to name just a few. Russia is clearly falling behind other oil-producing states in terms of environmental friendliness due its usage of outdated technology and equipment at oil refineries. This problem is exacerbated by the conflict of interests between oil companies and the state.

Large-scale decline is the result of the extensive use of outdated equipment and a reluctance to invest in upgrades and renewal. It stands to reason that at the amortisation level, which has not yet reached a critical level, the share of worn out fixed assets increases. In most cases, the aim of Russian oil companies is to generate profits at a low cost, which leads to their poor performance and pollution of the environment.

Increasing investment in the oil industry during recent years as well as the increasing demand for domestic oil products is forecast to change current this trend. However, the decline in equipment raises serious concerns, as it results in low quality products, high energy consumption and shallow depth of oil during processing and insufficient use of production capacities.

**Product quality**

Russia exports few value-added oil products. In the European market Russian oil products are traded as raw materials for further processing. This complicates selling and reduces the income from exports. Nevertheless, in today’s climate, Russian companies are prioritising the export of crude oil.

Unfortunately, the predominance of raw materials in exports – due to the lack of capacity and poor technical facilities – has given rise to the belief that selling crude oil is bad practice, whilst selling highly processed products is preferable. This opinion is misinformed for a number of reasons. Firstly, exports generate profits because the products exported are of a basic quality, thus reducing costs; exporting higher quality products is less profitable because of the cost of transporting them.

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**Table 1. World proved oil reserves.**

<table>
<thead>
<tr>
<th></th>
<th>Year end 2007*</th>
<th>Share of world oil reserves (%)</th>
<th>Year end 2014**</th>
<th>Share of world oil reserves (%)</th>
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<tbody>
<tr>
<td><strong>World total</strong></td>
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<tr>
<td>Oil reserves (billion t)</td>
<td>168.6</td>
<td>100</td>
<td>239.8</td>
<td>100</td>
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<td><strong>Industrially advanced countries, including:</strong></td>
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<td>USA</td>
<td>3.6</td>
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<td>Canada</td>
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<td>27.9</td>
<td>10.2</td>
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<td><strong>Former USSR, including:</strong></td>
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<td>Russia</td>
<td>10.9</td>
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</tr>
<tr>
<td>Kazakhstan</td>
<td>5.3</td>
<td>3.2</td>
<td>3.9</td>
<td>1.8</td>
</tr>
<tr>
<td><strong>OPEC countries, including:</strong></td>
<td>127.6</td>
<td>75.5</td>
<td>170.5</td>
<td>71.6</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>36.3</td>
<td>21.3</td>
<td>36.7</td>
<td>15.7</td>
</tr>
<tr>
<td>Iran</td>
<td>19.0</td>
<td>11.2</td>
<td>21.7</td>
<td>9.3</td>
</tr>
<tr>
<td>Iraq</td>
<td>15.5</td>
<td>9.3</td>
<td>20.2</td>
<td>8.8</td>
</tr>
<tr>
<td>Kuwait</td>
<td>14.0</td>
<td>8.2</td>
<td>14.0</td>
<td>6.0</td>
</tr>
<tr>
<td>UAE</td>
<td>13.0</td>
<td>7.9</td>
<td>13.0</td>
<td>5.8</td>
</tr>
<tr>
<td>Venezuela</td>
<td>12.5</td>
<td>7.0</td>
<td>46.6</td>
<td>17.5</td>
</tr>
<tr>
<td>Nigeria</td>
<td>4.9</td>
<td>2.9</td>
<td>5.0</td>
<td>2.2</td>
</tr>
<tr>
<td>Qatar</td>
<td>3.6</td>
<td>2.2</td>
<td>2.7</td>
<td>1.5</td>
</tr>
<tr>
<td><strong>Non-OPEC countries</strong></td>
<td>23.6</td>
<td>14.1</td>
<td>50.0</td>
<td>20.1</td>
</tr>
<tr>
<td>China</td>
<td>2.1</td>
<td>1.3</td>
<td>2.5</td>
<td>1.1</td>
</tr>
<tr>
<td>Brazil</td>
<td>1.7</td>
<td>1.0</td>
<td>2.3</td>
<td>1.0</td>
</tr>
<tr>
<td>India</td>
<td>0.7</td>
<td>0.4</td>
<td>0.8</td>
<td>0.3</td>
</tr>
<tr>
<td>Egypt</td>
<td>0.5</td>
<td>0.3</td>
<td>0.5</td>
<td>0.2</td>
</tr>
<tr>
<td>Malaysia</td>
<td>0.7</td>
<td>0.4</td>
<td>0.5</td>
<td>0.2</td>
</tr>
</tbody>
</table>

Secondly, the production capacity of existing refineries is sufficient to meet demand. Thirdly, oil refining depth and the quality of produced oil products are determined by demand. High-grade fuel is more expensive than low-grade, and consumers do not want to overpay. As for the supply of high-quality fuel for export purposes, transportation problems exclude the possibility of making a profit in the case when domestic demand for more expensive fuel is low. One of the possible solutions to the problem of petrochemical transportation is the construction of refineries in border areas, which would make transportation by water and rail much cheaper.

**High resource consumption**

Compared to other countries, Russia’s consumption of resources during the production and processing of crude oil is high. As a result, this affects the net cost of production and the whole supply chain, from oil extraction, up to refining and transport. This is another reason why domestic engineering is falling behind foreign suppliers in terms of mining equipment and oil products processing machinery.

**Low oil refining depth**

Oil refining depth is the ratio of the volume of petrochemical products to the total amount of crude oil used. In Russia, oil refining depth amounted to 72.4% in 2014, which is a 0.7% increase from its value in 2013. In Europe and the USA, oil refining depth is 85% and 96%, respectively.

When Alexander Novak, Head of the RF Ministry of Energy, met with the Russian President, Vladimir Putin, on 2 March 2015, Mr. Novak announced that it was quite possible that the oil refining depth in Russia could reach 85% by 2020. In 2014 alone, 13 new drilling rigs were put into operation and the volume of investment in the oil industry was RUB290 billion.

However, passing the 75% mark will only be possible if all existing refineries (28) carry out secondary processes that deepen oil refining, i.e. carbonisation and all types of cracking.

Generally, however, large Russian refineries have long periods of operation – a huge number of enterprises were put into operation 60 years ago. According to the Nelson Complexity Index (NCI), the assessment of efficiency of technological refinery processes proves that it would be difficult for Russian oil refineries to overcome the gap between them and their foreign counterparts. NCI for most of the Russian oil refineries is lower than the world’s average value (4.4 versus 6.7). In addition to this, the popular opinion is that new oil refineries with NCI lower than 10 are not a profitable investment.

Therefore, the deepening of oil refining requires a large investment. It is clear that the RUB290 billion investment, which in 2014 prompted a 0.7% increase in oil refining depth, will continue to benefit the industry for years to come. However, more major investments, along with development of modern technologies are required to achieve the target of increasing the depth by 13%. Meeting these requirements, in turn, is hindered by anti-Russian sanctions.

**Low process utilisation**

According to the statistics, the capacity of existing refineries is sufficient to meet demand. Russia produces twice the required amount of fuel for domestic consumption, and half of the produced fuel is exported. But is it necessary to build new plants if the existing ones are underutilised? In fact, throughput performance is determined by demand, and producing to stock is not the best way of doing business. During the first decade of the 21st Century the level of refineries’ process utilisation had increased significantly: from 70% to 85% by the end of the period. Moreover, many of the main companies in the industry are almost fully loaded, e.g. the enterprises of LUKOIL are at over 99%.

As for the positive situation regarding excess refining capacity, high indicators refer to chiefly crude capacity. Historically, processing capacity of most refineries is characterised by imbalances between crude capacity and re-refining capacity, with a considerable bias towards the former. Scarce re-refining facilities, which ensure the output of value-added products are of high quality, are almost fully used, as, for example, at the enterprises of LUKOIL (as discussed above). It is the lag in the development of re-refinery that is the main cause of the low refining depth in the whole industry.

The lack of modern technology and equipment has a significant impact on process utilisation. Unlike in earlier years when financial investment was the key hurdle technological development, sanctions placed on Russia are now the main obstacle. As a result, the creation of domestic modern technology and equipment is a vital task, together with ensuring energy security and sovereignty of the country as a whole. However, equipment for oil production and processing has not been produced in Russia for a long period. At the same time, the companies that use foreign equipment which is now on the sanctions lists, are experiencing problems with upgrading even if there are significant funds available for investment.

**Distance of refineries**

Distance between oilfields and oil refineries directly affects the net cost and the price of products – there are almost

---

**Table 2. Depreciation of fixed assets.**

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extraction of crude oil and associated gas</td>
<td>54.6</td>
<td>46.2</td>
<td>48.1</td>
<td>49.4</td>
<td>52.8</td>
</tr>
<tr>
<td>Share of worn-out fixed assets</td>
<td>24.1</td>
<td>20.0</td>
<td>20.2</td>
<td>20.2</td>
<td>23.5</td>
</tr>
<tr>
<td>Production of oil-products</td>
<td>36.7</td>
<td>41.2</td>
<td>41.9</td>
<td>41.8</td>
<td>40.0</td>
</tr>
<tr>
<td>Share of worn-out fixed assets</td>
<td>13.4</td>
<td>13.0</td>
<td>13.1</td>
<td>13.6</td>
<td>12.2</td>
</tr>
</tbody>
</table>

Source: Promyshlennost Rossii. 2014. – Moscow: Rosta, 2014. Table 3.5.
no operation bases in some regions of the country, and the geographical location and poor infrastructure make transportation of goods unprofitable and often detrimental.

All existing refineries in Russia were built in the time of the Soviet Union and their location was determined by the ease of control from a single centre.

**Currency rate**

Today in the world market, Russian oil and oil products are traded in US dollars. With the strengthening of the US dollar, Russia’s budget revenue from oil exports in rubles is increasing, whereas with a stronger Russian ruble the value of export revenue declines noticeably, even if production and exports volumes are unchanged. Exchange rate fluctuations may even be detrimental to oil exports. As revenue from oil exports is a large proportion Russia’s income, the dependence on the exchange rate endangers the entire economy of the country.

**Large scale development of accessible oilfields**

One of the main challenges facing the Russian oil industry is large-scale development of easily accessible oilfields (approximately 45%).

The solution to this issue is to bring modern technologies, which will increase the level of oil recovery. But the question of transportation even from mature oilfields remains urgent, because existing pipelines need upgrading.

**Oil shocks and their impact on the global economy**

16 October 1973 saw the first significant increase in oil price in the world market, which later became known as the ‘oil shock’. The second ‘oil shock’ of 1980 was associated with concerns regarding the possible cessation of Iranian oil exports. After this, a new economic recession that had hit the economies of many countries began. The crisis continued until 1982 with the arrival of a third oil shock. However, the decline in oil prices in recent years can also be attributed to oil shocks, as they lead to investors losing confidence in their investments, and to the slowing down of industry modernisation. The third oil shock is related to military operations and policies of the US and the EU in Arab countries. The consequences of these conflicts can be enormous and unpredictable not only for the economic situation of many countries, but also for the global political balance.

Taking into account that the Arab countries possess the largest portion of the world’s oil reserves, the consequences of such conflicts can be disastrous.

As well as being influenced by price fluctuations, the dynamics of energy trade are influenced by the risks related to the possibility of supply interruption due to the exposure to different non-economic factors. Another factor is political conflicts that threaten to interrupt the supply by traditional transportation corridors (as in the case of Iran – in order to pass through the Strait of Hormuz, all vessels including those of the United States Navy must pass through Iran’s territorial waters); ISIL’s entry into the oil market, which has led to an increase in ‘gray’ and ‘black’ oil trade schemes, is also putting pressure on the oil market. Industrial disasters and system blackouts, natural phenomena and terrorist acts account for just some of the factors behind the ‘oil shocks’.

But both political convulsions and corporate wars in the oil market are aimed at the struggle for reserves.

**The struggle for reserves**

Oil is not a renewable commodity. The question for the future is: what can be expected from the leading oil producing countries? According to the forecast by TNK BP, oil reserves are likely to completely run out in 54 years, provided that the level of oil production remains as it was in 2011. Russia, holding the 8th place in global reserve rankings, has oil reserves sufficient for only 23.5 years (although it should be noticed that the data on proven oil reserves is constantly revised and the figures increase from year to year, as shown in Table 1). The situation for Russia is not favourable, because:

- Russia does not have sufficient oil reserves to be able to dictate terms to other countries.
- Russia’s economy is highly dependent on oil exports (approximately 50% of the GDP), which endangers its future. This situation is worsened by the absence of other big income items.
- The Russian oil industry has fallen behind considerably in terms of efficiency and technology.
- High net cost of oil producing and processing, consisting of: cost of exploration, cost of crude oil extraction, cost of transportation and storage, cost of amortisation etc., makes it impossible to receive bigger profits.

On the other hand, the exploration of the Arctic shelf and new oilfields should allow Russia to counter these challenges and maintain its position of one of the leading suppliers of carbonaceous feeds in the global oil market.

**References**

2. The oil company TAIF-NK has to reduce production because its customers are not willing to buy fuel of a very high quality. The Russian government had developed and passed technical regulations that forbid oil companies from producing euro-2 fuels from 1 January 2009, and euro-3 fuels from 1 January 2010. Even when customers are reluctant to spend large sums on fuel, they have to pay more for the high quality in circumstances when low quality fuel is prohibited. That is why TAIF-NK launched the production of euro-4 fuel at the end of 2008. The government, however, postponed the launch of the technical regulations. This came a surprise for TAIF, whose technology, unlike that of many other companies that had started their modernisation, was not designed to worsen the quality of products in order to lower their net cost. Other companies had hesitated to start the required modernisation, expecting the launch of the technical regulations to be postponed. Indeed, some refineries, which were not ready for a complete switch to the production of euro-3 and 4 fuels, benefited from this situation, because they had lower cost of production, and hoped that the situation would last for a long time.
5. http://www.rosvj.ru/2015/03/02
6. The Nelson complexity index (NCI) assesses the level of the secondary conversion capacity of a petroleum refinery relative to the primary distillation capacity. NCI is increasingly used to measure the efficiency of a project, displacing the term ‘oil refining depth’.
7. Ibid 4
8. However, this indicator reaches 90 - 95% in developed countries. http://marketing.rbc.ru/research/562949981766940.shtml
9. Cascading system blackouts in the US in 1965 and 1977 left respectively 25 and 10 million people without electricity for a day, in 2003 - 50 million people for almost two days. The most recent example is the hurricane ‘Sandy’, which in November 2012 left several million people in the US and in Cuba without electricity.
10. After the hurricanes in the Gulf of Mexico it took almost a year to increase the level of oil and gas production to be restored.
11. In 2015 alone, the world experienced more than 300 terrorist acts in oil and gas facilities in Iraq, Pakistan, India, Georgia, Azerbaijan, Nigeria, etc. The losses of this kind are very large. For example, BP’s possible loss from the Baku – Tbilisi – Ceyhan pipelines disorders – per month, with BP’s 30.1% stake in the capital of the company, excluding income from transportation tariffs – is estimated at US$100 million (RBC daily, 14 August, 2008).
The decline in oil and gas prices and operators’ growing needs to generate maximum returns from assets has ensured that reservoir modelling remains an important decision-making tool within the reservoir management workflow.

Most operators use 3D reservoir modelling to obtain information on where to drill, what production strategies to adopt and how to maximise oil and gas recovery from both existing and newer fields.

The smallest percentage recovery improvements within a field can have a significant impact on the bottom line (especially if the infrastructure is already in place). Therefore, an accurate and integrated reservoir modelling workflow can make all the difference between a field being commercially viable or not.

Yet in reality, using 3D reservoir models does not always guarantee the best results. This article will look at the key elements behind an accurate and integrated reservoir modelling workflow and why it is so crucial.

Managing uncertainty
The latest studies and developments show the importance of uncertainty quantification, particularly in regard to solid and accurate reservoir models. Being able to generate realistic structural scenarios gives operators the necessary confidence when it comes to reservoir economics and predictions of oil and gas volumes.

Uncertainty quantification is one of the key strategic developments behind Emerson’s reservoir modelling software, Roxar RMS. The software

Cécile De La Motte Rouge, Emerson Process Management, Norway, explains how improved returns are generated through integrated, accurate reservoir modelling.
includes tightly integrated structural modelling tools that enable users to quantify uncertainty more effectively across the prospect lifecycle.

Uncertainty management decision-making is enhanced through a closer integration between structural modelling and 3D gridding tools as well as horizon uncertainty models tools that allow users to incorporate realistic uncertainties into the horizon model.

The latest release also includes a grid adjustment tool that supports the calculation of residuals between the grid and well picks. This enables the grid to be adjusted to exactly match the well picks and leads to greater flexibility in well data conditioning and improved well targeting and placement.

**Model-driven interpretation**

The new uncertainty quantification tools within the software also build upon Emerson’s model-driven interpretation workflow that allows users to build models directly from the geophysical data.

Model-driven interpretation involves a geologically consistent structural model being created (and updated) every time the interpreter makes a measurement of a subsurface feature. Uncertainty information is collected and paired with an interpreted geologic feature (horizon, fault, etc.) to create an uncertainty envelope.

In this way, users can set and collect uncertainty information associated with an interpretation; easily and reversibly test geologic hypotheses; and add more detail to the model as and when required.

**Quantifying GRV uncertainty in a Middle East field**

In one offshore Middle East example, the operator used the model driven interpretation approach to quantify gross rock volume model-driven GRV uncertainty.

The reservoir in question was in the appraisal/early development stage. It had nine wells unevenly distributed across the field, not all of which had penetrated the bottom of the reservoir.

The quality of the seismic data was also only fair, with limited well and seismic data and limited confidence in the velocity model. Against this background, there was a need to quantify uncertainty within the reservoir model and in particular calculate GRV uncertainty.

Figure 1 illustrates the fault uncertainty envelopes generated through model-driven interpretation. The uncertainty along the faults can be provided during interpretation for each point or can be kept constant and defined manually on both the hanging wall and the footwall side during the structural modelling workflow.

The next stage of the workflow was the creation of a 3D grid, out of which multiple realisations were generated to quantify GRV ranges. This generated the P10, PS0 and P90 GRV values as well as indicating which horizons, velocity models or fluid contacts are affecting the GRV calculation.

The result for the Middle East operator was improved GRV uncertainty, valuable input into field appraisal and development plans, and reduced risk.

**Evergreen model updates**

Accurate reservoir models though are not enough. What if a very precise model cannot be updated? Or that it takes so much time to update the model that it ends up being rebuilt from the beginning? How can value be generated from rapid, incoming and fast changing data?

In such cases, rapid model updates, workflow automation and the efficient updating of the whole workflow from seismic to simulation, including the model’s structure, are vital.

To this end, a multi-realisation ‘evergreen ensemble’-based workflow was developed. In such a workflow, the modelling process is highly automated and flexible enough to incorporate new data, concepts or applications as soon as they become available and at any time.

**Increased collaboration**

Too often in the past, there have been limited incentives for asset managers working within individual domains in the reservoir modelling workflow to talk to each other – that is unless inconsistencies occur.

Furthermore, by this stage, so much time will have been spent creating the model that major fixes and time will often be required to address such inconsistencies.

With an integrated framework, however, any discrepancies can be identified and fixed earlier in the process with all domains aware of the bigger picture and the modelling project’s overall goals.

This integrated and collaborative approach represents the underlying principles behind the new evergreen ensemble-based workflow.

As part of the new approach, all asset members share a common workflow where each specialist can see the direct influence of their domain on the end result and can contribute in the same timeframe to a shared framework, from seismic to simulation. This leads to greater accuracy with the latest information from new wells always incorporated into the model, improved history matching (through Tempest ENABLE), and better targeted drilling campaigns – whether greenfields, brownfields or fields moving between the two phases.

What is done in one domain can also be automatically tested and there is a shared responsibility for the tasks, with asset members collaborating in choosing the correct parameters. This also allows for uncertainties to be added where they apply and further propagated throughout the workflow to where they matter.

The automated workflow subsequently generates an ensemble of multiple models that can be created rapidly, with all models then going forward to simulation without choices having to be made on the most appropriate model. The result is improved information for field development planning, well placement and as input to economic analysis.

**Creating an open platform**

An open and flexible platform for workflow integration, data sharing and model updating is another key element of successful reservoir management.

To this end, the company has developed an ‘extensibility’ solution based on the application programming interface (API), resulting in a software platform for building geoscience, reservoir engineering and oilfield technology applications.

The new platform provides extensibility to RMS and interoperability with other platforms.
software applications. This ensures the preservation of vital reservoir information across multiple-stage workflows.

It also improves data management and workflow integration, enabling operators to integrate their own IP and specific applications and ensure maximum flexibility.

**Integrated production management**

However, integration does not stop after reservoir modelling and simulation. Operators today are looking for an integrated workflow from seismic interpretation and reservoir modelling right through to reservoir simulation and production optimisation.

They are also looking to combine data from their predictive reservoir models with their production modelling and field instrumentation. Through this, they can monitor production continuously and use field information for operational decisions and for forecasting future reservoir performance.

It is with these issues in mind that in July 2015 Emerson acquired Norwegian company Yggdrasil, a provider of flow assurance and production optimisation software.

The incorporation of Yggdrasil’s production management solutions within the Roxar Software Solutions portfolio helps operators get the most out of their reservoir. It is targeted at reservoir and production engineers, providing them with access to a wide variety of thermo-hydraulic calculations within one single application.

The new flow assurance and production modelling solution also enables operators to calculate single well or flowline performance of mono and multiphase flow systems; generate life of field simulations; simulate well and flow line behaviour; and put in place virtual metering for the allocation of production to wells.

The new software also integrates data from a variety of databases, connects to proxy reservoir models and reservoir simulator processes, and models flow behaviour from the reservoir to the surface. The hardware outputs generated, for example, can be easily linked with the Tempest MORE simulator.

The result is that operators are able to align their modelling, uncertainty quantification and simulation data with production via an integrated production modelling system.

They can also optimise their field development and production plans, and increase oil and gas recovery in challenging environments.

**Other developments**

Technology and innovation are essential to operators when it comes to getting the most out of their reservoirs and increasing profitability.

Emerson’s future development strategy is embracing a host of innovations, strengthening Roxar software’s interoperability, performance and usability. This will include advances to the Roxar Tempest reservoir engineering software, the testing of multiple realisations, and improved uncertainty quantification on volumes and cumulative production.

**Helping operators unlock their assets**

In today’s cost conscious environment, operators are looking to recover more from their fields and in as effective a way as possible. Reservoir modelling is a key means towards achieving this.

Emerson and its latest integrated reservoir management software solutions are enabling operators to quantify uncertainty and ushering in a world of rapid model updating; generating integrated and open workflows from seismic interpretation right through to simulation and production; and instilling the latest in integrated production management advances.

The integration of reservoir modelling and its influence across the prospect lifecycle has never been more important – particularly in today’s tough economic climate.
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