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Technological Challenges and Developments

Technological developments and breakthroughs have been essential in the expansion of the global oil and gas industry for much of its history, and particularly since the 1970s. Looking at the most recent decade (2000–11), cumulative new gross world oil and gas reserves added amounted to over 600 bn boe (2P), whilst oil and gas production rose by 38 mboe/d, defying a perceived shortage of reserves. Of the total additions, new conventional hydrocarbons accounted for approximately 40 percent, whilst non conventional hydrocarbons and offshore environments accounted for the rest. During this period, LNG, SAGD, deepwater, horizontal drilling, long reach drilling, EOR, fracking in tight rocks, 3D seismic imaging and visualisation technologies, logging while drilling, among others, became more widespread.

It would not be an understatement to say that during the last decade the 'technology factor' helped transform the energy map in ways that were not conceived by long-term planners and CEOs since the 1970s. However, among policy makers, energy institutions, and most analysts, the impact of technological developments has been treated more as a surprise factor, let alone understood or predicted.

This issue of Forum focuses on 'technological themes' across upstream and downstream covering the Arctic, tight oil, deepwater pre salt, shale gas, heavy oil, EOR, GTL, all of which are centre stage today and have the potential to continue to transform the industry as well as the energy map.

David Bamford reviews the Arctic; in his view despite the huge potential, exploration success in the wider Arctic is not a 'given'; onshore Arctic exploration and development has a significant history, notably in Alaska and West Siberia but outside remains undeveloped. Bamford explains that in addition to political and environmental issues, data in much of the rest of the Arctic areas are scarce or difficult to obtain and in some cases currently envisioned technologies are too costly in comparison with the other options that explorers may have. But could this all change?

The discovery and development of Brazil deepwater pre salt, the most significant new offshore province since the North Sea, is no doubt a major technological challenge, which Petrobras is undertaking pretty much alone. Crucially, the expectation that costs will come down has been presented as a major factor for its long-term success. A paper by BCG and Petrobras summarises the opportunities identified by the experience curve concept to the pre salt development campaign now underway. Petrobras has incorporated the experience curve program, which factors in technology and learning curves among others as the scale of the activity rises, as part of a process

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to reduce the total cost of wells and subsea systems.

Michelle Foss discusses US shale gas, arguably the main event that has transformed the story of unconventionals. Foss starts by reminding us that US shale gas production has caught the whole industry by surprise, changed the structure of US gas prices, and led to new projections of production increases in US gas and exports for the foreseeable future. All of this thanks to improved interpretation of geological models and integration of large volumes of data, drilling and stimulation technologies and application of technologies that could help define 'sweet spots' at the exploration and exploitation stage. However, the 'backstory' context may be more nuanced. The large shale resource abundance is not in doubt but the recovery of shale resources is, explains Foss, contingent on the ability of industry to achieve continued cost reductions, driven by technological progress.

Trisha Curtis provides an overview of the major US liquid rich tight rock, their history and outlooks. New crude oil, condensate, and natural gas liquid supplies, combined with the current surge in natural gas production, offer the promise of a renaissance. However, this dramatic increase in production will not come without complications and constraints.

Today the industry leaves behind as much as 70 percent of the in place oil volumes in conventional reservoirs, and 90–95 percent of the in place volumes of difficult hydrocarbons including extra heavy oils, complex reservoirs and tight rocks. In conventional oil reservoirs, improved recovery and EOR (enhanced oil recovery) techniques are the main alternative. Samer Ashgar of Saudi Aramco sheds light on the reservoir management practices that the company has adhered to over the years, widely considered by industry to be leading edge, and the direction it is heading in this important area.

Looking at the difficult heavy oils, Robert Skinner indicates that the technology challenge in finding and producing heavy oil is not simply to increase its volume, but most critically, to greatly improve the efficiency of its production, to improve unit economics and reduce its environmental footprint. Skinner says that we hardly need reminding that technological breakthrough alone is not enough to assure a growing future for these difficult resources. Interestingly, in Canada, probably the most benign link in the heavy oil value chain – transportation – has recently become its weakest.

Franz Ehrhardt addresses the refining sector from a strategic point of view and focuses on how technology will play a role in addressing increasing levels of heavier crudes. The most significant and innovative refining-related improvements can be expected in the catalyst chemistry and application. Ehrhardt concludes that there are economically attractive technologies and processes available, especially Delayed Coking that will continue to contribute, and that it can be safely assumed that revolutionary technology changes in fundamental thermal and hydro-treating processes in petroleum refining are unlikely to emerge as game changers.

In a joint paper, Shirvani and Inderwildi provide an analysis of GTL. With large stranded gas reserves, GTL is viable, and may be very big. The authors conclude that GTL fuel products may help to address energy security concerns and improve local air pollution levels, but are by no means considered environmentally friendly fuels; yet due to significant lead times, efficiency of the process, and the high upfront investment needed, it is unlikely that a substantial volume will go on-line in the foreseeable future.

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Technological Developments and Challenges

Ivan Sandrea traces global technological revolutions and the oil and gas industry

The broader impact of technological developments in society, industries and economies has been well documented and researched by authors including Kuznets, Schumpeter, Freeman, and Perez.

Looking back, research by Perez shows that in the last 250 years, global economic growth and political changes have gone through five distinct stages associated with technological revolutions resulting from the synergistic interdependence of a group of industries and diffusion of technology. The five periods are: the industrial revolution (1770 to 1820), the age of steam and railways (1820 to 1870), the age of steel, electricity and heavy engineering (1870 to 1910), the age of oil, automobile and mass production (1910 to 1970) and the age of information technology from late 1970 to now. Each of these have lasted sixty years or so.

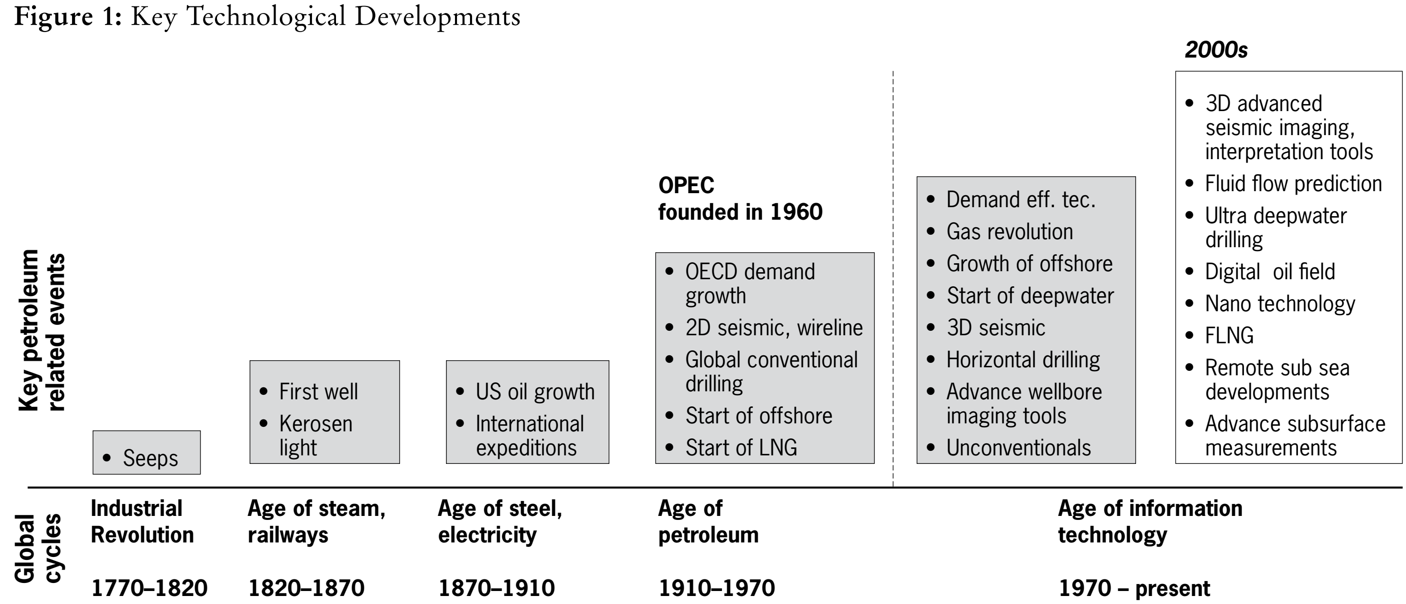
Through time, the oil and gas industry has also undergone significant changes and benefited from the diffusion of technology. In oil and gas exploration, for instance, for several decades activities were dominated by following oil seeps, surface structures, and undertaking shallow onshore vertical drilling – a technology that evolved from earlier Asian experiences. All of this changed with the coming of seismic, wireline logs, improved earth modeling, and when the industry developed the capability to drill offshore in the 1950s. And crucially with the coming of the IT revolution, computers provided the industry with new tools, modeling, and measurements and the ability to process ever increasing complex volumes of data. The IT revolution coincided with geopolitical events of the 1970s, which led to new technological inventions which in turn supported important new oil and gas developments: The North Sea, Prudhoe Bay, 3D Seismic, are all examples.

Changes in OPEC oil policy may also be linked or framed to technological changes rather than economic, price, and political events. In fact, from a technological point of view, there may be two distinct periods in OPEC history: one from 1949 until the mid 1970s which was mainly dominated by political drivers (post colonisation events, exercise of sovereign rights, and re-alignment of interests) – during this period the impact of technological developments (supply and demand) was not strong or apparent – and a second period, which started in the late 1970s and that continues until today. Post 1970s, a broad technological revolution in the industry led the way to the rise of the then technologically complex shallow water oil from the North Sea, the Arctic took off, electronic trading took off and many other developments that followed, which one way or another impacted OPEC decision making.

"Changes in OPEC oil policy may also be linked or framed to technological changes"

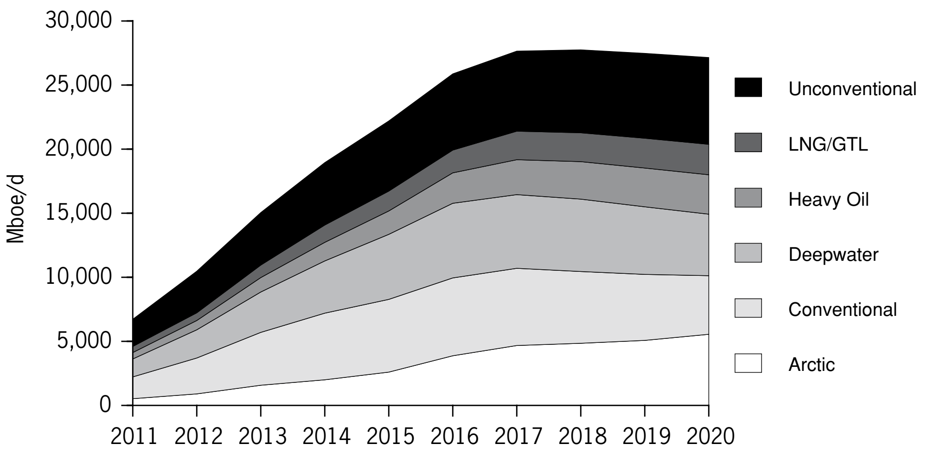
As a whole, there have been essentially two types of breakthroughs: 1) those that in a relatively short period of time have suddenly appeared unexpectedly to industry and policy makers at large, and something that

Figure 1: Key Technological Developments



Source: Ivan Sandrea; Perez (modified)

Figure 2: New Sources of Oil and Gas Reserves to 2020



Source: Energy Intelligence and Gordon Energy

was not viable suddenly becomes viable, 2) a second type when the combination of old methods and new technologies resulted in a new development. Looking at the oil and gas industry specifically, examples of the first, include wire line logging and seismic acquisition, whilst the second case includes offshore and horizontal drilling, seismic imaging, fluid prediction, and tight rock fracking to name a few.

In the upstream side, most reports and outlooks today explain that incremental new sources of future oil and gas reserves and production will come from technologically challenging reservoirs and environments. For most of these the technology is in place or there are expectations that new developments and advances will make material contributions. The new source volume coming from uncoventionals, deepwater, heavy oil, Arctic, and via LNG is in fact quite significant but it is interesting to note that this was not part of the conventional wisdom just a decade ago. These represent the majority of the new oil and gas reserves added in the last decade, and the bulk of the Yet to Find. (Figure 2)

The oil and gas industry has always lived with many uncertainties, but three are important to single out. First, what is going to happen to oil and gas prices in the future? Second what will be the demand for fossil fuels and how will it be met? And third, how will the major players including governments respond? In all three cases, technology and technological developments will continue to be a major wild card.

David Bamford looks at exploration technology for the Arctic

Western oil and gas technical journals as well as ordinary newspapers wax lyrical over the hydrocarbon resources of the Arctic, typically referring to it as the next global frontier. Huge resource estimates are bandied about – the USGS has suggested as much as 400 billion barrels oil equivalent remains to be discovered, with over 80 percent of that thought to lie in offshore fields.

Equally, there are a growing number of conferences on Arctic Technology, many of them seemingly assuming that significant oil or gas discoveries will be made and therefore focussing on how to develop fields in seasonal ice, what to do about icebergs, pipeline routes and petroleum export. Of course, onshore Arctic exploration and development has a significant history, notably in Alaska and West Siberia, and there has been intermittent exploration in the Barents, southern Kara, Chukchi and Beaufort Seas, so there are many ideas – both conceptual and proven – to look at.

Nevertheless, a significant part of the Arctic is represented by the largest shelf on Earth, the Eurasian epicontinental shelf, of which the major portion, amounting to some 3.5 million sq kms, is located in the Russian Arctic. As a calibration, this is an area roughly equivalent to 700 offshore Angola deepwater blocks or 152,000 Gulf of Mexico deepwater blocks! The area is, to a large extent, sparsely explored due to its harsh environment, high cost of operations and forbidding logistics.

What Data and Knowledge do we Have at the Moment?

From the efforts of Soviet scientists and their successors, we know that the Eastern Barents, Kara, Laptev, East Siberian and Chukchi Seas contain over 40 sedimentary basins. For most of the basins, there is a reasonable understanding of stratigraphy, sedimentology and structural geology; long wavelength gravity and magnetic data are available, as is a certain amount of 2D refraction and reflection data, the latter of which can be supplemented to some extent.

The Russian Barents and the southern Kara Seas represent the most explored petroleum provinces with large proven resources. In contrast, the North Kara is virtually unexplored, and there is only sparse seismic data over the other areas.

Drachev, Malyshev & Nikishin (in a publication by the Geological Society, London, 2010) give an excellent overview of the Tectonic History and

Petroleum Geology of the Russian Arctic Shelves, and I have no intention of repeating what they say here. However, building on this overview, I believe explorers face three key questions:

1. How do we prioritise the aforementioned 40 plus sedimentary basins?
2. Can we figure out in advance of drilling which ones are 'oily'? There is a prejudice that these basins may be dominated by gas due to the provenance of the organic material in the source rocks.
3. Is it even remotely possible to envisage huge swathes of Arctic 'exploration' 3D seismic at an affordable price? IOCs have got used to exploring with vast amounts of 'exploration' 3D seismic. For example, the 40–50,000 sq kms of deepwater and ultra-deep water Angola are covered 'wall-to-wall' with such 3D, enabling Total, BP and others to enjoy a success rate of >90 percent in Blocks 15, 17, 18, 31 and 32. This 3D typically costs around $3000 per sq km.

Let's begin by considering the second point.

When one starts digging into the knowledge base on source rocks for the Russian Arctic, using compilations by for example the USGS, Bernstein Research and the aforementioned review by Drachev et al., it quickly becomes apparent that actual data are generally absent. Thus for example in the Laptev Sea, one may freely speculate, unconstrained by any hard facts, that there may be present Palaeocene and Mid-Eocene marine shales or Lower Cretaceous and Paleogene syn-rift sediments, or for the Russian Chukchi Sea that there may well be analogues to the prolific petroleum systems of the Arctic coast of Alaska.

But in truth, the areas where there is actual positive evidence of working source systems are the East Barents Sea where there are Triassic organic-rich gas-prone coal-bearing shaly sediments and the South Kara Sea where there are Bazhenov bituminous shales, the main source rock of the West Siberia basin, which may have generated significant gas plus possibly oil at the basin margins.

It is not surprising therefore that in addressing question 1 above, the current actions of western IOCs seem oriented towards either a fresh look at the Barents Sea or accessing the South Kara Sea – the target of BP's ill-starred venture with Rosneft.

> "the Eastern Barents, Kara, Laptev, East Siberian and Chukchi Seas contain over 40 sedimentary basins"

It's difficult to see other areas opening up rapidly given the absence of source rock indicators. Relevant technologies do exist. It is possible to infer the existence of active source rock systems from satellite imagery – at least this has been achieved in open oceans – and there are direct sampling methodologies.

What about Seismic Acquisition?

Broadly speaking, the Arctic presents two related problems to seismic acquisition – the ice itself and the limited time when the ice is open.

Two seismic service companies – ION Geophysical and Polarcus – have stated that they are addressing this issue and elsewhere I have reviewed their approaches in a little more detail (*Geoexpro*, 8, 5, 2011). These companies have great technology ideas, great innovations, but with the best will in the world I cannot see either of them shooting vast tranches of 'exploration' 3D at a cost of $3000 per sq km – five or ten times that, perhaps?

My point is that this changes – displaces – what has been the basis for efficient and effective offshore exploration since the mid 1990s and makes me wonder whether Arctic exploration can in fact be undertaken at a reasonable cost? If we go back to exploring with 2D seismic, then we face drilling $100m plus wells at a risk of 1 in 4 or worse – not what we want to do!

Perhaps the next stage of geophysics should be to fly extensive Full Tensor Gravity (gravity gradiometry) surveys which experience onshore, for example in East Africa, has shown can be a reliable tool for defining significant leads in a basin; two or three companies offer this service. Integrated with existing knowledge, this approach is capable of producing a basin-by-basin lead inventory.

The next step in the exploration process would then be to shoot 'postage stamp' 3Ds over the most interesting leads, to mature them into prospects: drilling could then follow.

I hope I don't make this sound too simple? Getting to grips with potential source rocks and generating a reconnaissance exploration data base is an expensive, extensive and detailed project which is beyond any one company and needs to be commissioned by the Russian government prior to licensing rounds.

> "drilling in the Arctic could be up to four times as expensive as drilling in the North Sea"

What about Exploration Drilling?

Just recently DNV presented the results of intense and targeted work, coming up with a concept for year-round drilling and exploration offshore north-east Greenland. More than anything their work illustrates a massive need for new technologies, improved standards and increased Arctic research. But that's not all; they predict that drilling in the Arctic could be up to four times as expensive as drilling in the North Sea. And this could be an underestimate.

One Final Issue that we Need to Face

The Deepwater Horizon/Macondo tragedy set shock waves around the industry at large, leading to a focus on how wells are designed, how rigs communicate with onshore, how well trained rig crews are and so on. With reference to the Arctic, North American academics and other experts have asserted that a similar spill in Arctic waters could be devastating, with ice possibly hampering any spill responses for months. Many of the problems are logistical. Apart from having only a few months to do any remedial or clean-up work, airfields are remote, weather can ground flights and workers for weeks at a time, and it would likely be impossible to bring large numbers of boats (remember there were up to 1000 employed in the Gulf of Mexico clean-up) up to the Arctic.

"Both Greenpeace and the WWF are very exercised by the prospect of a major Arctic spill"

Few companies have the resources to do what BP did in the Gulf anywhere, let alone in the Arctic. Shell has described what they believe is needed, saying that for its proposed offshore Alaska drilling programme, it has a three-tier Arctic oil-spill response system consisting of an on-site oil-spill response fleet, near-shore barges and oil-spill response vessels, and onshore teams – with the latter able to respond within one hour. Clearly this is a major undertaking and cost.

Both Greenpeace and the WWF are very exercised by the prospect of a major Arctic spill, for which they claim that no oil company is adequately prepared, painting a picture of relief wells unable to be completed in a single drilling season, oil trapped – and moving – under ice, and so on. Not only has Greenpeace targeted rigs that are currently drilling offshore Greenland but also 'polar bears' have broken into an oil company's head offices in Edinburgh.

In Conclusion

What I have attempted to explain in this short review is that exploration success in the Arctic is not a 'given'. In addition to profound political and environmental issues, data are scarce or difficult to obtain and in some cases (seismic, drilling) currently envisioned technologies are exceedingly costly – leading to exploration that is expensive in comparison with the other options that explorers may have, for example, probing 'resource plays' (shale oil, shale gas) in North America or more conventional exploration in Deep Water or Onshore.

Whilst I have focussed here on the Russian Arctic, my commentary could be applied equally to the Canadian Arctic for example and to a large extent to West and East Greenland.

Petrobras and Boston Consulting Group authors* investigate the impact of experience curves on the development of Brazil's presalt cluster

Petrobras, working in partnership with the Boston Consulting Group (BCG), recently conducted a study applying the concept of experience curves to the development of Brazil's presalt cluster in the Santos basin. Underlying the study was the belief that the magnitude and duration of the presalt development campaign would strongly drive experience-effects gains via continued optimisation efforts. The study, thus, had as its key objective the identification of initiatives that could intensify the experience effects for critical items in the construction of oil wells and installation of subsea systems in the presalt, reducing Petrobras' expected production development capex over the next 20–30 years. This article provides a brief summary of the applied concept, methodology and results achieved.

Concept: Experience Curves

The experience curve concept, which posits that unit costs for a given product or process will decline at a predictable rate as cumulative production volume increases, was developed by BCG founder Bruce Henderson in 1968. In contrast to the well-known concept of a learning curve, which typically represents a passive observation of short-term gains in repetitive processes, experience curves cover longer periods of time and can encompass a large range of factors, from planning and process optimisation to scale effects and the implementation of new technologies. In this context, they can be used to direct investments and managerial efforts to the places where they will yield the most impact. While a cost curve converges to an asymptote as volume increases in a linear scale, on a log-log graphic it approaches a straight line; this has been defined as the experience curve.

The slope of an experience curve describes the relationship between cost and volume – specifically, the percentage decrease in unit cost for a given percentage increase in cumulative volume. If a product has an 80 percent experience slope, its unit costs will decline 20 percent (1 minus the experience slope) every time cumulative production volume doubles. Experience curve slopes typically range from 70 to 90 percent, and their calculations in real-world processes involve a complex set of analyses and data adjustments to isolate intrinsic experience effects from those related to commodity prices, exchange rates and inflation, for example.

Estimating Experience Curves for Presalt

The methodology applied in this study involved five main steps, developed by Petrobras' key managers and technicians and BCG's upstream experts:

1. Definition of standard scenarios for wells and subsea systems and their respective cost structures
2. Prioritisation of critical items according to cost materiality and experience potential
3. Identification of applicable analogs for each critical item and estimation of respective historical experience curve slopes
4. Projection of the experience curves for the prioritised items in the presalt context for the next 20–30 years
5. Consolidation of the individual experience curves for each critical item into single experience curves for a presalt oil well and subsea system.

The first step was to define standard types of wells and subsea system scenarios that would be applicable to the presalt campaign. This analysis led to the following:

- Three types of wells: vertical, vertical lean (an open well without intelligent completion and minor reservoir-evaluation intensity), and open horizontal
- Four subsea collection systems, having as variables the number of interconnected wells, whether or not the systems use manifolds, and whether the systems' risers are rigid or flexible
- Three subsea gas-export systems based on riser type (auto-sustainable hybrid, rigid or flexible).

For each of these wells, subsea collection and subsea gas-export scenarios, a detailed cost breakdown was developed leading to the prioritisation of ten critical cost items for wells and five critical cost items for subsea systems. Those items included drilling systems (bottomhole assembly, bits, fluids, etc.), reservoir evaluations, rigs and their respective maritime logistics support, subsea trees and manifolds, and the installation of flowlines and umbilicals.

It is important to note that experience curve projections were run initially for each of the selected critical items rather than for the wells and subsea systems of the presalt as a whole. This is because the curve calculation depends on a historical cost base that is technically comparable to the presalt situation. This historical base is not available for presalt wells due to the recent discovery of the Santos basin fields and the limited existence of wells in comparable situations around the world. It is, however, possible to analyse a presalt well through its subcomponents, by identifying applicable analogs for which there might exist historical databases and adjusting these using pertinent normalisations (e.g., adjustments by water depth, well length and geometry, etc.) to calculate the respective individual experience curve for each subcomponent (Table 1). These curves could then be compounded to generate the synthetic experience curve for a whole oil well or subsea system.

Based on the defined analogs and collected data, the next step was to determine historical slopes for each critical cost item. This entailed the definition and vetting of a number of parameters, such as the ones illustrated below that were used to define the historical experience curve slopes associated with productive rig time in the drilling stage:

*Choice of Analog***.** Given limited historical data for presalt drilling, the performance from Petrobras' postsalt fields was used as an analog. This analog was considered applicable to the presalt due to the finding that, via several simulations, the experience

Table 1: Examples of Analogs to the Presalt Environment

Example of prioritized items	Analog	Rational for applying to presalt
Drilling sysems	Drilling performance (ROP) in offshore postsalt wells (internal data by bit type, geology and well geometry)	Analysis indicates that the experience curve slopes are similar, regardless of bit type, geology or well geometry considered
Subsea trees	Time recorded by Petrobras in the installation of subsea trees in deep and ultra-deep waters in the postsalt (normalized by water depth)	Installation process for subsea trees in deep and ultra-deep waters is similar; analysis should only consider the normalization by water depth
Special metallurgy	Material perspectiv: Stainless steel cost Product perspective: OCTG cost Triangulation with Super 13-Cr data	Experience effects are related to the steel production process (billets and pipes) and not to the presalt in particular
Rig performance	Productive rig time in the construction of offshore production development wells by Petrobras	Curves have similar slopes regardless of the typ of rigs (shallow, deep or ultra-deep waters)
Flexible and rigid lines	Product and material perspective (standard metallurgy lines) Material perspective (special metallurgy lines)	Both standard and special-metallurgy lines will be used in presalt (not disruptive vs. industry practice elsewhere)
Nonproductive time (NPT)	%NPT in the industry and at Petrobras (Europe, Gulf of Mexico and Brazil postsalt)	No specific NPT root causes exist in the presalt vs. other offshore operations

curve related to drilling performance tended to present the same slope, regardless of the lithology, bit type or well geometry in question.

*Applied Assumptions***.** Due to the absence of a global database on drilling efficiency, Petrobras' internal data was used as an approximation of performance for the industry as a whole. Considering that the companies supplying drilling systems are major corporations operating globally, this approach was assumed to faithfully reflect the historical rate of gains in drilling efficiency for the industry.

*Experience Curve Metrics***.** For the y-axis, hours per metre drilled was used, being a physical measure of drilling efficiency, including useful time and maneuvers. For the x-axis, cumulative drilled metres in the industry was used.

*Applied Data***.** Records from Petrobras' wells were mined for drilling times as the source for the y-axis, and a selection of international databases were used to estimate the reference base as a source of the x-axis.

*Required Normalisations***.** Because in this example there were no monetary measures involved (only physical ones; i.e., metres drilled), adjustments to eliminate the effects of inflation or changes in commodity prices were not needed.

*Historical Curve Parameters***.** To estimate the historical curve parameters, several databases were tested, including a consolidated base of Petrobras' offshore wells (about 1200), a base of drilling performances with PDC and tricone bits (65 wells in Albacora field and 69 wells in Barracuda field, respectively), and a base of drilling performances in horizontal and vertical wells (about 40 wells in Albacora). Estimation of slopes for each of the samples was performed through a regression on a logarithmic base (log-log) according to the formula:

$$T_d = a + b \cdot \log D$$

where T_d is the drilling time per metre and D is the drilled depth in metres, which yields a slope of 2^b. For all of the considered historical data samples (offshore wells in general, verticals and horizontals, with tricone and PDC bits and for different lithologies, such as carbonates), performance gains in drilling across the years presented very similar slopes. Accordingly, the same obtained slope value could be applied to the drilling phases in a presalt well, regardless of the respective lithology of each phase.

This process for estimating historical slopes was performed for each critical item in the wells and subsea systems, with each estimation considering a careful selection of reference bases and applicable analogs, as illustrated in the example above. Having obtained those historical slopes, it was now possible to project how the costs of each critical item would evolve for the next 20–30 years given the experience effects over that time period. To do so, three key parameters had to be estimated:

*Current cost reference for each item in the presalt context (C_0)***.** This is the item's unit cost today, from which experience effects are applied at each doubling in the cumulative production volume. It is important to emphasise that the initial cost C_0 should be the one from which the respective production process leaves the 'laboratorial' stage (during which the unit costs exhibit erratic behavior, with no statistical meaning), migrating to a more standardised production process (from which experience curve effects start to materialise). Another important consideration is the definition of a proper metric for the unit cost measurement. For instance, for the experience curve for drilling bits, several metrics could be used, such as cost per bit, well, phase or drilled metre.

*Volume reference base (V_0)***.** This is the current cumulative volume from which volume duplications (doublings) will be measured. To assess this parameter, it is vital to be clear about the reference base applicable to the item under consideration. In the case of subsea trees, the reference base applicable to the presalt is that of subsea trees in deepwater and ultra-deepwater conditions, given similar operating environment characteristics. In contrast, subsea trees used in shallow water have very distinctive characteristics, including different installation processes, and, therefore, could not be used as a reference for the presalt. Thus, when considering volume projections for presalt subsea trees, the starting reference base should be the total volume of all deepwater and ultra-deepwater subsea trees installed up to the current time.

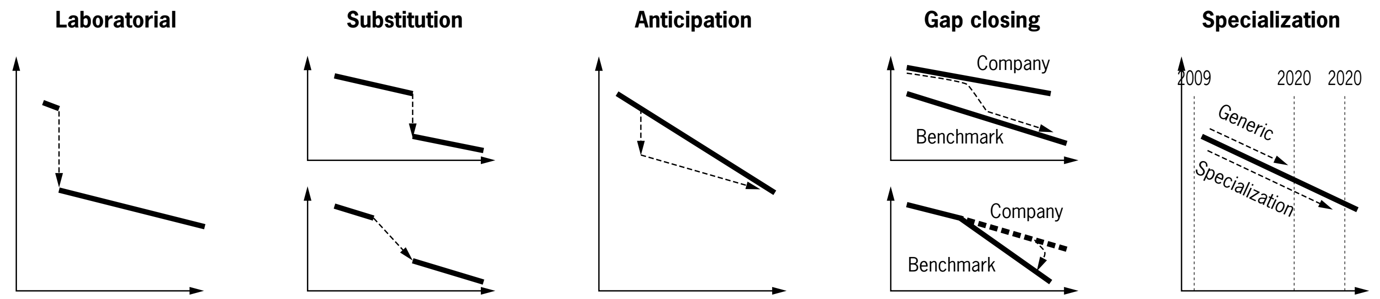
*Slope***.** This would be the historical slope estimated as described previously in this paper using analogs for which historical cost bases and operational performance indicators were available.

Once these three parameters (C_0, V_0 and slope) were obtained for each critical item applied in presalt well construction and subsea systems, the respective projections of cost (or performance) for each item would then be directly dependent on the future duplications expectation of their respective volume reference bases. Projections could thus be made for how all of the relevant reference bases would evolve for the next twenty years and for the expected cost reduction driven by experience effects.

After completing projections for individual experience curves for each item, *consolidated* experience curves for an oil well and for a subsea system as a whole were estimated. That estimation was done through a complex simulation model developed by BCG, which compatibilised the different reference bases (V_0) of the individual items' experience curves into one single reference base (number of wells) allowing the projection of consolidated cost curves for different types of wells and subsea systems considered for the presalt. As inputs, this model receives the individual experience curves estimated for the critical items and some other specific characteristics of the presalt campaign, including water depth, well length and rock formation composition.

Based on the estimation of consolidated experience curves, the potential for investment reduction in wells and subsea systems across the presalt campaign could be calculated. In present value, these investment reductions added up to 11 percent for well

Figure 1: Experience Curve Intensification Patterns



Abrupt shift of the curve in the very beginnibg of the product cycle

Abrupt or over-time shift thoughout the cycle

Trend anticipation, but with reversion to the original curve throughout time

Changing procedures to match industry standards

Specialization allowing increased doubling (faster advancement in the curve) in the same time period

drilling and completion and 10 percent for subsea systems. Combined, these savings amounted to about 8 percent of the total forecast investment for the presalt campaign (including FPSOs).

Intensifying Experience Effects

The approach used to seek opportunities to intensify experience effects in the presalt included analysis of key experience levers (identified by running simulations in the model described above) and a series of workshops with Petrobras expert teams by function and key processes. During these discussions, the technical teams identified typical experience-effect intensification patterns, reflected in increased slope or downward vertical shift of the curve (Figure 1). As a result of these exercises, more than 150 intensification initiatives were identified, with 30 of them being prioritised as having the greatest potential impact for the presalt wells and subsea systems. The identified initiatives are diverse in nature and include not only technical matters related to the concept, planning and execution of the offshore production systems, but also organisational considerations, performance management drivers and supplier relationship development. Three of these prioritised initiatives are illustrated below:

*Reservoir Evaluation Prioritisation***.** Given the heterogeneity of the presalt reservoirs and the magnitude of the development campaign, the value of the information from well testing and logging tends to be quite significant. On the other hand, these reservoir evaluations can be very costly to perform in the presalt context. The experience curve approach recognises the fact that, as these evaluations are performed, Petrobras will gradually reduce the uncertainty (or gain experience) on how to best exploit the fields, changing its reservoir evaluation needs from more sophisticated methods (drillstem tests conducted by rigs and complete sets of wireline logging) to simpler mixes of evaluations (production tests with or without bottomhole closure by intelligent completion systems and simpler logging sets).

From this basic concept, a detailed initiative to identify the optimum mix of reservoir evaluations was conducted for all production modules and blocks in the presalt, shedding light not only on how information through time would benefit the individual well, but also on how the evaluation of each specific well impacted the reduction of uncertainty of its module and field. As a result, this initiative yielded a 33 percent cost reduction in the presalt planned investments in reservoir evaluations, while ensuring the same value from the information gathered in such evaluations as in the original plan.

*Rig Specialisation Model***.** The expected scale of the production development campaign in the presalt allowed the analysis of a new rig allocation model, in which specialised rigs, with shorter operating cycles, would be deployed for the construction of specific parts of the well instead of having only one type of rig responsible for all drilling and completion activities. This model would allow not only the intensification of experience effects through specialisation and faster ramp-up of crew and equipment performances, but also an optimised use of the asset base, allocating the most sophisticated rigs only to the most demanding steps of the well construction process. In this initiative, two large stochastic models were developed. The first model tested the economic feasibility of different specialisation scenarios (which, at the limit, included up to eight different types of vessels/rigs participating in the construction of a well) and generated Petrobras' demand curve for each type of rig for the next 20 years (considering a 95 percent service level to meet the desired exploitation plan and production curve). The second model then used this specialised rig fleet as an input and applied a predefined day-to-day allocation rule for each rig in order to test stochastically the expected degree of fleet idleness.

As a result, a robust optimised specialisation scenario has been identified, considering the use of a top-hole driller for the first and second drilling phases (the ones above the salt layer), a sixth-generation rig to perform the more complex drilling (salt and reservoir) and completion activities, and a light workover rig to perform the well testing and subsea tree installation, besides eventual necessary workovers. This initiative has identified savings of at least 9 percent in the rigs to be allocated in the production development of the presalt fields, something made possible given the concentrated scale of Petrobras E&P operations.

Manifold Usage Optimisation. Traditionally, manifolds present very limited experience effects over time, mainly due to their nonstandardised, project-by-project production characteristics. In this context, an initiative was conducted to analyse the tradeoffs and potential experience effects associated with a more standardised use of manifolds in the sizeable presalt campaign. The initiative analysed different scenarios and was able to identify gains from the acceleration of experience effects representing roughly 17 percent of the cost of the overall subsea systems to be deployed in the presalt campaign.

All in all, for each of the thirty prioritised initiatives, the potential for additional cost savings from experience effect intensification was mapped, resulting in an estimated aggregate capex savings of 17 percent in present value for the presalt campaign as a whole. It is important to note that, although this figure assumes a constant investment level for the FPSOs (as they were not part of the scope of this project), it is certain that experience effects are also applicable to these production units. If these effects were included and correctly estimated, the total aggregate capex savings potential for the presalt campaign would most likely be greater than 20 percent. A separate internal Petrobras program has been carried out to optimise the investments associated with FPSOs.

Finally, all prioritised initiatives were structured in individual projects, with approaches, work plans and teams assigned for their execution. Those initiatives were then consolidated into an implementation program under the name Presalt Capex Optimization Program (PROINV). In its current stage, this program is being conducted until early 2012 under the coordination of Petrobras' Master Development Plan for the Santos Basin Presalt Cluster (PLANSAL), with the continued supervision of Petrobras E&P top management and the support of BCG.

Conclusions

The opportunities identified by applying the experience curve concept to the presalt development campaign are now being rolled out broadly at Petrobras, encompassing not only the presalt projects, but all of its major E&P development projects. In this context, Petrobras has incorporated the experience curve programme structure as part of a systemic process to reduce the total cost of wells and subsea systems, aiming for continuous investment optimisation over the decades to come.

* *José Miranda Formigli Filho, Mauro Yuji Hayashi and Renato Da Silva Pinheiro, Petrobras; Jean Le Corre, Ilson Dalri, Jr., André Truzzi and Henrique Sinatura, Boston Consulting Group*

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Michelle Michot Foss looks at shale gas development in the USA

The 'Story' and the 'Backstory'

Much has been written about the impact shale plays are having on the US exploration and production businesses. Already, results achieved in US drilling are altering views around the world regarding unconventional oil and gas resources in general, and shales in particular. Even more, viewpoints are being altered when it comes to US energy supply and especially the 'call' on liquefied natural gas (LNG) that was supposed to emanate from the United States.

The 'story' is that shale gas plays essentially have made the USA energy independent, perhaps even moving the country into the column of natural gas exporters. (It already was an exporter by virtue of the first long-term LNG trade route, Alaska to Japan, albeit one scheduled to go out of business at year-end 2011.) Moreover, shale gas abundance and production, and the ability to deliver shale gas production 'just in time' through 'manufacturing' drilling and development schemes that facilitate cost management, are expected to keep US natural gas prices low and stable for the foreseeable future. The worldwide implications are clear: pressure on natural gas prices everywhere by virtue of the low US Henry Hub price signal; pressure to shift gas supply contracts away from an oil price basis and toward a natural gas index like Henry Hub (to the consternation of a number of gas exporting countries); widespread interest in proving up shale gas plays in every country that has potential. In sum, the US experience would induce a 'golden age of gas' worldwide. Gas would be elevated from its status as a fuel for peak use and graduate to base load from its role as simply a 'bridge' fuel to a cleaner energy future. Energy geopolitics would be altered.

The 'backstory' context is more nuanced and perhaps more realistic. Shale resource abundance is not in doubt. Recovery of shale resources is, however, fully contingent on the ability of industry players to achieve continued cost reductions extending into the less attractive portions of shale basins. This is no small challenge, given the stubborn upstream cost structure that companies face. Shale basins are highly variable; success is most likely where sufficient porosity and permeability exist to enable commercial well completions. Public concerns and opposition to drilling, and resulting pressures for increased regulatory oversight, complicate matters and further strain costs. One arena of concern – the amount of water required for hydraulic fracturing – has some legitimacy, witnessed in drought stricken Texas and other sensitive locations. The search for operational alternatives and solutions is difficult, at best. Water is a powerful enabler of oil and gas development. A relatively cheap substitute is not in sight and water management approaches (recycling and so on) are not easily done. The bottom line of the backstory context is not so different than US natural gas history to this point, with higher and bumpier prices while various stages and plateaus are achieved in developing the potentially rich but complex shale resource base. If deliverability from shales cannot be assured investment flows must be drawn back to conventional plays, shoved to the sidelines in the low gas price environment, with their inherent exploration (dry hole) risk. All of this certainly complicates and renders much more uncertain the benign world view that has been put forth.

What can be expected for the foreseeable future? Will recoverable resource, geological favorability plus industry know-how, deliver a profitable, sustainable business at, say, the roughly $4 per million cubic feet (mcf) that has prevailed since late 2009? Or, will a higher price deck be needed to provide adequate returns, encourage interest, and keep investments flowing?

The Facts

The US natural gas resource base is known to be robust. Ever since disputes about reliability of natural gas supply in the 1970s, a progression of resource assessments have affirmed what many had argued persistently. The United States has a large technically recoverable resource base considering all geological features (conventional reservoirs and unconventional sources – meaning 'tight' formations of all types and 'resource' plays in which hydrocarbons are extracted directly from the source rocks, including shales and coalbed methane) and all locations (onshore, Lower 48 and offshore, predominantly Gulf of Mexico, as well as Alaska). Various development eras introduced technology and other improvements that enabled the USA to sustain a recoverable resource base of about 1600 trillion cubic feet (tcf) through the 1990s. The most recent, 2009 resource assessment by the US Potential Gas Committee puts recoverable natural gas resources at about 2000 tcf with the main difference being a more pronounced contribution from shale gas basins. Notably, the USA also has abundant methane hydrates, with the US Gulf of Mexico considered to be the most prospective for eventual commercial development. Some put ultimate technically recoverable US natural gas resources at thousands of tcf with these possible additions.

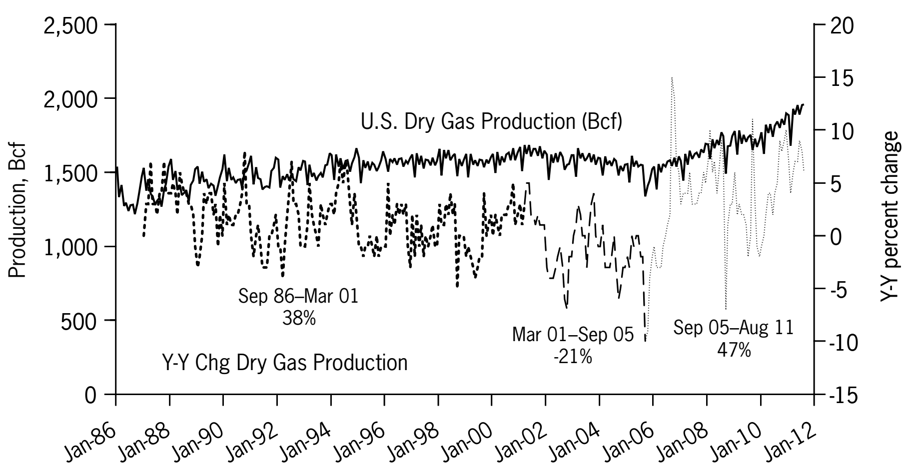
> "it is increased use of gas for electric power that is driving future expectations most strongly"

'Technically recoverable' is the key terminology. The US oil and gas industry has demonstrated many times its resilience and ability to prove up new tranches of hydrocarbons in response to price signals and with innovation. Yet innovation and, more pointedly, market penetration of new technology in this industry is slow. Drilling in the Texas Barnett shale began in the early 1980s as companies searched for then scarce opportunities in the USA. Higher oil prices and a variety of policy changes geared towards debottlenecking the natural gas industry and reducing, and ultimately eliminating, federal control of wellhead prices spurred activity. It has taken more than thirty years for the combination of hydraulic fracturing and horizontal drilling, neither one new in concept or practice but both modernised and transformed into 'off the shelf' oil field service products, to yield the results demonstrated in the US shale plays since 2006. In truth, it was new ways of measuring gas in place or GIP (canister desorption at the wellhead) and the damage done to shale production recovery estimates with higher GIP measures that created the momentum needed to push technology forward. Resource play technologies – horizontal drilling with multiple hydraulic fracture stages to squeeze hydrocarbons out of tight rocks – were the answer. Producers simply had to be able to report recovery rates attractive enough (about 30 percent) to justify capital expenditures through the mid- to late 1990s gas price swoon.

The pronounced jump in US natural gas production year-over-year in September 2006 got attention. Subsequent years of production formed a trend that, by 2009, demonstrated the turnaround in domestic gas supply with all attendant future possibilities. As usual, industry endeavor and success led to inevitable downward pressure on price, made worse with the 2008 recession and lackluster economic performance since then. The buildup in gas supply crashed head on with deterioration in demand, resulting in the 1990s-style low price deck witnessed today. (Figure 1)

Deployment of resource play technologies also has been applied in new oil plays. A turnaround in US oil production, initially from the North Dakota Bakken but later in the Texas Eagle Ford and other locations, was achieved. In many respects, revitalised domestic oil production is even more significant than the natural gas turnaround. US oil supply had been disparaged for quite a long while. Coupled with natural gas liquids (NGLs) production, revenues from the more valuable liquids plays have helped to offset losses in dry or non-associated gas locations. Make no mistake: without the benefit of higher oil prices, and without the possibility of liquids production to cover drilling economics, the US natural gas 'patch' would be in a much different, and much more difficult, shape today than it is. To a large extent, companies have been able to retain their skilled (if expensive) exploration and development staffs, honour leasehold obligations, continue to attract investment interest,

Figure 1: Natural Gas Production Trends



Author analysis based on production data as reported by US Energy Information Administration

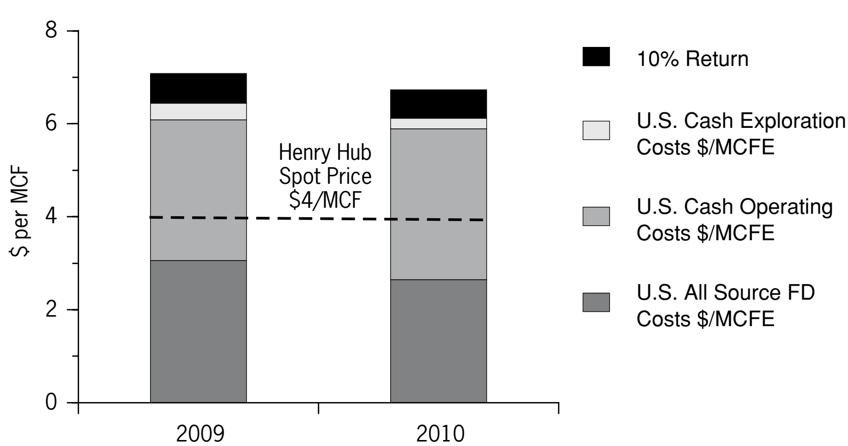
and crucially, given US economic conditions, contribute jobs and income largely because the oil price premium over gas provides a safe haven. The precipitous drop in gas-directed drilling- a shift of 299 rigs by November 2011 from a high of about 1200 in June 2005 – and the parallel surge in oil-directed drilling – a gain of 970 or so rigs from the low of 140 in June 2005 – were stunning, in retrospect. For many market watchers, the shift couldn't happen soon enough and the continued additions of associated gas production made the tempered drilling activity a Faustian bargain. The future is clouded by the rapidity of the shift away from gas drilling, the stress on upstream properties induced by lower natural gas prices, and the great uncertainties created by the whipsawing of events and policy and regulatory actions that will affect both supply development as well as how natural gas is utilised.

Looking Ahead

Indeed, it would be fair to ask whether defeat might be snatched from the jaws of victory. All ambitions to use natural gas more aggressively for power generation (attractive given its cleaner burning attributes), to re-build the US industrial base (numerous proposals are being floated for NGLs offtake and natural gas is an essential feedstock as well as fuel for US petrochemicals and manufacturing), or even to boost natural gas vehicle market share are contingent on reliable supply deliverability at competitive prices. Regulatory actions that could spur increased utilisation are very likely to be contradicted by an assortment of decisions that would make natural gas (and domestic oil) more scarce and expensive, rather than less. These range from rules that could affect drilling and well completions directly (hydraulic fracturing and water use for drilling) to endangered species protections, air emissions and other regulatory requirements that have broad implications. Laws and rules are evolving across all jurisdictions – cities, counties, states, and the federal level. They are intended to address nuisances like traffic and roads, and public health concerns about clean air and water. Coupled with complex geology and inherent development risks in the shale plays, the added cost and complexity of policies and regulations have substantial negative connotations for natural gas upstream costs and profitability. At an assumed Henry Hub price of $4, US producers already are dealing with negative margins given average breakeven costs of $5–6 (our work and review of numerous proprietary studies). A 'balancing' price of $6 is most often bandied about. This is well within the comfort zone of large customers that also deal in petroleum products, as long as oil prices remain at current levels. Sensitivities begin above $6, but in various ways producers have signaled that $8 may be what it takes to attract and retain drilling investment. (Figure 2)

The bane of the natural gas industry is price volatility, the essential trade-off in the 'grand bargain' that constituted regulatory restructuring in the USA (and Canada) since the 1980s. High volatility – and volatility has been higher for natural gas in its traded history than for oil and most other

Figure 2: Average Breakeven Costs (All-in) for A Sample of US Natural Gas Producers



Based on analysis by author and Miranda Ferrell Wainberg, senior researcher, Center for Energy Economics, using company financial reports.

commodities – fosters perceptions that natural gas is unreliable. While natural gas utilisation could evolve in other directions, it is increased use of gas for electric power that is driving future expectations most strongly. In power generation, the cost of building natural gas plants is relatively cheap. At times the cost of fuel has been very expensive since restructuring was completed in 1992, especially relative to coal. Lower cost, abundant natural gas with lower and more stable prices now offers an alluring vision. The main tensions centre around reliance on coal, traditionally purchased on long-term contracts and, until recently, cheaper than gas but more polluting, and ambitions to displace a considerable amount of coal capacity, if not all of it, with natural gas-fired generation. Yet, periods when natural gas prices have moved strongly are those when deliverability has been a problem, either because drilling lagged growth in demand (the situation coming out of the 1990s gas bubble), because of short-term disruptions (hurricanes that affected offshore production), midstream bottlenecks (pipeline outages), and the like. It is worth noting that periods of higher price volatility have occurred against the backdrop of expanding resource assessments and, in some instances, underlying growth in deliverability.

The future story hinges on many contingencies. Stay tuned!

This article is drawn from a new working paper posted by OIES, The *Outlook for US Gas Prices in 2020: Henry Hub* at $3 or $10? by Michelle Michot Foss.

Trisha Curtis describes the building blocks of the North American petroleum renaissance

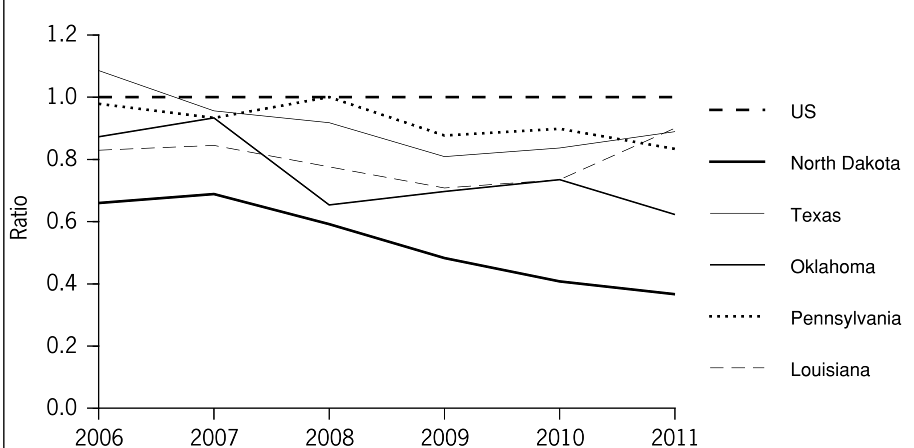
In 2009, the United States became the world's largest producer of natural gas and all indications are it will remain so for the next twenty years. The shift in expectations on domestic natural gas output took place across a remarkably short time span. In June 2003, Alan Greenspan, Chairman of the U.S. Federal Reserve, testified before the Congress Committee on Energy and Commerce that the USA was in a state of crisis due to declining natural gas production. A consensus among both policy makers and much of the domestic petroleum industry led to an accelerated programme to construct facilities to import liquefied natural gas (LNG). Approximately $30 billion was spent to construct LNG import facilities over a 3–4 year period, but the simultaneous turnaround in domestic gas output was large and quick. Today these import facilities are operating at less than 10 percent capacity. Some LNG facilities are now applying for licences to export American natural gas to world markets.

This remarkable shift in the outlook for natural gas production directly resulted from the application of two critical advances in modern petroleum development: horizontal drilling and hydraulic fracturing. Advances in the art and science of these petroleum development technologies are now migrating to unconventional shale/tight oil plays throughout the United States.

In this article references to shale oil refer to a broad range of so-called unconventional oil development including tight and carbonate oil formations. US shale oil production has taken root in North Dakota and Texas where combined production has risen from negligible volumes to 500,000 barrels a day (b/d) in just three short years. These shale oil plays have helped raise US liquids production to its highest level in nearly a decade, more than offsetting Gulf of Mexico production losses from leasing and development delays after the Macondo spill. It is no longer unthinkable that US production alone could rise by over 2 million b/d in the next ten years.

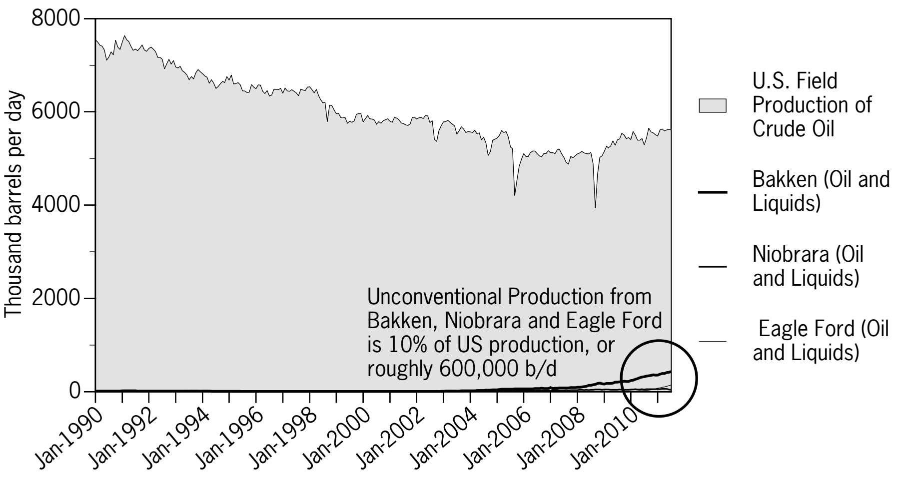
In a period in which the US economy is suffering from high unemployment and lagging economic growth, the petroleum industry remains a bright spot. Figure 1 illustrates the ratio of national unemployment to four prominent oil- and gas-producing states. For the state of North Dakota, the benefits from oil production are widespread. Taxes on oil production and extraction have allowed the state to put millions of dollars into a legacy

Figure 1: Ratio of State Unemployment Compared to USA



Source: Data from the Bureau of Labor Statistics, seasonally adjusted, data for April of given year.

Figure 2: Unconventional Production as a Percentage of US Production



Source: HPDI and EIA Data, EPRINC Calculations (conservative)

Note: Bakken production does include some NGLs (natural gas liquids) but is primarily oil; Eagle Ford includes more NGLs and about 20,000 b/d are oil; Niobrara does include some NGLs, but is primarily oil.

fund, to invest in water resources, communities, education and research, and to lower income, corporate, and property taxes. In the fiscal year of 2011 oil taxation brought in $977.8 million.

Beyond the direct benefits of improving the fiscal outlook for oil-producing communities and improving employment opportunities, rising oil production (both crude and natural gas liquids) provides cost-effective import substitution and new competitive opportunities for American refineries and petrochemical plants. Most of the crude oil coming out of these shale basins is of premium quality, very light and sweet. Bakken oil from North Dakota and Montana typically has an API gravity of over 43 degrees. Light sweet crude oil is well matched to the less complex refineries on the East Coast and some in the mid-continent. These refiners typically operate on very small margins and face fierce foreign competition. Most refiners on the East Coast must purchase high cost crudes from Nigeria and the Middle East – also subject to fierce competition from imports of gasoline components from European and even some Asian refineries – that can be processed in less complex facilities. This high cost and competitive operating environment is characterised by low utilisation rates, poor margins, routine closures and maintenance, and now the threat of additional capacity losses from permanent closures. With the necessary development in infrastructure through pipeline and rail, light sweet Bakken oil could supplant portions of Middle East imports on the East Coast or other refining sectors in the United States and give refiners a potentially lower cost alternative than waterborne imports.

Due to a rise in Canadian imports overtime and the increase in US production primarily from the Bakken, the two global crude oil benchmarks, Brent and WTI, have diverged and this currently puts Brent at $10 premium to WTI. This means that East Coast refineries that import waterborne crude are paying a higher price than Midwest refineries which have access to domestic produced crude, currently selling at a discount.

Figure 2 shows unconventional production as a percentage of US production.

The Plays

Shale oil has historically been difficult and costly to produce because it is found in formations characterised by both low porosity and low permeability. Essentially the rock is hard and tight with minimal natural fractures; the lack of porosity (holes) and permeability (connections) prevents the oil from easily flowing out.

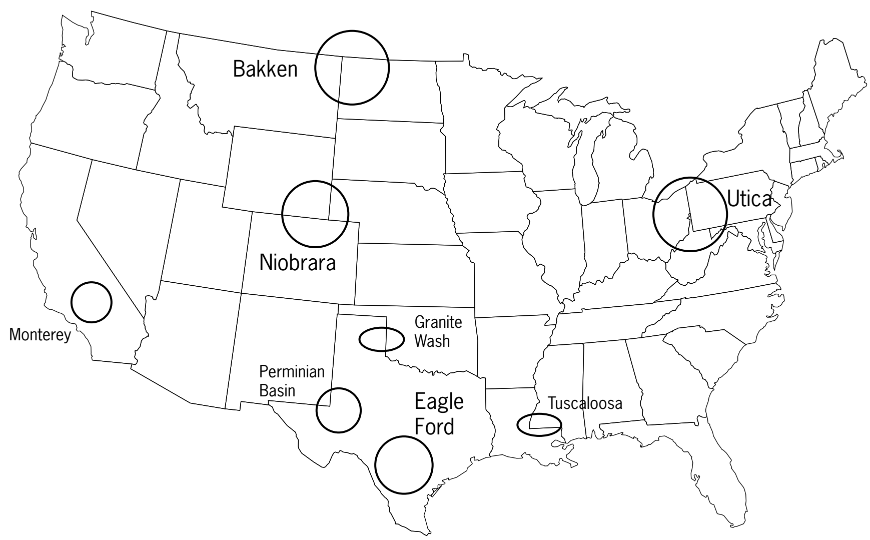
Traditional vertical well technology and production methods touched only a portion of the producible rock. This left the wellbore (the drilled hole exposed to the producing rock) exposed to only a small portion of the tight oil formation, thus not allowing it to be produced to its true potential. Attempts to access shale oil in North Dakota using horizontal drilling technology had been tried in the past, but had not advanced to longer laterals and multiple hydraulic fracturing stages in the correct layer of rock. This technique was pioneered in the shale gas revolution and applied to oil prone shale in North Dakota's Bakken formation where its success has triggered a frenzy of investment across the country's liquid basins. (Figure 3)

North Dakota's Bakken

North Dakota is now the fourth largest oil-producing state with production topping 464,000 b/d in September 2011. (Figure 4) The majority of this production is Bakken oil from the Bakken and Three Forks formations. It is conventional, light-sweet crude oil, trapped 10,000 feet below the surface within shale rock. The Bakken shale play consists of three layers, an upper layer of shale rock, a middle layer of sandstone/dolomite, and a lower layer of shale rock. The middle sandstone layer is what is commonly drilled and fracked with the horizontal lateral today.

The Bakken and underlying Three Forks formations are part of the larger Williston Basin, which encompasses Saskatchewan, Manitoba, North Dakota, Montana, and South Dakota. Bakken producing zones are mainly present in Western North Dakota, Southern Saskatchewan, and Eastern Montana. Beyond the Bakken and Three Forks there are other potential rock members within the Williston

Figure 3: US Shale/Tight Oil Formations



Source: EPRINC Map. Formations are not to scale and indicate roughly their location for visual understanding. This is not inclusive of all US shale/ tight oil.

Basin that could offer further oil production opportunities.

What makes the Bakken unique from other formations in the United States and the world is that it is a continuous oil accumulation, possibly the largest in the world according to the USGS. It is an over pressured system which is in part why many wells experience such high initial production. The high pressure in the formation suggests that the oil is contained within the petroleum system. This means that the oil remains in place and is tightly contained throughout the geologic structure.

While Bakken oil is of the highest quality, very light and sweet, it still suffers from a discount due to its distance to major refining markets and limited take-away capacity. This discount has substantially narrowed in recent months with significant rail and pipeline developments.

Southern Texas' Eagle Ford

The Eagle Ford in south Texas has become something of an overnight miracle. After years of proving up the Bakken, drillers began an active exploration and development programme in the Eagle Ford around 2008. As well as other major shale plays, the Eagle Ford is now experiencing significant investment from both major and independent oil companies, accompanied by high acreage costs, and multiple joint ventures.

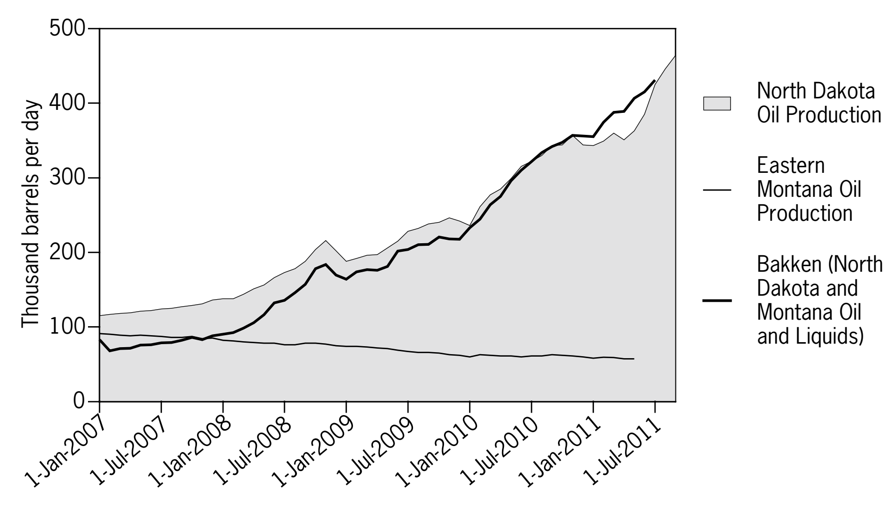
The Eagle Ford is more of a carbonate than a shale, but is produced in the same manner as the Bakken with horizontal drilling and multi-stage fracking. It includes three hydrocarbon windows: oil, wet gas/condensate/ NGLs (natural gas liquids), and dry gas respectively with play zones ranging in depth from 4000 ft. to 14,000 ft. As the play moves eastward across Texas from oil to gas it increases in depth, thermal maturity, and API gravity.

Right now the most prolific part of the Eagle Ford play is the wet gas/ NGL/condensate window. Condensate valuations are similar to oil and remain a major target in exploration and development efforts. Oil production is increasing in the Eagle Ford and is currently around 20,000 b/d, but will likely increase as necessary take-away infrastructure comes online. Close proximity to the Gulf Coast refinery district has helped the Eagle Ford take off quickly, but substantial infrastructure constraints still exist. Figure 5 shows liquids and gas production from 2008 to 2011.

Colorado's Niobrara

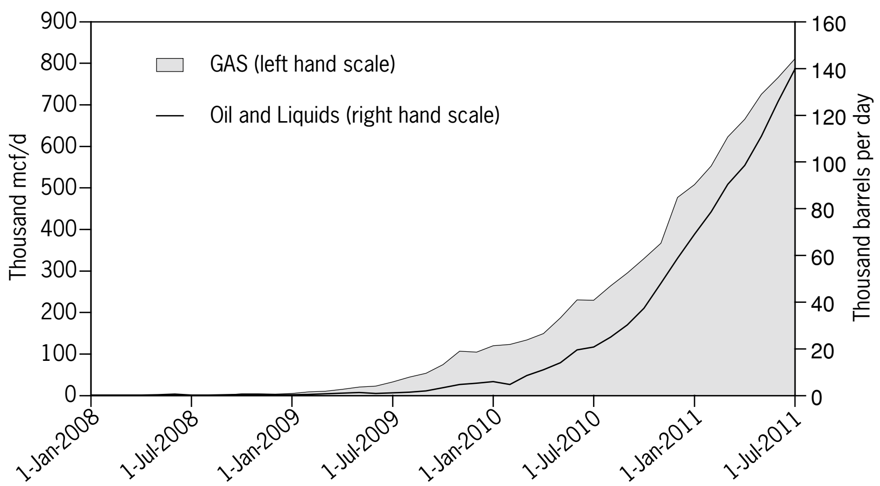
Unlike the success seen in the Bakken and the Eagle Ford, the Niobrara has proven to be more difficult to crack. Some initial well results were extremely promising, but over the past year production results have varied. Many wells being drilled in the Niobrara are still vertical and companies are still testing the prospectivity of much of the play. The most notable success has been seen in Weld County in eastern

Figure 4: North Dakota, Montana, and Bakken Oil Production



Source: State production data from North Dakota Pipeline Authority, Bakken production HPDI

Figure 5: Eagle Ford Liquids and Gas Production



Source: HPDI

Colorado, known for its historical gas production.

The Niobrara is not a pure oil play like the Bakken. Weld County for example ranges from more gas production to more oil production as you move north. The Niobrara – a broad name that actually includes multiple shales and basins – spreads across parts of Colorado and Wyoming and parts of Nebraska and is a mix of chalk, limestone, and shale. While this play is not an overnight victory, many companies are doing exceptionally well in Weld County and companies are still testing different fracking techniques.

Additionally, unlike typical shale wells in the Bakken and Eagle Ford, which have high IP (initial production) rates and substantial decline rates, some Niobrara wells indicate a moderate IP rate and a flatter decline curve. With a better understanding of the geology across the play and application of the appropriate completion methods, the Niobrara may yield increasingly positive results in the future. Figure 6 shows liquids and gas production from 1990 to 2011.

Ohio's Utica

In the past several months notable independents and major oil companies have leased up sizeable amounts of land in Eastern Ohio. Permit activity is accelerating and drilling is underway. Only a few well results have been released, but thus far the play looks extremely promising.

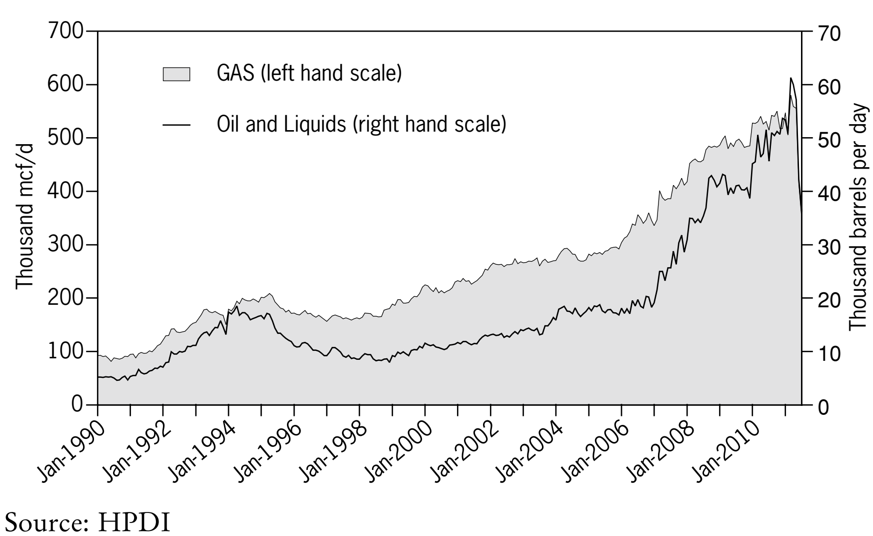
The Utica sits well below portions of the Marcellus and reaches from eastern Ohio into Pennsylvania, but the most prospective liquid prone area is eastern Ohio and parts of Western Pennsylvania. According to some images, the Utica source rock extends into New York, Virginia, West Virginia, and Kentucky as well. The Utica has received a lot of attention due to the success seen in the Bakken and Eagle Ford. It is also structurally similar to the Eagle Ford in that it has three potential hydrocarbon windows for production: oil, wet gas/condensate/NGLs, and dry gas respectively (from west to east). Prospective drilling depths in Ohio range from 3500 ft. to 10,000 ft. The formation is interlayered with shale and carbonate.

Time will tell if this play is in fact similar in productive nature to the Eagle Ford and if so may have a significant economic impact on employment in the rust belt as well as the depressed refining sector on the East Coast, including refineries in Ohio and Pennsylvania.

Looking Ahead

North America is at the beginning of a turnaround in domestic crude oil production driven by the same technology that sparked the shale gas revolution. New crude oil, condensate, and natural gas liquid supplies, combined with the current surge in natural gas production, offer the promise of a renaissance in petrochemical processing and petroleum refining industries. This dramatic increase in domestic oil production from unconventional reservoirs does not come without complications and constraints. In the coming years, both industry and policy makers will face challenges to bring about essential infrastructure to expand needed takeaway capacity with the onset of new oil plays.

Figure 6: Niobrara Liquids and Gas Production



Source: HPDI

Horizontal drilling and multistage fracking technology used to unlock shale gas has been proven in the Bakken and Eagle Ford, but also has the potential to yield additional crude volumes from plays on the periphery as well as older fields. Multiple shale plays not mentioned here have the potential to yield significant oil production results with time and technology. The Granite Wash in Texas and Oklahoma, for example, was historically known for its gas production, but is now seeing drilling in multiple layers of rock beneath the gas. Oil that could not previously be reached underneath the gas is being tapped and produced and offers a prime example to the potential of new oil production from older fields across the United States. In fact, the gas is said to be helping with the production of oil in this play. Additionally, the well-known Permian Basin is seeing significant drilling activity and production with multiple shale and tight oil plays.

Rising oil and gas production can generate sustained employment growth and expand the national economy. For American policy makers the emerging paradigm shift in the outlook for North American supplies of oil and gas creates both opportunities and challenges. Embracing the new economic opportunity will provide revenue for state and local governments and much needed economic activity, but it will also require sophisticated management of the challenges to the environment and the accompanying rapid industrial development.

Samer Ashgar on the prudent use of technology and reservoir management best practices for large carbonate reservoirs

More than 60 percent of the world's oil reserves reside in carbonate reservoirs. Saudi Arabia has the lion's share of these 'giant' hydrocarbon reservoirs. Given this magnitude of the resource, its exploitation and management becomes paramount and its management is the responsibility of Saudi Arabia's national oil company, Saudi Aramco. While Ghawar, the world largest oil field, has been the focus of much attention, the company manages several other large carbonate and clastic fields, producing both oil and gas. Over the years Saudi Aramco has implemented best-in-class reservoir management and production practices in its fields to play the role of an efficient, stable, and reliable oil producer that the world can depend on for their energy needs. This article sheds light on some of the prudent reservoir management practices that the company has adhered to over the years and the direction it is heading to maintain that leadership role in providing reliable oil supply to the world.

The Past

From its beginning some 75 years ago, Saudi Aramco has come a long way. The company has positioned itself as a world leader in managing large or super-large reservoirs. A lot has been shared in the literature about Saudi Aramco's reservoir management strategies, especially as it applies to Ghawar, Abqaiq and a few other large fields. Saudi Aramco has a portfolio of several large reservoirs, both carbonates and clastics, containing light to medium-heavy oils that have generally high porosities and permabilities. Most of the reservoirs were developed with peripheral water injection, and over the years a huge water injection and oil-gathering infrastructure has been put in place. In most reservoirs the oil flows naturally because of the healthy reservoir pressure supported by peripheral water injection.

The super-giant Ghawar was discovered in 1948, came on stream in 1951 and was put on peripheral water injection in 1965. The field is 280 kilometres long and 40 kilometres at its widest. The main carbonate Arab-D reservoir produces an Arabian light crude oil. The main strategic development philosophy that Saudi Aramco adheres to is maximising oil recovery. Some of the tenets of reservoir management include low overall depletion rates, maximum contact with the reservoir rock, application of advanced diagnostics, implementation of fit-for-purpose state-of-the-art technologies, and above all prudent reservoir management best practices. Adhering to these tenets has resulted in production sustainability, outstanding sweep efficiency, managed watercuts and optimum reservoir performance. The philosophy has been in continuous learning and improvement.

Another excellent example of the benefits of this strategy is demonstrated with the performance of Saudi Arabia's oldest producing field, Abqaiq, which has been in production since 1948. It continues to produce today with peripheral water injection, low watercuts, and very high ultimate oil recoveries, all without tertiary or enhanced oil recovery (EOR) implementation.

The Present

Reservoir management at Saudi Aramco has adhered to the philosophy of maximising oil recoveries while ensuring sustainable oil production. This has come about through life cycle economics with the adoption of latest technologies. The mantra has been to lengthen the production plateau in the most cost-effective manner, while maximising ultimate oil recovery. The large carbonate reservoirs have been produced under peripheral water injection at a predetermined low depletion rate. This allows a delicate balance between gravity and other physical forces to help maximise the ultimate recovery.

The main success factors for optimum reservoir management at Saudi Aramco have been a close collaboration between engineering and other geosciences, coupled with the application of fit-for-purpose technologies. The role of new technology can be exemplified in several case studies, the Haradh Increment III, the newly developed Khurais field, and other large scale carbonates.

> "Reservoir management at Saudi Aramco has adhered to the philosophy of maximising oil recoveries while ensuring sustainable oil production"

Haradh field is the southernmost part of the Ghawar complex and covers an area that is 75 kms long and 26 kms at its widest. The field consists of three sections of approximately equivalent reserves and each with a production capacity of 300,000 b/d. Production at Haradh-I started in 1996, followed by Haradh-II in 2003 and Haradh-III in 2006. The field increment developments spanning a period of over a decade provide a unique opportunity to gauge the impact of technologies. Haradh-I was developed using vertical wells exclusively, Haradh-II was developed using horizontal wells, and Haradh-III was developed using maximum reservoir contact (MRC or horizontal wells with multilaterals), smart completions with downhole Inflow Control Valves (ICVs) for flow control, extensive use of real-time geosteering, and Intelligent Field initiatives. The average well production capacity rate in Haradh-III was targeted at 10,000 b/d and a total of 32 smart MRC wells were drilled to provide the targeted production capacity for the entire increment which is about three times less wells than HRDH-I and 36 percent less wells than HRDH-II. Haradh-III stands out as a flagship in the convergence of these technologies at a scale and high degree of complexity for Saudi Aramco and, arguably, for the petroleum industry. It sets the stage, in many respects, for a new era in upstream projects, specifically in the area of real-time reservoir management.

A technology that has provided significant dividends in Haradh-III was real-time geosteering of wells. The essence of this technology is the ability to steer the well as it is being drilled using advanced equipment that transmits real time data from thousands of feet deep to identify the trajectory of the well as well as the reservoir quality. The objective is to place the well in a location to achieve the desired well production rates.

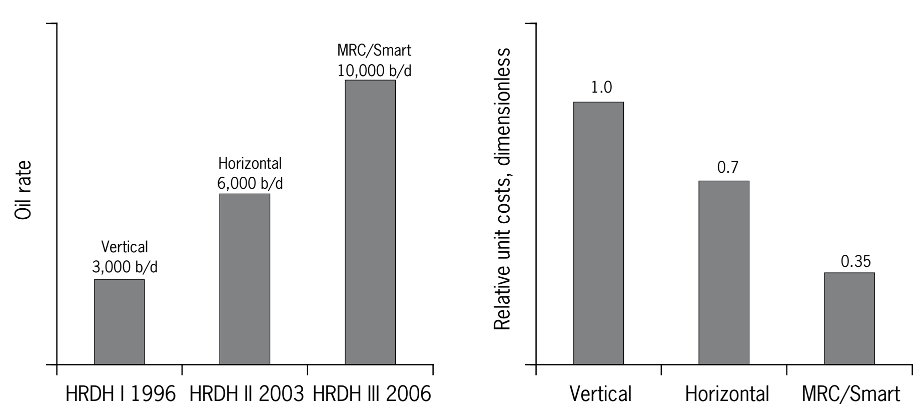
Another technology that played a key role was the Intelligent Field, which was an integral part of real-time reservoir management plans for Haradh-III and Khurais complex. The producers and injectors in addition to dedicated observation wells were heavily instrumented with Permanent Downhole Monitoring System (PDHMS), multiphase flow meters, and remotely controlled chokes for real-time measurement of fluid rates and well control. The surveillance master plan called for a network of wells providing full areal coverage to monitor key reservoir performance attributes continuously. The Intelligent Field was used to monitor reservoir performance during pre-production and production periods, and the data (pressure, temperature, rates, etc.) were transmitted in real-time to headquarters for monitoring, analyses and proactive reservoir management and well control.

The production performance for Haradh-III has been excellent. The field has been meeting its production requirements. The reservoir performance and reservoir pressure behaviour have met or exceeded the planned criteria. Watercut from these fields has been very low and the productivity of the wells has been very high. The use of the cutting-edge technologies described earlier has resulted in production sustainability, managed (low) watercuts, and development cost effectiveness (Figure 1).

Since then, Saudi Aramco has applied these game-changer Intelligent Field technologies to all the new field developments and is retrofitting the older fields to be Intelligent Field compliant. It has given the opportunity to continuously monitor, manage and optimise wells and field performances in real-time.

Advances in technology and leveraging best-in-class reservoir management practices have enabled Saudi Aramco to maximise waterflood oil recovery before deploying more difficult options such as EOR, which will not be needed for a long time. The focus has always been on 'ultimate' oil recovery rather than 'immediate' oil recovery. This commitment to a long-term view

Figure 1: Relative Unit Well Costs and Oil Rates for Haradh-III



Source: A.O. Kaabi, et al. 'Haradh-III: Industry's Largest Field Development', SPE Production and Operations, pp. 444–7, November (2008).

has ensured optimum exploitation of the company's oil resource by keeping the depletion rates low, and improving the secondary oil recovery through sustainable development.

The Future

Some of the reservoir management strategies described earlier are the current state-of-the-art and Saudi Aramco has taken a leadership role in implementing them in the company's large reservoirs. Some specific technology concepts, such as the MRC well construction and smart completions were developed specifically within the company for deployment. The quest to produce the maximum oil from its reservoirs continues and the next frontier is to increase the ultimate oil recovery beyond conventional waterflooding.

> "Technology by itself may not necessarily improve reservoir performance. … the efficient use of technology to improve performance is in the hands of the people who develop and deploy these technologies"

Saudi Aramco, through its upstream arm (EXPEC Advanced Research Center – EXPEC ARC), has invested heavily in R&D and is accelerating the pace in the deployment of new technologies. The focus is on game-changer technologies that will have a long-term impact on reservoir and recovery performance. Some of the new research and technologies on the drawing board include pushing the envelope from intelligent to fully autonomous fields (or the Next Generation intelligent fields), advanced monitoring and surveillance methods, application of nano-technology in reservoir engineering, deep diagnostics with the ability to 'illuminate' the reservoir, and tailored advanced recovery such as Smart Waterflooding.

Intelligent and fully autonomous fields

The fully autonomous fields represent a target for the Intelligent Fields. The vision is to capture real-time data, monitor the fields, facilities and wells remotely, visualise the data, evaluate reservoir and field performance and proactively make the best possible decision. The vision is analogous to an airplane that is on auto-pilot. The pilots will be there but the field will be on 'cruise control'. They can look at all the real-time streaming data flowing into their consoles and steer the reservoir/field towards the best course.

This will involve heavily instrumenting the fields and facilities, placing sensors in individual wells, both at the surface and subsurface, to continuously measure production/injection rates, pressures, temperatures and stream data in real-time. The wells will also have advanced smart completions with downhole remotely activated valves which enable flow optimisation of each lateral in multi-lateral wells. Most elements have been developed and were described earlier. In addition, advanced simulation tools such as Saudi Aramco's GigaPowers reservoir simulator capable of efficiently simulating multi-billion cell models will be a key in realising its vision.

Advanced reservoir monitoring and surveillance

Reservoir monitoring and surveillance (M&S) plays a very important role in understanding the reservoir and improving reservoir performance. The ability to track saturations and fluid movements in the reservoir helps in understanding reservoir characteristics, and in optimising oil sweep efficiency. This information also helps in identifying and minimising bypassed or trapped oil and in intervening with corrective actions. Saudi Aramco has made a concerted effort to improve its M&S capabilities over the years and continues to do so. Some aspects of this emerging research include deep diagnostics using electromagnetics (EM), seismic and gravimetry methods, and the use of in-situ sensing and intervention through nano-technology applications.

Through in-house research and by working with its technology partners Saudi Aramco is expanding the envelope in the area of deep reading, or the ability to use direct measurements in the 100 to 1000+ metres of reservoir space or depth of investigation. The concept of deep diagnostics using electromagnetic or seismic surveys helps in illuminating the reservoir, akin to an MRI or x-ray for the human body. EM and seismic help with better reservoir characterisation, deep measurements of key reservoir properties, fluid front monitoring, and determination of fluid saturations and their changes with time. Significant value is being realised by combining the strengths of both seismic and EM into one unified approach, and focusing on delivering an integrated EM and seismic solution for both borehole and surface measurements. Surface gravity, as well as borehole gravity techniques, is also being explored to add value to this picture, thanks to the recent advances in sensing capabilities. EXPEC ARC is working to develop hyper-sensitive devices to measure gravity accurately in the microgal range.

Another research initiative taken by EXPEC ARC is in the area of nano-technology. The researchers plan to deploy in-situ reservoir nano-agents (RNA) or RESBOTS™ to ultimately monitor reservoir parameters (e.g. temperature, pressure, pH, salinity, saturation, and so on). The first generation RNAs or 'smart tracers', equipped with a sensing/activation mechanism, have been manufactured and are currently being tested. The ultimate goal is to use them for reservoir monitoring and surveillance, in-situ sensing and intervention to improve reservoir performance.

In the framework of Next Generation Intelligent Field developments, the combination of ad-hoc logging surveys, with sensors permanently/semi-permanently installed at the surface and inside borehole completions will likely boost the deployment of gravity, electromagnetic and seismic methods for reservoir mapping and monitoring. The challenge is to integrate these illumination techniques into the reservoir life cycle and to leverage their strengths for reservoir characterisation and production monitoring. The ultimate goal is to increase the recovery factors.

Advanced recovery technologies

Saudi Aramco has primarily focused on waterflooding methods to increase oil recoveries. Currently there are no enhanced oil recovery projects by the traditional definition of EOR. The company has started to look at advanced and fit-for-purpose EOR methods including the impact of water chemistry on recovery. This includes efforts on research and funding for game changing technologies that will make a big difference on recoveries including low cost chemicals, and applications of nanotechnology.

One of the options being considered is the use of 'Smart Waterflooding'. Here the idea is to adjust injected water to an optimised composition (in terms of salinity and ionic composition) into the reservoir instead of any available water that may currently be injected or planned to be injected. Recent research has shown salinity and/or ionic composition can play an important role in oil recovery during waterflooding and may yield significant additional oil recoveries when compared to unoptimised water injection. This option has several advantages compared to EOR including achieving a higher ultimate oil recovery with minimal investment in current operations and infrastructure, it can be applied during the early lifecycle of the reservoir as opposed to EOR, and the payback is faster. Saudi Aramco has initiated a strategic research programme in this area to explore the potential of increasing oil recovery by tuning the injected water properties. Laboratory studies and preliminary field trials have shown a lot of potential.

Saudi Aramco is also conducting research and exploring the potential of other EOR techniques in their carbonate reservoirs. These include the injection of CO_2 and chemicals to maximise ultimate oil recovery. The main objective of planned field pilots and demonstration projects is less for boosting production rates, but to test the feasibility of different methods and acquire field data. Sometime in the future appropriate decisions can be made regarding the implementation of one, or all of these methods to boost the recovery factor and the production rates.

Postscript

Technology by itself may not necessarily improve reservoir performance. Ultimately the efficient use of technology to improve performance is in the hands of the people who develop and deploy these technologies. Petroleum engineers cannot work alone anymore. They must work with researchers, geoscientists, facility engineers, and others to best develop and manage reservoirs. Multidisciplinary asset and functional teams are common and essential in almost every aspect of the upstream value chain.

Robert Skinner assesses the technological challenge of producing heavy oil

Introduction

From the Indus Valley to Mesopotamia, California and northern Canada, natural seeps of degraded petroleum or bitumen have intrigued humans for thousands of years. At some unknown time a value-adding technological breakthrough took place along the Athabasca River in northern Alberta when an aboriginal discovered that if bitumen oozing from the oil sands on the river bank was mixed with the tar or pitch from spruce trees, it made a far superior caulking material for canoes than pitch alone.

As sources of lighter grades of crude oil become depleted and what remains increasingly inaccessible for the international oil industry, its attention has turned to unconventional oil and gas. A decade ago few knew or cared about this sub-sector of the petroleum business. By 2010 according to IHS Herold, unconventional resources accounted for 25 percent of global oil and gas M&A value; US and Canadian unconventional oil and gas deals amounted to $100 billion over the past five years. In 2009 and 2010, 30 to 40 percent of all acquisitions were by Asian NOCs. They seek a position in these vast resources and the technical expertise of the local companies, who have been testing technologies to develop them, but lack sufficient capital to launch major projects. Paradoxically, while unconventional oil and gas have attracted a large share of M&A capital, their contribution to world oil supply is unlikely to exceed 10 percent by 2030. Technological breakthroughs could change this, but it is argued here, this is unlikely.

The Challenge

To produce most forms of unconventional oil and gas we have to either reverse or accelerate geology; this takes significant inputs of energy and other natural resources, materials, manpower and technical ingenuity. For example, to convert the kerogen, the precursor to hydrocarbons, in the extensive, geologically immature shale deposits of south western USA, we must hurry up geology. Similarly to produce the gas and oil that has not migrated out of mature shales requires prodigious quantities of water, chemicals, propants and energy to fracture the shale to increase its permeability. The 4 or 5 trillion barrels of heavy hydrocarbons remaining in Venezuela's Orinoco belt and Alberta's Athabasca oil sands are the degraded residues of what was once together perhaps 10 or more trillion barrels of light crude oil. To reverse this degradation, we have to extract, thermally crack and re-saturate the long chain carbon molecules with hydrogen in a resource-intensive, series of processes that is far from being environmentally benign.

The technology challenge in producing heavy oil is not simply to increase its volume, but most critically, to greatly improve the *efficiency* of its production, to improve unit economics and reduce its environmental footprint. And production is only part of the battle; nobody wants pure bitumen. It must be either upgraded at site or it has to be diluted with lighter hydrocarbons ('diluent') in order to pipe or truck it to refineries with deep conversion capacity. It is a manufacturing, value chain business – pursuing efficiencies in all links of the chain in repeated, incremental phases of production over several decades.

> "To produce most forms of unconventional oil and gas we have to either reverse or accelerate geology"

There are three basic means of producing heavy oil; primary, thermal or chemical. The focus in this note is on the latter two and specifically as applied to the extra heavy oil (<15°API, such as in Venezuela) and bitumen (10 to 8°API) in the oil sands of Canada. In the Orinoco, because the reservoir is hot, the oil can be brought to the surface without stimulation techniques. However recovery rates are less than 10 percent, wasteful from a resource conservation perspective.

The viscosity of oil in the reservoir can be reduced with heat or solvents. Heat can be sourced directly as in a fire-flood, with dry or wet steam, or using electricity – either direct conduction or indirectly by induction. Generally, thermal technologies result in better recovery rates, perhaps as much as 70 percent. However, no in situ technology is ever likely to achieve the recovery factors of mining – more than 95 percent.

Thermal technologies generally rely on horizontal wells to maximise contact with the reservoir. The technology of choice in the Athabasca oil sands region is Steam Assisted Gravity Drainage (SAGD); two horizontal wells 500 to 1000 metres long in the lower part of the reservoir, where the upper well is the injector and the lower the producer. Some variation on this basic well configuration is used for other emerging techniques that rely on solvents such as VAPEX (solvent only in gaseous state), hot liquid solvent and Solvent co-injection (steam and solvent). The obvious challenge in using solvents is to ensure their maximum recovery and recycling as their value is much greater than bitumen's.

Horizontal drilling techniques have made major strides in the last fifteen years and are an enabling technology for heavy oil. Combined with advances in 3-D seismic and Logging While Drilling it is possible to 'see' one's way and drill into optimum reservoir and, in the case of SAGD well pairs, keeping a constant and level distance between injector and producer to avoid hot spots that can destroy very expensive electrical submersible pumps (ESPs).

The technological complexity of the heavy oil value chain means there is great technological upside. Improvements worth a few cents/barrel apply to a widening wedge of future production. Some opportunities include,

- better understanding and 3-D modelling of reservoir geometry,
- down-hole monitoring of steam chamber evolution in combination with 4-D seismic,
- 'wedge wells' (producers placed between well pairs),
- injection of non-condensable gas to utilise reservoir heat once steaming stops,
- ESPs for high temperature, corrosive and abrasive conditions,
- improved efficiency of heat exchangers,
- more reliable water management systems, and
- electricity-based production technologies.

Significant advances have been made by transferring in technologies from other businesses: truck-and-shovel mining to replace draglines, bucket-wheels and conveyor belts; electrical scrubbing techniques used for soil remediation, and potentially, plasma technology currently used to recover valuable noble metals from metal mine waste piles.

Technology as Business Strategy

Technology is always a sub-theme in the business strategies for firms in the oil sands. Every company, big and small, attempts to create a mystique around some 'unique' or 'special', black box or technique in particular or the firm's technological prowess in general (often demonstrated in some other part of the conventional oil business, like the offshore, with little or no relevance to being successful in the oil sands). They do this to attract investors or to placate their environmental critics, or even to convince themselves that this business is for them. Strategies vary depending on company size, capital, business diversity and the quality and size of their resource base. Most technologies being touted as potentially capable of reducing energy intensity (and at the same time reducing carbon emissions) are merely variants on what has already been tested by others over the last several decades with mixed results.

> "Technological change in the heavy oil value chain has been slow"

Natural gas as the fuel for heat is not a long-term option; several promising experiments are being conducted using electricity. An IOC proposes to test electrical, in situ upgrading in the fractured, karsted carbonates beneath the oil sands, estimated by the authorities to have more than 400 billon barrels in place. A small Canadian independent has discovered a rich bitumen zone in the carbonates beneath its oil sands and is testing electrical conduction heating in horizontal wells, referred to as Thermal Assisted Gravity Production (TAGP). Another start-up has had success piloting a thermo-electrical project that takes advantage of the electrical conductivity of the water skin between the bitumen and sand grains. This and electrical induction technology hold promise for developing the billions of barrels of bitumen that are too deep to mine yet too shallow for steam injection technologies.

Old is New Again

Technological change in the heavy oil value chain has been slow. Canadian government scientists began testing techniques to extract the bitumen from the Athabasca oil sands in the late 1800s. The basic caustic soda separation process used today in the mining operations was first demonstrated in 1925 by a government researcher. After two plants were built and burnt, it wasn't until 1967 that the first commercial integrated mining operation started, and is now operating at nearly ten times its original capacity. Most of the technologies for development of the deeper deposits (90 percent of the resource) in the Canadian oil sands and extra heavy oil were dreamt up in the seventies, generally by small companies or in government labs. SAGD, the technology of choice today for the Athabasca oil sands, was conceived over forty years ago, piloted/confirmed by a consortium of companies and governments about twenty years ago and saw its first commercial projects ramp up in the last decade. Of all the schemes for production, only Steam Soak and Flood schemes (for example, in 'lighter' heavy oil of California and Indonesia), Cyclic Steam Stimulation (CSS) and SAGD can be declared convincingly commercial. Solvent Co-injection is planned for at least one SAGD project under construction. It is critical to understand that technologies cannot easily be transferred from one geological formation to another or even within the same formation as geological variability is so extreme between oil sands leases.

There are over sixty oil sands projects announced, before regulators, under construction or operating. If all were to reach capacity as scheduled, total production from the oil sands would exceed 7.7 mmb/d by 2020. In reality, the industry will be hard pressed to reach 3 mmb/d by that date. Of the 17 SAGD projects currently operating, only a couple have achieved or exceeded their design capacity. In the month of September, 2011 Alberta SAGD volumes were 360 kb/d with an annualised utilisation rate of 70 percent (to some extent reflecting several new projects in early ramp-up stage); three CSS ('Huff 'n Puff', piloted more than fifty years ago) operations produced 275 kb/d in the Cold Lake oil sands area.

> "emboldened by the advice of experts from Hollywood, the Obama administration recently 'punted' the decision whether to approve the Keystone XL pipeline until after next year's presidential election"

Any company that claims its technology programme will yield efficiency gains/emissions reductions beyond a modest, few percentage points within ten years – and they have yet to put steel in the ground to test their technologies – is simply naïve or attempting to mislead someone. It can take more than three years just to get regulatory approval, two to build, one to three to ramp up, monitor and measure and perhaps a couple more to analyse – and that is only for a pilot, not a full-scale commercial project: that can take another four to six years to produce initial results. And if the history of piloting is any guide, the analysis often concludes there were insufficient observation wells and measurements of the right parameters to provide conclusive data.

Heavy oil is slow in more ways than in how it flows. The interest in proving up new technologies has waxed and waned with the fluctuation in oil price and the impatience and fickleness of investors.

Patents

The dramatic surge in patents filed towards the end of the last decade for technologies to produce, transport, treat or upgrade bitumen from the oil sands is a proxy for the increasing inaccessibility of developable prospects of conventional oil. Most were for production technologies, one quarter for thermal methods, fewer using solvents, and more than half were filed by large oil and gas companies followed by the service companies. While universities, independent inventors, academics, vendors and service companies do come up with innovative, new technologies or ideas, without oil leases or the financial resources to pilot them, these ideas remain untested. Also, some inventors have unrealistic expectations, demanding royalties measured in dollars per barrel when the operators are measuring successful improvements in pennies per barrel.

Confronted with their business being characterised as 'Dirty Oil', the industry has responded with more than just public relations programmes. A major shift in attitude is seen in their approach to collaboration. Whereas technology development used to be cloaked in secrecy, industry is now collaborating on technologies for use 'above the ground' that can improve efficiency and decrease environmental impacts, while competing below the ground where improving recovery confers a competitive edge.

Technology is not Enough

We hardly need reminding that technological breakthrough alone is not enough to assure a growing future for these enormous but difficult resources. Probably the most benign link in the heavy oil value chain – transportation – has recently become its weakest, if only by perception. Faced with well-organised, unrelenting and impressive opposition by groups who see heavy oil as the marginal source of a commodity the world must stop using, emboldened by the advice of experts from Hollywood, the Obama administration recently 'punted' the decision whether to approve the Keystone XL pipeline until after next year's presidential election; the line would provide access for Canadian bitumen blend to the Gulf Coast refineries. In response, Canada's Prime Minister has declared that Canada's oil will not be held captive to the single US market. This political declaration comes just as the nation's pipeline environmental and energy regulators start the public review of a proposed pipeline to Canada's west coast, aimed at Asian markets; already a record 4000 participants have registered to be heard.

Franz B. Ehrhardt discusses global refining – game changing trends, response strategies, and the role of technology

The petroleum refining industry has never been without substantial challenges, and it is appropriate from time to time to review the latest trends and challenges that will impact the industry.

This article will address from a strategic impact point of view two of several prevailing and emerging trends that are of adequate significance to be considered game changers, and to review how technology can and will play a role in addressing effectively the related issues.

In general, it can be safely assumed that revolutionary technology changes in fundamental thermal and hydro-treating processes in petroleum refining are not likely to emerge as game changers. All of these core processes have reached a very high level of maturity and sophistication, and improvements are more likely to emerge at the evolutionary level. The most significant and innovative refining-related improvements can be expected in the catalyst chemistry and application.

The degree of application of the many well-proven technologies, processes, and concepts, however, will change significantly as a result of several factors. These include the ever increasing share of more difficult-to-process crude oils, like heavy and extra-heavy higher sulphur, higher metals, more acidic, etc. crude oils, as well as the environmental factors of global warming and CO_2 emissions, the need for more efficient fuels, the 'aging' and the 'rust factor' of many refineries that have been in existence for fifty and more years. Also important is the shift of actual petroleum processing from consumer countries to crude oil-producing countries, and countries that promote, support, and facilitate the construction of mostly export oriented new mega-size refining industries.

The two game changers to be discussed here are the continuous increase in the production of extra heavy high sulphur crude oil and the construction of more and more mega-size, high conversion, high complexity refineries.

Significant Increase in the Share of Extra Heavy Sour Crude Oil

It is a well known fact that over time the production of heavy-sour crude oil has taken an ever increasing share of all crude produced, a trend that most certainly will continue. While a number of new reserve finds contain light sweet crudes, the presently known reserves of (extra) heavy crude oil are slightly over twice that of light crude oil. Actually, as per the most recent Annual Statistical Bulletin of OPEC, Venezuela just surpassed Saudi Arabia as the country with the largest crude oil reserves in the world, most of it being of the (extra) heavy sour grade. Canada also weighs in at a top position with the heavy grade crude oil reserves from Oil Sands.

The added challenge beyond the heavy grade is the higher sulphur content which is considered 'sour' at and above 1 percent.

Traditional refineries have been designed and built to process the light sweet crude oil that in the past was abundantly available (and much easier to extract than heavy crude). The metallurgy of the processing units and pipes in those refineries is inadequate to handle sour crude oil and they will rapidly corrode and suffer fundamental damage if exposed to crude oil with the much higher sulphur content. Therefore, the world's refining industry in general is long in sweet crude and short in sour crude capacity.

The technology and the know-how to convert refineries to heavy sour crude processing capability have been readily available for quite some time. Thus, the determining factors for a process upgrade are really outside the actual technology and processes, and are driven by economic and financial considerations. Beyond that, even if all components are favourable, to obtain the essential permits for the upgrades faces tremendous hurdles in most developed countries mainly due to government red tape and especially environmental concerns … whether justified or not!

"Traditional refineries have been designed and built to process the light sweet crude oil that in the past was abundantly available"

Another (extra) heavy crude oil processing challenge for refiners is the fact that such crude oil in the first thermal separation process step, the distillation, generates a much larger percentage of heavy ends or residual products (resids), products that usually are turned into asphalt, Bunker C, or other heavy fuel products.

Historically, there has always been a surplus of these 'heavy end' products, which, naturally, caused a very distressed price level that in reality did not even pay for the cost of the crude feed. The increasing share of the 'heavy end' products caused by processing more and heavier crude oil, contributes further to a deterioration of the processing economics of heavy crude oil. The major benefactor of this situation, however, has been mainly the global shipping industry through the plentiful availability of very low-cost Bunker C fuel.

On the other hand, this challenging situation for the refiners can be resolved with a very attractive technology – the Delayed Coking Process. In this process the heavy ends, the residual fuel, is 'baked' under high pressure and high temperatures in a coke drum. The results are, depending on the coking technology and process actually used, liquids of 40–50 percent in the range of C5 and up, and petroleum coke (pure carbon) for the balance.

"The technology and the know-how to convert refineries to heavy sour crude processing capability have been readily available for quite some time"

Further hydro-treating and desulphurisation produce diesel products that provide a rather attractive value upgrade over the feedstock. The petroleum coke can be used as a feed for power plants, for cement kilns, and select further upgrades. For example, Conoco uses petroleum coke to feed a fluid bed combustion power plant at their Lake Charles refinery, a technique that now has much wider applications.

Refiners who have installed both heavy sour crude oil processing capability and substantial bottoms-upgrading capacity like hydro-crackers and especially delayed cokers are currently enjoying, and will for quite some time to come, a significant competitive advantage through very favourable incremental earnings. For example, the heavy sour processing and delayed coking pioneer among the independent refiners, Valero of the USA, has reported that their investment of $350 MM for their Texas City Coker contributed about $200 MM in 2004 alone, suggesting a pay-back period of less than two years. Many existing refineries have added delayed cokers and many new refineries incorporate them in their basic design.

New high Complexity, high Conversion Mega-size Export Refineries outside Traditional high Demand Countries

The traditional oil industry strategy has always favoured the construction of refineries in or near high finished product demand locations. This concept was primarily based on the fact that the transportation cost of crude oil to a refinery location in high demand countries was considerably lower than that of finished products to be transported from the refinery to the end-user.

Several factors have, however, initiated a trend to build mega-size, high complexity, high flexibility export refineries in crude oil-producing countries, i.e. Saudi Arabia, Kuwait, and so on, as well as in countries that actually permit, and even encourage, the construction of new refineries providing an attractive business model for strict business ventures by industry newcomers like Reliance and Essar in India.

These developments are unquestionably encouraged by the impossibility of securing the essential (mainly environmental) permits in the USA, Europe, and other developed countries. For example, the last new refinery in the USA was built 35 years ago. If I recall correctly, the last new refineries in Western Europe were built in the UK in 1968 and in 1975 in Germany. In general significant capacity expansions at existing refineries do not materialise either, due to the same permit and bureaucracy challenges.

The inability to expand the capacity to an economically viable and competitive size and to increase conversion capabilities of older and relatively small size refineries in the high-demand countries, rather effectively renders the profitability of those refineries unacceptable, especially when they try to compete with the favourable incremental economics of the new mega refineries. This situation has resulted in the disposal of many older and smaller to mid-size refineries by the major oil companies, mainly in Europe and in the USA.

Established Independent Refiners, like Valero in the USA, and independent newcomers to the industry, like Petroplus in Europe, have acquired – and will likely continue to acquire – most of those refineries and convert them to a business model of becoming economically viable through more cost-efficient operation and considerably lower O&O expenses.

The challenges to this business model, however, will be the longer-term investment needed to modernise the facilities with existing technologies and processes to remain competitive with the finished products imported from the before-mentioned mega refineries. Furthermore, the environmental challenges and the usual government red tape are likely to stall any upgrading attempt by these independent operators in the same way that they blocked the previous owners, the major oil companies, from that avenue.

Conversely, for the crude oil-producing nations (i.e. OPEC), the construction of mega refineries on their soil, and with the support of a highly facilitating government, not only provides local employment and a significant value upgrade for the crude oil stream over the net export price, it also voids the need to count the processed crude oil against their respective (OPEC) export quota, thus permitting a higher level of crude oil production.

The pure size of these mega refineries will provide highly attractive incremental economics that are further enhanced by incorporating the latest conversion and upgrading technologies into the design, including technologies that will enable the flexibility to shift the individual fuel production among products following prevailing market price swings. This combination provides these mega refineries with significant sustainable competitive advantages that will be very challenging to overcome by the remainder of the refining industry.

It is easily conceivable that the traditional international major oil companies have detected this trend on the radar screen and that, for instance, Marathon and Conoco have made it a factor in their decision to split Downstream from Upstream into separate companies, anticipating a return to the decades of dismal financial returns from the refining and marketing business. Otherwise, one can also ask why the previously highly touted strategic benefit of full integration was ditched by these companies!

"to stay competitive, the refining industry has to rethink its prevailing business model and generate innovative applications of existing technology"

It is also very interesting to note that with the 'downsizing' over the last two decades, the international oil majors have 'outsourced' most of the refining research and development, which together with the resulting new technologies is now in the hands of independent service companies that are only too happy to provide their services directly to the new mega refinery clientele – so rendering obsolete their need to partner with international oil companies for refining ventures.

One more comment regarding the sustainable competitive advantage of a high level of conversion and flexibility capability in the design of the latest mega refineries – while a few years ago in the second edition of the book *Petroleum Refinery Process Economics* (2000), author Robert Maples noted that US refineries rank highest in the Nelson Complexity Index, averaging 9.5, compared with Europe's at 6.5, at present, the Reliance mega refinery in India has a 14.0 index (now the highest in the world) and Essar is expected to have a 12.8 rating after completion of the present upgrade.

There is little doubt that to stay competitive, the refining industry has to rethink its prevailing business model and generate innovative applications of existing technology, processes, and know-how to compete effectively with these benchmark performers.

Conclusion

There are adequate and economically attractive technologies and processes available, especially delayed coking, to absorb and manage the increasing level of heavier and sour crude oil supplies.

While there is unquestionably a need for refineries in the high demand locations, the NIMBY (Not In My Back Yard) factor will continue to prevent such developments and hand the financial value upgrade and job opportunities to entities and countries outside Europe and the USA.

The new mega export refineries will be able to supply global markets with the full range of products that meet the most stringent specifications at prices that will severely challenge the economic viability of a large number of refineries, forcing more and more shut downs.

Until a highly innovative and revolutionary refining process like chemical hydro-carbon separation and chain manipulation at ambient temperatures is invented, the presently known and applied thermal technologies and processes can master quite capably the most challenging tasks in refining with the assistance of continually advanced catalysts.

Tara Shirvani and Oliver R. Inderwildi provide a futuristic view of gas-to-liquid technology

The search for alternative fuels is relentlessly under way with 90 percent of transport fuels being oil-derived and uncertainty around depletion levels of conventional oil reserves mounting. Global vehicle ownership is forecast to reach two billion in the near future and climate change concerns, induced by anthropogenic greenhouse gas (GHG) emissions, expected to rise. The central challenge involves the transformation of our oil dependent transport industry, as we face the so-called input problem of dwindling conventional crude oil reserves as well as the so-called output problem of increasing GHG emissions. Liquid fuels derived from gas, coal or unconventional oil sources may be able to offset the input problem of diminishing oil supplies, but will inevitably exacerbate the output problem of rising GHG emissions. Biofuels can be a viable substitute for fossil fuels, most notably when produced in a sustainable manner and from feedstock that is not in direct competition with food or animal feed. The transition towards advanced biofuels may contribute towards a low carbon, sustainable fuel mix, but is unlikely to be sufficient to meet the current energy demand of our global transport system. Recently, the interest in synthetic fuel production from unconventional resources has been revived through the rise in crude oil prices. Global production from unconventional sources has been projected to increase by 2030 to 7.4 million barrels per day or 10 percent of global conventional oil supply. The industry's expectation illustrates that there are other factors at play aside from the rise in global petrol prices, which will facilitate the rapid introduction of synthetic fuels into the market.

Historically, in 1942 Germany avoided the fatal economic damages of a long-lasting oil embargo and a prolonged war by deriving almost 90 percent of its total energy consumption from coal-based Fischer-Tropsch (FT) fuel production. Similarly, the Apartheid regime in South Africa was responding to an oil boycott in 1950 by using their vast coal reserves to produce liquid fuels and meet their domestic transport fuel demand. Even today, the South African energy industry still obtains 30 percent of its road transport fuels from indigenous coal reserves.

The search for alternative fuels is relentlessly under way with 90 percent of transport fuels being oil-derived

Synthetic fuels, made from natural gas are referred to as gas-to-liquid (GtL) fuels. Analogously fuels manufactured from biomass or from coal are referred to as biomass-to-liquid (BtL) and coal-to-liquid (CtL), respectively. Through a fuel conversion process which includes FT technology, natural gas is converted into longer chain hydrocarbons which can be refined to yield gasoline, kerosene or diesel. In the first step, sulphur components and other impurities are removed from the methane-rich natural gas feedstock, which is later cooled down to separate methane from other hydrocarbons. Through a catalytic partial oxidation or steam reforming process, methane is reacted with oxygen to produce a mixture of carbon dioxide (CO_2), carbon monoxide (CO), hydrogen (H_2) and water (H_2O). In the second stage, the gaseous mixture of H_2 and CO is fed into the FT reactor which yields long-chain, waxy hydrocarbons and considerable volumes of water as by-product. In the presence of zeolite catalysts and hydrogen the waxy hydrocarbons are catalytically cracked into shorter hydrocarbons as part of the final upgrading phase. The synthetic crude is then distilled into a variety of fuel products ranging from kerosene to diesel, oils and naphtha.

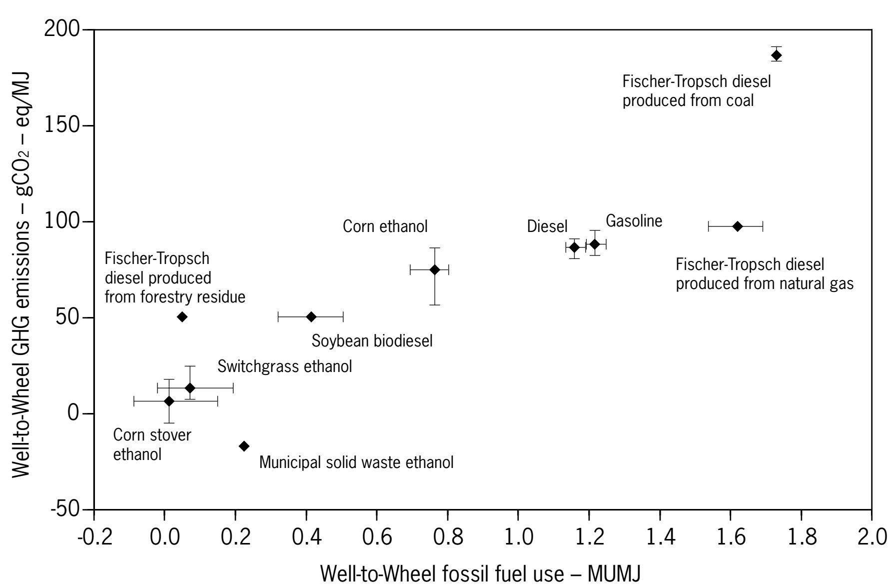
Overall, the GtL production process is estimated to produce 75 percent middle distillates and 25 percent non-fuel chemical products.

Due to in part the success of the synthetic fuel production process, FT-diesel is considered to be a strong technical candidate for the substitution of conventional diesel. FT-fuel products have received considerable attention for their favourable characteristics for use in compression ignition engines as for instance the Diesel. These high quality fuels benefit from superior autoignition characteristics and can replace conventional fuels at any ratio (0 to 100 percent) as they are fully miscible. The energy density is comparable to conventional diesel, which qualifies them for use in unmodified diesel engines. Experimental studies have further shown that the thermal efficiency of diesel engines is improved when GtL blends are used. In addition, GtL fuel properties are also environmentally advantageous, outlining a high cetane number of 75, virtually zero sulphur and aromatic hydrocarbon content. As a result, combustion of GtL fuels yields 12 percent less nitrogen oxide (NOx) and 30 percent less particulate matter (PM) emissions making them superior fuels especially in urban environments.

GtL fuel products therefore may help to address energy security concerns and drastically improve local air pollution levels, but are by no means considered environmentally friendly fuels. In comparison to conventional petroleum-derived diesel, GtL fuel products result in increased GHG emissions over their lifecycle, see Figure 1.

This is partly due to the high energy requirements of the FT process and the conversion of a hydrocarbon feedstock such as methane which leads to significant CO_2 emissions during the production stage. On average the carbon footprint of GtL-fuels is 10 percent higher than that of conventional fossil fuels. However, compared to synthetic fuels from other unconventional resources such as coal or oil shale, Gtl fuels highlight a lower carbon footprint (see Figure1). Nevertheless, with a global consumption of liquid transport fuels in 2009 resulting in 11.3 billion metric tons of CO_2, substituting 50 percent of this conventional fuel supply with GtL fuel products would have increased emissions by 0.5 billion metric tons of CO_2. The fuel synthesis process may not even be economically feasible

Figure1: Life cycle Fossil Fuel Use and GHG Emissions per MJ Fuel for Biofuels and Synthetic fuels in the USA



Source: X. Yan, O. R. Inderwildi and D. A. King, *Energy & Environmental Science*, **3**, 190–7.

when carbon capture and storage (CCS) facilities are considered, since the improved environmental balance will result in lower efficiency levels and reduced energy gains.

> "On average the carbon footprint of GtL-fuels is 10 percent higher than that of conventional fossil fuels"

When it comes to the availability of natural gas reserves required to satisfy the rise in liquid fuel demand, fuel consumption is not expected to be limited by a resource constraint per se. Geographically, natural gas reserves are disproportionately distributed globally, with three countries, Iran, Qatar and Russia holding more than 50 percent of global conventional reserves. In particular, the North-Dome-South-Pars complex within the Persian Gulf accounts on its own for 50 thousand cubic metres (tcm) of natural gas, an amount that equals 23 percent of proven natural gas reserves. The IEA estimates the remaining volume of recoverable natural gas reserves at 405 tcm. With a projected rise in annual natural gas demand around 71 to 77 tcm p.a. by 2030 and the current level of technology, a surplus reserve of 333 to 327 tcm of conventional gas resources can be estimated. The additional on-line capacity could be used to produce more than 1 trillion barrels of GtL syncrude and Liquefied Petroleum Gas (LPG) products which would be enough to replace the demand for crude oil with syncrude for the next two decades. However, the geopolitical turmoil within most of the producing nations, the exorbitant capital requirements for the development of GtL production plants and the significant lead-times for additional on-stream capacity, prevent GtL fuels from being produced on a sufficiently large scale. Currently, global GtL production capacity is limited to 151,500 barrels a day (b/d), a volume that merely replaces 0.2 percent of global transport fuel demand. In-house research at the Smith School of Enterprise and the Environment, at Oxford University, estimates that under a high oil price scenario the share of global GtL fuel products will increase to 1.2 million b/d by 2030. Compared to the projected increase in global fuel demand to 107 million b/d by 2030, the share of GtL fuels will remain marginally low at a maximum of 1.14 percent of global crude demand.

Availability of large volumes of low-priced and stranded natural gas feedstock is critical to the economics of GTL plants. We refer to stranded gas as cheap gas that is uneconomic to develop due to transport distances or lack of infrastructure. Feedstock costs may not remain low enough to make GTL economically attractive in the mid-term future. Another option for the monetisation of stranded gas would be liquefied natural gas (LNG) production for which the cost of LNG liquefaction terminals is declining and demand from South East Asia is increasing. This trend will increase the opportunity costs of stranded gas and negatively influence the economic viability of GTL plants. At present, assuming an average natural gas price of $180/tcm, GtL fuel products would enter the market at a corresponding oil price of 70 $/b, see Table 1.

Table 1: Market Entrance Crude Oil Prices for Liquid Fuel Production from Different Resources

Resources	*Market entrance oil price ($/barrel)*
Tar sands	38
Extra-heavy oil	30
Oil shale	70 (short run) 30 (long run)
CTL	86
GTL	70
Corn ethanol	40

GtL fuels are economically unfeasible when prices are below 40 $/b. This figure would be higher, where carbon-intensive energy sources are used throughout the production process and a high carbon tax is applied. Even, under a high oil price scenario of 120 $/b combined with a low carbon tax, natural gas prices would only have to reach $15/thousand cubic feet for GtL fuel products to become economically unfeasible compared to petroleum-based fuels.

To conclude, GtL fuels are high quality fuel products which are virtually zero in sulphur and aromatics and consequently emit significantly less local pollutants. The supply of GtL fuels in urban areas can therefore drastically improve local air quality. However, given the energy-intensive nature of the FT fuel production process and the use of a fossil energy source, the transition from petroleum-based fuels to synthetic fuels from natural gas would lead to a considerable rise in GHG emissions from transport. As part of a larger mission to diversify the source of transport fuels, GtL technology will need to complement our current fuel mix alongside unconventional fuel supplies from tar sands as well as biofuels. GtL fuel production may not be limited by feedstock availability and could theoretically mitigate future oil supply shocks; however, due to significant lead times for additional capacity of GtL fuels and the high upfront investment needed, it is unlikely that a substantial volume will go on-line in time to absorb future oil supply shocks. Analysis of earlier studies on the economics of GtL plants leads us to the conclusion that when large stranded gas reserves and cheap gas are available, GtL is profitable and allows international oil companies a certain degree of independence from OPEC oil. These endeavours are consequently part of a larger strategy that would allow energy companies to strengthen their supply security and be more independent from national energy security undertakings.

Asinus Muses

Caveat lector

Having been elevated from the pack to become a commentator on global affairs, Asinus no longer considers himself a mere beast of burden. Yet as he writes these words he has a small infant strapped to him, directing his movements no less rigorously than the sternest of pack drivers. Unlike the honest reward one expects after a day's menial labour, however, baby boot camp allows no more than three hours of sleep at a time.

Late-night tantrums

Asinus's ongoing sleeplessness gives him a new insight into the antics of our politicians in their late-night negotiations. David Cameron's dramatic wielding of the UK veto to prevent the use of EU institutions in Germany's proposed fiscal union was probably a low point of mutual understanding and sympathy, and many think it has left the UK isolated. But Asinus has himself recently had reason to wish he had such a veto, and not just another nursery rhyme, to wield at four in the morning.

Save the tree frog

The most impressive feat of diplomacy observed by Asinus recently was performed by Ecuador. Beneath its Yasuní national park, part of the Amazon rainforest, lie an estimated 900m barrels of oil, worth US$7.6bn in revenues to the Ecuadorean government. Yet the park is also home to two still-uncontacted indigenous tribes and possibly more varieties of flora and fauna than any other place on Earth. Noting that these natural wonders are probably worth more to the rich world than to Ecuadoreans themselves, the government decided to offer the world the chance to buy out its oil option at a bargain half price. For a mere US$3.8bn, it declared itself willing to leave the oil in the ground and spare the precious biodiversity. One study presented the scheme as a radical new way to 'leverage' hydrocarbons to protect the environment. To Asinus the oil looks not so much like a lever as a gun held to the head of a hostage – 'pay up or the tree frog gets it.' But this is too cynical even for Asinus. Since most countries have paid no attention whatever to the biodiversity destroyed by their extractive industries, Ecuador can hardly be criticised for offering an alternative. Indeed, the economics are impeccable: a global public good like biodiversity should be paid for globally. And pay up they have, or at least partially: so far US$116m has been raised from various friendly governments plus an array of celebs including Leonardo DiCaprio, Edward Norton and Al Gore. The Belgian region of Wallonia paid US$2m, worth mentioning more for the comic value of its name than any substantive reason.

What goes up might stay there

While the tree frogs will be happy, those of us languishing from high energy prices have less reason to celebrate oil staying in the ground. Those prices are particularly upsetting when incomes are remaining flat and people are continuing to lose their jobs, as witnessed throughout the non-recovery of 2011. The raised cost of energy imports contributed to our inflationary misery, compounded by the depreciation of the pound in your pocket. But Asinus hastens to point out that much of our shocking 5.2% inflation was due to the government's decision, in its infinitesimal wisdom, to increase most prices by 2.5% with its VAT rise. Yet voices clamouring for a rise in interest rates to slow that inflation, despite the UK economy idling far below potential output, were always suffering from a failure to understand the differential calculus: *remaining high* is different from *continuing to rise*. While global economic gloom suggests further oil price rises are unlikely, those of us who watch these prices are necessarily Socratic: we know that the one thing we know about energy prices is that we don't know what they will be in a year's time.

Dire straits

Apropos of which, sabre rattling by Iran in response to threatened sanctions have been spooking the oil market lately. While most analysts are somewhat sceptical of the vice-president's promise that 'If they impose sanctions on Iran's oil exports, then not even one drop of oil can flow through the Strait of Hormuz,' it usually pays to be nervous. An important reason for scepticism is the fact that neither the vice-president nor the president himself has the power in Iran to initiate hostilities. Apparently it is only the Supreme Leader and his ironically-titled Revolutionary Guard that have that honour. Further confusion is sown, at least in Asinus's mind, by the fact that Iran's chief nuclear negotiator, Saeed Jalili, recently announced that 'We formally declared to them to return to the path of dialogue for cooperation.' The country's bafflingly complex political system is a model of the division of powers. It brings to mind an observation once made by Newt Gingrich of the United States government: that their founding fathers deliberately created a system so inefficient that no dictator would ever be able to bend it to his will.

Happy New Year

According to the FT, US$6.3 trillion was wiped off the value of global stock markets in 2011. Since some market participants recorded healthy profits, the question, as so often, is: who was left holding the baby? In Asinus's household, there is little doubt.

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