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Dr. R.K. Malhotra
Director General, FIPI
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CONTENTS

In This Issue

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From the Desk of the

Director General

Greetings from the Federation of Indian Petroleum Industry (FIPI)!

Dear Members,

What a year it has been. This time in 2019, we had no idea what 2020 held in store for us. Today, we are on the verge of closing the year, but not without a lot of scars, pain, frustration, and pure exhaustion. I sincerely hope that the year 2020, while holding you in the confines of your home, provided the opportunity to spend time with your loved ones at home and reconnect with old friends though virtually. In an otherwise fast paced life, 2020 also gave us the opportunity to learn the new ways of working which eventually may be the new norms.

The global economy went through unprecedented turmoil in 2020. From the very start of the year there were serious apprehensions about the already ailing global economy due to the slowdown reported in many regions and the trade war between the US and China. In March, the COVID-19 virus hit the global economy like a tsunami. The COVID inflicted lockdowns and travel bans brought all economic activities to a standstill and left all major economies gasping for air. While the global economy has recovered to an extent, since the horrors of the second quarter 2020, on conclusion of Q3, 2020, all major economies, barring China, are still struggling to fully recover from the impact of the pandemic. Consequentially, the global economy is set to contract by 4.4 per cent this year. While most economists are optimistic about a strong recovery in 2021, a lot will depend on how well respective countries manage the spread of the virus and the effectiveness of their vaccination programme. The resurgence of the virus in some parts of Europe and the US has again raised serious concerns and forced the Governments to implement some form of lockdowns and restrictions. As the year approaches an end, the COVID-19 pandemic has already claimed over 1 million lives, placing unprecedented pressure on medical services and healthcare systems.

The global oil industry has been among the worst affected sectors due to the spread of the pandemic. In March, subsequent to a fall out in OPEC + over production cuts, oversupply in the market resulted in sharp fall in oil prices. The oversupply situation further worsened in April due to the widely implemented lockdowns, resulting in an unavailability of storage facilities for the over supplied crude. In a historic first, on April 21, the WTI prices crossed over to the negative territory and reached as low as - USD 36/Bbl. However, the oil prices have made a remarkably swift recovery since then. At the end of the year, oil prices have surpassed the USD 50/Bbl mark. The recovery in prices was driven by OPEC + decision to cut production by 9.7 Mbpd, almost 10 per cent of the global supply. The continued rise in the prices was also seconded by the rising consumption in the second half of the year as all major economies started opening up after lockdowns. The transport sector that accounts for almost two third of the

global oil consumption was among the worst hit due to the pandemic. The collapse of aviation sector due to the grounding of airline services is set to leave a lasting scar. The weakness in demand from the aviation sector is expected to continue well beyond 2021.

In the Indian upstream sector, fifth round of OALP was conducted in the month of October. The 11 blocks under this round are spread across eight sedimentary basins and include eight on-land blocks (six in Category I basin and one each in Category II and III basins), two shallow-water blocks (one each in Category I and II basins), and one ultra-deepwater block (Category I basin). The current round seeks investments in approximately 19,800 Sq Kms located in Western Offshore (Saurashtra & Mumbai) & Eastern Offshore (Cauvery) and also spread across the states of Rajasthan, Gujarat, West Bengal, Odisha, Arunachal Pradesh and Assam over eight sedimentary basins. ONGC & Oil India won 7 & 4 blocks respectively. On 18 December, Reliance Industries and BP Plc started production from the R-cluster, ultra-deep-water gas field in block KG D6 off the east coast of India on 18th of December. RIL and BP are developing three deepwater gas projects in block KG D6 - R-cluster, Satellites cluster and MJ – which together are expected to meet around 15 per cent of India's gas demand by 2023. On 20 December, ONGC opened India's eighth hydrocarbon producing basin when it started oil flow from a well Asokenagar-1 in 24 Pargana district of West Bengal.

Taking a stride towards the vision of gas based economy, the cabinet committee on Economic affairs, chaired by the Hon'ble Prime Minister has approved 'Natural Gas Marketing Reforms'. The reforms envisage to provide a reasonable pricing mechanism to the domestically produced natural gas through a transparent and competitive gas bidding. In a long awaited reform, the Petroleum and Natural Gas Regulatory Board (PNGRB) has now simplified the country's gas pipeline tariff structure to make the fuel more affordable for distant users and to attract investment for building gas infrastructure. The new unified tariffs will be applicable based on two zone structure related to distance from source of gas. Providing a fillip to the Government's efforts to increase the share of natural gas in the primary energy mix, Shri Dharmendra Pradhan, Minister of Petroleum & Natural Gas and Steel has laid the foundation stone for the first 50 LNG fueling stations, across the golden quadrilateral and major National Highways. In India's quest to promote Hydrogen as a clean fuel for the mobility sector, the hon'ble Minister also launched trial run of Delhi's buses on Hydrogen-blended CNG (HCNG) at the Rajghat Bus Depot-I of DTC.

The demand for petroleum products in the country dropped by 0.12 per cent in December compared to last year. The fall in December came after showing a strong demand recovery in November. Despite the complete or partial lockdowns, in the first nine months of FY 20-21, the overall demand for petroleum products rose by 1.8 per cent. The demand for diesel fell 0.70 per cent in December to 7.3 MMT as compared to 7.38 MMT in 2019. Overall, in the first nine months of the financial year, diesel demand rose 0.76 per cent to 62.7 MMT. Demand for gasoline increased by 3.21 per cent to 2.5 MMT in December and 8.42 per cent to 22.85 MMT in the April-December 2019 period. Demand for bitumen, an indicator of road construction activity, declined by 8.40 per cent 567 TMT in December but remained flat in the first nine months of the current financial year. Demand for Liquefied Petroleum Gas (LPG) and Aviation Turbine Fuel (ATF) increased 9 per cent and 2 per cent, respectively, during the month.

FIPI joined hands with BP India to organize BP Energy Outlook – 2020 on 19 October, 2020. Due to the ongoing COVID-19 pandemic, this year the outlook was unveiled on a virtual platform, allowing a much broader participation from across the energy industry in India. The session proved extremely successful. Especially Mr Dale's presentation triggered a very fruitful Q&A session and brought out some deep insights about the global and the Indian energy sector. The session witnessed an overwhelming participation from more than 200 industry experts, academia, Ministry officials and industry members.

During this year, FIPI alongside IHS Markit organized the fourth India Energy Forum. Inaugurating the Three day conference, the Hon'ble Prime Minister of India, Shri Narendra Modi

underlined that in spite of various challenges like fall in energy demand by a third, prevailing price instability, impacted investment decisions, projected contraction in global energy demand over the next few years, India was projected to emerge as a leading energy consumer and is projected to nearly double its energy consumption over the long term. The Forum was organized over a virtual platform and was attended by Shri Dharmendra Pradhan, Minister of Petroleum and Natural Gas and Mines; Hon Smt Nirmala Sitharaman, Minister of Finance and Corporate Affairs; Shri Piyush Goyal, Minister of Railways and Commerce & Industry; Mr Rajiv Kumar, Vice Chairman, NITI Aayog; Mr Sanusi Barkindo, Secretary General, Organization of Petroleum Exporting Countries (OPEC); HRH Prince Abdul Aziz Bin Salman, Minister of Energy, Kingdom of Saudi Arabia; and Hon. Dan Brouillette, Secretary of Energy, US DoE among other dignitaries and representatives of global energy industry.

FIPI had earlier in 2017, organized a workshop on 'EOR – Expanding Horizons: Creating Value'. The workshop initiated a constructive discussion on the requirement for advanced EOR/IOR to augment production from aging fields in the country. Consequently, the Government of India introduced the EOR/IOR policy in 2018 that proved to be a game changer for the sector. On 11 December 2020, on demand from the Ministry and the industry, FIPI organized edition of its EOR/IOR workshop. The workshop proved extremely helpful in bringing forth some of the international best practices alongside key recommendations to further fine tune the existing EOR/IOR policy. The workshop was attended by representatives from the University of Calgary alongside key officials from the Ministry and Indian oil and gas industry.

The Way Forward

The year 2020 has proved to be a very difficult year for the oil and gas industry globally and India has not been an exception. However, the oil and gas industry in India has shown remarkable resilience in picking itself up from the lows seen in April and May to close the year on a high note.

For the Indian oil and gas industry, the year 2021 will also present significant challenges alongside the wide horizon of opportunities. The scars of the COVID-19 pandemic are expected to pinch the industry for some time to come. As the world embraces the post-COVID new normal, the Indian oil and gas industry will also have to prepare for a highly digitized low carbon future. Over the last few years, the progressive new policies of the Government and interventions in the sector have set the stage for a fast-paced growth of the industry. Going forward, we firmly believe that inclusion of key petroleum products under GST; complete marketing and pricing freedom for natural gas; further liberalization of fuel retailing policy; and creation of a robust natural gas market in the country will continue to require support from the Government.

As we step into the new year, the country has left behind the horrors of 2020 and is extremely optimistic about the opportunities that the new year will present. With the Government of India now set to roll out the vaccination programme from January 2020, the mood in the country is exuberant with the expectation of life soon returning to normal. In the new year, we hope that India will place itself on a path to rapid recovery and subsequently to achieve the much coveted double-digit growth rate. Under such circumstances, it will not only be the responsibility but also an opportunity for growth of the Indian oil and gas industry while catering to the ever-growing energy needs of this country.

At the cusp of this new year, I assure you that FIPI will be at the forefront advocating for the industry issues and scripting the growth story of Indian oil and gas industry.

Wishing you a very happy, prosperous and safe new year.

Dr. R. K. Malhotra

Sustainability, Growth and Technology

Ron Beck
Marketing Strategy Director

Aspen Technology Inc.

Energy underpins economic and social progress, as well as the empowerment of individuals to move into the middle class. How can companies to do this while protecting the world's climate, clean water and air, and biodiversity? The region's energy, chemicals and metals producers are at the nexus of these questions. Technology is the silver bullet.

Sustainability is forcing rapid changes in strategy and thinking among energy and chemical companies worldwide. There are regional nuances to the way companies are responding to this challenge, attributable to regional government and societal pressure, but at its core is a global movement for change, since international financial markets are punishing those companies that do less than what is expected.

Sustainability presents a difficult set of challenges for areas, such as business strategy, financial, and technical. Within this framework, the EIA forecasts global energy demand to grow by close to 50% between 2020 and 2050. This will continue to drive the need for energy. Of course, the question is which energy sources. And therefore the "energy transition" as the sustainability movement drives the globe towards "greener" energy sources. The challenge, of course, is the formidable reality of global energy mathematics. The numbers are so high, that no matter the rate of adoption of renewable energy sources, hydrocarbons will remain a crucial element of the world energy picture for at least the next several decades.

The extent of this complexity requires balancing the many objectives across a company's assets, and a data-based and quantitative approach. Digitalization and Industrial AI (artificial intelligence) will be crucial tools in this balancing act.

Financial Pressures

Perhaps the most visible financial influences originated from JPMorgan Chase, who have announced several initiatives around sustainable investing metrics. JPMorgan Chase committed in February of 2020 that they would make a $200 billion commitment to direct investments toward companies supporting the UN's sustainable development goals (SDG) and specifically $50 billion towards green investments. JP Morgan Asset Management has put teeth behind that, establishing a proprietary ESG scoring framing, to rate companies and proposed investments. And they have become more directly engaged by announcing an Energy Transition Team, to advise energy companies on energy transitions strategies. Other financial institutions, globally, will most likely follow suit.

(1 https://www.jpmorganchase.com/news-stories/jpmorgan-chase-expands-commitment-to-low-carbon-economy-and-clean-energy)

India's Regional Challenges

India and Southeast Asia have some challenges and opportunities distinct from other regions. First, projected GDP growth rates will be higher in India, SE Asia, and China, than in other regions. Several forecasts (for example, from International Energy Agency or EIA and IHS Markit) show that with the growth of middle class and GDP in these regions through 2030 and beyond, power and energy needs will grow, even as growth rates narrow in Japan, Korea, Europe and North America. Within South and Southeast Asia regions, universal access to electricity and clean water are still high priorities. India faces a more severe near- and long-term shortage of drinking water than most other regions.

Crucial drivers in India include reducing carbon intensity of operations, reducing water use (while increasing water recycling), and reducing material and plastic wastes. Above that is the need to provide basic supply of clean water and power in the South Asian region.

The energy transition will be complicated for an oil and gas, refining or chemical company to navigate. There are many factors at play that make this more complex that may appear. How to rise above the crowd in these next few years? Technology is proving to be a valuable weapon in navigating and thriving during energy transition and will help companies be leaders.

Levers in Energy Transition

How can technology help adapt hydrocarbon use to achieve better sustainability results? Let's look at three of the key levers that industry has, and the key role technology will play. We will look at resource (energy and water) efficiency, energy transition and decarbonization, and circular economy. (see figure 1)

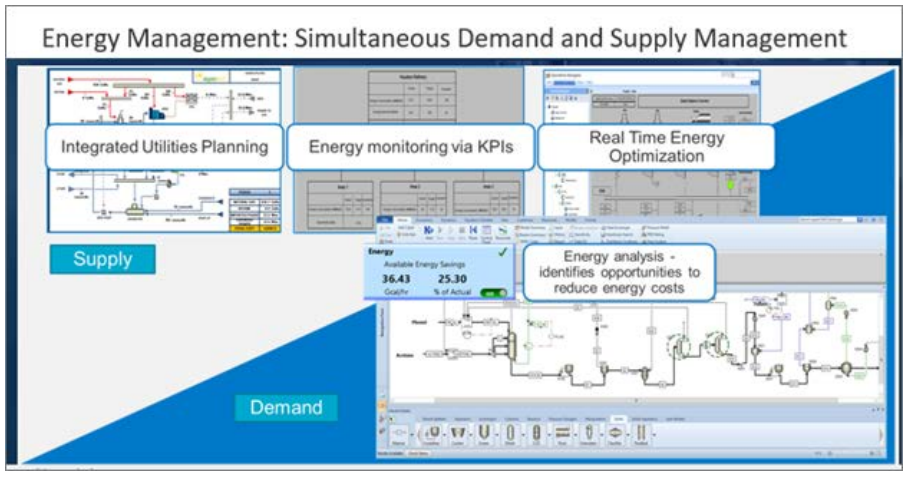
Energy Efficiency in Oil and Gas, Refining and Chemicals

Energy is consumed inefficiently in the conversion of hydrocarbons, synthesis of chemicals and the supply chain. Technology will play a key role in helping the industry navigate a drive towards carbon neutrality. Energy demand can be optimized in several ways:

First let's look at energy efficiency, that is, "the demand side". How do we reduce the demand side? Modeling technology, known as pinch analysis, performs an important optimization task called heat integration. Put simply, how can a refinery, fertilizer plant or chemical site be made more efficient by re-using heat and cooling sources, so there is no waste? AspenTech has innovated here, by the way, by hiding the technical difficulty of this approach through an intuitively guided automated approach, called ***Aspen Activated Energy.*** Asian companies like SCG in Thailand and S-Oil in Korea, have led the way in implementing this approach. SCG, for example, has already reduced energy use by over 10% at several sites with this approach.

Another way to increase energy efficiency is through production efficiency of existing operations. Several digital optimization technologies can contribute to increasing the production efficiency of oil and chemical operations. Both ***digital twin monitoring systems, dynamic optimization, and multivariate process control (APC) solutions*** can together save 5-15% energy use, reducing carbon emissions a proportional amount. Refiners such as Spain's CEPSA, India's Reliance Industries and BPCL, and Japanese chemical industry players such as Mitsui are leaders in using this approach.

The "supply side" of energy use can also be improved. This is done by dynamically using data from the plant to always select the best utility source for each part of the plant. The digital technology weapon here is utility supply optimization. As plants looks to minimize carbon emissions, the choices between oil, gas, biofuels, and renewables can be made on a sophisticated basis. The choices can be made minute by minute, or at any longer interval. The technology can model the interplay between multiple plants, and multiple utility sources, for example choosing between a wind energy source, natural gas – based electricity, or diesel combustion at the plant taking into account dollar cost, carbon costs, and reliability. The same models, by the way, can incorporate choices for minimizing water use in addition. Companies like India's Bharat Petroleum (BPCL) are making important use of this approach. Australia's Alcoa is using this approach to reduce electricity use and cost in Aluminum processing. The technology BPCL and HPCL use in this area is Aspen Utilities, a planning and optimization model.



Water Conservation

Water is projected to be increasingly a resource that is in short supply globally. To meet that concern, industry needs to effectively husband its water use. Processes can be, to some extent, be redesigned to be more water efficient. The same process simulation models and utility optimization models that are helping companies to improve their energy use, can similarly help in conserving water. Two key weapons for Indian companies are desalination and membrane-based water treatment (for reuse). Both are energy-expensive and technically challenging. AspenTech's hybrid models, which "supercharge" simulation models with AI-based machine learning, are key tools in designing and operating these water-conservation approaches economically and effectively.

Natural Gas as a 'Bridge Fuel" to Reduce Carbon

Natural gas is emerging as an important future energy source. To make natural gas transportable, though, requires the energy-intensive and complicated liquefaction (LNG) process. Technology is playing a key role in improving the costs and reliability of natural gas supply. Digital twin models and advanced control have already proven to be crucial in the reduction of energy use during LNG processing. Much more use of technology will be necessary here, as the producers, driven by both economic reality and sustainability needs, are embracing these proven approaches beyond the initial successful adopters of these tools. Each implementation of this technology further advances the green-ness of natural gas.

Huge capital has been tied up in these projects, and so utilization rates of these capital-intensive LNG plants is crucial. There, the ***prescriptive maintenance technology,*** which embeds machine learning and advanced AI analytics in solutions which alert operators to conditions that create risk of degradation of the high-capital compressors and cold boxes, are now beginning to have an important impact. The confidence of owners and developers in this technology, will enable several large development projects to proceed quickly.

For highly complex and demanding assets, such as LNG plants, the ***self-optimizing plant,*** a future vision for industry in which data and AI contribute to make these investments self-learning, self-adapting, and self-sustaining, will be important.

Scaling of Renewables

To achieve the aggressive targets of global players who are pledging to reach "zero carbon" operations by dates ranging from 2030 to 2050, increasing the pace of developing renewable power assets is viewed as crucial. These technologies, though, are still relatively you in terms of the maturity curve. Utility scale wind and solar arrays are just now beginning to reach the operational phase where maintenance and uptime become concerns. Again, as is being applied for LNG capital assets, wind farms have already begun successfully adopting prescriptive maintenance solutions, which provide asset health alerts to maximize the availability and utilization of these large assets, which have not yet established a long term reliability and maintainability record. This advanced digitalization technology will be crucial in monitoring the health of equipment which is inherently installed remotely, under environmental stresses, and requires maximum uptime to be reliable in the energy mix.

Future Growth of Renewables

An interesting analysis compiled by global political thinker Peter Zeihan, looks at the distribution of land across the global which is suited for utility-scale renewable electricity production. Interestingly, he shows that roughly half of the world's population is located in Eastern and Southeastern Asia, which has low potential for solar and wind farms. (see Figure 3).

Perhaps as a consequence of that, Southeast Asia has pursued a path of exploitation of palm oil plantations as a potential source of bio-energy and bio-chemicals. The balance of that ledger, however, is not clear, as clearing of rain forest in favor of palm oil farms, is arguably a net negative on the sustainability scale.

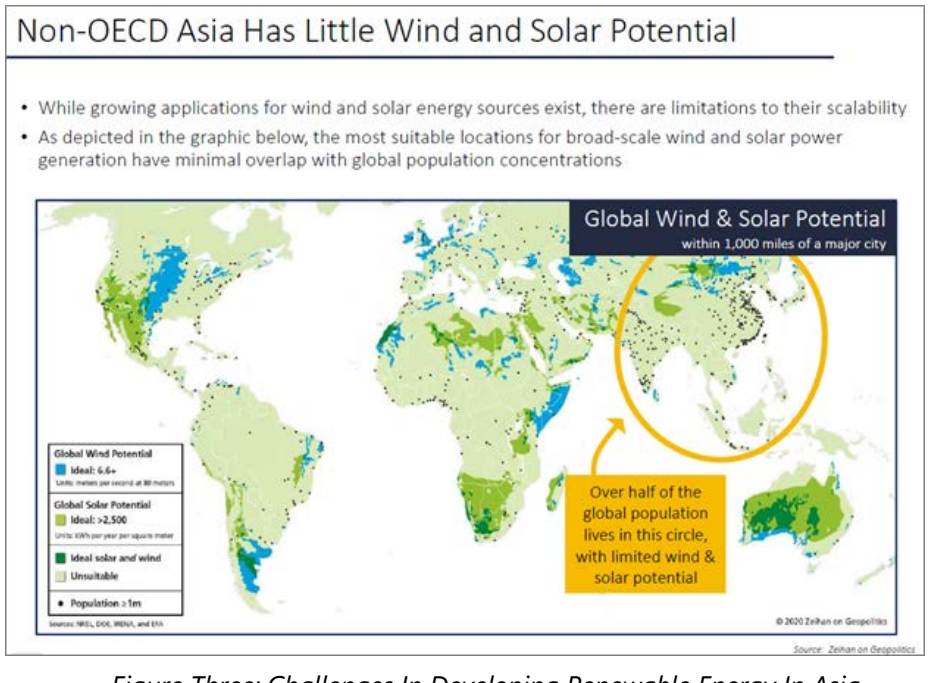


Figure Three: Challenges In Developing Renewable Energy In Asia
Source: Zeihan on Geopolitics and Enterprise Products LLC

Bioenergy Sources

Bioenergy conversion approaches, including bioethanol, biodiesel, waste-to-energy pyrolysis, algae conversion, and biochemicals, have gained acceptance at least partially through the benefit of subsidies and government policy. Process modeling technology is totally crucial, although not widely enough used, in improving the performance of these processes. These processes are hamstrung by the high energy consumption of currently accepted technology. In order to contribute effectively to sustainability and energy transition, advanced modeling and optimization is needed to achieve fundamental improvement.

Dr. Eric Dunlop, in some groundbreaking work on Algae-to-fuels has pioneered these approaches. Reliance Industries is developing their first algae-to-fuels project. New startups continue to innovate with novel new technologies to improve bio energy conversion, and the new generation of hybrid modeling, which combine AI analytics with rigorous process modeling (such as AspenTech's innovative AI model builder that harnesses industrial AI for Hybrid Model technology), will be playing a big role here in improving the technical pace of innovation and commercialization opportunities. This will be an important area in India.

Carbon Capture And Utilization

Carbon capture is a key area that is receiving increasing investment attention within the industry. As hydrocarbons and metals continue to be in demand in the global energy and resource mix, CO2 will continue to be a byproduct of conversion. Carbon capture, using several technology alternatives, is racing towards broader commercial viability. The key challenges include minimizing energy use during CO2 capture, being able to understand and optimize CO2 capture processes in the face of complex chemistry, and effectively maximizing the recharge and re-use of catalysts to avoid creating a secondary waste disposal challenge. Advanced process modeling is a key element of solving these technical challenges, improving economics, and ensuring operational integrity, optimization and improvement. In this area, AspenTech has been a pioneer in providing the rigorous process models, in particular the Aspen Plus family, used in much of the R&D and commercialization of carbon capture. Aspen Plus is a crucial tool that is empowering the progress being made, for instance, at the Research Center Mongstad, in Norway, a leading demonstration project for carbon capture.

Reusable and Recyclable Plastics and Other Materials

Global social action and politics have put huge pressure on governments and industry to reduce production and use of not-recycleable plastic. Addressing this issue is a business and technology challenge. Technology has many roles to play here. A fundamental step for chemical companies, is to understand the energy intensity and carbon footprint attributable to the production and distribution of their portfolio of chemical and plastics products. This requires an understanding and accounting of the entire creation and distribution "value chain" from an energy use and carbon viewpoint. One approach, as chemical processes and plants evolve, is the mass-balance approach. As renewable feedstocks (such as bio-based feedstocks used in production of a chemical product) and renewable energy sources (such as wind-power generated electricity used within a chemical plant) are introduced, the percentage of production that can be tracked to those non-carbon intensive sources can be tracked. Plant-wide, site-wide and value chain wide mass balance models provide an important technology edge to companies who are championing this approach.

In addition to this approach, new processes are being innovated, which will enable pyrolysis of plastic wastes, to "down-cycle" the material into building block molecules to synthesize new plastics, and new conversion processes to use the diverse recycled-plastic and bio-material feedstocks in plastics manufacture. To prove these and scale them quickly, industrial AI will be a key player in utilizing lab and plant data streams to fully understand and optimize these new processes.

Future Path

Predicting peak oil demand is the forecaster's elusive gold star. Will it be 2025, 2030, 2040 or later? This will depend on factors including global economic growth (only really forecasted to grow significantly in Asia as the world recovers from the 2020

pandemic), energy conservation (or "intensity") in different regions, shift to electric power over combustion and others. The IEA in its most recent report has forecast peak oil demand will take place in the 2030s.

Corporations globally have acknowledged the onset of the energy transition. Some have chosen to reflect this through their investments and their actions. An IHS analysis shows that Total, Shell, BP and Equinor have made at least 66 acquisitions in the past several years to diversify their energy portfolios. Others have chosen to focus on innovation in use of capital and on operational excellence to build a resilient market position. Indian players also have innovative projects underway are considering their future strategic directions.

As the industry navigates the energy transition, technology will be a key partner as organizations and their executives make strategic moves to improve their agility and competitive positions into the future. Because of the complexity of the tradeoffs involved, and the mountains of data at hand that must be analyzed to create insight in making these tradeoff decisions, industrial AI will be increasingly crucial in effectively navigating sustainability and the energy transition.

Those companies who adopt some or all of the technology opportunities mentioned in this article will be bound to have an advantage.

Ron Beck
Marketing Strategy Director, Aspen Technology, Inc.

During his 10 years at AspenTech, Ron Beck has been responsible for oil and gas and engineering and construction industry marketing, as well as engineering product marketing. He has over 30 years' experience in providing software solutions to the process industries and 15 years' experience in chemical engineering technology commercialization. Ron has authored papers on key industry topics and presented at several public industry events. He has a bachelor's degree from Princeton University in New Jersey.

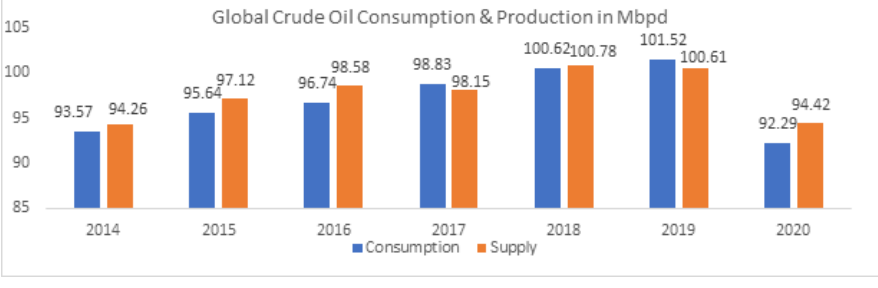
Impact of Covid-19 in Upstream Industry: Digitalization & Strategy for Future Revival

Anand Vaidyanathan
Senior Assistant Director (E&P)

Federation of Indian Petroleum Industry

Background: Global Consumption & Production:

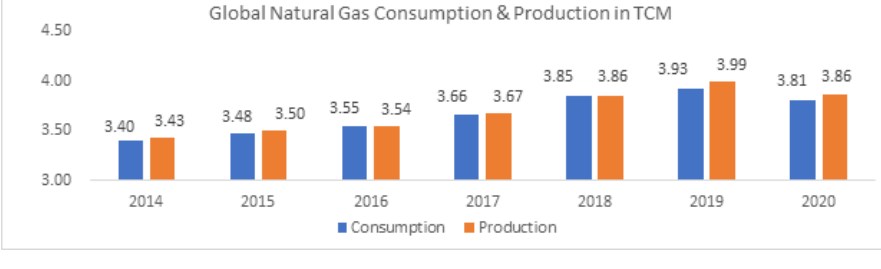
Crude Oil: Crude oil production and consumption across the globe was increasing on y-o-y basis in the last decade. In 2018, for the first-time crude oil production & consumption touched the 100 mbpd mark primarily due to the increase in oil production from the US Shale basins. Despite the increase in consumption, the oil market was in continuous possession of excess crude oil which kept the price in control in last 4-5 years.



Source: BP Energy Outlook

Natural Gas:

Natural gas saw a new high in 2019 in terms of production and consumption. While global natural gas production reached 3.99 TCM, gas consumption stood around 3.93 TCM. Between 2009 and 2019, natural gas consumption grew by 33.5% as natural gas replaced other polluting fuels used for industrial activities and domestic consumption.



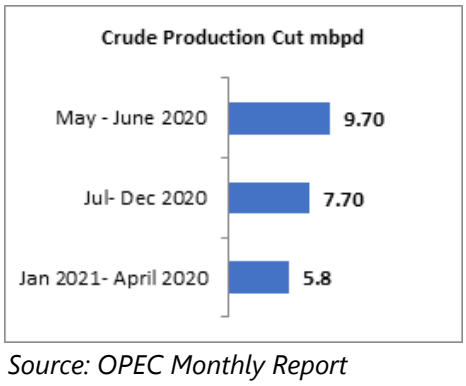
Source: BP Energy Outlook

Impact of Covid-19:

In November 2019, first case of Covid-19 was reported in China. By January 2020, Covid-19 spread was reported in several countries across the globe. By March 2020, Covid-19 outbreak was declared as pandemic as countries sealed their border to control the outbreak of the deadly virus. With lockdowns, transportation was totally restricted, industries stayed close leading to decline in demand for crude oil and natural gas. The industry saw a demand shock which prompted major producers to trim down the production as demand -supply gas had widened to a extreme level. Covid-19 impacted the E&P industry and the E&P companies in an unparalleled way. Reduction in sale of crude oil due to decline in demand has impacted companies' cash flow. As a result, it has forced the E&P companies to cut budgets and investments planned for 2020-21.

Impact on Demand & Supply:

Crude Oil: As countries around the globe entered into lockdown to contain the spread of Covid-19, the demand for crude oil took a hit. With transportation sector coming to stand-still situation, the crude oil demand saw a significant fall. Combined demand and supply shock led to the sharpest oil price fall since the times of Gulf War in 1991 while demand falling for the first time since 2009. Demand shocks are mostly short-lived as they react instantly to the situation. With lifting of restrictions across the globe, demand for crude oil in expecting a quick recovery. Demand for crude oil went down by around 25%.



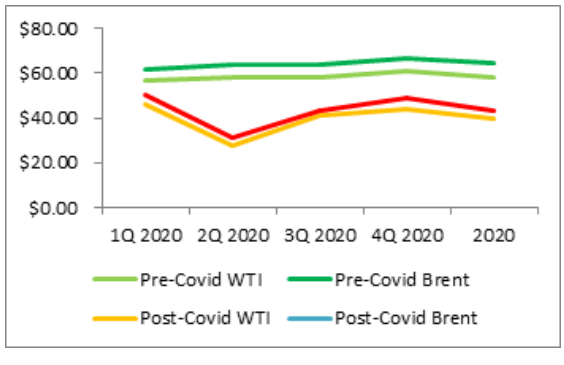
Source: OPEC Monthly Report

Natural Gas: Implementation of lockdown also impacted the sectors that consume natural gas. In transportation sector, consumption of CNG declined as high number of vehicles were off road baring the ones which were used for essential services. Closing of key industries like fertilizer, ceramics, metals, etc. led to decline in demand for natural gas. As a result of covid-19, natural gas consumption declined by 3-4% globally.

Oil Price:

Throughout 2019, oil prices-maintained consistency as Brent crude averaged above USD 60 per barrel while WTI averaged above USD 55 per barrel. In January 2020, Brent averaged USD 64.75, while WTI averaged USD 58.98 despite the minor imbalance between demand and supply. By mid-March, outbreak was spread all over the world and many countries implemented lockdowns and banned air travel to stop the spread of Covid-19. Crude benchmarks had a free fall in March by falling around 35%.

Pre-covid estimates & post covid prices for oil price are given below:



Source: World Bank Pink Sheet, OPEC reports

Natural Gas Price: Natural gas price was earlier impacted in 2020 due to mild winter in northern hemisphere. With imposition of lockdown, the demand for natural gas further went down. With the onset of summer, the demand declined further leading to excess supply in the market. Europe saw a demand decline by 7%. By May 2020, natural gas price in Henry Hub dropped to USD 1.75/MMBtu, while in the European hub it dropped to USD 1.58/ MMBtu. Asian LNG cargoes were sold less than USD 3/MMBtu as the market was flooded with excessive LNG.

Impact on Production:

Decline in demand for crude oil due to covid has resulted in surplus oil in market which further triggered the oil price low. To stabilise the oil price,

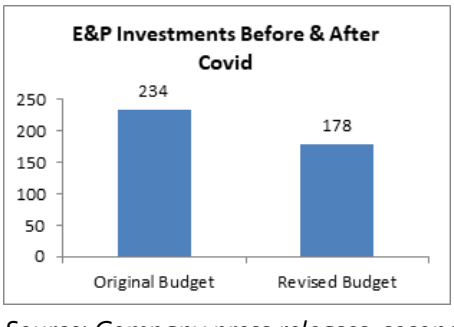
OPEC and other major oil producers arrived at a deal to cut 9.7 mbpd of crude oil per day from 1st of May for an initial period of two months, followed by an adjustment of 7.7 mbpd until the end of year and 5.8 mbpd until 30th April 2022.

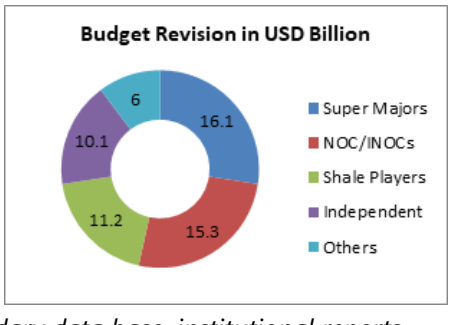
CAPEX Deferment & OPEX Reduction: There has been significant CAPEX reduction for 2020 by the oil companies. EU majors contribute to 25% of the budgets cuts while US majors contributed to 30% of budget cuts. Budget constraints have also impacted other activities like delay in buy backs, rise in debts, asset divestment etc. These budget cuts could delay the development of new projects globally. Planned Mergers & Acquisitions (M&As) in the E&P sectors are delayed or postponed or cancelled as companies are keen in saving the cash to manage the free cash flow.

With lower oil price, oil companies are now increasingly focused on achieving operation cost savings. Improving operation efficiency of the oil & gas operation, reduction in operational costs and higher energy efficiency are the new priorities for the oil companies post Covid-19.

Impact on Future Investment:

Fall in crude oil price and sales impacted the planned capital investments of the oil and gas companies for 2020-21. Before the oil price crashed, E&P investment stood at USD 234 billion. Forced production cuts and lower oil price trimmed the budget to USD 178 billion. This is likely to impact all the new oil and gas exploration projects.





Source: Company press releases, secondary data base, institutional reports

Other challenges faced by the companies:

Crew rotation and shortage of semi-skilled labour: With air travel restrictions and transport restrictions, movement of technical crews to the drilling sites, offshore platforms were impacted. This led to extended duty time for the crew who were already in the sites. In India, reverse migration of labour to their home led to shortage of semi-skilled and unskilled labour.

Low scale of digitalization: Though adoption of technology is not new to the industry, it still trails behind the other industries in terms of digitalisation. With huge amount of data generated in the exploration & production operations, inefficient use of these data has hindered companies from achieving the best outcome in terms of cost reduction and operational efficiency.

Future: Going ahead for the Oil & Gas Companies

While the demand is likely to reclaim slowly, it will take at least a year for oil to reach the pre-covid levels. As per EIA assessment, the market is likely to balance by late 2021. On the price, several assessments from financial institutions and energy bodies, crude oil is likely to average around USD 45-50 by Q4 2020 and is likely to enter range of USD 60.

While the demand is likely to remain sluggish due to second wave of Covid, oil and gas companies should reshape their approach going forward. Oil & gas companies have limited themselves to trimming production and slashing budget whenever market is faced with turbulence. Be in the 2008 global slowdown or 2014 oil price crash.

1) Deploying Digitalization:

Oil & gas companies are not new to adopting technology; however the industry trails behind other industries in adopting latest wave of digital transformation. Oil & gas operations generate significant data which are left unused. Companies can unlock tremendous values from these data by deploying data analytics which can transform the way of operation by harnessing the potential of digital strategies. Case studies on deployment of digitalization in upstream activities have shown significant outcomes. Digitalization can help in gaining better productivity by managing the OPEX with better preparation, scheduling and risk management.

i) Role of Digitalization in Seismic:

A) Multi-Client model for Seismic survey through Cloud -system

Given the large unexplored area in India, traditional approach of proprietary data and selective surveys for exploration campaigns can lead to high costs, difficulty in integration of data with the existing data due to difference in data formats over the time. This issue can be tackled by allowing multi-client service model in which, survey companies can partner with government, regulatory body, oil companies to undertake seismic surveys across wide acreage. This data can be made available to E&P in pay-as-you-use model.

Multi-client model enabled using cloud technology allows companies and geoscientists to focus more on the interpretation of new prospects. Availability of data at basin level further improves the success rate of exploration campaign and helps in managing the economies of scale. Cloud bases storage and computation give easy access to data and lower investment for E&P players.

For India's unexplored/under explored sedimentary basin, the multi-client model can be a win-win situation in terms of data acquisition and help in generating interest from E&P companies.

B) Cloud based seismic data collection, processing and interpretation: One of the major priorities for the oil and gas companies is to reduce the time for first oil/gas production. Traditionally, the key issue is the time consumption of 24-46 months for seismic data collection, processing and interpretation. Traditional approach is resource intensive activity and requires state-of-the-art on-site hardware and workstations for data processing.

With the advent of cloud-based technology, E&P companies are shifting data processing and storage activities on cloud. In cloud-enabled system, seismic data acquired from the remote field is uploaded to the cloud platform. This data is used for the processing of seismic data with the help of geological and geophysical applications and software. Usage of cloud reduces the need for high investments for on-site workstations.

Cloud storage and transfer of seismic data can reduce the processing time and cost by 50% as it reduces the need for multiple tape transcription of data. Usage of Cloud solutions can help companies in making well informed decisions for drilling a thereby reducing the chance of dry well.

ii) Role of Digitalization in Drilling operations:

A) Real-Time Operation Center in Drilling with Artificial Intelligence & Machine Language: Drilling operations have improved vastly in recent times with increased depth, directional drilling, high pressure and high temperature etc. Advanced control systems have helped in improving the drilling activity over the period of time. Managing drilling program timelines and improving the performance have been the key focus for E&P companies. Increasing well complexities, challenging drilling environments, remote drilling site location, unstructured data have added complexities to the drilling performance. An integrated Real-Time Operation Center (RTOC) with the integration of people, process and technology with well construction can play a key role in solving real-time problems.

Machine Learning & Artificial Intelligence based analytics of offset well in RTOC: Use of AI & ML allows companies to leverage everything reported in offset wells for immediate, accurate and detailed insights to take corrective action. Identification of possible geological hazards, well profile, formation details, gas kicks and corresponding mud types is made possible with implementation of RTOC with

ML & AI. Offset well analyses must be carried out from the planning phase to the drilling phase and any deviation must be monitored and corrective action must be taken through integrated RTOC. This can help in achieving improved efficiency and drilling performance by up to 30%.

B) Industrial Internet of Things (IIoT) for Real-time transmission and analysis:

E&P companies rely on low-frequency data shared by the rig operator to monitor drilling activities and drive efficiencies. Traditionally, the operators process the data manually to evaluate historic and current drilling performance and efficacy of the activities. Manual tracking of low-frequency data reduces the ability of the operator to optimize the operations on real time basis. Every meter of drilling generated vast amount of data, which can give a complete picture about the subsurface geology. With real-time transmission, E&P operators can collect and leverage these data at the extremities of their assets. However, data transmission alone can improve efficiency. These data must be converted into useful information for taking proactive steps to prevent or reduce inefficiencies.

Data combined with IIoT architecture gives an opportunity to increase asset/equipment uptime, reduce safety risks and optimize operational costs. E&O operators must apply machine learning models, which can consume real-time data and provide insights. This can help in automation of daily drilling reports, continuous improvement in issues like long pipe connection time, slow rate of penetration, hole cleaning etc. With deployment of IIoT, a key E&P operator in the Middle East region achieved 13% improvement in drilling connection, 75% improvement in casing speed and reduced down time.

iii) Role of Digitalization in Operational Efficiency: Operational efficiency is one of the key areas of focus for E&P companies. Improved & efficient operations can reduce the operating cost.

A) Digital Twin & Data Analytics for Physical assets:

Digital twin refers to a digital replica of physical assets. They provide a digital representation of physical processes and their dynamics. This is a new concept by which operators use P&ID diagrams to assess the equipment which is not the most efficient way. These are used for helping field technicians to carry out the maintenance and repair jobs. By incorporating multi-physics simulation, data analytics and machine language capabilities, digital twins demonstrate the impact of design changes, usage scenarios, environmental conditions and other variables. This eliminates the need for physical prototypes, reduces the development time and improve quality of finalized products.

Digital twins use data from sensor installed on physical assets to ensure accurate modelling over the entire lifetime of a product. These sensors give real-time performance, operating conditions and changes over time. Digital twin evolves and updates continuously to reflect any change to the physical asses throughout the lift cycle by creating a closed-loop feedback. When integrated with Data Analytics, it can used for predictive maintenance of the physical assets. Preventive maintenance reduces the chance of equipment breakdown, reduces the equipment down time and helps in optimization of maintenance operations. E&P companies can achieve 20%-40% reduced maintenance cost by using predictive maintenance and digital twins.

iv) Role of Digitalization in Health, Safety & Environment

A) AR/VR assisted Safety training

HSE has always been the top priority for E&P operators. In most organization, contractors and employees are required to undergo mandatory safety training programs that are imparted by safety engineer/instructor. Mostly these training programs are imparted in classroom lectures, using printed material or video clips. Training is tracked through a database and based on the requirement; training is carried out. This process is a time consuming one and there are challenges like limited classroom infrastructure, limited time slots and effectiveness of the program.

These training programs can be highly automated with increased effectiveness with usage of AR/VR based tools. Using virtual reality, employees can be engaged in real-world conditions and emergency

situations without actually being exposed to the risk. Given the current scenario of travel restrictions and social distancing in the outbreak of covid-19, these programs can help workers to attend the training program from any part of the world through the digital platform.

B) HSE – Smart Wearables for tracking workers: Average worker in the rig site, offshore platform, processing plants face risks of slips, fall, electrocution, cuts, exposure to toxic gas and these could be fatal at times. Real-time monitoring of site conditions and workers health can help in overcoming the issues. It involves, usage of industry grade sensors for gases like Hydrogen Sulfide, Nitrogen dioxide etc. Usage of smart wearables can help in tracking location of the worker, posture, bodily parameters like blood pressure, heart beat and temperature.

Strategies for oil and gas companies going forward:

1) Focus on low break-even, high potential assets:

Oil & gas companies have different production portfolios like low break-even price high potential, high break-even price high potential, low break-even price low potential and high break-even price low potential.

Companies must actively promote low break-even prices and high potential assets to increase the reserves and production. Concentrating on these assets will help them sustain the low oil price. High break-even, high potential & low break-even, low potential assets must be rationalized through improved operational efficiency and optimized production. Assets with high break-down prices and low potential must be reduced gradually to achieve a sustainable production and sustainable financial position.

2) Incentive based outsourcing & collaboration with service providers:

Outsourcing is not new to oil & gas companies. Well operations, Production enhancement, well interventions are outsourced to third party vendor and support functions. However, all outsourcing activities might not be sufficient and it might need improvement to achieve the success. Setting incentive-based outsourcing can help the oil and gas companies achieve its goal. For example, when oil and gas companies engage with field service companies for enhanced recovery, incentive based contract can ensure that the service company deploys its full efficiency to achieve the target. This will set a common goal for the operator and the service company.

Budget cuts from the oil & gas companies has impacted the already troubled service providers. Reduced cash flow for service providers might impact the R&D process which could lead to delays in achieving new technology developments. This brings the need for collaboration between the oil and gas companies & the service providers for mutual survival in the prevailing situation.

3) Rationalize activities:

Activities that go without consideration of their value and planning can lead to wastage of time and OPEX. These resources can be used elsewhere for better results. Therefore, it is essential for oil and gas companies to adapt zero-based planning where every planned activity of the company is scrutinized and prioritized methodically based on value addition. Using data analytics, asset conditions can be compared and prioritized to have more targeted and efficient workover or production enhancement operations.

For example, an operator with more than 30 wells in a field plans for well intervention program. Before executing the operation, the operator must analyze and categorize the wells that give higher value on doing a workover operation. Using this methodology, the operator can categorize wells into three categories i) Wells that need immediate intervention ii) wells that needs optimization and iii) wells that need to be shut. This can help operator in reducing the expenditures and focus on the wells which offers improved production.

Going Ahead:

Future course of action for oil and gas companies is not limited to above mentioned, but these can help oil and gas companies in developing an optimum operating model to face any future downturn or market turmoil. Oil and gas demand will rise once the global economy stabilizes and the world will still need hydrocarbon to sustain development and improve prosperity in the developing world where the need for energy is rising on day-to-day basis.

A Strategy for Successful EOR Implementation in India: Discussion of Technology Adoption to Deliver Success in the Current Volatile Market

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Abstract

Maximizing hydrocarbon production and recovery over field life is a primary objective of any operator, more so ever now as in the current landscape of low oil prices and lower investments in exploration, discovery of new oilfields is becoming increasingly challenging. The percentage of original oil remaining varies from field to field and is directly related to drive mechanism, reservoir/ fluid properties, production regime and field development. Studies suggest that only 33% of the original oil in place is recovered through primary and some secondary recovery techniques. The paper discusses the key attributes and technologies that are important in considering the need to increase the recovery factor to beyond 40%.

Integration business models historically, and in multiple global settings has proven very robust to clearly demonstrate value proposition when it comes to project delivery expediency, Health & Safety and Service Quality improvements, and creating an opportunity for improving local content including development of local talent for future industry benefits. This paper is not by any means comprehensive in terms of accessible and required technologies but should be reviewed by the reader as an indication to the technology profiles that will support the production increase from the mature fields in India by looking for Enhanced Oil Recovery Methods (EOR) in the current environment.

India Policy Landscape

With India importing 85% of its energy needs and with an ambitious target of the government to reduce its import bill by 10% by 2022, it is becoming imperative to look for avenues to harness the recovery from its existing fields.

The policy framework to promote and incentivize enhanced recovery methods for oil (and gas) was published by the Ministry of Petroleum and Natural Gas in Q4 2018[1]. The key intent of this policy is to reduce energy imports, and therefore providing incentives to increase domestic production from mature fields in an extremely challenging timeframe. The key directive E&P organizations need to take from this policy is to rapidly select an appropriate Production Enhancement and EOR technology basket at an agreed uncertainty to achieve economic success, given the incentivized framework.

EOR Overview

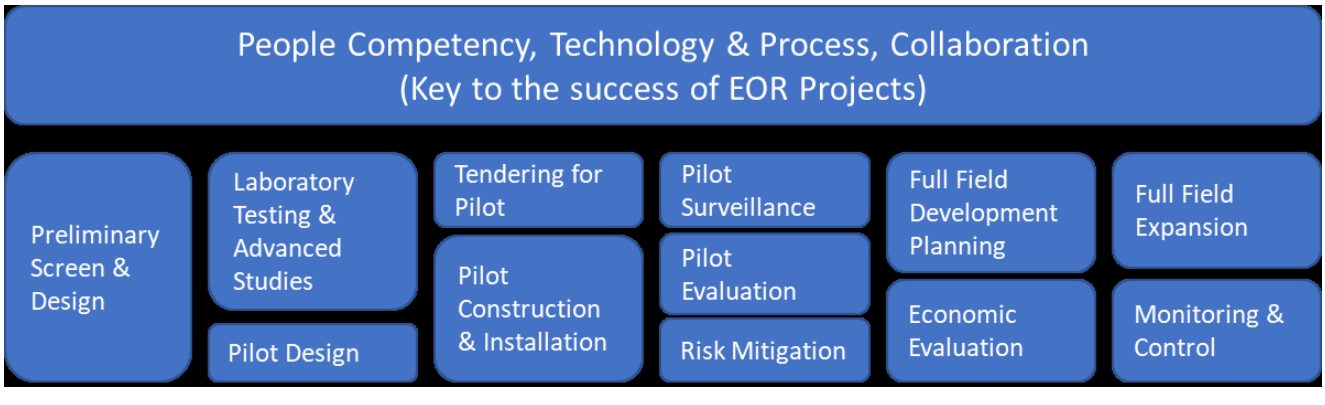
Post successful field implementation of a secondary recovery method, for example waterflood, significant volumes of oil may remain in the reservoir. This by-passed oil can be targeted by various data acquisition techniques such as advanced logging tools, cross well evaluation and surface seismic techniques. These techniques together with 3D modelling are key in the understanding the prospect of potential available oil recovery.

EOR processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced, economically by conventional means. Key challenges in establishing the techno-economic feasibility of any advanced secondary or tertiary recovery enhancement process is determined by:

- Uncertainty in the prediction of oil/gas prices
- Technological challenges
- Reservoir characterization

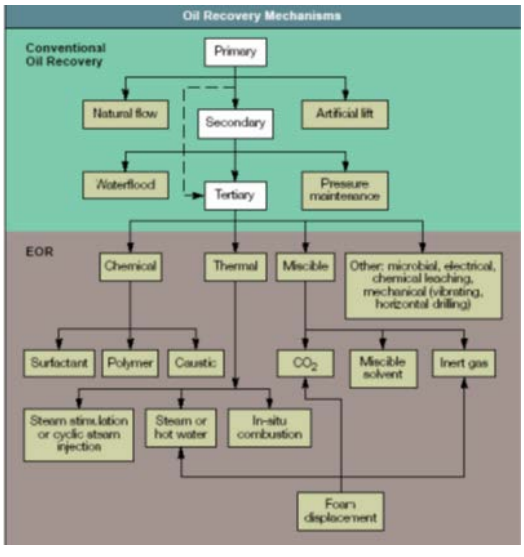
Oil prices together with tougher environmental constraints may determine the feasibility of an EOR project. EOR projects are among the most complex and difficult undertakings in the upstream industry. From the early stages with state-of-the-art technology to substantially shorten the cycle time to proof-of-concept and further to the full field implementation where reliable monitoring and control are deployed are key to ensure long-term economic success.

Not all EOR techniques are applicable for all kinds of reservoirs and formation fluid types. Careful screening, analysis and planning is required to ensure success of the EOR project and hence reduce the risk of failure of EOR pilot. To begin with, it is important to have an in-depth understanding of the reservoir and fluid properties. Knowledge of areal and lateral sweep efficiency (conformance) are key factors. This is then followed by screening, laboratory testing and simulation. Subsequently, pilot testing will confirm the simulation and validity of the technique selected for a specific part of the field. Following is a tabular representation of the generic life cycle of an EOR project:



EOR Processes

The EOR processes may include, but are not limited to, chemical, miscible & immiscible gas, thermal, and microbial processes. Chemical processes involve the injection of chemicals, such as surfactants, polymers and foams, to effectively displace the reservoir oil. Thermal processes can be sub-divided into three categories including cyclic steam stimulation, steam flooding, and in-situ combustion. Under each category, there are several technologies such as SAGD for steam flooding, toe-to-heel air injection (THAI) for in-situ combustion. Miscible displacement processes involve the injection of gases that are miscible or near miscible with the reservoir fluid at the reservoir pressure and temperature conditions. The gases include carbon dioxide, hydrocarbon gases, flue gases, nitrogen, or hydrogen sulphide. A diagrammatic representation of such different EOR processes is shown in the following figure.



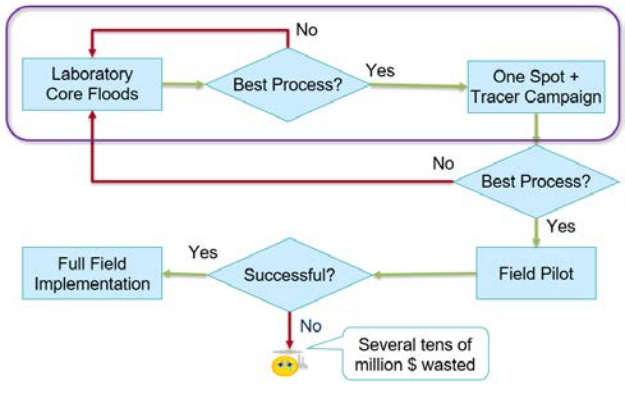
Strategic Requirements for EOR Success

Each EOR project has unique characteristics. Success lies in improving efficiency in every step of the EOR roadmap by synchronizing diverse measurements, applying advanced technologies, and integrating knowledge across multiple domains. Hence it is imperative for the organizations to adopt and apply an integrated approach to ensure the success of any production enhancement initiative including EOR. There are three key attributes that will enable an Integrated project to succeed:

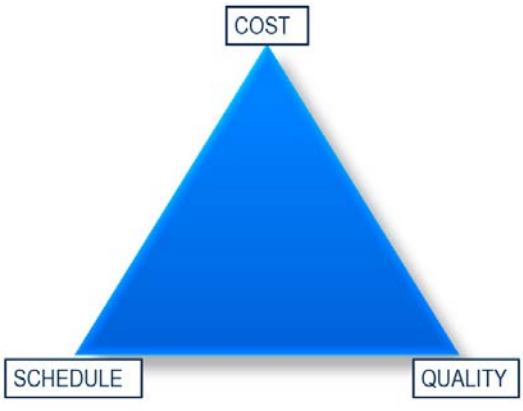
1. People (Project Manager Selection, Experience, and Training)
2. Technology & Process (Project Readiness Assurance, System Automation, and Digitalization)
3. Collaboration Mind Set (Trust, Teamwork, and Workflow optimization)

Technology Components for Successful EOR Implementation

The objective for an O&G operator in the India and vis-à-vis the policy framework incentives is to determine the optimum solution for the reservoir that will provide the best combination of the Recovery Factor and Economics in the least possible time.



In the flow chart above, a standard industry practice is for the O&G Operator to spend more time in the upstream processes (Laboratory and One-spot pilot and/or tracer programs) before embarking on a final investment decision for a larger scale pilot or a full field implementation of the recovery technology. This approach adds time, which is a luxury the O&G operator does not have in the policy framework. It is also very important to address the fact that Schedule improvements (time reduction) should not be achieved at the cost of loss of Quality. A standard Project Management Triangle with orthogonal objectives in Cost, Schedule and Quality is shown below. A drop-in quality will imply decisions that may not be sound towards the objectives the O&G Operators in India be taken.



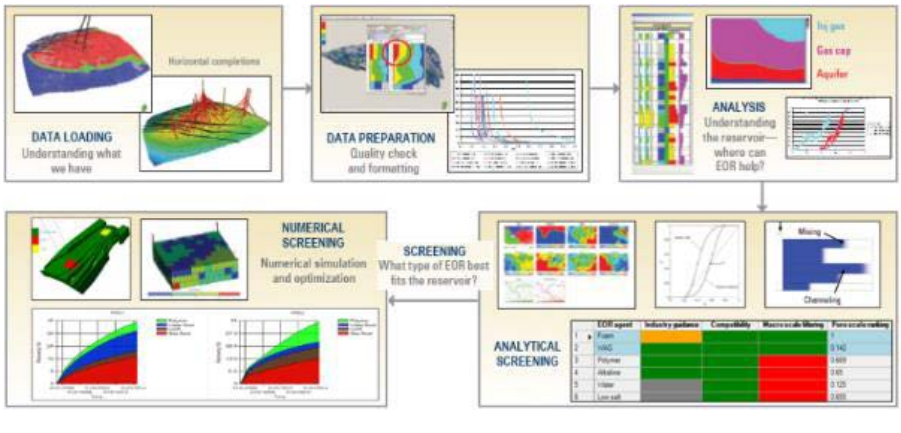
The following sections addresses some key technology elements that provide enablers to address the above narrative and reduce uncertainty & risks associated with the life cycle of any EOR project.

Screening and Selection of EOR studies applicable for the target fields

Some major E&P operators globally have developed inhouse matrices for prescreening of EOR schemes that would fit their company guidelines (technically & commercially) and use that to screen their reservoir portfolios. Schlumberger is supporting the Industry through its inhouse developed software, EOR-SD which enables the user to apply a comprehensive and robust EOR method screening within a relatively short time frame. In this software the worldwide expertise of Schlumberger's technical community has been consolidated and incorporated on a first-of-its-class guided automatic EOR screening tool. This tool helps the technical team to:

- Compare the industry experience and their own reservoir parameters to corroborate the EOR method selection
- Provide analogue fields from an industry wide database, which enables them to do a comparative analysis of their reservoirs versus global averages
- Systematically takes their inhouse reservoir model and identifies appropriate sectors for EOR studies
- Uses numerical simulation to quantify recovery and rank the best EOR alternatives
- Provides a preliminary forecast of all streams for economic screening

A high level EOR screening workflow is shown in the representation below:



Laboratory Analysis

It is said that "Field is the most expensive laboratory that a reservoir engineer can afford". A chemical EOR process will involve complex chemical interactions between formation fluids and the injected agents. Modern equipment in the laboratory set-ups allow the user to simulate in-situ conditions and study most of these complex phenomena or physical interaction of EOR agents in a controlled laboratory environment. Some miscible gas EOR fluid testing include:

- Solubility swelling tests
- Rising bubble apparatus test for minimum miscibility pressure (MMP) measurements
- Slim tube displacement test for MMP measurements
- Equilibrium contact (equiphase) tests
- Forward and/or backward multi-contact test
- Interfacial tension (IFT) measurements

Other standard laboratory analysis for EOR pilot design include:

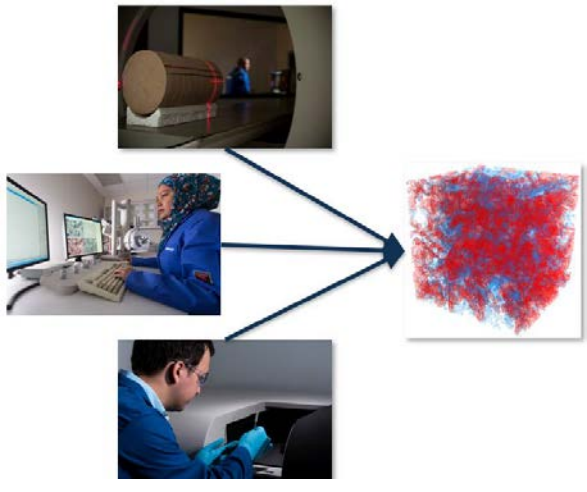
- Fluids Analysis
  - o Routine PVT properties
  - o Routine water properties
  - o Fluid compatibility
  - o Solids precipitation or deposition
  - o Water, oil, and gas interactions
  - o Slimtube
  - o Rising bubble apparatus
  - o Minimum miscibility pressure (MMP)
  - o Interfacial tension (IFT)

- Rocks Analysis
  - o Routine core analysis
  - o Special core analysis laboratory (SCAL) testing

- Core Flooding (Gas/Chemical)
  - o Coreflooding provides a measure of the recovery factor and the microscopic displacement efficiency

Schlumberger Reservoir Laboratories through its global outreach is helping clients across the world to conduct the above tests to aid in pilot design and improving chance of success of the EOR scheme. Some specialized and advanced laboratory analysis that are further helping our clients are described below:

CoreFlow* technology improves the time spent in a laboratory setting by utilizing a fully digitally enabled solution to integrate the physical and digital rock/fluid analyses. This technology creates as 3-Dimensional reservoir model to simulate flow performance in multiple production scenarios as depicted in the picture below.



The process involves whole-core computed tomography (CT) scanning, Micro CT scanning, and Scanning Electron microscope (SEM) Imaging, to build into a novel Direct Hydrodynamics (DHD) pore flow simulation. This enables a digital representation of the reservoir with geophysical, fluid, and petrophysical properties captured to create multiple simulation of EOR fluid changes to understand recovery enhancement. This technology enables moving from brute force laboratory measurements to a true digital space, thus saving time. Selected references for this technology are available in SPE 165258, 182037, 195872, 196695, and 196928.

EOR Pilot Design and Monitoring

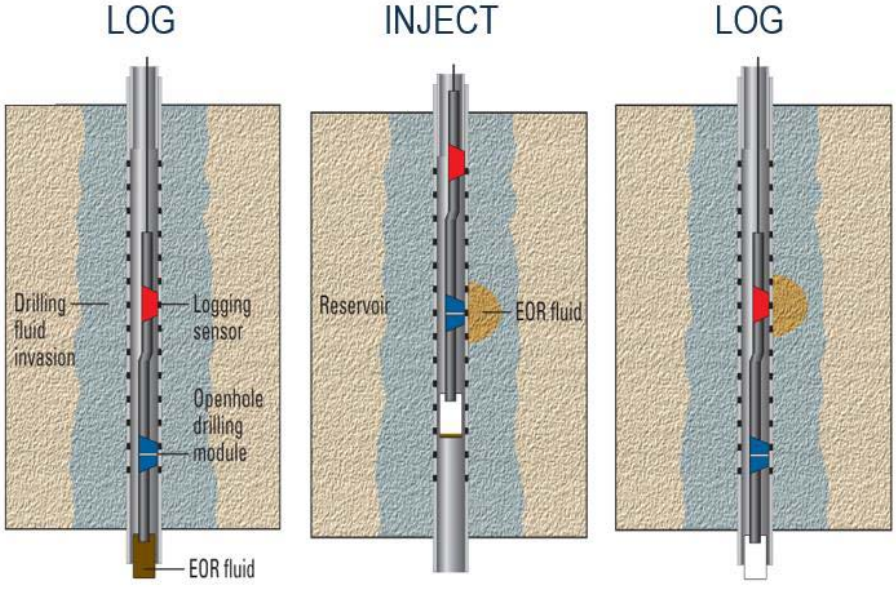
It is worth mentioning that a large percentage of EOR pilots fail to reach a logical conclusion. Some of the factors attributing to this are:

- Results of Pilot are not conclusive in terms of key objectives
- The economic drivers of the project are not very well understood by the team and executive management
- Long lead times for pilot execution and upscaling to full field implementation
- Gaps in integration of subsurface aspects and facility design

State of the art monitoring and surveillance is necessary to ensure that EOR pilots can be properly managed and evaluated. Continuous measurement of inflow and outflow profiles, pressures, temperatures and other parameters coupled with interpretation workflows build a foundation for field scale success.

To illustrate the above with an example, it is well understood based on scientific principles that polymer improves conformance by allowing better control of water mobility and surfactant improves recovery by reducing residual oil saturation via modification of rock-fluid wettability and interfacial tension during a chemical flood. Careful design and execution of a pilot helps to improve the economic success of a chemical EOR process because of prohibitive costs of the injection agent, by consuming the "right-EOR agent-at the right time-in the right quantity". Also, a careful technical analysis during the pilot is needed to understand the complex chemical interactions especially with regards to salinity and emulsion formation, in order to have a favourable OPEX.

Micropilot* technology from Schlumberger improves the quality of the data and therefore reduces the uncertainty before larger scale investment decisions need to be made into a full-scale field pilot. This technology involves controlled injection of EOR agents in-situ into reservoirs, measurement of recovery and/or displacement of oil in-situ in reservoir, to enable fast tracking of EOR screening in-situ in the reservoir. This technology relies upon the value of testing the EOR agents in situ in the reservoir.



The process involves a Log – Inject – Log technique. The pre-injection log captures the existing oil saturation, the injection phase introduces the EOR agent into the specific facies, and the post-injection log captures the resulting oil saturation. The before and after provides a measurable improvement in oil recovery. The log measurements are typically independent of salinity, agent chemistry, and wettability alteration. These in situ screenings of EOR agents validates hypothesized recovery factors. The value in such a technology is to be able to fast track reservoir in situ screening using multiple agents and tested in multiple facies. And by executing this technology in multiple wells, reservoir special heterogeneity uncertainty can be mitigated. This technology could be applied to reduce reservoir in situ screening from months & years to weeks. Selected references for this technology are available in SPE 161559, 129069, 136767, and IPTC 14507).

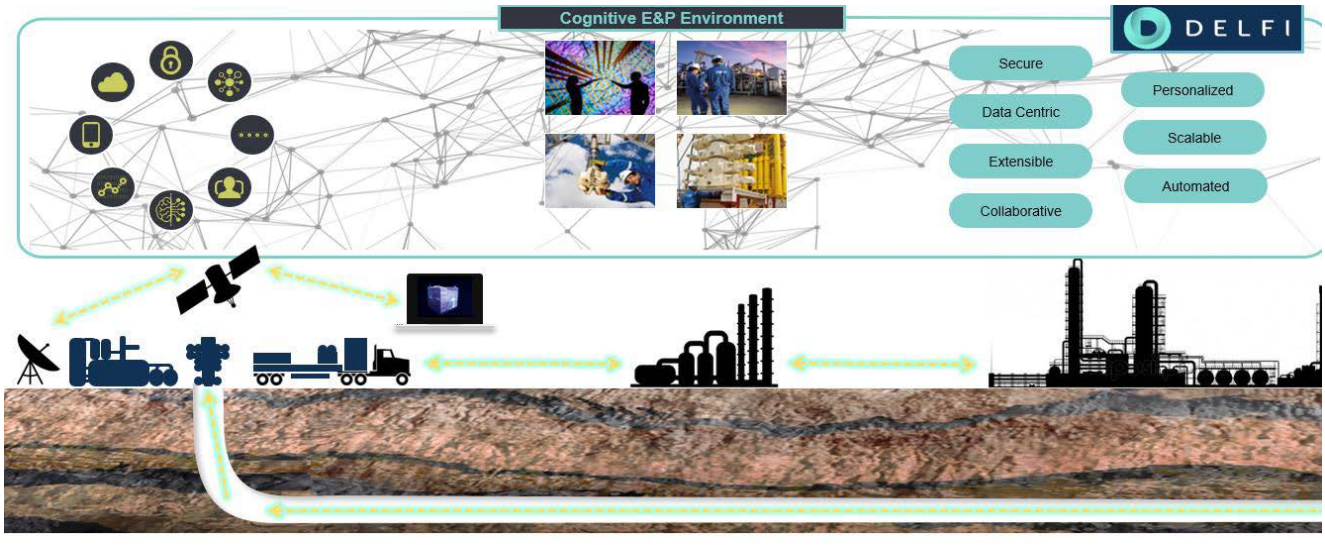
Full field EOR Development Planning & Expansion

The further success of an EOR Project towards the field implementation is dictated by the economic parameters, which would be dictated by the ROI and NPV of the investment that will be needed to be allocated to the project in return of incremental barrels over the life of the project. The evaluation should include.

- Understanding of elementary costs of the selected EOR process (facility costs, disposal cost, operational costs and injectant cost) as well as economic evaluation parameters (commodity prices, discount rates).

- Economic evaluation of the project (either single reservoir or a pool of connected reservoirs).
- Evaluating economic impact of industrialization of the EOR technology across multiple fields in company's portfolio. Due to economies of scale, this could possible result in converting a not so commercially attractive proposal into a commercially acceptable one for a selected EOR scheme.

Also, technology for upstream to downstream integration is becoming a reality and has been built upon already well-established technologies for Reservoir (pore) to Surface facilities (pipeline). These technological building blocks enable a process and workflow driven synergy to develop optimized project delivery. An example of such an ecosystem is shown in the image below. Here a cognitive E&P Environment based on engines that are supported by deep domain knowledge is shown. Such an ecosystem enabled by both data-secured cloud infrastructure, and on premises infrastructure enables seamless workflow execution that is required to realize efficiencies in the industry.



Some tools that help the user in the above process are described below:

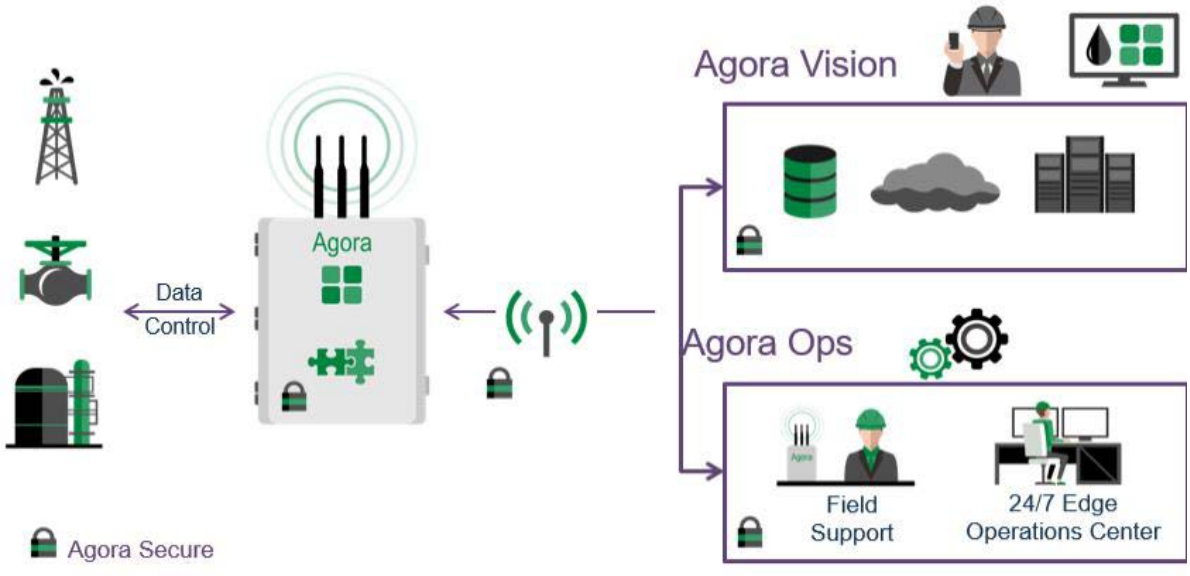
Reservoir Simulation

The INTERSECT* software empowers the users to perform complex reservoir simulation studies they need to perform in order to be successful for further upscaling of EOR projects. Its cutting edge EOR functionality allows reservoir engineers to perform modeling studies for variety of schemes ranging from traditional EOR processes such as thermal (including CSS, SAGD and VAPEX) and CO2 flooding to complex polymer flooding and surfactant injection (capturing the effects of salinity and emulsion formation).

The FrontSim software provides a special improved reservoir optimization feature and an associated scale-up workflow for rapid feasibility studies and management of very large EOR operations. This composite workflow uses ECLIPSE* compositional functionality to capture the full physics of EOR processes that can be applied on streamline models.

Platform for connectivity and excellence in Edge Processing

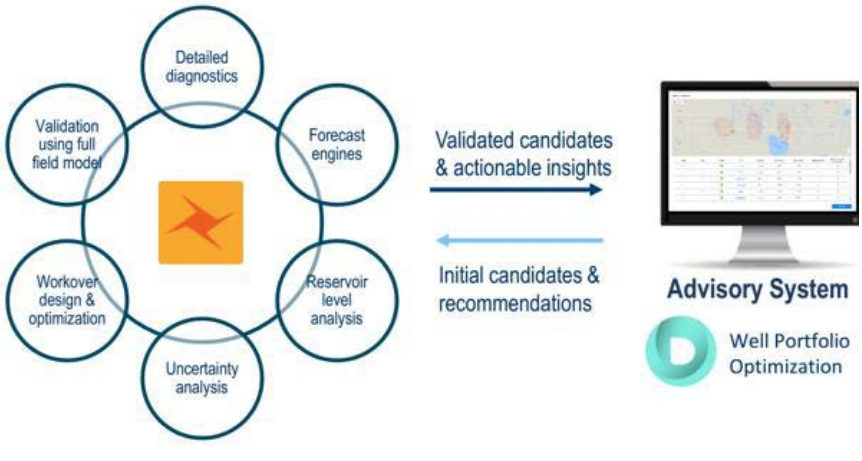
It is very often the industry finds that mature fields are not well instrumented or if they are instrumented the data is not visible at a central repository to aid in strategic decision making. This gap can be handled by technology built on the AGORA Platform, which bring in a game-changing workflow automation, AI & ML solutions. AGORA delivers an end-to-end managed service, providing an open, secure and scalable platform to harness the power of Edge Computing and analytics to enable improved decision making and fast-loop control.



Workflow Automation and Advisory System

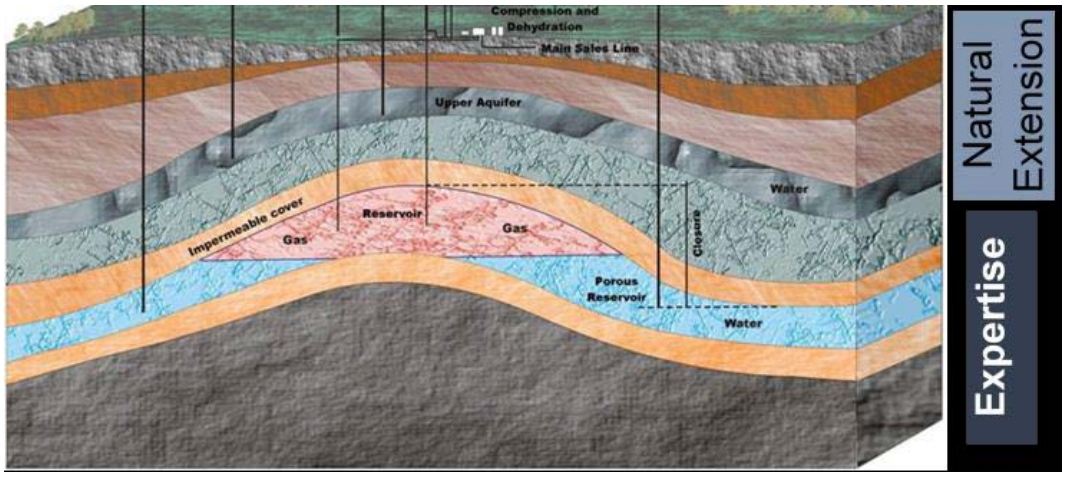
The economic objective that should motivate the O&G operators is to increase production from existing wells at a lower unit cost ($/bbl). And it is well established through decades of experience that better reservoir quality results in better performance. The challenges in mature fields typically are high well counts, significant capex constraints for field development, and time required to screen well candidates for intervention opportunities based on the afore mentioned well established hypothesis. To over come these challenges, PROACTIVE ASSET

team a constant awareness of intervention opportunities in a standard methodology towards measurable time saving and accelerated recovery. Full field reservoir models equipped with uncertainty & optimization scenarios and based on Reservoir Engineering, Production Engineering and Economics domain enable an efficient and automated workflow.



A Sustainability Thought

With increase in Oil production, comes another concern that is of paramount importance: Water. There is an increased demand for water, as oil production in most cases depend on water availability. Global water cut, i.e., water pumped with oil averages more than 70%. There are numerous national mandates for Water Security that is key. O&G Operators should be additionally motivated as managing water smartly leads to a better Environmental Sustainability Index. The natural extension of the O&G subsurface and reservoir knowledge is into the water aquifer. It is therefore important for the O&G industry to start including water security into their objectives.



Conclusions

The authors would like to leave the readers with a few key messages:

1. EOR techniques to achieve an increase in domestic oil production in India is no longer a 'nice-to-have' – it is a need, to realize the National Energy mandate. If implemented correctly, such techniques will form a low hanging fruit to meet the oil demand.

2. Time to implement EOR projects are key, and robust technology-based tools and processes are available to shorten the time to implement without compromising on quality.

3. EOR agent selection depend on various performance, economic and supply chain considerations, and such a determination for specific reservoirs must happen in an Integrated Execution that will include reservoir, surface facilities, operations, and monitoring & surveillance, and control.

4. Step change in operational efficiency can be achieved by analyzing the appropriate data at the appropriate time and delivering edge enabled intelligence for control & optimization.

5. EOR injectant cost can be controlled by employing technologies to optimize the fluid rheology and well bore/reservoir conformance to ensure minimal loss of expensive additives into the undesirable reservoir layers.

Innovative Methodology for Deodorization and Decontamination of Ethyl Mercaptan Residue

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Abstract

The main objective of this technical paper is to bring out most effective, fast reactive, low cost and eco-friendly solution for deodorization and decontamination of ethyl mercaptan residue. Ethyl mercaptan is universally accepted odorant used in hydrocarbon Industry. Interestingly, it has Odour Threshold Limit (ODL) of 0.00035ppm. Being a hazardous chemical, its proper deodorization and decontamination in the residual container assume great significance keeping denizens in mind. The PQCL (Process and Quality Control Lab) at Dahej Plant, ONGC took this field problem of disposal as an innovation opportunity. A number of proprietary chemicals or generic chemicals are being used for deodorization and decontamination of empty barrel of ethyl mercaptan. However, there is no standard industrial practice available. There was an ongoing issue in safe disposal of these empty barrels and practices followed elsewhere were not found effective as Dahej Plant does not have any ETP or alternate disposal system. Experimental studies were carried out at Dahej Plant with potassium permanganate, hydrogen peroxide, zinc acetate and sodium hypochlorite for environmental friendly solution. It was observed that 6% w/v sodium hypochlorite solution can oxidize the ethyl mercaptan to ethane sulphonic acid which is non odorous, having low toxicity and environmentally benign. The concentration of ethyl mercaptan is also below the detectable limit of mercaptan detector tubes (range 5 to 120 ppm) which is also below the hazardous limit of ethyl mercaptan. Based on the laboratory findings, the empty barrels of ethyl mercaptan at Dahej Plant have been deodorised and decontaminated successfully and neutralised content were disposed off in an environmentally safe manner.

Introduction

In Dahej Plant, rich liquefied natural gas is received from Petronet LNG Ltd. (PLL) and value added products C2, C3 and C4 are extracted by using Core-flux technology. The lean LNG is sent back to PLL, whereas extracted C2, C3 and C4 are transported to ONGC Petro additions Limited (OPaL) through pipe line for further value addition. In case of OPaL shut down or lower capacity utilization, there is an arrangement in Dahej Plant to mix excess C3 and C4 through blending facility and

the resultant mixture is called liquefied petroleum gas (LPG). LPG is colourless, odourless and not detectable by normal human senses. LPG intended for domestic or commercial consumption is globally odorised so as to be readily detectable well below flammable or suffocating level of LPG in air. The most common odorant is ethyl mercaptan and it is being used since 1937 in the industries.

Ethyl mercaptan is a colourless or yellowish liquid with pungent, garlic or skunk like odour and b.p. 35^0C. It is highly inflammable and a dangerous fire hazard. It is hazardous to health and environment too. The ethyl mercaptan is supplied and stored in 160 Kg MS drums at Dahej Plant. After consumption of chemical, the empty barrel of ethyl mercaptan is required to be deodorised and decontaminated prior to final disposal as per statutory requirement.

The present practice to deodorise and decontamination of empty barrel of ethyl mercaptan at Dahej Plant as well as at Hazira Plant is by using 5-6% of zinc acetate solution, whereas 5-6% potassium permanganate solution is being used at Uran Plant. Also, a number of proprietary chemicals or generic chemicals are being used for deodorization and decontamination of empty barrel of ethyl mercaptan. In the present technical paper, an attempt has been made to identify a novel chemical which can effectively deodorise and decontaminate the residual ethyl mercaptan present in empty barrel of ethyl mercaptan in eco-friendly manner.

Experimental Study

Apparatus

All the experiments (as per method ***ASTM D-5305-12***) for deodorization and decontamination of ethyl mercaptan were carried out with the help of following apparatus and equipment:

1. Dragger pump (M/s Uniphos)
2. Mercaptan detector tube (M/s Gastec, range 05 to 120 ppm)
3. pH meter (M/s Spectralab)

Procedure

With 6% (W/V) Potassium Permanganate Solution

Total five no. of reagent bottles (250 ml each) were taken and poured 50 ml of tap water in each reagent bottle. Thereafter with pipette, 0.5ml of ethyl mercaptan equivalent to 0.431g was added in each reagent bottles marked as 1,2,3,4 and 5. Regent bottle no. 1 was treated as blank solution (without potassium permanganate) and 5 ml, 10 ml, 15 ml and 20 ml of 6% (w/v) potassium permanganate ($KMnO_4$) were added with measuring cylinder in bottles marked as 2, 3, 4 and 5 respectively. After addition of potassium permanganate solution, all reagent bottles were tightly closed with glass stopper and vigorously shaken then kept for ten minutes for completion of reaction.

Thereafter, concentration of ethyl mercaptan and pH in each reagent bottle was measured by mercaptan detector tube fitted with rubber stopper and pH meter respectively.

The results are described in Table-1

Table-1: Deodorization of Ethyl Mercaptan with 6% (W/V) Potassium Permanganate ($KMnO_4$)

S. No.	Sample Type (Mercaptan+ Tap Water)	Volume of $KMnO_4$ added	Mercaptan (ppm)	pH	Observation	
					1st Day	2nd Day (after 24 hrs.)
1.	0.5 ml + 50 ml	0 ml	> 120	7.89	Strong odour, clear solution	Strong odour,clear solution
2.	0.5 ml + 50 ml	5 ml	> 120	10.81	Strong odour, light brownish ppt.	Strong odour , clear solution with settled light brownish ppt.
3.	0.5 ml + 50 ml	10 ml	> 120	12.63	Strong odour, brownish ppt.	Strong odour , clear solution with settled dark brownish ppt.
4.	0.5 ml + 50 ml	15 ml	> 120	12.72	Strong odour, brownish ppt.	Strong odour , clear solution settled dark brownish ppt.
5.	0.5 ml + 50 ml	20 ml	> 120	12.82	Strong odour, thick brownish ppt.	Strong odour , clear solution with settled dark brownish ppt.

With 6% (W/V) Hydrogen Peroxide Solution

Procedure is same as discussed above in case of 6% (W/V) Potassium Permanganate Solution The results with 6% (W/V) Hydrogen Peroxide Solution are described in Table-2

Table-2: Deodorization of Ethyl Mercaptan with 6% (W/V) Hydrogen Peroxide (H_2O_2)

S. No.	Sample Type (Mercaptan+ Tap Water)	Volume of H_2O_2 added	Mercaptan (ppm)	pH	Observation	
					1st Day	2nd Day (after 24 hrs)
1.	0.5 ml + 50 ml	0 ml	> 120	7.9	Strong odour , clear solution	Strong odour , clear solution
2.	0.5 ml + 50 ml	5 ml	> 120	2.29	Strong odour , milky white solution	Strong odour , clear solution
3.	0.5 ml + 50 ml	10 ml	> 120	2.19	Strong odour , milky white solution with oil droplets	Strong odour , clear solution with oil droplet
4.	0.5 ml + 50 ml	15 ml	> 120	2.18	Strong odour , milky white solution with oil droplets	Strong odour , clear solution with oil droplet
5.	0.5 ml + 50 ml	20 ml	> 120	2.04	Strong odour, milky white solution with oil droplets	Strong odour, clear solution with oil droplet

With 6% (W/V) Zinc Acetate Solution

Procedure is same as discussed above in case of 6% (W/V) Potassium Permanganate Solution The results With 6% (W/V) Zinc Acetate Solution are described in Table-3

Table-3: Deodorization of Ethyl Mercaptan with 6% (W/V) Zinc Acetate [Zn $(CH_3COO)_2$

S. No.	Sample Type (Mercaptan+ Tap Water)	Volume of Zn $(CH3COO)_2$ added	Mercaptan (ppm)	pH	Observation	
					1st Day	2nd Day (after 24 hrs.)
1.	0.5 ml + 50 ml	0 ml	> 120	7.89	Strong odour , clear solution	No Change No Change
2.	0.5 ml + 50 ml	10 ml	> 120	4.46	Strong odour , Curd like ppt.	
3.	0.5 ml + 50 ml	20 ml	> 120	4.73	Strong odour , Curd like ppt.	
4.	0.5 ml + 50 ml	30 ml	> 120	5.04	Strong odour , Curd like ppt.	
5.	0.5 ml + 50 ml	40 ml	> 120	5.04	Strong odour , Curd like ppt.	

3.4 With 6% (W/V) Sodium Hypochlorite Solution (pH 13)

Procedure is same as discussed above in case of 6% (W/V) Potassium Permanganate Solution The results with 6% (W/V) Sodium Hypochlorite Solution (pH 13) are described in Table-4.

Table-4: Deodorization of Ethyl Mercaptan with 6% (W/V) Sodium Hypochlorite Solution (NaOCl) pH 13

S. No.	Sample Type (Mercaptan+ Tap Water)	Volume of NaOCl added	Mercaptan (ppm)	pH	Observation	
					1st Day	2nd Day (after 24 hrs.)
1.	0.5 ml + 50 ml	0 ml	> 120	8.03	Strong odour , clear solution	Strong odour , clear solution
2.	0.5 ml + 50 ml	5 ml	> 120	10.11	Strong odour , milky white solution	Strong odour , clear solution with some ppt.
3.	0.5 ml + 50 ml	10 ml	> 120	10.8	Strong odour , milky solution with white ppt.	Strong odour , clear solution with ppt.
4.	0.5 ml + 50 ml	20 ml	>5<10	12.16	Less odour , milky solution with less white ppt. and oil droplets	Less odour , clear solution with less white ppt. and few oil droplet
5.	0.5 ml + 50 ml	30 ml	< 5	12.26	Very less odour, light milky solution with clear oil droplets and very less ppt.	Fruity odour, clear solution with very less ppt. and few Oil droplet

With 6% (W/V) Sodium Hypochlorite Solution (pH 10)

Procedure is same as discussed above in case of 6% (W/V) Potassium Permanganate Solution The results with 6% (W/V) Sodium Hypochlorite Solution (NaOCl) pH 10 are described in Table-5

Table-5: Deodorization of Ethyl Mercaptan with 6% (W/V) Sodium Hypochlorite Solution (NaOCl) pH 10

S. No.	Sample Type (Mercaptan+ Tap Water)	Volume of NaOCl added	Mercaptan (ppm)	pH	Observation	
					1st Day	2nd Day (after 24 hrs.)
1.	0.5 ml + 50 ml	5 ml	> 120	8.92	Strong odour , light milky solution with oily sheen	Strong odour , clear solution with oily sheen
2.	0.5 ml + 50 ml	10 ml	> 120	8.90	Strong odour, light milky solution with oily sheen	Strong odour , clear solution oily sheen
3.	0.5 ml + 50 ml	20 ml	>5<10	8.78	Less odour , light milky solution with oil droplets	Less odour , clear solution with few oil droplet
4.	0.5 ml + 50 ml	30 ml	< 5	8.32	Very less odour, light milky solution without oil droplets	Very less fruity odour, clear solution without oil droplet

Results

Reactions with different reagents are shown below:

The oxidation of mercaptan with potassium permanganate takes place as per the following reaction.

$$RSH + 2KMnO_4 + H_2O \longrightarrow RSO3H + 2MnO_2 + 2KOH$$

The oxidation of mercaptan with hydrogen peroxide takes place as per the following reaction.

1. $2RSH + H_2O_2 \longrightarrow R\text{-}S\text{-}S\text{-}R + 2H_2O$ (Incomplete Oxidation)
2. $RSH + 3\,H_2O_2 \longrightarrow RSO_3H + 3H_2O$ (Complete Oxidation)

The precipitation reaction of ethyl mercaptan with zinc acetate takes place as per the following reaction

$2RSH + Zn(CH_3COO)_2 \longrightarrow Zn(R\text{-}S)_2 + 2CH_3COOH$

The oxidation of mercaptan with sodium hypochlorite takes place as per the following reaction.

1. $2RSH + NaOCl \longrightarrow R\text{-}S\text{-}S\text{-}R + NaCl + H_2O$ (Incomplete Oxidation)
2. $RSH + 3NaOCl \longrightarrow RSO_3H + 3NaCl$ (Complete Oxidation)

From laboratorical findings, It was observed that 6% w/v sodium hypochlorite solution can oxidize the ethyl mercaptan to ethane sulphonic acid which is non odorous, having low toxicity and environmentally benign. The concentration of ethyl mercaptan is also below the detectable limit of mercaptan detector tubes (range 5 to 120 ppm) which is also below the hazardous limit of ethyl mercaptan. The results are depicted in Figure 1. Based on the experimental outcomes, the empty barrels of ethyl mercaptan at Dahej Plant have been deodorised and decontaminated successfully and neutralised content were disposed off in an environmentally safe manner.

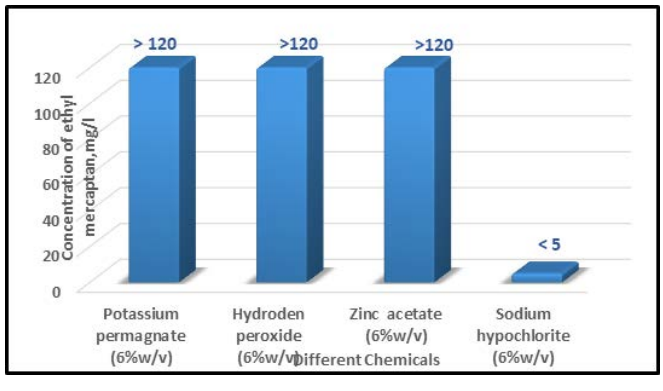

Figure 1: Comparison of Deodorisation and Decontamination of Ethyl Mercaptan with different chemicals

Conclusions

Based on the above experimental study, following conclusions regarding deodorization and decontamination of ethyl mercaptan can be drawn:

- 6% w/v potassium permanganate solution leads to increase of solid load due to precipitation of insoluble manganese dioxide in effluent which increases the disposal cost. Odour persists owing to adsorption of ethyl mercaptan on manganese dioxide precipitate.
- 6% w/v hydrogen peroxide solution is incomplete as it results in the formation of diethyl disulphide. It needs rigorous conditions that are use of catalyst, excessive deodorant and increase in temperature for its complete oxidation to ethane sulphonic acid, which ultimately increase the cost of catalyst.
- 6% w/v zinc acetate solution leads to increase of solid load in effluent due to precipitation of zinc mercaptide which increases the disposal cost and also the odour persists due to adsorption of ethyl mercaptan on zinc mercaptide precipitate.
- 6% w/v sodium hypochlorite solution (pH 13) is rapid and leads to formation of non-odorous, low toxic and biodegradable ethane sulphonic acid without any solid load in effluent.
- 6% w/v sodium hypochlorite solution (pH 10) is rapid and leads to formation of non-odorous, low toxic and biodegradable ethane sulphonic acid with lower pH which is environment friendly for disposal of effluent.

Study on the Effect of Chemical Additives on the Variations of Different Rheological Aspects of Waxy Crude Oils of Western Onshore




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Abstract

Crude oils with high wax content show non-Newtonian behaviour at low temperatures and tend to develop some inherent time dependent rheological properties such as thixotropy and yield stress which can be correlated to several flow related complications associated with waxy crude oils. At lower temperatures wax precipitation and formation of wax crystals result in gelation of waxy crude oils. Study of thixotropy, yield stress and viscosity are important to have an understanding about the extent of gelation and gel strength. Crude oils of wells Linch#A and Jotana#B of Mehsana Asset, Western onshore have high wax content and are facing problems during transportation at lower temperatures. In this paper; viscosity, thixotropy and yield stress of these two crude oils have been analysed and the effect of chemical additives on these rheological properties have been investigated. Studies show that these two crude oils have high thixotropic area and yield stress values at 25°C with significant improvement in the rheological properties when mixed with chemical additives.

Keywords: *Thixotropy, yield stress, viscosity, Waxy crude oil, chemical additives*

1. Introduction

The continuous exhaustion of global oil reserves propels the oil and gas industry to explore heavier fractions of crude oils with significant amount of paraffin waxes. At low temperature conditions wax gel formation, precipitation and deposition of waxes during the transportation of waxy crude oils in the pipelines contribute to several problems such as reduction in flow, excessive pumping cost affecting the crude oil production. Complications related to flow assurance with waxy crude oils arise due to temperature dependent solubility of wax molecules in the crude oil. Waxy crude oils generally have high wax appearance temperature and pour point. As the crude oil flows toward surface facilities and through surface pipelines, due to loss of heat to the surrounding, temperature of crude oil start to drop. When the temperature of crude oil reaches its wax appearance temperature, wax molecules start to crystallize and solid wax appears in the crude oil. With further decreasing of temperature, more wax crystals precipitate out, the crude oil then become a pseudo-plastic fluid [1]. Gelation of waxy crude oil occurs as a result of interlocking of precipitated wax crystals and formation of a three dimensional sponge-like network of wax crystals at the gel point

temperature, crude oil then turns into gel from sol phase[1]. Waxy crude oils below its wax appearance temperature are likely to develop time dependent rheological properties i.e. thixotropy and yield stress as a result of wax crystal precipitation and gelation.

Thixotropy is a continuous and reversible time-dependent change in viscosity when a particular shear rate is applied on a material continuously. For waxy crude oils thixotropy is one of the low temperature rheological behaviour. Thixotropic behaviour of waxy crude oils is found to have the characteristic of partial reversibility [2]. These kind of time-dependent changes in viscosity occur due to gradual change in the microstructures of the substance resulting from the application of shear continuously [3]. Materials showing thixotropic behaviour can consist of more than one type of structures in which some may be very sensitive and will break down even by low shear. The other type may be more robust and can survive at moderate to high shear rates [4]. Upon applying shear structure breakdown occurs which eventually leads to reduction of viscosity. Upon ceasing the shear rate which caused the breakdown, the material reforms its internal network and the viscosity recovers. Thixotropy of waxy crude oil can be analyzed by hysteresis loop area method using a Rheometer.

Yield stress is the stress that corresponds to transition from elastic to plastic deformation, the value of shear stress above which material flows [5]. Oil pipelines may shut down as a result of planned repair of production facilities or in case of failure. In case a pipeline is shut down for a longer period of time, the oil may cool down and become a non-Newtonian fluid with strong structural behaviours resulting into gel formation as discussed earlier. In such scenario, restarting the flow becomes main concern for transportation of waxy crude oil. Gel structure has to be broken down in order to restart the flow which can be done by applying a pressure. In order to determine the pressure required for breakdown of gel structure to restart the flow, it is important to know the yield stress of the gelled crude oil.

Thixotropy and yield stress are very important rheological characteristics in determining flow recovery and safe restart of pipeline. Variation in viscosity of crude oil with changing temperature is also a crucial rheological aspect with respect to flow assurance. In this study different rheological properties i.e. viscosity, thixotropy and yield stress of waxy crude oils has been investigated. For this purpose waxy crude oils of Linch#A and Jotana#B have been taken and the effect of different chemical additives on the rheological properties of crude oils have been evaluated.

2. Experimental Details

2.1 Materials and Equipment

One crude oil sample each from Linch and Jotana field of Western onshore are taken for this study. Xylene (AR Grade) and chemical additives from different vendors are used. All rheological measurements have been carried out on Rheometer-301.

2.2 Sample preparation

A measured quantity of crude oil and previously weighed chemical additive of the required dose are mixed carefully in a flat/round bottom flask and refluxed for one and half hour keeping the flask in a water bath at 65-70°C.

3. Results and Discussion

3.1 Physico chemical characterization of crude oil

Linch#A and Jotana#B crude oils have wax content of 21.53 Wt% and 18.75 Wt% & pour point of 39^{0}C and 42^{0}C respectively. Other physico chemical parameters are given in Table 1.

Table 1: Physico chemical characterization of Linch#A and Jotana#B crude oil

Sl. No.	Property	Unit	Results	
			Linch#A	Jotana#B
1	Water content	%	Traces	10
2	Density	g/cc	0.8296	0.8696
3	API Gravity	°API	39.06	31.22
4	Pour point	°C	39	42
5	Wax	Wt%	21.53	18.75
6	Resin	Wt%	7.86	8.67
7	Asphaltene	Wt%	1.12	2.42

3.2 Study of different rheological properties of crude oil

The chemicals EC 5353A & IGPPD 12048G for Linch#A and EC 5353A & Dewax DK 9173 for Jotana#B crude oils after dose optimization results were found to be effective for improving the rheological behavior of crude oils.

The following four mixtures were prepared for studies

Mixture 1: Linch#A crude oil+ EC 5353A (2000ppm) +2 % xylene
Mixture 2: Linch#A crude oil+ IGPPD 12048G (2000ppm) +2 % xylene
Mixture 3: Jotana#B crude oil+ EC 5353A (2000ppm) +2% xylene
Mixture 4: Jotana#B crude oil+ Dewax DK 9173(2500ppm) +2% xylene

3.2.1 Effect of chemical additives on viscosity of crude oils

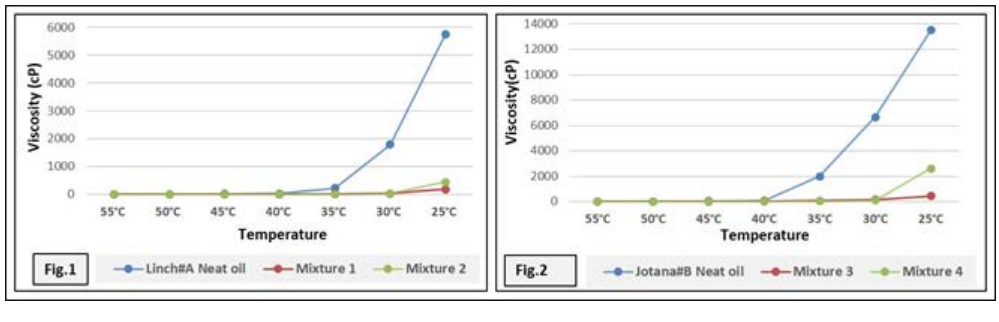
The viscosity of neat crude oil of Linch#A at 55°C is 14 cP and it goes up to 5740 cP at 25°C. EC 5353A and IGPPD 12048G both in 2000 ppm doze with 2% xylene gave the best results and are able to reduce the viscosity of Linch#A crude oil by 96.63% and 92.31% respectively at 25°C (Table 2, Fig.1).

Viscosity reduction of 96.67% and 80.75% is observed at 25°C for Jotana#B crude oil by the addition of EC 5353A(200ppm) and Dewax DK 9173(2500ppm) respectively using 2% xylene as a common solvent (Table 2, Fig.2).

Table 2: Effect of additives on the variation of viscosity with temperature and Pour point of crude oils

Sl. No.	Crude oil/Mixture	Viscosity(cP) at 30 s^{-1} shear rate							% Reduction at 25°C	Pour Point (°C)
		55°C	50°C	45°C	40°C	35°C	30°C	25°C		
1	Linch#A neat oil	14	15	23	37	232	1800	5740	-	39
2	Mixture 1	7	8	10	13	18	37	193	96.6	27
3	Mixture 2	6	7	9	11	16	34	441	92.3	27
4	Jotana#B neat oil	23	27	44	85	1980	6660	13500	-	42
5	Mixture 3	23	25	30	43	68	162	449	96.6	27
6	Mixture 4	17	19	23	29	45	98	2598	81	27

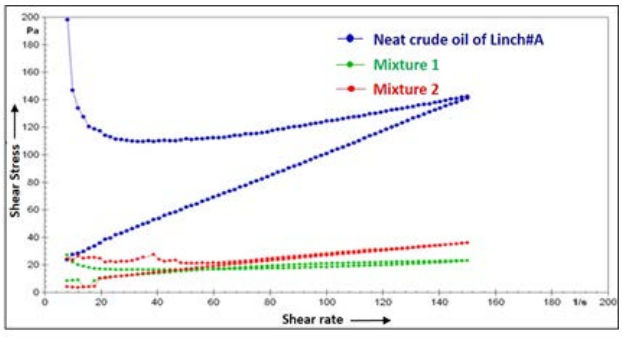
Fig.1&2: Effect of additives on variation of viscosity with temperature for Linch#A & Jotana#B crude oil



3.2.2 Effect of chemical additives on thixotropic behaviour of crude oils

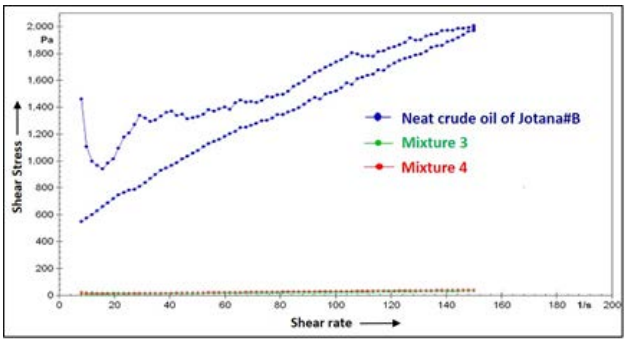
Thixotropic area of crude oil has the dimensions of energy per unit volume. To evaluate thixotropic area, variation in shear stress were observed with shear rate varying from 8 to 150 s^{-1} for a predetermined period at constant temperature of 25°C. Hold time of 15 seconds at shear rate of 150 s^{-1} is given to maximize the breakage of built structure and then again shear rate is ramped down from 150 to 8 s^{-1} in equal time. The area under increasing and decreasing curve gives the thixotropic area in Pa/s which means it is the amount of energy required to breakdown the thixotropic structure. For Linch#A neat crude oil, the thixotropic area is found to be 6262.79 Pa/s at 25°C and for mixture 1 & mixture 2, it is reduced to 102.08 & 685.44 Pa/s respectively (Fig.3).

Fig.3: Effect of additives on thixotropic behaviour of Linch#A crude oil



Thixotropic area of Jotana#B crude oil is reduced to 779.38 and 141.3 Pa/s from 32387.18 Pa/s when treated with EC 5353A(2000ppm) and Dewax DK 9173(2500ppm)respectively, both blended with 2% xylene (Fig.4). So, thixotropic area of both the waxy crude oils is reduced to significant extent when treated with additives which means that lesser amount of energy will be required to break bonds of gelled structures.

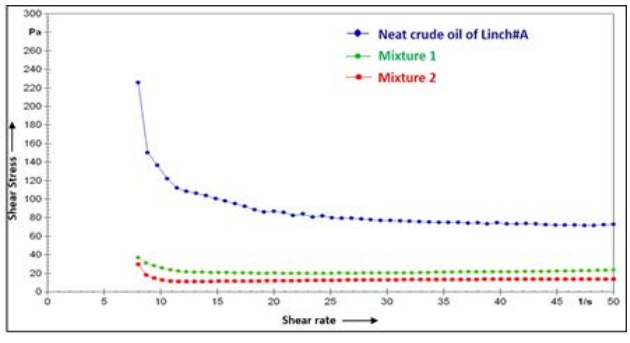
Fig.4: Effect of additives on thixotropic behaviour of Jotana#B crude oil



3.2.3 Effect of chemical additives on yield stress of crude oils

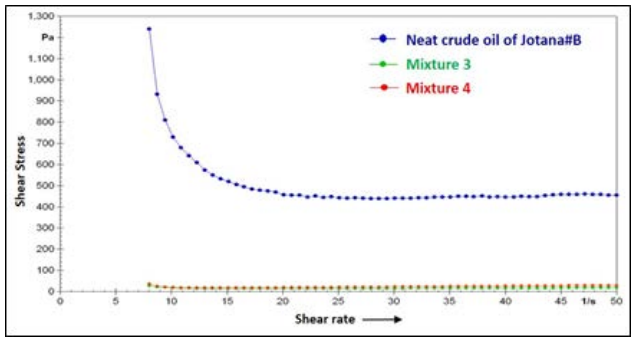
Yield stress measurements were carried out with shear rate varying from 8-50 s^{-1} at a constant temperature of 25°C. Yield stress value is calculated by Rheometer-301 using Herschel-Bulkley equation. The yield stress of the Linch#A crude oil is 3006 Pa at 25°C and it is sharply reduced to 20.94 Pa & 11.973 Pa with the mixing of chemicals EC 5353A and IGPPD 12048G in 2000 ppm doze respectively with 2% xylene (Fig.5).

Fig.5: Effect of additives on yield stress of Linch#A crude oil



For, Jotana#B crude oil yield stress value is decreased to 14.68 Pa and 18.12 Pa from 11274 Pa (neat oil) when treated with EC 5353A (2000ppm) and Dewax DK 9173(2500ppm) respectively with 2% xylene common to both additives (Fig.6).

Fig.6: Effect of additives on yield stress of Jotana#B crude oil



3.3 Effect of additives on the pour point of crude oils

Pour point of Linch#A crude oil is 39°C and it is reduced to 27°C for both mixture 1 and mixture 2. Pour point of Jotana#B crude oil is reduced from 42° C to 27°C for mixture 3 and mixture 4 respectively thus showing the depressing effect of additives on the pour point of crude oils (Table 2).

3.4 Wax dispersion and inhibition studies

For waxy crude oils, deposition of solid wax and clogging of pipelines is a common problem. An additive which is efficient to disperse and inhibit wax depositions would be suitable choice. Wax dispersion and inhibition study on these crude oils with the additives have been carried out using a Cold Finger apparatus. EC 5353A (2000ppm) and IGPPD 12048G (2000ppm) with 2% xylene have shown dispersion & inhibition efficiency of 24.36% and 23.11% & 45.82% and 44.03% respectively on Linch#A crude oil.

For Jotana#B crude oil, EC 5353A (2000ppm) & Dewax DK 9173(2500ppm) mixed with 2% xylene has been able to disperse deposited wax by 33.91% & 35.23% and also has inhibition efficiency of 61.19 % & 55.64% respectively.

4. Conclusion

Linch#A and Jotana#B crude oils are both waxy in nature with significant amount of wax and have high pour points of 39°C and 42°C respectively. Viscosity of Linch#A and Jotana#B crude oils are 5740cP and 13500cP at 25°C. EC 5353A & IGPPD 12048G have reduced the viscosity of Linch#A crude oil by 96.6% & 92.3% respectively and a reduction in the viscosity by 96.6% & 81% is achieved for Jotana#B crude oil by EC 5353A and Dewax DK 9173 respectively at their optimized doses.

Thixotropic and yield stress studies on these crude oils revealed that Linch#A crude oil has notable thixotropic area of 6262.79Pa/s & yield stress value of 3006 Pa and for Jotana#B crude oil thixotropic area is 32387.18 Pa/s with yield stress value of 11274 Pa which are very high indicating high gel strength. Reduction in thixotropic area by 89-99.5% with these chemicals are achieved, implying less energy will be required to break the gel structure. Yield stress values of these crude oils have been reduced by more than 99% with addition of respective chemical formulations, indicating that less pressure will be required for initiation of flow during transportation of the crude oils.

The studies indicate that the treatment of waxy crude oils of Linch#A, Jotana#B with these chemical formulations can lead to enhancement of different rheological properties and help in flow improvement.

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Views expressed in this paper are of authors only and not of the organization that they belong to.

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Challenges and Opportunities in Exploitation of Gas Hydrate Resources in Krishna Godavari Offshore Basin of India

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Abstract

Gas hydrate exploration in India has been carried out under the National Gas Hydrate Program (NGHP). Till date two expeditions (NGHP) 01 & 02 have been undertaken in Indian ultra-deep waters. During NGHP-02, two world-class gas hydrate reservoirs were discovered in Krishna Godavari (KG) offshore located in the east coast of India. However, exploitation of gas hydrate remains a challenging prospect globally and Indian ultra-deep waters is no exception. Gas hydrate production from ultra-deep waters of the east coast of India provide a unique set of challenges and opportunities. In order to mitigate risk from gas hydrate production from KG offshore basin, one has to take a holistic view of all the variables in the equation such as geology, available technology for production, the regulatory regime in India, environmental concerns, the market for gas and techno economics.

The share of natural gas in the energy mix of India is expected to increase to 20% in 2025. As India strives to be a 5 trillion dollar economy in the next 6-7 years, the natural gas demand is all set to grow significantly at a compounded annual growth rate (CAGR) of 6.8%. Currently, India imports nearly 50% of its total demand of gas. Most of the gas is imported in the form of LNG whose cost varies between $6.5- $7.0 per MMBTU.

During NGHP-02 two world-class gas hydrate (mainly pore filling and fractures type) reservoirs in sand dominated facies were discovered in KG offshore. Studies identified turbidites and debris flows as two prominent types of depositional systems responsible for the deposition of gas hydrate-bearing reservoirs. Based on the inputs of NGHP-02, simulation studies and techno economics have been worked out and reported. The price band for gas produced by gas hydrates from KG offshore has been put in the price band of $4.7- $9.0 per MMBTU depending on various production profiles. India's new Hydrocarbon exploration and licensing policy (HELP) allows the operator of the block to have full marketing and pricing freedom to sell. Discovery of prices will be on the basis of transparent and competitive bidding. Also, a single licence of the block allows exploitation of all the hydrocarbon resources including gas hydrates. Gas Hydrate production from offshore comes with its unique set of environmental concern such as seafloor subsidence, gas leaking and runaway reaction from gas hydrate dissociation etc. Based on recent evidences and the available geological information in KG offshore, these environmental risks are discussed.

In this paper we have discussed potential challenges and opportunities arising in gas hydrate production from KG deep water based on evidence gathered during NGHP Expedition 02 and the studies done thereafter. Analysis of various available production strategies, techno economics models and potential geo-hazards from producing gas from gas hydrates in KG offshore area have been addressed. All this analysis will pave way for better understanding and planning in commercializing gas from gas hydrates in KG offshore area.

Keywords *- Gas Hydrates, Krishna Godavari offshore basin, NGHP-02, Risk, Gas Production*

Introduction

India is one of the fastest growing economy of the world. Energy is required for the country to lift 1.3 billion population from $2000 per capita income to $10000 per capita income (developed country threshold). India imports 50% of its total gas demand and the total gas demand is expected to rise at 6.8% CAGR. Almost 60% of the demand comes from the power and the fertilizer sector. Thus there is an urgent need to increase domestic gas production to plug the supply and demand gap.

Gas hydrate exploration under National Gas Hydrate Program (NGHP) umbrella has established huge gas hydrate resources in KG offshore. Preliminary assessments put the total gas hydrate resource in the explored KG offshore area to 13.7 TCF. This abundant energy resource comes with its set of challenges and opportunities. In this paper we discuss few of the risk factors required to be addressed for successful gas hydrate exploitation in KG offshore basin.

Gas Hydrate Resource in KG Offshore Basin

Gas hydrate exploration in India is carried out under the umbrella of National Gas Hydrate Program (NGHP) which is a consortium of oil and gas companies and research institutes led by Ministry of Petroleum and Natural Gas. Till date two expeditions (NGHP-01 & 02) have been carried out in Indian offshore basins. NGHP-02 has established one of the best known gas hydrate reservoirs in KG offshore located in the east coast of India.

The KG basin is a major gas producing basin lying along the east coast of India and includes the deltaic and inter-deltaic areas of Krishna and Godavari Rivers and extends into the offshore. The basin covers an area of 28000 sq.km on land and 145000 sq.km in the offshore India. The basin is known to have significant hydrocarbon potential both in Tertiary deltaic systems and in deep-water channel-levee and fan systems. The basin has sedimentary fill from Paleozoic to Cenozoic in age (Bastia et al, 2006). The sites drilled during NGHP-02 were mostly on the fan system of the basin. Three areas (Area B, Area C and Area E) in the K-G basin were investigated.

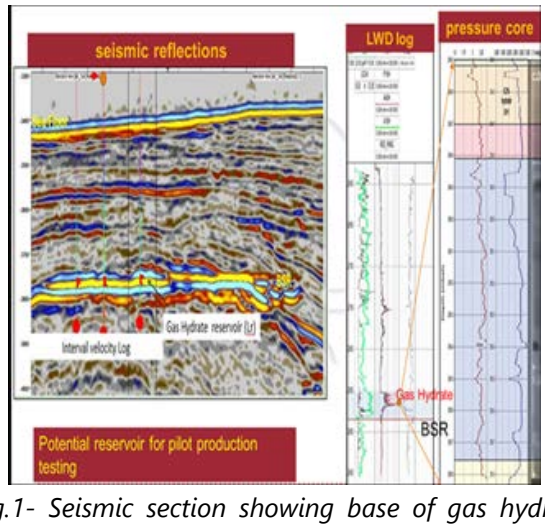

Fig.1- Seismic section showing base of gas hydrate. LWD log showing gas hydrate zones.

Onfield and lab studies during and after the expedition indicate presence of pore filling and fracture filling gas hydrate with saturation as high as 80% in coarser sediments (mostly sand).

Geochemical and isotopic analysis confirmed S-I type gas hydrate comprising of biogenic origin Methane (99.9%). Logging data indicates absence of free gas and presence of category –II (water layer beneath gas hydrate layer) gas hydrates.

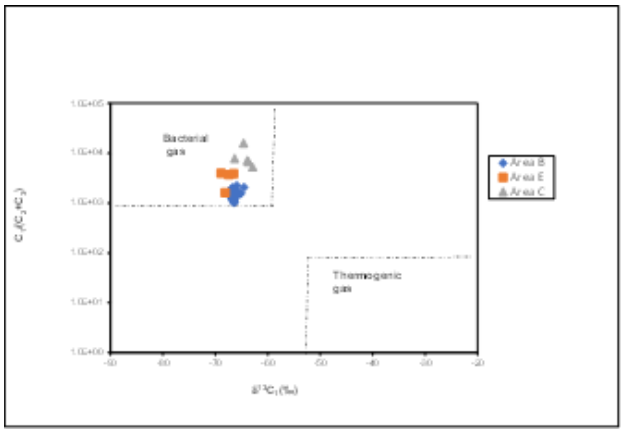

Fig. 2- Bernard Diagram showing biogenic origin of gases in gas hydrates in KG basin (Dixit et al, 2019)

For gas hydrate exploitations from KG offshore one must carefully analyze the challenges and opportunity. Let us discuss few of risk factors associated with gas hydrate production in KG offshore basin.

Business Risk

Any business faces supply and demand challenges along with policy uncertainties. India has huge appetite for natural gas which will keep on increasing with booming economy and climate issues.

Source	2010	2025
Coal	53%	50%
Oil	30%	25%
Gas	11%	20%
Hydro	5%	2%
Nuclear	1%	3%
	100%	100%

Fig. 3- Projected energy mix for India (Vision 2030-Report by Industry Group for Petroleum & Natural Gas Regulatory Board)

Fig. 4- Gas market zones near Gas Hydrate finds in KG offshore (Vision 2030-Report by Industry Group for Petroleum & Natural Gas Regulatory Board)

The gas hydrate finds in India have been mostly in KG offshore (Eastern coast). The gas hydrate finds are close to major port of Kakinada. Most of the oil and gas operations in KG offshore are based out of Kakinada giving it requisite infrastructure for hydrocarbon exploration. The eastern and the southern gas markets are the nearest gas demand centers. The proximity of gas hydrate resources near an established infrastructure and market gives commercial feasibility a good chance.

India has a new regulatory policy since the year 2016 called Hydrocarbon Exploration and Licensing Policy (HELP). Four main facets of HELP are-

1. Uniform license for exploration and production of all forms of hydrocarbon
2. An open acreage policy
3. Easy to administer revenue sharing model and
4. Marketing and pricing freedom for the crude oil and natural gas produced

Deepak et al carried out techno-economics analysis using simulation studies for gas hydrate production in one of the areas in KG offshore area. The study showed economic viability at a gas price of $9 per MMBTU based on assumed production rate of 6 MMSCMD of gas from 120 wells for 30 years. It is noteworthy that India imports gas in form of LNG at $6.5 per MMBTU.

Environmental Risk

One of the key risk involving gas hydrates exploitation is the environmental risk. Methane gas which constitutes majority of gas in gas hydrates is 30 times more potent greenhouse gas than carbon dioxide. In KG offshore gas hydrates occur at 2500m

plus water depth and gas hydrates are present 200-300m below seafloor. The gas hydrate stability zone (GHSZ) in this case is quite big and gas hydrates are stable but for the 500-600m sea column top. This implies any leakage of gas in GHSZ will be converted back to gas hydrate. Also Vielstädte et al, 2015, established solubility of methane in the top after sea column. He stated that almost 98 percent of methane is soluble in 80 m water column.

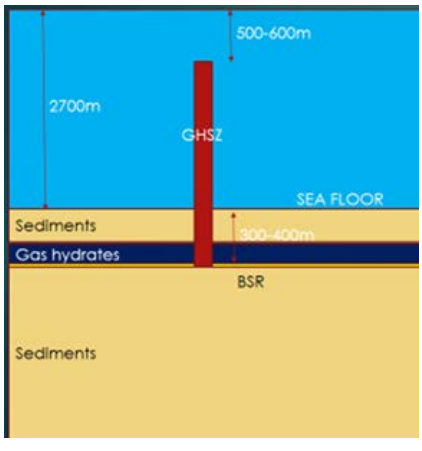

Fig. 5-Schematic represenation of Gas Hydrate system in KG offshore

Although methane is chemically non-reactive without life system metabolism of some sort, it is important as a nutrient at the base of the food chain in which different microorganisms consume it to produce oxygen, CO2, and other byproducts while themselves providing food for higher organisms. There is no free gas beneath the gas hydrates in KG offshore (Fig-1) which mitigates the risk of sudden gas leakage during drilling or production, one factor in a complex system of methane production and consumption.

The gas hydrates in KG offshore of India are biogenic in nature. Experimental studies have shown (Dixit et al, 2019) the gas hydrates in KG offshore of India are biogenic in nature and constitute mainly of pure methane gas (99.9%). This implies there is no presense of hazourdous gases such H_2S, CO_2 etc which are common in conventional oil and gas production.

The depressurization requirements for gas hydrate production at KG offshore, demonstrate a need for mechanical property measurements at effective confining stresses reaching 25 MPa. Studies by Lin et al, 2019, concludes that, assuming elimination of sand production through well designed sand control completion, the sediment remains stable within the gas production period studied.

The water released from dissociation of gas hydrate is pure water since gas hydrates during formation take in only pure water and all the impurities/salts are left behind. So unlike the convention oil and gas production where water disposal is big issue, gas hydrate production involves production of pure water which could be easily disposed or reused.

Sea floor slumping is also a major concern as gas hydrates have a very thin layer of un-consolidated sediments over them. Sea floor slumping is only possible when there is a run away gas hydrate dissociation reaction. The probablity of such run away dissociation is very less because- a) Gas hydrate dissociation is an endothermic reaction. This lowers the formation temperature on dissociation resulting in futher formation of gas hydrates. b) Dissociation of gas hydrates present inside the gas hydrate stability zone (GHSZ) will result in immediate reformation.

Also there are three criteria for the potential occurrence of submarine landslide that have been identified (He et al, 2017): (1) hydrates are widely distributed within the landslide areas; (2) the initial position of the landslide zone must be located at the phase boundary of the pressure-temperature field, (3) there is a low-permeability deposit under the hydrates which can maintain high pore pressure. The criteria suggest that submarine landslides caused by MGH decomposition are more likely to appear on shallow submarine slopes (Qin et al, 2011).

Still studies and pilot tests may be required in KG offshore to full proof the field development plan in a specific portion of the basin.

Production Risk

Producing hydrocarbons from deep water fields like those of KG offshore is capital intensive exercise. In case of gas hydrate production both technology and economics is a big challenge. The major techniques which have been used for gas hydrate extraction are-

1. Depressurization
2. Thermal
3. Molecular Exchange

Ignik Sikumi well in North Slope of Alaska performed pilot production test by injecting mixture of CO_2 and N_2 (Molecular exchange technique) into the well. The well flowed for 30 days with average gas rate ranging from 175000 scf/day to 20000 scf/day. Japan

conducted their second production test in Nankai Trough in the year 2017 using depressurization technique. The production in Nankai trough lasted 28 days with average gas production of 8500 m^3/day. China conducted their first production test in South China Sea using fluidization method where gas hydrate sediments were mined out from the sea bed. The production lasted for 60 days with average gas production of 5000 m^3/day. These production tests have not been long enough and the rates of production have been dismal. Rate of production of gas from deep/ultra-deep water offshore well should be sufficiently high having a long production life. Nevertheless it is a stepping stones for gas hydrate production technology.

During production and development, it is important to have real time monitoring of seabed deformation, reservoir stability, and methane leakage. Therefore, it is important to carry out long term, real-time, extensive, multi-parameter, in-situ monitoring to evaluate the impact that gas hydrate production has on the marine environment during production, development and after production is done.

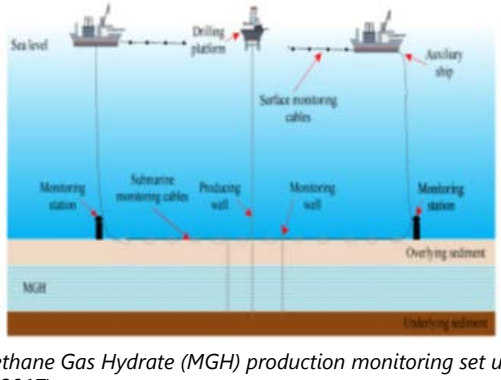

Fig. 6- Methane Gas Hydrate (MGH) production monitoring set up (He et al, 2017)

The gas hydrate finds in KG-offshore are in ultra-deep environment and will require lot of questions to be answered before the first gas comes out. Few of the other challenges are a) Sand ingress, b) Design of production assembly to prevent re-hydration and optimize flow and c) to handle huge quantity of fresh water generated during dissociation of gas hydrate.

Simulation studies (Evgeniy et al, 2019) for gas hydrate production in KG offshore have suggested of production rates ranging from 3000 to ~45,000m^3/day.

These production rates are still not good enough to make economics favourable for offshore production. However, with each new pilot production test there is advancement in production technology and the day is not far when commercialization of gas from hydrates becomes a reality.

Conclusions

The basic technology used for ultra-deep water exploration of conventional oil and gas is the pre cursor to gas hydrate exploitation. However, international gas prices, optimization of production technology and environmental concerns will play key role in deciding the future of gas hydrate commercialization in India. Many unconventional hydrocarbon resources such as shale gas and CBM have gone through similar uncertain phases. The size of opportunity in form of gas hydrates is too big to be ignored and with proper risk management these challenges can be overcome.

Acknowledgement

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Vision 2030- Natural Gas Infrastructure in India Report by Industry Group For Petroleum & Natural Gas Regulatory Board

Cross Country Pipeline Construction - In Pursuit of Zero Incident

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Abstract:

Cross country pipeline construction, as an industry, is more than 65 years old, the equipment, the methodology and technologies in this industry have not changed significantly as compared to other industries. The same incident reoccurs on one pipeline project, even though the incidents are investigated, reports are published, and root causes are known to management and communicated to workforce.

Pipeline construction activities are hazardous, fast paced, strenuous and are undertaken simultaneously at remote sites with limited access, making it difficult to monitor and control. Experience shows that the time spent on pre-construction and planning activities is simply rapid during construction phase of the work, when safety issues can be much more difficult to resolve. Road driving is another area of concern as lot of travelling is involved. Strategic, focused application of Health, Safety and Environment (HSE) programs and its monitoring and mitigation, would significantly improve the safety performance of the pipeline construction areas while improving the overall motivation of workers and time schedule to complete the project. These achievements are demonstrated through the development and implementation of strategic and focused HSE management programs that identifies the areas of concern along the pipeline and allocate the right type of resources at the right time to mitigate the probability of incidents. Pipeline construction industry will prosper in twenty-first century only if everyone, at every level, understands the importance of these safety issues and implements the practices that will safeguard both people and planet.

Introduction

The cross country pipeline construction activities right from acquiring the land, clearing ROU till pre-commissioning is full of safety challenges. Most of the equipment used in construction industry are unique in nature and have their specific hazards. The construction crew is faced with a plethora of challenges including steep and rocky terrain, crew change, culture, religion, unskilled workforce, varying land forms (sandy, bedrocks etc), unique hazards during operation of heavy equipment, etc. Such working conditions make it difficult to achieve the goal of Zero Incidents. Pipeline, usually traverses through hilly terrain, forest area, major rivers and underdeveloped areas. During the construction phase, a large number of unskilled workforce is hired for laborious work. Standardizing the HSE scope for contractors, strategic & focused implementation of HSE policy, regular trainings, systematic monitoring, audits and review, play a pivotal role in achieving Zero Incident in cross country pipeline construction phase.

Strategic and Focused Approach to Zero Incident Goal

Strategic and focused implementation of the following key elements throughout the pipeline construction phase is crucial in achieving Zero Incident goal.

Policy: HSSE policy of contractors and supervising contractors should be deliberated and aligned with the organization's goals. Once finalized, the relevant stakeholders should be briefed appropriately to ensure uniform communication. Safety is everybody's responsibilities; checks at regular intervals on effective discharge of responsibilities by both management staff and contractor supervisor is key towards taking ownership of HSSE programs.

Organization: Apart from providing qualified Safety Managers and engineers at site, a great deal of time and energy should be devoted towards short listing contractual safety officers. One safety engineer/ officer for a spread of @ 50 km, would be considered adequate to ensure monitoring and control of the activities. There should be at least one Safety Manager for every 3 spreads to coordinate and review the HSSE performance.

Planning and Implementation: Planning and implementation plays a great role in successfully completing the project in time, without loss of life. Before the start of the project, KPIs such as attainable HSSE objectives and targets, performance & minimum acceptable standards must be identified and communicated to contractors. Risk Register for all critical activities should be prepared in consultation with the construction workers and employees. HSSE should always be the top priority for every individual involved and ensure compliance to HSSE management system at all times.

Monitoring: Both active and reactive monitoring systems need to be put in place, for ensuring the success of any safety program. Active monitoring system will measure the achievement of objectives and specified standards, regular inspections and audits. Reactive monitoring system includes investigations of all failures in HSSE performance.

Reviewing and auditing Performance: Intra spread auditing system will not only help in identifying deviations (if any) from the agreed standards and causes for these deviations, but also bring to limelight good practices followed by other spreads. Project Managers must place the HSSE performance first on the agenda of the construction performance review meetings.

Training: In most of the projects, the workforce training focuses only on the tasks rather than the hazards. A step-by-step task list will help to address the hazards involved in a particular task and relevant control measures. To ensure that the safety rules are adhered to, the workers must be educated on the importance of these safety rules and the impact non-adherence would have on life.

Apart from the HSSE trainings, first aid training should be organized for selected workers to act as first aiders in case of any injury incident. The first aid training should include imparting knowledge on how to handle reptile bites at construction sites (sites include agricultural/barren land, hilly and forest areas). Concurrently, the sites should make arrangements with local hospitals in the nearby areas, which will be helpful in case of emergency.

During construction activities, large number of vehicles are hired for both material and people transportation from one place to another. Most of the drivers being locals, are not fully trained and hence pose serious risk to the passengers.

It is important that the drivers undergo defensive driving training program to avoid any mishap.

On many occasions due to reasons such as political or land issues, one has to let go of the trained workforce. The challenge that arises from such unprecedented situations is that of training the new workforce in safety procedures as they might not be aware of the construction activities, equipment and hazards associated with it.

Toolbox Talk Meeting: These meetings should be held prior to the start of any activity and focus on explaining the hazards concomitant to the activities being carried out and the control measures to protect them from any injury. The need of the hour is to ensure that every worker fully understands the toolbox talk, which should be conducted in local language at the workplace.

Standardization of Scope: Standardization of HSSE scope for contractors, Safe work practices, Risk Assessment for all the activities related to cross-country pipeline should be established in advance and made known to all contactors and their workforce before start of the work in the field.

Communication: It is integral to establish an open channel of communication between the workers and the management. Necessary steps should be taken to build trust amongst the stakeholders and respect each other. The management must be available to hear suggestions from the workers and ensure safe place to work, thus building a transparent culture.

Fatigue: In the construction industry, extended work hours is frequent. Long working hours causes fatigue, resulting in incidents. It is important to monitor the stretched working hours to avoid incidents.

Congested activities: At RoUs, amidst the fast paced activities, it is a challenge to identify an unsafe act, condition or practice, if one is not familiar with the equipment, methodology of operation and its limitation. To avoid any incident, it is advised that the safety officer/engineer observe the activities from a safe location and identify the hazards and take corrective actions.

Miscellaneous Hazards: Hazards due to HT line or road crossings, road settlement post laying pipelines, land & water contamination, plastic disposal, storage of hazardous chemicals and many more, should be assessed in advance and appropriate control measures should be communicated to the workforce to prevent incident and pollution.

Mobile phone usage: Mobile phone usage should be limited at the site while the work is in progress to avoid any kind of distraction. Under circumstances when the worker has to answer the cell phone, he should proceed to a safe location, finish the call and resume work.

Medical Facilities: Even though all strategic approaches are in place and practiced, the possibility of an incident at construction site cannot be ruled out due to changing environment, turnaround of workforce etc. In order to handle an emergency, a nurse should be appointed at the site, followed by identification of a nearest hospital. The hospitals shall also be equipped with anti-venom injections and scorpion bite medicines, common incidents while patrolling the pipeline area. The contact numbers of nearby hospitals must be available with at least 2-3 people in each spread or displayed on vehicle deployed at construction site.

Conclusion

HSSE is a **NO COMPROMISE** aspect in the cross country pipeline construction business. It is significant, to work towards a balanced approach by implementing the necessary rules for all employees including contract workers, to prevent incidents that could result in a serious injury or fatality. With the top management's commitment and leadership towards safety, in addition to the above mentioned points, safe and healthy working environment can be built.

Fired Heater Design: Integrating with Overall Process Objective Helps in Achieving Best Results

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Shilpa Singh
Deputy General Manager- Thermal

Sunil Kr. Saxena
Executive Director- Technical

Engineers India Limited

Introduction

Fired Heater or Furnace design involves multiple facets and requires close interaction among various specialisations. In many instances, it is seen that fired heaters are treated in form a 'package' completely delinked to the overall unit design. However, the practice results into multiple lacunas as the project progresses and ends up into un-optimised designs. Thus, it is prudent to integrate the furnace design with the overall process requirement at the unit design and engineering stage itself. Since these are energy consuming equipment operating at high temperature conditions and subjected to harsh operating environment, deeper thought process should be engaged in firming up the design basis of the furnace as neither too much overdesign nor too tight design helps the fired heater operability.

The present paper aims at addressing number of instances where integrating fired heater design with overall process can be beneficial in eliminating common pitfalls. There can be many other such examples which every heater designer faces in and out through the design life cycle. For simplicity, certain critical interactions are included in this paper for broader understanding and appreciation.

Fired Heater Broad classifications

Fired heaters range over various duties, types and order of size. Broad classification can referred from below Fig.1.

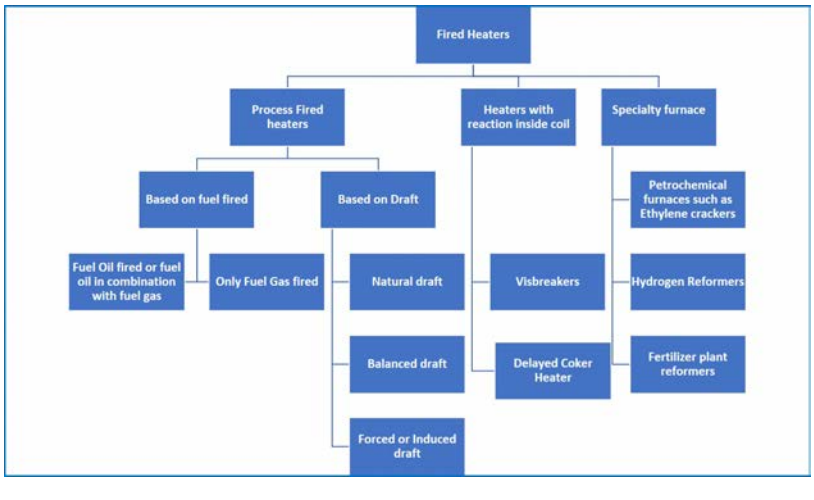

Fig.1: Type of heater systems

The present paper focuses on the critical aspects of process fired heaters only, although, similar analogy can also be drawn for the other categories.

As can be seen, design and conceptualisation of process fired heaters is not an 'off-the-shelf' activity as the fired heater being conceptualised must justify the capital cost, operating cost, environment stipulations, plot area availability as well as many other intangible factors. It is this huge gamut of intangible parameters that lend this equipment the requirement for 'Tailor made' design. A simple example is the case of a hot oil heater feeding a plant that process pitch. Going by general norm, a heater of process duty exceeding 20 MMKcal/Hr may well justify employing an elaborate air preheat system. However, the possibility of additional interlocks and trips associated with the air preheat system should also be taken into account. Where failure of hot oil flow can solidify the pitch and cause irrecoverable damage to the plant, tripping of furnace for rather minor reasons may not be very justifiable. There are similar innumerable intangible occurrences and reasons for which it is better to view the fired heater in conjunction with the overall process.

Some of the benefits of integrating fired heater design with overall process objective is highlighted herein:

Fixing up the design duty

Saying goes, "The more the merrier!" Probably, it is not the case for fired heaters. It has been observed that in hydrotreating units, need to address various process scenarios and requirements at times result in very high design margin while determining the design duty. The fired heaters in these units are designed for a process duty which may need to be attained only during unit start-up for few days. Therefore, in many cases, the actual operating duty of the fired heater during SOR (start-of-run) case or EOR (end-of-run) case is a meagre 20% or even less of the start-up or heater design duty case. Thus, the fired heater is continually operated near to turndown throughout a major part of its operating cycle. A general query arises- "so what if it is operated at a much lower duty than what it is designed for?" A very straightforward answer to this query is – safety! Large duty fired heaters when operated at lower duty shall have a cooler firebox temperature which is detrimental for complete combustion, thus, emitting CO (carbon monoxide). At one end, it is indeed a safety hazard whereas at the other end, it also pronounces fuel loss and emission concerns. The latter part is particular important as all fired heater stacks are fitted with CEMS (continuous emission monitoring system) which continually monitors the listed emissions including CO. Industry practice is to consider a firebox or arch temperature of minimum 540°C below which CO and incombustibles can be a concern. Thus, it is imperative that the expected firebox temperature at least during normal SOR operation or EOR operation should be above the threshold limit of 540°C, preferably with some cushion. This becomes a difficult task to ensure when the SOR or EOR duty is of the order of 20% of heater design duty. Hence, ample care must be taken while finalising the heater design duty in such cases. If required, alternate means to reduce the start-up duty should be explored so that the SOR normal operating duty is not less than approximately 35-40% of the heater design duty. An integrated process and fired heater design helps in achieving this task.

Case Study-1:

A hydrotreating unit fired heater was to be designed for multiple operating conditions, namely Rated case, SOR case and EOR case. The SOR case and EOR case are continuous operating cases. The duties and resultant design is noted below. Table-1 is a classic example where detail review of the rated duty figure should take place in case the heater is to be operated within allowable emission envelope during continuous operation (SOR or EOR case).

Table-1

Parameters	UoM	Rated Case	SOR Case	EOR Case
Heater Absorbed Duty	MMKcal/hr	23.6	4.4	12.3
Total Radiant surface area provided	Sq.feet	5300	5300	5300
Calculated Radiant flux	Btu/hr.ft^2	11760	2805	6900
Calculated Bridgewall Temperature	°C	880	500	734
Inference	• Continuous operating duty for SOR case is almost 18% that of the heater design duty. • BWT or Arch temperature for SOR case is only 500°C. Guaranteeing Carbon Monoxide emissions at this continuous operating condition is doubtful and turned down by burner vendor. • Large variation in operating duties leading to a cool firebox condition at SOR which may lead to unstable flame and stricter monitoring requirement.			

Heater Pressure Drop

In fired heater design, saying goes "Mass flux is the king!" Indeed it is. However, this cardinal aspect of heater design often has to be compromised due to lower specified available pressure drop across the furnace during a grassroot design. Allocating a low pressure drop may not be good idea as the value may be highly inadequate to ensure a good mass velocity. In turn, a poor mass velocity (as shown in fig.2), especially for heavy fouling services, can lead to coking issues which can turn into perennial problems. Thus, based on the type of the fluid being heated, it is recommended that pressure drop allocated to the furnace should be adequate to ensure a reasonable mass velocity not only at design, but also at turndown conditions commensurating with the unit's turndown capability. Such integrated design can pay out in the long term even if it takes few to-and-fro exercises at the design stage.

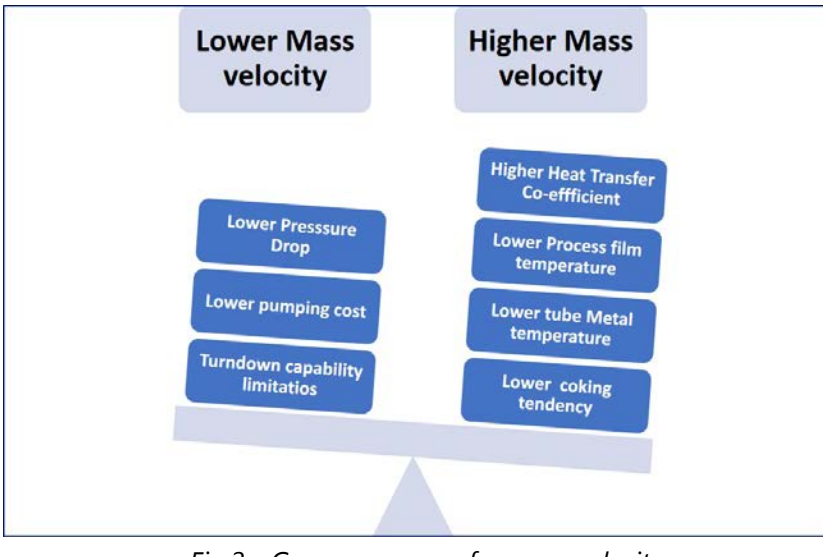

Fig.2: Consequences of mass velocity

Case Study-2:

A fired heater in hydrodesulfurisation service was analysed for the following conditions. Table-2 illustrates the importance of fixing pressure drop based on mass velocity instead of designing the heater for a pre-specified pressure drop:

Table 2

Parameters	Units of Measurement	Value
Heater Absorbed Duty	MMKcal/ Hr	6.4
Design Flowrate	Kg/ Hr	107000
Allowable Pressure Drop	Kg/cm^2	3.0
Allowable average radiant flux	$Btu/hr.ft^2$	12000
Options	5" NB tubes in radiant section	6" NB tubes in radiant section
Resultant Mass velocity in radiant section	~200 $lb/ft^2.sec$	~130 $lb/ft^2.sec$
Calculated pressure drop	3.9 Kg/cm^2	3.0 kg/cm^2
Inference	• The mass velocity has to be drastically reduced by 35% in order to meet the pre-specified allowable pressure drop. • Resultant mass velocity is not adequate for hydrodesulfurisation service with two-phase flow. The Licensor was approached and pressure drop allowable across the heater was enhanced to 4.0 kg/cm^2 to adopt the safer and better design.	

Fuel to be fired and its quality

It must be understood and decided at the initial stages itself regarding the fuel to be fired. Often, it is seen that furnaces are designed for firing both fuel oil and fuel gas although the refiner is well aware that only fuel gas shall be fired. For such instances, it must be noted that fired heaters solely designed to fire fuel gas shall have vastly different design compared to same heater with fuel oil firing. Predominant difference in feature include type of extended surfaces to be adopted in convection section tubes, burner to tube spacing, excess air percentage, fuel efficiency, presence of sootblowers etc. Thus, considerable cost can be saved if a conscious decision is taken at the design stage itself regarding the type of fuel to be fired in the long run.

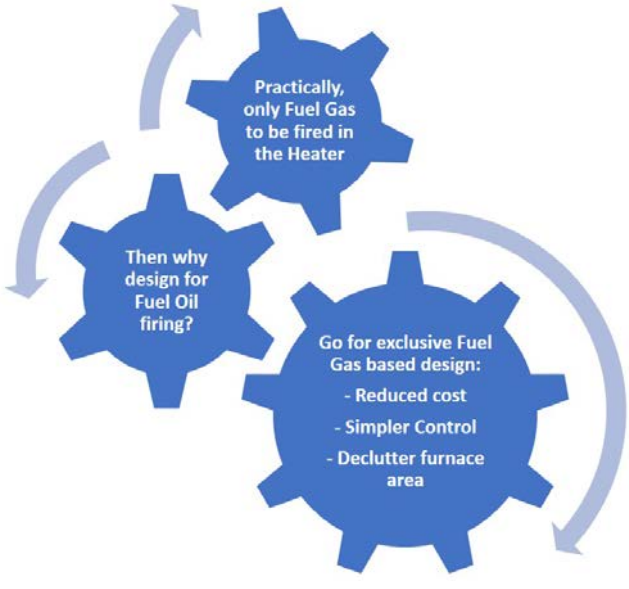

Fig.3: Effect of fuel firing on heater design

Even for firing fuel oil, the type and composition of fuel oil can impact the heater design considerably. Fuel oil components such as Sodium and vanadium can alter the metallurgy of the tube supports to be used. They do form a major part of the cost. Another critical aspect is the fuel Nitrogen content. Based on vast data available, it is seen that fuel oil with Nitrogen content exceeding 1200-1300ppmw and preheated air fails to comply with statutory NOx emission limits. Thus, there can be instances of altering the fuel oil pool even at very late stages in order to comply with emission requirements. For such instances also, integrating fired heater design with overall project requirements and limitations helps in multiple ways to skirt around possible contentious issues.

Auxiliary Utility

Another classic case of integration between process design and heater design is seen in deciding upon the utility medium. Fired heaters generally have a provision for emergency driving out of the process fluid when the flow suddenly fails. The driving medium can be steam with adequate pressure or it can be an inert medium like Nitrogen. Since steam is more readily available, often it acts as the default choice. However, steam as an emergency purging medium can be detrimental where there are reactors filled with catalysts downstream of the fired heater. Since, heater designer who generally has limited availability of data and characteristics of the overall process, it is beneficial in integrating the overall process design with fired heater design so that a proper channel of communication is established between the process designer and the heater designer. If not addressed at early design stage, issue such as this can magnify into major re-working at plant pre-commissioning and operation phases. Therefore, it is essential for a fired heater designer to interact with the process designer and familiarize with the process flow scheme in and around the heater area.

Similarly, there are instances in older refineries where header pressure of steam is appreciably lower than that for newer installations. In those cases, going by nomenclature of 'medium pressure steam' which is actually at only 9 kg/cm2g may be

insufficient for proper sootblower cleaning application where pressure of around 11 kg/cm2g is desired. Thus, it is essential to ascertain the level of MP steam from the process designer.

Fired Heater Emissions

Nowadays, new projects or even brownfield projects are accorded environmental clearance only when they comply with the statutory emission guidelines. Generally, the statutory body allows a figure for a particular pollutant which accounts for the combined emissions from all fired heater stacks within the refinery umbrella. Hence, there comes the difficult decision making when an economically viable project may just entangle its prospects due to environmental concerns. Among the listed pollutants, NOx is the most prominent. There are several post- combustion and pre-combustion techniques to rue NOx emission figures. However, cost again comes into play. As a saviour, it is well established that emissions from Fuel gas fired furnaces are appreciably lower than that from fuel oil fired furnaces. This critical tool can just prove to be the game changer for border line cases. Such optimization comes with its own concerns. For example, it may disrupt the overall refinery fuel balance tilting it more towards the fuel gas consumption side. Thus, such scenario can be better handled jointly between the process designer and the heater designer to select the combination that is 'win-win'. Even, there are instances where certain ratio of fuel oil and fuel gas firing has been determined which produces the NOx level just enough to be within the umbrella limit as well as satisfying the overall refinery fuel balance and profitability.

Case Study-3:

A large capacity Crude heater was analysed for various fuel firing modes w.r.t emissions. Table-3 provides a classic illustration of variation in emissions when transforming from heavy fuel oil firing to much cleaner fuel gas firing:

Table-3

Absorbed Heater Duty	**MMKcal/hr**	**~90**	
	100% Fuel Oil firing	**50% Fuel Oil firing + 50% Fuel Gas firing**	**100% Fuel Gas firing**
SOx emissions in Kg/hr	**95**	**50**	**5**
NOx emissions in Kg/Hr	**44**	**38**	**30**
CO_2 emissions in Tons/day	**700**	**630**	**550**
Inference	• **Firing the furnace with fuel gas reduces the emission levels drastically as compared to 100% fuel oil firing.** • **However, firing with 100% fuel gas will call for detail fuel balance across the refinery complex.**		

Conclusion

Fired Heaters have long been seen on an equipment level or a vendor item during the process design phase. The approach can have shortcomings which may assume larger role as the project progresses. The present paper proposes to integrate the fired heater design with the unit process design and thus, create a symbiotic relationship between both the activities. As discussed in the paper, it is imperative that the pressure drop across the heater should be a result of the fluid mass flux demand and not the other way round. Such a heater design will eventually pay off in the long run maximising unit's availability and avoiding frequent coking issues in heater coils. Optimal selection of heater duty avoiding seeming attractive copious overdesigns and determining proper range of heater's operation, enables the heater to comfortably meet the allowable emission limits, when

operated at its continuous run duty. A well-thought decision with regard to fuel selection for the heater can result into lucrative savings both in terms of Opex and Capex. Since, Fired heaters play a very critical and major role in determining overall refinery level emissions at the project approval stage, integrating fired heater design with the overall process design can drive the emission perspective into a project's favour.

Thus, to sum up, malfunctioning of fired heater due to design issues affects the overall unit performance which, in turn, can downgrade the profitability and reliability of the refinery installation resulting into reasons for heartburn in years to come. Hence, it is recommended to fired heater design should not be treated as a standalone activity delinked with the overall process objective. Rather, fired heater design 'keeping in mind' the overall process objective can be much more rewarding in the long run.

Disclaimer

The case studies included in this paper are for illustration purpose only and do not correspond to any particular project or refinery. Resemblance, if any found, to be reckoned as purely co-incidental.

Acknowledgment

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Recent Tax & Regulatory Measures to Revive the Indian Economy

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A. Backdrop and Prevailing Scenario

Given the backdrop of the prevailing Covid-19 pandemic, there has been significant pressure on business across all categories. A significant portion of 2020 witnessed complete or partial lockdown across the country. Most non-essential businesses experienced little or no commercial activity in these months owing to, and indirectly also leading to, lower consumer spending.

Disposable income has reduced due to pay cuts, bonus rollbacks or deferrals and freeze in hiring across industries. The quarter ended September 2020 witnessed partial resumption of business resulting in marginal improvement of the economic situation. The Government recently announced various policy, regulatory and tax measures to further boost the economy and provide an impetus to re-achieve normalcy. We shall discuss some of the reforms in the ensuing paras.

B. Key Policy Announcements

i. Revised purchase preference policy for Oil & Gas ('O & G') projects

The Ministry of Petroleum and Natural Gas ('MoPNG') had issued a Purchase Preference policy linked with local contact ('LC') ('PPLC – April 2017') in April 2017 for procurement by the Government and its majority owned entities in the O & G sector.

Subsequently, the Government of India had issued a revised Public Procurement policy ('PPP') in June 2020 aimed at increasing domestic (local value addition) participation in public procurement activities. However, the revised PPP is not applicable to companies in O & G sector and these companies are still covered under PPLC of April 2017.

In line with revised PPP, MoPNG has recently revised the PPLC to boost domestic manufacturing and service sectors. The policy will be applicable for all tenders issued by public sector O & G companies and their joint ventures. Among other changes, some key features of the revised policy are as under:

- Suppliers are classified into three categories
  - Class I bidder – with more than 50 per cent LC
  - Class II bidder– with 20 to 50 per cent LC
  - Non-local content bidder – with less than 20 per cent LC

- Purchase preference has been increased from 10% to 20% - i.e. Class I bidders would be given opportunity to match lowest bidder ('L1') Non-LC bidder if the difference in price range is less than 20% (which was 10% earlier).

• Following guidelines have been prescribed for bids/ Purchase preference to suppliers with LC:
  o Where the Government/ Ministry determines that there is sufficient LC domestically, only Class I shall be allowed to bid;
  o Only Class I supplier shall be eligible for purchase preference, if price is within 20% of L1 (lowest bid); and
  o For divisible contracts, L1 will be awarded 50% of contract value while lowest Class I bidder within 20% of L1 will be allotted balance 50% of contract value subject to matching L1. For non-divisible contract, the lowest Class 1 bidder within 20% of L1 will be awarded the contract if they are L1 or if they match L1.

Under the policy, both multinational and domestic suppliers and service providers are expected to manufacture/ procure goods as well as services locally. This Policy shall not only provide much needed thrust to manufacturing, services and EPC sector in the economy but shall also help in generating millions of jobs.

ii. Announcements under AatmaNirbhar Bharat 3.0 (Self-reliant India)

The Union Minister for Finance and Corporate Affairs Ms. Nirmala Sitharaman has announced 12 key measures on 12 November 2020[1], as part of Government of India's stimulus to the economy, under AatmaNirbhar Bharat 3.0. The net stimulus announced amounts to INR 2.65 trillion and includes the following:

• A new scheme "AatmaNirbhar Bharat Rozgar Yojana" has been launched to incentivize creation of employment. The subsidy will be provided for two years as under:

Nature of establishment	Quantum of subsidy
Establishments employing up to 1000 employees	Employee's contributions (12% of Wages) & employer's contributions (12% of wages) totalling 24% of wages
Establishments employing more than 1000 employees	Only employee's EPF contributions (12% of EPF wages)

Aforesaid benefits are available for new employees joining employment in EPFO registered establishments on monthly wages less than INR 15,000 and EPF members drawing monthly wage of less than INR 15,000 who made an exit from employment during the Covid-19 pandemic between March - September 2020 and are employed on or after 1 October 2020.

• Considering the impact of the lockdown on business activities, the Government released the Emergency Credit Line Guarantee Scheme ('ECLGS') to provide fully guaranteed and collateral free additional credit to Micro, Small and Medium Enterprises ('MSMEs'), business enterprises, individuals (loans for business purposes) and MUDRA borrowers. The Scheme has been extended until 31 March 2021.

• To provide ease of doing business and relief to contractors whose money otherwise remains locked up, performance security on government and public sector contracts has been reduced from 5-10% to 3%. This will also apply to ongoing contracts. The relaxations will be in force till 31 December 2021.

• INR 30 billion boost is being provided to EXIM Bank for promoting project exports under Indian Development and Economic Assistance Scheme (IDEAS Scheme). This will enable EXIM Bank facilitate Lines of Credit development assistance activities and promote exports from India.

• Production-linked incentive ('PLI') scheme worth INR 1.46 trillion has been unveiled to encourage domestic manufacturing investments in ten more champion sectors such as telecom, textiles, automobiles, food products, specialty steel, etc.. The Scheme shall help augment competitiveness of domestic manufacturing, promote exports and generate employment. While O & G sector is not currently covered under the Scheme, one will have to wait and watch if similar Scheme is introduced for O & G sector or the sector can make a suitable representation before the Government to be included under the scheme.

C. Recent Regulatory Reforms

i. Introduction of new Labour Codes

The existing labour laws framework is an elaborate network of 29 laws / legislations. Depending on the business, employers/ employees have been complying with multiple legislations. Keeping in

mind the Government's mission towards ease of doing business in India, aforesaid 29 laws have been subsumed into the following four labour codes:

- ***The Code on Wages, 2019*** aims to consolidate laws relating to wages and bonus and illustratively provides for equal remuneration, minimum floor wages at the Central Government level with ability to enhance the floor wage by the State Government, statutory bonus, working hours, overtime compensation, permissible wage deductions, early timelines for full and final settlement to name a few. It also provides for greater enforcement and stringent penal consequences for the employer.

- ***The Code on Social Security, 2020*** aims to provide for social security to all employees and workers in the organised or unorganised sector and illustratively introduces gratuity payments for fixed-term employees, social security for gig/ platform workers etc. It provides that contributions towards Employee's Provident Fund and Employees' State Insurance ('ESI') will be basis the new wage definition.

- ***The Occupational Safety, Health and Working Condition Code, 2020*** mandates provision of safe working conditions by all employers, enable employees to report unsafe working environment, provides for working hours and leave encashment by workers, special provisions for employment of women, etc.

- ***The Industrial Relations Code, 2020*** includes provisions relating to industrial disputes, standing orders, matters in connection with trade unions, approvals for retrenchment etc.

An illustrative list of some important provisions under these new Labour Codes are as under:

- New definition of 'wages' to include all salary components expressed in terms of money or capable of being expressed in money subject to specific exclusion subject to specified limit. Retirals will now be required to be calculated basis the new definition of Wage and that could result in higher cost for employers and/ or lower take home for employees;
- All employees will now be eligible for overtime pay at twice the normal rate of wages;
- Deduction from monthly wages capped at 50%. Further, there are specific conditions or approvals required for certain deductions;
- Additional burden as a principal employer to make payment to contractor before the date of payment of wages by the contractor;
- Gratuity will now be payable to fixed term employees;
- Workers will now be eligible to receive leave encashment at the end of each calendar year;
- Increase in threshold of workers to 300 for obtaining the consent of the concerned Government in case of lay off or retrenchment or closure of business.

These labour codes have endeavored to adopt a pragmatic approach by widening the application of various provisions, bringing in uniformity, increasing coverage to different types of employees and providing reliefs to certain small firms. However, given that the code is likely to come into force in the next few months, for complying with these codes, organizations may now need to relook at their entire employee lifecycle and focus their efforts to ensure that they are ready to embrace these new codes once the same comes into effect.

ii. Liberalization of regulations governing BPO and ITeS Sector

The Government has, vide Press Release dated 5 November 2020[2], announced certain relaxations for the Business Process Outsourcing ('BPO') and Information Technology Enabled Services ('ITeS') sector in relation to the applicability of Other Service Provider ('OSP') guidelines of Department of Telecom ('DoT'). Key features of the policy changes are provided below:

- Registration requirements for the OSPs has been done away with;
- BPO industry engaged in data related work have been taken out of the ambit of OSP regulations;
- Requirements such as deposit of bank guarantees, static IP requirements, reporting obligations, network diagrams, penal provisions etc. have also been removed; and

- Requirements preventing companies from adopting 'work from home' and 'work from anywhere' models have also been removed and additional dispensations have been provided for additional flexibility of the industry.

  The new framework not only encourages work from home, but also extends the guidelines to permit work from anywhere. Given the pandemic situation, these measures are expected to be well received by BPO and ITeS sectors. These changes would help the engineering and ITeS companies operating in the O & G sector and would provide them with much needed flexibility.

D. Recent Tax Reforms

i. Leave Travel Concession ('LTC') Cash Voucher Scheme

Under the existing regulations, salaried taxpayers can claim exemption for expenditure incurred on travel within India, subject to conditions. Such exemption is available to public sector and private sector employees based on block of year concept. Currently, employees can claim exemption for two journeys (airfare or rail fare) in a block of four calendar years, with the current block being 2018-2021.

The Covid-19 pandemic witnessed prolonged travel restrictions across the country which resulted in limited mobility of persons and disruptions in the transport and hospitality sector. As a result, employees have not been able to avail the LTC benefits. With a view to assist taxpayers in availing LTC benefits, which would have otherwise lapsed, and boost consumer demand in the economy, the Ministry of Finance vide Press Release dated 12 October 2020[3] announced the LTC Cash Voucher Scheme for central government employees.

As per the scheme, in lieu of one LTC payment in the current block of four years, cash payment shall be made to employees for:

Type of Payment	Taxability	Other parameters
Leave encashment	Taxable	--
Payment of fare in three flat slabs	Exempt	Slabs (INR 6,000 / INR 20,000 / INR 36,000) depending on designation-based entitlement to rail fare, economy airfare or business class airfare

There is no requirement for an individual employee to take actual leave to avail this scheme. However, to claim aforesaid exemption, central government employees need to fulfil certain conditions:

- Buy goods / services worth three times the deemed LTC fare and avail one-time leave encashment on or before 31 March 2021;

- Aforesaid spend to be made on goods, attracting Goods and Services Tax ('GST') of 12% or greater, from a GST registered vendor. Such spends should fall between the period 12 October 2020 and 31 March 2021; and

- Expenditure must be through digital mode and a GST invoice must be produced.

If the expenditure falls short of three times of the deemed LTC fare, the tax exemption shall be restricted on a pro-rata basis and excess LTC fare received would need to be refunded back to the employer. E.g. if the deemed LTC is INR 20,000 per person with 4 family members, total deemed LTC fare shall be INR 80,000. Accordingly, the expenditure on goods/ services needs to be INR 2,40,000 (3 times of INR 80,000). If expenditure is INR 2,40,000 or more, the employee he shall be entitled for full deemed LTC fare and corresponding income-tax exemption. However, if expenditure is less than INR 2,40,000, say INR 1,20,000 (50% of minimum spends), the entitlement shall be for 50% (i.e. INR 40,000) of deemed LTC fare and the corresponding income-tax exemption.

Subsequently, benefits under the scheme were also extended to non-central government employees vide Press Release dated 29 October 2020[4].

Coming to the private sector, where the salary package of employees is structured on the lines of CG employees (i.e., they are entitled to LTC only if they take leave and travel), the implementation may not pose significant challenges. However, where employees are paid Leave Travel Allowance irrespective of actual travel and under the revised Scheme the proportionate unspent amount is to be recovered from the employee, private sector players will face the predicament of modifying their compensation policy to accommodate the Scheme.

Considering that the Scheme has a short-term utility till 31 March 2021 and is intended to boost consumption in the economy amidst the COVID-19 pandemic, employers will need to evaluate the mode of implementation within the parameters of the policy announcements made so far.

E. Expectations

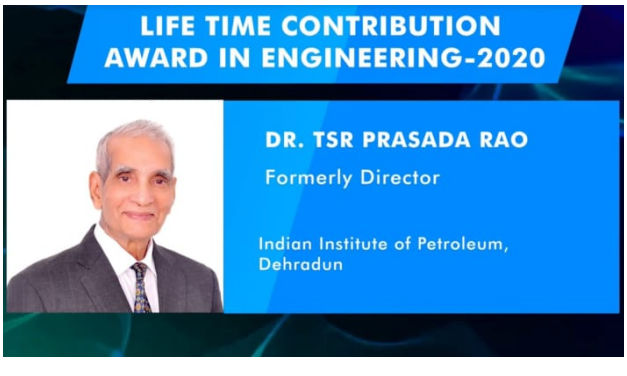
The above tax and regulatory reforms have indicated the Government's steps actions and intent to support businesses and help boost the economy. While certain measures have been announced by the Government, the industry would view Budget 2021 as another opportunity for the Government to announce policy reforms and rationalization measures. The following industry expectations would be a welcome move from an O & G industry perspective:

- Bringing natural gas within the ambit of GST – this would help in rationalization and bringing uniformity in prices by doing away with multiple tax levies and duties; and
- Grant manufacturing status to various activities under the CGD sector by way of issuing clarification to enable companies in the O & G sector to avail various incentives and subsidies available to manufacturing sector.

The journey to normalcy for most category of businesses would indeed be a long one. The Indian economy, however, could be nursed back to health if it is helped by reforms and initiatives taken by the Government from time-to-time and providing a fillip to industry and trade in general.

1. https://www.pib.gov.in/PressReleasePage.aspx?PRID=1672321
2. https://pib.gov.in/PressReleseDetailm.aspx?PRID=1670405
3. https://pib.gov.in/PressReleseDetailm.aspx?PRID=1663722
4. https://pib.gov.in/PressReleasePage.aspx?PRID=1668609

FIPI Congratulates Dr TSR Prasada Rao on receiving the Prestigious INAE Lifetime Contribution Award in Engineering - 2020



Dr. TSR Prasad a Rao, Formerly Director, Indian Institute of Petroleum, Dehradun has made outstanding contributions in developing mission-critical technologies that substitute processes available solely from multinational companies. His distinguished service to India is unique and notable because of his passionate and unrelenting efforts to go beyond the laboratory and apply science and engineering to develop and commercialise indigenous technologies for India's industrial development. His Key Word is Develop and Commercialise. He used his science and engineering achievements to develop and commercialise more than 10 technologies in collaboration with leading Indian companies including Bharat Petroleum, Indian Oil, GAIL, Indian Petrochemicals, Reliance, and Cadila Pharmaceuticals. Similarly, Dr. Rao led Indian Petrochemicals to acquire catalyst manufacturing capabilities, expanding India's position in the global catalyst manufacturing industry. Besides being an accomplished technocrat, Dr. Rao is widely recognised as a successful leader of Indian R&D institutions. As Director of CSIR - IIP during 1990-1999, he combined his passion for science and engineering with his experience in industry to transform the institute from a sick laboratory to a vibrant, world-class innovation centre. Since retiring from Government sector in 1999, Dr. Rao has passionately championed science-based entrepreneurship in India.

Dr TSR Prasada Rao is awarded the INAE Life Time Contribution Award in Engineering for the year 2020 in recognition of his outstanding contributions in developing indigenous mission - critical technologies and transforming of Indian Institute of Petroleum as a world-class innovation centre.

OIL & GAS IN MEDIA

Unified Tariff Introduced by PNGRB may Prove Game Changer to Achieve the Vision of Gas Based Economy

In a recent intervention, the Petroleum and Natural Gas Regulatory Board (PNGRB) has simplified the country's gas pipeline tariff structure to make the fuel more affordable for distant users and to attract investment for building gas infrastructure. PNGRB has introduced a regulation for 'unified' tariff structure for 14 cross country pipelines that form the National Gas Grid which will lead to a 20-30 per cent rise in transportation charges paid by users near the source but a reduction for consumers in the hinterland.

The PNGRB regulation said "Unified tariff shall be determined by the Board in respect of the national gas grid system for each financial year before the start of such financial year". Presently the pipeline tariffs are charged on the basis of distance transported. Longer the distance, higher are the charges. PNGRB has now notified a two-zone tariff structure - Zone-1 will be 300-km from the source of gas and Zone-II will be beyond that. PNGRB has indicated that the tariff for the first tariff zone will be 40 per cent of the tariff for the second zone. This is expected to lead to an immediate increase in tariff for user industries such as power plants and fertilizer units in Gujarat. However, the customer which are located far away from the source of the gas will now benefit from lower tariffs.

The new tariff structure would help create a single gas market in the country by attracting investment to complete the gas grid and make it more easily accessible. This is part of the government's plan to raise the share of gas in India's energy mix to 15 per cent by 2030 from the current level of about 6.3 per cent to cut its carbon footprint.

CCEA Approves Standard Procedures for Market Price Discovery

The Government of India has now approved E-bidding for discovering the market price of gas to be sold by producers. It permit affiliates to participate in the bidding for sale of gas, and allows marketing freedom to certain field development plans where production-sharing contracts already provide pricing freedom. The new regulations allow discoveries and field development plans approved after February 28, 2019, for complete marketing and pricing freedom. However, these regulations will not be applicable to bulk of the gas produced under the administered pricing regime.

The objective of the new policy is to present standard procedure to discover market price of gas to be sold in the market by gas producers, through a transparent and competitive process, permit Affiliates to participate in bidding process for sale of gas and allow marketing freedom to certain Field Development Plans (FDPs) where Production Sharing Contracts already provide pricing freedom.

The move is expected to attract more investors and help achieve the vision of gas-based economy. Shri Dharmendra Pradhan, Minister for Petroleum and Natural Gas and Mines mentioned that the decision will help increase domestic gas production by an additional 40 Mmscmd, from the current 80 Mmscmd. The government has already provided for pricing and marketing freedom to gas produced from blocks awarded under the Discovered Small Field Policy (DSF), Hydrocarbon Exploration and Licensing Policy (HELP) and Coal Bed Methane (CBM) contracts, and discoveries from difficult fields such as deep water, ultra-deep water and high pressure-high temperature areas.

ONGC starts Oil and Gas Production from West Bengal after 60 years Endeavor

Oil and Natural Gas Corporation Ltd (ONGC) has commenced oil production from the Asokenagar-1 well, Bengal Basin in West Bengal's 24 Paragana districts. With the development, the Bengal Basin has joined the ranks of Krishna-Godavari (KG), Mumbai Offshore, Assam Shelf, Rajasthan, Cauvery, Assam-Arakan Fold Belt and Cambay. Till now, ONGC has invested Rs 3,361 Crore to explore hydrocarbon in the Bengal Basin. More Rs 425 Crore will be spent on exploration activities in the basin in the coming two years. Oil extracted from the field is sent to Haldia refinery of Indian Oil Corporation. The discovery of the eighth producing basin of India will play a role for India's energy security. The first oil and gas reserve in West Bengal was discovered in 2018. The Ashoknagar field, which falls under the Mahanadi- Bengal-Andaman (MBA) basin, has been proved to be commercially viable. The appraisal programme of Ashoknagar discovery for an area of about 739 sq km would include 3D seismic, low frequency passive seismic survey and drilling wells besides acquiring 1300 LKM (line kilometre) of 2D and 2900 SKM (square kilometre) of 3D. These fields will also produce gas to the extent of 1 lakh cubic meters a day and oil between 15-18 cubic meters (1 cubic meter equals to 1,000 litres) a day.

Reliance, BP start Gas Production from Deep-water KG-D6 field

Reliance and BP are jointly developing three gas fields in the offshore KG-D6 block. Of these, the R Cluster field — which is expected to reach plateau gas production of about 12.9 million standard cubic metres per day (MMSCMD) in 2021 — now becomes the first project to come online? Located at a depth of more than two kilometers, the R Cluster is the deepest offshore gas field in Asia. The project was sanctioned in June 2017. The other two fields developed in the KG D6 block — Satellites Cluster and MJ project — were started in April 2018 and June 2019, respectively. The three blocks, entailing an investment of around Rs 35,000 Crore, are expected to cumulatively produce 30 mmscmd by 2023, accounting for a quarter of the country's domestic gas output. RIL is the operator of KG-D6 with a 66.7% participating interest while the remaining stake is held by BP. The KG-D6 fields have been given considerable pricing and marketing freedom via separate fiats over the last four years. The gas will be sold according to standard bidding norms for gas price discovery approved by the Cabinet in October. Currently, new gas fields (those other than the nominated fields) make up for less than fifth of the natural gas produced in the country, but these are expected to increase their share significantly in the coming years

FIPI EVENTS

BP Energy Outlook

Continuing the long tradition, the Federation of Indian Petroleum Industry (FIPI) joined hands with BP India to organize BP Energy Outlook – 2020 on 19 October, 2020. In its past editions, the outlook was unveiled in a physical gathering with participation limited to CXOs of oil and gas companies. Due to the ongoing COVID-19 pandemic, this year the event was organized on a virtual platform, allowing a much broader participation from across the energy industry in India.

The welcome address at the occasion was provided by Dr R K Malhotra, Director General (DG), FIPI. Dr Malhotra kicked off the proceedings of the day by extending a very warm welcome to all the participants joining at the webinar. He underlined that over the last few days the number of COVID cases in the country has witnessed a sharp decline. The impact of the falling number of cases is already visible in the Indian economy. Quoting a recent ICRA report, he highlighted that sale of cars, motor cycles and railway traffic has already shown a marked improvement over the last few months after contracting for straight four months. The global oil and gas sector was among the worst affected due to the pandemic. There was significant demand destruction and the oil prices touched their historic low in April this year. In this regard, India was no different either, however, the sector has shown clear signs of recovery since September. He hoped that in the near future, the economy will revive and the energy industry will continue to witness the growth it has been seeing over the last few years. He was confident that in the long run the betterment in living standards and aspiration of people will continue to drive the energy demand even further. Emphasizing the importance of the BP energy outlook, Dr Malhotra underlined that the report has acted as a guide for the global energy industry and helped prepare to tackle the uncertainties of the future.

Mr Spencer Dale, Group Chief Economist, BP Plc., made a detailed presentation on the BP Energy Outlook 2020. At the outset, he informed the participants that the outlook assess' the future possibilities under three broad scenarios namely:

Rapid Scenario: It shows a sharp increase in carbon prices along with other supportive Government policies towards climate change

Net zero scenario: It shows that in addition to climate policies and carbon prices there is change in societal behavior which led to further fall in Carbon emissions.

Business as Usual (BAU) Scenario: It assumes that policy, technology and societal behavior continue to improve in a similar way as past.

Mr S M Vaidya, Chairman, IndianOil and FIPI delivering his concluding remark for the session thanked Mr Spencer Dale for his detailed presentation. He highlighted that while accurate predictions cannot be made about the future scenarios due to a large number of variables and disruptions, the BP outlook has served as a guiding light for the entire industry in formulating strategies. The impact of the ongoing pandemic is clearly visible on the economy, trade and the oil and gas sector. The BP Energy outlook takes into account the impact of COVID and showcases three possible scenarios emerging in the future. This will help the oil and gas companies to navigate through the potential uncertainties surrounding energy transition. Today the energy space is changing fast with RE, digital technologies, energy efficiency and the imperative to address climate change requirements. Energy mix will get increasingly diverse in the future driven by the customer choice. For the oil and gas sector COVID has resulted in production cuts, fall in prices, investment cuts and asset restructuring while on the other hand RE has emerged more resilient from the pandemic in terms of demand and investment cuts. In India, while oil and gas will have a strong presence, RE will also continue to rise. Natural gas is expected to grow at a much higher rate than other fossil fuels in the country.

Mr Sashi Mukundan, President, BP India and Senior Vice President, BP group, delivering his vote of thanks highlighted the importance of this year's BP energy outlook in the backdrop of the COVID crisis.

The session proved extremely successful. Especially Mr Dale's presentation triggered a very fruitful Q&A session and brought out some deep insights about the global and the Indian energy sector. The session witnessed an overwhelming participation from more than 200 industry experts, academia, Ministry officials and industry members. A general inquisitiveness was noticed among the participants for the next edition of the BP Energy Outlook, that will account for the overall impact of the pandemic on the energy sector in general and oil and gas sector in particular.

NEW APPOINTMENTS

M.V. Iyer assumes charge as Director (Business Development) of GAIL

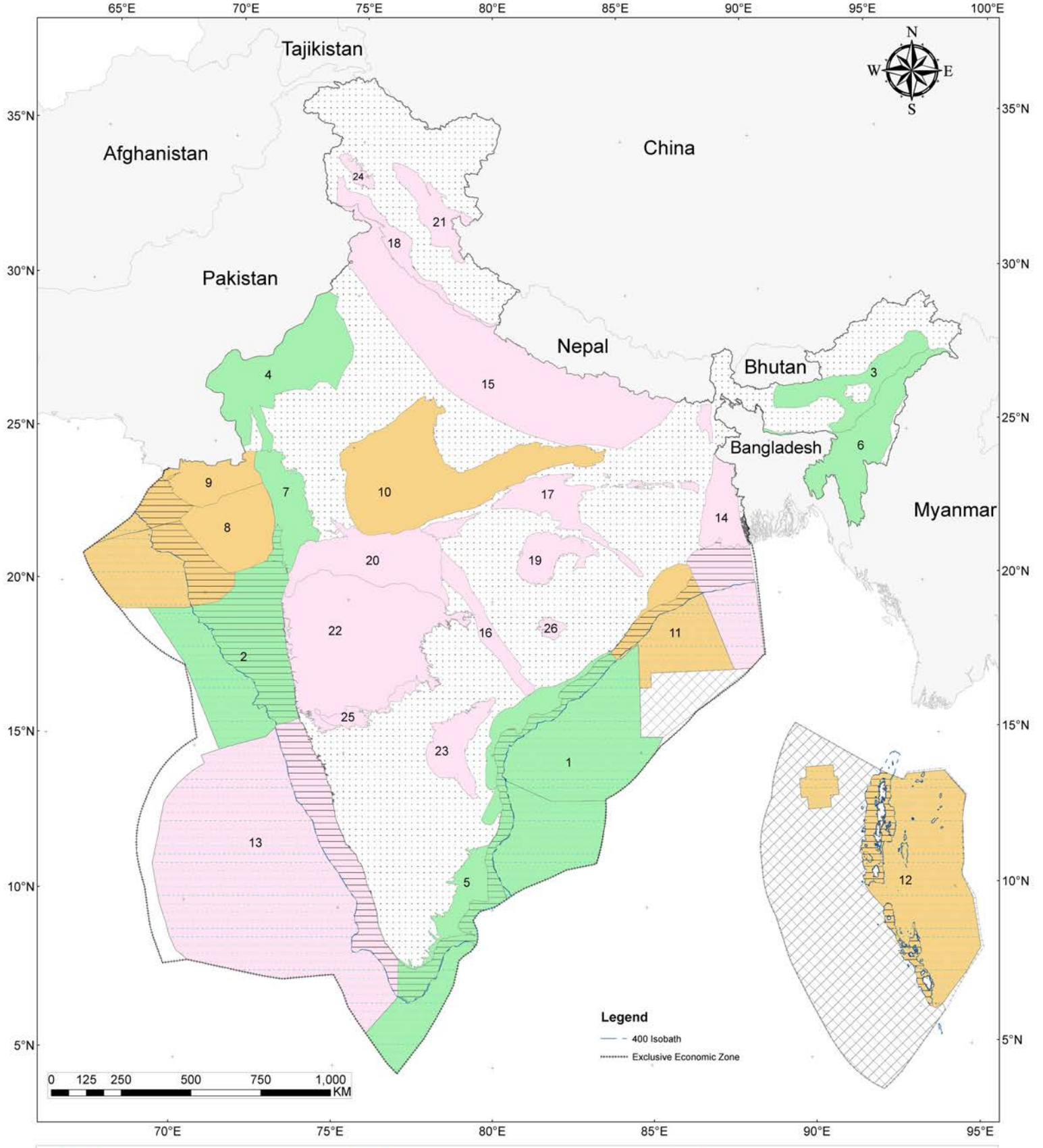
M.V. Iyer

Mr. M V Iyer assumed charge as Director (Business Development) of GAIL (India) Limited on 25th November 2020. Before this, he was working as Executive Director (Projects) with the company.

An Electrical Engineer, Mr. Iyer has 33 years of rich and diverse experience in GAIL in projects execution amounting to Rs 40,000 crores, including current projects worth Rs 25,000 crores spanning 16 states, 150 districts and City Gas Distribution (CGD) projects in six cities. As a target-oriented professional, he has consistently delivered results in Projects, Operations and Maintenance roles.

He has been part of the core team of GAIL for implementation of various long term and short term strategies in GAIL. Mr. Iyer is also Director in one of the GAIL's new Joint venture company Indradhanush Gas Grid Limited (IGGL) for implementation of North East Gas Grid. He has been associated with several non-core business areas like commissioning of the Dabhol LNG Terminal and implementation of 100 MW Wind power project, 5 MW Solar power projects and current thrust areas of City Gas Distribution (CGD) projects within short span of one year.

Indian Sedimentary Basins



Category - I
(Basins with 'Reserves' being produced and exploited)

Category - II
(Basins with 'Contingent Resources' to be developed and monetized)

Category - III
(Basins with only 'Prospective Resources' to be explored and discovered)

Pre-Cambrian basement/ Tectonic sediments

Shallow water areas (0-400 m Isobath)

Deepwater areas (> 400 m Isobath)

Un-assessed deepwater areas

Categary - I Basins	Categary - II Basins	Categary - III Basins	
01. Krishna-Godavari (KG)	08. Saurashtra	13. Kerala-Konkan (KK)	20. Narmada
02. Mumbai Offshore	09. Kutch	14. Bengal-Purnea	21. Spiti-Zanskar
03. Assam-Shelf	10. Vindhyan	15. Ganga-Punjab	22. Deccan Syneclise
04. Rajasthan	11. Mahanadi	16. Pranhita-Godavari (PG)	23. Cuddapah
05. Cauvery	12. Andaman	17. Satpura- South Rewa-Damodar	24. Karewa
06. Assam-Arakan Fold Belt		18. Himalayan Foreland	25. Bhima-Kaladgi
07. Cambay		19. Chhattishgarh	26. Bastar

Source: DGH

STATISTICS

Summary of Exploration, Production & Development activities in India FY 2019-20

1. Exploration Activities:

1.1 2D Seismic: In FY2019-20, 3,787.71 Line Kilometres (LKM) of 2D Seismic data was acquired. Out of this , 3,599.50 LKM was obtained from the Seismic activities carried out in the fields under Revenue Sharing Contract (RSC) regime.

1.2 3D Seismic Activities: In FY 2019-20, cumulative 3D seismic data acquired was 7,018.24 Square Kilometres (SKM). In the fields under RSC regime, 4,166.89 SKM of 3D Seismic data was acquired. 3/4th of 3D seismic data was acquired in offshore.

1.3 Exploratory Drilling: In FY2019-20, total of 121 exploratory wells were drilled. 84 wells drilled in onshore, while 37 wells were drilled in offshore. In terms of meterage, 340,130 meters was drilled. Onshore drilling meterage stood at 241,950 meters while, in offshore it stood at 98,180 meters. In terms of operator, ONGC drilled 106 wells out of the 121 wells.

Table 1: Exploration Activities in FY 2019-20

Sl. No	Subject	Parameter	ONGC (Nomination)	OIL (Nomination)	PSC (Pre-NELP & NELP)	RSC (OALP+DSF)	Total
1	2D Seismic data acquired	Onland (GLKM)	152.43	33.68	2.10	2,174.10	2,362.31
		Offshore (GLKM)	-	-	-	1,425.40	1,425.40
Total 2D Seismic			**152.43**	**33.68**	**2.10**	**3,599.50**	**3,787.71**
2	3D Seismic data acquired	Onland (SKM)	978.49	122.10	6.35	665.53	1,772.47
		Offshore (SKM)	1,744.41	-	-	3,501.36	5,245.77
Total 3D Seismic			**2,722.90**	**122.10**	**6.35**	**4,166.89**	**7,018.24**
3	Exploratory wells drilled	Onland	71	11	2	-	84
		Offshore	27	-	10	-	37
Total Exploratory wells			**98**	**11**	**12**	**-**	**121**
4	Exploratory Meterage drilled	Onland (1000 m)	204.46	30.79	6.70	-	241.95
		Offshore (1000 m)	74.73	-	23.46	-	98.19
Total Exploratory Meterage drilled			**279.19**	**30.79**	**30.16**	**-**	**340.13**

Source: India's Hydrocarbon Outlook 2019-20

2. Development Activities:

2.1 Development Drilling: A total of 526 development wells were drilled during the FY2019-20. 427 were onshore wells and 99 were offshore wells. Drilling meterage stood 1. 06 million metre. Onshore drilling meterage is 0.83 million metre and offshore drilling meterage is 0.23 million metre.

Table 2 Development Activities FY 2019-20

Sl. No	Subject	Parameter	ONGC (Nomination)	OIL (Nomination)	PSC (Pre-NELP & NELP)	RSC (OALP+DSF)	Total
1	Development wells drilled	Onland	273	25	129	-	427
		Offshore	79	-	19	1	99
Total Development wells			**352**	**25**	**148**	**1**	**526**
2	Development Meterage drilled	Onland (1000 m)	515.76	65.04	253.12	-	833.93
		Offshore (1000 m)	176.82	-	51.18	2.73	230.73
Total Development Meterage drilled			**692.58**	**65.04**	**304.30**	**2.73**	**1,064.66**

Source: India's Hydrocarbon Outlook 2019-20

2.2 Discoveries in Development Phase: A total of 26 Field Development plans (FDPs) and Revised Field Development plans (RFDPs) were approved in FY 2019-20. 6 FDPs and 13 RFDPs approved are under PSC regime. FDPs noted by 3

2.3 New Oil & Gas Discoveries: Total of 12 discoveries was accepted in FY 2019-20, out of which 5 are oil discoveries and 7 are gas discoveries. ONGC had the largest number of discoveries approved, 9. Till FY2019-20, 251 discoveries have been made in the PSC regime.

STATISTICS

INDIA: OIL & GAS

DOMESTIC OIL PRODUCTION (MILLION MT)

		2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept 2020	
									% of Total
Onshore	ONGC	6.1	5.8	5.9	6.0	6.1	6.1	3.0	39.2
	OIL	3.4	3.2	3.3	3.4	3.3	3.1	1.5	19.7
	Pvt./ JV (PSC)	9.1	8.8	8.4	8.2	8.0	7.0	3.1	41.2
	Sub Total	**18.5**	**17.8**	**17.6**	**17.5**	**17.3**	**16.2**	**7.5**	**100**
Offshore	ONGC	16.2	16.5	16.3	16.2	15.0	14.5	7.2	92.0
	OIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pvt./ JV (PSC)	2.7	2.5	2.1	1.9	1.9	1.5	0.6	8.0
	Sub Total	**18.9**	**19.1**	**18.4**	**18.1**	**16.9**	**16.0**	**7.8**	**100**
Total Domestic Production		37.5	36.9	36.0	35.7	34.2	32.2	15.4	100.0
	ONGC	22.3	22.4	22.2	22.2	21.0	20.6	10.2	66.1
	OIL	3.4	3.2	3.3	3.4	3.3	3.1	1.5	9.7
	Pvt./ JV (PSC)	11.8	11.3	10.5	10.1	9.9	8.4	3.7	24.3
Total Domestic Production		**37.5**	**36.9**	**36.0**	**35.7**	**34.2**	**32.2**	**15.4**	**100**

Source : PIB/PPAC

REFINING

Refining Capacity (Million MT on 1st October 2020)

Indian Oil Corporation Ltd.	
Digboi	0.65
Guwahati	1.00
Koyali	13.70
Barauni	6.00
Haldia	8.00
Mathura	8.00
Panipat	15.00
Bongaigoan	2.35
Paradip	15.00
Total	**69.70**

Chennai Petroleum Corp. Ltd.	
Chennai	10.50
Narimanam	1.00
Total	**11.50**

JV Refineries	
DBPC, BORL-Bina	7.80
HMEL,GGSR	11.30
JV Total	**19.10**

Bharat Petroleum Corp. Ltd.	
Mumbai	12.00
Kochi	15.50
Total	**27.50**

Hindustan Petroleum Corp. Ltd.	
Mumbai	7.50
Visakhapattnam	8.30
Total	**15.80**
Other PSU Refineries	
NRL, Numaligarh	**3.00**
MRPL	**15.00**
ONGC, Tatipaka	**0.07**
Total PSU Refineries Capacity	**142.57**

Private Refineries	
RIL, (DTA) Jamnagar	33.00
RIL , (SEZ), Jamnagar	35.20
Nayara Energy Ltd. , Jamnagar #	20.00
Pvt. Total	**88.20**

Total Refining Capacity of India 249.9 (5.00 million barrels per day)
Nayara Energy Limited (formerly Essar Oil Limited)
Source : PPAC

CRUDE PROCESSING (MILLION MT)

PSU Refineries	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept 2020 (P)
IOCL	53.59	58.01	65.19	69.00	71.81	69.42	26.90
BPCL	23.20	24.10	25.30	28.20	30.90	31.53	10.66
HPCL	16.20	17.20	17.80	18.20	18.44	17.18	9.19
CPCL	10.70	9.60	10.30	10.80	10.69	10.16	3.38
MRPL	14.60	15.53	15.97	16.13	16.23	13.95	4.35
ONGC (Tatipaka)	0.05	0.07	0.09	0.08	0.07	0.09	0.04
NRL	2.78	2.52	2.68	2.81	2.90	2.38	1.27
SUB TOTAL	**121.12**	**127.03**	**137.33**	**145.22**	**151.04**	**144.71**	**55.79**

JV Refineries	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April-Sept. 2020 (P)
HMEL	7.34	10.71	10.52	8.83	12.47	12.24	5.13
BORL	6.21	6.40	6.36	6.71	5.71	7.91	2.51
SUB TOTAL	**13.55**	**17.11**	**16.88**	**15.54**	**18.18**	**20.15**	**7.64**

Pvt. Refineries	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April-Sept. 2020 (P)
NEL	20.49	19.11	20.92	20.69	18.89	20.62	8.92
RIL	68.10	69.50	70.20	70.50	69.14	68.89	28.98
SUB TOTAL	**88.59**	**88.61**	**91.12**	**91.19**	**88.03**	**89.51**	**37.89**

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April-Sept. 2020 (P)
All India Crude Processing	**223.26**	**232.90**	**245.40**	**251.90**	**257.17**	**254.38**	**101.32**

Source : PIB Release/PPAC

CRUDE CAPACITY VS. PROCESSING

	Capacity On 01/10/2020 Million MT	% Share	Crude Processing April - Sept.2020 (P)	% Share
PSU Ref	142.6	57.1	55.8	55.1
JV. Ref	19.1	7.6	7.6	7.5
Pvt. Ref	88.2	35.3	37.9	37.4
Total	**249.9**	**100**	**101.3**	**100**

Source: PIB/PPAC

POL PRODUCTION (Million MT)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	April - Sept. 2020 (P)
From Refineries	217.1	227.9	239.2	249.7	257.4	258.2	105.2
From Fractionators	3.7	3.4	3.5	4.6	4.9	4.8	2.1
Total	**220.7**	**231.2**	**242.7**	**254.3**	**262.4**	**262.9**	**107.3**

DISTILLATE PRODUCTION (Million MT)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Light Distillates, MMT	63.2	67.1	71.0	74.7	75.4	76.8	32.7
Middle Distillates , MMT	113.4	118.3	122.5	127.5	130.8	130.2	49.9
Total Distillates, MMT	176.6	185.4	193.5	202.2	206.1	206.9	82.6
% Distillates Production on Crude Processing	**77.8**	**78.5**	**77.8**	**78.8**	**78.6**	**79.9**	**79.9**

Source: PIB/PPAC

PETROLEUM PRICING

OIL IMPORT - VOLUME AND VALUE

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Quantity, Million Mt	189.4	202.9	213.9	220.4	226.6	227.0	89.2
Value, INR ₹000 cr.	687.4	416.6	470.2	565.5	783.4	716.6	168.3
Value, USD Billion	112.7	64.0	70.2	87.8	112.0	101.4	22.5
Average conversion Rate, INR per USD (Calculated)	61.0	65.1	67.0	64.4	70.0	70.7	74.9

OIL IMPORT - PRICE USD / BARREL

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Brent (Low Sulphur - LS-marker) (a)	85.4	47.5	48.7	57.5	70.0	60.9	36.1
Dubai (b)	83.8	45.6	47.0	55.8	69.3	60.3	36.8
Low sulphur-High sulphur differential (a-b)	1.7	1.8	1.7	1.6	0.7	0.6	-0.8
Indian Crude Basket (ICB)	84.16	46.17	47.56	56.43	69.88	60.47	36.37
ICB High Sulphur share %	72.04	72.28	71.03	72.38	74.77	75.50	75.50
ICB Low Sulphur share %	27.96	27.72	28.97	27.62	25.23	24.50	24.50

INTERNATIONAL PETROLEUM PRODUCTS PRICES EX SINGAPORE, ($/bbl.)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Gasoline	95.5	61.7	58.1	67.8	75.3	67.0	38.4
Naphtha	82.2	48.5	47.1	56.3	65.4	55.2	35.5
Kero / Jet	66.6	58.2	58.4	69.2	83.9	68.5	36.3
Gas Oil (0.05% S)	99.4	57.6	58.9	69.8	84.1	74.3	42.8
Dubai crude	83.8	45.6	47.0	55.8	69.3	60.3	36.8
Indian crude basket	84.2	46.2	47.6	56.4	69.9	60.5	36.4

CRACKS SPREADS ($/ BBL.)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Gasoline crack							
Dubai crude based	11.7	16.1	11.1	12.0	5.9	6.8	1.6
Indian crude basket	11.3	15.6	10.6	11.4	5.4	6.6	2.0
Diesel crack							
Dubai crude based	15.7	12.0	12.0	13.9	14.8	14.0	6.0
Indian crude basket	15.3	11.5	11.4	13.4	14.2	13.8	7.4

DOMESTIC GAS PRICE ($/MMBTU)

Period	Domestic Gas Price (GCV Basis)	Price Cap for Deepwater, High temp Hingh Pressure Areas
November 14 - March 15	5.05	-
April 15 - September 15	4.66	-
October 15 - March 16	3.82	-
April 16 - September 16	3.06	6.61
October 16 - March 17	2.50	5.30
April 17- September 17	2.48	5.56
October 17 - March 18	2.89	6.30
April 18 - September 18	3.06	6.78
October 18 - March 19	3.36	7.67
April 19 - September 19	3.69	9.32
October 19 - March 20	3.23	8.43
April 20 - September 20	2.39	5.61
October 20 - March 21	1.79	4.06

Source: PIB/PPAC/OPEC

GAS PRODUCTION

Qty in MMSCM

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
ONGC	22088	23429	24677	23746	10979
Oil India	2937	2881	2722	2668	1242
Private/ Joint Ventures	6872	6338	5477	4766	1733
Total	**31897**	**32648**	**32875**	**31180**	**13954**

		2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Onshore	Natural Gas	9294	9904	10046	9893	4713
	CBM	565	735	710	655	313
	Sub Total	**9858**	**10639**	**10756**	**10549**	**5026**
Offshore		22038	22011	22117	20631	8928
	Sub Total	**22038**	**22011**	**22117**	**20631**	**8928**

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Total	**31897**	**32649**	**32873**	**31180**	**13954**
(-) Flare loss	1049	918	815	923	462
Net Production	30848	31731	32058	30257	13492

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Net Production	30848	31731	32058	30257	13492
Own Consumption	5857	5806	6019	6053	2896
Availabilty	24991	25925	26039	24204	10596

AVAILABILTY FOR SALE

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
ONGC	17059	18553	19597	18532	8473
Oil India	2412	2365	2207	2123	966
Private/ Joint Ventures	5520	5007	4235	3549	1157
Total	**24991**	**25925**	**26039**	**24204**	**10596**

CONSUMPTION (EXCLUDING OWN CONSUMPTION)

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Total Consumption	49677	53364	54779	57884	26477
Availabilty for sale	24991	25925	26039	24204	10596
LNG Import	24686	27439	28740	33680	15881

GAS - IMPORT DEPENDENCY

	2016-17	2017-18	2018-19	2019-20 (P)	April - Sept. 2020 (P)
Net Gas Production	30848	31731	32058	30257	13492
LNG Imports	24686	27439	28740	33680	15881
Import Dependency (%)	44.5	46.4	47.3	52.7	54.1
Total Gas Consumption*	**55534**	**59170**	**60798**	**63937**	**29373**

* Includes Own Consumption

Source:PIB/PPAC

SECTOR WISE DEMAND AND COMSUMPTION OF NATURAL GAS

Qty in MMSCM

		2017-18 (P)	2018-19 (P)	2019-20 (P)	April - September 2020						
					April	May	June	July	August	Sep-tember	Total
Fertilizer	R-LNG	7781	8711	9359	708	818	875	967	951	868	5187
	Domestic Gas	6862	6258	6519	581	754	699	507	526	509	3526
Power	R-LNG	2645	2869	3595	27	160	352	346	347	279	1511
	Domestic Gas	9375	9194	7473	731	772	709	647	610	597	4066
City Gas	R-LNG	3881	3981	4746	125	384	184	199	232	374	1498
	Domestic Gas	4659	5240	5736	256	195	323	310	413	434	1931
Refine y Petro-chemical Others	R-LNG	11109	12650	13169	854	1049	1141	1088	1155	1024	6311
	Domestic Gas	5225	5225	5061	628	738	853	351	380	217	3167

Source:PPAC

1. CGD INFRASTRUCTURE

		As on 31st March 2018	As on 31st March 2019	As on 31st March 2020	As on 31st Oct. 2020 (P)
PNG	Domestic	42,80,054	50,43,188	60,68,415	69,53,747
	Commercial	26,131	28,046	30,622	31,990
	Industrial	7,601	8,823	10,258	10,570
CNG	CNG Stations	1,424	1,730	2,207	2,486
	CNG Vehicles	30,90,139	33,47,289	37,10,916	37,95,749

Source: PPAC/Vahan

2. MAJOR NATURAL GAS PIPELINE NETWORK

Nature of pipeline		GAIL	GSPL Groups	PIL	IOCL	RGPL	Others*	Total
Operational	Length	8,241	2,338	1,460	132	312	171	**12,654**
	Capacity	171.6	48.1	85.0	20.0	3.5	9.1	**337.3**
Partially commissioned#	Length	3,533	806		23			**4,362**
	Capacity	-			-			**-**
Total operational length		**11,774**	**3,144**	**1,460**	**155**	**312**	**171**	**17,016**
Under construction	Length	6,352	4013		1,398		3,780	**15,543**
	Capacity	-			-		-	**-**
Total length		**18,126**	**7,157**	**1,460**	**1,553**	**312**	**3,951**	**32,559**

* Includes AGCL, DFPCL, ONGC and excludes CGD pipeline network

Source: PPAC/PNGRB

3. EXISTING LNG TERMINALS

Location	Companies	Capacity (MMTPA) As on 1st Dec. 2020	Capacity Utilisation (%) April-Oct. 2020 (P)
Dahej	Petronet LNG Ltd	17.5	95.0
Hazira	Shell Energy India Pvt Ltd	5	96.9
Dabhol*	RGPPL (GAIL- NTPC JV)	5	40.9
Kochi	Petronet LNG Ltd	5	15.8
Ennore	Indian Oil LNG Pvt Ltd	5	11.3
Mundra	GSPC LNG Ltd	5	36.2
Total Capacity		**42.5 MMTPA**	

*To increase to 5 MMTPA with breakwater . Only HP stream of capacity of 2.9 MMTPA is commissioned

Source: PPAC

Member Organizations

S No	Organization	Name	Designation
1	Antelopus Energy Pvt Ltd	Mr. Suniti Bhat	Chief Executive Officer
2	Axens India (P) Ltd.	Mr. Philippe Bergault	Managing Director
3	Baker Hughes, A GE Company	Mr. Neeraj Sethi	Country Leader
4	Bharat Oman Refineries Ltd.	Mr. Mahendra Pimpale	Managing Director
5	Bharat Petroleum Corporation Ltd.	Mr. K. Padmakar	Director (HR) and CMD (Incharge)
6	BP Group	Mr. Sashi Mukundan	Regional President and Head of Country, India
7	Cairn Oil & Gas, Vedanta Limited	Mr. Sunil Duggal	Group CEO, Vedanta Ltd.
8	Chandigarh University	Mr. Satnam Singh Sandhu	Chancellor
9	Chennai Petroleum Corporation Ltd.	Mr. S.N. Pandey	Managing Director
10	Chi Energie Pvt. Ltd	Mr. Ajay Khandelwal	Director
11	CSIR-Indian Institut e of Petroleum	Dr. Anjan Ray	Director
12	Decom North Sea	Mr. Will Rowley	Interim Managing Director
13	Deepwater Drilling & Industries Ltd.	Mr. Naresh Kumar	Chairman & Managing Director
14	Dynamic Drilling & Services Pvt. Ltd.	Mr. S. M. Malhotra	President
15	Engineers India Ltd.	Mr. J.C. Nakra	Chairman & Managing Director
16	Ernst & Young LLP	Mr. Rajiv Memani	Country Manager & Partner
17	ExxonMobil Gas (India) Pvt. Ltd.	Mr. Bill Davis	Chief Executive Officer
18	GAIL (India) Ltd.	Mr. Manoj Jain	Chairman & Managing Director
19	GSPC LNG Ltd.	Mr. Anil K. Joshi	President
20	h2e Power Systems Pvt. Ltd.	Mr. Siddharth R Mayur	Managing Director & CEO
21	Haldor Topsoe India Pvt. Ltd.	Mr. Alok Verma	Managing Director
22	Hindustan Petroleum Corp. Ltd.	Mr. M.K. Surana	Chairman & Managing Director
23	HPCL Mittal Energy Ltd.	Mr. Prabh Das	Managing Director & CEO
24	IHS Markit	Mr. James Burkhard	Managing Director
25	International Gas Union	Mr. Luis Bertran	Secretary General
26	IIT (ISM) Dhanbad	Prof. Rajiv Shekhar	Director
27	IMC Ltd.	Mr. A. Mallesh Rao	Managing Director
28	Indian Oil Corporation Ltd.	Mr. S.M. Vaidya	Chairman
29	Indian Strategic Petroleum Reserves Reserves Ltd	Mr. H.P.S. Ahuja	Chief Executive Officer & MD
30	Indraprastha Gas Ltd.	Mr. A.K. Jana	Managing Director
31	Indian Oiltanking Ltd.	Mr. Rajesh Ganesh	Managing Director
32	IPIECA	Mr. Brian Sullivan	Executive Director

S No	Organization	Name	Designation
33	Invenire Petrodyne Ltd.	Mr. Mannish Maheshwari	Chairman & Managing Director
34	Jindal Drilling & Industries Pvt. Ltd.	Mr. Raghav Jindal	Managing Director
35	LanzaTech	Dr. Jennifer Holmgren	Chief Executive Officer
36	Larsen & Toubro Ltd	Mr. S.N. Subrahmanyan	CEO & Managing Director
37	Maharashtra Institute of Technology (MIT) Pune	Dr. L.K. Kshirsagar	Principal
38	Mangalore Refinery & Petrochemicals Ltd.	Mr. M. Venkatesh	Managing Director
39	Megha Engineering & Infrastructures Ltd.	Mr. P. Doraiah	Director
40	Nayara Energy Ltd.	Mr. B. Anand	Chief Executive Officer
41	Numaligarh Refinery Ltd.	Mr. S.K. Barua	Managing Director
42	Oil and Natural Gas Corporation Ltd	Mr. Shashi Shanker	Chairman & Managing Director
43	Oil India Ltd.	Mr. Sushil Chandra Mishra	Chairman & Managing Director
44	Petrofac International Ltd.	Mr. Paolo Bonucci	Head of Business Development & Senior Vice President
45	Petronet LNG Ltd.	Mr. Vinod Kumar Mishra Mr.	Director (F) and MD & CEO (Addl Charge)
46	Pipeline Infrastructure Ltd.	Akhil Mehrotra	Chief Executive Officer
47	Rajiv Gandhi Institute of Petroleum Technology	Prof. A.S.K Sinha	Director
48	Reliance Industries Ltd.,	Mr. Mukesh Ambani	Chairman & Managing Director
49	SAS Institute (India) Pvt Ltd.	Mr. Noshin Kagalwalla	CEO & Managing Director-India
50	Schlumberger Asia Services Ltd	Mr. Gautam Reddy	Managing Director
51	Secure Meters Ltd.	Mr. Sunil Singhvi	CEO - Energy
52	Shell Companies in India	Mr. Nitin Prasad JJJJ J	Country Chair
53	SNF Flopam India Pvt. Ltd	Mr. Shital Khot	Managing Director
54	South Asia Gas Enterprise Pvt. Ltd.	Mr. Subodh Kumar Jain	Director
55	Tecnimont Pvt Ltd		Managing Director
56	Total Oil India Pvt. Ltd. U	Mr. Alexis Thelemaque	Chairman & Managing Director
57	University of Petroleum & Energy Studies	Dr. S.J. Chopra	Chancellor
58	UOP India Pvt. Ltd.	Mr. Mike Banach	Managing Director
59	VCS Quality Services Private Ltd.	Mr. Shaker Vayuvegula	Director
60	World LPG Association	Mr. James Rockall	CEO and Managing Director

FEDERATION OF INDIAN PETROLEUM INDUSTRY

CORE PURPOSE STATEMENT

To be the credible voice of Indian hydrocarbon industry enabling its sustained growth and global competitiveness.

SHARED VISION

For more details
kindly visit our website
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Follow us on:

- A progressive and credible energy advisory body stimulating growth of Indian hydrocarbon sector with global linkages.
- A healthy and strong interface with Government, legislative agencies and regulatory bodies.
- Create value for stakeholders in all our actions.
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- A financially sel -sustaining, not-for-profit o ganization.

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