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From the Desk of the

Director General

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

Dear Members,

As I look back at the past quarter to write this section, little else crosses my mind but the horrors of unprecedented human suffering in the second wave of COVID-19. By late April, the daily cases of COVID-19 infections, which had reached as low as 9000 in February, went past the 4-lakh mark. The rising number of cases forced many State Governments to implement strict lockdown amid rising casualties and unforeseen strain on medical infrastructure. It was only through timely and relentless efforts of the Government that the country could successfully control the second wave of the pandemic, and as I pen this message, life is fast approaching normalcy.

While the country was still grappling with the COVID infection, ONGC hired accommodation Barge P305 sank off the Mumbai Coast when Cyclone Tauktae was hurtling through the Western coastline of the country. The accident claimed the lives of over 80 personnel on board, drawing the attention of average citizen to the difficult and challenging circumstances this industry operates under.

During the second wave of the COVID pandemic, Indian Oil and gas companies, private and PSUs alike, were at the very forefront in battling the virus and bringing relief to the ailing nation. During these difficult times, many oil and gas companies worked overtime and focused all their energies to service the rising demand for medical oxygen in the country. In light of the surge in COVID cases, many of our member companies had set up large COVID facilities to make the necessary medical care available for the patients. It is at times like these, when compassion pushes business priorities to the back seat.

The World Bank in its June 2021 report, projects the global economy to expand 5.6% in 2021, the fastest post-recession pace in 80 years, largely on strong rebounds from a few major economies. However, many emerging market and developing economies will continue to struggle with the COVID-19 pandemic and its aftermath. Despite the recovery, global output will be about 2% below pre-pandemic projections by the end of this year. Per capita income losses will not be unwound by 2022 for about two-thirds of emerging market and developing economies. In the same report, World Bank projects the Indian Economy to grow at 8.3% for FY21-22. Economic activity will benefit from policy support, including higher spending on infrastructure, rural development, and health, and a stronger-than expected recovery in services and manufacturing.

Over the last quarter, the international oil prices continued to rise despite a fall in demand from India due to the COVID induced lockdowns. The continued rise in oil prices was primarily due to the extension of production cuts by OPEC countries and an additional voluntary cut of 1 Mbpd by Saudi Arabia. While the OPEC+ is expected to restore some of the production July onwards, experts believe that this gradual withdrawal of the cuts will not have any significant impact on oil prices. Many industry analysts have predicted that oil prices may soon surpass the USD 100/bbl mark, riding on increasing demand, inflation and rising shareholder pressure on oil majors to drastically cut emissions.

In the Indian upstream sector, Discovered Small Field (DSF) bid round-III for international competitive bidding was launched on June 10th. DSF bid round-III is offering 32 Contract Areas, comprising of 75 discoveries. These fields are spread over 9 sedimentary basins covering more than 13,000 square kilometers with In-place Hydrocarbon estimated to be around 230 MMT.

The domestic gas price notified at USD 1.79 per million British thermal unit for the six months beginning April 1 remains the lowest since the institution of the modified Rangarajan formula. Additionally, the ceiling on price for gas produced from deep water, ultra-deepwater, high temperature and high-pressure fields has also been announced at USD 3.62 per mmBtu for April-September 2021-22 which is 10.8 per cent lower than the price ceiling of USD 4.06 for October-March 2020-21 which is dampening the development of such projects. Natural gas production therefore is not a profitable proposition for most fields for the Indian upstream producers as the gas price remains at its lowest level.

In the downstream side of the industry, India's fuel demand in the first quarter of 2021-22 was significantly affected as restrictions to curb the second wave of COVID infections stalled mobility and muted economic activity. Petrol consumption in May 2021 was down 16 per cent over April 2021 and 27 per cent over the pre-COVID era. Diesel sales in May 2021 was down by 17 per cent over April 2021 and 29 per cent over the pre-COVID period. With travel restrictions curtailing airline operations, ATF sales declined by 36 per cent month-over-month basis and 60% when compared to pre-covid era. With easing of restrictions and pick up of economic activities in June, the demand for petroleum products recovered sharply. In June 2021, Gasoline and Diesel demand increased by 29 per cent and 18 per cent respectively over May 2021.

During the quarter, FIPI continued to organize virtual events and conferences for the benefit of the industry. On 15th April 2021, FIPI and The Energy Forum under the aegis of Ministry of Petroleum & Natural Gas organised a half day round table event on - "Developing a Hydrogen ecosystem for a Decarbonized Globe" over a virtual platform. This session was organised to study and explore the challenges and pathways to hydrogen becoming a clean and abundant source of energy that could help tackle the pressing sustainability issues that confronts the world today. The prestigious event witnessed participation and address by Energy Ministers from key nations, panelists from major global companies working on hydrogen and more than 3,000 delegates from across the world.

On 19th April, 2021 FIPI in association with Argus Media organized 'Adapting to a More Competitive Market: New Pricing Mechanism for Middle Eastern Crude'. The dialogue was aimed at understanding the new and emerging dynamics of the international oil market as the as the ICE Murban Crude Oil Futures market joins the ranks of prominent oil price benchmarks such as Brent and West Texas Intermediate. The team of experts joining from Argus Media included Mr Francis Osborne, Argus Global Head of Forecasting, Argus Media; Mr Alajandro Barbajosa, Vice President Crude Middle East; Mr Karl Kleemeier, VP Business Development, Argus Media; and Ms Azlin Ahmed, Asia Crude Editor, Argus Media.

FIPI in association with IndianOil R&D and World Petroleum Council, organized a webinar on "Energy Storage Systems" on May 20th 2021. The panelists during the panel discussion, shared their insights on various energy storage options, upcoming storage technologies and the future of energy storage and its economics. The webinar witnessed an overwhelming response from both Indian and International delegates.

The number of countries announcing pledges to achieve net-zero emissions over the coming decades continues to grow. However, even after all possible efforts, the world is falling short of what is required to bring global energy-related carbon dioxide emissions to net zero by 2050 and give the world an even chance of limiting the global temperature rise to 1.5° C. To address this challenge, and to define a pathway towards a net zero carbon future, International Energy Agency (IEA), released a report on 'Net Zero by 2050; A roadmap for the global energy sector' in May 2021. This report sets out clear milestones – more than 400 in total, spanning all sectors and technologies – for what needs to happen, and when, to transform the global economy from one dominated by fossil fuels into one powered predominantly by renewable energy like solar and wind. The report also highlights that no new oil and natural gas fields are needed in the net zero pathway, and supplies will become increasingly concentrated in a small number of low-cost producers.

The pain and sufferings during the second wave of COVID in April and May has reminded us that any deviation from COVID appropriate behavior may prove too costly. Today, the economy has started opening up again and we are fast approaching normalcy. I am certain that the entrepreneurial spirit of this nation supported by targeted new policies and interventions by the Government will soon set the country on a high growth trajectory. As India targets a double-digit growth, the oil and gas sector stands strong by the nation to fulfill its growing energy needs.

As the entire country looks forward to new beginning, I assure you that FIPI will always be at the forefront willing to deliberate on industry issues and scripting the growth story of Indian oil and gas industry.

Wishing you the very best.

Dr. R. K. Malhotra

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

- 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.
- Enablers of collaborative research and technology adoption in the domain of energy and environment.
- A vibrant, adaptive and trustworthy team of professionals with domain expertise.
- A financially sel -sustaining, not-for-profit o ganization.

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Exploration in Frontier Plays: Dealing with the Need to Reduce Risk and Cost

Indrajit Barua
Executive Director (BM-Frontier)

Oil India Limited

Introduction

The energy world is undergoing a slow but definite energy transformation today from a system based on fossil fuels to a system based on renewable energy in order to reduce global greenhouse gas emissions and avoid the most serious impacts of a changing climate.There has been acceleration in adaptation of renewable energy technologies even during the current pandemic.

The oil and gas industry - especially in Europe - is under increasing pressure from Governments, investors and the public to support the de-carbonization of the energy system and shift the energy system away from one dominated by hydrocarbons toward one in which low-carbon sources play the lead role. In Sep 2017, the French Parliament announced plans to phase out all oil and gas production by 2040, coinciding with the country's scheduled ban on the sale of gasoline and diesel vehicles.Denmark and New Zealand followed suit in similar lines during Feb 2018 and May 2018 announcing ceasing to grant licenses for exploration and drilling for hydrocarbons. These trends are pushing some oil and gas companies to shrink their legacy fossil fuel businesses, stop their search for new acreage and focus instead on lower carbon technologies and alternative sources of energy.

But such pressures do not necessarily imply that there is no future for oil and gas which is manifested by the projected growth in global energy demand. The energy transition will come but it is predicted that hydrocarbon consumption will stay there even until 2050 and it is estimated that oil and gas will cover 45-50 per cent of the global demand even then. Furthermore, according to the International Energy Agency (IEA), humanity could easily still be consuming oil at rates similar to today even as far into the future as 2040. Therefore despite the pressures, the world is still a long way from Beyond Petroleum. The industry is still required to meet the expected global oil and gas demand over the long term and unless a momentous transition in the global energy mix happens sooner than currently expected or at a much faster development pace than the current trend, organic hydrocarbon reserve replacement will need to be sustained and exploration for oil and gas is needed to be speeded up for years to come.

On the exploration front, since the last few decades, though reserves as well as oil and gas fields discovered have still kept growing, global oil and gas exploration have become more difficult with more complicated targets being explored. Also in a changing global scenario the trends of exploration have kept changing. Analyses by Rystad Energy indicates that oil and gas companies' exploration plans have included prospects with higher chances of success in mature areas as well as high-risk, high-reward wildcats in offshore regions which have become the hotspot of global oil and gas exploration, resulting in some game-changing offshore discoveries. Till the third quarter of 2020, the offshore volumes accounted for slightly over three-quarters of discovered resources.

In the onshore regions the focus of exploration has been less on the "frontier" areas but on low-risk, near-field exploration - in regions that already have production facilities. The aim, should they make a discovery, is to produce the resource quickly, shortening the length of time to deliver production and profits and lowering costs dramatically. But near-field plays won't necessarily generate the resources that will, on their own, be sufficient to overcome production declines and drive new growth. Frontier plays hold a lot of resource potential. However, pursuing these opportunities—even in a recovering industry environment—is considered too risky and too expensive.

Exploration workflow

Since the anticlinal theory replaced seepages as the key guiding factor and subsequently with the advent of the geophysical techniques and technology the conventional exploration model that the industry has been following for decades involves a certain order in the use of primarily 2D and 3D seismic tools supplemented sometimes by gravity-magnetic tools, according to the level of knowledge and the size of the area being investigated. Extensive use of seismic data is used to understand the geological framework in relation to hydrocarbon potential — whether there is evidence of structures favorable for the accumulation of hydrocarbons and followed by whether there is other evidence of a functional petroleum system. This was utilized to select the most favorable drilling sites. It is an axiom of the industry that ''only drilling an oilwell can confirm the presence of oil.'' Since this is by far the most expensive part of the exploration process, the geophysical tools are always exhaustively employed before a wildcat well is drilled (Jones 2017).

Industry has been extraordinarily successful in finding conventional oil and gas resources in this way and therefore this exploration model is being resolutely followed even today. However, this model indicate that the exploratory campaign in any frontier or other large exploratory areas will inevitably require huge investments and long lead times before reasonable knowledge about its prospectivity is accumulated. Even the conclusion that the explored area proves to be unfavorable for hydrocarbon accumulations and no discoveries can be expected, can only be reached after all the stages involved in the conventional exploration model have been completed. This means incurring of large costs and assuming huge risks that cannot be easily mitigated, regardless of the exploratory outcome. Therefore the same model that has been so successful in allowing large volumes of resources to have been discovered now in a different market scenario prevents companies from carrying out exploratory activities over much of the remaining prospective exploratory areas of the world.

Therefore, there is a need for a cost effective exploration campaign by reducing the lead time and risk in the exploration workflow. To overcome the current market difficulties that are holding back exploratory projects and to resume large-scale exploration activity in frontier areas, it is required to precede the conventional workflow by methods to focus detailed exploration on specific limited areas. New and emerging technologies and geological techniques could be the key to achieving this change for faster, less expensive and more direct way of assessing the prospectivity of large exploratory areas and identifying leads.

The Indian Context

The exploration, development and production of many frontier exploration plays are of strategic importance to the countries. India, being the world's third largest energy consumer globally and a yawning gap between its oil and gas production and demand, the requirement for finding new oil and gas resources becomes even more vital. The Government's supportive policies and mechanism during the last couple of decades have made the current period - the most favourable times for oil and gas exploration in the country.

This has led to the availability of a huge G&G database and using of this data as well as using modern techniques in the resource reassessment study has resulted in substantial accretion of the Yet-to-Find resources (YTF) in the country.

The National Seismic Programme has been effective in not only bridging data gaps but also enhancing the seismic database of the different sedimentary basins. The advantages provided by the HELP regime have already facilitated the focussed venturing into frontier exploration in areas which had been sparsely explored in the past.

In the Indian sedimentary basins, around 51% area still remains to be appraised while the undiscovered conventional resources in the different basins comprise around 71% of the total prognosticated resources as estimated during the resource reassessment study carried out in 2017.

Supplementing the Conventional Exploration Workflow

Extensive exploration acreages has been acquired by Oil India Limited, a premier upstream National Oil Company, with the advent of the HELP regime as part of the Nation's efforts at increasing oil and gas exploration in the country's sedimentary basins.

Exploration in large frontier areas is not only impeded by long lead times and high costs but also by logistical difficulties and regulatory clearances as well as socio-political issues. Oil India Limited has faced such challenges while carrying out exploration in the Assam Shelf and Assam Arakan Fold Belt (AAFB) basins. Exploration in the northeastern state of Nagaland has not been able to take off due to political and judicial issues. The exploration campaign in the extremely logistically difficult state of Mizoram in the AAFB basin has prolonged to more than ten years with the entire block area yet to be completely apprised. Similarly exploration in Namchik and Deomali blocks in the thrusted Belt of Schuppen area is yet to be completed due to the inordinate lead time in statutory clearances. The presence of National Parks and Wild life sanctuaries sprawling large areas also becomes no-go areas for conventional exploration. The concern for the fragile natural environment and limited weather windows also leads to additional time being incurred in the conventional exploration processes.

In this challenging economic scenario and the requirement to prospect immense frontier areas that could provide new and rewarding exploratory opportunities, there is a need to supplement to the conventional exploration model, focused on a faster, less expensive and possibly a more direct way of accessing the resource potential without any disturbance to the environment. New and emerging technologies and techniques are the key to achieving this change. Fortunately several technologies are now available and they have proven to be effective in specific areas across the globe for identifying and assessing prospective leads within the frontier blocks to further focus on.

Supplementing to the conventional exploration model implies adopting new concepts in petroleum exploration. The objective would be to first obtain indications of the existence of possible hydrocarbon accumulations. Subsequently, if any such accumulations were to be indicated, decision on conducting additional investigations, including using conventional seismic tools could be taken. This involves a profound inversion of the order in which the various stages of the conventional exploratory model are performed. However, it also requires the use of geophysical tools or geological techniques that could suggest an independent and direct indication of hydrocarbon accumulation potential, while being relatively inexpensive, fast and easy to employ right at the beginning of the exploratory process, over large areas.

Geophysical tools exist today that under the right circumstances could be capable of directly suggesting the existence of hydrocarbon potential, something that even the best seismic techniques have so far been unable to accomplish consistently and reliably.

Gravity-based geophysical investigation tools have improved markedly in the last few years and today include both gravimetry and gravity gradiometry technologies that can provide very detailed density imaging of the subsurface,down to the reservoir scale. Such tools have been very effective in order to provide complementary geological,structural and fluid information (Nabighian et al. 2005). Because gravity detection (based on mass density) is independent from other potential field methods, such as seismic or electromagnetic tools, its value also lies in providing an independent confirmation or denial of hydrocarbon accumulation potential. In particular, full tensor gradient (FTG) gravity data acquisition entails measuring the horizontal gravity tensor components (Txx, Tyy, Txy, Txz and Tyz), as well as the vertical tensor component (Tzz), with sensitive gravimeters (Murphy and Brewster 2007). These components represent the spatial rate of change of gravitational acceleration and have a much more precise response than the gravity magnitude vector, allowing a better estimate of depth and composition of targets.

Passive Seismic Tomography (PST) is another geophysical exploration technique to image the subsurface using natural seismicity of the earth as a source. By placing receiver stations at intervals of 2 to 10 kms for durations ranging from 6 to 9 months the technology records the first phase arrivals of P and S waves. Structural information, lithological data, rock properties and fault characterization is attempted using 3D P-wave velocity, 3D Vp/Vs cube, 3D Qp factor and focal mechanism stress tensors respectively.

Low Frequency Passive Seismic Method (LFPS) is yet another geophysical method that utilizes observations on low frequency band of the earth's micro-tremors to calculate the spectral ratio of vertical and horizontal components (V/H) and Power Spectral Density (PSD). Attributes based on the V/H ratio and the PSD have been suggested as tools to identify hydrocarbon reservoir location.

Other geophysical investigation tools that are still in the initial stages of development of their technological potential are magnetotelluric surveys, controlled-source electromagnetic (CSEM), and other tools based on detection of electromagnetic properties and Stress Field Detection (SFD) which is a technology that allows the identification of subsurface stress regime anomalies which are generally present in the case of major geological features, such as faults, folds, salt kinetics and others.

Geochemical exploration has been the oldest method of prospecting for petroleum with its search for oil and gas seeps. However today, the geochemical approach is concerned with micro-concentrations of petroleum substances which are invisible to the eye, while earlier approaches sought macro-concentrations which were visible to the eye. The main advantage of geochemistry over geophysics and geology is that it is not limited by the type of trap in which the hydrocarbons have accumulated and is especially useful in prospecting for stratigraphic pools which are not associated with easily discernable structural features.

Since the availability of seismic data from the 1920s onwards, exploration continued to be primarily prospect driven – recognition of an attractive structure on seismic data.This led to a number of important new discoveries, but also a great many failures. Prospect-based exploration still continues to play a major role in the industry, especially within mature or super-mature basins where the petroleum system is well established. In such basins, the focus is on the trap, relying on improvements in subsurface imaging that can recognize structures that could otherwise be overlooked.

However, prospect-based exploration is inherently riskier in frontier basins where data are sparse and unless the geological history of the basin and hence the nature of the rocks deposited is well understood. In contrast to prospect based exploration play-based exploration places less initial emphasis on the trapping mechanism. It focuses on the presence and effectiveness of the reservoir, source rock, and seal to develop play concepts and high-grade areas of interest. Play-based exploration (PBE) maps out where the elements of a play exist and where they are effective from a detailed understanding of the geological history of the basin under consideration. Such an approach allows prediction away from data control.

Conclusion

Carrying out preliminary geophysical and geochemical surveys as well as PBE studies over extensive unexplored or underexplored areas for obtaining prospectivity information upfront are ways that reduces time, cost and risk of exploratory campaigns. Conventional seismic acquisition is not replaced but utilized to focus on specific areas of the basin. This workflow facilitates identification of hydrocarbon potential areas with high confidence, shorten the exploration cycle, reduce costs of exploratory campaigns and make possible faster appraisal of large exploratory areas with minimum disturbance to the environment.

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[HP]^2 Catalyst: A Multispecialty Catalyst Formulation for Maximizing FCC Products Yield


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Introduction

Fluid catalytic cracking (FCC) is one of the most important conversion processes used in petroleum refineries and has existence of 75+ years. It is widely used to upgrade heavier cuts like vacuum gas oil and residues to more valuable petroleum products like gasoline and light olefins. It can readily adjust to changes in feed quality through modifications of catalyst and operating conditions. Catalysts and additives play important role with respect to activity and selectivity in FCC. FCC units typically produce around 4-6wt% propylene but can go as high as 12%, depending on feedstock type, operating conditions such as riser outlet temperature, reactor pressure, catalyst-to-oil ratio and the type of FCC catalysts/additives.

major source of ethylene and propylene is the traditional steam naphtha cracker that supplies about 57% of global propylene as a by-product to ethylene production. The FCC unit is also an important source of propylene producing about 35% of world propylene as a by-product to gasoline production. The remaining 8% of world propylene is produced by 'on-purpose' processes such as propane dehydrogenation, olefin metathesis and methanol-to-propylene. But due to shift of naphtha crackers to ethane crackers, the gap for propylene has been on increasing trend. Most of the new steam crackers coming online are designed to use ethane as the primary feedstock, which typically produces less than 2% of propylene compared to ethylene production. Propylene demand has increased at an average rate of nearly 4-5% per year. In India, growth rate for propylene stood at 2.33% CAGR and polypropylene (PP) at 3.85% CAGR for 2020-21. Enhancement of propylene yield from FCC from maximum of 12wt% to 20wt% is one of the option to meet growing demand of propylene. Refiners are integrating the modern configuration with petrochemical complex and petrochemicals from current average of 7% will go upto 20%.

Propylene is perhaps the most versatile building block in the petrochemical industry, in terms of its variety of end-use products and its multitude of production sources. High demand for polypropylene (PP) has been a major driver for the rapid expansion in propylene production processes and many polypropylene units are added by refineries. Worldwide, approximately two-thirds of propylene is used to make PP.

HP Green R&D Centre (HPGRDC) has developed a novel catalyst formulation: [HP]^2 (Hindustan Petroleum High Propylene) catalyst system for maximizing propylene yields. The catalyst formulation has been patented. The catalyst formulation acts as an additive in conventional FCC units. The catalyst system can be used in high severity FCC unit like HPCL patented [HP]^2 FCC Technology, DCC (Deep Catalytic Cracking) or other high severity FCC for maximization of light olefins. To assess the performance of the $[HP]^2$ catalyst field trials of the catalysts were carried out at HPCL's FCC units at 10% and 15% inventory change over. Performance of the catalyst formulations as a catalyst and additive is discussed here.

FCC Catalyst Design:

FCC catalyst is in the form of powder in Geldart A classification of fluidization and has particle size of around 75µm. Typically, FCC catalyst consists of USY zeolite, alumina, binder and filler. The main active component is a zeolite, usually a stabilized form of USY zeolite. Both clay & binder provides required critical FCC parameters such density, attrition resistance, particle size distribution and heat transfer medium to carry the heat for endothermic catalytic reactions. The catalyst design parameters is depicted in Figure -1. Activity, selectivity and accessibility is to convert the large feedstock molecules to the desired molecules. Attrition resistance is required to withstand the particle-particle and particle wall collision during circulation. Hydrothermal stability is to withstand the temperature and steam partial pressure in the regenerator. Metals tolerance is to withstand the effects of poisons in the (heavier) feedstock (Ni & V). Coke selectivity is desired as the minimum amount of coke at high cracking activity, especially when processing heavier feedstocks. Fluidizability is the ability that allows fluidization in the reactor-regenerator (Geldart A fluidization properties).

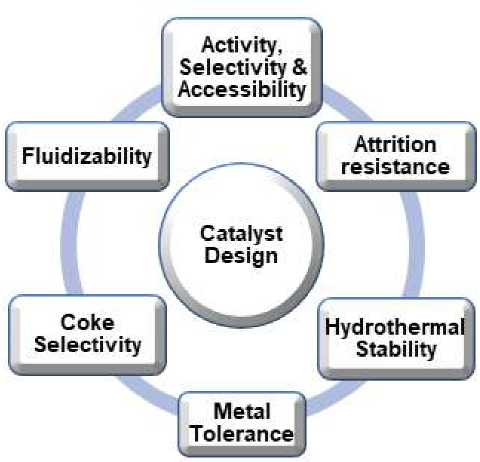

Figure-1: FCC catalyst design parameters

$[HP]^2$ Catalyst for Light Olefins:

Catalysts and additives play vital role in FCC for enhancing light olefins. The proprietary tailor made catalyst system has cracking functionality to crack feed molecules to gasoline by use of macro-mesoporous and micro-porous functions and increase light olefins by modified shape selective pentasil zeolite. In $[HP]^2$ catalyst there is upgradation of larges molecules by physical transport in macrospores (Lewis acid sites) and primary cracking mesoporous sites (medium acid sites) of alumina, which is surface modified to change the strength of the acid sites. The upgraded molecule diffuses into zeolite pores to give gasoline, which further cracks to light olefins in presence of modified shape selective ZSM-5 additive incorporated in the $[HP]^2$ catalyst formulation. The large molecules in the feed prefer to be first precracked on the alumina surface. The alumina catalytic function increases the catalyst activity and selectivity towards light olefins. The interactions between the active alumina and the zeolite exhibits catalytic advantages of the zeolite component and also retains the alumina-precracking ability in this tailor made catalyst formulation. These interactions enhance the catalyst activity and improves the product distribution/ selectivity. The feed molecules are 370+ boiling range consisting of saturates (C14-C34) and heavy aromatics (C14-C60) in the ranges of 40-60% and 35-45% having pore diameter of 12-20A° and 12-30A°. These hydrocarbon molecules are too large to fit into the zeolite pores. The macropores provide free path to these molecules to transport and crack on mesoporous of active alumina having pore size of 12-100 A°. The upgraded molecules viz: LCO range come in contact with Y zeolite pores having pore size of 7-8A° and convert to gasoline range molecules using strong acid sites and the gasoline range olefins are converted to light olefins (LPG Olefins) through modified shape selective ZSM-5 having pore size of 5-6 A°. It is important that the catalyst have the proper pore size distribution to enable large feed molecules to enter, crack into lighter products, and diffuse out before being over-cracked to coke and gas. Therefore, it is essential to design a catalyst with optimal porosity for effective kinetic conversion. The sequential cracking is depicted in Figure-2. Typical properties are given in Table-1.

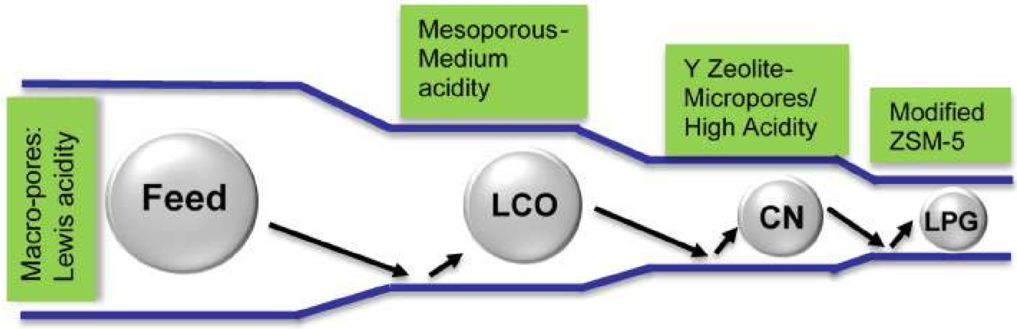

Figure-2: Sequential cracking of hydrocarbon feed to light olefins using [HP]2 Catalyst

Parameter	Values
Fresh surface area, m^2/gm	150-250
PV, cc/gm	0.35-0.4
APS, micron	75-85
ABD, gm/cc	0.75-0.85
Attrition Index, wt%	<3

Table-1: [HP]2 Catalyst properties

Catalytic cracking experiments (lab study):

The Catalytic cracking experiments were carried out in a fixed fluid bed micro reactor unit (ACE unit). Hydro-treated vacuum gas oil was used as feedstock having density of 0.9 g/cc. Using this feed, the tailor made $[HP]^2$ catalyst formulation was subjected to catalytic cracking at temperatures of around 570°C. The product yield obtained is compared with fresh deactivated USY zeolite with equivalent ZSM-5 of 20wt% as in case of $[HP]^2$ catalyst formulations and results are depicted in Figure-3.

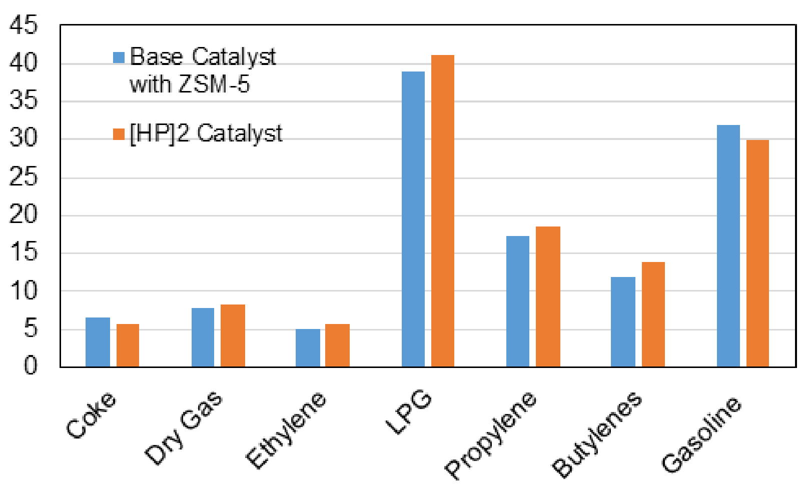

Figure-3: Cracking results at constant conversion of 85wt% for high severity applications

It is clear that $[HP]^2$ catalyst formulation is selective towards propylene (18.53wt%) and butylenes (13.87wt%) compared to base catalyst with equivalent ZSM-5. The formulation gives ~1% lower bottoms compared to base. The modified ZSM-5 of the formulation is having metal function to increase the light olefins. The catalytic cracking of alkanes occurs via bimolecular and monomolecular reaction mechanisms. If the monomolecular mechanism is dominant, the yield of light olefins (e.g., ethylene and propylene) is more. Bimolecular reactions are hydrogen transfer reactions, which will saturate the olefins. Hydrogen transfer in FCC is a well-known phenomenon and reduces the gasoline range olefins. The cracking rates of gasoline olefins on ZSM-5 are higher than those of paraffins and therefore, an increase in hydrogen transfer reduces the effectiveness of ZSM-5 additives. The synergistic alumina and Y-zeolite cracking of feed molecules as explained will provide maximum activity and higher gasoline range olefins for cracking on modified ZSM-5. The ratio of monomolecular to bimolecular for the $[HP]^2$ catalyst formulation is 0.44 as compared to base catalyst with equivalent ZSM-5 (0.31), indicating monomolecular reactions are dominant in $[HP]^2$ catalyst formulation. The paraffin to olefin ratio, which is measure of hydrogen transfer reactions is almost 50% less in [HP]2 catalyst formulation, indicating the design of the catalyst is selective towards light olefins.

Field demonstration of $[HP]^2$ catalyst:

The catalyst formulation also acts as an additive in conventional FCC units. Refinery trials were taken at two FCC units to assess the performance of the catalyst as an additive.

Field trial at FCCU-A:

Trial were conducted by 10% inventory changeover over the period of one and half month. Unit throughput was 100 m^3/hr with ROT of 490°C, feed density of 0.88g/cc sulphur-0.3wt% and CCR-0.11wt% with unit cat/oil of 5.7wt/wt. Test run was conducted to see the performance of $[HP]^2$ catalyst as an additive at 10% concentration. Performance of $[HP]^2$ catalyst showed 0.6 wt% increase in LPG, 0.5wt% increase in propylene, increase in RON by 0.6 units and reduction in bottoms by 0.2wt%. Product yields are given in Figure-4.

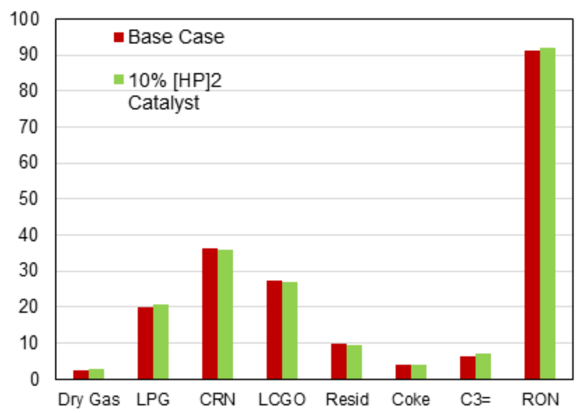

Figure-4: Product yields with 10% $[HP]^2$ catalyst at FCCU-A

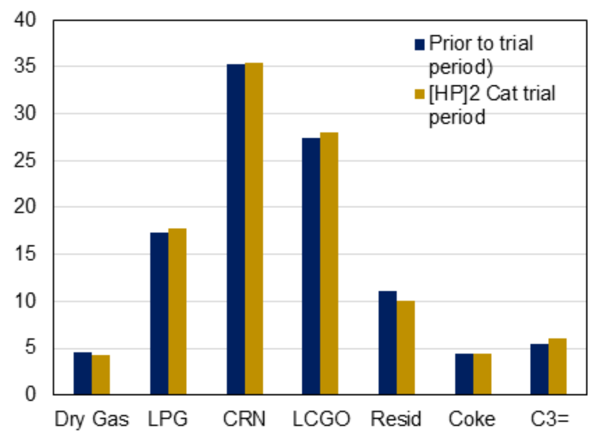

Figure-5: Monthly average product yields obtained at FCCU-B

Field trial at FCCU-B:

Trial were conducted at FCCU-B by 15% inventory changeover over the period of one month. Unit throughput was 130 m^3/hr with ROT of 524°C, feed density of 0.918g/cc sulphur-1.6wt% and CCR-0.62wt % with unit cat/oil of 7.1wt/wt. Monthly average yields of before and after addition of $[HP]^2$ catalyst are given in Figure-5. Performance of $[HP]^2$ catalyst showed 0.32wt% decrease in dry gas, 0.50wt% increase in LPG, 0.54 wt% increase in propylene, increase in LCO by 0.62wt% and reduction in bottoms by 1wt% w.r.t to base case.

In both FCC unit field trials, the C3= selectivity in LPG was seen to increase by 2.5 to 5 vol% from base value of 34-35 vol%. During, the trial period, there was no observation on incremental catalyst loss from the FCC units, due to the addition of $[HP]^2$ catalyst. Hence, meeting catalyst compatibility with the existing base catalyst.

Conclusion:

Based on the lab study and field trials at FCCU-A & B, $[HP]^2$ catalyst can be used an additive in existing FCC units to maximize the product yields and selectivities and increase the RON barrels. In a high olefin FCC unit, the catalyst improves propylene yield by 1.3wt%. Commercial demonstration at one of the high olefin FCC unit is underway.

A Study on the Effect of Improper Heat Treatment of PSA Bed Bolts of Hydrogen Generation Unit in a Petroleum Refinery

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Abstract

It is always an endeavor of plant operators to run their plant free from any interruptions. In spite of this, their plants do face interruptions on account of variety of reasons. The failure of components in one or another unit / machinery is one of the leading causes of such interruptions. Sometimes a failure of critical components causes major upset in the plant and calls of either operation under part capacity or complete shutdown of the units(s) leading to major production losses.

Hydrogen generation unit (HGU) is one of the critical units in a petroleum refinery. Any interruption in the operation of this unit for any reason, such as failure of a vital part, may interrupt the function of other units. This paper describes the failure investigation of pressure swing adsorption (PSA) bed bolts of hydrogen generation unit in a petroleum refinery which occurred without any indication and led to an unplanned breakdown of downstream units.

A number of tests were carried out in laboratory to address the reasons of failure. The observations point out towards failure by fatigue mode. Needle type plate martensitic structure with hardness significantly higher than the specified limits was observed which indicated insufficient / lack of tempering treatment of bolt material and accentuated the fatigue mode in the root of a the threaded bolt. An in-house tempering treatment was given to failed bolt to study the resulting effect on microstructure and hardness.

Keywords:
Scanning Electron Microscope (SEM), Martensite, Beach marks

1.0 Introduction

Refineries and petrochemical industries consist of many process units that convert crude oil into final products such as gasoline, diesel, kerosene and jet fuel etc. by utilizing hydrogen [1]. The required hydrogen is generated in the hydrogen generation unit of the plant by steam reforming of naphtha. The hydrocarbons i.e. naphtha is made to react with steam in the presence of catalyst at very high temperatures [2] to generate hydrogen. After production of hydrogen, purification process is carried out by pressure swing adsorption (PSA), a technique to separate hydrogen from a mixture of gases, to achieve the desired purity of hydrogen gas [3].

Corrosion, fatigue, wear and abrasion are the most common failure modes in these industries [4]. Various measures are taken at design and process stage to minimize the failure of components during service. Tempering is one of the most common heat treatment processes for all the steel fasteners but it is often taken for granted. The as- quenched microstructure of a hardened steel fastener is primarily martensite, which is highly unstable and present in a strain-induced state. Tempering is, therefore, the modification of this hardened microstructure towards a more equilibrium condition [5]. The resulting change of martensite also results in a slight increase in grain size and a decrease in volume as a function of increasing tempering temperature.

As the failure of the bolts occurred without any gross indication and all of a sudden it led to an interruption in the supply of hydrogen in the downstream units which caused interruption in the operation of downstream units and a huge loss of production.

2.0 Experimental Work

2.1 Visual Inspection

A close view of the bolt failure site location is shown in Fig.1. Visual inspection of the received bolt revealed no corrosion or erosion damage and fracture surface indicated smooth brittle fracture as shown in Fig.2. The observation indicated the smooth, bright brittle fracture initiation zone with final fast fracture.

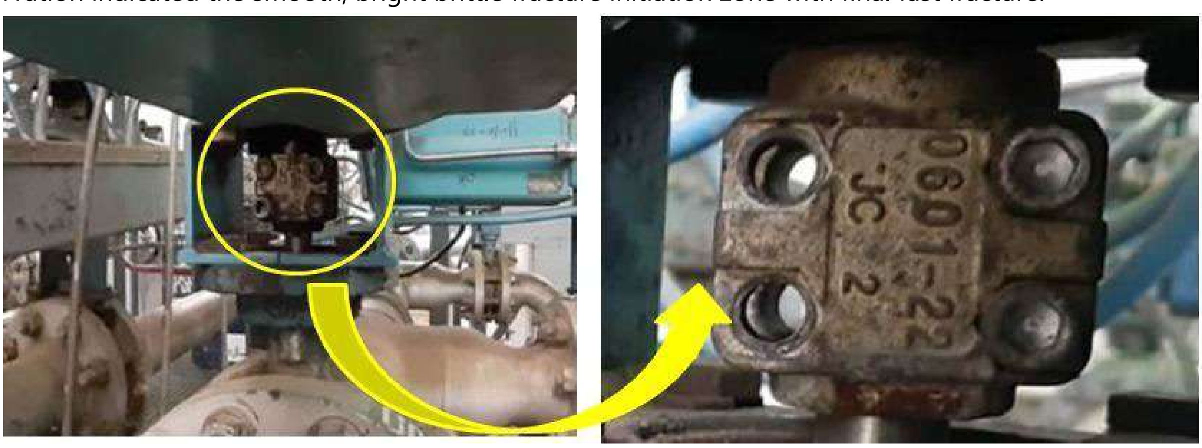

Fig.1: Onsite images of PSA bed valve

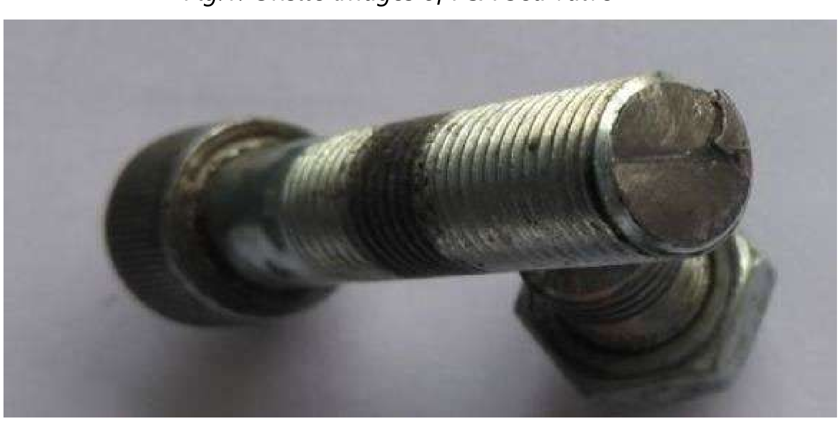

Fig. 2: As received failed bolt sample

3.2 Fractography analysis by SEM

Scanning Electron Microscope (SEM) was used to analyze the fracture surface of the bolt sample. The study clearly indicated failure initiated at the root of the thread where some amount of stress concentration is experienced by a bolt under its normal operation as shown in Fig. 3(a). After a very slow initial stage the stress went up and raised stress increased width of crack in every cycle and some beaching effect could be seen as shown in Fig. 3(b). This strongly indicated brittle mode of failure resulting from fatigue. A number of bright facets are also seen that are indicative of a brittle mode of failure as shown in Fig. 3(c). Final fast fracture is shown at Fig. 3(d).

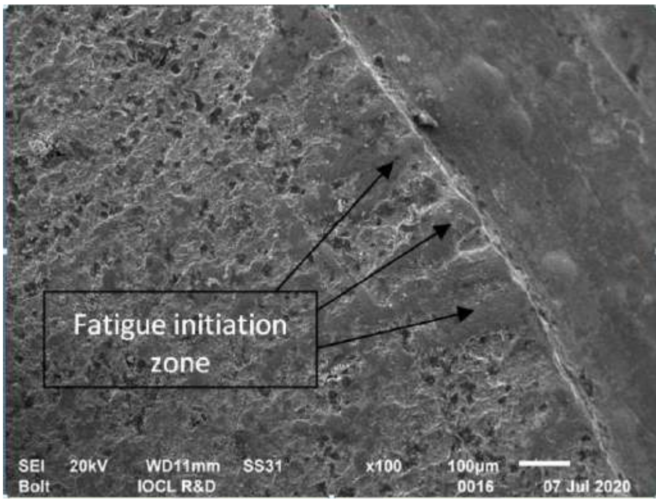

Fig. 3(a): Fracture initiation zone

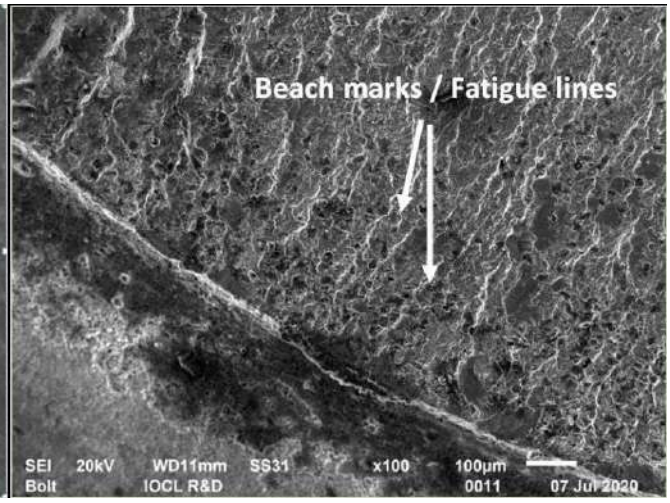

Fig. 3(b): Beach marks

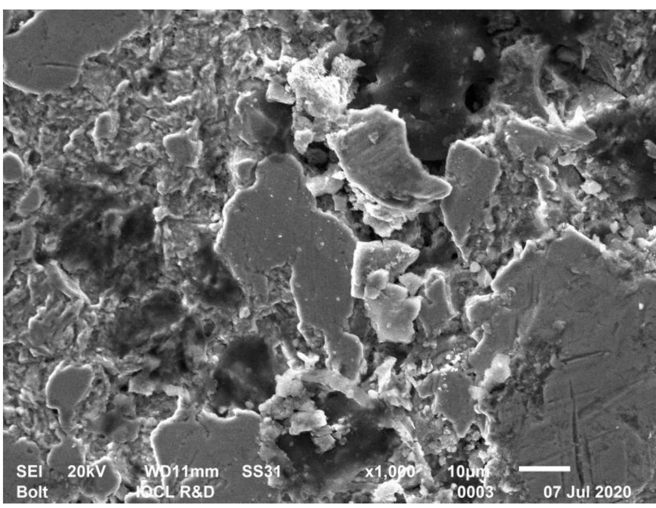

Fig. 3(c): Brittle facets

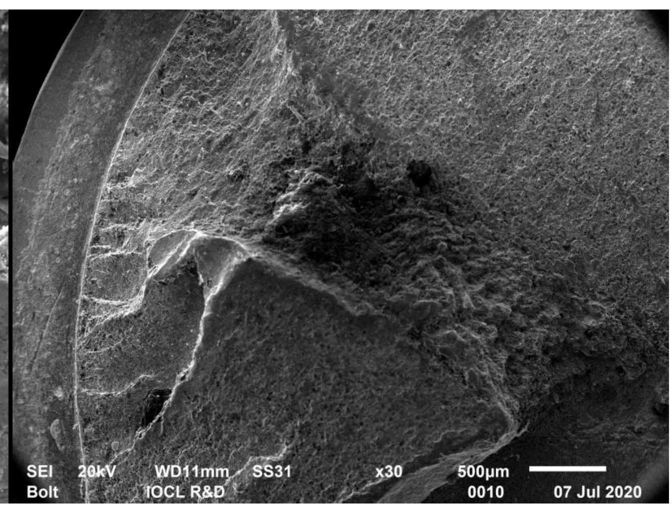

Fig. 3(d): Final fracture zone

3.3 Tempering treatment and study of Micro structure

The microstructure analysis of as received bolt material was carried out by using an optical microscope to examine microstructural condition. Since bolt components of the valves of the PSA bed operate at ambient temperature therefore no in service material degradation was expected.

Analysis was carried out at near and away from the fracture zone of the sample. These samples were polished up to mirror finish and then etched with nital (95% methanol + 5% HNO_3) for microstructure analysis. Microstructure section just beneath the fracture zone shows predominantly needle shaped martensite of plate morphology which is hard and brittle phase with poor toughness along with bainite (mixture of carbide and ferrite coalesced during tempering) as secondary phase as shown in Fig. 4(a).

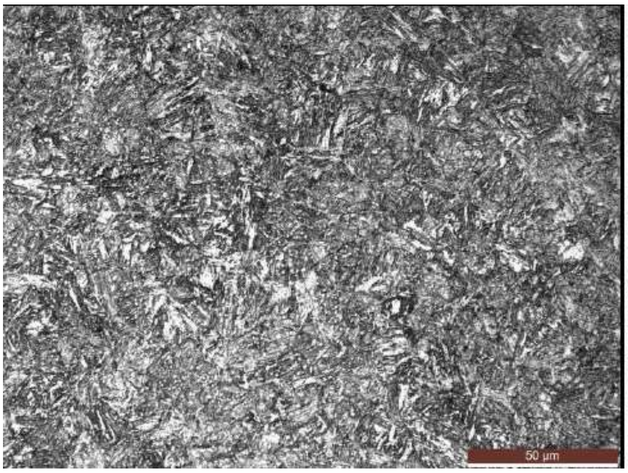

Fig. 4(a): Microstructure of as received failed bolt material

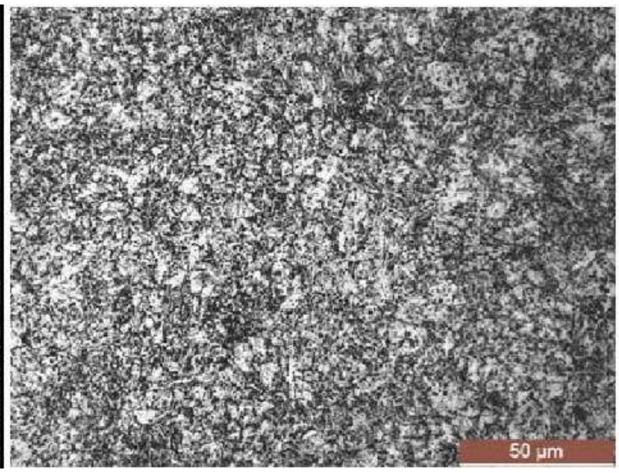

Fig. 4(b): Microstructure of bolt material after tempering treatment

An in-house tempering of the bolt failed material was carried out. The material was tempered by heating up to 500 °C followed by 5 hour soaking at same temperature and subsequent furnace cooling. The microstructure of the heat treated material revealed the tempered martensite with uniform dispersion of carbides in the matrix as shown in Fig. 4(b). Tempered martensite exhibits better material toughness as compared to needle shaped martensite.

3.4 Hardness study of bolt material

Hardness measurements of bolt samples were carried out before and after tempering treatment by using Universal Hardness Testing machine (Zwick Roell make). As received bolt sample indicated the hardness in the range of 395 to 410 BHN, which is significantly higher than the specified limits of 255 to 321 BHN in ASTM A449 [6]. This high hardness resulting from predominantly needle shaped martensite of plate morphology can reduce fluctuating stress bearing capacity of the material and accentuate fatigue failure.

Further, the hardness of tempered material was measured and found in the range of 240- 260 BHN. The tempering treatment of 5 hour at 500 °C reduced the hardness to specified limits. The tempering treatment causes diffusion of vacancies and other point defects and results in the decrease in hardness.

4. Conclusion & Recommendations

From the above discussed laboratory studies, failure of the bolt occurred in fatigue mode. Materials with very high hardness have poor toughness and don't show enough resistance to fatigue failure. In the present case the bolt is found to have hardness much higher than ASTM A449 specified values. This high hardness of the material is an outcome of insufficient / lack of tempering treatment at the bolt manufacturing stage.

After in-house tempering heat treatment of bolt material for 5 hour at 500 °C, significant microstructural changes along with reduction of hardness to specified limits were observed. Therefore, high hardness of bolt material due to insufficient tempering was inferred as the prime reason of bolt failure by fatigue. The presence of some vibrations and incorrect tightening (loose or over tight), though not confirmed, might have also made some contributions in fatigue failure of bolts.

5. References

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Aviation - Biojet Fuels : A Way Forward

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1.0 Introduction

The aviation sector contributes approximately 2% of the total anthropogenic CO_2 emissions, and predictions estimate that air traffic will double in the next 20 years, doubling fuel requirements and CO_2 emissions. In 2010 carbon dioxide (CO_2) emissions from international aviation mounted to 448 megatonnes (Mt), with forecast of increased emissions ranging from 682 Mt to 755 Mt by 2020, and as high as 2700 Mt by 2050 if no action is taken (International Civil Aviation Organisation; ICAO, 2016)[i]. Given this sector's growing contribution to global CO_2 emissions, aviation will play a key role in meeting the international climate targets set forth in the 2015 Paris agreement. Many airlines, aircraft manufacturers and industry associations have committed to voluntary, aspirational targets that would collectively achieve carbon–neutral growth by 2020 and a 50% reduction in GHG emissions by 2050. A significant long-term reduction of emissions would require airlines to use biofuels that are renewable and sustainable for jet aircraft. The International Air Transport Association (IATA) has identified the development of renewable aviation fuel, known as biojet fuel, as the most promising strategy to reduce the environmental impact of the aviation sector. The renewable hydrocarbons that constitute biojet fuel are also known as synthetic paraffinic kerosene (SPK), and their properties are almost identical to those of jet fuel. SPK has the advantage of containing very little sulfur, producing lower CO_2 emissions than jet fuel. Biojet or Bio-jet fuels are the only option to achieve significant reductions in aviation emissions by 2050. The production process of biojet fuel is the key to satisfy both technical and economic goals required to obtain a more competitive biofuel, and allow the sustainable development of aviation sector.

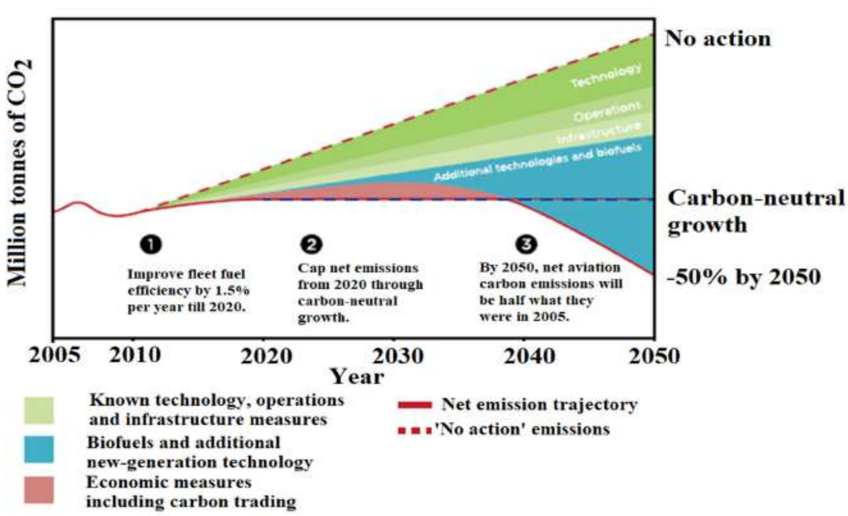

Fig 1. *Emissions from aviation in the absence of any action, and emission reduction goal set by industry*

(Source: Air transport action group)

Commercial jet fuel is a fossil fuel primarily consisting of C8 to C16 hydrocarbons. Table 1 reports a typical composition of jet fuels. The production of an alternate source such as biojet fuel can be a viable sustainable option, but the stumbling block is the high price of biojet fuel, which is three to nine folds more expensive than conventional petroleum jet fuel[ii]. The development of biojet fuel from renewable sources would not only reduce the reliance on fossil fuels, but can also potentially reduce CO_2 emissions by up to 68.1% in 2050[iii].

Table 1. Jet Fuel Specifications

	Jet A-1				JP-8	Bio-ATF
	ASTM D1655-04a	IATA	Def Stan 91-91	ASTM D7566	MIL-DTL-83133E specification	ASTM D7566 – 20c
Acidity, Total (mg KOH/g)	0.1, max	0.1, max 0.015, max	0.012, max	0.1, max	0.015, max	0.015
Aromatics (vol%)	25, max	25, max	25, max	25, max (8, min)	25, max	—
Sulphur, Total (wt%)	0.3 max	0.3 max	0.3 max	0.3 max	0.3 max	—
Distillation Temperature						—
10% Recovery (°C)	205, max	205, max	205, max	205, max	205, max	205, max
20% Recovery (°C)	—	—	—	—	—	
50% Recovery (°C)	—	—	—	— (15, min)	—	
90% Recovery (°C)	—	—	—	— (40, min)	—	
Final BP (°C)	300, max	300, max	300, max	300, max	300, max	300, max
Flash Point (°C)	38, min	38, min	38, min	38, min	38, min	38, min
Freezing Point (°C), max	-47	-47	-47	–40 Jet A; –47 Jet A-1	-47	–40
Viscosity @ -20°C (cSt)	8, max	8, max	8, max	8, max	8, max	-
Net Heat of Comb. (MJ/kg)	42.8, min	42.8, min	42.8, min	42.8, min	42.8, min	—
Density @ 15°C (kg/m3)	775-840	775-840	775-840	775-840	775-840	730 to 772

2.0 Pathways for bio-jet fuel production

The raw material costs and its transportation affects the supply chain, hence the availability of raw materials plays a major role in the selection of best biojet fuels production pathways. Depending on the renewable raw material, the following pathways are identified to produce biojet fuel.

(i) Alcohol to Jet (ATJ)
(ii) Hydroprocessed esters and fatty acids (HEFA)
(iii) Hydrothermal Liquefaction (HL)
(iv) Pyrolysis
(v) Gas to jet fuels (GTJ)
(vi) Direct sugars to hydrocarbons (DSHC)
(vii) Aqueous phase reforming (APR)

Table 2. Pathways for Jet Fuel Production

Sr. No	Category	Pathways	Companies	U.S. or International Agencies	Airline Companies / Manufacturers
1	Alcohol-to-Jet (ATJ)	Ethanol-to-Jet	Terrabon/MixAlco; Lanza Tech/Swedish Biofuels; Coskata	Defense Advanced Research Projects Agency, FAA	Boeing, Virgin Atlantic
		Butanol-to-Jet	Gevo; Byogy; Albemarle/Cobalt; Solazyme	U.S. Navy/NAWCWD, AFRL, DLA, USAF	Continental Airlines ; United Airlines
2	Hydroprocessed esters and fatty acids (HEFA)	Hydroprocessed Renewable Jet (HRJ)	UOP; SG Biofuels; AltAir Fuels; Agrisoma Biosciences; Neste Oil; PetroChina; Sapphire Energy, Syntroleum/Tyson Food; PEMEX ; ASA	U.S. Navy, USAF, Netherland Air Force, NASA, Dutch Military, EADs	Boeing, Lufthansa, Virgin Atlantic, Virgin Blue, GE Aviation, Air New Zealand, RollsRoyce, Continental, CFM, JAL, Airbus, KLM, Pratt & Whitney, Air China, TAM Airlines, Jet Blue Airways, IAE, United Airlines, Air France, Finnair, Air Mexico, Thomson Airways, Porter Airlines, Alaska Airlines, Horizon Air, Etihad Airways, Romanian Air, Bombardier
3	Hydrothermal Liquefaction (HL)	Catalytic Hydrothermolysis (CH)	Applied Research Assoc., Aemetis/Chevron Lummus Global	FAA CLEEN, NRC Canada, AFRL	Rolls-Royce, Pratt & Whitney
4	Pyrolysis	Hydrotreated Depolymerized Cellulosic Jet (Pyrolysis or HDCJ)	Kior/Hunt Refining/Petrotech, Envergent, GTI, Dynamotive	FAA	N/A
5	Gas to Jet (GTJ)	FT Synthesis	Syntroleum; SynFuels; Rentech; Shell; Solena	U.S. DOE, U.S. DOD, USAF, Ontario government	Qatar Airways, United Airlines, Airbus, British Airways
		Gas Fermentation	Coskata; INEOS Bio/Lanza Tech; Swedish Biofuels	N/A	Virgin Atlantic
6	DSHC	Catalytic Upgrading of Sugar to Jet	Virent/Shell, Virdia	Amyris/Total, Solazyme, LS9	N/A
		Direct Sugar Biological to Hydrocarbons	Amyris/Total, Solazyme, LS9	U.S. Navy, FAA	Boeing; Embraer; Azul Airlines; GE; Trip Airlines
7	Aqueous phase reforming (APR)	Catalytic conversion of soluble plant sugars into a mixture of water, hydrogen and chemical intermediates (such as alcohols, ketones, acids, furans, paraffins and other oxygenated hydrocarbons). These can in turn be converted to fuels and high value chemicals	Tesoro/Virent's BioForming platform	Tesoro, USA	N/A

The American Society for Testing and Material (ASTM) certification is required before commercial airlines can use a fuel for international flight. From all the above pathways (Table 2) available for bio-jet fuel production, ASTM had certified four different technology pathways to produce bio-jet fuels. The four pathways are:

1. Hydroprocessed Esters and Fatty Acids (HEFA bio-jet), using oleochemical feedstocks such as oil and fats. This is the foundation technology, which ASTM certified in 2011.

2. Gasification through the Fischer-Tropsch method (FT), using municipal solid waste (MSW) or woody biomass as feedstock. ASTM certified it in 2009.

3. Synthesised Iso-Paraffinic fuels (SIP), formerly known as the direct sugars-to-hydrocarbon route (DSHC) (farnesane). Certification came in 2014.

4. Alcohol-to-jet based on isobutanol (ATJ), certified in 2016.

3.0 Feedstocks for biojet production

Biojet fuel production on biomass based feedstocks can be categorized as follows: first-generation (1-G), second-generation (2-G), third-generation (3-G), and fourth generation (4-G). Table 3 presents some examples for biojet fuel production in each category. An important factor in choosing a feedstock is its availability. For cultivated feedstocks, their availability, and potential yield are interrelated. Figure 2 shows the potential yields for a number of 1-G and 2-G feedstocks. Palm Oil has the highest yield at 19.2 t/ha/year among all these feedstocks. For 3-G feedstocks, the potential yield for microalgae has been reported to be 91 t/ha/year, much higher than 1-G and 2-G. However there is an uncertainty in the production value of 3-G, since most of the algae cultivation is done from lab-to pilot scale[iv].

Table 3. Feedstocks for bio-aviation fuel production

Sr. No	1G (1st Generation)	2G (2nd Generation)	3G (3rd Generation)	4G (4th Generation)
1	• Oil-seed crops: camelina, oil palm, rapeseed, soybean, sunflower, salicornia	• Oil-seed energy crops: jatropha, castor bean	• Algae: microalgae	• Genetically modified organisms
2	• Sugar and starchy crops: corn, wheat, sugarcane, sugar beets	Grass energy crops: switch grass, miscanthus, Napier grass		• Non-biological feedstocks: CO_2, renewable electricity, water
3		Wood energy crops: poplar, willow, eucalyptus.		
4		Agricultural and forestry residues: corn stover, sugarcane bagasse, wood harvesting/processing residues.		
5		Food and municipal waste: used cooking oil, animal fats, biogenic fraction of municipal solid waste.		

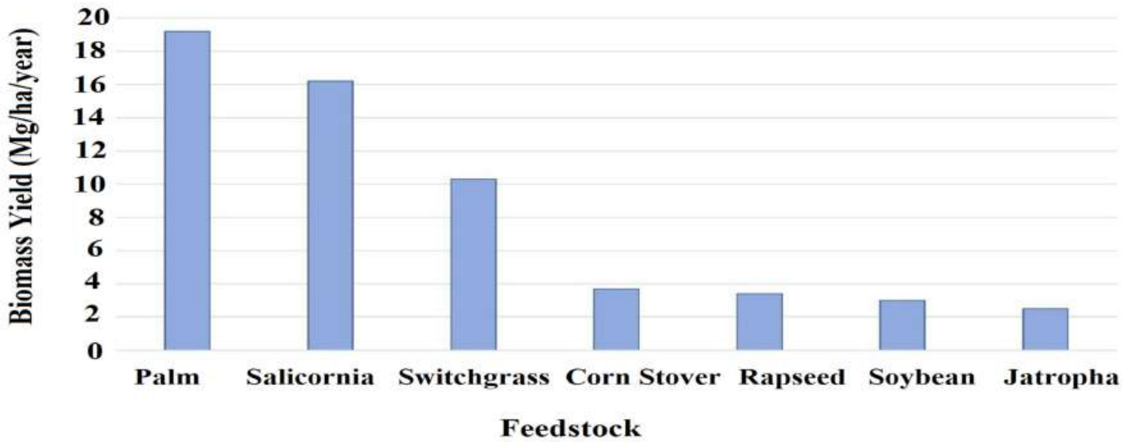

Fig 2. Typical potential yields of some 1-G and 2-G feedstocks for biojet fuel production (Plotted using data from Stratton et al., 2010[v])

The competitiveness of sustainable aviation fuel depends on its production cost relative to that of fossil jet kerosene (which varies with crude oil price). Sourcing of an economic feedstock is key for sustainable Bio-Fuels option. Alternatively, low cost waste streams and residues are increasingly being developed as feedstocks. To date, UCO/WCO (used cooking oil/waste cooking oil) is considered as the most economical and environmentally friendly feedstock for bio jet fuel production (Table 3). It not only addresses the environmental problems associated with the disposal of waste oils but also improves the economic viability of biofuels[vi].

When processing oils, the fatty acid profile is an important issue. For instance, a greater hydrogen supply is needed if more unsaturated fatty acids are present in the oil. **Table 4** summarizes the fatty acid profiles for the oil feedstocks. Vegetable oils, waste cooking oil, and algal oil are in the diesel fuel range C16–C22. Oleic acid is a predominant proportion of vegetable oils.

Table 3. Oil Selling Price[vii]

Oil	Palm	Rapeseed	Soybean	Jatropha	Camelina	Algal	Salicornia	Waste cooking oil
Oil Price ~ (Rs/kg)	29.75	56.43	22.72	3.55	18.32 ~ 68.16	57.90	36.64 ~ 109.93	20.05 ~ 31.15

Table 4. Fatty Acid Profiles and Carbon Chain Length in Oil Feedstocks[viii]

Fatty acid profile	Palm oil (%)	Rapeseed oil (%)	Soybean oil (%)	Jatropha oil (%)	Camelina oil (%)	Algal oil (%)	Salicornia oil (%)	Waste cooking oil (%)
C8:0	0	0	0	0	0	0	0	0
C10:0	0	0	0	0	0	0	0	0
C12:0	0	0	0	0	0	0	0	0
C14:0	0.5-2	0-1	0	0.5-1	0	10	0	1
C14:1	0	0	0	0	0	0	0	0
C16:0	32-45	1.5-4	7-11	12-17	8	20	20	20
C16:1	0	0	0	0	0	21	0	0
C17:0	0	0	0	0	0	0	0	0
C18:0	2-7	0.4-3	2-6	5-10	3	0	9	9
C18:1	38-52	22-60	22-34	37-63	17	5	19	53
C18:2	0	12-14	43-56	19-41	23	0	43	14
C18:3	5-11	5-7	5-11	0	31	0	4	1
C18:4	0	0	0	0	0	6	0	0
C20:0	0	3-5	0	0.3	0	0	0	0.1
C20:1	0	0-1	0	0	12	0	0	1
C20:5	0	0	0	0	0	23	0	0
C22:0	0	0-3	0	0	0	0	0	0.03
C22:1	0	0-5	0	0	3	0	0	0.07
C22:5	0	0	0	0	0	0	0	0
C22:6	0	0	0	0	0	8	0	0
C24:0	0	0-3	0	0	0	0	0	0.04

4.0 Current technologies and process advances for biojet fuel production

There have been great strides made in the research on biojet fuel production platforms, and some have been approved for industry use. Figure 3 shows the relative maturity of these technologies in terms of technology readiness level (TRL) against the resource availability of feedstocks. Having commercial readiness at TRL > 7, bio-aviation fuel from FT and HEFA have been approved in, up to 50% blends with conventional jet fuel (CJF) (ASTM, 2019). Although biojet fuel through ATJ process is allowed for 50 percent blending with conventional jet fuel, relatively few commercial-scale technologies are known. Following further research and flight tests, their efficacy with the existing engines determines the approval of higher blends in the future. Increasing the TRL would entail additional investments, studies and demonstrations but as long as a technology receives continued interest, its commercialization could happen in the coming years. The aviation industry could potentially choose from a variety of production pathways based on available feedstock and existing infrastructure. Consequently, these can help reduce geographical dependency on feedstock and ultimately make global implementation of biojet fuel possible.

Today, the vast majority of currently available commercial volumes of bio-jet fuels are HEFA bio-jet (Figure 4), and a number of commercial-scale facilities can produce it **Table 5**. In total, the operational capacity of the world's current HEFA facilities is about 4.3 bln Liters per year. Even if all of this were to be used to make bio-jet, supply would still amount to less than 1.5% of the world's jet fuel requirements.

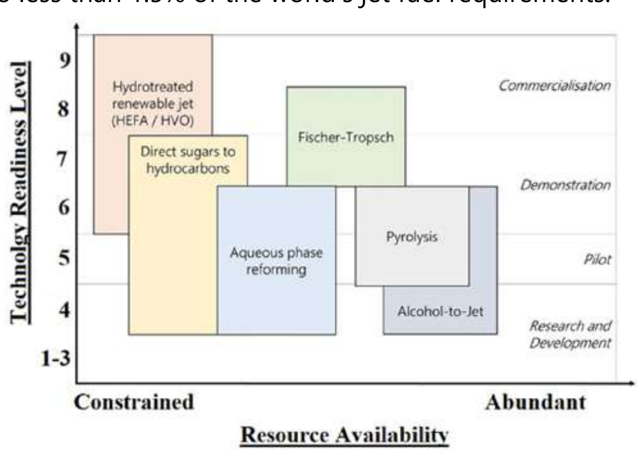

Fig 3. Future scope for adapting processes to a commercial level based on resource availability and technology maturity (Drawn using data from Mawhood et al., 2016[ix]; Bosch et al., 2017[x]).

Table 5. Existing companies producing hydroprocessed esters and fatty acids#

Company	Technology	Process	Feedstock	Capacity (Mt/year)	Fuels Produced
Neste Oil	NExBTL	Hydrotreating	Waste, Residues, Vegetable oils (Palm)	2.6	Biodiesel and Bio-aviation fuel
Renewable Energy Group	-	-	Waste, Residues, Vegetable oils (Palm)	1.6	Biodiesel only
AltAir Fuels	Ecofining	Hydrotreating + Isomerisation	Inedible agicultural waste/, Waste fats/oils	~0.13	Biodiesel and Bio-aviation fuel
Petrixo Oil and Gas	Ecofining	Hydrotreating + Isomerisation	-	0.5	
Eni	Ecofining	Hydrotreating + Isomerisation	Palm oil	0.315	Biodiesel and Bio-aviation fuel
Diamond Green Diesel	-	-	Animals fats, Used cooking oil	~0.45	Biodiesel
Total	-	-	Used oils, Vegetable oils	0.5	-
Solazyme	-	-	Oils from microalgae	0.1	-
Tyson Foods Inc.	-	Hydrotreating	Animals fats: Beef tallow, Pork Lard, Chicken Fat, Grease	-	Biodiesel and Bio-aviation fuel
Syntroleum Corporation	-	Hydrotreating	Animals fats: Beef tallow, Pork Lard, Chicken Fat, Grease	-	Biodiesel and Bio-aviation fuel
Haldor Topsøe	-	Hydrotreating	Raw Tall Oil		Biodiesel and Bio-aviation fuel

(#Data from Sotelo-Boyas et al. 2012[xi] , Richter et al. 2018[xii]).

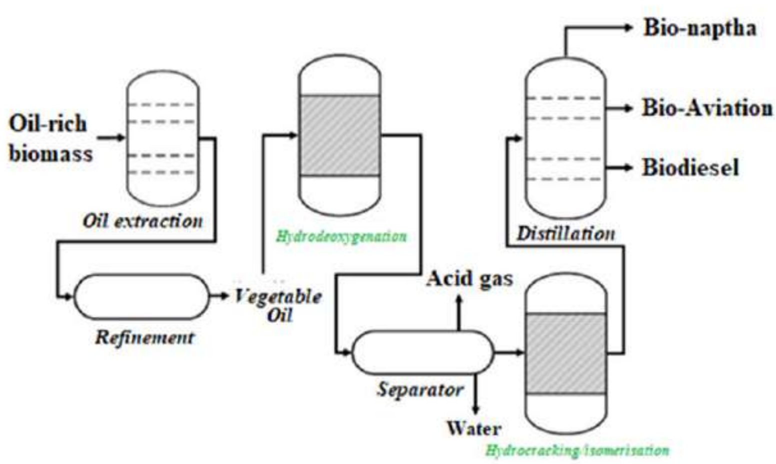

Fig 4. Hydroprocessed esters and fatty acids production process from oil-rich biomass (Drawn using data from Wang and Tao (2016[xiii]))

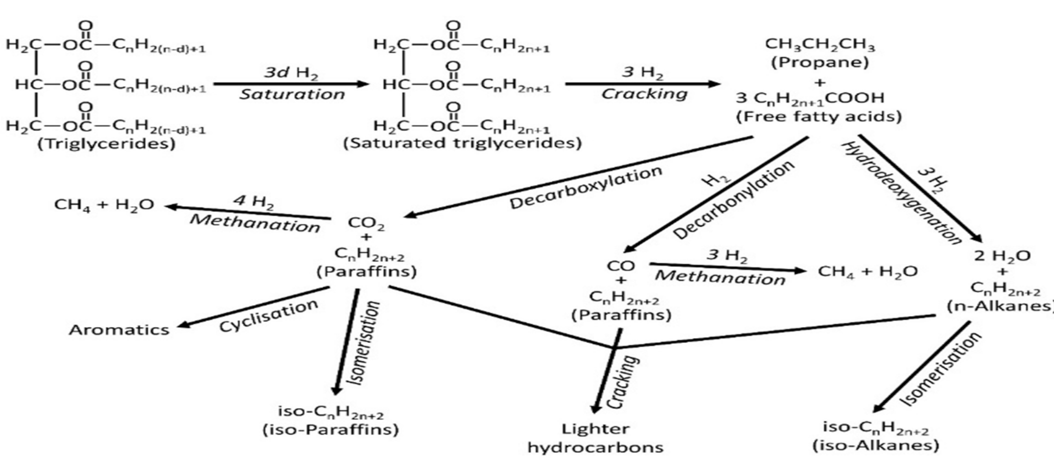

Fig 5. Reaction pathways for synthetic paraffinic kerosene production (Drawn using data from Vásquez et al. (2017)[xiv])

Table 6. Commercially available technologies for biojet fuel production

Sr.No	Technology	Feedstock	Process	Ref
1	Ecofining (ENI/Honeywell-UOP)	Triglycerides and/or free fatty acids	Hydrotreating & Isomerization	xv
2	Bio-Synfining (Renewable Energy Group)	triglycerides and/or fatty acids from animal fats, greases, vegetable and algae oils	Hydrotreating & Isomerization	xvi
3	HydroFlexTM (Haldor Topsøe /UPM)	Raw tall oil	Hydrotreating & Isomerization	xvii
4	NExBTL process (The Neste Oil.)	Palm oil and waste animal fat	Hydrotreating & Isomerization	xviii
5	Vegan (Axens)	Vegetable oil, animal fats and algal oil	Hydrotreating & Isomerization	xix
6	BP	Municipal solid waste	Hydrotreating & Isomerization	xx
7	Cetane Energy	Waste grease, tallow, algae, algal oil, vegetable oil, and soybean oil.	Hydrotreating & Isomerization	xxi

5.0 Biojet fuel scenario in India and challenges

Fuel consumption for international aviation could be as high as 852 million tonnes (Mt) by 2050 (ICAO, 2016), and could require 426 Mt of bio-jet to meet the GHG emissions-reductions goals. Current production is however very limited at less than 0.1% of global total consumption of all types of jet fuels.

In India the first commercial trial biojet fuel,was prepared from "non-edible tree borne oil" by CSIR-IIP, Dehradun, and is procured from various tribal areas of India. SpiceJet operated India's first biofuel-powered flight on 27th August, 2018 from Dehradun to Delhi. A blend of oil from jatropha seeds and aviation turbine fuel propelled the country's first ever bio-jet fuel powered flight on Monday between Dehradun and Delhi. The 43 minute flight was operated by SpiceJet's Bombardier Q-400 aircraft with 20 officials and five crew members onboard. A blend of 25% of bio jet fuel and 75% of aviation turbine fuel (ATF) was carried in one of the two engines of the plane, while the other engine carried only ATF. International standards permit a blend rate of upto 50% bio fuel with ATF. With the test flight, India has become one of the few countries and probably the first among the developing nations to use biofuel for flying planes.

On 31st January, 2020 an AN-32 aircraft of the Indian Air Force, powered with a 10 per cent blend of Indian bio-jet fuel took-off from Kushok Bakula Rimpochee Airport, Leh. This fuel is made from Jatropha oil sourced from Chattisgarh Biodiesel Development Authority (CBDA) and then processed at CSIR-IIP, Dehradun. The project was a combined effort of IAF, DRDO, Directorate General Aeronautical Quality Assurance (DGAQA) and CSIR-Indian Institute of Petroleum. Addressing the nation in his monthly Mann ki Baat radio, Prime Minister Mr. Narendra Modi on Sunday (February 23, 2020) hailed the use of biofuel in an Indian Air Force transport, saying such innovations would bring down carbon emissions and lower the nation's oil import bill.

India's circumstances scenario and current challenges

India currently accounts for about 8% of Asia's jet fuel demand, but it is projected to contribute to an average of 12% to overall regional jet fuel demand growth over the 2020-25 period, according to Platts Analytics.

In addition, the industry will be keeping a close eye on the government's plan to privatize state-run Air India and the implications it might have on the domestic aviation sector.

Looking ahead to the current year, jet fuel prices might see some upward risk in the first quarter of 2021 on the back of unexpected Covid-19 and a possible escalation of tensions in the Middle East.

6.0 Policy measures are crucial to stimulate sustainable aviation fuel demand

There is a key role for policy frameworks at this crucial early phase of biojet fuel industry development. Without a supportive policy landscape, the aviation industry is unlikely to scale up biofuel consumption to levels where costs fall and biojet fuel become self-sustaining.

The policy measures that could support biojet fuel market development include:

- Financial de-risking measures for refinery project investments (e.g. grants, loan guarantees).
- Measures to provide guaranteed biojet fuel offtake, e.g. mandates, targets and public procurement.
- Other mechanisms that close the cost gap between biojet fuel and fossil jet fuel e.g. carbon pricing.

Countries have more control over policy support for domestic than international aviation, and the introduction of national policy mechanisms to facilitate biojet fuel consumption is gathering pace. Country establishing policy mechanisms which will support the use of aviation biofuels will gain the confidence of policy makers and the general public, such support will need to be linked to robust fuel sustainability criteria.

The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), introduced in 2021, will be the principal mechanism to meet aviation's long-term decarbonisation targets. Biojet fuel consumption and the purchase of carbon offsets are the two principal means to achieve CORSIA compliance, with the relative attractiveness of these to the aviation industry dependent on their cost per tonne of CO_2 emissions mitigated.

7.0 Summary and future outlook

With the demand on the aviation sector projected to increase in the near future, the dilemma is how to satisfy this demand while complying with international emissions reductions.

The implementation of alternative jet fuel is a pivotal step that will help the sector decarbonize and simultaneously become independent from limited fossil fuel supply.

The key conclusions are as follows:

1. A range of feedstocks for bio-aviation fuel production is available with different economic potential and environmental benefits. In the short- to medium-term, low-cost and high yield oil-rich feedstocks could be an effective transitionary solution. The negative environmental consequences of land based crops, such as palm oil and jatropha, can limit their applicability, while the great potential of microalgae as a feedstock, due to its higher yield than oil-bearing crops can be considered. The great potential of waste streams such as used cooking oil and municipal solid waste will be economical in the long-term. A wide range of feedstocks are needed to ensure security, availability, and sustainability of bio-aviation fuel.

2. Increased use of sustainably derived biojet is essential for the aviation sector to meet its carbon emissions-reduction goals. Currently the vast majority of biojet fuels are derived from oleochemical feedstocks and use the HEFA pathway. This will likely remain the main conversion route over the next five to 10 years, as methods using biomass, lignocellulosic and algal sources, and other advanced bio-jet technologies, are not sufficiently matured for broad commercial usage.

3.HEFA, being a mature technology, could be a solution for the immediate, cost-effective implementation of bio aviation fuel. It is necessary to explore other production pathways further, especially FT, which has near commercial maturity and higher GHG savings than other pathways but involves higher capital costs.

4. The structure of biomass feedstock and refined fuel products transportation, whether distributed or centralized, should be optimally designed to streamline supply chains. Utilizing multiple transport modes in the chain would lower transportation costs and GHG emissions over long distances.

5. Given the trans-boundary nature of the aviation industry, specific policies must be standardized internationally but with enough room for flexibility for the varying national goals of different countries.

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Prepaid Metering in Domestic PNG

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Background

The City Gas Distribution (CGD) sector is going to be one of the infrastructure growth engines in India for the next 8-10 years. From about 7 million domestic PNG connections made till the last decade, after the 9th and 10th round authorisations recently, the total number of domestic connections is expected to go beyond 50 million in this decade, a multifold increase over the current base. As more bidding rounds for authorisation are called, this number is going to rise further.

All the PNG connections are metered. The present day installed meters are mostly conventional credit meters and meter readers do a physical meter reading at set frequency. Along with conventional meters come the whole set of operations involving meter reading, bill preparation and distribution, revenue collection and billing-related customer grievance handling. As the number of connections increase, all these operations will become a hugely Opex-intensive job and alternative mechanisms need to be thought of.

That's where technology comes into the picture; it can help provide solutions to some of the issues being faced by the CGD sector.

Introduction

Pre-payment as a concept has been there in the domestic LPG gas customer segment for a long time. People have been using bottled LPG gas cylinder since the domestic LPG industry started. This concept further permeated daily life since the mobile revolution began in India, nearly two decades ago, and DTH operators entered the market.

Pre-payment or "pay as you go" system is receiving more and more attention worldwide as different utilities are looking at ways to improve customer service, convenience, cash flow, operational efficiency, and smarter ways of doing things to minimise their risks. Various factors have led to the genesis of pre-payment metering concept in India, keeping in view the benefits that will accrue to all involved in the concept and its acceptance. The concept of pre-paid remains the same, but there is going to be a paradigm shift in the application. It's altogether a new arena in metering, which is likely to be crucial for revenue management. In the days to come, this will open up new vistas for investment and deployment of infrastructure for better customer services. There will be immense benefits, which the CGDs and citizens of India will reap.

Geographically, prepayment metering has been deployed across the globe. South Africa and UK have deployed this system in huge volumes and with considerable success. Other countries who have adopted the system include Brunei, Oman, Argentina, USA, Poland, New Zealand, Malaysia, Israel, Zimbabwe, Nigeria, Ghana, Kuwait, France, Bangladesh etc.

In India, various electricity utilities in West Bengal, Delhi, UP, Rajasthan, Meghalaya, Manipur, Karnataka, Haryana, Bihar have been using prepaid meters and have been reaping the benefits.

The concept

Pre-payment metering system is straightforward. It puts the customer in the driver's seat for purchasing gas. It's like filling your bike or car with petrol. You monitor the fuel level and decide when you should refill. Adding money to your account allows you to "refill". You pay for your gas before it is used.

A new kind of meter is installed in the customer's house, which has an in-built disconnecting device. The customer buys gas in monetary terms, in advance, by paying through any recharge mechanism. Once the amount is exhausted, the meter automatically disconnects the supply after alarming the customer. Customers can re-connect themselves by buying more gas and recharging the meter.

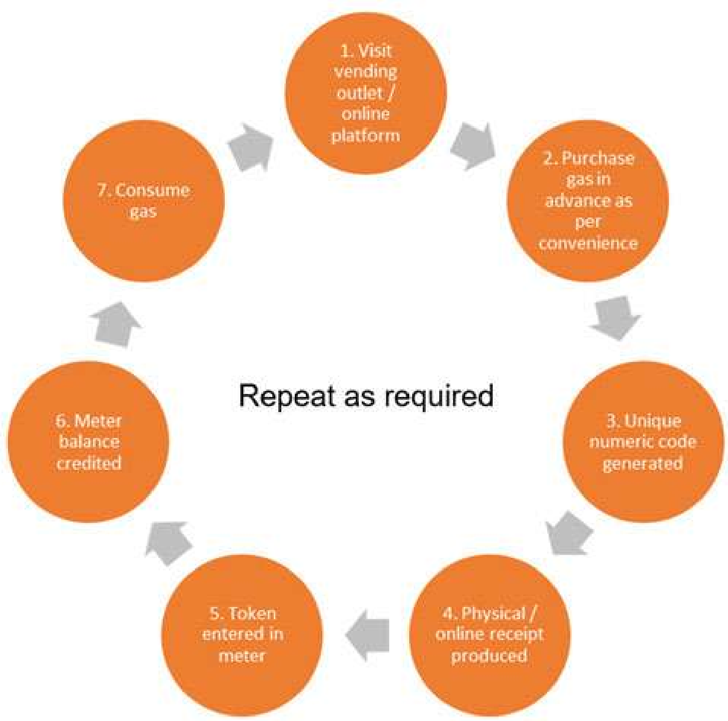

Fig 1: The prepayment metering cycle – how does it work

Historically, the pre-payment metering system dates to over 100 years. GE manufactured the first pre-payment meters in 1899, which were coin operated – a concept similar to the coin operated telephone booths. Technological advancements saw a new generation of pre-payment meters using magnetic cards and then smart cards. The latest generation of pre-payment meters use keypad technology; wherein there is a telephone like keypad on the meter for recharging. With the evolution of communication and technology, customers are also able to interact with the meter through their smartphones.

What benefit it brings?

A pre-paid metering system can bring a world of benefits to both the CGD and the end customer.

Benefits to CGD

i. Upfront payment for gas
Gas is paid for before it is consumed. This contrasts with the prevalent practice of credit metering and billing in current CGD practice but is not different from the other segment of pre-paid bottled LPG supply. Cash flow in advance will be a big plus for the CGD.

ii. No unpaid bill
Since the gas is paid for in advance, it eliminates the problem of collection of arrears and unpaid bills; CGDs will not require to put up a team for collection and recovery activities. So, it's an ideal zero-debt scenario.

iii. Lower overheads
As there is no billing, bill generation and bill distribution, there is a gradual decrease in overheads. CGDs can divert their workforce to other important, value-adding tasks like growing new connections, maintenance, emergency services, etc.

iv. No incorrect bills
Since the gas is paid for in advance, there is no need to generate bills Furthermore, the problem of incorrect billing due to inaccurate meter readings is also eliminated.

v. No disconnection / reconnection
The pre-payment system will naturally remove the CGDs need to get involved into the unpleasant and often difficult task of disconnecting errant customers. This will lead to direct savings in terms of workforce, transportation and legal expenses.

vi. No account queries
A considerable amount of time is often wasted in re-checking meter readings and statements due to customer queries. This requirement is altogether eliminated.

vii. Event detection
With an array of in-built software and hardware in the meter, pre-payment system brings in a host of diagnostics and features, which are absent in a normal credit meter. The meter can log and store events like meter tilt, magnet interference, on-off valve operation, etc.

Benefit to customers

i. Pay-as-you-go system
It allows the customer to buy gas in advance, as and when required.

ii. Convenience
The system can provide flexibility in making payments through various online and offline methods. Customers will know in advance when they need to recharge their meter and can purchase gas as per their budget, usage, and convenience.

iii. Allows budgeting
The pre-paid system empowers customers to understand the cost of energy and thus enable them to budget their usage according to their financial position and lifestyle. Since it is not required to pay large bills every quarter or month, they may choose their own time and frequency for purchasing gas.

iv. Display of remaining credit
People do not understand complex terms like SCM and MMBTU, and the tariff associated with these terms. But they do understand money. That's where pre-paid meters can help. They display the actual remaining credit and consumption in money value, and the approximate number of balance days left. This helps customers to manage their gas purchase to suit their requirements. Since the meter displays credit instead of SCM units, it's easy for customers to co-relate the tariff with their expenditure.

v. No disputes
The pre-payment system gives daily, weekly and monthly consumption information to the customer. Therefore, they are aware of their consumption at any given point in time. A bill doesn't come to them as a shocker. A continuous flow of information between the CGD and the customer through the meter helps avoid disputes related to consumption and billing.

How to make pre-payment successful?

Any successful implementation of a pre-paid system requires a whole ecosystem that works together to make it successful and reap its benefits to justify economic viability.

CGD, customer, regulator and manufacturer are the four pillars and parts of this ecosystem. Pre-payment can give all-round benefits vis-à-vis traditional credit metering when everyone is involved in the process.

i. Social acceptance

Proper marketing and PR campaign can help customers understand the value and benefits of pre-payment. No disconnection at odd times - night or Sundays / holidays would negate the inconvenience caused to customers. Automatic disconnection and reconnection will simplify things for the customers. Customers don't really appreciate a nasty surprise with their bills; they would rather be happy to pay for what they use. They can budget efficiently using the financial information provided by the meters and buy gas to suit their needs on monthly / weekly / daily basis.

Socially, the concept of pre-payment can be successful if society accepts the system as a whole and thus its introduction should be strategically planned.

ii. Vending infrastructure

The convenience of payment for gas in terms of location and denominations of one's own choice helps the customer. Pre-paid mobile industry has increased the level of customer expectation for recharging their mobile phones. A mobile phone can be recharged by buying cash cards from multiple outlets which are conveniently located.

Similarly, customers for pre-payment metering system would look forward to buying gas conveniently from several vending outlets.

With the technological advancement, they would also prefer to purchase gas using internet, and mobile phones, and as such an online system, just like the banking system, would be preferred. On the other hand, CGDs would like to have a negligible initial investment in the vending infrastructure and may in turn agree to pay a per transaction fee. This is where the manufacturers come in – they should provide different types of online and offline vending outlets.

iii. System integration

An easy and robust system integration between the manufacturer's system, CGD systems, and online and retail cash collection would make the system very popular.

iv. Lifetime costs

The pre-payment system, as a whole, is viewed from what it delivers over its entire asset life, and the purchase decisions should not be based on upfront L1 pricing. Accordingly, the system should be cost-effective to facilitate deployment on a large volume. The economic viability comes from reduced operating costs for the CGD, upfront cash collection, better cash flow, reduction in customer complaints, and reduced failure rate of meters. Along with the lifetime cost, CGDs should start asking for products with long term field reliability and should start pushing manufacturers for long terms warranties. These will go a long way in reducing the cost to the CGDs for avoided asset replacement and the Opex associated with it.

v. Regulatory acceptance and push

The regulatory body can play a significant role in facilitating the introduction of these systems. It can ensure that:

- customer interests are properly being taken care of in the new system
- customers are being incentivised to opt for pre-payment voluntarily
- processes are simplified for CGDs
- tariffs are rationalised
- competition is created in the market so that the system becomes cost-effective.

At the same time, the regulations can mandate testing of meters at a fixed frequency in the field so that there is push for long term reliability, ultimately leading to reduced cost-to-serve to the CGDs.

Opportunities for Small-scale LNG in India

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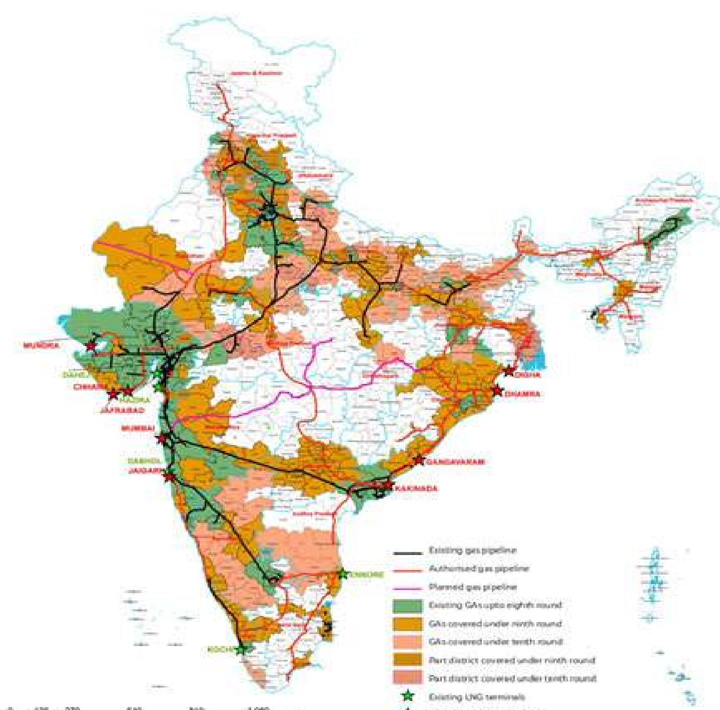
Introduction

India is the third-largest consumer of energy in the world and consumed more than 400 kilo tonnes of oil equivalent (ktoe) of energy (total final consumption) in 2019 (NITI Aayog 2019). However, much of this energy is produced from coal and oil (90 per cent), with natural gas contributing a meagre share (6.7 per cent) (NITI Aayog 2019). This contrasts with the global average, where more than 20 per cent of the primary energy is produced from gas (IEA 2021).

The country consumed 155 million standard cubic metres per day (mmscmd) of gas in 2019-20 (MoPNG 2020). About 52 per cent of the total gas consumed was supplied through the five LNG terminals, with nine more being planned or under construction (PPAC 2020a; PPAC 2020b). Transmission of gas relies upon a 17,000-kilometre-long network of pipelines; 15,000 additional kilometres are being planned or under construction (see Figure 1). With the recent tenth bidding round for city gas distribution (CGD) development, 70 per cent of the population would be covered by CGD networks once they are operational.

Figure 1
Pipeline infrastructure map of India



Source: PNGRB 2021

While the proposed transmission pipeline coverage is fairly extensive, several districts in the South and East could remain without piped gas in the foreseeable future since the transmission pipelines meant to feed the upcoming city gas grids have not been constructed yet. It could take up to a decade for these demand centres to get access to piped gas. Aside from the coverage limitations, the uncompetitive pricing of piped gas vis a vis incumbent fuels for industry, priority allocation of cheaper domestic gas to non-industry sectors, and the slow ramp-up of new pipeline capacity utilisation have limited gas growth in India. These conditions have resulted in the overall low capacity utilisation of pipelines - the average CUF of all operational pipelines was only 52.4 per cent in 2019-20 (MoPNG 2020). This, in turn, has affected the utilisation of major LNG terminals such as those in Ennore and Kochi. New terminals being constructed could also face this issue.

Considering that LNG terminals are in reasonable proximity to several demand clusters, there is significant potential to supply these prospective consumers with gas through small-scale LNG (ssLNG) distribution systems, which could solve both the access and cost-competitiveness challenges plaguing gas consumers in India.

Distributing gas through ssLNG systems entails transporting LNG in cryogenic containers from the LNG terminals by road, rail or waterways. The LNG is stored and regasified using small-scale equipment installed at the consumer's site.

Small-scale LNG uses scalable, flexible and movable assets which do not require significant capital investments or scale of operations. Hence, these systems circumvent several typical issues with gas distribution, such as high capital cost for pipelines, investment risks, varying demand, and stranded assets.

Potential roles of ssLNG

● Small-scale LNG could build demand for upcoming or planned transmission pipelines. Since the assets are flexible, demand can be gradually built up to a level that warrants or justifies a pipeline connection. This would eliminate the hesitancy to initially invest in pipeline infrastructure where the CUF in the early years would be low, thus limiting the profitability.

● Small-scale LNG could be the permanent gas source for those regions and consumers that either do not have a planned pipeline connection or are difficult to connect to gas pipelines (such as mining and quarrying equipment). Even when an area is allotted for CGD development, the CGD could utilise ssLNG to deliver gas to those consumers located in regions off their main grid that cannot be economically connected through their pipelines.

● In regions where existing pipelines are capacity-stressed, ssLNG can serve as an alternative or complementary gas source. Here, consumers can source gas or augment existing supplies with ssLNG.

● The micro, small and medium enterprise (MSME) sector contributes 30 per cent to the country's GDP (Vasal 2020). The sector faces challenges with competitive fuel prices and is difficult to decarbonise due to the size and variety of consumers. However, MSMEs organised in clusters without access to pipelines could switch to gas through ssLNG distribution without significant investments.

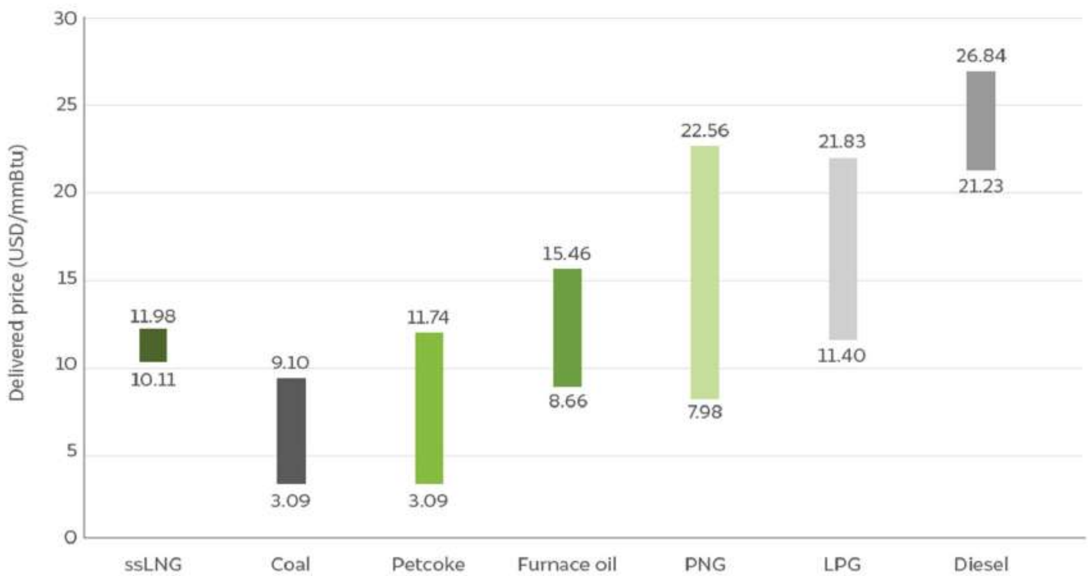
● The Ministry of Road Transport and Highways is planning several LNG refuelling stations along major highways in the country in anticipation of growth in LNG-powered heavy-duty vehicles. Small-scale LNG systems would be required to service these LNG refuelling stations. As CNG vehicles become more popular, ssLNG could also serve L-CNG stations within districts that do not already have a pipeline connection.

● The Ministry of Shipping's Sagarmala initiative seeks to expand the use of waterways for inland transportation. If the vessels using our waterways were encouraged to use CNG or LNG engines, it would greatly reduce the potential environmental impact on sensitive ecosystems. These vessels could then be supplied with gas through ssLNG distribution.

ssLNG economics

To determine the economic feasibility of ssLNG, we developed a price model for gas that considers factors such as import price of LNG, transport costs, taxes, and the cost of regasification equipment. Assuming an average LNG import price of 7.39 USD/mmBtu for the year 2017-18, we estimated the delivered price of gas as ssLNG, i.e., regasified LNG, to be between 10.11 USD/mmBtu (200 km one-way distance by road, 3 per cent VAT) and 11.98 USD/mmBtu (1000 km one-way distance by road, 14.5 per cent VAT). This price compares favourably with prices of other fuels such as LPG, diesel, certain grades of petcoke and furnace oil, and also with piped gas in certain locations. Figure 2 shows the comparison of estimated ssLNG prices and prices of other fuels (MoSPI 2020).

Figure 2 The delivered price of ssLNG compares favourably with several other fuels



Source: Authors' analysis

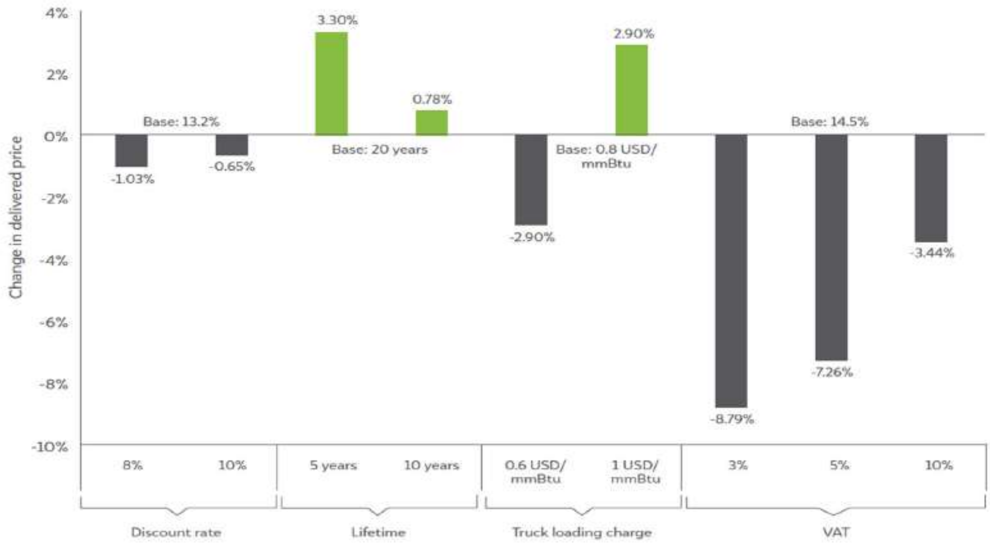
Note 1: Prices for states in proximity to terminals - Andhra Pradesh, Chhattisgarh, Gujarat, Jharkhand, Karnataka, Kerala, Maharashtra, Odisha, Rajasthan, Tamil Nadu, Telangana, and West Bengal.

Note 2: 10th and 90th percentile of prices of fuels to remove outliers in the states considered.

Note 3: 2017-18 average LNG import price considered for ssLNG range due to lack of data on individual import cargoes.

We carried out a sensitivity analysis to understand the effects of certain variables on the delivered price of ssLNG. The sensitivity for an LNG import price of 6 USD/mmBtu is shown in Figure 3. We can observe that lower discount rates for the ssLNG equipment do not significantly affect the price. While a lifetime of 20 years of regasification equipment was considered for the base case, even a short life of only 5 years would increase the delivered price only by 3.3 per cent (without including any salvage value). This is specifically important since some consumers may want to utilise ssLNG only for a limited duration till they get access to a pipeline. Truck loading charges at the LNG terminal can change the delivered price by ±2.9 per cent with a 0.2 USD/mmBtu loading charge difference. Of the analysed parameters, the sales VAT has the highest impact on delivered prices. If the VAT is reduced from 14.5 per cent (as in Kerala) to 3 per cent (as in Maharashtra), the delivered price will reduce by almost 9 per cent.

Figure 3 VAT has the highest impact among the considered sensitivity variables



Source: Authors' analysis

Note: Sensitivities shown for an LNG import price of 6 USD/mmBtu

Opportunities to scale natural gas through ssLNG

As observed in Figure 2, ssLNG prices are most competitive with LPG, diesel and certain grades of FO. To understand the potential market size of ssLNG in India, we estimated the total demand for LPG, HSD, LDO and FO consumed by industry in those states that are around 600 km from LNG terminals. The gas-equivalent demand for each of these states is shown in Table 1. A demand of 5.8 mmscmd from industrial LPG consumers can be replaced by ssLNG without significant investment at the consumer end, since minimal equipment changes would be required to facilitate a gas-to-gas fuel switch. The remaining demand from liquid fuels could switch to natural gas, albeit with some retrofitting requirements. However, depending on the type of equipment, the economics could still make sense considering the price spread between the fuels.

Table 1 Significant potential for ssLNG to competitively replace incumbent fuels in industry

State	Gas-equivalent demand (mmscm)			
	LPG	HSD	LDO	FO
Andhra Pradesh	158.3	163.9	18.5	136.7
Chhattisgarh	39.3	70.5	38.9	85.0
Dadra & Nagar Haveli	2.9	6.0	0.9	42.2
Daman & Diu	1.3	4.0	-	13.2
Goa	9.4	13.1	0.2	20.6
Gujarat	156.2	239.7	26.8	394.8
Jharkhand	50.3	84.1	17.6	59.1
Karnataka	235.5	282.2	18.5	154.1
Kerala	137.4	109.3	5.6	146.7
Maharashtra	415.7	407.3	75.0	404.3
Odisha	73.6	113.8	51.8	486.6
Puducherry	6.0	12.4	0.1	20.6
Rajasthan	185.0	225.4	45.3	-
Tamil Nadu	289.8	264.7	18.5	265.5
Telangana	133.2	154.8	13.0	58.1
West Bengal	238.8	147.0	40.7	205.8
Total	**2,132.8**	**2,298.3**	**371.4**	**2,493.3**
Total (mmscmd)	**5.8**	**6.3**	**1.0**	**6.8**

Source: MoPNG 2020, MoSPI 2020
(Disclaimer: Numbers are indicative in nature)

Thus, expanding the ssLNG market could service demand of nearly 20 mmscmd from industrial consumers alone, equivalent to about 13 per cent of the total gas consumed in the country. Replacing the above fuels with natural gas would mitigate the emission of more than 4.5 million tonnes of CO2eq per year. The potential demand for city gas could be even higher if ssLNG were to replace LPG in those urban centres that do not have piped gas supply through a transmission pipe connection. There is also significant growth potential for ssLNG due to the future demand from new LNG vehicles and retrofitted diesel vehicles.

Several demand sectors in various parts of the country could benefit from ssLNG distribution to switch to natural gas at competitive prices. Small-scale LNG could allow gas infrastructure development at lower risk by building demand in key sectors and regions. Consumers without access to gas pipelines could still reap the advantages of natural gas without relying on expensive infrastructure developments. Small-scale LNG will be a key enabler for the transport sector to adopt LNG as a vehicle fuel. With a diverse set of applications and cost-competitiveness with incumbent fuels, the prospects of ssLNG in India are promising.

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Assessment of Marine Environment with respect to Nutrient Analysis: A Case study around north Bombay of ONGC's offshore filed (NA, NQ platforms), Arabian Sea India


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1. Abstract

Offshore environmental Monitoring becomes essential on the basis recent trend of exploration and production (E&P) activities for hydrocarbons in the Arabian Sea. Nutrients are one of important parameter for the growth of primary production in the sea. This paper aims to measure the current concentrations of nutrients around North Bombay of ONGC's offshore field (NA, NQ Platforms) in the Arabian Sea. The results show that nutrients concentrations are well within in oceanographic range and comparable with other ocean also. The mean values are comparable with reference values.

Keywords: Arabian Sea, Nutrients, Anthropogenic, ONGC

2. Introduction

Marine ecosystems cover approximately 71% of the Earth's surface and contain approximately 97% of the planet's water. Coastal and estuarine waters are increasingly subject to anthropogenic input and high-quality measurement of nutrients is required to assess the marine ecosystems. The input of the major biologically active nutrients (nitrogen, Phosphorous and silicon) to the ocean plays an important role in regulating global oceanic production. In surface waters of the open ocean, uptake of nutrients by organisms usually results in one or more of those nutrients becoming limiting to their growth. Most of these nutrients are terrestrial in origin, finding their way to the oceans via riverine and atmospheric pathways. Once in the marine system, nutrients are made available to biological organisms for primary production either through nutrient-rich water being drawn up from below, or by local regeneration resulting from cell breakdown. In surface waters of the open ocean, uptake of nutrients by organisms usually results in one or more of those nutrients becoming limiting to their growth (i.e. when the nutrient is used up, production ceases). However, coastal and estuarine waters are increasingly subject to anthropogenic input stress, whereby frequent input of nutrients as run-off from agricultural land results in artificially prolonged algal growth. In either case, the need for high-quality measurement of nutrients is driven by economic factors associated with climate change, depleted fisheries, eutrophication and aquatic ecosystems being out of balance. Nutrients are most essential chemical elements that organisms need to survive and reproduce (Smith & Smith 1998).

3. Study Area

Indian offshore petroleum industry is concerned about western offshore which is considered to be the significant address for oil and gas reserves after discovery of Mumbai High. E&P activities have been established on Indian west coast almost six decades ago by public as well private operators.

In this present study, nutrient concentration around NA, NQ platforms are discussed.

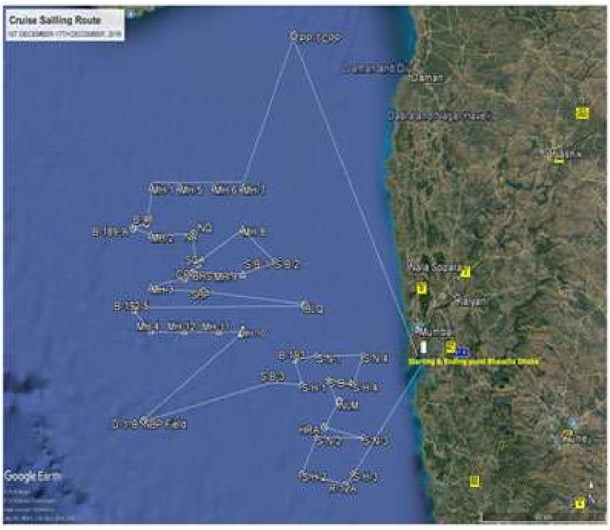

Fig 1

4. Materials and Methods

4.1. Sample Collection

Samples were collected as per OSPAR guideline. 18 sampling stations were fixed around each installation at circle of radios from 250 m to 4000 m from the centre of installation. **Reference point** was fixed approximately 10 km away from installation point. Samples were collected from three depths of each location. Samples were collected from three depths (surface, middle & bottom) of each location.

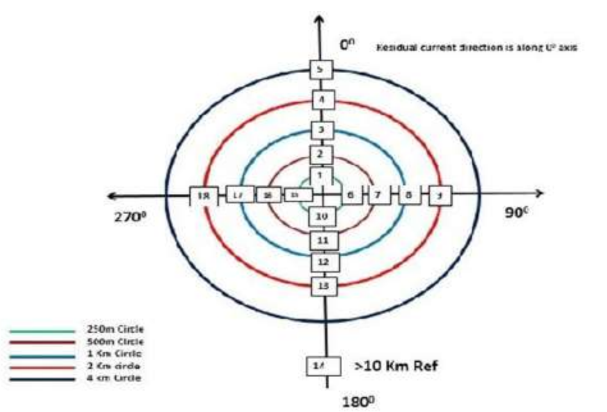

Fig.2

4.2. Laboratory Analysis

Nutrients

Nitrite – Nitrogen

Nitrite was measured by the method of Bendschneider and Robinson wherein the nitrite in the samples was determined by diazotising with sulfanilamide and coupling with N (1-Naphthy)-ethylene diamine-dihydrochloride. The absorbance of the resultant azo-dye was measured at 543 nm by a HACH (DR- 3900) Spectrophotometer.

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Phosphate – Phosphorus

Dissolve reactive phosphate-P was measured using the method of Murphy & Riley. First, sea water samples were made to react with acidified molybdate reagent and reduced using ascorbic acid. The absorbance of the resultant blue complex was measured at 880 nm using HACH (DR- 3900) Spectrophotometer.

Silicates

The determination of silicates in seawater was based on the formation of a yellow silicomolybdic acid when a nearly acidic sample was treated with a molybdate reagent. The yellow silicomolybdic acid was reduced to an intensely colored blue complex using ascorbic acid as the reluctant and the colour was measured spectrophotometric ally.

5. Results and Discussion

5.1. Installation NA

Nutrients

Nitrite – Nitrogen

The concentration of nitrite values (an intermediate product of during both nitrification and de-nitrification processes) are generally governed by the oxygen content, nitrate and plankton productivity of the region. Nitrite values observed at all the stations are found below detection limit (BDL: 0.05 mg/l). The results are shown in Table.1.

Nitrate – Nitrogen

Nitrate is essential nutrient, often a limiting factor for plankton productivity, in the marine environment. The distribution of nitrate nitrogen at stations (Table.1) ranged from 0.86–3.17 mg/l, with an average of 2.035 mg/l. The distribution of nitrate values at the stations follows no regular trends.

At the reference station approximately 10 km away from installation point (NA-10 in Table.1), the nitrate- nitrogen value varies from 1.05 to 2.85mg/l with an average of 2.09. The observed values are well within the oceanographic range.

Phosphate – Phosphorous

This is an important nutrient required for the good health of the marine organism. The variation in the amount of dissolved phosphate at stations (Table.1) was from 0.19 – 1.11 mg/l with an average of 0.402 mg/l. The vertical distribution of phosphate at most of these stations followed no particular trend.

At the reference station approximately 10 km away from installation point (NA-10 in Table.1), the phosphate value varies between 0.33 to 0.505 mg/l with an average 0.51 mg/l. The observed phosphate values were within the oceanographic range.

Silicates

Silicate is important because it is required for phytoplankton growth, which is the basis for marine food chain. The range in the distribution of silicates at stations (Table.1) was from 0.12-0.42 mg/l with an average of 0.267 mg/l. The variation of silicate values did not follow any particular trend.

At the reference station approximately 10 km away from installation point (NA-10 in Table.1), silicate value varies from 0.25 to 0.40 mg/l within an average of 0.33 mg /l.

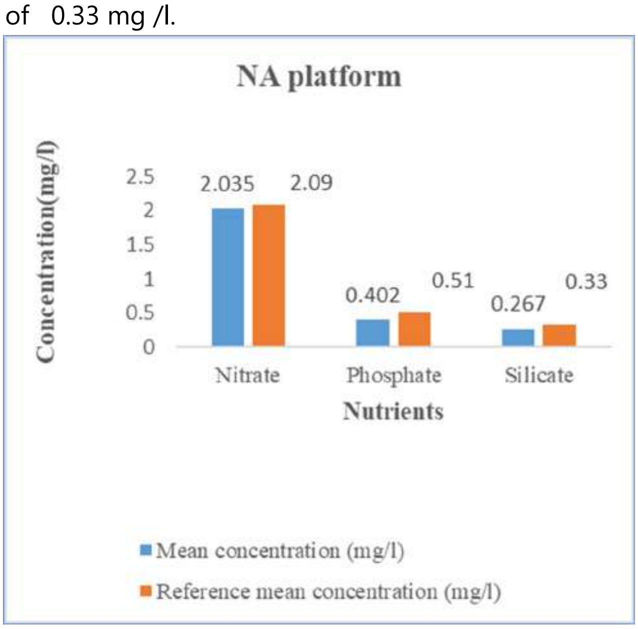

Fig. 3

5.2. Installation NQ

Nutrients

Nitrite – Nitrogen

The concentration of nitrite values (an intermediate product of during both nitrification and de-nitrification processes) are generally governed by the oxygen content, nitrate and plankton productivity of the region. Nitrite values observed at all the stations are found below detection limit (BDL: 0.05 mg/l).

Nitrate – Nitrogen

Nitrate is essential nutrient, often a limiting factor for plankton productivity, in the marine environment. The distribution of nitrate nitrogen at stations (Table.2) ranged from 1.24–4.33 mg/l, with an average of 2.58 mg/l. The distribution of nitrate values at the stations follows no regular trends. At the reference station approximately 10 km away from installation point (NQ-10 in Table.2), the nitrate- nitrogen value varies from 3.74 mg/l to 4.38 mg/l with an average 4.09 mg/l. The observed values are well within the oceanographic range.

Phosphate – Phosphorous

This is an important nutrient required for the good health of the marine organism. The variation in the amount of dissolved phosphate at stations (Table.2) was from 0.22 – 1.03 mg/l with an average of 0.39 mg/l. The vertical distribution of phosphate at most of these stations followed no particular trend.

At the reference station, approximately 10 km away from installation point (NQ-10 in Table.2), the phosphate value varies between 0.09 to 0.32 mg/l with an average 0.23 mg/l. The observed phosphate values were within the oceanographic range.

Silicates

Silicate is important because it is required for phytoplankton growth, which is the basis for marine food chain. The range in the distribution of silicates at stations (Table: 2) was from 0.17-0.48 mg/l with an average of 0.29 mg/l. The variation of silicate values did not follow any particular trend. At the reference station, approximately 10 km away from installation point (NQ-10 in Table.2), silicate value varies from 0.476 to 0.49 mg/l with an average of 0.48 mg/l. The values were in good.

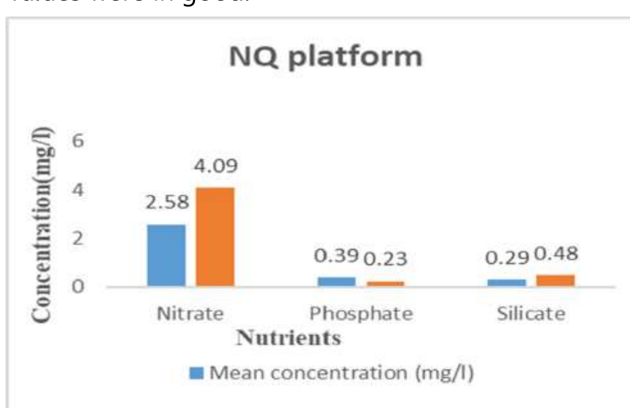

Fig. 4

6. Comparison between NA and NQ

The results show (Fig.5) that variations nutrients concentrations of NA and NQ platforms are almost close and are within oceanographic range.

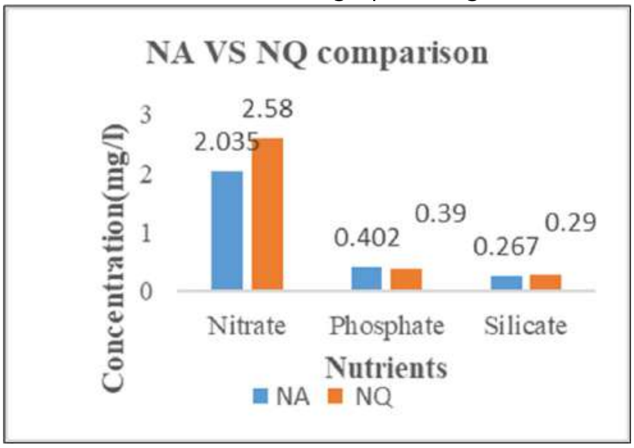

Fig. 5

7. Conclusion

After the discovery of oil and gas in Western offshore area, Mumbai High in 1974, ONGC increased its attention towards the field and deployed several rigs and commissioned process platforms and more than 100 unmanned platforms. Therefore, there is a need for time scale monitoring of the levels of these nutrients in all the marine resources, so as to establish the trends that could be linked to anthropogenic activities The paper includes the output of monitoring activities of ONGC considering variation of concentrations of nutrients i.e. phosphate-phosphorous, Nitrite-Nitrogen, Nitrate–Nitrogen and silicates for assessing the influence of E&P activities on marine environment. It has been observed from the study that values of nutrients are well within range of oceanographic range and no particular trend is observed. Primary production is not disturbed by exploration and production activities of ONGC's offshore operations. Therefore, sea water in Arabian Sea around NA and NQ platforms is not polluted with respect to nutrient concentration.

8. Acknowledgement

The authors are grateful to ONGC's management for encouraging in preparation of this paper. They also wish to acknowledge ED-HOI, IPSHEM for his continuous guidance and support.

9. Reference

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10. Supporting table

NA Platform

Coordinates: 19º34'15.00"N 71º21'32.40''E
Date of Sampling: 08th January, 2021
Time of Sampling: 07.18 - 10.40 hrs

Sampling Station	Distance from the installation In meter	Sampling Depth	Nutrients			
			Nitrite-N in mg/l	Nitrate-N in mg/l	Phosphate-P in mg/l	Silicate-Si in mg/l
NA-1	250 m E	Surface	BDL	2.54	0.794	0.320
		Middle	BDL	1.84	0.845	0.340
		Bottom	BDL	1.26	0.420	0.120
NA-2	500 m E	Surface	BDL	1.58	0.680	0.300
		Middle	BDL	1.95	0.630	0.420
		Bottom	BDL	2.74	0.410	0.290
NA-3	1000 m E	Surface	BDL	2.56	0.530	0.280
		Middle	BDL	1.98	0.220	0.190
		Bottom	BDL	1.48	0.560	0.240
NA-4	2000 m E	Surface	BDL	2.31	0.560	0.280
		Middle	BDL	1.36	0.390	0.260
		Bottom	BDL	2.45	0.450	0.210
NA-5	250 m N	Surface	BDL	1.87	0.630	0.350
		Middle	BDL	2.54	0.250	0.210
		Bottom	BDL	0.98	0.220	0.190
NA-6	500 m N	Surface	BDL	1.87	0.590	0.250
		Middle	BDL	1.59	0.280	0.270
		Bottom	BDL	1.58	0.740	0.250
NA-7	1000 m N	Surface	BDL	2.88	0.810	0.230
		Middle	BDL	2.86	0.824	0.360
		Bottom	BDL	1.69	0.750	0.310
NA-8	2000 m N	Surface	BDL	1.44	0.310	0.320
		Middle	BDL	1.52	1.082	0.400
		Bottom	BDL	2.54	0.480	0.290
NA-9	4000 m N	Surface	BDL	2.56	0.390	0.380
		Middle	BDL	0.86	0.236	0.280
		Bottom	BDL	2.85	0.580	0.250
NA-10	10000 m N	Surface	BDL	2.98	0.330	0.340
		Middle	BDL	1.05	0.695	0.400
		Bottom	BDL	2.25	0.490	0.250
NA-11	250 m W	Surface	BDL	1.24	0.410	0.290
		Middle	BDL	1.97	0.220	0.220
		Bottom	BDL	2.36	0.310	0.280
NA-12	500 m W	Surface	BDL	1.96	1.021	0.220
		Middle	BDL	2.59	0.420	0.210
		Bottom	BDL	3.17	0.721	0.320
NA-13	1000 m W	Surface	BDL	1.44	0.230	0.190
		Middle	BDL	1.58	0.250	0.170
		Bottom	BDL	2.02	0.380	0.220
NA-14	2000 m W	Surface	BDL	2.17	0.260	0.290
		Middle	BDL	2.54	0.290	0.220
		Bottom	BDL	2.35	0.310	0.250
NA-15		Surface	BDL	1.98	0.280	0.250
		Middle	BDL	1.29	0.190	0.240
	250 m S	Bottom	BDL	1.58	0.550	0.320
NA-16		Surface	BDL	0.98	0.340	0.240
		Middle	BDL	2.58	1.110	0.220
	500 m S	Bottom	BDL	2.36	0.280	0.380
NA-17		Surface	BDL	1.81	0.310	0.330
		Middle	BDL	1.26	0.660	0.250
	1000 m S	Bottom	BDL	1.69	0.280	0.260
NA-18		Surface	BDL	1.98	0.290	0.260
		Middle	BDL	2.86	0.290	0.360
	2000 m S	Bottom	BDL	3.08	0.250	0.410

Table.1

NQ Platform

Coordinates: 19º34'15.00"N 71º21'32.40''E
Date of Sampling: 08th January, 2021
Time of Sampling: 08.50 - 11.15 hrs

Sampling Station	Distance from the installation In meter	Sampling Depth	Nutrients			
			Nitrite-N in mg/l	Nitrate-N in mg/l	Phosphate-P in mg/l	Silicate-Si in mg/l
NQ-1	250 m E	Surface	BDL	3.09	0.32	0.24
		Middle	BDL	3.47	0.27	0.17
		Bottom	BDL	4.33	0.22	0.26
NQ-2	500 m E	Surface	BDL	1.85	0.84	0.32
		Middle	BDL	2.48	0.36	0.36
		Bottom	BDL	3.44	0.31	0.22
NQ-3	1000 m E	Surface	BDL	1.86	0.25	0.20
		Middle	BDL	2.42	0.23	0.25
		Bottom	BDL	2.13	0.26	0.23
NQ-4	2000 m E	Surface	BDL	2.89	0.75	0.27
		Middle	BDL	3.48	0.31	0.26
		Bottom	BDL	3.66	0.31	0.31
NQ-5	250 m N	Surface	BDL	2.42	0.26	0.38
		Middle	BDL	2.24	0.29	0.26
		Bottom	BDL	3.22	0.47	0.22
NQ-6	500 m N	Surface	BDL	1.97	0.29	0.34
		Middle	BDL	2.05	0.32	0.23
		Bottom	BDL	1.83	0.67	0.41
NQ-7	1000 m N	Surface	BDL	3.49	0.27	0.27
		Middle	BDL	2.18	0.33	0.23
		Bottom	BDL	2.36	0.48	0.20
NQ-8	2000 m N	Surface	BDL	2.42	0.41	0.36
		Middle	BDL	1.86	0.67	0.46
		Bottom	BDL	2.29	0.22	0.35
NQ-9	4000 m N	Surface	BDL	1.84	0.32	0.35
		Middle	BDL	2.14	0.25	0.29
		Bottom	BDL	3.49	1.03	0.33
NQ-10	10000 m N	Surface	BDL	3.74	0.3	0.46
		Middle	BDL	4.15	0.32	0.49
		Bottom	BDL	4.38	0.09	0.49
NQ-11	250 m W	Surface	BDL	3.62	0.34	0.23
		Middle	BDL	3.58	0.44	0.47
		Bottom	BDL	3.02	0.73	0.28
NQ-12	500 m W	Surface	BDL	3.17	0.29	0.29
		Middle	BDL	2.46	0.24	0.25
		Bottom	BDL	1.94	0.86	0.43
NQ-13	1000 m W	Surface	BDL	4.26	0.48	0.25
		Middle	BDL	2.14	0.34	0.33
		Bottom	BDL	2.32	0.24	0.21
NQ-14	2000 m W	Surface	BDL	2.29	0.26	0.25
		Middle	BDL	1.24	0.27	0.23
		Bottom	BDL	1.86	0.34	0.24
NQ-15		Surface	BDL	3.33	0.31	0.35
		Middle	BDL	3.44	0.39	0.33
	250 m S	Bottom	BDL	2.22	0.43	0.48
NQ-16		Surface	BDL	1.87	0.22	0.35
		Middle	BDL	2.12	0.464	0.47
	500 m S	Bottom	BDL	1.74	0.31	0.38
NQ-17		Surface	BDL	1.56	0.3	0.41
		Middle	BDL	2.52	0.32	0.27
	1000 m S	Bottom	BDL	3.45	0.264	0.25
NQ-18		Surface	BDL	2.42	0.4	0.25
		Middle	BDL	2.66	0.36	0.28
	2000 m S	Bottom	BDL	1.62	0.459	0.19

Table.2

Methane Emissions: - A Global Context & Learnings

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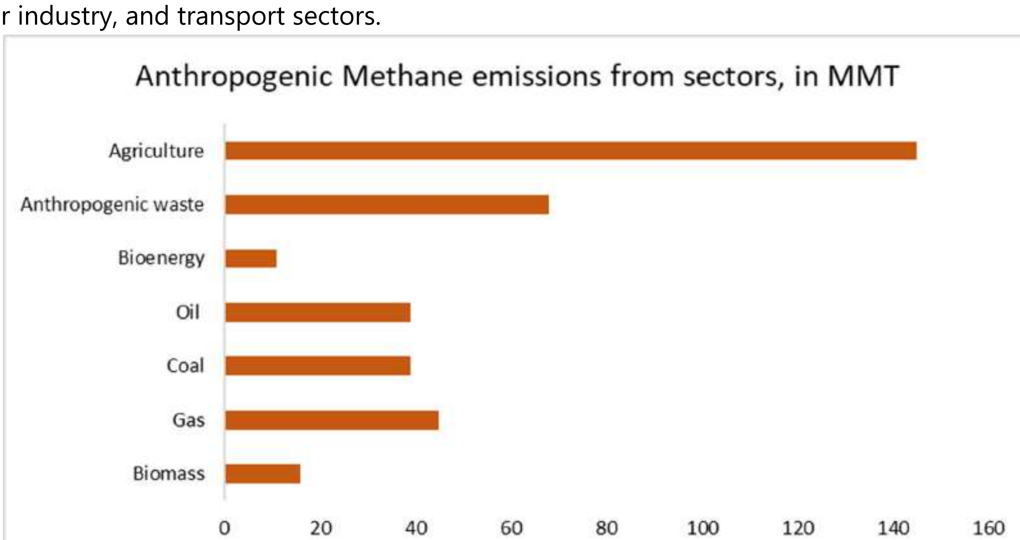
Federation of Indian Petroleum Industry (FIPI)

Methane is the second most important GHG in terms of its contribution to climate change; it accounts for 15% of the total human-induced greenhouse effect, with carbon dioxide (CO2) contributing the majority at 57%. Methane contributes to the production of tropospheric ozone, which is not only another GHG but is also harmful to ecosystems, human health and food production.

According to a study by the Global Carbon project and IEA analysis, suggests that annual global methane emissions are around 570 million tonnes (Mt). This includes emissions from natural sources (around 40% of emissions), and those originating from human activity (the remaining 60% - known as anthropogenic emissions).

The highest emitting anthropogenic source of methane is the agriculture sector, which emits 40% of all anthropogenic methane emissions. Oil & Gas together are the second highest emitting source, contributing just under a quarter (23%), while the waste sector is the third highest emitter at 19%. Coal comes in at 4th and contributes for 11% emissions. The remaining 7% of methane emissions are sourced from the residential, biomass, other industry, and transport sectors.



Source: IEA, 2020

Methane implications on climate change

Methane has important implications for climate change, particularly in the near term. Two key characteristics determine the impact of different greenhouse gases on the climate: the length of time they remain in the atmosphere and their ability to absorb energy. Methane has a much shorter atmospheric lifetime than CO2 (around 12 years compared with centuries for CO2) but it is a much more potent greenhouse gas, absorbing much more energy while it exists in the atmosphere. Methane has a Global Warming Potential (GWP) of 28 – 36 over a period of 100 years. By definition, CO2 has a GWP of 1 regardless of time period of use, as it is the gas being used as a reference. This means that one tonne of methane can considered to be equivalent to 28 to 36 tonnes of CO2 if looking at its impact over 100 years.

As methane has an atmospheric lifetime of around 12 years, any reduction in emissions will result in a more rapid decrease in atmospheric concentrations compared with CO2 which has a much longer atmospheric lifetime of centuries; this makes methane an ideal target for climate change mitigation strategies. Also, since methane has a higher GWP, methane emissions reduction should be looked at with the same seriousness as Co2 if not more.

According to the IEA's World Energy Outlook 2020, there is a huge potential to reduce methane emissions within oil and gas operations—reducing emissions by 75% is technically feasible, with 40% achievable at zero net cost. Reducing methane emissions from oil and gas is feasible and cost-effective as technology and finance are largely already available. In the section below, we have highlighted some of the key proactive measures taken by countries for reduction of methane emissions.

Global initiatives by key countries in O&G sector for methane emissions reduction

Canada

Canada is the third largest oil producing region, by reserves, in the world, and Alberta is the largest hydrocarbon producing province in the country. Since 2016, the Alberta Energy Regulator (AER) has had a mandate to reduce methane emissions in Alberta by 45% by 2025, using 2014 data as a baseline. The following requirements have been established by the AER with regard to reducing methane emissions:

- ***AER definition & directives:*** This is important because different jurisdictions around the world have different definitions. The AER definitions cover 'routine venting', 'non-routine flaring', 'fugitive', 'venting', etc. Note that 'routine venting' is defined by the AER as a continuous or intermittent venting system that relieves pressure to the atmosphere every day. 'Non-routine' includes venting related to emergencies and other incidents that have to take place for safety reasons.

  The AER's Directive 060 sets out the requirements for flaring, incinerating and venting in Alberta at all upstream petroleum industry wells and facilities. It regulates by site, whereby each site has an overall vent gas limit, and a more stringent routine vent gas limit included within the overall limit. There are also equipment specific limits for both existing and new devices, with new devices defined as those having being installed after 2022. The latter are subject to more stringent requirements.

- ***Risk informed fugitive survey frequencies:*** this consists of tri-annual inspections for high-risk facilities and annual inspections for non-high-risk facilities, as well as screening once a year for other sites.

- ***Annual reporting & periodic regulatory review:*** this consists of operators compiling inventories of all their equipment, and quantifying all emitting sources, by estimation or measurement, from the bottom up to produce an annual report for all of their facilities.

Compliance & benefits achieved:

• Though the AER regulations came into effect only in early 2020, positive results have already started to show up in the region. More than 30,000 methane reports have been filed by companies in 2020, this will help AER in assessing the management of methane emissions in the region.

• For remote detection, the AER has used a range of technologies, which have all been of value, including:

o remote aerial detection technologies—used to survey 8,000 sites;
o commercially available satellites—used to survey 288 sq km;
o Tropospehric Monitoring Instrument (TROPOMI) data—used since 2018 to help select and triage areas; and
o Vehicle-mounted sensors—driven more than 7,000 km.

United States of America

In the US, the EPA has regulated new and modified emission sources in the oil and gas industry specifically, since 2012, although gas plants were regulated prior to this. In addition to these federal regulations, states have also implemented their own regulations such as the Volatile organic compounds regulation.

Volatile organic compounds regulation (VOC): the scope of regulation has been to control emissions sources at well sites, compressor stations and gas plants, with VOCs being listed as the regulated pollutant. Even though the main aim of this regulation is to manage VOC emissions, methane emissions are reduced as a co-benefit. The requirements of the regulation are as follows:

- A process of 'reduced emissions completion' is required for gas wells to ensure that gas is captured once separation is possible. If the gas cannot be sent to a gas gathering line it has to be sent to an emissions combustion device.

- High bleed natural gas-driven pneumatic controllers can no longer be installed. Instead, low bleed or intermittent vent natural gas-driven pneumatic controllers or other non-emitting devices are required for new installations.

- Pneumatic pumps are required to be controlled— gas plants are now required to have pneumatic pumps that are not driven by natural gas.

- Optical gas imaging cameras are required for the performance of leak detection and repair (LDAR) inspections, with well sites being inspected biannually and compressor stations subject to quarterly inspections.

Europe

Europe is the only continent where methane emissions are declining. However, despite this, a significant level of emissions is associated with imported fuel that is consumed within the EU; this is something that the EU's methane strategy aims to address. The EU's methane strategy includes cross-sectoral and sector-specific initiatives, focusing not only on the energy sector but also on the waste and agriculture sectors.

- ***Cross-sectoral actions:*** Priority cross-sectoral actions include improving the measurement, reporting and verification (MRV) of emissions as well as LDAR programmes for known emission sources.

- ***Review and update of EU regulations:*** The EU Emissions Trading System and Effort Sharing Regulation will be reviewed in 2021, with a focus on efforts to tackle methane emissions.

- ***International methane emissions observatory:*** Another key initiative planned is the establishment of an International Methane Emissions Observatory, which will utilize satellite data to verify the bottom-up 'on the ground' emissions data that the EU receives from companies.

- ***Biogas:*** Finally, there will be targeted support for biogas from sustainable organic waste and residues, with the aim of minimizing emissions in the waste and agriculture sectors.

Key Learnings

The measures adopted globally for mitigating methane emissions offer significant learning opportunities for countries that are yet to look at methane as a gas with high Global warming potential and instil a framework for reducing emissions. Few of the pointers that may be helpful in drawing up the framework are listed below:

1) Creating awareness: As a first step it is essential to create awareness about methane emissions and its global warming potential.

2) Monitoring & Gathering data: Next step to identify all emission points across the upstream, midstream and downstream of oil & gas operations and collecting data pertaining to the extent of emission levels.

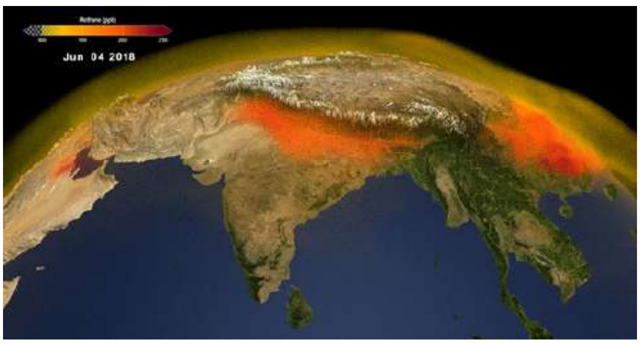
3) Creation of a nodal agency: Creating a nodal agency for analysis of data submitted by O&G companies. Publishing of data and tracking emissions progress

4) Sound policy & regulations: Defining standards and creating sound policies for keeping emissions within prescribed standards across operations.

5) Creating incentives: Developing financial instruments and creating incentives for companies for lowering emissions.

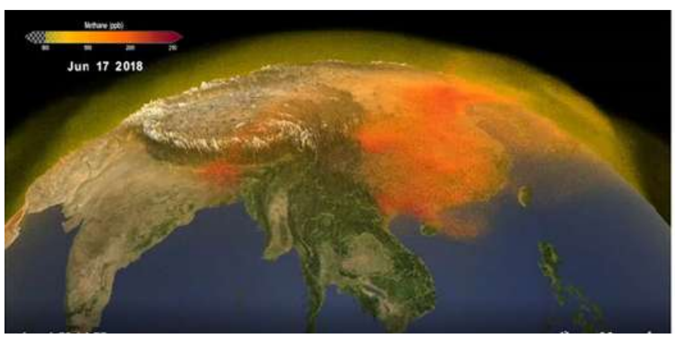
6) Utilizing biomass potential: For major agrarian countries like India, it becomes important to utilize the available biomass potential for methane emission reduction.

Visualization of sources of Methane emissions by NASA



India & SE Asia: Methane emissions due to rice cultivation & Livestock

South America: Methane emissions due to flooding of the Amazon Basin



China: Methane emissions due to economic expansion & high demand of fossil fuels

Complete video by NASA on visualization of methane emissions is available at the link below: https://svs.gsfc.nasa.gov/4799

References:

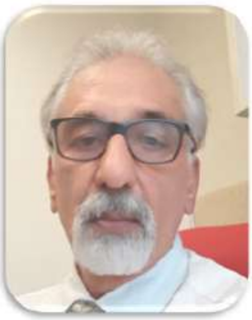
1) US Environment Protection Agency: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

2) IEA report on methane emissions: https://www.iea.org/reports/methane-tracker-2020

3) IPIECA report on reducing methane emissions: https://www.ipieca.org/events/methane-science-workshop/

4) Global Methane Project report: https://www.globalcarbonproject.org/methanebudget/20/presentation.htm

New Tax Rules to Tax the Untaxed: Significant Economic Presence



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Development in technology in the last few years has resulted in drastic changes in the way business is transacted, which primarily includes business models operating remotely through digital medium. Under digital business models, a non-resident interacts with its customers in another country without having any physical presence in that country. Such business models resulted in evasion of taxes where services are rendered without any physical presence in the country where customers are located. Given the large population in India, India is one of the top revenue generating country for digital businesses. Addressing the tax challenges raised by digitalisation has been a top priority of The Organisation for Economic Co-operation and Development ('OECD')/ G20 Inclusive Framework in Base Erosion Profit Shifting ('BEPS') since 2015 with the release of the BEPS Action 1[1] Report. However, various countries have levied unilateral taxes (in the form of Significant Economic Presence or Equalisation Levy) on such digital businesses over the last few years.

In India, these emerging remote business models remained outside the realm of the Income-tax law due to the restrictive scope of the definition of business connection in India. Pursuant to BEPS discussions, India introduced the following measures to bring digital economy under the direct tax net:

► Imposing of Equalisation Levy (EL) on online advertisement and related services. Further, vide Finance Act 2020 scope was expanded to include e-commerce supply and/ or services.

► Widen the scope of business connection to include the concept of 'Significant Economic Presence' (SEP) through Finance Act, 2018.

The said SEP provisions were intended to apply from Financial Year (FY) 2018-19 onwards, however, considering the on-going discussion at OECD/ G20 with respect to taxation of digital transactions, Government of India deferred the applicability of SEP provisions and the same are now applicable with effect from FY 2021-22.

We have discussed below the newly introduced SEP rules, challenges around it and the way forward.

Overview of SEP provisions:

► As per Explanation 2A to section 9(1)(i) of the Income-tax Act, 1961 (the Act), a non-resident shall constitute a Business Connection in India, if it satisfies the following conditions:

► Revenue linked condition: Any transaction in respect of any goods, services or property carried out by a non-resident with any person in India, including provisions of download of data or software in India, if the aggregate of payments arising from such transaction or transactions during the tax year exceeds the amount as may be prescribed; or

► User-linked condition: Systematic and continuous soliciting of its business activities or engaging in interaction with such number of users in India as may be prescribed

► The CBDT vide notification no. 4/ 2021 dated 3 May 2021 prescribed the threshold limit for revenue and user linked conditions by introducing new Rule 11UD under Income-tax Rule, 1962, for applicability of SEP provisions as under:

Particulars	Threshold
Revenue linked condition	Exceeds INR 2 crores
User linked condition	Exceeds 3 Lacs users

► Revenue threshold of INR 2 crores is to be determined in aggregate and not qua customer.

For instance, if non-resident sells goods worth INR 1 crore to 5 customers, then non-resident may trigger SEP provisions in India since aggregate value of transaction excess INR 2 crores.

► Further, SEP provisions shall be applicable irrespective:
(i) the agreement for such transactions or activities is entered in India; or
(ii) the non-resident has a residence or place of business in India; or
(iii) the non-resident renders services in India.

► The main motive to bring SEP into gamut of taxation is to cover the Digital Economy. However, basis the wordings of SEP provisions, it appears that the intention is to cover all transactions of non-residents entered with any person in India.

► However, given that SEP provisions have come into effect under the Act, a non-resident being a person from a country having a Double Taxation Avoidance Agreement (DTAA) with India – may claim non-taxability position under the DTAA subject to conditions[2]. However, the non-resident shall have to undertake various compliances as explained below to claim non-taxability position under the DTAA.

► Where the non-resident company is incorporated from a country not having DTAA with India, SEP provisions may have a high impact.

Impact on Oil and Gas ('O&G') sector:

The Indian O&G sector is of a vast expanse encompassing a host of Multi-national Companies ('MNCs') and renowned international business houses. Various non-resident players/ Indian Public Sector Enterprises ('PSUs') engaged in O&G activities in India procure goods and services from outside India. The new age O&G companies procure goods/ provide services through digital platform to their customers/ group companies. There is possibility that such activities of O&G companies may come under the scanner of the tax authorities for applicability of SEP provisions.

Further, the impact of SEP provisions is broad and in absence of any clarifications/ FAQs, is subject to diverse interpretations. As a result, there are certain nuances/ issues that may be faced by such non-resident O&G companies in rendering services/ supplies in India.

► <u>Non-resident engaged in business of sale of physical goods and such sale is completed outside India (for eg: on FOB or CIF basis) OR Provision of services from outside India via conventional means (for eg: emails, via independent agents)</u>

Given the broad impact of SEP provisions and in absence of a specific clarification from the Indian Revenue Authorities, such transaction may trigger SEP provisions as the nexus is with the customer being in India and it requires a detailed analysis.

Once SEP is created in India, profits attributable to such operations shall be taxable in India. It is pertinent to note that the existing attribution rules do not cover transactions of digital economy. As per the existing attribution rules, a position may be adopted that only activities carried out in India shall be taxable in India.

► <u>Non-resident engaged in business of supply of goods/ provision of services from outside India via digital means (including provision of software where user threshold are met)</u>

In such a case, it is imperative to determine the interplay between SEP provisions and Equalisation Levy provisions.

As per EL provisions, where an income is subject to EL, the same shall be exempt under section 10(50) of the Act.

Accordingly, one may have to undertake a detailed analysis to determine whether the income is taxable under EL provisions or SEP provisions.

Separately, where any transaction shall be taxed as 'Fees for Technical Services' or 'Royalty' under the Act or DTAA, the same being specific in nature may not be by covered under SEP provisions.

Open topics under the SEP provisions:

► As per clause(b) of Explanation 2A to Section 9 of the Act, SEP provisions are triggered where non-resident performs 'systematic and continuous' soliciting of business activities or engaging in interaction with users in India, the limit of which excess 3 lacs users. The words 'systematic and continuous' has not been defined under the Act. Accordingly, various interpretation to these words would lead to prolonged litigation. Further, Finance Act, 2020 amended the user linked condition to remove words 'through digital means', which means that solicitation and interaction activities through physical mode may also get covered. Hence, since SEP provisions do not link to payment but to users, it requires detailed evaluation of the user linked condition.

► Even though the wordings of SEP provisions are said to cover all types of transactions entered into by non-resident with any person in India, there is still an ambiguity and needs further clarification as to whether this would cover a transaction by non-resident which is completed outside India (for eg: offshore sales or offshore services).

► ***Attribution of profits where SEP provisions are met:*** The existing attribution provisions cover attribution of profits based on physical presence/ activities undertaken in India. However, SEP provisions intend to tax all transactions undertaken by a non-resident where the user is based out of India. Accordingly, one may contend that the rules for attribution of profits are substantially different as it targets to tax new business models.

► The customer in India may force a non-resident supplier for a valid Tax Residency Certificate and where the same is not available, for a lower/ Nil withholding tax order from the non-resident. In absence of the same, the customer may withhold taxes at an arbitrary rate which could lead to cash flow issues for the non-resident.

Conclusion:

► The Government of India is quickly responding to taxing digital economy and is introducing amendments in the domestic tax law. It would be interesting to see going forward how the SEP provisions are interpreted by the tax authorities, especially the manner in which they proceed to question NR taxpayers.

Compliances:

Where the SEP provisions are triggered, irrespective of the DTAA benefits, a non-resident shall have a business connection in India and thereby undertake various compliances such as:

► Obtaining Permanent Account Number and Tax Deduction Account Number
► Application for lower/ Nil withholding tax order where DTAA benefits are not available to the non-resident
► Filing of income-tax return
► Applicability of transfer pricing provisions including master file compliances
► Applicability of Minimum Alternate Tax ('MAT') provisions
► Applicability of withholding tax on payments made to residents/ non-residents

1 Source: https://www.oecd.org/tax/beps/beps-actions/action1/
2 Satisfaction of Principal Purpose Test, Tax Residency Certificate, etc. and other compliances

Oil & Gas in Media

Govt aiming for composite energy retailing, says Petroleum Minister Dharmendra Pradhan

Asserting that the future of fuel retail is mobile, Petroleum Minister Dharmendra Pradhan said that "we are bringing in innovation in energy retailing and making it mobile and delivering at the doorsteps". Union Minister of Petroleum and Natural Gas Dharmendra Pradhan said on Tuesday (June 08, 2021) that the Government aims to move towards the concept of energy retailer where all different transport fuels — hydrogen, diesel, petrol, compressed natural gas (CNG), liquefied natural gas (LNG) and EV batteries swapping facility —shall be available at a single point.

Source: financialexpress

Draft cabinet note floated for 100% FDI in oil PSUs approved for disinvestment

The commerce and industry ministry has floated a draft cabinet note seeking inter-ministerial views on a proposal to allow up to 100 per cent foreign investment under automatic route in oil and gas PSUs, which have an 'in-principle' approval for disinvestment, sources said. The move, if approved by the union cabinet, would facilitate privatisation of India's second biggest oil refiner Bharat Petroleum Corp Ltd (BPCL NSE 0.80 %). The government is privatising BPCL and is selling its entire 52.98 per cent stake in the company.

As per the draft note, a new clause would be added in the FDI policy under the petroleum and natural gas sector. According to the proposal, foreign investment up to 100 per cent under the automatic route would be allowed in cases where an 'in-principle' approval for disinvestment of a PSU has been granted by the government. For BPCL privatisation, mining-to-oil conglomerate Vedanta had put in an expression of interest (EoI) for buying the government's 52.98 per cent stake in the PSU. The other two bidders are said to be global funds, one of them being Apollo Global Management. After collating the views, the commerce and industry ministry would seek approval of the union cabinet on the proposal. At present, only 49 per cent FDI is permitted through automatic route in petroleum refining by the public sector undertakings (PSU), without any disinvestment or dilution of domestic equity in the existing PSUs.

Source: economictimes

Reliance, BP begin production from second deepwater gas field

Reliance Industries and BP have begun production from their second deepwater gas field in the KG D6 block. RIL-BP's 'Satellite Cluster' field has come onstream two months ahead of schedule despite Covid-19 challenges, the two companies said in a joint statement. The field will produce gas from four reservoirs utilizing a total of five wells and is expected to reach gas production of up to 6 million metric standard cubic meters per day (mmscmd).

Source: economictimes

DSF Round 3 auctions: 32 contract areas comprising 75 discoveries on offer

The third round of auctions under the Discovered Small Fields (DSF) regime for oil and gas blocks was launched on Thursday. Under this bid round, 32 Contract Areas comprising 75 discoveries are on offer. These exploratory fields are spread over 9 sedimentary basins covering acreage of about 13,685 square kilometers and have a potential of approximately 232 million tonnes. These oil and gas discoveries were once made by public sector undertaking oil companies, Oil and Natural Gas Corporation (ONGC) and Oil India (OIL). But they were eventually relinquished citing unviability. This was either due to their small size or because of the restrictive fiscal regimes under which they were awarded to these companies. There are 19 onshore, 54 shallow water and 2 Deepwater discoveries on offer in this third round. This is the largest number of discoveries on offer in any of the DSF rounds till now. In the first DSF round, the Centre had offered 46 contract areas spread across 67 fields. There were 25 contract areas covering 59 fields in the second round. After the first round, 30 contract areas were awarded while 24 were awarded after the second round. According to Petroleum Minister Dharmendra Pradhan, production from a block awarded in the first round of Discovered Small Field (DSF) auctions is going to start within a week. He said this while speaking at an event to mark the launch of the third round of DSF auction. "The Petroleum Ministry and Directorate General of Hydrocarbons (DGH) should devise innovative ways for early resource monetization, including expediting production timelines under DSF I & II. We have to work at exponential speed and on a mission-mode to monetize our natural resources," Pradhan said. "The focus of DGH and Petroleum Ministry should also expand to monetize idling oil and gas assets that are with government-controlled companies and the private sector. A policy direction for the same should be readied by the end of this year. There must be concerted efforts to increase domestic oil and gas output," he added.

Source: business-standard

FIPI Events

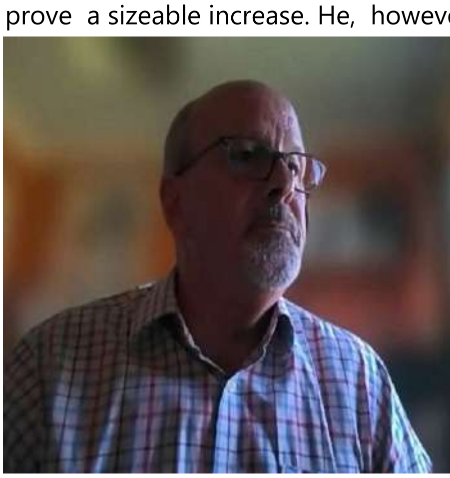
Adapting to a More Competitive Oil Market: New Pricing Mechanism for Middle East Crude

The Federation of Indian Petroleum Industry (FIPI) in association with Argus Media organized a webinar on 'Adapting to a More Competitive Market: New Pricing Mechanism for Middle Eastern Crude' on 19 April, 2021. The dialogue was aimed at understanding the new and emerging dynamics of the international oil market as the as the ICE Murban Crude Oil Futures market joins the ranks of prominent oil price benchmarks such as Brent and West Texas Intermediate. During the session, the experts joining from Argus Media helped the participants better understand the changing energy markets after the pandemic and the factors that will set the pace and direction for the market in the medium to long term. The team of experts joining from Argus Media included Mr Francis Osborne, Argus Global Head of Forecasting, Argus Media; Mr Alajandro Barbajosa, Vice President Crude Middle East; Mr Karl Kleemeier, VP Business Development, Argus Media; and Ms Azlin Ahmed, Asia Crude Editor, Argus Media.

Commencing the proceedings of the day, Mr Rajiv Bahl, Director – Finance, Taxation and Legal, FIPI extended a very warm welcome to the speakers and participants at the session. He highlighted that the initiation of the ICE Murban crude futures market by Abu Dhabi will bring about tectonic changes to the international oil markets. Mr Bahl underlined that this development will have far reaching consequences, especially for the Asian consumers. It is expected that with the new futures market coming online will yield better prices for the Asian buyers. He further mentioned that there is also a rising probability that more of the Middle Eastern crude suppliers might soon break free and follow suit. He hoped that through this session, experts from Argus Media would help the participants gain a better understandings into the future of oil market and how the latest developments will change its course.

Mr. Rajiv Bahl, Director(Finance Taxation and Legal), FIPI delivering the opening remarks

Mr Francis Osborne in his presentation on the crude market outlook mentioned that the OPEC plus has been largely successful in managing the oil markets and keeping the oil production well below the pre-COVID levels. In April, OPEC plus has decided to increase the oil supply by as much as 2.4 Mbpd by June, which will prove a sizeable increase. He, however, highlighted that the unity among the OPEC plus is not very strong and it is expected that some countries, like Russia and Iraq, may opt to move out in the near future. The crude prices have rallied since the fourth quarter of the last year and a key factor behind this rally has been the roll out of the vaccination drive by most countries. He pointed out that while the demand for oil has recovered from the lows seen last year, the pace of recovery has been very slow. He highlighted that while China has recovered from the pandemic in H1 and the economy is back on track the oil consumption in the country still remains largely flat. In India, he said, the demand has recovered but is still struggling to grow. As the country is facing possible lockdowns due to the rising number of infection cases demand from India is expected to weaken over the next few months. He expected that the global oil markets will rebalance by the end of the year 2021. With oil prices remaining strong there is also an expectation of increase in investment by 2022.



Mr. Francis Osborne, Argus Global Head of Forecasting, Argus Media presenting his presentations on Oil Market Outlook

The following presentation at the session was by Mr Alejandro Barbajosa and Mr Karl Kleemiere on the 'New Pricing Mechanism for Middle East Crude'. The presentation pointed out that the pricing scenario in the oil market today are truly historic. One of the driving force behind this shift has been the surplus of crude in the Atlantic basin driven by the growth of Shale oil in the US. This has presented serious challenge to the Middle-Eastern monopoly on the Asian market.

The Middle-Eastern suppliers are now forced to take into account the pricing signal arising from the marginal barrel imported from Atlantic basin. This has also provided the Asian refiners with a choice of buying crude from alternative sources. Today India is one of the major buyer of the US crude, importing close to 600,000 bpd. Speaking of the increasingly competitive market, experts pointed out that Murban, Qatar Land and Arab Extra light are similar grades to the extent that Murban and Qatar land were priced retroactively to Arab Extra Light. Karl further pointed out that going forward Murban crude will be available to refiners from the exchange for June deliveries. Due to uncertainty over the Official Selling Prices (OSPs) of Saudi grades, some refiners will be inclined towards buying Murban crude with higher price certainty. This may force Aramco to react to the price signals at the Murban futures market. Experts predicted that since Murban will be traded at a market reflective price, there is a possibility that the other grades may have to soon follow suit. From the point of view of the Indian refiners, the above developments are largely seen as favorable as they will assure them market linked pricing. With increase in competitive pricing in the region, Indian refiners located closest to the source will benefit from these developments. Concluding the presentation the experts remarked that with Murban futures market, ADNOC does not only commit on price but also on supply transparency. They predicted that demand from refiners across South-East Asia for the Murban crude will ensure there will be enough participation to guarantee transparent and accurate pricing signals at the Murban futures market.

Mr. Alejandro Barbajosa, VP crude Middle East & Asia-Pacific, Argus Media giving his presentation on 'New pricing mechanisms for Middle Eastern crude: UAE'.

Mr. Karl Kleemeier, VP Business Development, Argus Media delivering his presentation on 'New pricing mechanisms for Middle Eastern crude: UAE'

The next segment of the session was audience Q&A. For this session, an overwhelming number of questions were received from the audience, which also stood testimony to the audience interest and timeliness of the subject matter. The experts from Argus Media provided detailed answers to the audience questions. The one and a half hour long session witnessed an overwhelming participation by over 250 participants across the oil and gas value chain in the country. Such overwhelming interest and participation from the industry has been a constant source of inspiration for FIPI to organize such knowledge sharing sessions. The session was brought to an end, wishing all speakers and participants the best of health and expectations of meeting soon physically.

STATISTICS

INDIA: OIL & GAS

DOMESTIC OIL PRODUCTION (MILLION MT)

		2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)	
									% of Total
Onshore	ONGC	6.1	5.8	5.9	6.0	6.1	6.1	5.9	39.3
	OIL	3.4	3.2	3.3	3.4	3.3	3.1	2.9	19.4
	Pvt./ JV (PSC)	9.1	8.8	8.4	8.2	8.0	7.0	6.2	41.3
	Sub Total	**18.5**	**17.8**	**17.6**	**17.5**	**17.3**	**16.2**	**15.1**	**100**
Offshore	ONGC	16.2	16.5	16.3	16.2	15.0	14.5	14.2	92.6
	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	1.1	7.4
	Sub Total	**18.9**	**19.1**	**18.4**	**18.1**	**16.9**	**16.0**	**15.4**	**100**
Total Domestic Production		37.5	36.9	36.0	35.7	34.2	32.2	30.5	100.0
	ONGC	22.3	22.4	22.2	22.2	21.0	20.6	20.2	66.2
	OIL	3.4	3.2	3.3	3.4	3.3	3.1	2.9	9.6
	Pvt./ JV (PSC)	11.8	11.3	10.5	10.1	9.9	8.4	7.4	24.2
Total Domestic Production		**37.5**	**36.9**	**36.0**	**35.7**	**34.2**	**32.2**	**30.5**	**100**

Source : PIB/PPAC

REFINING

Refining Capacity (Million MT on 1st May 2021)

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	2020-21 (P)
IOCL	53.59	58.01	65.19	69.00	71.81	69.42	62.35
BPCL	23.20	24.10	25.30	28.20	30.90	31.53	26.22
HPCL	16.20	17.20	17.80	18.20	18.44	17.18	16.42
CPCL	10.70	9.60	10.30	10.80	10.69	10.16	8.24
MRPL	14.60	15.53	15.97	16.13	16.23	13.95	11.47
ONGC (Tatipaka)	0.05	0.07	0.09	0.08	0.07	0.09	0.08
NRL	2.78	2.52	2.68	2.81	2.90	2.38	2.71
SUB TOTAL	**121.12**	**127.03**	**137.33**	**145.22**	**151.04**	**144.71**	**127.50**

JV Refineries	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
HMEL	7.34	10.71	10.52	8.83	12.47	12.24	10.07
BORL	6.21	6.40	6.36	6.71	5.71	7.91	6.19
SUB TOTAL	**13.55**	**17.11**	**16.88**	**15.54**	**18.18**	**20.15**	**16.26**

Pvt. Refineries	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
NEL	20.49	19.11	20.92	20.69	18.89	20.62	17.07
RIL	68.10	69.50	70.20	70.50	69.14	68.89	60.94
SUB TOTAL	**88.59**	**88.61**	**91.12**	**91.19**	**88.03**	**89.51**	**78.01**

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
All India Crude Processing	**223.26**	**232.90**	**245.40**	**251.90**	**257.17**	**254.38**	**221.77**

Source : PIB Release/PPAC

CRUDE CAPACITY VS. PROCESSING

	Capacity On 01/05/2021 Million MT	% Share	Crude Processing 2020-21 (P)	% Share
PSU Ref	142.6	57.1	127.5	57.5
JV. Ref	19.1	7.6	16.3	7.3
Pvt. Ref	88.2	35.3	78.0	35.2
Total	**249.9**	**100**	**221.8**	**100**

Source: PIB/PPAC

POL PRODUCTION (Million MT)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
From Refineries	217.1	227.9	239.2	249.7	257.4	258.2	229.2
From Fractionators	3.7	3.4	3.5	4.6	4.9	4.8	4.2
Total	**220.7**	**231.2**	**242.7**	**254.3**	**262.4**	**262.9**	**233.4**

DISTILLATE PRODUCTION (Million MT)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
Light Distillates, MMT	63.2	67.1	71.0	74.7	75.4	76.8	71.4
Middle Distillates , MMT	113.4	118.3	122.5	127.5	130.8	130.2	110.5
Total Distillates, MMT	176.6	185.4	193.5	202.2	206.1	206.9	182.0
% Distillates Production on Crude Processing	**77.8**	**78.5**	**77.8**	**78.8**	**78.6**	**79.9**	**80.5**

Source: PIB/PPAC

PETROLEUM PRICING

OIL IMPORT - VOLUME AND VALUE

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	2020-21 (P)
Quantity, Million Mt	189.4	202.9	213.9	220.4	226.6	227.0	198.1
Value, INR ₹000 cr.	687.4	416.6	470.2	565.5	783.4	716.6	463.0
Value, USD Billion	112.7	64.0	70.2	87.8	112.0	101.4	62.7
Average conversion Rate, INR per USD (Calculated)	61.0	65.1	67.0	64.4	70.0	70.7	73.8

OIL IMPORT - PRICE USD / BARREL

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	2020-21 (P)
Brent (Low Sulphur - LS-marker) (a)	85.4	47.5	48.7	57.5	70.0	61.0	44.3
Dubai (b)	83.8	45.6	47.0	55.8	69.3	60.3	44.6
Low sulphur-High sulphur differential (a-b)	1.7	1.8	1.7	1.6	0.7	0.6	-0.3
Indian Crude Basket (ICB)	84.16	46.17	47.56	56.43	69.88	60.47	44.82
ICB High Sulphur share %	72.04	72.28	71.03	72.38	74.77	75.50	75.62
ICB Low Sulphur share %	27.96	27.72	28.97	27.62	25.23	24.50	24.38

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

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	2020-21 (P)
Gasoline	95.5	61.7	58.1	67.8	75.3	67.0	47.5
Naphtha	82.2	48.5	47.1	56.3	65.4	55.1	43.9
Kero / Jet	66.6	58.2	58.4	69.2	83.9	70.4	45.8
Gas Oil (0.05% S)	99.4	57.6	58.9	69.8	84.1	74.1	50.0
Dubai crude	83.8	45.6	47.0	55.8	69.3	60.3	44.6
Indian crude basket	84.2	46.2	47.6	56.4	69.9	60.5	44.8

CRACKS SPREADS ($/ BBL.)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20 (P)	2020-21 (P)
Gasoline crack							
Dubai crude based	11.7	16.1	11.1	12.0	5.9	6.7	2.9
Indian crude basket	11.3	15.6	10.6	11.4	5.4	6.5	2.6
Diesel crack							
Dubai crude based	15.7	12.0	12.0	13.9	14.8	13.8	5.5
Indian crude basket	15.3	11.5	11.4	13.4	14.2	13.6	5.2

DOMESTIC GAS PRICE ($/MMBTU)

Period	Domestic Gas Price (GCV Basis)	Price Cap for Deepwater, High temp Hingh Pressure Areas
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
April 21 - September 21	1.79	3.62

Source: PIB/PPAC/OPEC

GAS PRODUCTION

Qty in MMSCM

	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
ONGC	22088	23429	24677	23746	21872
Oil India	2937	2881	2722	2668	2480
Private/ Joint Ventures	6872	6338	5477	4766	4319
Total	**31897**	**32648**	**32875**	**31180**	**28671**

		2016-17	2017-18	2018-19	2019-20	2020-21 (P)
Onshore	Natural Gas	9294	9904	10046	9893	9601
	CBM	565	735	710	655	477
	Sub Total	**9858**	**10639**	**10756**	**10549**	**10078**
Offshore		22038	22011	22117	20631	18428
	Sub Total	**22038**	**22011**	**22117**	**20631**	**18428**
	Total	**31897**	**32649**	**32873**	**31180**	**28506**
	(-) Flare loss	1049	918	815	923	721
	Net Production	30848	31731	32058	30257	27785

	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
Net Production	30848	31731	32058	30257	27785
Own Consumption	5857	5806	6019	6053	5736
Availabilty	24991	25925	26039	24204	22049

AVAILABILTY FOR SALE

	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
ONGC	17059	18553	19597	18532	16972
Oil India	2412	2365	2207	2123	1930
Private/ Joint Ventures	5520	5007	4235	3549	3147
Total	**24991**	**25925**	**26039**	**24204**	**22049**

CONSUMPTION (EXCLUDING OWN CONSUMPTION)

	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
Total Consumption	49677	53364	54779	58091	54910
Availabilty for sale	24991	25925	26039	24204	22049
LNG Import	24686	27439	28740	33887	32861

GAS - IMPORT DEPENDENCY

	2016-17	2017-18	2018-19	2019-20	2020-21 (P)
Net Gas Production	30848	31731	32058	30257	27785
LNG Imports	24686	27439	28740	33887	32861
Import Dependency (%)	44.5	46.4	47.3	52.8	54.2
Total Gas Consumption*	**55534**	**59170**	**60798**	**64144**	**60646**

* Includes Own Consumption

Source:PIB/PPAC

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SECTOR WISE DEMAND AND COMSUMPTION OF NATURAL GAS

Qty in MMSCM

		2018-19	2019-20	2020-21 (P)												
				April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan	Feb	Mar	Total
Fertilizer	R-LNG	**8711**	**9556**	708	818	875	967	951	868	1141	1100	1125	1059	906	818	**11336**
	Domestic Gas	**6258**	**6559**	581	754	699	507	526	509	414	452	458	478	425	528	**6331**
Power	R-LNG	**2869**	**3554**	27	160	352	346	347	279	385	328	402	355	354	295	**3630**
	Domestic Gas	**9194**	**7526**	731	772	709	647	610	597	578	538	526	530	499	552	**7289**
City Gas	R-LNG	**3981**	**5146**	125	384	184	199	232	374	417	403	474	490	428	459	**4169**
	Domestic Gas	**5240**	**5737**	256	195	323	310	413	434	462	466	503	515	486	536	**4899**
Refinery Petrochemical Others	R-LNG	**12650**	**13130**	854	1049	1141	1088	1155	1024	1259	1053	1020	926	990	946	**12505**
	Domestic Gas	**5225**	**5285**	628	738	853	351	380	217	321	368	399	444	468	753	**5920**

Source:PPAC

1. CGD INFRASTRUCTURE

		As on 31st March 2018	As on 31st March 2019	As on 31st March 2020	As on 31st March 2021 (P)
PNG	Domestic	42,80,054	50,43,188	60,68,415	78,20,387
	Commercial	26,131	28,046	30,622	32,339
	Industrial	7,601	8,823	10,258	11,803
CNG	CNG Stations	1,424	1,730	2,207	3,101
	CNG Vehicles	30.90 lakhs	33.47 lakhs	37.10 lakhs	39.54 lakhs

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 May 2021	Capacity Utilisation (%) April-Mar 2020-21 (P)
Dahej	Petronet LNG Ltd	17.5	94.0
Hazira	Shell Energy India Pvt Ltd	5	76.8
Dabhol*	Konkan LNG Ltd	5	75.6
Kochi	Petronet LNG Ltd	5	17.3
Ennore	Indian Oil LNG Pvt Ltd	5	13.0
Mundra	GSPC LNG Ltd	5	34.8
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	President, bp India & Senior Vice President, bp group
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. Rajeev Ailawadi	Managing Director (i/c) & Director (F)
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. R.K. Sabharwal	Director (Commercial) & CMD (Addl. Charge)
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	HPOIL Gas Private Ltd.	Mr. Arun Kumar Mishra	Chief Executive Officer
25	IHS Markit	Mr. James Burkhard	Managing Director
26	International Gas Union	Mr. Luis Bertran	Secretary General
27	IIT (ISM) Dhanbad	Prof. Rajiv Shekhar	Director
28	IMC Ltd.	Mr. A. Mallesh Rao	Managing Director
29	Indian Gas Exchange Ltd.	Mr. Rajesh Kumar Mediratta	Director
30	Indian Oil Corporation Ltd.	Mr. S.M. Vaidya	Chairman
31	Indian Strategic Petroleum Reserves Reserves Ltd	Mr. H.P.S. Ahuja	Chief Executive Officer & MD
32	Indraprastha Gas Ltd.	Mr. A.K. Jana	Managing Director
33	Indian Oiltanking Ltd.	Mr. Rajesh Ganesh	Managing Director
34	IPIECA	Mr. Brian Sullivan	Executive Director

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

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