Investment Outlook and Global Competitiveness

Comparative Analysis with Global Oil & Gas Regulations for Upstream activities

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SOCIETY FOR PETROLEUM PROFESSIONALS DGH ओएनजीसी ONGC ऑयल इंडिया OIL INDIA

Agenda

- Indian E&P Sector growth – Evolution of Fiscal regimes

- Way forward – Intensifying E&P activities

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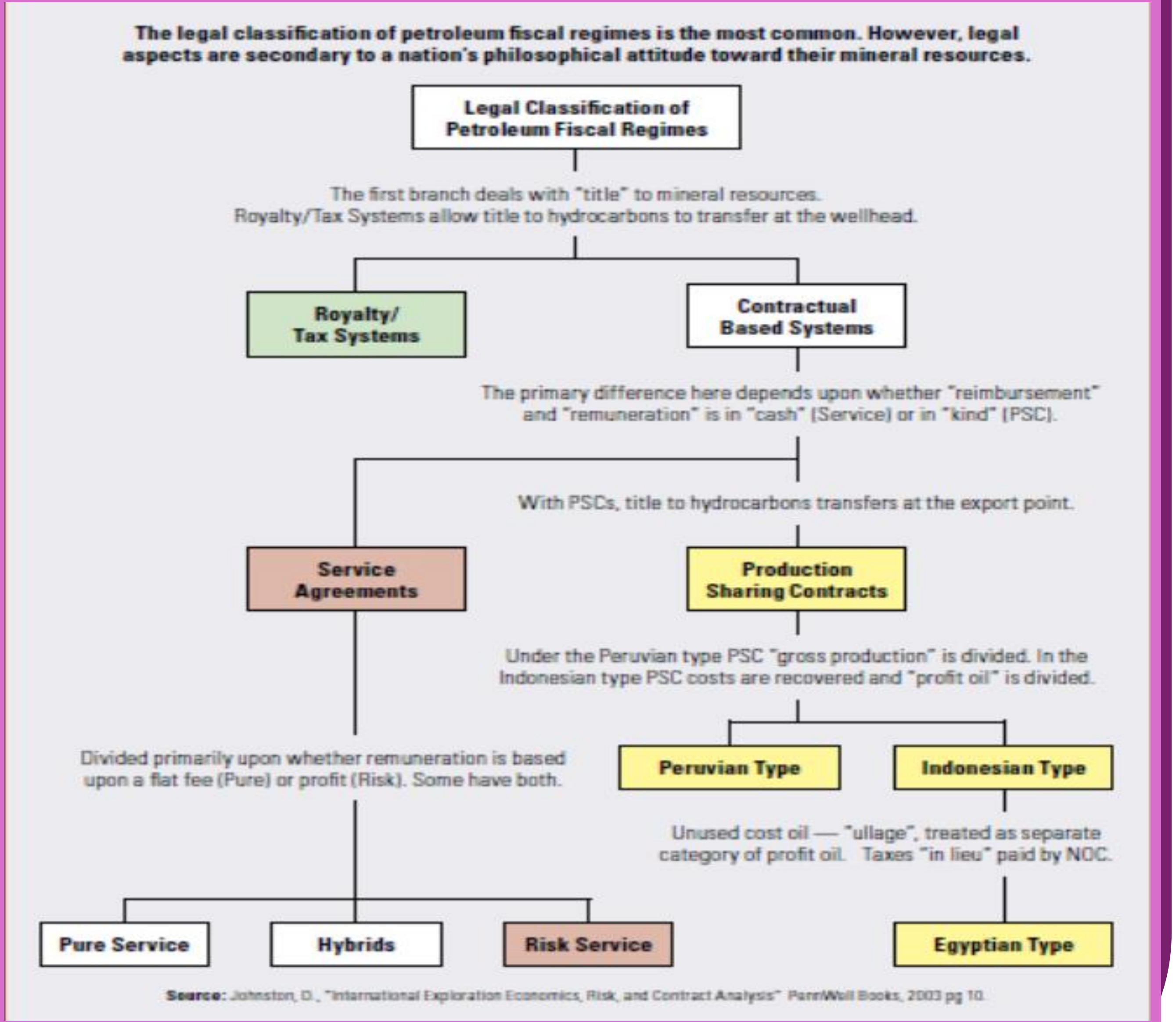
Fiscal Regimes

The most common Fiscal regime in E&P industry are

- Production Sharing Contract (Profit split) - Mostly !!
- Royalty/Tax system (R/Ts)
- Revenue Sharing Contract (Revenue Split)
- Service Contract



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Indian E&P Sector growth – Fiscal regimes

Nomination Regime
(NoCs)

↓

Pre NELP
(Working/Carried Interest by NoCs - PSC)

↓

NELP
(Level playing - PSC)

↓

HELP
(Level playing - RSC)

- ✓ To improve production, intensify exploration , bringing technology & risk sharing Govt. brought Pre NELP **(PSC)**
- ✓ To further bring in level field & attract investment, NELP was brought in **(PSC without Cess)**
- ✓ To remove micro management & give freedom to operators, Govt. brought HELP/NDR/OALP/DSF **with RSC** along with Marketing & Pricing freedom
- ✓ **Net importing countries like Brazil, China & Malaysia also adopted similar**

Indian E&P Sector growth – Fiscal regimes

Nomination regime (Till 1980)

- Exploration Acreages on Nomination to ONGC/OIL (+350 PML). NoCs to Pay Royalty/Cess to Govt (Oil-20%, Gas-10%, Cess-20%).
- No contract, Govt. monitoring. Nomination acreages >80% - Resource & 76% Production.
- In Most of the countries, Oil & Gas resources are owned by State except US where private lands own the resources. Offshore resources are by
- Most of the Fields of this regime are at Mature stage or under declining phase. Need incentive to maximise recovery & produce difficult Oil. ER Policy to be made more E&P company friendly – Govt. set to gain more Oil & Royalty (USA & other countries -Special benefits are given to companies for EOR projects).

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Production Sharing Contract (PSC) – Profit Sharing & Cost Recovery

Pre NELP(Exploration) - After 1980s:

(Risk sharing & Technology infusion)

- 28 Exploration block awarded (~10 Active)
- ONGC/OIL as Licensee /Govt. Nominee
- Licensee to Pay Royalty/Cess
- Major discoveries – In RJ-ON-90/1, CB-OS-2 (Advanced stage of exploitation), EOR implemented successfully

Pre NELP (Development)-After 1990

- 28 Discovered blocks awarded (Small & Medium size) ~ 20 Active
- Production Sharing Contract (PSC) – Profit Sharing based on IM/PTRR & Cost recovery, CRL/BDC in some of the contracts
- Contractor as Licensee /Govt Nominee, NOCs had PIs
- Major Fields – PMT, Ravva, Hazira, Bakrol, Karjisan,

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Production Sharing Contract (PSC) – Profit Sharing & Cost Recovery

NELP after 1997 – Level Playing

- 254 blocks in nine rounds ~ 30 Active
- No preferential treatment for NOCs, 100%FDI
- Royalty, No Cess,
- Contractor as Licensee /Govt Nominee
- +100 discoveries under NELP – Specially in KG-DWN-98/2, KG-DWN-98/3 blocks etc

Many Reforms brought in By Govt. for PSC

- Exploration Phase Extension to enable complete CWP/AWP
- Rig Holiday for Deep-water & Merger of Phases
- Exploration in PML areas
- Extension of PSC for Pre NELP Blocks

Early monetization of discoveries

Hydrocarbon Exploration Licensing Policy (HELP) - 2016

To avoid micro management of the contract and giving freedom to contractors - Operational & Procurement, Govt. introduced HELP-2016 based on Revenue Sharing Contract (RSC) in place of PSC

- **Unified License, Open Acreage Licensing, Revenue Sharing Contract, Continuous Exploration & Market Freedom**

OALP-I to IX

- Blocks as per contractor choice thru EoI/Bidding;
- > 150 Blocks awarded thru 9 rounds, +10 discoveries
- 10th OALP round on offer
- Continuous reforms

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HELP – DSF & Reforms

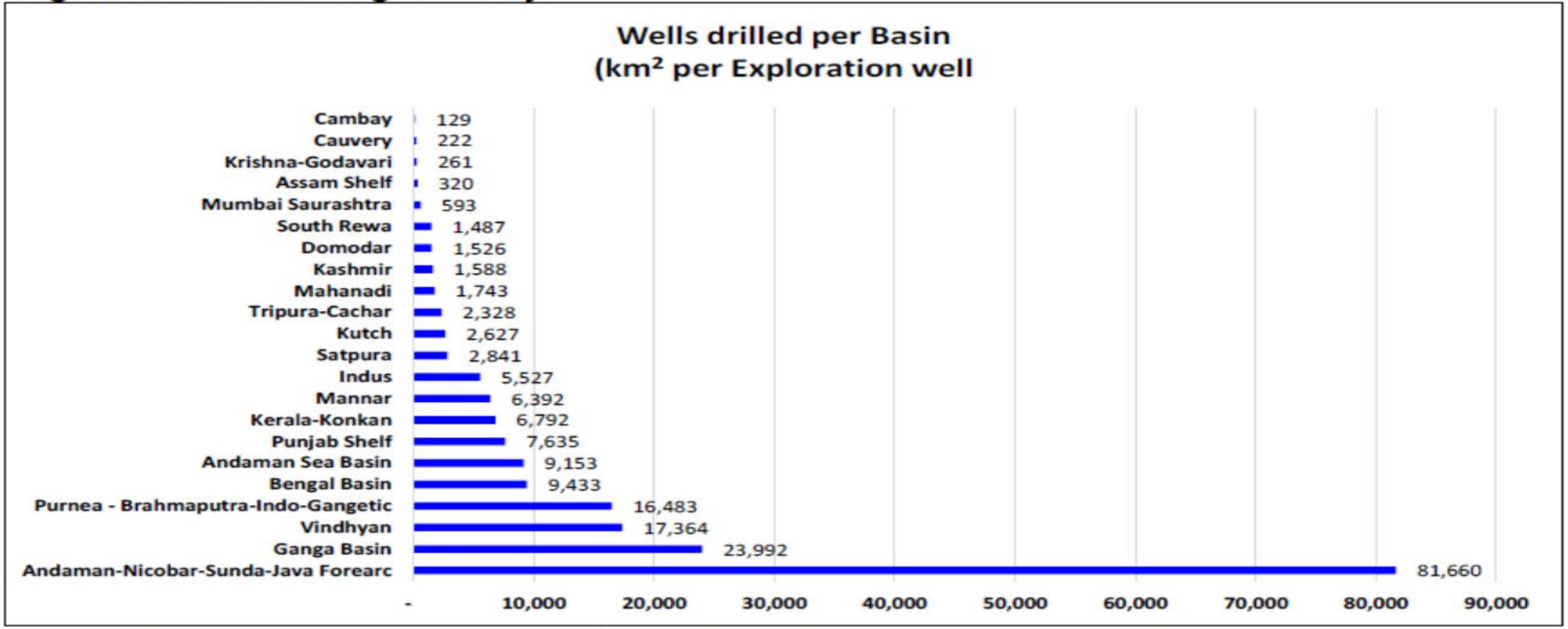
DSF- I to III

- Discoveries/Fields couldn't not developed by NOCs
- Revenue Sharing & WP (Weightage 50% each)
- Three rounds completed, 4th round on offer
- Continuous improvement over three rounds

Reforms brought in By Govt. for HELP-RSC

- Major reforms for OALP in 2019 & 2023
- To intensify exploration, no revenue for Cat-II & III Basins
- More Focus on WP rather than revenue
- Capping of Revenue Share with Govt.
- Swapping of WPs for Cat-II & III

Figure 8: Basin drilling intensity



Source: Includes content supplied by IHS Global Ltd;

To intensify exploration drilling in Cat-II & III Basins, Revenue Share has been removed.

What more to be done – Exploration

To intensify exploration & for EoDB, following may be incorporated in the policies/regulations

1. Exploration Phase for Cat-I Basins (OALP) may be increased to 5/6/7 years for Onshore/Shallow/DW. Also introduce simplified Extension Policy for HELP as was in NELP based on merit
   - ✓ To complete WP including Seismic API & interpretations, 3/4 years is less
   - ✓ Australia – 6 + 5 years extension, Azerbaijan – 10 years, Angola - 3+1+1+0.5 (Extensions), Banglasdesh -3+2+2 (extensions) and 5 years for Gas Marketing, China-10years

2. Work Program Swapping for Cat-I Basin as is for Cat-II & III

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What more to be done - Exploration

3. Tax Holiday for 7 years may be introduced in Deep Water/Ultra DW as incentives (Initially existent in NELP-PSC, later withdrawn). Morocco – 10 years Income Tax Holiday, Zero Royalty on Initial Production.

4. Re-categorisation /Sub-categorisation of Basins for Fiscal benefit

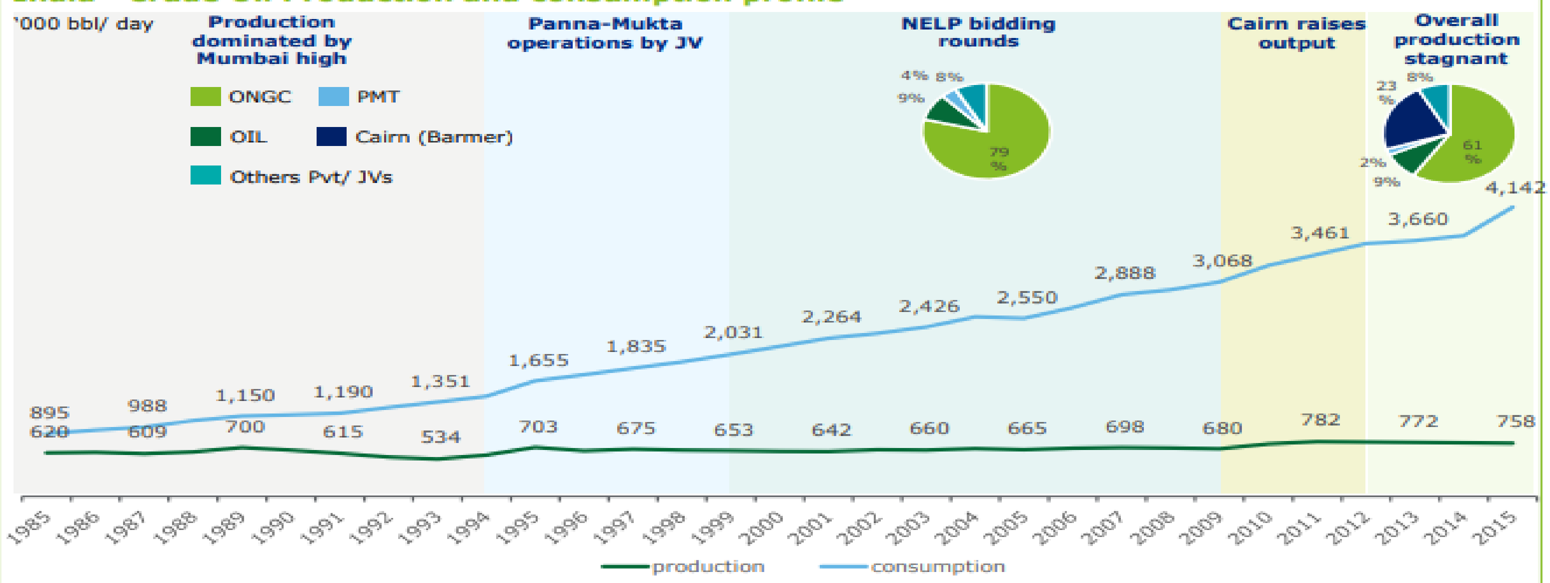
- ✓ Cauvery DW/UDW – No commercial discovery, still Cat-I
- ✓ Rajasthan – different sub basins at different stages, all in Cat-I
- ✓ (Bikaner-Nagaur, Jaisalmer, Barmer-Sanchor)
- ✓ Based on one small discovery, Bengal–Purnia Basin may not be upgraded
- ✓ This issue was discussed earlier between GoI & Stakeholders

What more to be done – Development & Production

India domestic production

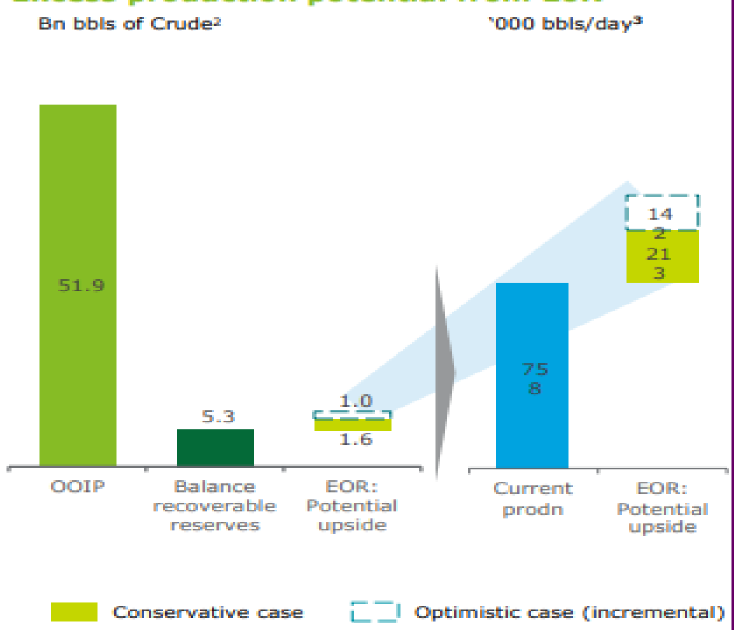
Indian crude production has lagged behind the growth in demand, EOR may present an opportunity

India - Crude Oil Production and consumption profile[1]



- Demand for oil is expected to grow at a CAGR of ~ 4% from 2015-2035
- Domestic crude production as a percentage of consumption has reduced from ~ 69% in 1985 to ~ 18% in 2015. Major production fields of ONGC, OIL ONGC, PMT etc. have matured
- Since Cairn (almost a decade ago), no major discoveries have been made

Excess production potential from EoR



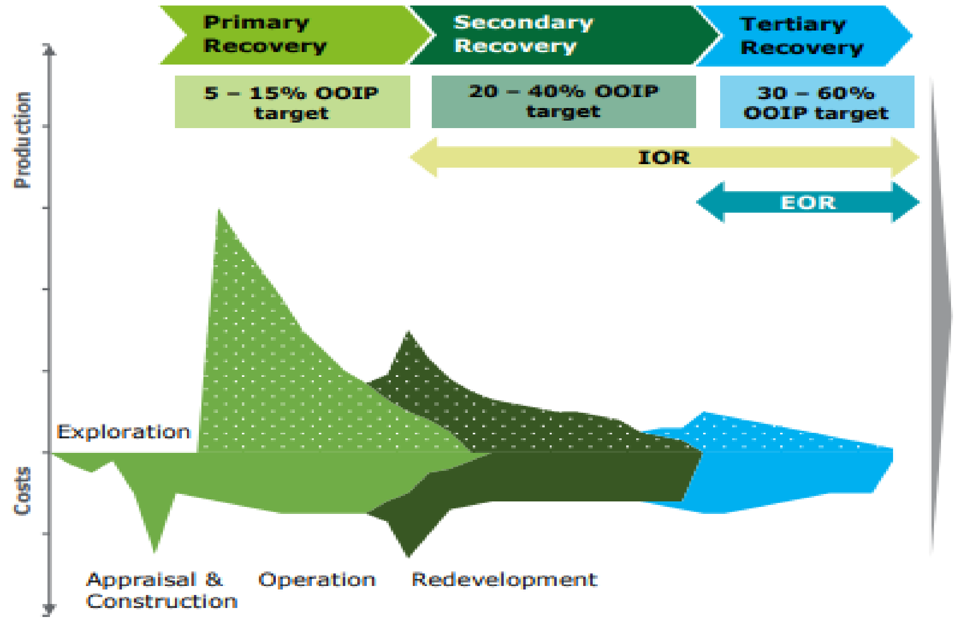
Use of Enhanced Oil Recovery (EoR) techniques could potentially increase output by 45%

Sources: MoPNG, EIA, DGH, Indian Bureau of Mines, BP Energy Outlook 2017, Annual corporate filings of RIL, Cairn India etc.
Notes: 1) Pie-charts for share of production have been provided for FY2003 and FY2016 for representation; 2) OOIP recovery upside is assumed as 3% (conservative case) and 5% (optimistic case); 3) Assumes an average lifespan of 20 years for oil-fields;

Enhancing recoveries

Secondary and tertiary recovery methods are important for extracting maximum value of a reservoir

Lifecycle of a petroleum reservoir



- **Primary Recovery**
  - Natural flow
  - Artificial Lift (Pumps etc.)
- **Secondary Recovery**
  - Water flooding
  - (Immiscible) Gas flooding
    - Gas injection
    - HC gas flooding
- **Tertiary Recovery**
  - Thermal Flooding
    - Cyclic steam (CSS)
    - Steam flooding
    - In-situ combustion
  - Chemical flooding
    - Polymer flooding
    - Alkali flooding
    - Surfactants
    - Alkali-Polymer (A+P) flooding
  - Miscible (gas) flooding
    - CO_2 flooding
    - N_2 flooding
    - HC flooding
  - Others
    - Simultaneous WAG[1]
    - Foam assisted WAG
    - Microbial

Improved Oil Recovery and Enhanced Oil Recovery are capital investments done to recover additional oil from the reservoirs

Sources: EIA

Notes: 1) Water alternating gas

Legend: Technologies which have been primarily used in India

Petroleum regimes across the world and potential EOR incentives

Major regimes are concessions, product sharing contracts and service contracts

Regime

Factors for consideration	Concessions – Royalty and tax regime (Concessions)	Concessions – Pure tax regime (Concessions)	Royalty and Production sharing contract regime (Production sharing contract)	Pure Production Sharing Contract regime (Production sharing contract)	Service Contracts regime
Risk Sharing	Oil company takes all the risk. Payments to have to pay royalty and tax. Taxes could be both Income tax and/or special oil tax.	Oil company takes all the risk. Taxes could be both Income tax and/or special oil tax	Oil company takes exploration risk. Oil company and government share risk of development and production costs. Risk higher as royalty is also paid	Oil company takes exploration risk. Oil company and government share risk of development and production costs	Government takes complete risk as oil companies get full compensation of costs and guaranteed margins. No upside available to Operators.
Example countries[1]	US, Colombia	UK, Norway	India[2], Angola	Indonesia, Egypt, Malaysia[3]	Iran, Philippines
Potential EoR / IoR Incentive Mechanisms	Reduces royalty and /or tax rates	Reduce tax rate	Reduce royalty rates, allow capital cost recovery for EOR investments	Allow capital cost recovery for EOR investments	Government decides if EOR to be undertaken. Offer additional compensation

Notes: 1) Some of the other countries have a mix and match of these regimes; 2) India, along with royalty and production sharing contract, recently introduced revenue sharing contract regime; 3) Malaysia also has a service contract regime for marginal fields

Global EOR

EOR contributes ~3% of world crude oil production; Investments into EOR compete against other non-conventional investments

	Extraction Cost US$ / bbl	Lead Time to Production # Years	Risk Profile	
Onshore Conventional	• MENA: ~5 to 18 • Russia: ~35 to 60 • RoW: ~24 to 60	3 – 5 years	• Exploration risk is ***medium-to-high*** • Technology is widely available	Conventional extraction has a weighted average cost of ~US$15/ bbl in MENA, ~US$51/ bbl in Russia, and ~US$44/ bbl in the Rest of the World
Offshore	• Shallow: ~15 to 43 • Deep: ~25 to 53	> 9 years	• Exploration risk is ***medium-to-high*** • Technology is available with experienced operators	Shallow water and deep-water projects have a weighed average cost of ~US$32/ bbl, ~US$38/ bbl respectively
Shale/ Tight Oil	• USA: ~28 to 58	< 1 year	• Exploration risk is ***Low,*** as shale-rich US basins are well-mapped • Technology is available with experienced operators	Extraction costs have declined sharply for USA Shale - from weighted averaged cost US$60-84/ bbl in 2014 to US$ 31-37 in 2016, leading to continued investments
Enhanced Oil Recovery (EOR)	• CO_2 EOR: ~20 to 70 • Other EORs: ~30 to 80	5 – 8 years	• Exploration risk is ***Low*** as EOR is implemented on existing wells • Technology is evolving and available with experienced operators	Economic returns limited as projects have an higher ongoing operating expenditure and also the volumes upside is lower

In a low oil price environment, Capital follows options based on economic potential

Sources: IEA, Wood Mackenzie, Rystad, Columbia Energy Institute, Oil and Gas Journal, News Articles

Case study 1: USA

Market forces drive the concession based US market, which requires EOR to compete with unconventional sources

Total oil demand	Total oil production	Unconventional oil production	Primary contract type
15.8	13.9	4.9	Concession with Royalty Payments

Figures in MMBOE per day

1991 – Introduction
Section 43 of the internal revenue code provides an EOR tax credit as a component of the general business credit

2000-2003 – Detailed guidelines
Detailed guidelines issued on cost allowed under qualified tertiary injectants for claiming credit

2005 – Unavailability of credit as crude prices increase
Credit was un-available as crude prices were greater than the threshold value for claiming incentives

2016 – Credit available due to drop in crude prices
Credit again available due to fall in crude prices

- *The US EOR production has declined from 0.76 to 0.72 Mn BBL during the period 1992 – 2014. Number of active projects have also declined from 273 to 218 during the same period.*
- *Tax credit linked to crude oil prices made the policy unavailable for almost 10 years from 2005 to 2015*

Incentive mechanism	Incentive process	Investor/Stakeholder views	Latest developments	Pros	Cons
• Federal credit at 15% of qualified EOR cost and state specific tax exemptions/ concessions are available. • Incentives are available if commodity price as notified by IRS for the year is below a defined threshold. This threshold is adjusted annually for inflation. • Credits earned may be carried back (1 year) or carried forward (20 years). • The qualifying project has to be completed within defined period, use specified recovery technology and meet well output restrictions	• EOR to commence after December 1990 • Applicable to both oil and gas fields • A qualified engineer is required to certify eligibility of a project, technology used and eligible production to claim benefits	• The scheme is viewed by O&G companies as a valuable scheme in the current low price environment to manage their tax burden and improve cash flow. • However following concerns are raised ▪ No differentiation between onshore & offshore fields ▪ Only specific technologies are covered	• Carbon dioxide (CO2) enhanced oil recovery (EOR) has received increased attention and US has laid large infrastructure to support transport of CO2 from source to fields	• Cost based incentive based on audited numbers • Simple to administer • Applicability notified by IRS leaving little scope for disputes • No delays in incentive realization	• Only specified technologies allowed for EOR • No differentiation for onshore/ offshore

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EOR Tax Credit for Tertiary Projects, if price below a threshold

Case study 2: Alberta, Canada

Alberta in the recent policy has allowed enhanced recovery incentives for all hydrocarbons, thus EOR would need to compete with enhanced recovery measures for other hydrocarbons

Total oil demand	Total oil production	Unconventional oil production	Primary contract type
1.87	4.05	2.47	Concession with Royalty Payments

Figures in MMBOE/day

2011 – Conduct study
Alberta Energy Regulator (AER) determined the Enhanced Oil Recovery potential in Alberta

2014 – Introduced policy
Government introduced the Enhanced Oil Recovery Program ("EORP") for **tertiary EOR techniques** with royalty rate **floored at 5%.** The policy was applicable to **Oil fields only**.

2017 – Revised policy launched
Government replaced existing EORP with Enhanced Hydrocarbon Recovery Program which allowed even **secondary EOR technique** with royalty rate of **flat 5%.** The new program is applicable **for crude oil, natural gas, gas product or oil sand.**

The new policy has reduced royalty rate to flat 5% for EOR project whereas average royalty rate has been in the range of 15% to 20% for oil.

Incentive mechanism	Incentive process	Investor/ Stakeholder views	Latest developments	Pros	Cons
• Alberta Government provides royalty rate reduction to incentivize EOR • The term is predetermined and dependent on the percentage of incremental crude oil recoverable from pool through tertiary methods • For secondary EOR techniques, the term is determined on case to case basis	• The new program is applicable for crude oil, natural gas, gas product or oil sand. • Every applicant has to submit supporting technical and financial information along with expected additional production to claim the EOR incentives	• Petroleum producers welcomed the policy as it recognized the higher risks and greater project costs of drilling and implementing secondary recovery schemes	• In 2017, to support oil production, the country also allowed incentives for secondary EOR techniques	• Secondary EOR techniques are also eligible for incentives • Applicable to all fossil fuels	• Benefits like additional production has to be quantified with a field development report • Case to case basis analysis requires a strong regulator • Same incentive for all fields & techniques

Sources: Alberta Energy website, Park land institute, EIA, EIU

EORP – Royalty Rate ~ 5%, Secondary included later

Case study 3: Malaysia

The Government is using the existing production sharing regime to promote EOR activities by signing EOR specific PSC with large companies

Total oil demand	Total oil production	Unconventional oil production	Primary contract type
0.69	0.72	NA	Production Sharing

Figures in MMBOE/day

2008 – PSC for EOR
Exxon and Petronas entered into a PSC for development of 7 Oil fields through EOR activities

2010 – Incentive scheme launched
Government rolls out incentive mechanism for promotion of EOR activities and is applicable even for existing fields

2011 – PSCs signed for 2 large projects
Shell & Petronas enter into two 30 years PSC Contracts for Chemical EOR projects – Sabah and Baram Delta fields. Expected increase in recovery factor from 36% to 50%

2014 – PSC expanded to include gas
Commencement of operations from the Exxon-Petronas Tapis EOR project

Expanded BaramDelta PSC with Shell to include Natural gas production

2016 – Large # projects undertaken
24 IOR / EOR / IGR production enhancements projects under way

Production Sharing Model with project specific approval allowance has no bearing on crude prices and recovered for the life for the project

As per Petronas estimate 1 billion barrel plus of oil from 14 fields have been identified for EOR projects

Incentive mechanism	Incentive process	Investor/Stakeholder views	Latest developments	Pros	Cons
• Investment allowance equal to 60% of the capital expenditure to be deducted against statutory income. • Maximum 70% of statutory income can be deducted in a year • Investment Allowance can be recovered during the life of the project until it has been fully recovered	• EOR applicable for tertiary methods • The incentive provided is technology agnostic and the same for all the tertiary methods • Separate PSCs are signed for EOR projects	• "EOR activities could boost oil production from Tapis by up to 35,000 barrels per day (bpd) from the present 3,000 to 4,000 bpd, increase the economic value of the field by more than 25 years" Director – Petronas • "Malaysian Government has given tax incentives to encourage more EOR projects and PETRONAS has provided a lot of facilitation for PS contractors and new PSC arrangements to make it attractive" - Head of Technology – Petronas	• Tapis field has become the largest South East Asia's largest EOR project • Petronas has become the largest operator of EOR techniques in offshore fields	• Capital expenditure based incentive de-risking operators • PSC signed considers actual field conditions on case to case basis	• Needs a strong regulator to appreciate EOR techniques being used and accordingly modify PSC • Largely off-shore fields which makes EOR costly and difficult

Sources: Petronas; Shell; Exxon Mobil; Newspaper articles; Petroleum Regulations 2013; Oil and Gas Overview by Malaysia International Chamber of Commerce and Industry; EIA, EIU

Shell & Petronas entered into PSC for EOR – Investment allowance ~ 60% against Statutory payments

What more to be done – Development & Production

To improve production and recovery of Indian Fields, following may be incorporated in the policies/regulations

1. Australia - "Use it or loose it" policy for acreages. No renewal after fix tenure. Being done in DSF ! Considering all reasons …… !!

2. ER Policy launched by Govt. in October 2018 has triggered ER in the country. However, there is need to review the ER Policy, to improve production and recovery. Deloitte, 2017 indicate that use of EOR can help in improving production by 45%

- ✓ For IR projects, cut off of 60% for Oil and 80% for Gas need to be reduced (Oil-30-35%, Gas-50%)
- ✓ Fiscal incentive for reference point 80$/bbl be removed
- ✓ Fiscal incentive should continue beyond 120 months
- ✓ Fiscal incentive (50% Cess reduction and equivalent in other regimes) may be increased

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Indian E&P Sector – What more to be done ??

3. DSF Rounds

- ✓ No revenue share for small discoveries (< 1 or 2 MMTOE). In case of wind fall gain, Revenue share ~ 10-30% may be shared. Similar to Cat-II & III as in OALP.
- ✓ Technical capability of the Contractor should be eligible criterion

4. Production Enhancement Contract (PEC) for Producing Fields. In Nomination Regime only & NoC to Bid out with

   - ➢ $/bbl for Base Profile, $/bbl for Incremental production, No of Development well
   - ➢ Technical experience should be mandatory

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Indian E&P Sector – What more to be done ??

5. Cess and Royalty Rationalization

- ✓ Reduce cess on crude oil (currently levied at 20%) for Declining Nomination Fields for brining investment & improving recoveries
- ✓ Reduce Cess on Marginal fields
- ✓ Graded Royalties for EOR/IOR projects

Govt. has brought in many reforms over the years to intensify E&P activities. There is still need to brought in more reforms. Detailed Global Comparative study need to constituted

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Thank you

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	Nigeria	Cote D'ivorire	Congo	Cameroon	Guinea	Uganda
Sign Bonus	$25m	$12	-	-	$1.5m	$0.5
Prod Bonus	0.1%	<200mbbl $12m	-	-	$5m	-
Royalties	8%	-	15%	12.5%	13%	12.5%
State Participation	Varies	10% initial + 10% AI interest @ LIBOR + 1%	-	Carried Interest 50%	-	20% initial + 15% + interest @ LIBOR
Cost recovery and other invest incentives	Exploration & Dev. Cost 20% uplift on CAPEX in year of acquisition	Cost Recovery cap 80% of gross production	70% cap on cost recover	No limits on cost recovery	No limits on cost recovery	60% limit on cost recovery
Tax Allowance	50% on capex	-	-	-	-	-
Income Tax	65.75%, 85% petroleum profit tax	27%	35%	57.5% / 48.65%	35%	30%
Split of Profit Oil with State	Split of Profit Oil with State	20%	>20,000 bpd 30%	Split of Profit Oil with State 50%	Split of Profit Oil with State	Split of Profit Oil with State
Additional Oil Entitlement (AOE)	35%	46%	50%	-	<30% RoR @ 0%	-
Others: Rentals	-	-	-	-		

Source: Data taken from Amoako-Tuffour & Owusu-Ayim (2010) with adjustments to reflect the characteristics of the Jubilee Field. Ernst & Young (2011), Global Oil & Gas Tax Guide, EYG no. DW0092.

Case study 4: UK

With most large fields reaching maturity and not much large discoveries happening the Government has created a detailed plan to increase the recovery from the existing fields

Total oil demand	Total oil production	Unconventional oil production	Primary contract type
1.6	1.01	NA	Concession – Pure tax regime

Figures in MMBOE/day

2010-13 — Fall in Production
Decline in domestic production by 37% largely due to declining efficiency and declining exploration activity. In 2013 govt. did a review of the fall

2014 — The Wood Review
The committee submitted a detailed report and steps to revitalize the UKCS. Maximising Economic Recovery also highlighted

2015 — Oil & Gas Authority (OGA)
Establishment of the Oil & Gas Authority in April 2015 in line with Wood's recommendation. It was executive agency of the Dept. of business & energy

2016 — MER UK & EOR Strategy
Maximising Economic Recovery plan adopted in January 2016

New EOR strategy adopted in July 2016. An 8 step delivery Programme finalized in Dec 16

2016 — OGA independent
OGA made an independent body. OGA launches corporate plan 2016-2021 with one of its vision to increase production by 250 mmboe using EOR

Currently no incentive to promote EOR activity; In Dec 2016 Govt. launched an 8 step process to increase EOR production which is under implementation.

Incentive mechanism	Incentive process	Investor/Stakeholder views	Latest developments	Pros	Cons
• Currently no incentive mechanism which has been defined by the Govt. • By Q4 2017, as part of the 8 step program OGA plans to outline a business case for EOR activities in the UKCS.	• To be decided once the incentive processes are finalized	• "Companies stated that not only is EOR prohibitively expensive to provide an economically viable solution in the UKCS but there is also no supply chain to offer these techniques at competitive price. Thus, organizations call for fiscal incentives targeted at encouraging companies to take up and develop technologies pertinent to EOR to meet MER UK plans" - Summary of interview of various oil & gas executives	• Captain polymer EOR project to start production by Q3 2017 • Clair ridge low sanity EOR scheme start-up by Q3 2017	• Strong collaboration between the industry, operators and oil & gas authority • An 8 step plan clearly charted out with defined timelines	• Slow progress of recommendations of the Wood committee • Lack of fiscal incentives to promote areas like EOR