TURNKEY as a SOLUTION to CAP the COST and REMOVE RISKS from OPERATORS

For the Monetization of Marginal Fields

Is it REALISTIC and PRACTICAL?

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Author:
J. Muthu Kumar, iWells Integrated Management Consultants DMCC, Dubai ("iWells")

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Brief Profile of the Author J. Muthu Kumar

An upstream oil and gas industry professional with 38+ years of experience across many countries with in-depth knowledge and extensive experience in:

- ✓ Asset Acquisition, Monetization and Development – to 1st oil and crude evacuation,
- ✓ Project Management and Delivery,
- ✓ **Well Construction and Well Intervention (Core Expertise),**
- ✓ Short, Mid and Long Term Business Models,
- ✓ Systems, Policies, Principles, Procedures and Standards,
- ✓ Optimization and Integrated Project Risk Management,
- ✓ Emerging Technology Applications, and
- ✓ High Performance Coaching

Senior Positions Held:

- CTOO
- COO
- CDO
- Head of IPM
- Group GM – D and C and WI
- Founder and MD of Ajapa and iWells (IPM Consultancy)
- WDL and PDL

Versatility of Experience:

- Worked on most types of production agreements, like PSC, PA, JV, Marginal Fields, Sole Risk etc.
- Integration of Field Development Plan and Early Monetization of Projects
- Environments:
  - Onshore, Transition, Swamp, Shallow Offshore, Deep Water, HPHT, LR, ERD and Horizontal
  - Wild Cat Exploration, Appraisal, Development, Work Over, Well Intervention, Infill Wells and Abandonment

Education:

Master of Technology in Chemical and Petroleum, IIT, Kharagpur, India

Bachelor of Technology in Chemical Annamalai University, India

Post Graduate Program in Data Sciences from University of Texas, Austin, USA

Publications:

- "Why, How Far and How Long Fall in Crude Oil Prices" - Jan 2016
- "Well Cost Optimization for Oil and Gas Wells in a US$ 30 per Barrel World" – Q1, 2016
- "Oil Model +2020" - Q1, 2020
- "Well Cost Optimization for Oil and Gas Wells in a US$ 35 per Barrel World" – - Q1, 2020
- "Futuristic Drilling Organization 2021 and Beyond" – July 2021
- "Drilling and Completions as a Business Unit"- December 2021
- "Tech Diary" in Jan 2010 – To be republished in Q1 2024
- "Drilling Automation Systems" SPE ME, 1997
- "Well Control Techniques in Horizontal Wells" SPE Malaysia 1996

Books:

- "Well Control for Beginners" Book – 1993 and 2003
- "Practical Well Control Beyond a Mandatory Certificate" – Volume I in Q4, 2023
- "Practical Well Control Beyond a Mandatory Certificate" – Volume II in Q2, 2024
- "Optimum Hydraulics and Effective Hole Cleaning" - in Q4, 2023
- "Well Integrity for Life Cycle of the Well" - in Q1, 2024
- "Best Habits of Highly Effective Drilling Engineers"- in Q3, 2024
- A 6 book series on "59 Second Concepts of Drilling Technology" – First of the Series in Q1, 2024

Innovation and Intellectual Property:

- WDDI – Well Delivery Difficulty Index – Under Testing, Paper to be published and Model to be launched in Oct 23
- RPDP^{D} – Resilient Drilling Project Delivery Process – A Resilient-Agile-Stage Gate Process and Technology – Proposed Model Published in 2021 and will be launched formally in Q1, 2024
- WBS – Well Integrity Barrier Diagram (with M.P. Shri Vignesh)
- D^{OPT} – Hydraulics and Hole Cleaning Optimization (with M.P. Sri Krishna)
- L^{AH} – Look Ahead Software (with M.P. Shri Vignesh and M.P. Sri Krishna)
- DDR – Daily Drilling Report Software
- IPRM^{D} – Integrated Project Risk Management for Drilling
- DCPR – Drilling Competency Person Report

Preamble

Today the concept of marginal fields is a growing opportunity worldwide in the upstream oil and gas sector in all environments, land, swamp, shallow offshore and deep water.

However, the seed for development and monetization of marginal fields was planted more than two decades ago.

Oil Majors, IOCs and NOCs were focused primarily on high priority fields. They were hence unable to allocate resources, efforts, and time on fields with low volume of reserves and/or marginal economics (“Marginal Fields”), which were generally located within large oil and gas blocks.

Due to this, these marginal fields were lying idle for several decades.

- ➔ Additionally, matured oil fields which had reached the uneconomical production level of costs vs returns balance, were shut down. Appropriate technology was also not available to enhance production.

However, the industry outlook started to change in early 2000 immediately after the severe South Asian Financial Crisis in the second half of 1990’s.

The world’s demand for oil started to expand and the oil prices started to increase correspondingly. From an average of less than US$ 20/bbl before the year 2000, the oil price moved up to high 20’s and by 2005, it crossed the US$60+/bbl mark. Advanced and new technologies also played a significant role for this major step change.

This phenomenal increase in demand and price of oil made several developing countries to realize the economic potential of these low volume fields.

This was the triggering point for the marginal fields. The drive that followed to exploit and monetize the national resources from these fields were also aimed at:

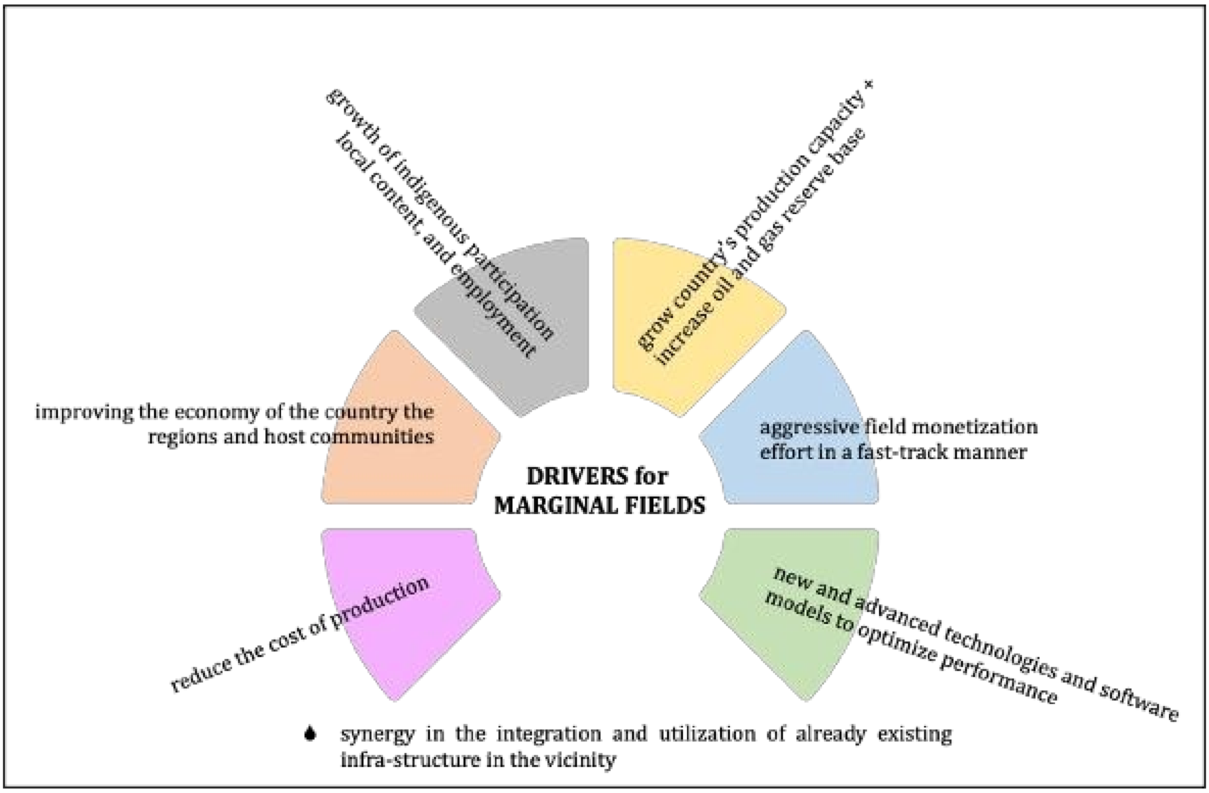

Fig.1.1 – Drivers for Marginal Fields

As the economics of marginal fields are generally tight, cost of development plays a major role to make a marginal field development project commercially viable.

Accordingly, several countries started to award such idle fields **as marginal fields** to small, independent, and indigenous companies **as they could operate at lower costs and in a faster manner** as compared to multi-national and major oil and gas companies.

Developing the marginal fields became one of paramount importance. However, the monetization of the marginal fields did not succeed up to the scale of expectations due to various reasons like:

- X offering of marginal fields as exploration license under a Production Sharing Agreement (PSC)

    - ➔ associated challenges of finding funds for exploration, discovering oil and declaring commerciality in a marginal field,

- X marginal economics that cannot withstand a standalone economics,
    - X isolated locations without infra-structure in the vicinity,
    - X prohibitive development costs,
    - X surface and/or technological constraints,
    - X unfavourable fiscal regime, etc.

The concept however stayed alive. The industry tried several other models including:

- ✓ protection of investment by offering discovered and/or proven fields,

- ✓ aged declining producing fields with,

    - ✓ favourable royalty and taxation,
    - ✓ pricing structure and freedom to trade,
    - ✓ faster cost recovery,

- ✓ extended freedom to operate including Operator's own internal process for procurement (to expedite execution) without the involvement of regulatory or the government, etc

    - ➔ However, even then, only a fraction of marginal fields achieved sustainable commercial production and monetization successfully.

    - 🕮 While surely some marginal field operators in countries like US, Europe, India, Nigeria, Indonesia etc have proved to be successful, that percentage is relatively small as compared to the potential, total number of fields and operators.

Despite that, as the drivers and the model for marginal fields are sound, countries like India, Nigeria and few others awarded several marginal fields to indigenous companies in the last few years.

- With oil prices staying steady above the US$ 60/bbl for the last two years post COVID-19, the interest to develop and monetize the marginal fields is mounting up steadily.

However, the perception of fast tracking the 1st oil in marginal fields with minimum CAPEX and very low risk is not practically happening as the reality is different when it comes to execution.

Keeping aside the issues related to funding, collaboration between partners and hydrocarbons category (proven or prospective), one of the major reasons for delayed monetization is the lack of understanding of the:

(1) project viability, in terms of execution, cost and deliverables, and

(2) appropriate and the right execution model.

In reality, the execution challenges are much different than **what is envisaged** during acquisition.

- most acquisitions are based on subsurface work, subsurface CPRs, reserve estimates and project economics with **arm's length development cost,** that is usually low without basis.
  - during acquisition, the project delivery leadership is not generally involved.
  - Investors also do not generally seek a Project Viability CPR or Drilling CPR, however difficult the terrain, subsurface complexities and risks are.

    This is primarily due to:

    - ➔ project execution, its complexity and risks are pushed aside as **"details"** with statements like **"technology is available to bring oil to surface".**
      - ? **Yes, but at what costs and risks?**
      - ? What is the right and appropriate technology?
      - ? Who decides that during acquisition?

  Ironically, this is the story that occurs even today globally. Exceptions exist but they are rare.

A critical point:

- Just because it is termed as "a marginal field", the behaviour of the well or the need for right infra-structure is not going to be softer.
- Whether the well/project is in a marginal field operated by a new small size independent Operator, **or** it is in a major development field operated by an IOC, the delivery challenges apply equally for both.
- The difference is how those challenges are envisaged during planning and handled during execution.
- If not handled properly, some of the risks can turn into a compromised delivery or a catastrophic disaster, which can happen even in a marginal field.

  Before challenging the observations above, please ponder on the points below:
  - *The existing old wells in a marginal field were most likely drilled by an IOC, NOC, or Oil Major.*
  - *Despite that, several of those old wells had experienced various hole problems including well bore stability, wireline log issues and stuck pipe. In some cases, well control incidents were also encountered.*
  - *Side tracking or abandoning of a well due to unsuccessful fishing of a stuck string or other wellbore problems is not uncommon.*
    - ? *If that had happened to an IOC, NOC, or Oil Major, why it would not happen to a marginal field operator, unless prudent practices are applied?*

Rule 1:

A well or the entire project (which includes all components until crude evacuation), requires

the respect that it deserves

irrespective of the environment, status, and the Operator.

Hence, the belief that marginal fields are easier to monetize is not practical.

Thus, developing a marginal field safely, cost effectively and at minimum risk requires a novel strategical approach different from that of a conventional large field with already producing wells or at a higher scale of economics.

- ✓ More importantly, it needs to be understood that "one size does not fit all", and
  - ♈ copying the operating model of an IOC/Oil Major or another operator, will not always work in a marginal field.

It is hence critical to fully understand the limitations, boundary conditions, risks, and the strategies to be considered for monetizing a marginal field.

Some of the **critical criteria** to develop a marginal field are:

(1) Recognizing opportunities and the right techno-commercial solutions to achieve best economics at low risk

(2) Novel wells that create value in terms of:

- ✓ optimum number of wells
- ✓ optimized well type and completion design that allows minimum well intervention,
- ✓ increased production efficiency, and
- ✓ optimization at the lowest practically possible cost

(3) Innovative approach for minimum facilities/infra-structure concept to minimize CAPEX and optimize the OPEX to achieve:

- ♈ the lowest practically possible overall cost/bbl of production

(4) Appropriate and new/advanced technology and efficient use of resources to reduce operating footprint

(5) Applying synergy using simplified design, portfolio models and standardized engineering and equipment

(6) Real time data availability through advanced cloud and acquisition models, application of well reservoir facilities management (WRFM) and improved oil recovery methods to ensure that:

- every drop of oil that can be recovered techno-economically is recovered

(7) Most effective and efficient contract structure for wells, facilities, and crude evacuation to ensure that:

- ♈ the execution objectives and project deliverables including schedule, cost and risk management are achieved seamlessly.

The purpose of this paper is not to discuss all of the above except the point no (7) above on the practical and the right contracting strategy.

We need to acknowledge that there are some very successful marginal field operators across the world. This paper may not apply to them, but the lessons captured from their journey to success are a good reference to evaluate their applicability in each Operator's environment.

Accordingly, this paper is made of six sections:

Section	Title	Brief Summary
1	Marginal Fields	An introduction
2	The Perception	What is generally envisaged to develop the marginal fields in a fast track very low risk manner
3	Is that Perception Realistic and Practical?	Analysis of the Perception
4	Perception of Risks	Causes, implications probability, and complexity of a well delivery project - Critical
5	What Then is the Right Approach?	Seven different strategies that are prevailing in the industry plus a cost saving model are discussed briefly
6	Conclusions and Action Plan	Briefly discusses the action plans to arrive at the right strategy to implement

This paper is not designed to exhibit any negativity or pessimism on marginal fields.

The concept of marginal field is a practical, workable, essential, and apt solution to monetize low reserve volumes fields and matured fields effectively and efficiently.

However, a marginal field needs to be treated with respect it deserves to make that a profitable venture for the investors, operators, and a valuable model for the governments.

This can happen only by understanding the limitations, risks and gaps that exist commonly in monetizing the marginal fields.

Hence, this paper is designed to create a positive and educated approach to identify and apply the right strategy to execute and deliver a marginal field project successfully.

Please refer to **Section 7.0** for further interaction and details.

1.0 Marginal Fields

Marginal fields are not wild cat or exploration fields.

Most marginal fields are discovered fields. They have at least a well drilled and evaluated using wireline logs. Some are tested with wireline test tools and very few by a proper DST. However, in most cases, the commerciality is not proven or confirmed to be viable.

There is no universal definition for marginal fields. In most cases, they are called marginal fields due to the following:

- low volume reserves and marginal economics,
- at least a well is drilled, and hydrocarbons discovered,
- commerciality is not confirmed by testing and/or appraisal,
- not developed for more than ten (this can vary) years after discovery,
- fields relinquished from large field(s) after exploration phase,
- unconventional oil or gas,
- fields undeveloped due to surface complexity and lack of infra-structure,
- matured oil fields that had reached uneconomical production levels (in terms of a threshold set by the Oil Major, IOC or NOC), etc.

A minimum threshold of reserves volume is also generally used to rank the priority for development rather than the risk.

The minimum threshold of reserves volumes to determine if a field is marginal is estimated based on various factors including:

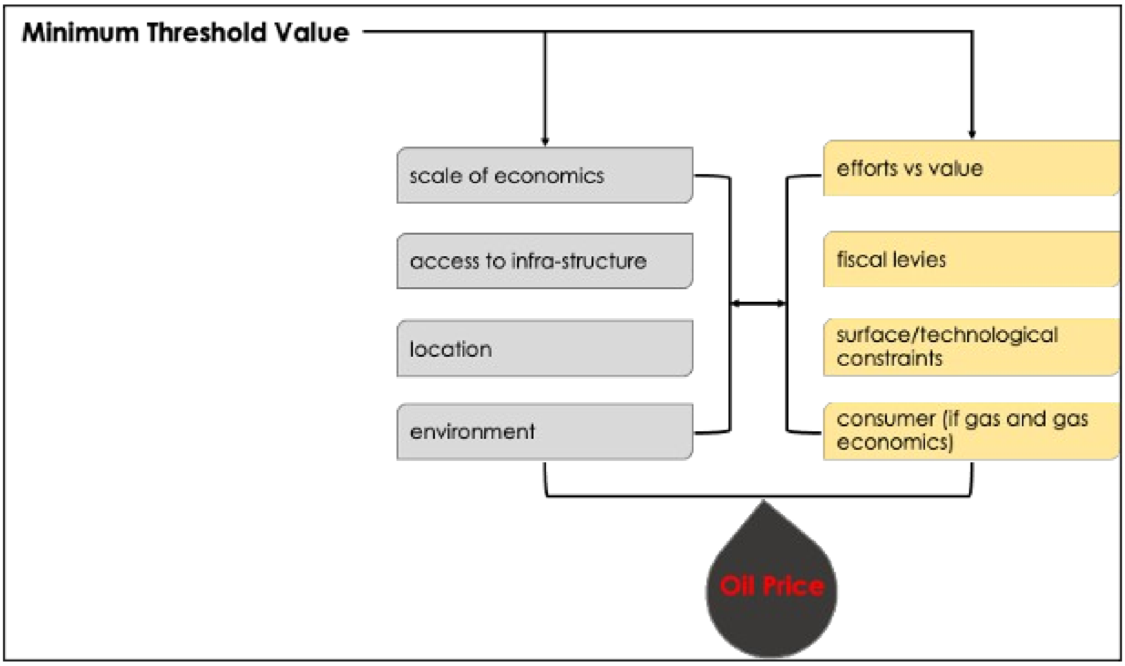

Fig.1.1 – Factors that Influence the Minimum Threshold Reserve Volumes

Most of the marginal field owners do not have prior upstream oil and gas experience as an Operator to operate and monetize an oil and gas asset.

Although many might own business portfolios and/or managed businesses,

- ✓ in the service sector of the upstream oil and gas industry;
- ✓ businesses other than upstream oil and gas industry;
- ✓ in businesses related to the mid-stream or downstream sectors;

they may be new as an **Operator** of a marginal field in the upstream sector involving the exploitation and monetization of oil and gas.

Acquiring an oil and gas asset as marginal field is one aspect.

- ➔ However, monetization of such asset safely, cost effectively, with minimum risk in a fast-track schedule is a completely different aspect.

The general belief that in a marginal field, existing old suspended well(s) can be re-entered and put on production for commercial monetization using a temporary production facility and crude evacuation model at the,

- ✓ fastest schedule possible,
- ✓ at minimum CAPEX,
- ✓ temporary facilities and infra-structure for crude evacuation on OPEX,

does not materialize in reality.

Many marginal field operators are unable to bring the field on production even after several years of acquiring the field.

Few critical reasons are:

- 🕮 despite being termed as marginal field with well(s) drilled and hydrocarbon(s) discovered, the field may have no proven oil reserves for the investors to be attracted to fund the project,
  - ➔ in that case, the field needs to be appraised to move the hydrocarbons category to proven (P1) category and raising funds for this appraisal work may be difficult.
- 🕮 Further, even with funds raised, the marginal field project economics is marginal and tight.
  - ➔ Hence the cost of development needs to be low.

This makes the execution model and the right contracting structure, critical.

However, the lack of clarity on the most practical and workable contract structure to execute the project is a prevailing predominant issue.

This paper discusses the current perception of contract models by many marginal field operators, their effectiveness, and the appropriate approach to achieve the right strategy.

2.0 The Perception

There is a growing perception among the marginal field operators with respect to developing the marginal fields either in land, swamp or shallow offshore.

What is that perception?

The perception is that **"Doing Everything as Turnkey or All Inclusive Contract Under One Contractor".**

Traditionally a turnkey contract has few advantages but also several disadvantages like:

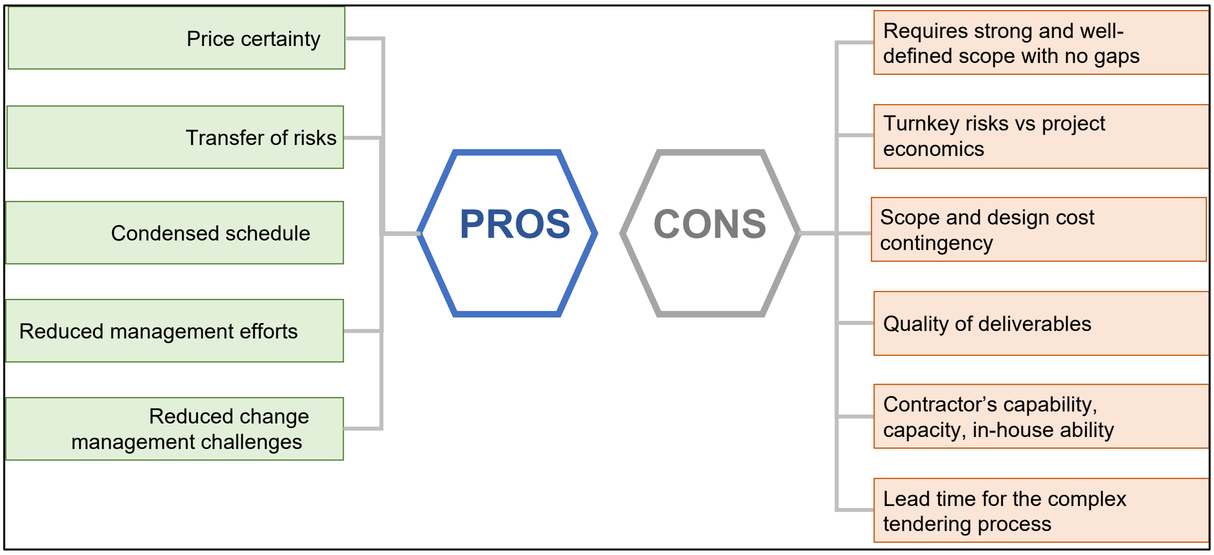

Fig.2.1 – Pros and Cons of Turnkey Contracts

What are the expectations from the turnkey model that is perceived?

The fundamental root cause for such a belief in 100% turnkey or all-inclusive contract solution for marginal fields is that such a model is expected to guarantee the marginal field operators the following:

(1) the cost is capped;

(2) all the risks and liabilities except statutory and regulatory are removed from the Operators;

(3) the schedule risk is passed on to the Contractors;

(4) the Operator is fully indemnified without a limit or cap;

(5) the contractor delivers the entire project deliverables under one umbrella using sub-contractors as needed;

- ➔ this allows minimum footprint and organization resources for the Operators;

(6) with all the above included, the cost of the turnkey is lower or optimal;

This Turnkey Solution is sought by the marginal field operators generally on three models.

Model 1 is for well construction only to bring 1 st oil to surface and hand over to production.

Model 2 encompasses the entire process from well construction to crude evacuation.

Model 3 is to split the well construction, facilities, crude evacuation into three major categories.

Please refer to the picture below for details.

Model 1 — Scope	Model 2 — Scope	Model 3 — Scope
✓ 1st oil through re-entry of a suspended well or a sidetrack of that well and/or drill a new well	**All Inclusive:** ✓ 1st oil through re-entry of a suspended well or a sidetrack of that well and/or drill a new well ✓ temporary production facilities ("TPF") for the first few months ✓ crude export by trucks or barges or pipeline to either to a FSO, a terminal or a refinery ✓ a permanent production facility ("PPF") within a specified time frame to replace the TPF ✓ operations and maintenance of the facilities for a defined period or on long term	**Category 1:** ✓ 1st oil through re-entry of a suspended well or a sidetrack of that well and/or drill a new well **Category 2:** ✓ temporary production facilities ("TPF") for the first few months ✓ operations and maintenance of the facilities for a defined period or on long term ✓ a permanent production facility ("PPF") within a specified time frame to replace the TPF **Category 3:** ✓ crude export by trucks or barges or pipeline to either to a FSO, a terminal or a refinery

Fig.2.2 – Models 1, 2 and 3 for Turnkey Contracts

What are the issues with the above stated perception and concept?

The fundamental but major issue in the perception of turnkey solution under one contractor with respect to 1st oil project of a marginal field is that **"it is unrealistic and impractical".**

3.0 Why that Perception is Unrealistic and Impractical?

First, there is no service provider in the entire world who has the in-house capability and capacity to provide the entire spectrum of service for Model 2 from:

- ✓ Subsurface
- ✓ Well construction
- ✓ Production facility
- ✓ Production operations
- ✓ infra-structure for Crude evacuation
- ✓ All the other peripheral works to deliver the above

Even for Model 1 which consists of only well construction, the expectation of a 100% turnkey irrespective of the level of uncertainties, risks, and unknown factors in the well and the field is impractical and unrealistic.

There is no service provider including multi-nationals has the capability for a 100% well construction solution on their own. They depend on several sub-contractors, including the drilling rig, to execute the whole project under their umbrella. However, no multi-national service provider will accept a 100% turnkey solution with all liabilities passed on to the Contractor without limits especially in 1st oil ventures.

In fact, none of the IOCs. NOCs and Oil Majors have all these capacities, despite having a large pool of resources in-house in each discipline. They also depend on several contractors including 3rd party consultants to deliver the whole project.

Few additional critical points:

The IOCs, NOCs and Oil Majors do not generally engage a single contractor for the complete list of services and deliverables either for Model 1 or Model 2.

In rare cases, where a well construction project is given to a single contractor, it is most likely an Integrated Project Management on hybrid (combination of Day Rate + Fixed Cost) or day rate structure and not a 100% turnkey.

Where does then the turnkey concept apply?

(1) Turnkey contracts for well construction are awarded only to well-known fields with minimum ambiguities and uncertainties.

(2) Such turnkey contracts have:

- ✓ adequate duration, number of wells and project scope to make sensible project economics against the turnkey risks,
- ✓ well defined scope,
- ✓ properly defined and agreed turnkey exclusions.

(3) Turnkey contracts are not a model for a single re-entry well or new well as the project economics will not justify the turnkey risks.

- 🕮 No multi-national service provider will directly accept a turnkey contract for a single or just a few wells in a field that has several uncertainties, unknown factors, and risks.

- 🕮 Some local companies may readily accept a turnkey solution even for a single well contract.

  - ➔ It might be due to several reasons, but it could also be due to underestimation of the turnkey risks. Further the local company may still need a multi-national service provider's support for project delivery.

  - ➔ In such situations, a multi-national service provider may agree to work as a sub-contractor to the local company who takes the entire liability of the turnkey elements such that,

    the multi-national service provider is paid on day rate or activity-based rates by the local company without any turnkey risk elements associated with it.

- 🕮 If a service provider agrees to a 100% liable turnkey contract for a single well or for a limited project work that,

  (a) has several uncertainties, unknown factors, and risks and
  (b) does not justify turnkey risks compensated project economics,

  Operators need to be extremely cautious for such contract agreements.

  - ✓ A very detailed due diligence must be done on the contractor to ensure without ambiguity his capability and capacity to execute the turnkey contract.

Even in a matured field with low level of uncertainties and risks, a single contractor cannot provide all the deliverables. It is only possible by an efficient and effective integration of several domains or disciplines through various sub-contracts.

➔ However, integration of such a wide distribution of domains and respective expertise is not an easy task for a single entity **without having** a fully qualified, skilled project delivery and integration team with adequate experience of an Operator's perspective (not just from a contractor's perspective).

Note:

A turnkey contract or an all-inclusive** IPM contract on day rate does not always work **if the contractor does not have the ability to perform most of the services in-house** and depend mostly on 3rd party subcontractors.

*** - includes rig, tangibles, and services plus all liabilities without limits*

♈ One of the most common mistakes made on turnkey contracts is to award contract to a contractor who is specialized in a particular service portfolio.

- ➔ He then sub-contracts all other services required to execute without even having a working knowledge of those services.
  - ➔ This recipe is rare to succeed as the lead contractor will depend fully on his subcontractors to do a turnkey (or an all-inclusive) performance.
- ➔ One exception probably is if the lead contractor is a fully qualified, experienced integrated project management company with significant experience from an Operator's as well as Contractor's perspectives.

Note:
Some international drilling contractors maintain(ed) a separate arm's length well engineering and design entity for such contracts.

Let us critically review each of the **expected guarantees of the perceived total turnkey solution:**

(1) Cost is Capped

This is the foremost expectation of most of the marginal field operators to prefer a 100% turnkey or all-inclusive solution.

However, a turnkey solution is not straight forward, and it **does not** eliminate 100% of an Operator's risk as believed or claimed.

First, the turnkey model:

- 🕮 Must have a well-defined scope with (1) adequately stipulated conditions, and (2) without ambiguities.

  Developing the scope is the most difficult part of a turnkey contract. It requires knowledge, experience and understanding.

  - ➔ If it contains gaps or ambiguities in the scope, then at every instance of a surprise, unknown situation, or deviation from an already agreed plan, the cost of such events will be treated by the turnkey contractor as **"outside scope".**
  - ➔ Absence of clearly stipulated conditions to define **"within"** and **"outside"** of scope in a turnkey contract, does not guarantee Operator's de-risking of all liabilities.
  - ➔ Hence, all the costs of **"outside"** scope will forcefully become the Operator's accountability.
- 🕮 Must have adequate duration for the whole process between preparation of tender and award of contract to ensure that the bidders are evaluated at a common platform and the terms are properly negotiated.

- ➔ If the scope is unclear and inadequate, the turnkey bid submissions will not be uniform as each bidder would have used his best understanding and approach.

- ➔ If the evaluation is not done properly to bring them all under a common platform, then the commercials can be misguiding.

  - ➔ It is not uncommon for a contractor to become L1 bidder just because he had missed some critical steps/resources than others and it was not caught by the evaluating team.

  - ➔ This issue backfires during execution as the contractor would claim those missed steps/resources as "outside" of turnkey scope.

Second, even in a well-defined turnkey model with clearly stipulated conditions:

- The turnkey contractor will be accountable only for costs associated with the works of **"within"** scope.

- All the costs of **"outside"** the scope will have to be borne by the Operator.

- The only difference in this scenario is that the Operator knows his liability if **"outside"** scope occurs instead of getting into a surprise or forcefully pushed to accept accountability.

- ♈ One more critical aspect is that turnkey solutions **do not always guarantee quality** as the turnkey contractor would push for speed rather than quality.

  Hence, in several cases, quality gets compromised unless the Operator has a very strong and highly experienced team to oversee the performance.

Hence, "cost being capped" is to be considered unrealistic.

(2) All Risks and Liabilities are Removed from an Operator

A turnkey or an all-inclusive solution (with all liabilities taken by the Contractor in day rate or hybrid model) for such vastly distributed scope of deliverables **does not remove all the risks** for the Operator.

A contract with all liabilities passed onto the contractor looks good in paper and may bring comfort to the board and stakeholders but it does not apply in practice due to the following:

Part 1: Ultimate Principal Ownership

Fundamentally, the Operator is the ultimate principal owner of the field/block. Hence, the burden of such ownership cannot be removed by signing a contract with the contractor taking 100% of liabilities and accepting to indemnify the Operator without limits.

In such situations,

- ♈ If the contractor fails to rectify or manage the impact caused by a risk occurrence, especially on environment, personnel life, and asset, then the Operator will ultimately become accountable to the government, regulatory, host communities and affected society.

- ♈ If the contractor's insurance underwriter (please see **Part 2** below) rejects the claim, no contractor will have the financial strength to manage the impacts created by catastrophic and disastrous risks.

  - ➔ In that situation, the contractor will most likely go bankrupt or walk away from the contract.

- ➔ While the Operator has the right for legal recourse against the contractor if he walks away, the situation in the field is not going to wait until the verdict is obtained.

  Hence, as the ultimate principal owner, the Operator must then forcefully take up the liabilities at that time.

  Imagine the risk here:
  By believing such a contract, if the Operator does not take adequate and appropriate insurance to cover his liabilities, no Operator can survive the cost exposure with his own funds.

Part 2: Claimable Insurance by the Contractor

The contractor cannot obtain **claimable insurance** for certain liabilities like:

(a) consequential losses

- ➔ having a contract where all liabilities with respect to consequential losses incurred by the Operator are passed on to the Contractor is a misnomer as no prudent insurance underwriter will give insurance for consequential losses incurred by another party of the contract.

- ➔ If by any rare chance, an insurance underwriter provides such insurance, the **clause on exclusions** and **conditions for claims** will be extremely tight.

  - ➔ In such instance, Operators must carry out a proper due diligence on the insurance underwriter to ensure his claim track record for this type of insurance.

  - ➔ If an insurance claim is unsuccessful and if the Contractor is unable to fulfill his obligations for this liability, the Operator will become liable as in **Part 1** above.

(b) Blowout and pollution liability

Insurance for blowout and pollution liability come under **Operator Extra Expenditure ("OEE")** insurance.

Passing this liability to a contractor creates a major risk for the Operator.

The conditions for the claim with the exclusions for such insurance obtained by the contractor will create a conflict of interest which will make the Operator's position extremely weak.

If a blowout happens, the contractor must invoke the insurance claim immediately so that the cost of blowout control is managed by the insurance underwriter.

Without a successful insurance claim, no contractor will have the financial strength to execute the blowout control or pollution management operations.

If the insurance company rejects or delays the claim, the contractor will not be able to manage the impact.

- ➔ In that situation, the Operator will become ultimately accountable as the principal owner of the field irrespective of what is in the contract.

➔ **Imagine a situation where due to this contract, the Operator does not have the OEE insurance.** No Operator can survive such a massive cost exposure with his own funds.

📖 Note that 3rd party well control experts will not generally engage or involve in blowout control if there is no claimable insurance.

(c) Limit of Liability

A contract with no limit of liability has no value because a contractor cannot get an unlimited insurance.

In that case, even if a Contractor signs the agreement, it is not valid as no contractor can work with unlimited liability without such insurance.

As mentioned in (a) and (b) above, if the Contractor fails to fulfill the agreed terms of this unlimited liability, the ultimate accountability will fall on the Operator only.

It is hence meaningful and prudent to define a limit of liability so that the Contractor can obtain a claimable proper insurance to perform the contract effectively.

➔ This also allows the Operator to get appropriate insurance to manage Operator's defined liabilities.

(d) Operator's Liabilities

Irrespective of a contract structure, an Operator will have the following liabilities as a minimum:

OPERATOR'S LIABILITIES		
IMPORTANT	MAJOR	CRITICAL
Community and security	Ingress and Egress to and from location	Regulatory permits and approvals
Force Majeure	Consequential Losses pertaining to the Operator	Blowout control and pollution
	Mutual indemnity liabilities with the Contractor	Reservoir damage and underground blowout
	Liability of copy right infringement	Operator's insurance
	Operator's liabilities due to Contractor non-performance	Operator's liabilities due to Contractor insolvency

Fig.3.1 – Operator's Liabilities

➔ Others that are not listed above

Hence, there is no contract model that relieves an Operator completely devoid of any liabilities.

(3) Schedule Risk is the Responsibility of the Contractor

Schedule is a combined work of all parties involved. Passing the full responsibility to the Contractor, even in a 100% turnkey contract, is inappropriate as Operator has several responsibilities that have direct influence and impact on the schedule.

Even if the contractor does his part of the work very effectively, if delays occur due to the Operator by not fulfilling his responsibilities in time, the schedule will be affected.

Hence, passing the entire schedule risk to a contractor is not practical and useful.

Fig.3.2 – Operator's Responsibilities for Schedule

➔ Other requirements that fall under the Operator's envelope.

If a contractor agrees full accountability for schedule risk, the Operator needs to be cautious before awarding the contract as ultimately it is the Operator who would be affected if the schedule slips indefinitely.

Some Operators believe to include liquidated damages clauses for schedule delays as a remedy but that alone does not help to resolve the issue beyond certain limits.

(4) Turnkey Cost is Lower or Optimal

The expectation that a turnkey or all-inclusive hybrid model cost will be lower or optimal than a day rate option with a cap on the cost despite the turnkey risks taken by the Contractor is not practicable.

The reality is, for every activity that is on turnkey, a contractor will add the cost of turnkey risk margin.

➔ The magnitude of such margin depends on the extent and level of the risks and complexity.

If a contractor agrees for a turnkey or an all-inclusive hybrid solution based on an optimistic approach without considering the risks and uncertainties adequately, then the Operator must be cautious because if a problem occurs, the contractor may not have the financial strength to rectify the problem at zero charges beyond a certain limit.

Further, as discussed in this **Section 3,** a turnkey contract would include conditions at which the turnkey will not be applicable. When such conditions are encountered, Operator needs to bear the associated cost.

Hence, both the beliefs of (1) cost is capped, and (2) cost will be the lower and/or optimal are not the reality.

The only time the average turnkey cost can be lower than a day rate option is when:

(1) Turnkey contract duration is long term with several wells (a minimum of 10 wells)
(2) The wells are drilled back to back without gaps in between
(3) Within the same operating area with known factors with minimum gaps and uncertainties
(4) Well complexity levels are low-medium
(5) Balanced contract that has appropriate mutual indemnities and well defined liabilities
(6) Quality, capability, and capacity of the Contractor

Note:
Contrary to the general belief, the day rate option is not always a risk with respect to time and cost.

Majority of the Day rate contracts deliver the project within time, budget and allowed + accepted variance.

Probably up to 20-30% of the projects on day rate model may face severe challenges with cost and time over runs. This happens due to various reasons but that can be controlled by:

- ✓ adequate preparation time,
  problems arise when the importance of preparation is ignored. The most common practice to cut costs is to reduce the preparation time.

  Remember:
  "If you Fail to Prepare,
  Then You Must Prepare to Fail".

- ✓ a prudent design with defined contingencies,
- ✓ robust and effective preparation,
- ✓ seamless execution,
- ✓ quality supervision, and
- ✓ skilled leadership.

Such a process with a skilled team will deliver a day rate contract safely and successfully.

The day rate model also gives higher control and management of services to the Operator.

At the same time, not all turnkey contracts are successful. Compromised turnkey contracts create a much worse situation for the Operator than cost over runs of a day rate contract.

Further discussion on this is beyond the scope of this paper.

4.0 Perception of Risks

This is a very important section for all marginal field operators, the board, the management, and stake holders.

Two of the major reasons for failure of most of the projects in the world, whether oil and gas or any other industry, are:

(1) inappropriate perception of the risk, and

(2) the misunderstanding of the confidence to overcome a perceived risk.

In drilling, facilities and infra-structure development of the upstream oil and gas industry, these two reasons play a major role in defining success or failure.

Irony:
From a general perspective,

- ✓ while the industry accepts the subsurface risks of finding or appraising hydrocarbon presence or volumes,

- X there is an aversion to hear about drilling risks among the management, board, and stakeholders.

While even a 40-50% probability of success is accepted for subsurface and reservoir engineering models,

Drilling has no such margins or justifications.

- ➔ In drilling, failure is not an option.
  - ✓ Drilling cannot stop at 5 m above a reservoir in a 3,000 m well and claim that more than 98% is achieved.

    Unless the target is reached at the prescribed depth and sub-surface location, drilling is termed as a failure even if it stops at just 5 m above the target.

This fundamental difference cannot be eliminated between subsurface and drilling due to the nature of the game.

However, the issues can be managed more effectively only if drilling risk is considered as a serious matter rather than pushing it aside as “Details”.

Unfortunately, the issue of drilling is also associated with competency bias between drilling experts. All of them do not see the risks in the same way.

- ➢ Most drillers are expected to be brave and confident.
  - ➢ However prudent and diligent they are, cautious drillers are discouraged.
    - ➢ With that kind of pressure, some drillers exhibit very optimistic attitude which are highly encouraged by the peers and management.
      - ➔ Ironically, if the project fails or compromised due to excessive optimism, they would be forgotten with adequate justifications.
    - ➢ However, if a cautious driller fails, it would be termed as the consequences of his pessimistic attitude from the start.

➔ **The result:**
Unjustifiable failures caused by unjustified excessive optimism are accepted as learning for the future.

Whereas even justifiable failures caused by justified pessimism face rejection.

Globally optimism is always encouraged. Diligent and prudent approach are invariably discouraged if they are not aligned with the management or leadership objectives.

It is critical to understand that in executing complex projects like drilling and infra-structure development in the upstream oil and gas industry,

➔ the **pessimistic and optimistic strategies are to be integrated.**

✓ **Where is pessimistic strategy critical?**
The design, engineering and plans must be developed through a pessimistic approach so that all possible risks and uncertainties are properly evaluated, and mitigation strategies are put in place.

✓ **Where is optimistic strategy critical?**
The execution and operational aspects need to be optimistic to manage the real time challenges effectively and efficiently despite the quality of design and program.

X **What is not prudent?**
An optimistic engineering, design and plan would compromise risk management strategy.

The optimistic design is directly related to the two major reasons for project failures stated in the beginning of this section.

Of course, as everyone understands, a pessimistic execution model will invariably fail.

🕮 Drilling is a complex process.

🕮 Every well requires its due respect.

🕮 Where caution is required, it must be adhered.

🕮 Where the **pessimistic and optimistic strategies are integrated properly,** the chance of successfully delivering a project is truly high.

4.1 Understanding Risks

Although understanding risk is essential for the entire upstream oil and gas industry in different magnitudes, the discussion below is for drilling risks to demonstrate the risk model.

Drilling has at least 16-20 factors that act simultaneously or has direct influence on drilling performance on a continuous basis.

Non-performance by or surprises from any one of them will negatively impact drilling efficiency and effectiveness.

For consistent effective and efficient drilling performance, the 16 actions shown in **Fig. 4.1** below must always work in synchronization and harmony as planned and programmed for execution.

🕮 Please note that these 16 points are not exhaustive. Others may add additional factors/actions. For this paper, let us consider the 16 factors given below.

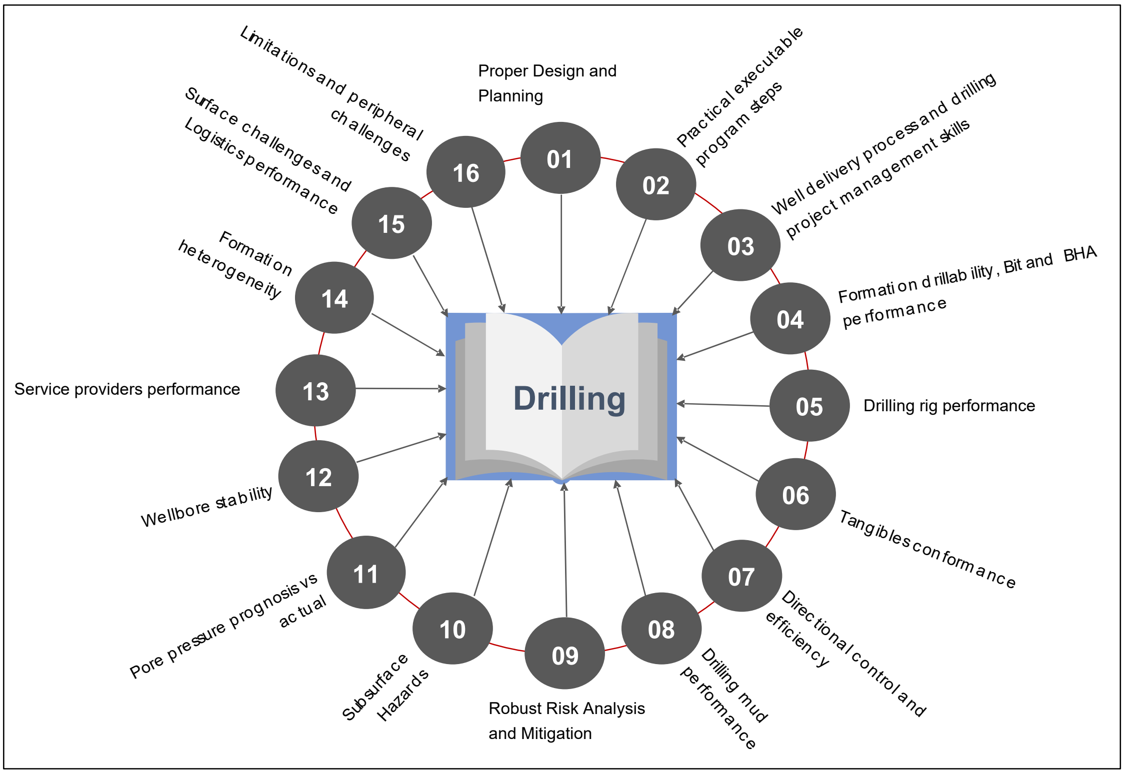

Fig.4.1 – Drilling Risks

If someone is confident of 90% chance of success in delivering the drilling project as required, it sounds really very good but is it practical, and right?

For a drilling project to have 90% chance of success, each of the 16 factors in the figure above must succeed essentially at the same level, i.e., each of the 16 factors must succeed at 90% level.

Even if that happens, the overall probability will not be at 90%.

In statistical probability aspect, the overall probability of success or confidence level is as follows:

Case Number	Efficiency Levels	P_S as per Statistical Perspective
Case 1	Each of the 16 factors operate at 90% efficiency	**$P_S = 0.9^{16} = 18.5\%$**
Case 2	Each of the 16 factors operate at 95% efficiency	**$P_S = 0.95^{16} = 44.0\%$**
Case 3	10 factors perform at 95% level, 4 factors at 98% and 2 factors at 88% efficiency	**$P_S = 0.95^{10} \times 0.98^{4} \times 0.88 \times 0.88 = 42.8\%$**
Case 4	Each of the 16 factors operate at 98% efficiency	**$P_S = 0.98^{16} = 72.4\%$**

Obviously, the chances of success calculated above is from statistical probability and this cannot be considered for decision making on drilling.

At the same time, assigning 100% chance of success for each of the 16 factors is also not correct.

What else is then missing?

When 90% confidence level is proclaimed, it must NOT be from **the driven optimism arising out of perceived knowledge and experience.**

➔ If that happens, this perceived optimism may lead to perceived over confidence to ignore adequate, appropriate, and proper treatment of uncertainties, risk evaluation and developing risk mitigation.

➔ If such optimism is encouraged rather than integrating pessimism and optimism, it may lead to compromised drilling project deliverables at the project green light and investment decision itself.

What then is the right approach?

As discussed in Section 4.0, the pessimistic and optimistic strategies are to be integrated.

Optimism and confidence to execute must arise truly based on a project viability work, integrating pessimism and optimism, that consists of but not limited to:

- prudent engineering, design and preparation,
- understanding uncertainties and developing "what if" scenarios with solutions,
- identify all the risks and the probability of occurrence adequately,
- estimate the impact of risk occurrence, and
- ranking of the identified uncertainties and risks,
- developing mitigation techniques

If the team is well prepared, if the risks occur, they will be ready to face the challenge. If the risk does not occur, the operations will continue smoothly.

It is better to be ready for something that is expected but may not happen than not to be ready when that happens.

➔ Such optimism must be the driving force to determine the % confidence levels to indulge in drilling and upstream field development ventures.

Such optimism will elevate the chance of success as well as allow the execution team to be ready and well prepared to face any challenges encountered during execution.

➔ An optimism exhibited without such efforts but only from experience with self-confidence derived out of perceived knowledge may most likely lead to a failed or compromised project.

4.2 Drilling Risks

Drilling probably has the highest number of non-linear random risks as compared to any other industry and it is impractical to comprehend the challenges and the impact of risks without adequate experience and competence.

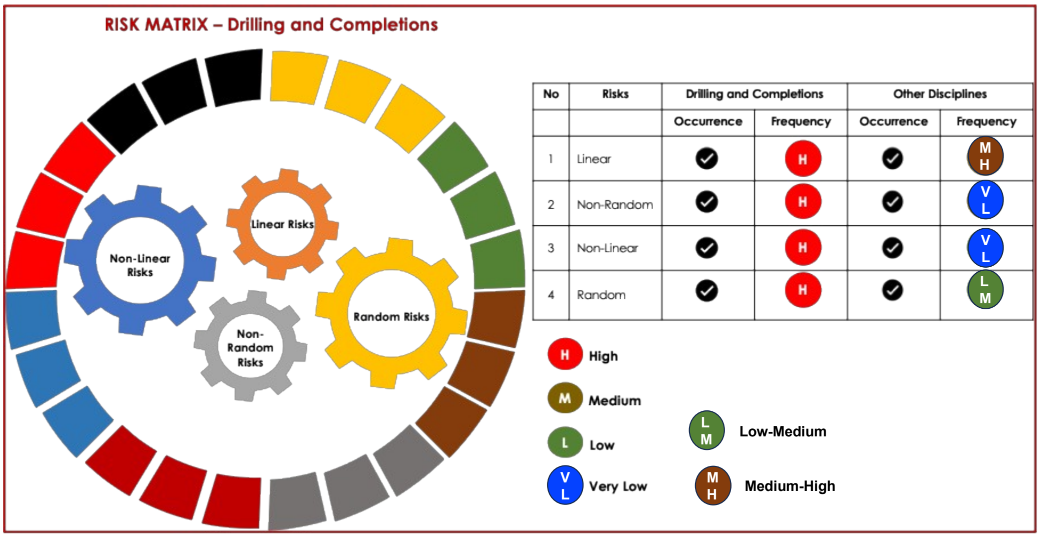

Fig. 4.2 – Risk Matrix Model

Drilling of oil and gas wells is a non-linear non-intuitive complex process.

The complexity and associated risks always exist in drilling. They do not disappear until the well is drilled, completed, and handed over to production.

- Even then, the integrity of the well continues throughout the production and abandonment to the end of its life.

The impact of risks like a blowout in drilling can result in catastrophic disasters and major environmental incidents. Such extent cannot be imagined in any other industries, except probably nuclear plants.

While drilling risks are more prominent in wild cat exploration and appraisal wells, even in a fully developed field, the risks may exist.

- In fact, well control incidents are not uncommon in normal pore pressure development wells in a matured field.

  - This also applies to a re-entry and completion of a suspended well. The risk and complexity increase if the data related to the suspended well and field are incomplete and/or unavailable.

Why Understanding Drilling Risks is Critical?

The advances that were achieved in the technology of process plants like:

- refineries,
- petrochemicals,
- fertilizers,
- power plants,
- manufacturing etc,

made them much safer and efficient in the last five decades.

However, despite being an industry of more than hundred years, every day, at some part of the world, drilling problems occur.

- Despite all the advancements made in the last three decades in drilling technology, even today at least 20% of the wells face some kind of challenges.

  - Considering that nearly 50,000 wells are drilled per year globally, this 20% relates to nearly 10,000 wells.

    - At least 20% of these 10,000 wells, say around 2,000 or so get in to major problems or fail majorly in meeting the objectives.

      - Probably around 20-30% of these 2,000 wells, say around 400-600 or so result in side tracking or loss of well or suffer very high cost over runs.

Note: Data is not based on established statistics.

- Further, despite the advances made in the industry with respect to mitigation and management of well control risk using:

  - ✓ mandatory certificates for personnel,
  - ✓ training, coaching and drills,
  - ✓ established operational policies and procedures,
  - ✓ robust instrumentation and well control equipment, and
  - ✓ modern digitalization for better monitoring and control real time,

blowouts still happen.

Process establishments like refinery, petrochemical and power plants etc, do not face failures of this nature. If such catastrophic failures happen, they are extremely rare.

In drilling, such challenges continue to exist due to the:

- complexity,
- high level of uncertainties,
- impact levels of a risk occurrence,
- extensive dependency on skilled and talented personnel, and
- the need for effective integration of nearly 30-40 services.

5.0 What Then is the Right Approach?

There is no right or wrong approach in developing a marginal field.

The strategy needs to be developed based on the various factors that have an impact on the project.

Detailing such strategies with pros and cons of each are beyond the scope of this paper.

Few common strategies applicable for marginal fields are provided below:

Note:
A100% fully qualified in-house team that can run the entire project by hiring the rig and services directly under the Operator is not an option for marginal fields as the project economics may not allow to establish such a large team and be deployed on a long term.

Strategy 1: Lean Model (may not applicable for large fields with higher scale of economics)

Model	Features	Rate Options
Lean in-house team led by an experienced, qualified, and skilled chief officer**	supported by consultants (contracted either directly or through a manpower supply company)	Day Rate
Rig, Tangibles and Services	are hired by the Operator through the agreed project delivery process with the in-house + 3rd party consultants' team that allows the Operator to exercise good control on service providers	

** - (with significant experience from an Operator's perspective)

Strategy 2: An IPM Model without Rig, Tangibles and Services

Model	Features	Rate Options
An integrated project management ("IPM") consultancy led by a highly skilled integration lead**	an experienced senior project person with a lean team at the Operator's side to oversee the IPM team's work	IPM Consultancy on Option 1: Day Rate only Option 2: combination of Day Rate + Fixed Cost
Rig, Tangibles and Services	are hired by the Operator through the agreed project delivery process with the IPM team that allows the Operator to exercise good control on service providers	

** - (with significant experience from an Operator's perspective)

Note:
This is a no conflict, most common, well established, and proven strategy in the industry.

Strategy 3: An IPM Model with Rig, Tangibles and Services

Model	Features	Rate Options
An integrated project management ("IPM") consultancy led by a highly skilled integration lead***	an experienced senior project person with a lean team at the Operator's side to oversee the IPM team's work	IPM + Rig, Tangibles and Services on Option 1: Day Rate only Option 2: combination of Day Rate + Fixed Cost
Rig, Tangibles and Services	are hired by the IPM and provided as a single package	

*** - (with significant experience from an Operator's as well as Contractor's perspectives)

Note:
This model is good for an Operator as it reduces the responsibility, but

➔ can lead to a serious conflict of interest between the IPM, the rig and services with respect to performance and overall integrity.

➔ Operator has lesser control on the services.

X This model is not a common model unless the Operator has a very strong and qualified in-house team to oversee the performance.

✓ Many international IPM companies prefer to execute a pure IPM concept without conflict as in Strategy 2.

Strategy 4: Footage with Bonus Contracts, Applicable for drilling only
Footage: Drilling to a particular depth

Model	Features	Rate Options
Footage with Bonus Contracts: Applicable for drilling only Contract to a lead contractor usually an IPM consultancy and/or a drilling rig contractor	an experienced senior project person with a lean team at the Operator's side to oversee the lead contractor work	IPM + Rig, Tangibles and Services on Option 1: Day Rate only Option 2: combination of Day Rate + Fixed Cost
Rig, Tangibles and Services	**Option 1:** are hired by the lead contractor and provided as a single package, Operator has much lesser responsibilities and load **Option 2:** are hired by the Operator through the agreed project delivery process with the lead contractor that allows the Operator to exercise good control on service providers	
Footage Bonus Model	A time scale is agreed to reach a particular depth. The lead Contractor and the Drilling Rig Contractor are paid a bonus if the depth is reached within the agreed time scale.	

Note:
Although sounds good, this strategy is not applied often in practice due to the complexity of integrating several services and each service expecting a pie of the bonus.

Strategy 5: Footage Turnkey Contracts, Applicable for drilling only

These contracts are modified turnkey model. This is normally done only in well-known areas.

<table>
<tr><th>Model</th><th>Features</th><th>Rate Options</th></tr>
<tr><td>Footage Turnkey Contracts: Applicable for drilling only

Contract to a lead contractor usually the drilling rig contractor or rarely an IPM consultancy</td><td>an experienced senior project person with a lean team at the Operator’s side to oversee the lead contractor work</td><td>All including Rig, Tangibles and Services at a lumpsum using a Cost/ft or Cost/m agreement for an agreed total depth</td></tr>
<tr><td>Rig, Tangibles and Services</td><td colspan="2">are hired by the lead contractor and provided as a single package, Operator has much lesser responsibilities and load</td></tr>
<tr><td>Footage Turnkey Model</td><td colspan="2">A turnkey lumpsum cost in units of Cost/ft or Cost/m is agreed to reach the TD of the well (including running and cementing of casings and installation of wellheads)</td></tr>
<tr><td>Outside Turnkey Scope</td><td colspan="2">All other activities after reaching TD like logs, DST and completions including X-Mas tree etc will be on day rate.

The Operator can choose to supply the tangibles or ask the contractor to provide at costs + margin.</td></tr>
</table>

Note:
This model is common and may work in well-known areas with minimum subsurface uncertainties and challenges.

Strategy 6: Incentive Contracts, Applicable for drilling only

These contracts are performance-based model. This is normally done mainly for flat times reduction and only in well-known areas.

<table>
<tr><th>Model</th><th>Features</th><th>Rate Options</th></tr>
<tr><td>Incentive Contracts

Contract to a lead contractor usually an IPM consultancy or a drilling rig contractor</td><td>an experienced senior project person with a lean team at the Operator’s side to oversee the lead contractor work</td><td>IPM + Rig, Tangibles and Services on
Option 1: Day Rate only

Option 2: combination of Day Rate + Fixed Cost</td></tr>
<tr><td>Rig, Tangibles and Services</td><td colspan="2">Option 1: are hired by the lead contractor and provided as a single package, Operator has much lesser responsibilities and load

Option 2: are hired by the Operator through the agreed project delivery process with the lead contractor that allows the Operator to exercise good control on service providers</td></tr>
<tr><td>Incentive Model</td><td colspan="2">A performance-based incentive contract for specified activities or a whole section.</td></tr>
</table>

	An incentive is paid if that activity or the section is completed at lesser time than agreed. In some contracts, a penalty is applied for times longer than agreed with a margin for variance.

Note:
However, in incentive-based contracts, as the contractor will attempt to speed up, the safety aspects need to be closely monitored.

This model is common and may work in well-known areas with larger number of wells with minimum subsurface uncertainties and challenges.

Strategy 7: 100% Turnkey Contracts

The 100% turnkey option has been discussed in detail already in this paper. Hence, not discussed further here.

Two important factors:

Tender Preparation:

Unlike the day rate contract, turnkey tender preparation is completely different.

- ✓ The turnkey tender needs a well-defined detailed scope definition that leaves no ambiguities or gaps.
- ✓ The turnkey inclusions and exclusions and conditions if exclusions occur need to be defined.
- ✓ The terms and conditions of the contract must be prepared for the specific tender and scope.
- ✓ The price template must have 100% clarity to prevent any misalignment.

Please refer to Section 3 for some additional points.

Strategy 8: Cost Savings using Remote Model – applies except for Mobilization and Execution

Beyond the models indicated above, for cost savings, Operators can consider using the growing model, especially post COVID-19, of

- ➔ remote work through online for engineering, design, preparation, real time monitoring and project closure (except mobilization and execution) which may be much cheaper, at least by 40%, than conventional models for such work.
- ➔ As a reference, one such service provider is www.drillersdesk.com

Note :
There may be other models in the industry than listed above. Hence, please consider the models listed above only as a reference and guide.

The right model must be chosen with proper due diligence on the status, internal capability and capacity, project requirements and deliverables.

6.0 Conclusions and Action Plan

For majority of the marginal fields, the primary focus and goals would be to monetize the field in the fastest possible time with minimum capex.

As discussed in **Section 1.0,**

- acquiring an oil and gas asset as marginal field is one aspect.
- However, monetization of an asset safely, cost effectively, with minimum risk exposure in a fast-track schedule is a completely different aspect because the reality is different.

Apart from raising funds, the project execution requires a holistic approach with proper contract structures, project execution plan and implementation process for a successful project delivery.

Please refer to the **critical criteria** listed in the **Preamble** section to develop a marginal field as compared to a conventional field with large number of wells and/or at the higher scale of economics.

Although the criteria (7) was only discussed in detail in this paper, all the seven criteria's under **"critical criteria"** must be evaluated and integrated to select the right strategy for implementation.

So, to conclude,

the recommended approach to effectively monetize the marginal field is as follows:

Basis:
(a) Although hydrocarbon is discovered, consider that the commerciality of the field is not declared yet
(b) The economics is marginal and hence lower development cost with minimum risk is extremely critical

Considering the basis above,

Step 1: Develop a robust strategy with an experienced and qualified project expert (with significant experience from an Operator's perspective) supported by a lean team at the start of the monetization process to create:

(1) an overall draft master plan for the marginal field development defining each phase
(2) statement of requirements for the 1st oil and crude export to ultimate buyer
(3) appropriate contract structures and models
(4) relevant and effective supply chain model
(5) practical draft outline project execution plan
(6) practical and achievable schedule
(7) data availability, uncertainties, risk matrix and mitigation
(8) budget and cash flow burn rate
(9) resources required, their capability, and the model for deploying resources

Note:
This is not a detailed work. This is the First Stage of an Agile-Stage Gate Process that combines the feasibility with opportunities to create a model to progress to the Second Stage of project delivery and hence this level is classified as Level 3 (or Level 4).

Step 2: Conduct a "Connect to Execute" or "CTE" workshop to connect the entire team who is involved in the process including the board and stakeholders as applicable.

Step 3: Conclude on the best strategy for implementation.

Step 4: Execute as approved and agreed post the CTE workshop diligently by deploying the right resources and contractors.

7.0 Further Discussions

The Author and/or his team is available for further discussions, presentations or workshops on the subject matter.

Please write to us at:

projects@iwellsmc.com
projects@drillersdesk.com

Website: www.iwellsmc.com and www.drillersdesk.com

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