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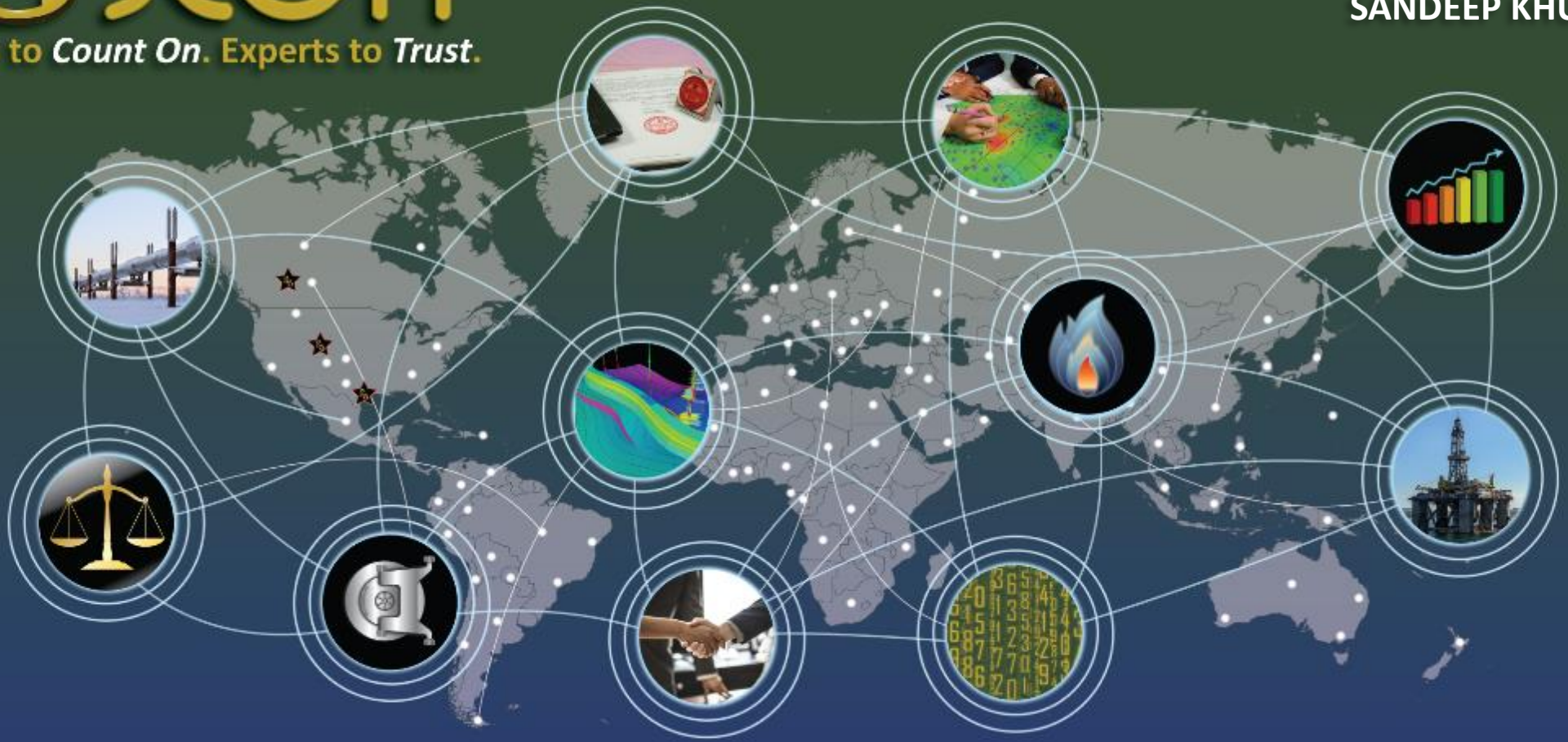
DEEPWATER DEVELOPMENT ENABLERS

"PROMOTING FROM CONTINGENT TO RESERVES"

SEPTEMBER 2020

SANDEEP KHURANA, P.E.



Geosciences Certifications Reserves Evaluation Reservoir Simulation Reserves Audits

Management Advisory Litigation Support Integrated Field Development Studies Enhanced Oil Recovery

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ABSTRACT

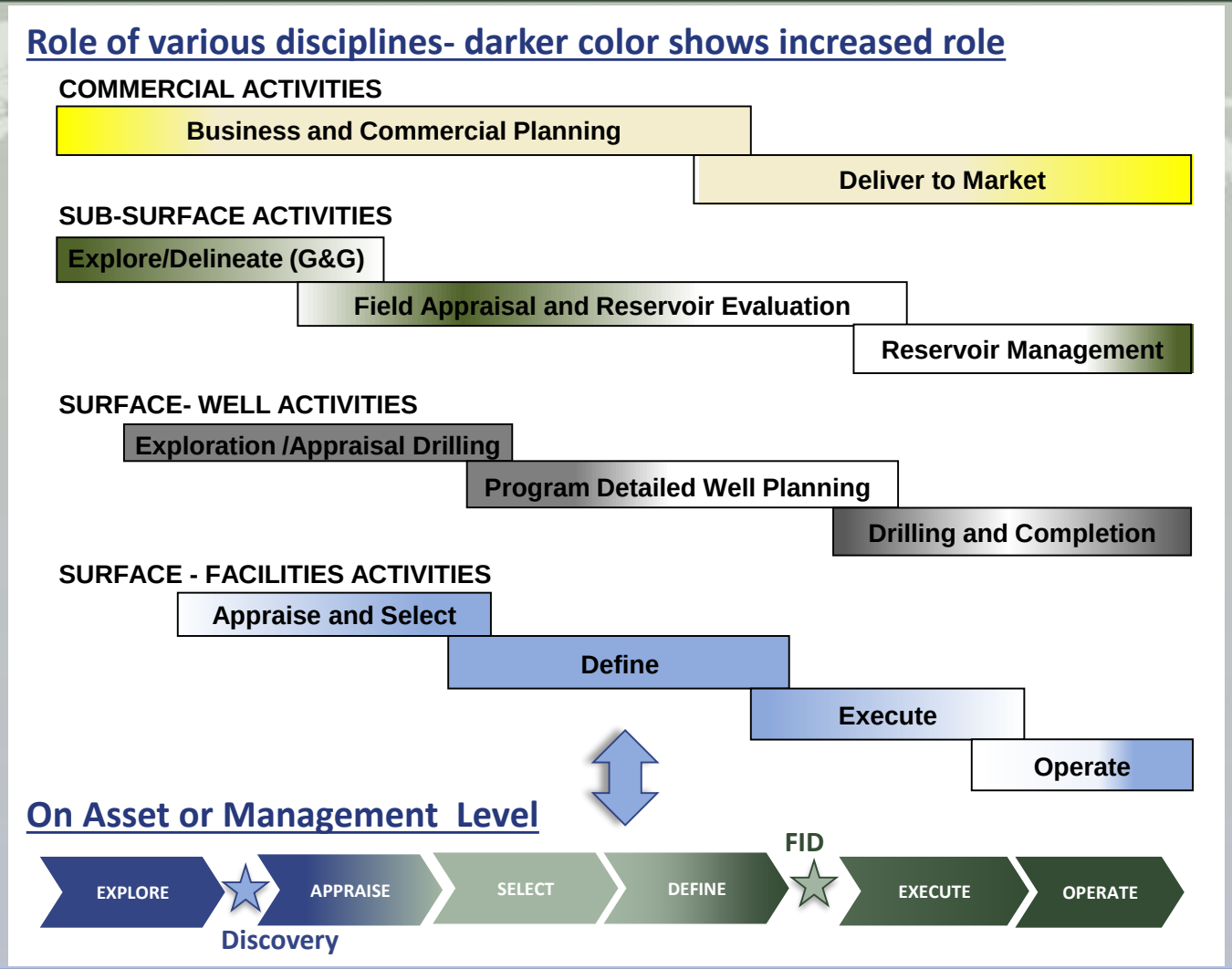
- This presentation covers best practices, cost reduction strategies with new technologies, and creative commercial solutions that have made, and will continue to make, deepwater profitable and sustainable in this wildly fluctuating and rather depressed commodity prices.
- It provides insights in the evaluation, assessment, and development planning to generate value in deepwater.
- Aspects covered:
  - Industry best practices in development providing baseline for investment profile
  - Cost reduction strategies and new enabling technologies.
  - New trends and commercial arrangements in the deepwater infrastructure.

TOPICS COVERED

Part I: Development Planning versus SPE-PRMS	Relating “Best Practices” of Project Planning from Discovery to FID with SPE-PRMS 2018
Part II – Cost Assessments and Reduction	Assessing development costs and strategies to reduce breakeven development cost ($/boe)
Part III- Deepwater Infrastructure Financing	New Commercial Arrangements for Deepwater Infrastructure
Part IV - Conclusion	“The future is not what is used to be”

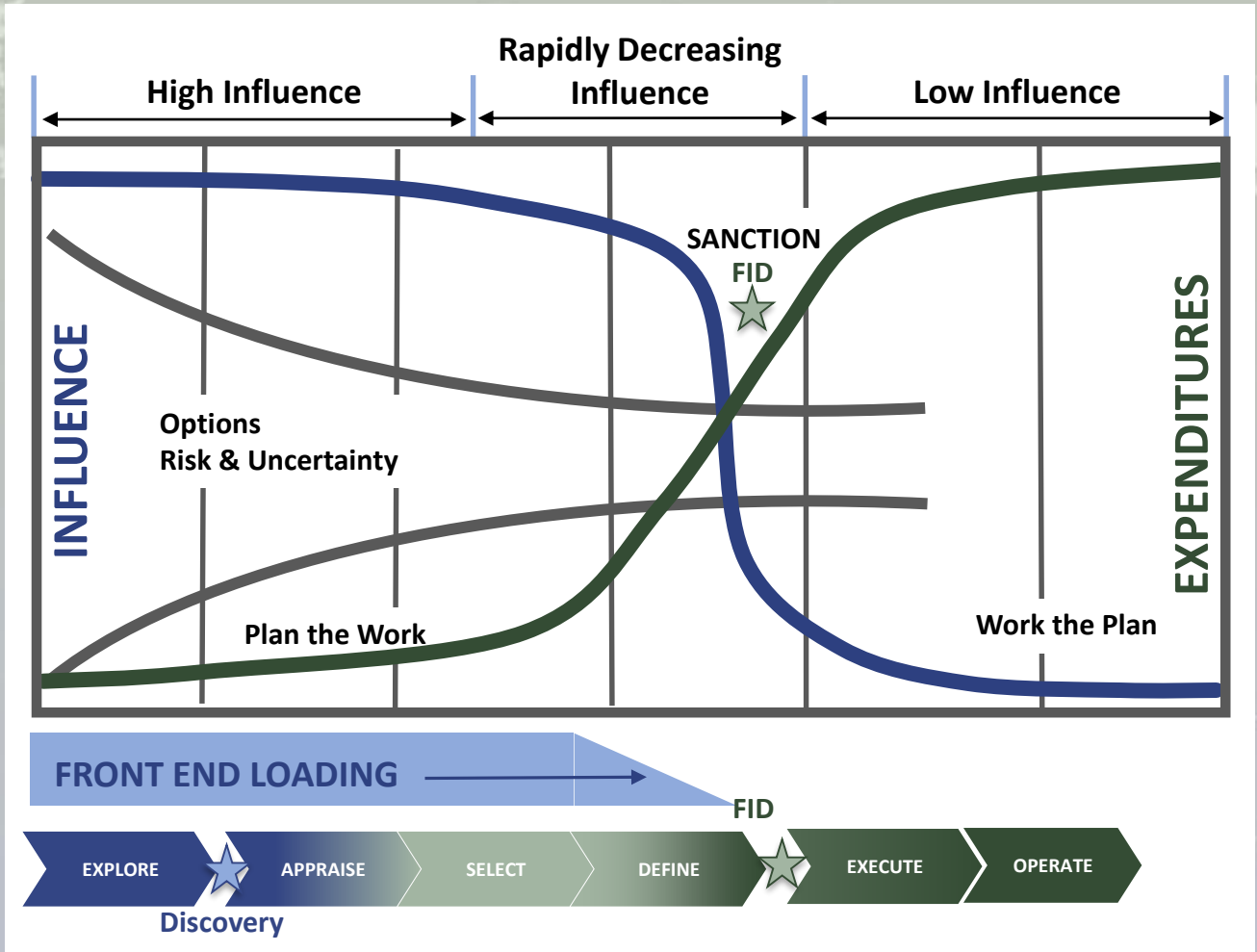
BEST PRACTICE

- A best practice is “an optimal way recognized by industry to achieve a stated goal or objective”
- Creating value by aligning multi-disciplinary teams Commercial; Sub-Surface (G&G/Reservoir); and Surface (Wells and Facilities)



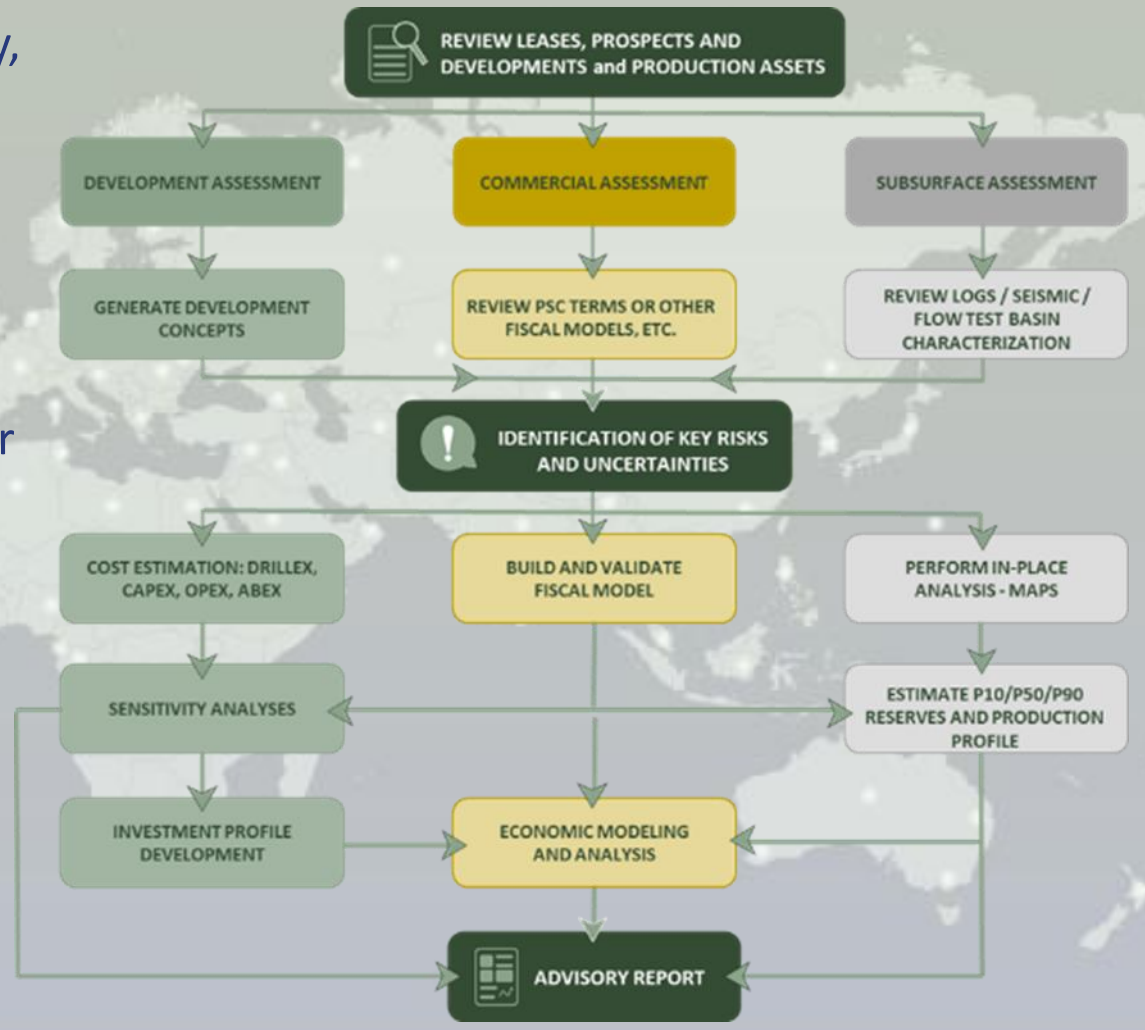
FRONT END LOADING (FEL)

- Discovery to Final Investment Decision (FID) is commonly referred to as Front End Planning or Loading, a stage for an oil company where they have the highest influence and lowest expenditure exposures
- The company works to characterize Uncertainty (in reservoir) and Risks (Project Development) to keep narrowing it to arrive at FID



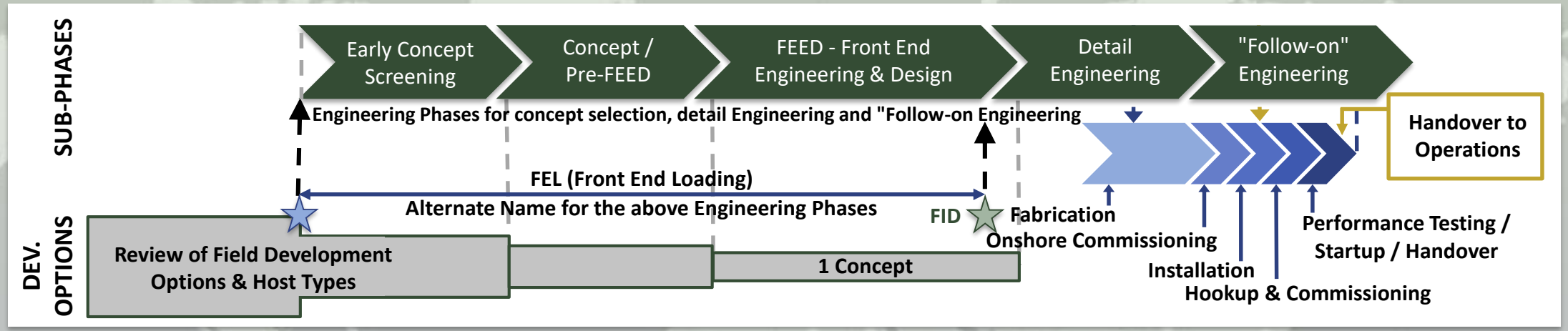
ALIGNING WORK STREAMS

- **Sub- Surface** work-stream reviews basin geology, and reservoir engineering work. The main objectives is to generate the product flow-streams that feed into the facilities in order to monetise the hydrocarbon resources.
- **Surface Development** engineering work-stream review the drilling, facilities, and project plan. Project plan entails review of major contracts for project in place. It also addresses regulatory requirements and permits. The objective is to assess the schedule and costs input into the economic model.
- **Commercial** work-stream reviews the fiscal regime, production sharing arrangements, etc. The objective is to assess the commercial parameters and assumption within the business case.

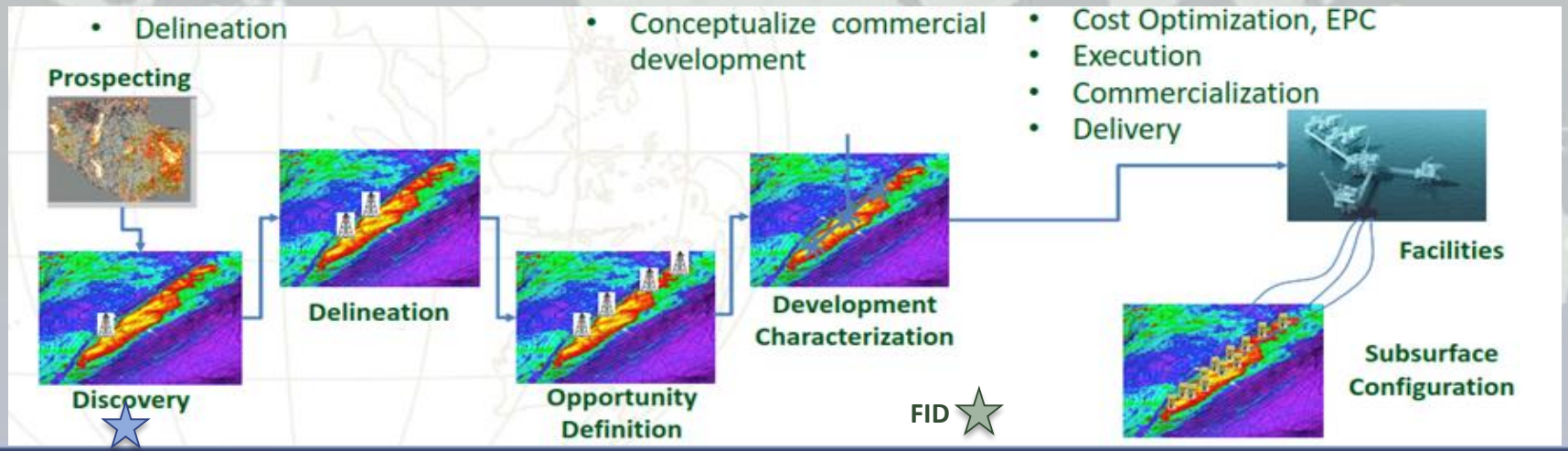


TECHNICAL VIEWPOINT

Surface View

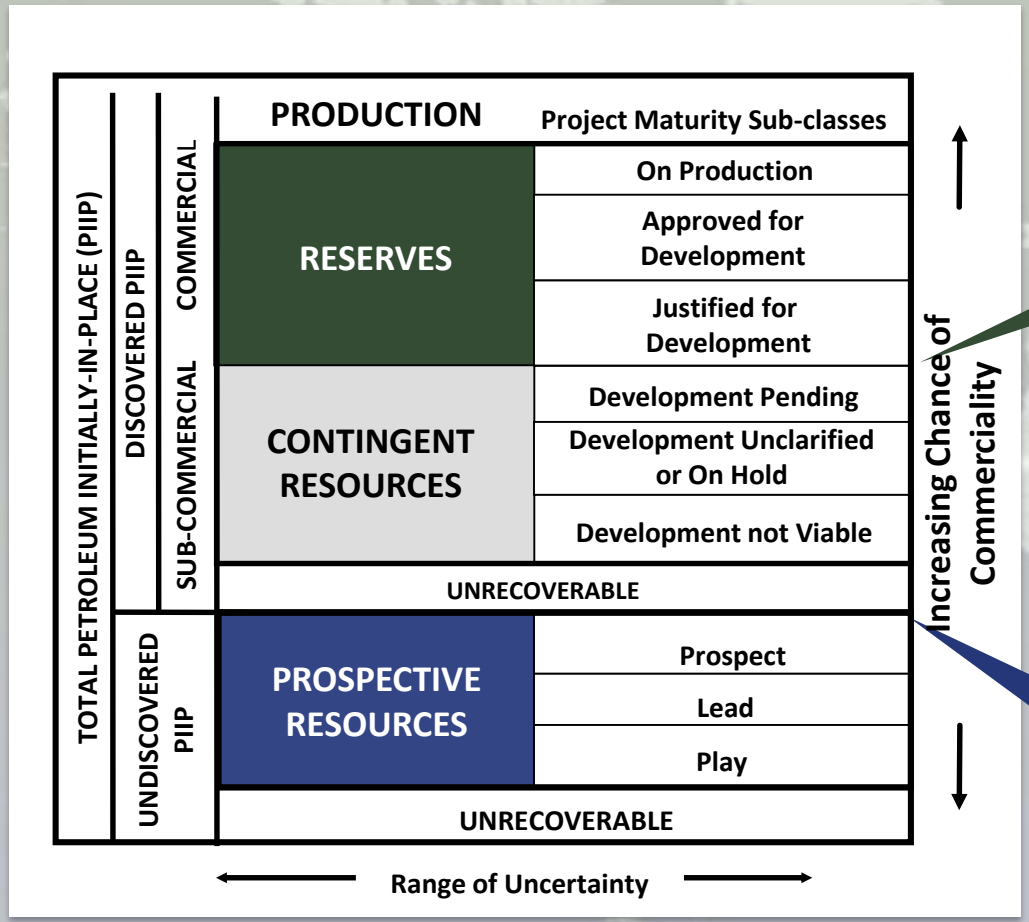


Sub-Surface View



SPE-PRMS 2018 ON PROJECT MATURITY

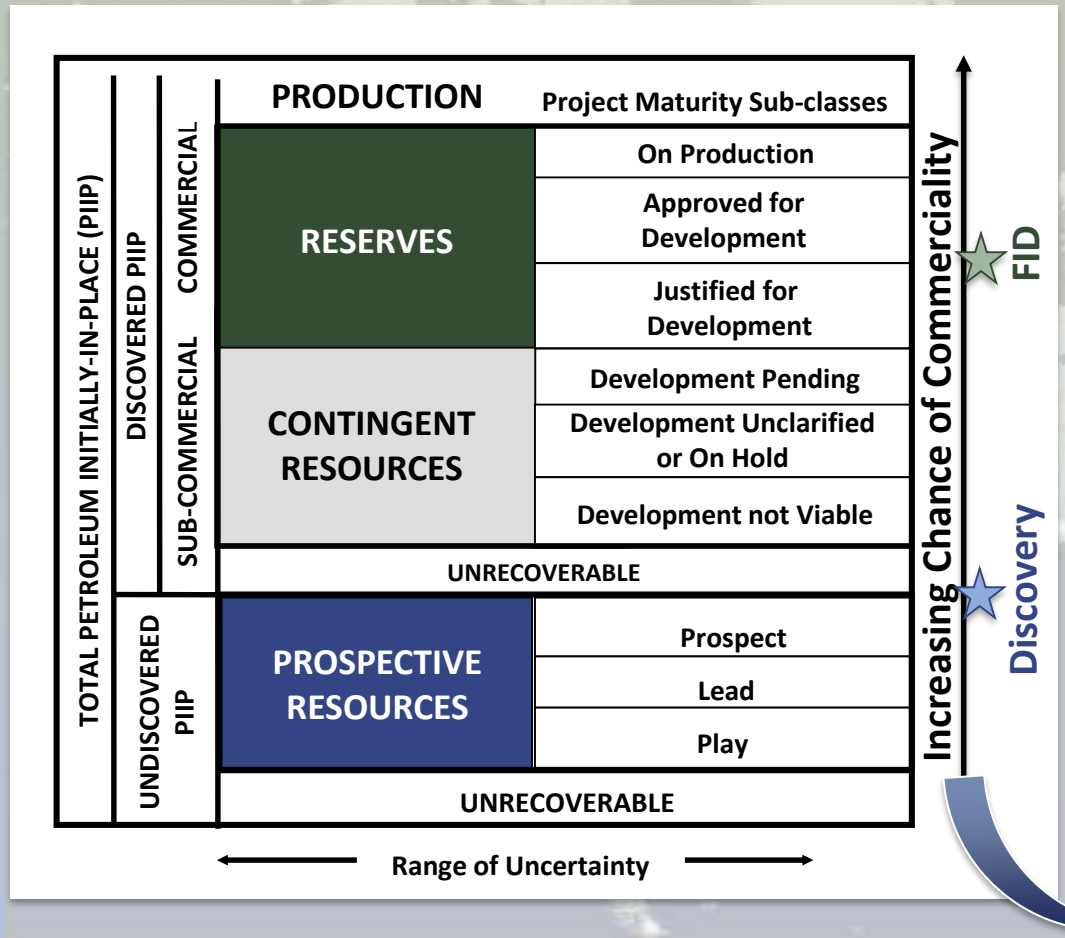
SPE PRMS Figure 2.1—Sub-classes based on Project Maturity



- Project Maturity with chance of commerciality on one axis
- Range of uncertainty of on the other axes
- Discovery and Commerciality are well defined
- FID (Final Investment Decision) is left to the Operator. Excerpts from PRMS
  - 2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves.

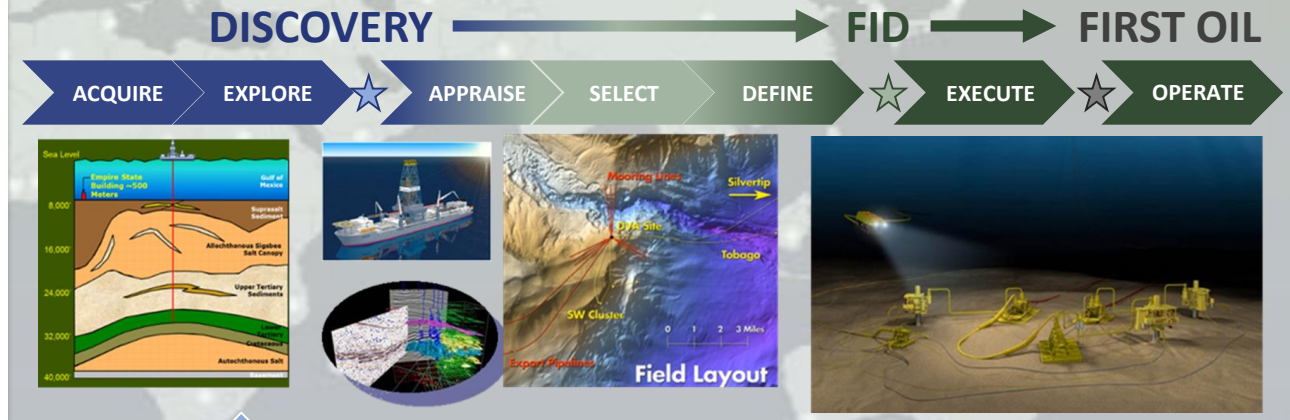
SPE-PRMS VERSUS DEEPWATER DEVELOPMENT

SPE-2018 PRMS Figure 2.1

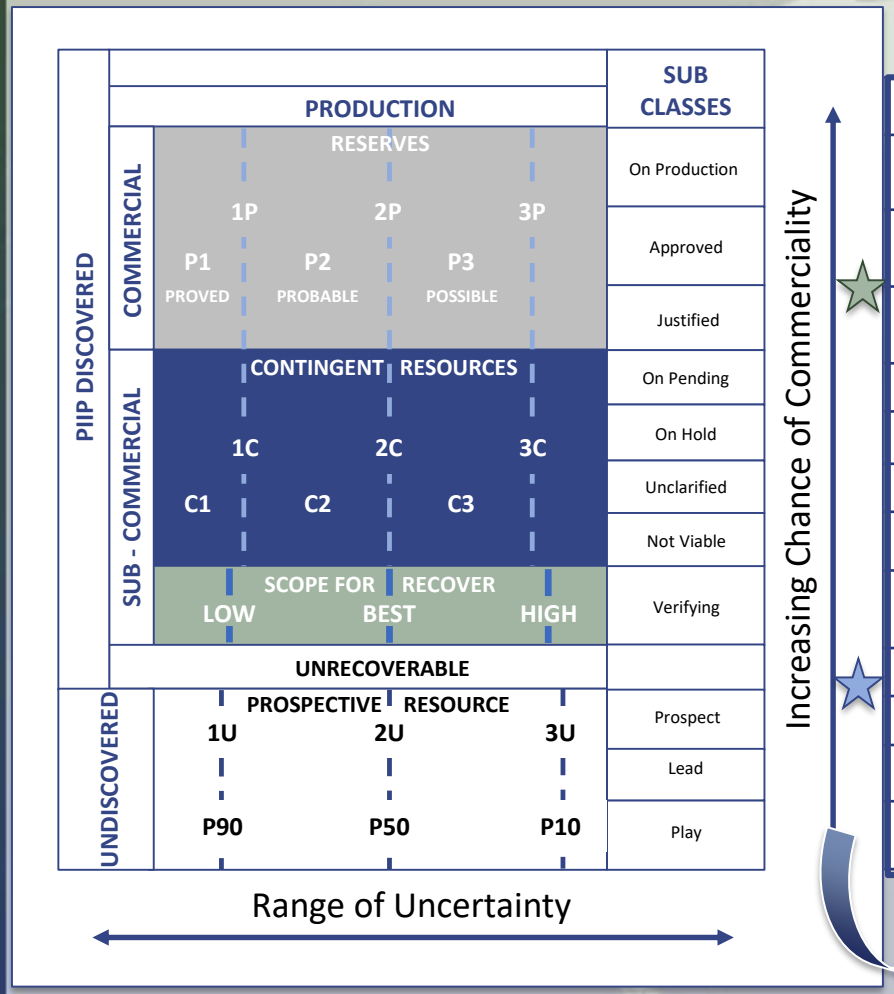


Deepwater Development

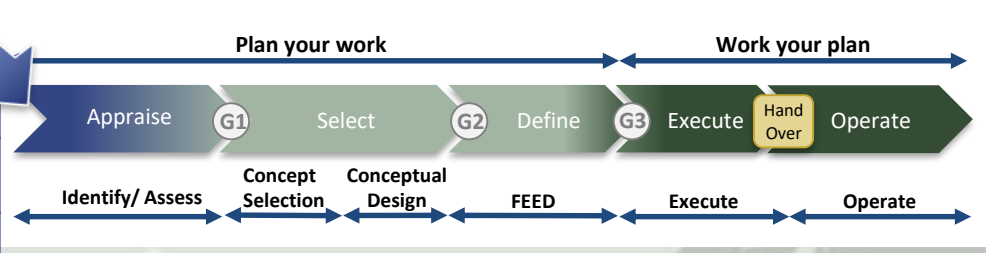
- Increasing Project Maturity is on horizontal axis
- Major Industry Milestones are Discovery, Final Investment Decision (FID), and First Oil



MAPPING- A CASE STUDY



Project	STATUS
Operate	Developed
Post G3	Undeveloped Project Awarded
Post G3 (Commitment)	Undeveloped EPC Progress
Post G2 / Pre G3	FEED Progress
Post G2 / Pre G3	FEED on Hold
Pre G2	Undeveloped
No activities @ G	Undeveloped
Pre-Project	Undeveloped
Commercial Dev.	Undiscovered
Feasible Dev.	Undiscovered
Hypothetical Dev.	Undiscovered



- We did mapping to SPE-PRMS for Client's project maturity to maximize cash flow and protect investors by incorporating "Scope for Recovery"
- Decision Gates (G) were directly linked to Project sub-classes and maturity Status
  - Committed Projects (Reserves) Post DG3 w/ FEED (CAPEX defined)
  - Project under investigation (Contingent Resources)- DG2 to DG3
  - Conceptual Project (Scope for Recovery)

PART II- COST ASSESSMENTS & REDUCTION

Part I: Development Planning versus SPE-PRMS	Relating "Best Practices" of Project Planning from Discovery to FID with SPE-PRMS 2018
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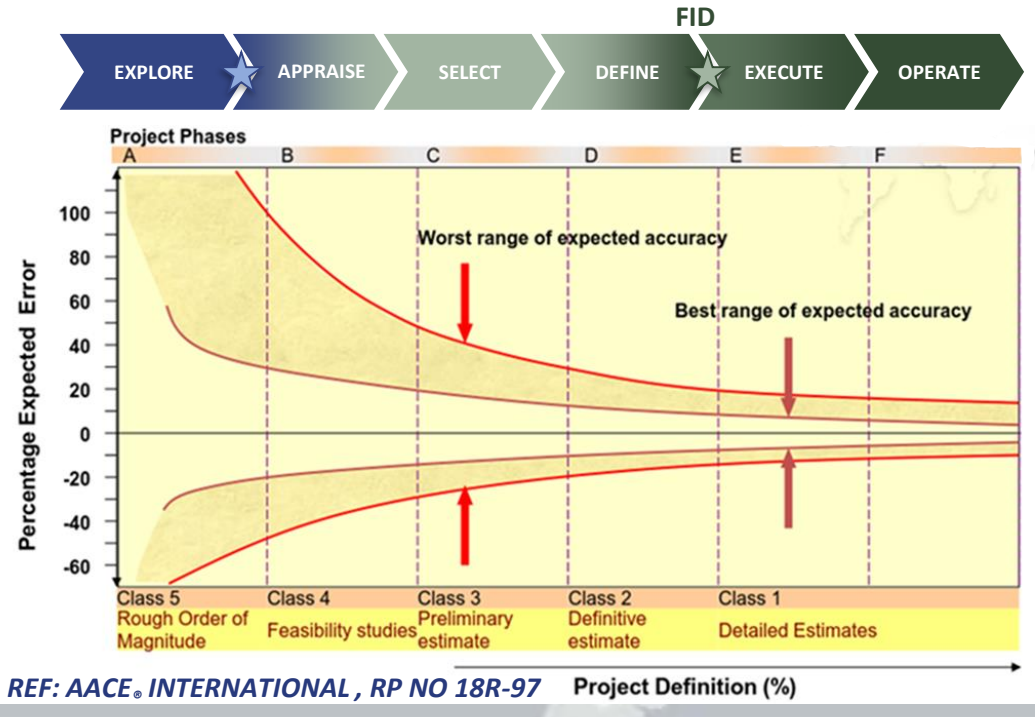
COST AND SCHEDULE ASSESSMENT

Aligning Project Maturity with Definition to generate the desired cost accuracy



REF: AACE® INTERNATIONAL, RP NO 18R-97

Schedule Type

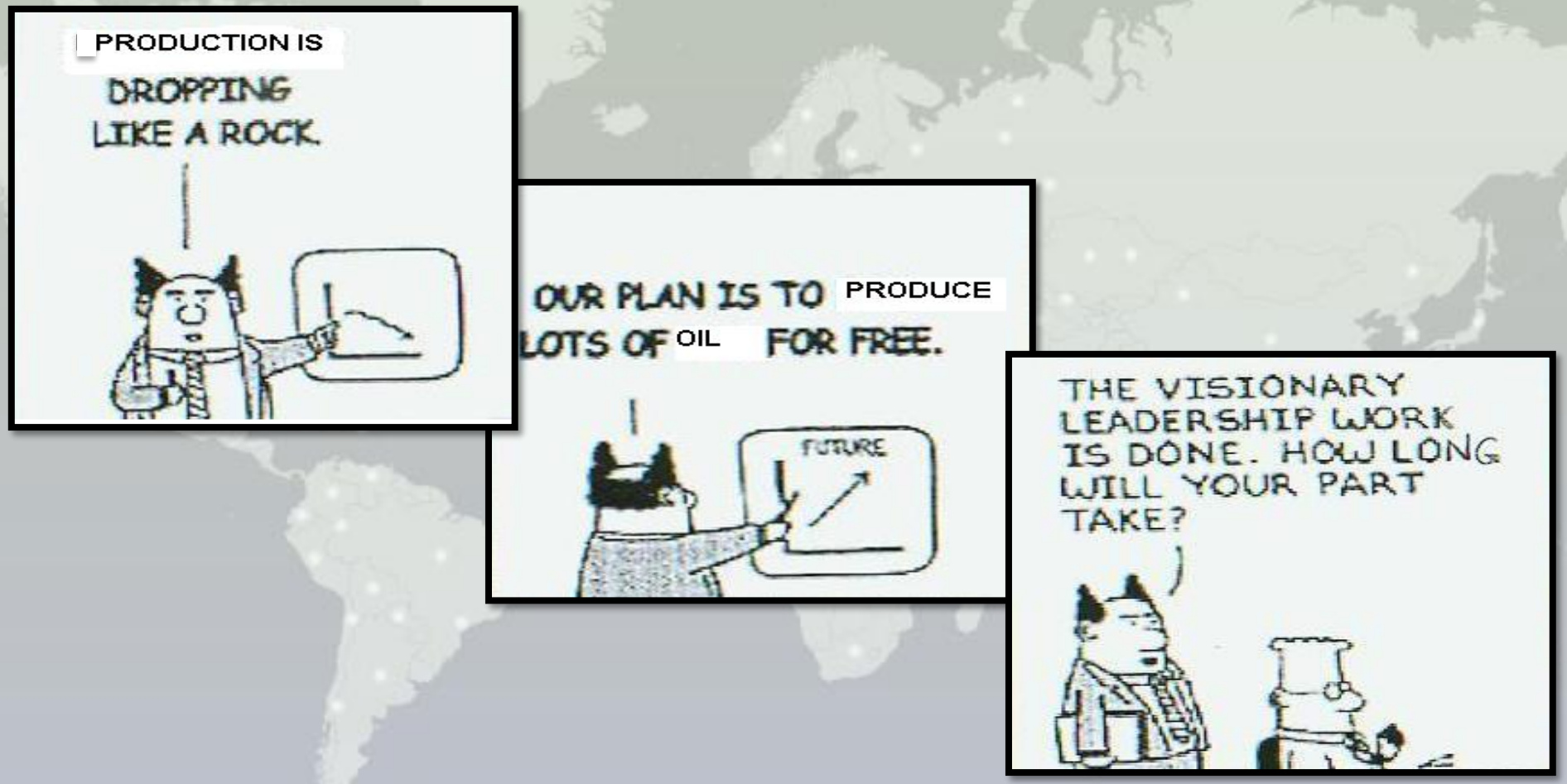
Level 1 → Level 2 → Level 3

Work Plan and Cost Estimating Model

Appraise	G1	Select	G2	Define	G3
• Develop reservoir models and define the possible development strategy • Identify preliminary development alternatives and quantify the expected economic value		• Generate and screen alternative concepts • Evaluate screened concepts and select preferred option • Develop conceptual design for selected concept		• Define the selected concept through basic engineering / FEED • Finalize the Project Execution Plan • Prepare tender documentation for project execution LLIs	
Cost Accuracy	**±50%**		**±30%**		**±15%**

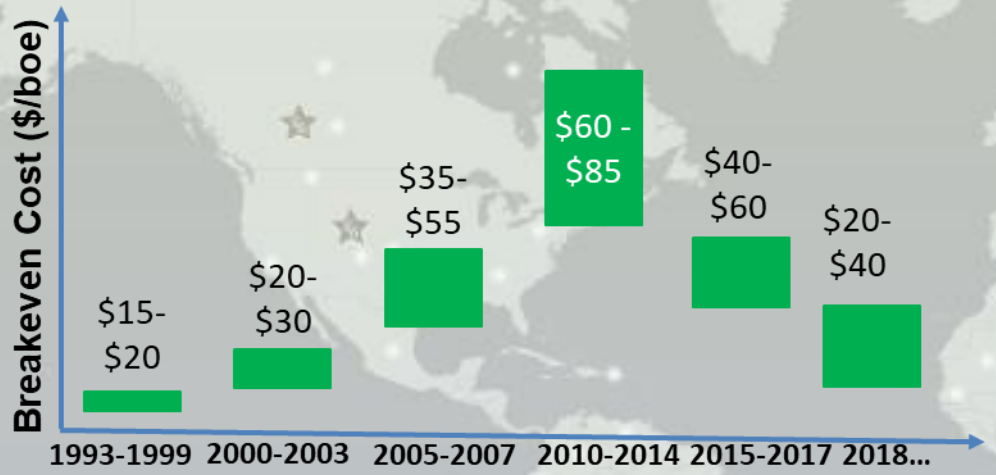
Project Definition (%)

COST REDUCTION



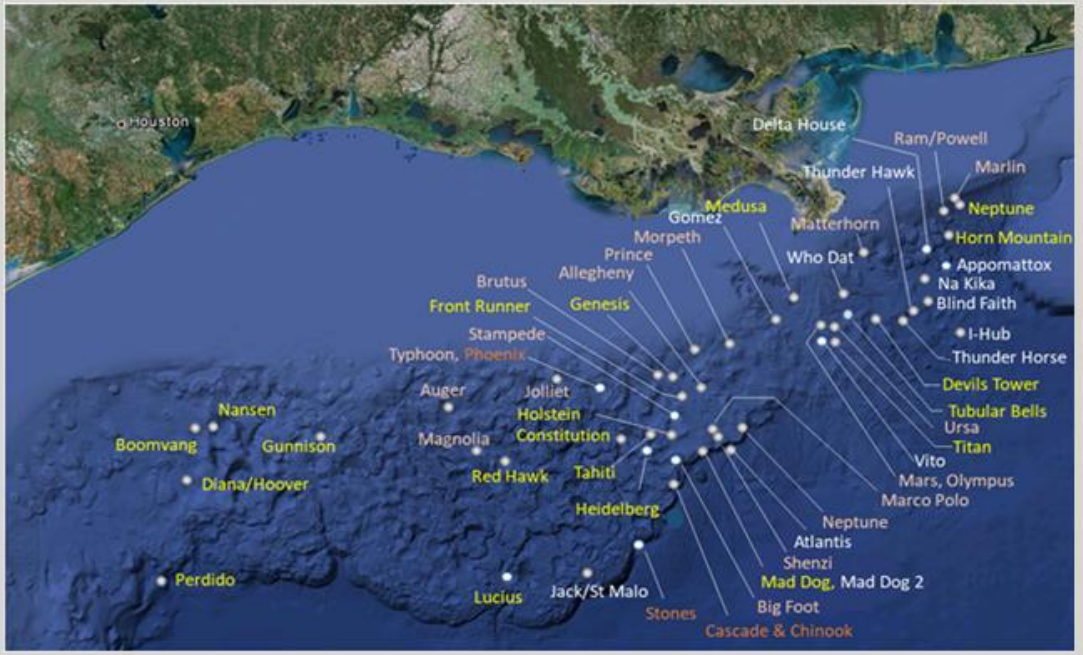
GOM CASE STUDY
FLOATING PRODUCTION SYSTEMS (FPS)

FPS sanction activities can be broadly divided into six phases based on number of projects sanctioned and recent efforts to reduce breakeven oil price of sub-$30



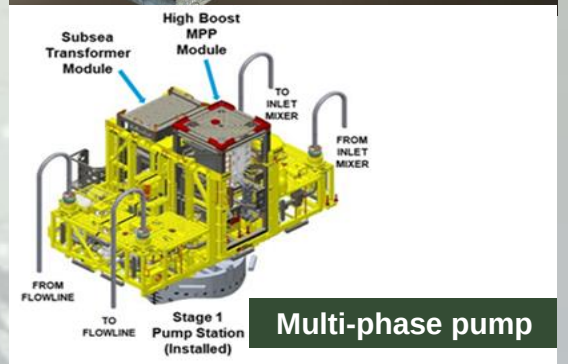
- Evolution 1993-1999: Low Capex inflation
- Exuberance 2000-2003: Supply chain extended
- Inflation 2005-2007: Capex inflation matches WTI
- Hyper-Inflation 2010-2014: Capex inflation above WTI
- Correction 2015-2017: Capex Reduction
- Innovation 2018...: A Step Change

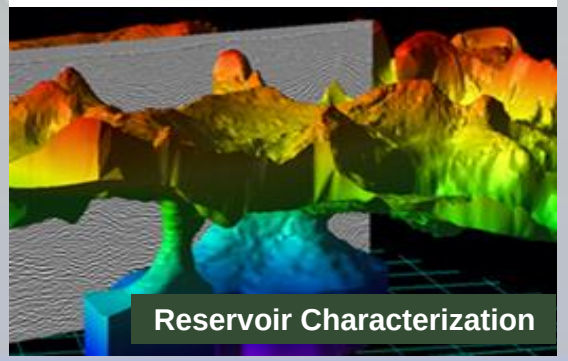
From 1993 to date there have been fifty-two (52) floating production systems (FPS) sanctioned in the GOM.

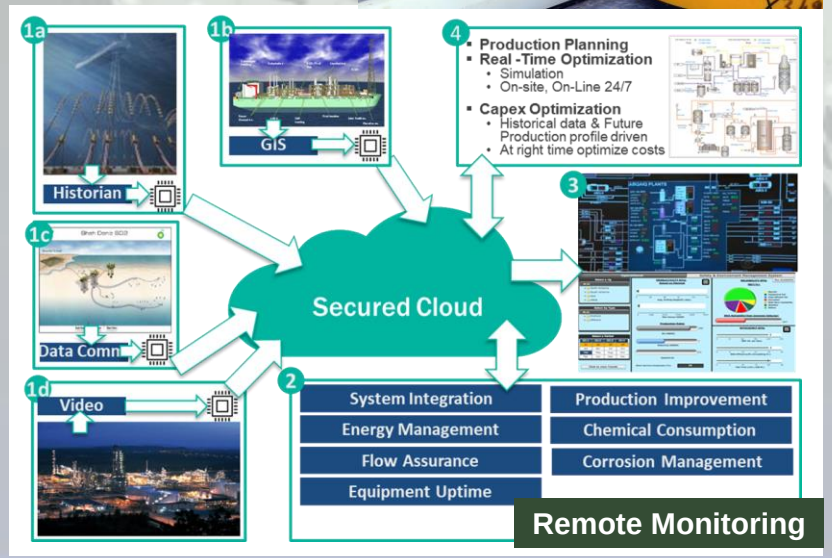


INNOVATION AND TECHNOLOGY

- Reducing Project Complexity
- Factory approach via standardization
- Long Tie-back fields/reservoirs
- Digitalization- Remote monitoring
- Coming up
  - 20K psi (CVX Anchor Field)
  - Seismic Technology e.g.
    - Ocean bottom nodes
    - Advanced Processing





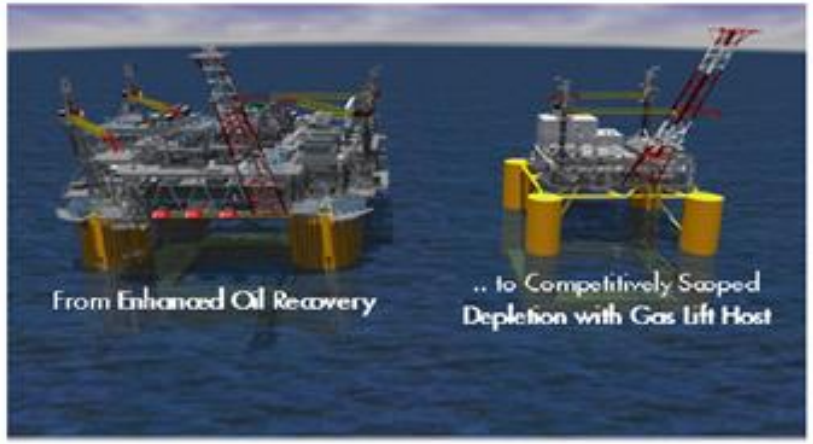


REDUCING PROJECT COMPLEXITY

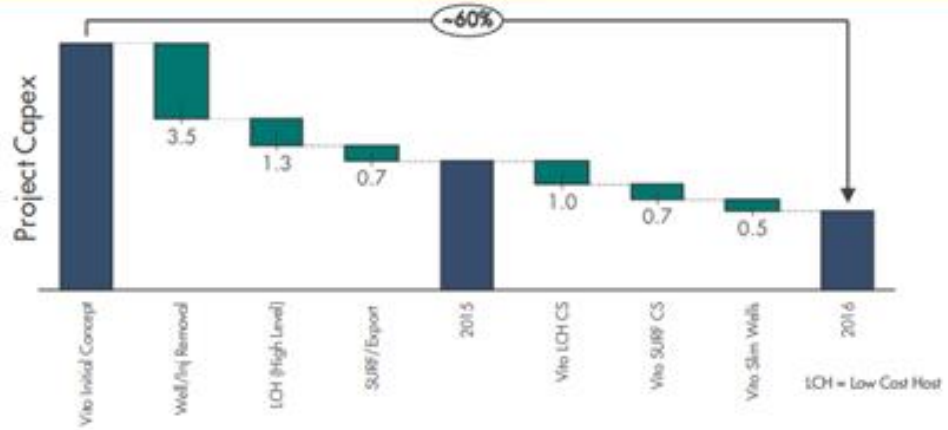
- Optimizing development plan in increasing water depth and drill depth
- Standardization of development solutions

Case Study - Shell Vito (Source: Feb 2018 MTS Presentation)

1 Project Concept: Simple = Cheaper



2 >60% Cost Reduction: Through Competitive Scoping



3 Further Cost Reduction: Through competitive benchmarking and leveraging partners

4 Re-invented Project: Focus on value levers with strong team integration and stakeholder engagement

STANDARDIZATION

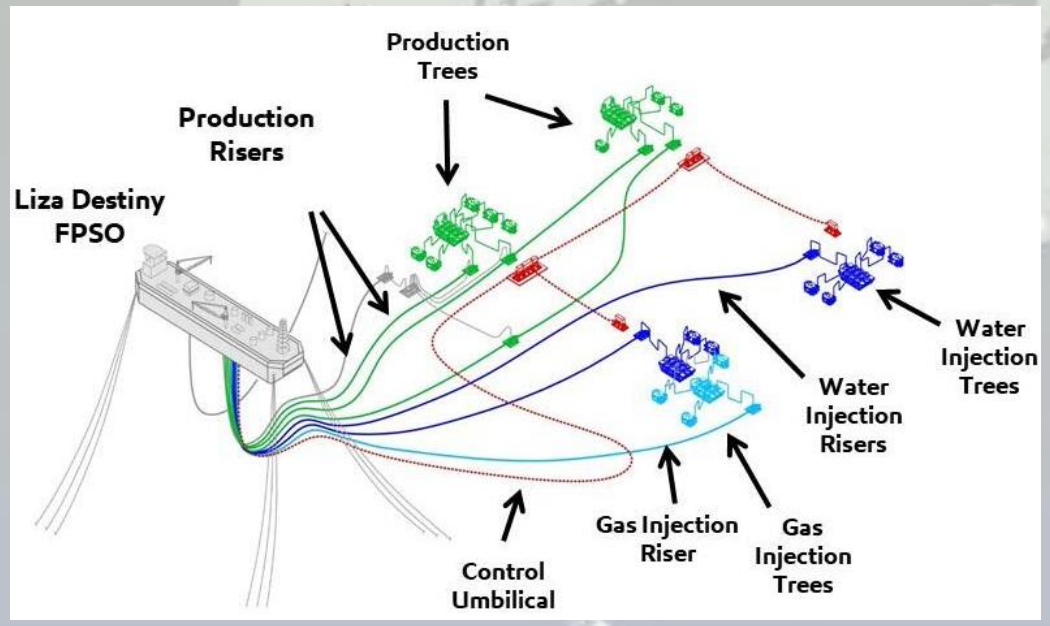
- In 2005 ExxonMobil “Design One, Build Two” FPSOs in Angola to leverage their upfront engineering costs and project management teams (PMT).
- This became a repeatable model “Design One Build Many” applied now in Guyana with SBM as FPSO supplier. SBM FPSO standardization offering fast track delivery & lower CAPEX.

DEEPWATER VERSUS UNCONVENTIONAL

Per HESS Nov 2019 Slides

- ~$35/bbl Brent breakeven for Liza Phase 1, ~$6/BOE development costs
- ~$25/bbl Brent breakeven for Liza Phase 2, ~$7/BOE development costs

Guyana Liza Phase I Development Plan (from XOM)



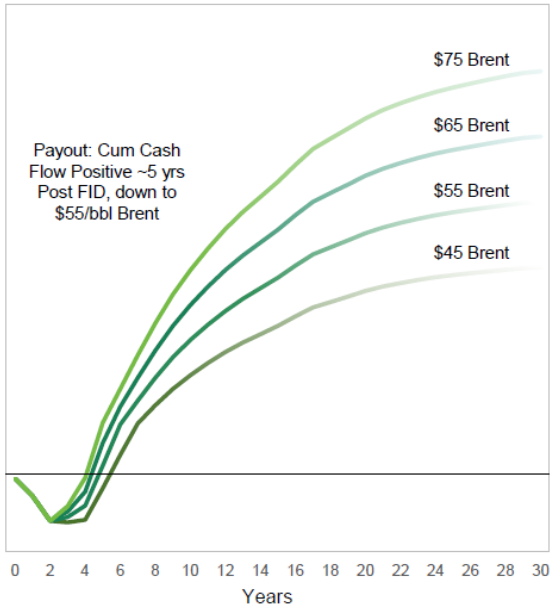
HESS BOA Merrill Lynch- Global Energy Conference Nov 2019

Guyana: Stabroek Block

Low development costs and outstanding financial returns…

	Guyana Liza Phase 1 Development[1]	Delaware Basin Illustrative 50,000 Net Acre Development[2]
Peak Production	120,000 BOED	120,000 BOED
Peak Production Oil	120,000 BOD	90,000 BOD
Initial Investment to Peak Production	3 years	10+ years
Reservoir Quality	Multi Darcy	Micro Darcy
Total Production Wells	8	1,500
Avg. EUR / Production Well	~63 MMBO	~1.1 MMBOE ~0.7 MMBO
Development Capex	$3.7 Billion	$12.8 Billion
Unit Development Costs	~$7/BO ~$6/BOE	~$12/BO ~$8/BOE
Cost Environment	Deflating/flat	Inflating
Required WTI price for 10% Cost of Supply[3]	**~$30/bbl**	**~$40/bbl**

Liza Phase 1 - Cumulative Cash Flow



Liza Phase 1 offers breakevens superior to premier U.S. shale plays

EXTENDING TIEBACK DISTANCES

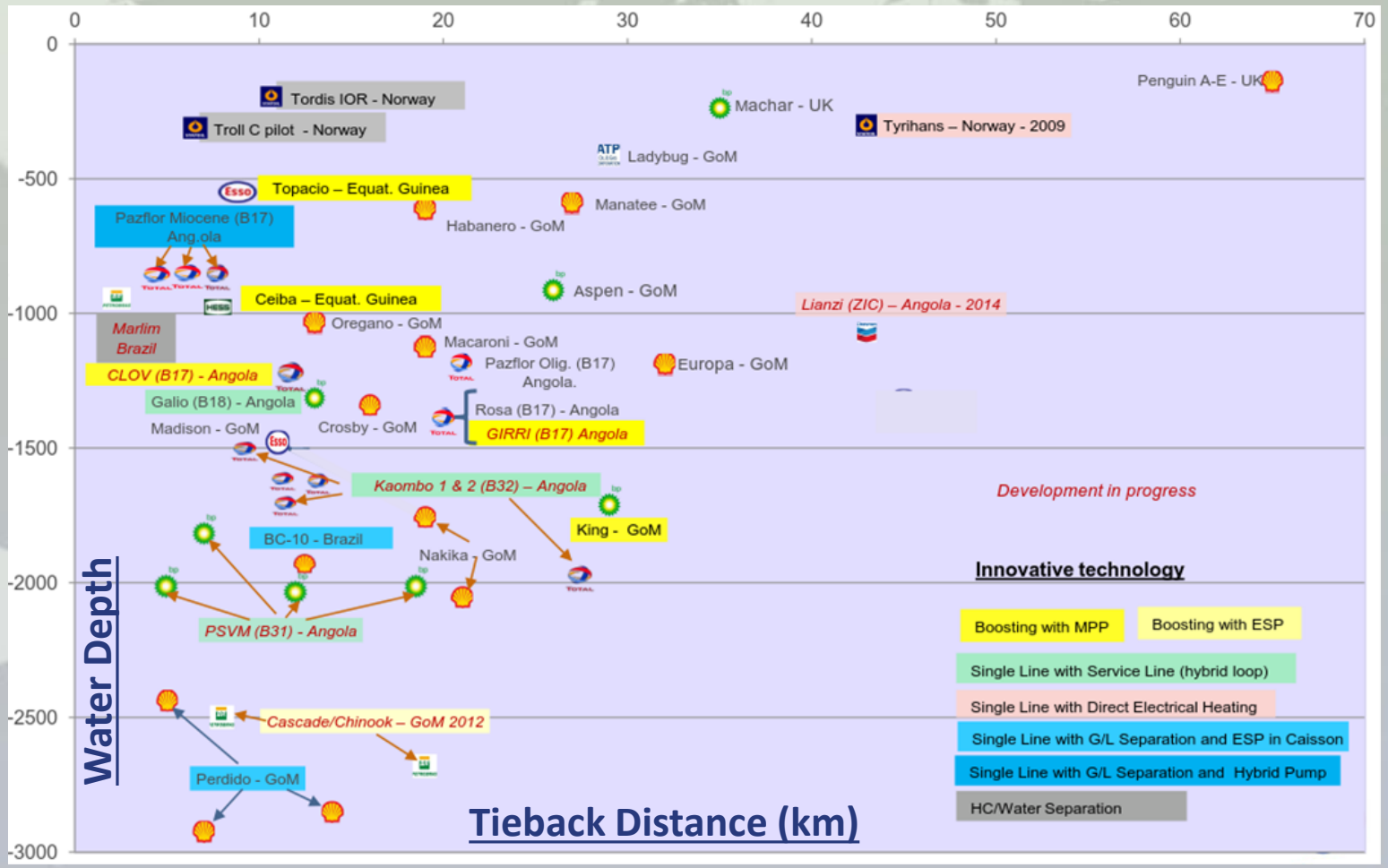
Accomplished but being honed:

- Boosting with multi-phase pumps
- Gas Liquid Separation and ESP in Caisson

In Progress

- Single Line with Direct Electrical Heating
- Subsea Separation

Subsea Tiebacks Increasing Lengths (Source: Total 2017)

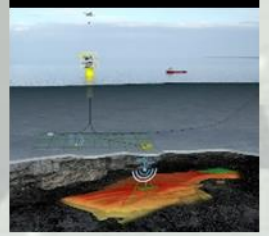


DIGITALIZATION

- Low-Manned Platform in North Sea to Normally Unmanned Installation (NUI) are becoming a norm with remote monitoring.
- Equinor digitalization for future-fit portfolio states
  - New concept compared to conventional facility and robotics could reduce CAPEX by 30% and OPEX by 50%
  - Automated drilling compared to conventional reducing cost by 15%

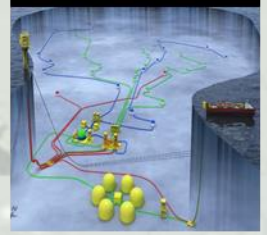
Equinor ROF Remotely Operated Factory (Source: MTS Presentation Feb 2017)

Peon



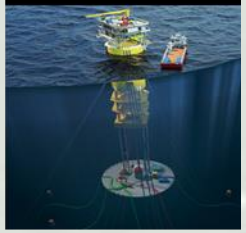
Stand alone gas/condensate development

UK and Barents



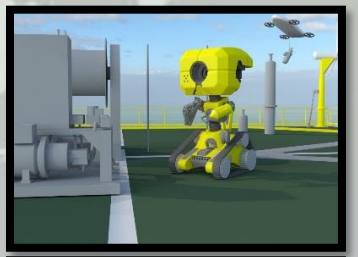
Stand alone remote oil and gas field developments

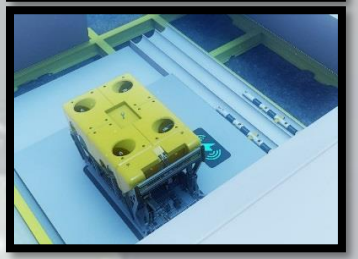
Brazil



Ultra deep water UPP™

Robotics





Field of the future potential

Capex	Opex
-30%	-50%

Automated drilling potential

Cost
-15%

PART III - INFRASTRUCTURE FINANCING

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★ Part III based on OTC-30806-MS Private Equity Financing and third-party infrastructure: Future Enabler by Khurana, Wilson, etc.

DRIVERS

Basins with pipelines to the market

- As pipelines proliferated, pipeline companies entered into contractual ownership of transportation systems using simple tariff models i.e. take or pay contracts.
- Fluctuating commodity prices and rising infrastructure costs in deepwater developments, challenged operators to create win-win scenarios to balance risk and rewards.

Progression in Remote Basins

- Historically E&P operators purchased FPSOs to develop a field.
- As fiscal regimes in countries evolved often through production sharing contracts/agreements (PSC/PSA), operators often moved to lease arrangements through the service providers.

GOM MULTI-OPERATOR APPROACH

- **In 2005** Anadarko (now OXY) pioneered the multi-operator approach in the GOM with Independence Hub with ownership of FPS by 3rd Party
- Immediate followers were Marco Polo, Devil's Tower, Thunder Hawk FPS
- **In 2014** as a Repeatable Model: HESS for Tubular Bells had facilities agreement with Williams Partners (includes Marubeni) to construct and operate Gulfstar 1 FPS and related export pipeline system.

Independence HUB 2005 Financing Model

Overview 1

- **Atwater Valley Producers group** and **Enterprise Products Partners (EPP)** finalized agreement to develop deepwater nat. gas discoveries (2004)
- Utilized "multi-operator" approach w/ infrastructure owned by midstream company to develop "stranded" deepwater gas
- Capital cost:
  - $413M for FPS
  - $280M for export pipeline

Key Players 2

- Key investors:
  - **Andarko & field owners**
    - Independent E&P
    - Hub facility for various gas fields
  - **EPP**
    - Midstream company
    - Focus on pipelines
  - **Helix Energy Solutions**
    - Subsea construction & offshore service company

Anadarko Petroleum Corporation

HELIX ENERGY SOLUTIONS | Enterprise Products Partners L.P.

Project Financing 3

Infrastructure investment

- EPP owns the export pipeline and 80% of the host facility
- Helix Energy Solutions owns 20% of the host platformrm
- Anadarko will operate the platform and owns largest % of wells

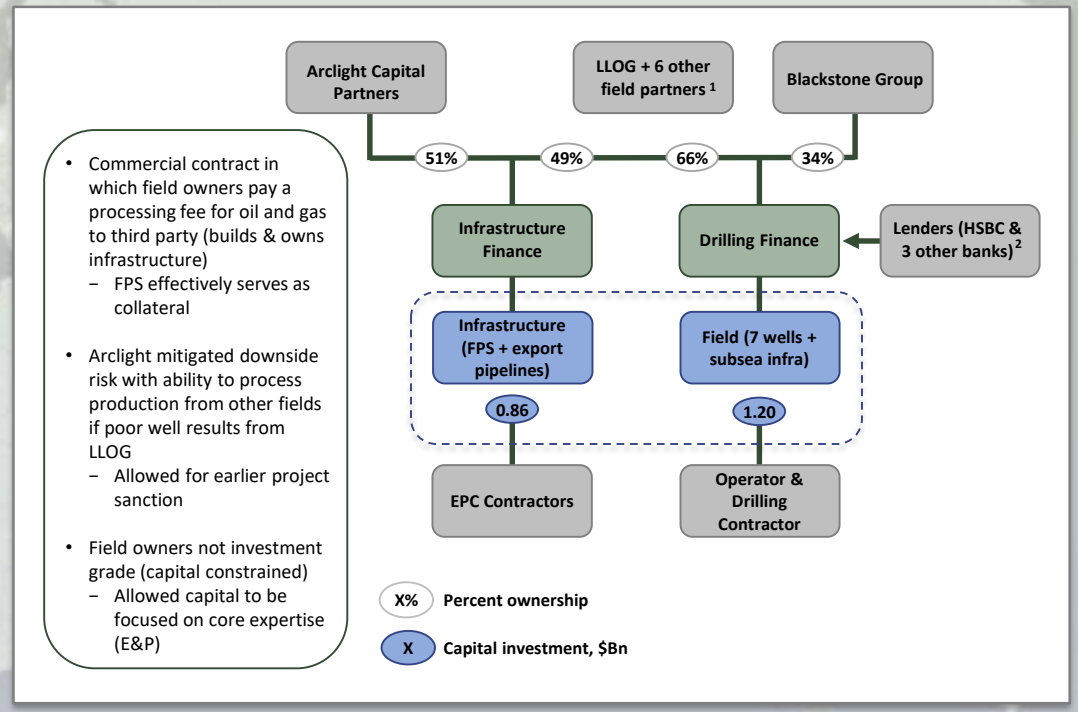
Advantages

- EPP earned volumetric fees from platform and pipeline in addition to monthly demand fees from the hub
- Reduces upfront capital cost burden on the operator – allowing them to focus expertise on E&P

EVOLVING PRIVATE EQUITY (PE) AS 3RD PARTY INFRASTRUCTURE OWNERSHIP

- In 2015, a large drop in commodity prices created the right environment for PE investments in FPS infrastructure
- LLOG brought PE firm Arclight to provide equity and debt financing.
- A tiered processing fee structure assures ArcLight of a reasonable return on the low end of the reserves range, and producers will not have to overpay under high reserves scenario.
- Trend continues with Murphy operated fields with King's Quay FPS to come online in 2022.

Financing Model



- Commercial contract in which field owners pay a processing fee for oil and gas to third party (builds & owns infrastructure)
  - FPS effectively serves as collateral
- Arclight mitigated downside risk with ability to process production from other fields if poor well results from LLOG
  - Allowed for earlier project sanction
- Field owners not investment grade (capital constrained)
  - Allowed capital to be focused on core expertise (E&P)

REMOTE BASINS

- Multiple Potential Transportation Solutions: Concept selection is driven by many variables, notably; existing infrastructure as well as the ultimate desired destination of the resources
- The remoter the resource the more is shift to FSO or FPSO

Pipeline Installation

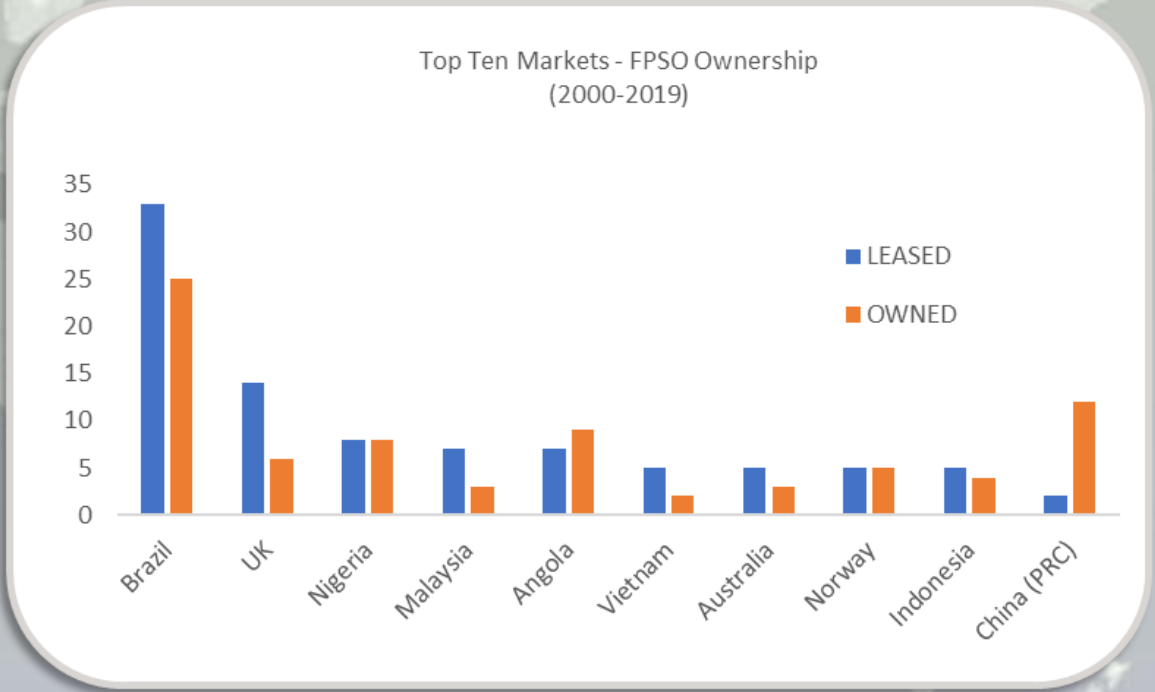
FSO

FPSO

GLOBAL FPSO OWNERSHIP TRENDS

- **1980s:** Oil companies designed and built their FPSOs under contracts with shipyards e.g. PP Moraes, Seillean and others in the Campos Basin Brazil
- **1990s:** The model shifted to leasing in this sphere. Shell was the first operator to start leasing FPSOs from Service Providers in the 1990s but the trend has grown stronger over time, especially among majors.
- **Decision Criteria:** Is Pendulum swinging to Leasing?

Ownership decisions in 2000-2019
Brazil had more leased vs. owned versus Angola



NEW FPSO FINANCIAL MODELS

Challenges for Service Company

- Minimal FPSO residual value in case of early termination.
- Ability to redeploy FPSO, however, redeployment requires field matching and many times a high upgrade cost (CAPEX).

Redeployment Case Study

- Murphy Azurite FPSO lease 2009 to 2016 with extension option to 2024 was released in 2014 to BW Offshore.
- BW Offshore took the opportunity re-deploy “Adolo FPSO” by refurbishing it for Gabon Duffasu Project for 1st oil in 2018 where BW Energy invested in the operatorship of the E&P field.
- BW Energy is now using this repeatable model for Maromba Brazil with re-deployment of BWO’s Berge Helene.

Azurite FPDSO to Aldo FPSO

PART IV- CONCLUSIONS

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LOWERING BREAKEVEN COSTS…

- Continuing cost reduction with digitalization leading to unmanned platforms.
- Expected increase in automation across the value chain.
- Lower-risk, higher-return subsea tiebacks will grow in matured basin e.g. infrastructure led exploration (ILX).
- Service providers will continue to reduce CAPEX with standardized equipment- “pre-designed with industry standards and ready to deploy”

SIGNS OF COMMERCIAL FUTURE….

- PE taking on both sides, E&P and Infrastructure, in the GOM to connect the chain for smaller, quick-turnaround developments.
- Monetizing existing infrastructure by bringing in the 3rd-Party ownership with drivers for further expansion.
- Subsea equipment as the next piece of the infrastructure owned by third parties.
- FPSO providers will try to integrate vertically using FPSO fleets to invest in E&P while securing services contracts.

SANDEEP KHURANA

Head Advisor Upstream and Midstream Integrated Services

Sandeep has three decades of global asset and project management experience in the upstream and midstream oil and gas industry with a proven track record of success in leading these developments from discovery through design, execution and operations resulting in maximized production.

Previously he worked for KerrMcGee, Devon, and Noble Corporation, and more recently with service providers such as Halliburton and KBR. He is a Fellow of the Marine Technology Society (MTS) and a board member of the Offshore Technology Conference (OTC).

Sandeep earned a master's degree in 1990 from Rice University. He is a registered Project Management Professional (PMP) and a Professional Engineer (PE) in Texas.

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