Concept Selection
for
Deep Water Field Development Planning

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At
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- 2013-Now: Sevanmarine AS, Senior Naval Architect
- 2009-2013: NTNU, Department of Marine Tech. PhD Candidate
- 2007-2009: IOEC, Head Engineer
- 2005-2007: Fulton Yacht Shipyard, Naval Architect
- 1999-2005: MSc in Offshore Engineering

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Objectives

The main goal:
To introduce a methodology for concept selection for offshore deep water fields development.

- Overview of offshore oil field development planning process.
- Main stackholders.
- Main decision drivers.
- Information and data to be generated.
- Sources of uncertainity and methods to handl them.
- Necessary information for concept selection.
- Structured concept selection methodology.
- An example.
- Questions

Time Table

- **Part I**: Deep Water Field Development Planning (45 min)
- **Part II**: Concept Selection Process(35-40 min)
- **Part III**: Example (35-40 min)

Why This Topic

- My personal concern.
- Was not touch upon properly during my education.
- One of the main challenges for all operators.
- Interdiciplinary task.

What should you expect after this lecture:

- You will be familiar with concept selection process for deep water offshore oil and gas fields.
- This presentation only give you an introduction.
- You will not be a deep water field developer.

Classification Offshore Oil and Gas Fields

To reduce the effort to select proper Technology, Strategies, Cost Estimation Methods for field development.

- **Water Depth (production):**
  - Shallow Water: < 420m (Bullwinkle Jacket)
  - Intermediate Water: 420m - 1000m
  - Deep Water: 1000m to 2000m
  - Ultra Deep Water: > 2000m
- **Environment Condition (100-year):**
  - Harsh Environment: 16 < Hs , 25 < WS (Northsea WOS)
  - Moderate Environments: 8 < Hs < 16 , 15 < WS < 25
  - Benign Environment: Hs < 8, WS<15 (West Africa)

Hs: Significant Wave Height [m], **WS**: Wind Speed [m/s]

- **Reserves Size:**
  - Marginal Reservoirs: Reserves < 75 mmboe
  - Medium Size Reservoirs: 75 < Reserves < 175 mmboe
  - Large Reservoirs: 175 < Reserves < 1500 or larger

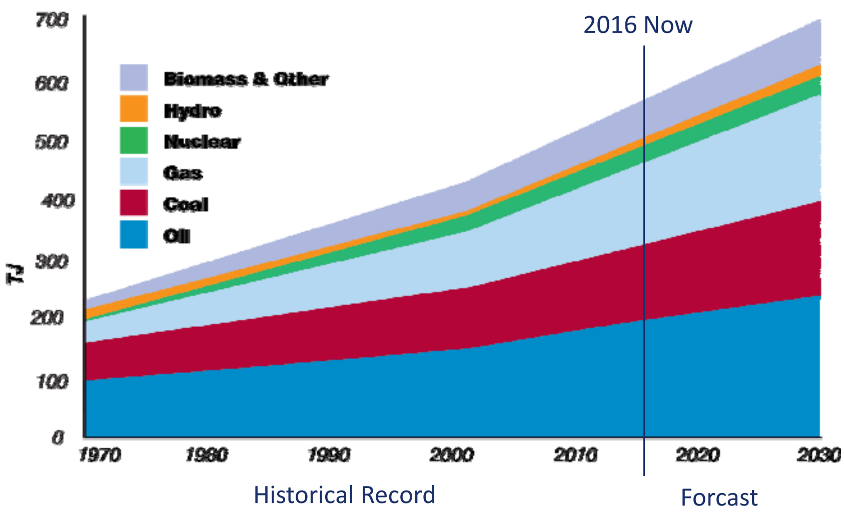
Classification Offshore Oil and Gas Fields

To reduce the effort to select proper Technology, Strategies, Cost Estimation Methods for field development.

- **Hydrocarbon Type:**
- Oil Reservoir
- Gas Reservoir
- Oil and Gas Reservoir
- **Pressure and Temperature:**
- LPLT
- MPMT
- HPHT

Why Deep Water

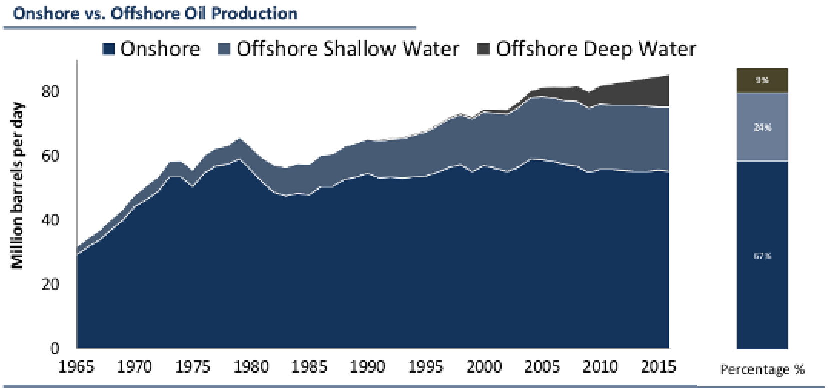
- Global Energy Demand is increasing.
- Oil and gas still make a major contributions.



Why Deep Water

- Onshore oil production has passed the peak and declining (4%-8% /year).
- Shallow water offshore production is declining.
- Only deepwater (>1000 m) production contribution is increasing :

From 9% now to 35% in 2030 (forcast)



Sources: Infield Systems, BP

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Why Deep Water

Deep water offshore oil and gas E&P is more challenging !
What makes offshore oil field development different from onshore and shallow water offshore ?

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Why Deep Water

- Technology has been developed for deepwater exploration and production, up to 3000m.
- What still makes the business difficult compare to onshore and shallow waters?
  - Higher capital , drilling and exploration costs.
  - High uncertainities in most of commercial parameters: well performance and recovery and oil price.
  - Substantial risks: remote area, harsh environments, HPHT reservoirs.

Fundamental Questions to be Considered

When should concept selection process be started ?

What is the required information ?

How should we make a decision based on the available information ?

Who are participating in the concept selection?

Typical Offshore Oil and Gas Field Life Cycle

Concept selection is a subset of a multi-diciplinary process:

FIELD DEVELOPMENT PLANNING

Acquire
- Government
- Size of the block
- Location
- Bidding Process

Explore
- Geological Study
- Exploration method
- Exploration tech.
- Location
- Reservoir

Appraise
- Dimensions
- Field Life
- Characteristics
- Production rate
- Reserves

Select
- Technically Feasible
- Economically Viable
- Revenue
- Investment
- High uncertainty

Define
- Engineering

Execute
- Procurement
- Construction
- Transportation
- Installation

Operate
- Commissioning
- Start -up
- O & M
- Safety

Abandon
- Remove: Environment
- Reuse: Commercial benefits.

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Importance of Field Deveopment Planning

- First FPU 1986 : Green Canyon 29 Semi-Submersible
- 1986 – 1999: 12 FPU were sanctioned (Spar, Semi-sub and TLP) by **major** operators.
- 2000 – 2001: Boom in using FPU, 14 FPU in GOM (11xDryTree+3xWet Tree) **independent** operators came to the game.
- 2000- 2005: 13 FPU were sanctioned in GOM (10xDryTree+3xWet Tree)

Reason for acceleration:

High price of oil and gas.

Lack of oil and gas for US and UK 1970s.

Relatively low Upsream capital cost.

High competition for acquiring the new leases and increasing the production.

Move the operators towards faster and cheaper solusions.

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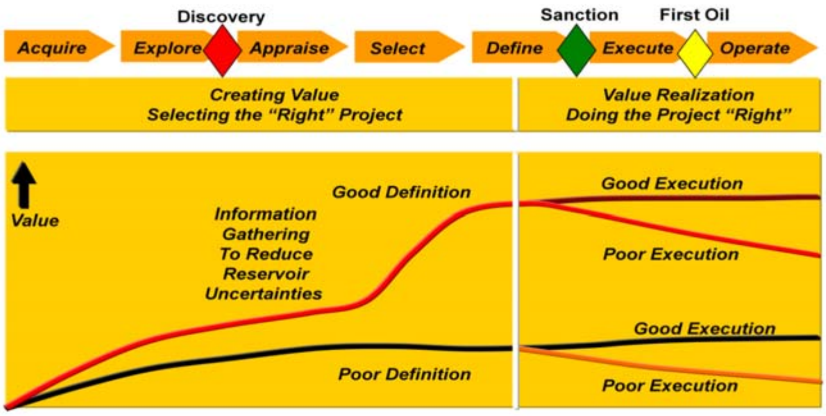
Importance of Field Deveopment Planning

- An assessment of existing projects (2005) revealed that a significant percentage of deep water offshore oil and gas reserves were underperformed technically and commercially, due to *poorly executed field development planning*.
- The reason was operators intention for faster and cheaper developments.



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Objective of Field Development Planning

- The main objective of field development planning is the selection of plan that satisfies an operator's commercial, strategic and risk requirements, subjected to regional and site constraints. The main objective is to maximize the revenue for a given investment.

UI = NPV/NPI

PLAN

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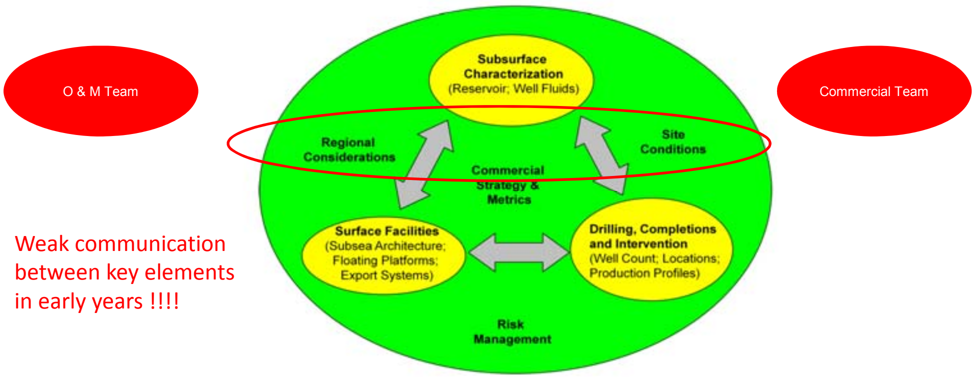
Key Elements in FDP

- This requires continuous and effective collaboration and alignment amongst main stakeholders: Subsurface, Well Construction, Surface Facility, Operation and Commercial Teams.



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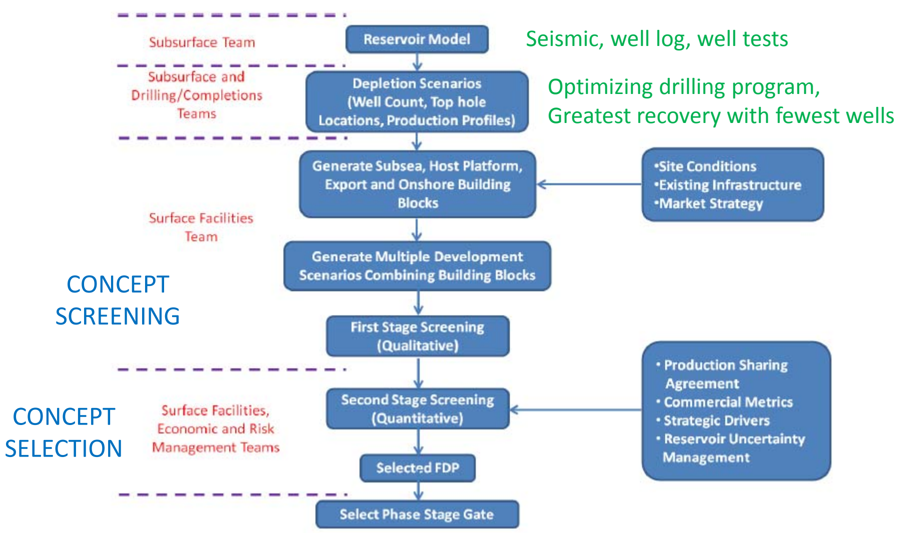
Overview of Methodology for Concept Selection



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Main Input Parameters and Their Effects

A. Reservoir Geometry and Geology (greatest impact)
   - Recovery factor and flow rates.
   - Well count, location and construction.
   - Secondary recovery methods.

B. Fluid Properties
   - Subsea and topside design.
   - Operation and maintenance(hydrate, wax and deposits, corrosion).

C. Drilling and Completion
   - Well management and well intervention frequency.

D. Regional Considerations and Regulations: block size, infrastructure, contract.

E. Site Characteristics: water depth, metocean condition, bathymetry.

F. Operator Strategy: type of the operator company.

Main Input Parameters and Their Effects

Relative importance of the parameters: Reservoir Geology and Geometry.

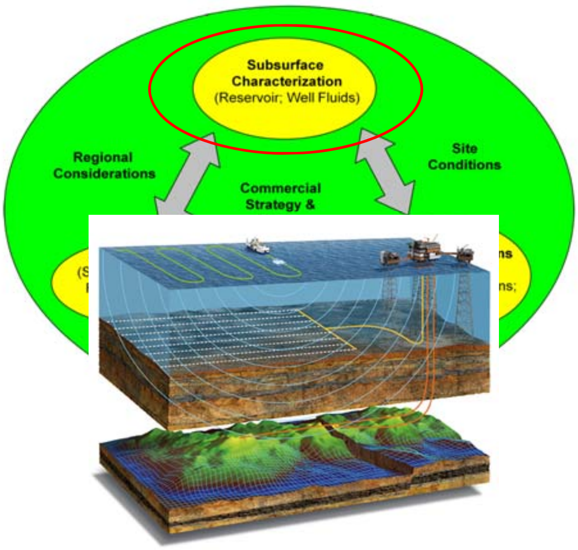
Key Reservoir Properties	Units	Impact on Key Field Development Components			
		Well Construction	Well Completion (Rate & Recovery)	Well Count	Secondary Recovery (Injection, Boosting)
Rock Properties					
Permeability	md	Low	High	Low	High
Porosity	%	Low	Med	Low	High
Productivity Index	psi/bpd/ft	Low	High	Low	High
Geometry & Stratigraphy					
Thick Overlaying Salt Diapir	ft	High	Low	Low	Low
Single or Stacked		Med	High	Med	Low
Payzone Thickness	ft	Low	High	High	Med
Depth to Payzone	ft below mudline	High	High	Low	High
Areal Extent	Sq. miles.	Med	Med	High	Low
Connectivity		Med	Med	High	Low

Main Input Parameters and Their Effects

Relative importance of the parameters: Fluid Characteristics.

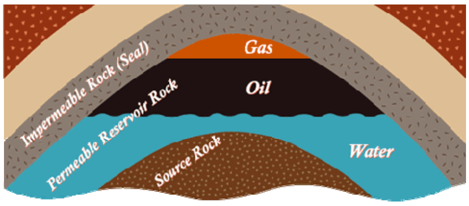
Key Reservoir Fluid Parameters	Units	Estimated Range of Values	Impact on Key Field Development Components			
			Process	Flow Assurance	Secondary Recovery	Subsea, Flowlines, Risers
Low API Gravity	°	< 20°	High	Med	Low	Low
High Viscosity	cp	> 100 cp	Med	High	Med	Low
Low Shut-in Pressure	psi	< 5000 psi	Med	High	High	Low
High Shut-in Pressure	psi	> 15,000 psi	Low	Low	Low	High
Low Temperature	°F	< 150°F	Med	Med	High	Low
High Temperature	°F	> 250°F (or 300 °F)	Med	Low	Med	High
Low GOR	scf/stb	< 500 scf/stb	Low	Med	Med	Low
High GOR	scf/stb	> 2,000 scf/stb	Med	Low	Med	Low
High CO_2, H_2S, Chlorides	ppm	20,000ppm; 100 ppm; 100,000 ppm	High	Low	Med	High
High Asphaltenes	%	CII > 1	Med	Med	Med	Low
High Wax Appearance Temperature	°F	> 95°F	Med	Med	Med	Low

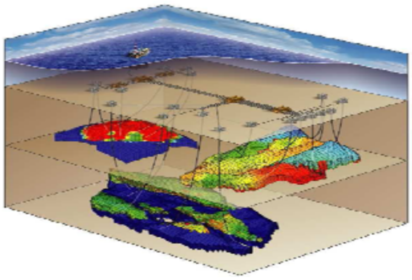
Subsurface Team



Field Development Phases: Oil and Gas Reservoir

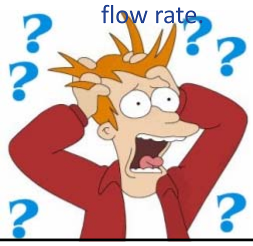
- An oil and gas reservoir is characterised by:
  - Geometry: areal extend, dimensions and connectivity .
  - Rock properties: lithology, porosity and permeability.
  - Hydrocarbon type and saturations.
  - Oil-Water and Oil-Gas contact lines.
  - Fluid physical properties: API, GOR, WOR, Pressure, Temp.
  - Fluid system and chemical compositions.
  - Driving mechanisms: recovery factor and recovery methods
  - Flow rate and pressure variation over time





Field Development Phases: Exploration

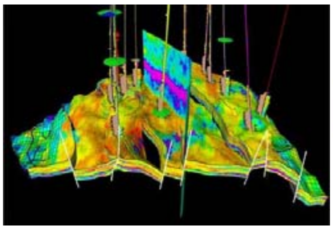
- The first step after acquiring the lease.
- **Goal:** The goal is to find an economic oil and gas reserves.
- **Task:** Suitable locations for exploration drilling and TD.
- **Activity:** Wildcat drilling, setp-out drilling and measurements.
- **Exploration Team:** Geologists, geophysicists, drilling engineers, reservoir engineers, mud loggers
- **Exploration Methods:** Satellite Survey, gravitymeter, magnetometer and Seismic (*horizontal resolution*), exploration drilling, MWD, LWD (well loging), core samples (*vertical resolution*), well testing (DST, WLFT, IPT).
- Initial reservoir model is prepared for development: reservoir geometry, rock properties, fluid characteristics, reservoir pressure and flow rate.



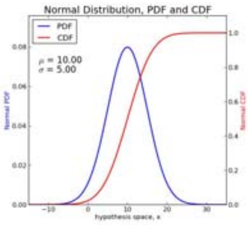
Big Question ?
Is it an economical oil and gas reservoir ?
($ 10-100 mUSD answer)
Substantial uncertainty in the measurements
and reservoir information.

Field Development Phases: Appraisal

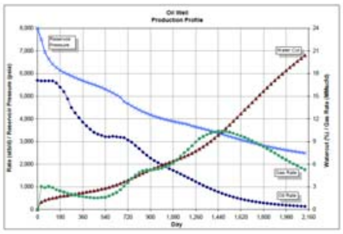
- **Goal:** Improving the quality of the data and reducing uncertainty.
- **Outcome:** Well fluid characteristics, OOIP, Recoverable oil, production profile, with sufficient uncertainty.
- **Method:** More appraisal wells will be drilled, more measurements.
- **Subsurface Team:** provide robust model of a reservoir from seismic data, appraisal wells and well logs and well tests.
- **Tools**: Multiple simulation with varying well count and location and type, tuning PDF for stochastic parameters.



Reservoir Model



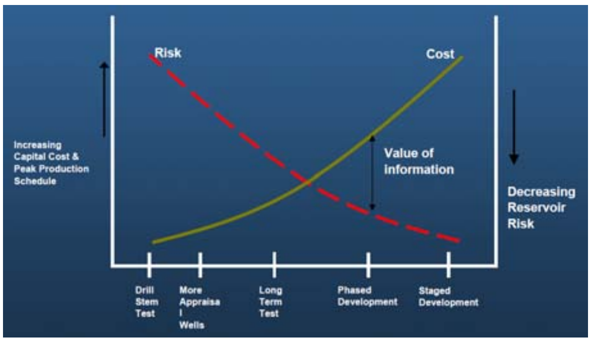
Tuning PDF - CDF



Production & Pressure

Field Development Phases: Appraisal

- There are several methods and strategies to reduce uncertainty.
- There is a trade off between capital cost and uncertainty.
- Methods:
  - Drill stem test.
  - More appraisal wells.
  - Extended well test.
  - Early production.
  - Staged development.
- Application Depends on:
  - ✓ Reservoir size and Char.
  - ✓ Operator Strategy
  - ✓ Available Technology.



Field Development Phases: Appraisal

Comparison of methods:

Strategy	Description	Duration (months)	Pros	Cons	Examples
Drill Stem Test	Single Well producing to MODU, gas flared	1-2 per well	• Relatively low cost ($100M - $150M per well); • MODU can be used for testing.	•Some (but insufficient) well performance data •Limited well connectivity data	Jack (Lower Tertiary, GOM)
More Appraisal Wells and Sidetracks	Drill additional appraisal wells to define extent and connectivity of reservoir	6-12 per well	•Some wells designed as keepers •More reservoir data and improved reservoir model	•Increased cycle time to sanction •Limited well performance data	
Extended Well Test	Single well producing to production platform	6-12	•Improved confidence in well performance and recovery •Better definition of reservoir connectivity	•18-24 months to mobilize production platform •Capex in $400M - $600M range	Roncador (Campos Basin, Brazil)
Phased Development (Early Production System)	Multiple wells producing to mobile production platform; gas exported or injected	36-60+	•Significant reduction in well performance and reservoir connectivity risk; •Test enabling technologies and completions; •Optimize full field development plan to capture reservoir upside.	•Significant Capex ($1B $3B) outlay •36+ months to mobilize platform	Cascade & Chinook (Lower Tertiary, GOM)
Staged Development	Bring wells online to a production platform in stages	Life of field	• Flexibility to capture reservoir upside • Maximize reservoir recovery	•Largest Capital investment and longest schedule to peak production among all options	Perdido (Lower Tertiary, GOM)

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A Glance to the Mathematics

- Original oil in Place (OOIP) Volumetric Method

$$OOIP=7758 \times A \times h \times \theta \times OS / FVFo$$
$$Ga = OOIP \times GOR$$

A: Areal Extent (Seismic, drilling, reservoir modeling)
h: Net pay (Seismic, drilling, reservoir modeling)
θ: Porosity (well log, core sampling)
os: Oil Saturation (well test)
FVFo: Oil Formation Volume Factor

$$OGIP=43560 \times A \times h \times \theta \times OS / FVFg$$

These parameters are *stochastic time varying* parameters.

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A Glance to the Mathematics

- Oil Production Rate:

$$Q=7.08 \times K \times h \times (Pe-Pw) / MuxBxln(Re-Rw)$$

- Q: Oil Flow Rate (bopd)
- h: Net pay (Seismic, drilling, reservoir modeling)
- K: oil effective permeability
- Pe: Formation Pressure
- Pw: Well bore pressure
- Mu: Viscosity
- B: Formation Volume Factor
- Re: Drainage radius
- Rw: Well bore pressure

- Well test and curve fitting (simple models)
  - Exponential
  - Harmonic
  - Hyperbolic

- Sophisticated models: Reservoir model and energy balance methods

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Integration of All Uncertainties

It is difficult to make a decision on multi-variable stochastic problems.

As suggested by SPE (Society of Petroleum Engineers):
For financial evaluation, uncertainty in all parameters should be integrated into production profile :

- Production profiles are calculated for three different confidence level:
  - Proven: 90%
  - Probable: 50%
  - Possible: 10%

Field development will be based on one of these three values depending on strategy and commercial risk of the operator.
Typicaly 50% will be used.

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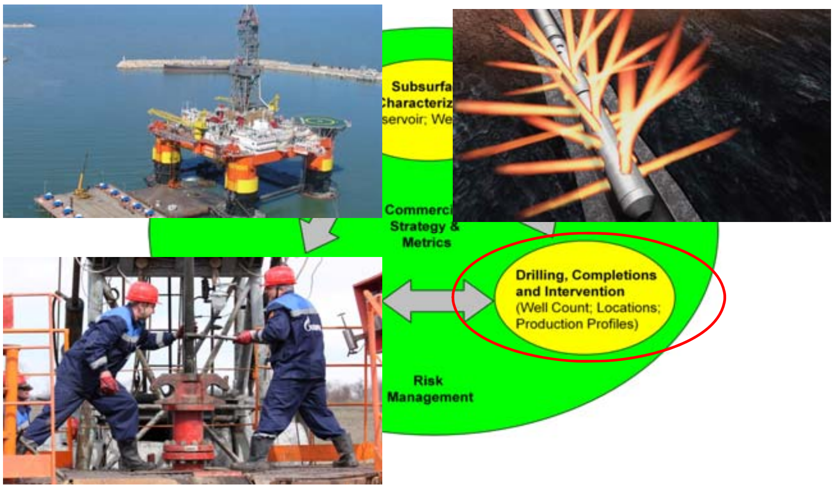
Drilling, Completions and Intervention Team



Well Construction and Intervention.

- Well Construction:
  - **Construction:** Location, depth and direction, well casing.
  - **Type of the well:** production, water or gas injection.
  - **Type of completion:** Perforation zone and sequence, perforation method.
  - **Main Decision:** DVA or nonDVA

  Direct effect on productivity and frequency of well intervention. (Operation Costs)

- Well Intervention and Workover:
  - **Options:** From production platform or Workover unit (MODU)
  - Depends on well type, construction and reservoir properties.
  - **Typical services:** (Heavy to light) Casing repair, Recompletion, Replacement of downhole boosting pump, logging

Well Construction and Intervention.

During operation:

- Well have to be periodically re-entered for reservoir management, remediation and recompletion.

Sand Production

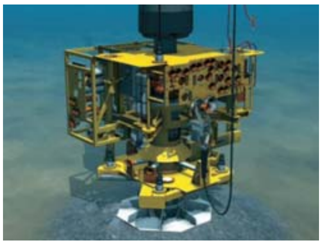
Well Cleanup

Re-Perforation

Well Construction and Intervention.

- Main decision is well type and access: (location of X-mas tree)
  - Subsea well (wet tree) with DVA or non DVA
  - Surface well (dry tree) with DVA

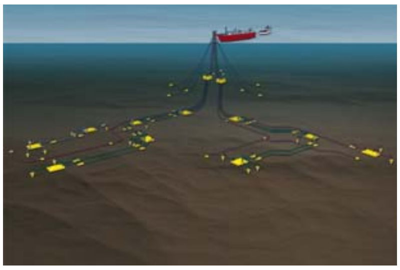
Dry Tree



Wet Tree

Well Construction and Intervention.

- Wet Tree or Subsea Well :
  - ➢ Lower CAPEX but higher OPEX
  - ➢ Lower Recovery (5%-10% lower than dry tree)
  - ➢ Low pressure reservoir.
  - ➢ Greater flexibility for well placements and field architecture.
  - ➢ Suitable for high uncertainty reservoir and multiple sub-economic reservoirs development.
  - ➢ All host units support wet tree.
  - ➢ DVA and nonDVA are possible.

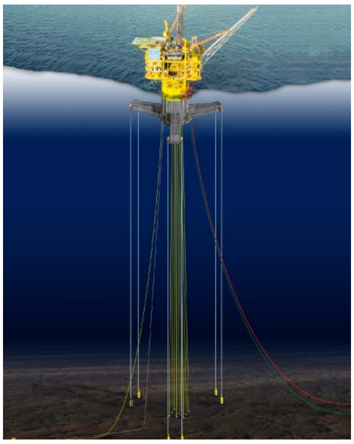


Well Construction and Intervention.

Dry Tree or Surface well:

- ➢ Higher CAPEX but lower OPEX.
- ➢ Higher Recovery
- ➢ High pressure reservoir
- ➢ Only Fixed platform, TLP, SPAR
- ➢ Only DVA

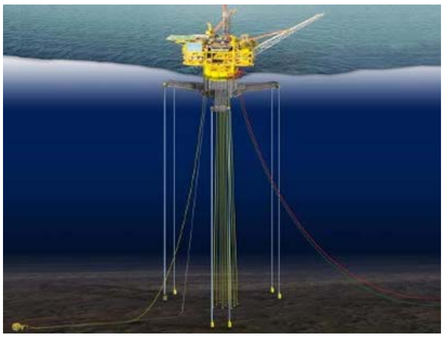
- Dry tree requires direct access to the well and Top Tension Risre.
- Full drilling package on FPU requires Dry Tree
- Requirements for full drilling package depends on the size of the reservoir and number of the wells: (GOM, 170 mmboe, 12 wells)



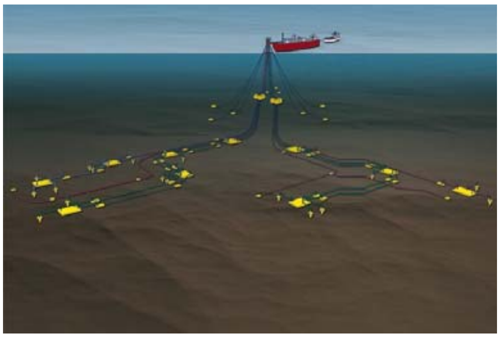
A TLP with Dry Tree System
Central well cluster

Well Construction and Intervention.

- Selection depends on areal extend and complexity of the reservoir.
  - Small and compact reservoir: Surface tree with central well cluster architecture.
  - Stacked, highly faulted and arealy extended reservoirs: subsea tree with satellit well architecture tieback to the manifold.

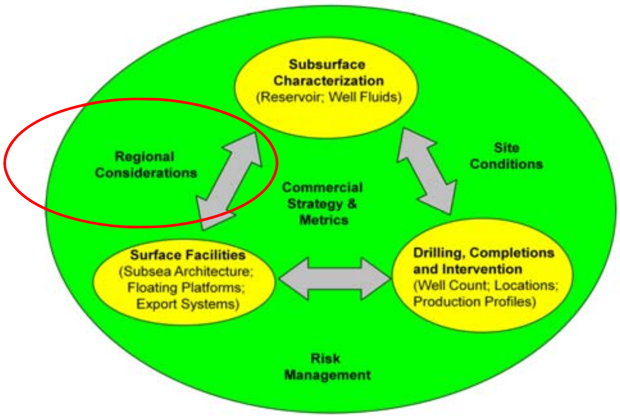


small and compact reservoir



FPSO with satellit well architecture
stacked, faulted, arealy extended reservoir

Regional Considerations



Regional Considerations

Have a significant impact on the NPV and FDP process.

- **Block size:** 10 sq. mile to 230 sq. Miles: development strategies
- **Infrastructures:** Pipeline, and development in the area and available production units.
- **Market Influence:** Availability of vendors and engineering companies, construction yards. Tide market (2000-2001) increases the development costs and schedule
- **Local contents:** Effect on local economy, job, industry
- **Regulations:** Host country dictates the terms and conditions, Flag type (Johns Acts), single hull, double hull, flaring of gas, distance to the market, HSE regulations.
- **Contract terms and conditions with host country:** Type of contract, Production sharing contract, concession contract, service contract: Risk to the operator, capital cost recovery, taxes and royalities.
- **Sustainable Developments:** Authorities prefer concepts which provides greater economical benefits and lower environmental impacts.

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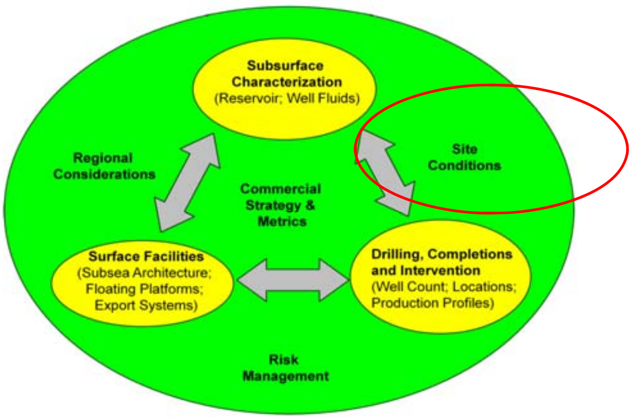
Site Characteristics and Conditions



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Site Characteristics and Conditions

Field architecture and floating platform are highly influenced by:

- **Water Depth:** drilling costs, design and installation of risers and mooring systems and pipeline, temperature at seabed and flow assurance.
- **Bathymetry and Geology:** Subsea flowline installation costs, anchor design
- **Metocean Condition:** Installation window, cost of facilities
- **Remoteness:** increases cost and risk of installation, favors the concepts with minimize offshore installation and operation, multiple reservoirs with single hub platform

These data should be provided prior to undertaking the facility development plan.

Operator Strategies

- Strategies of the operator depends on the type and size of the operator company.
- Type of the oil companies:
  - **Independent Oil Companies:** Premier-Oil, VNG Norge.
  - **International Oil Companies:** Shell, EXON, BP, SLB
  - **National Oil Companies:** NIOC, Petrobras, Statoil

- Operator positions for trade-off pairs:
  - CAPEX vs OPEX
  - Standardization vs Improvement
  - Proven Technology vs Innovative Technology
  - Min Capacity vs Future Capacity

Operator Strategies

- Independent Oil Companies:
  - 15% of deep water offshore production
  - Focus on small to medium size fields (75-175 MMBOE)
  - Join with other operators to share the risk.
  - Prefer leasing strategy over owning & tieback over self production facility.
  - Short development cycle time.
  - Small engineering teams with fast tracks.
  - First user of new technologies, more flexible towards vendors.
  - Subsurface is the largest team.
  - Confidentiality is high.

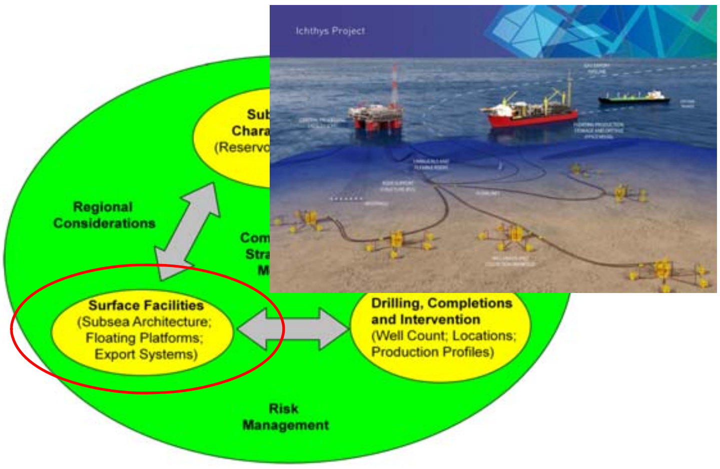
Operator Strategies

- International or Integrated Oil Companies:
  - 50% of deep water offshore production
  - Focus on medium to large size fields (>175 MMBOE)
  - Using their own technology as long as possible.
  - More process driven stage gates which increases development cycle time to first oil.
  - Prefer to use proven technology.
  - Standardized technology, less flexible towards vendors.

Operator Strategies

- National Oil Companies:
  - 35% of deep water offshore production.
  - Focus on global development plan and basin development rather than block development.
  - Phased development strategy.
  - Early production users to reduce uncertainty.
  - Higher risk margins.
  - Exploration results can be publicly available.

Surface Facility Team



Concept Screening & Concept Selection Process

A Review:
Concept selection is a subset of field development planning.
Exploration and appraisal phases provide required information for concept selection.
Success of concept selection phase highly depends on the quality of the data provided in the previous phases.

Subsurface, Drilling and Completion Team:
Multiple depletion senarios:
- Well count, locations and type.
- Drilling and workover and well intervention.
- Production Profile.
- Fluid composition
- Recovery Methods.
- Dry tree or Wet tree
- Well intervention, methods and frequency
- Drilling requirements during production

Surface Facility Team:
Corresponding development senarios:
- Field Subsea Architectures
- Host units: Hull type, mooring and risers
- Workover and Well intervention package.
- Exporting methods.

Commercial and Management Team:
- NPV
- NPI
- Risk Assessment

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Concept Screening & Concept Selection Process

Overal differences ?

	Concept Screening	Concept Selection
Definition	Primary Systems	Basic Design (Pre-FEED)
Cost Estimation	Class 5	Class 4
Risk Assessment	Optional	Mandatory
Qualitative Ranking	Attribute level	Sub-attribute
Stochastic Analysis	Mandatory	Optional

Simmilar process, different in the accuracy and level of implementation.

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Concept Screening and Study

Facility Framing Workshop with representatives from all stakeholders present early in the selected phase.

The purpose of this workshope is:

- To establish the objectives of the project.
- Strategies to reach this objectives.
- Establish Design Basis and Functional Requirements
- Generate Concept Development Matrix
- Generate Development Scenarios (10-80)
- Develop decision drivers and ranking methodology

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Concept Screening & Concept Selection Process

Main Steps:
Input: Field depletion scenarios

1. Establish basis of design and functional requirements.
2. Establish ranking criteria and methodology.
3. Identify building blocks from proven technologies.
4. **Concept Screening:** 1st stage definition, Combining building blocks to generate different development scenarios. (10 – 80 scenarios) ranking and comparing different scenarios (5-10): Qualitative and quantitative
5. **Concept Selection:** 2nd stage definition, ranking and comparison (5-10)
6. Use tie-breakers and operator strategy for final decision (if more than 1)
7. International benchmarking
8. Concept definition.

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Concept Screening & Concept Selection Process

It is a two steps process

- Concept Screening:
  - ✓ To identify all possible solutions (80)
  - ✓ Technically feasible
  - ✓ Economically viable: Rough cost estimation (cost class 5)
  - ✓ Reduce the number of scenarios to 5-10 for concept selection
  - ✓ Identify the optimum number of wells (for marginal fields)

- Concept Selection:
  - ✓ Main objective: Maximizing the profit.
  - ✓ Select the best concept.
  - ✓ More accurate cost estimation and assessment is required.

Design Basis Documents

In the early concept screening.
Provides the framework and the constraint within which the development team must operate.
As a minimum it should include:

- **Reservoir characteristics and depletion plan:** well count and seabed locations, fluid properties, production profiles, enhanced recovery, reservoir management. (Well count may be fixed or not, size and uncertainty of the reservoir)
- **Drilling and Completion:** Well location, Rig specification, Durations, workover type and frequencies.
- **Site and regional conditions:** Water depth, metocean data, seabed bathymetry and geohazards, infrastructure and logestics, local content requirements.

Functional Requirements

- Processing: Deck space and payload sensitivity
- Storage and Export: Hull and Geometry
- Well Access: Motion
- Drilling and Workover: Motion and Deck Space
- Enhanced Recovery

Ranking Strategies and Methods

Ranking Methodology and Strategy can be categorized:

- Quantitative or Qualitative
- Deterministic or Stochastic assessment
- Cost estimation accuracy and class

- Qualitative Ranking :
  - Uncountable parameters: operability, constructability, installation ease
  - Less accuracy is required.
  - Technical issues.

- Quantitative Ranking:
  - Countable parameters: cost, time and schedule
  - More accuracy is required

Ranking Strategies and Methods

Economic Factors (significant number of parameters but summerized by):

- NPV : (cash inflow-cash outflow, discount rate) Production Profile, Field Life, Sale Price
- NPI : CAPEX, DRILEX (# well), OPEX, ABEX
- UI=NPV/NPI
- Stochastic analysis is required in early stage due to uncertainty

AACE issued International Recommendation Practices on Estimate Classification:

- Cost Class 5: Concept screening and study, cost dispersion +100% to -50%
- Cost Class 4: Concept Selection, cost dispersion +50% to -25%

Ranking Strategies and Methods

Noneconomic factors that drives an operator's decision:

- Construction Period
- Operability
- Fabrication
- Reliability
- Risk Assessment

Qualitative or Semi-Quantitative Parameters

Can be evaluated into two levels:

- Attributes: Concept screening
- Sub-Attributes: Concept Selection

General Decision Drivers:

- Minimizing technical risk.
- Maximizing hydrocarbon recovery.
- Constructability.
- Schedule to first oil. (expected execution and installation period)
- Expandability: Flexibility for future expansion.
- Flexiblity to adapt to reservoir uncertainity.

Concept Screening and Study

Concept Definition for Concept Screening:
Objective is to define all surface facility components to a level sufficient for class 5 (-50% to 100%) capex, opex and schedule estimation.

- Use available commercial (OGM) or inhouse databases:
- Typical required inputs are:
  1. Basic subsea equipments: flowlines, manifold, Ch. Tree, risers
  2. Number of wells, Production profiles, Hydrocarbon sale price
  3. Basic topside components and capacities
  4. Type of host unit and required displacement

Step 2: Calculate NPV and NPI
Step 3: Compare different concepts based on UI as a function of NPV. (No. Wells)
Step 4: Choose the concepts which pass NPV and UI threshould.

Concept Selection

Concept Definition for Concept Selection:
Objective is to define all surface facility components to a level sufficient for class 4 (+50% to -25%), capex opex and schedule estimation.

- Size flowlines, risers and pipelines and determine arrival condition by simple flow assurance simulation.
- Specify the topside, drilling and workover equipments and make an initial layout by process simulation, PFD, P&ID.
- Make initial sizing of the hull to support topside, riser, mooring weight.
- Performe stability and motion analysis to ensure operability and survivability in extreme conditions to design mooring and riser system.
- Make an execution plan for design, fabrication, integration, transportation, installation and commisioning to estimate capex and schedule.
- Cost and schedule estimation, Compare and rank scenarios.
- Risk assessment.
- Validate by benchmarking against similar projects.

Risk Assessment

A relative risk assessment will be performed including:
- Technical
- Execution
- Operational
- Safety
- Commercial risks

Tie Breakers

When economic and performance indications of two concepts are indistinguishable an operatore's tie breaker will be used:

HSE: Concepts with larger deck, gives greater separation between hazardus and non-hazardus areas

Flexibility: Scenarios provide more felexibility, both for contracting and to adapt to the reservoir uncertainity are prefered.

Mobility: Ease of decommissioning and relocation to other fields

Building Blocks

Building Bloks:
A deep water facility development scenario can be constructed from the following building blocks:

Subsea Production	Enhanced Recovery	Drilling Platform	Host Production Platform	Export System	Onshore Facility
•Single well tieback •Cluster well manifold with dual flowline tieback	•Mudline Separation and ESPs •Multiphase Pumps •Subsea Gas Compression •Gas Lift •Gas Injection •Water Injection	•Mobile Offshore Drilling Unit •Tender Assist Wellhead Spar •Full drilling wellhead Spar •Tender assist wellhead TLP •Full drilling wellhead TLP	•Dry Tree Spar with Drilling •Dry Tree Spar with Workover •Wet Tree Spar •Dry Tree TLP with Drilling •Dry Tree TLP with Workover •Wet Tree TLP •Shipshape FPSO •Cylindrical FPSO •Production Semisub •Production/ Drilling Semisub •FLNG •Existing Host •Fixed Platform	•Oil Pipeline •Gas Pipeline •Oil shuttle tanker •LNG shuttle Tanker •FSO with Oil Shuttle	•Oil Tank Farm / Terminal •Gas Processing Plant •Gas to Liquids Plant •Gas to Power Plant •LNG Plant

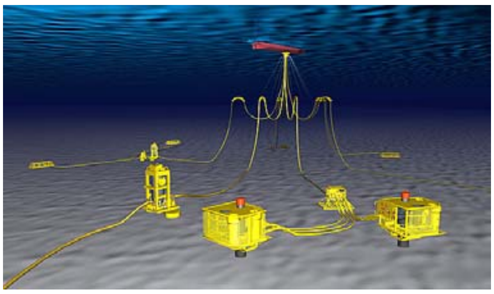
Subsea Systems + Enhanced Recovery + Drilling Platforms
\+ Production Platforms + Export Systems + Onshore Facilities
= Facility Development Options

Building Blocks: Subsea Systems

A subsea systems consists of an assemblage of:
- Trees and wellheads, Manifolds, Jumpers
- Umblicals and Flowlines
- Pipeline End Termination

Basic Building Blocks:
1. Single well tieback
2. Multiple wells manifolded tieback

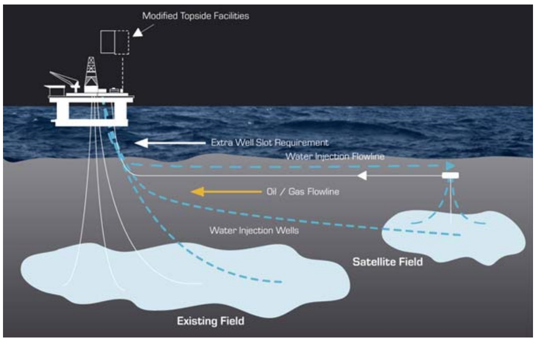
Subsea Architecture is driven by
- Number of wells
- Location of wells
- Distance to host unit
- Subsea bathymetry
- Fluid properties to determine the flow line dimention.
- Arrival production rate, temperature and pressure at PLEM.



Building Blocks: Enhanced Recovery

Basic building blocks:
- Downhole boosting.
- Gas lift
- Gas injection
- Water injection

Secondary and enhanced (tertiary) recovery methods.
- Steam flooding
- Fire floodin
- Chemical injection
- Polymer injection



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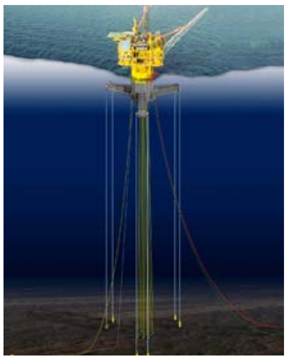
Building Blocks: Drilling Platforms

Depend on the size of the reservoir and type and distanceof the well.

Basic Building Blocks:
•Tender assissted drilling
• MODU
• Permanent Drilling Platform.



Satellite well system with subsea well. MODU or drill ship.

Single drill center and Surface well. Tender assissted or Drilling Platform.

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Building Blocks: Drilling Platforms

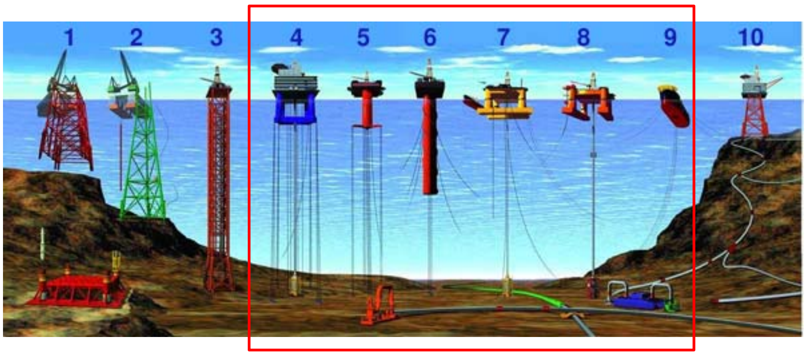
MODU	Tender Assissted Drilling	Full Drilling Package
		
Amirkabir	West Alliance TLP	TLP Mars GOM
wet Tree satellite Well heavy workover	dry Tree well Cluster heavy workover payload limit	dry tree well cluster drilling and workover

Building Blocks: Drilling Platforms

Guideline for early decision on Key Platform Functions

Reservoir	Drill Centers	Wet or Dry Tree Development	Drilling, Workover or Production Rig
Small	Single	Wet	Production
Medium, stacked or compact	Single	Dry	Workover
Large, staked or compact	Single	Dry	Drilling
Large, areal extensive	Multiple	Wet	Production
Multiple, sub-economic	Multiple	Wet	Production

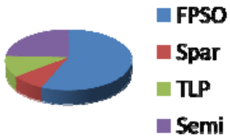
Building Blocks: Host Platforms



Consists of:

- Topsides.
- Hull.
- Station-keeping system.
- Riserer system.

Host platform:
With drilling and workover
With only workover
Without drilling and workover



Building Blocks: Host Platforms

Fundamental differences between the floating platform:

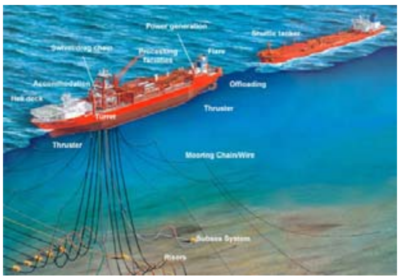
- Drilling and Workover Capacities
- DryTree or WetTree Support
- Storage Capacity
- Scalability to water depth and payloads
- Heave and Pitch motions.
- Execution risks: Construction, Installation and Operation, Abondenment and Reuse.

Building Blocks: Host Platforms

		Spar	TLP	Semisubmersible	FPSO
Variants		Classic, Truss or Cell	Classic, Extended, MOSES or Sea-star	Conventional or Deep-draft	Shipshaped or cylindrical
Functionality		Dry/Wet Trees; Surface BOP drilling, completion, intervention	Dry/Wet Trees; Surface BOP drilling, completion, intervention	Wet Trees; Subsea BOP drilling, completion, intervention	Wet Trees; Subsea BOP drilling possible in mild conditions; Integrated oil storage
Constraints	**Water Depth**	Dual Barrier HP production riser to 5000 ft	Tendons to about 5000 ft.	Limited envelope of SCR applicability	Tower or wave risers required
	Topside Payload	< 20,000 tons dry weight	None	None	None
Offshore Installation, Integration, Commissioning		Complex offshore operations; high execution risk	Relatively complex offshore operations; moderate execution risk	Relatively simple offshore operations; low execution risk	Simple offshore operations; low execution risk
Decommissioning, Relocation and Expansion Flexibility		Difficult and costly	Difficult and costly	Simple	Simple

Building Blocks: Export Systems

Export methods depends on:
- Distance to the market.
- Distance to the available infrastructures: pipeline.
- Storage capacity of host platform.
- Field life and neighbouring fields.



Possible methods:
- Oil and Gas Pipeline .
- Direct shuttle tanker offloading (no onsite storage)
- Shuttle tanker offloading (with FSU or FPSO)
- LNG carrier (FLNG)

Building Blocks: Onshore Facilities

- Tank farm and Loading terminal.
- LNG Plant.
- Gas to liquid plant.
- Gas to wire plant.

Example: Concept Screening

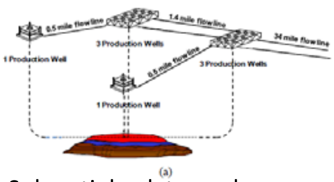
Case Study: A gas field
After exploration and appraisal
Initial number of scenarioes: 1x4x4x2X4 = 128

Field Development Concept Matrix				
Hydrocarbon	Hub	Well Type	Transport	# Wells
Gas	Submersible	Vertical	Tanker	4
	Fixed Platform	Directional	Pipeline	6
	Subsea	Horizontal		8
	FLNG	Multi		10

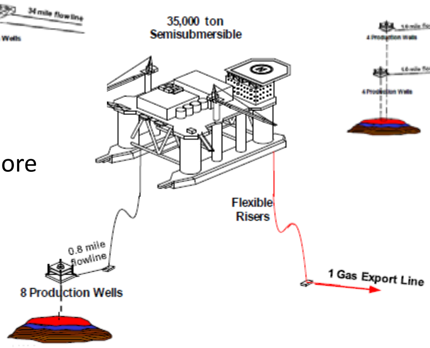
Example: Concept Screening

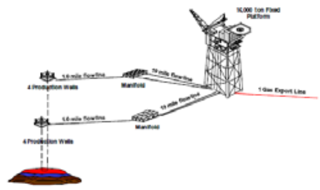
- Technical feasibility leads to final 12 scenarios:
  - 4 subsea well systems: 4, 6, 8, 10
  - 3 Host platform: Tieback, Jacket, Semisub

Semisubmersible



Subea tieback to onshore





Jacket

Example: Concept Screening

- NPI are calculated from total cost:
  - ➢ CAPEX
  - ➢ DRILLEX
  - ➢ OPEX
  - ➢ ABEX

Cost of infrastructure, drilling, operation and abandonment

	4 Wells	6 Wells	8 Wells	10 Wells
Tie Back	1372	1651	1930	2209
Semi	1695	1974	2253	2532
Jacket	2045	2324	2603	2882

- NPV are calculated from :
  - ➢ Hydrocarbon sale price
  - ➢ Production profile P50 for number of wells

Example: Concept Screening

- NPV and UI should be maximized simultaneously.

- Tie back system gives the max NPV.
- For jacket and semi, NPV and UI are maximized simulatneously with 6 wells.
- For tie back 6 wells should be selected as there is a risk of 25% production loss if one well is below its expected production rate.

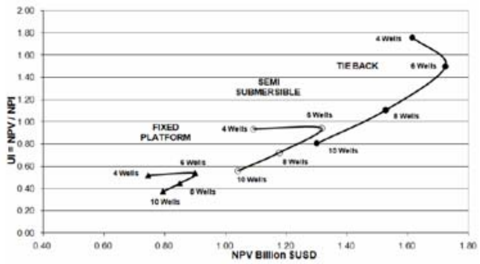
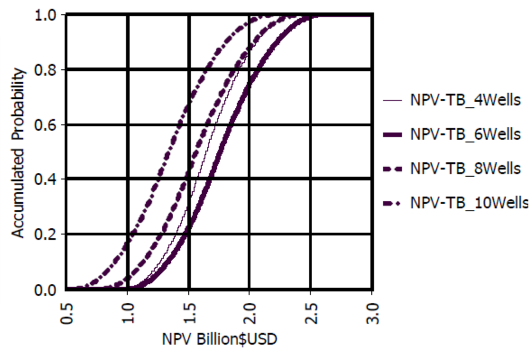


Figure 3. Optimizing the number of wells for a gas field based on economical indicators.

Example: Concept Screening

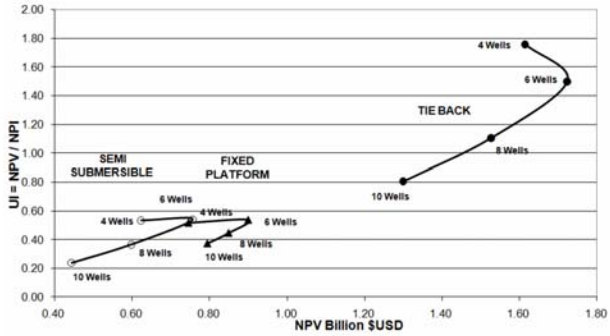
- There is high uncertainty in the cost estimation which need to be captured by a Montecarlo simulation for NPV and NPI.
- A triangular distribution is asigned to the main input parameters based on the min, mean and max value recommended by experts.
- CDF for NPV will be calculated for each case.

Tie Back	Triangular Probability Distribution		
	Minimum	Medium	Maximum
Gas Price ($US/MCF)	$5.50	$7.32	$9.50
Cost (MM $USD)		Class 5 - 4	
Well	$125.56	$139.52	$153.46
Shore Station	$186.69	$207.43	$228.17
Pipe	$211.00	$234.44	$257.89
Subsea System	$63.61	$70.68	$77.75
Umbilicals	$64.85	$72.05	$79.26
OPEX	$161.30	$179.23	$197.15
ABEX	$45.31	$50.34	$55.37



Example: Concept Screening

- This method only relies on economical indexes.
- If we include the noneconomic parameter such as schedule to first oil, result will be different.
- Subsea Tieback and Jacket: 3 years
- Semisubmersible: 5 years



- Economic evaluation alone is not be sufficient for final decision.

Example: Concept Selection

For concept selection, scenarioes should be compared in sub-attribute levels.

Analytical Hierarchy Process (AHP):
A decition making method to prioritize concepts under qualitative multiple attributes decision drivers.
We have to select the attributes that can make difference between all the concepts.
Step 1: Selection of attributes and sub-attributes with brainstorming multi-diciplinary workshop (drilling, sybsea systems, flow assurance, pipeline, floating system, process)

Example: Concept Selection

Selection of Attributes and Subattributes

Attributes	Sub-attributes
Operability	Easy to start or shut down Production management Gas quality at the delivery point Operation flexibility
Fabrication & Installation	Easy to fabricate Easy to install Availability of drilling equipments
Time to First Production& Costs	Total cost Utility Index Time to first production
Reliability	Prevention of flow assurance events Inspection, maintenance, repair redundancy

Example: Concept Selection

Ranking the selected attributes according to the importance in the exploitation systems.
A criteria for weight is defined:

Weights for attributes and sub attributes comparison	
Absolutely more important	9
Very strongly more important	7
Strongle more important	5
Weakly more important	3
Equally important	1
Weakly less important	1/3
Strongly less important	1/5
Very strongly less important	1/7
Absolutely less important	1/9

Example: Concept Selection

Make a pairwise comparison and weight the attributes.
Normalaize the columns and sum-up the rows in normalized matrix.

Attribute Weighting					
Attribute Weighting:	1. Operability	2. Fabrication and Installation	3. Time to First Production and Cost	4. Reliability	
1. Operability	1	5.000	1.000	3.000	
2. Fabrication and Instalation	0.200	1	0.200	0.143	
3. Time to First Production and Cost	1.000	5.000	1	1.000	
4. Reliability	0.333	7.000	1.000	1	
Summation:	2.533	18.000	3.200	5.143	
Normalization:					**Weights**
1. Operability	0.395	0.278	0.313	0.583	**0.3921**
2. Fabrication and Installation	0.079	0.056	0.063	0.028	**0.0562**
3. Time to First Production and Cost	0.395	0.278	0.313	0.194	**0.2949**
4. Reliability	0.132	0.389	0.313	0.194	**0.2569**
Summation:	1.000	1.000	1.000	1.000	1.000

Weight of each attribue is the final result.

Example: Concept Selection

Rank the field development concepts from 1 to 4 for each sub attribute.

Normalize the ranking by attribute and sub attribute weights.

Sum-up the results for each concept to get final ranking result.

				Pair-Wise Rating			Normalised Pair-Wise Rating		
Attributes	**Attribute Weight**	**Sub-Attribute**	**Sub-Attribute Weight**	**Tie-Back**	**Fixed Platform**	**Floating System**	**Tie-Back**	**Fixed Platform**	**Floating System**
1. Operability	0.39								
		Easy to start or shut down	0.11	3	4	4	0.126	0.168	0.168
		Production management	0.41	3	4	4	0.484	0.645	0.645
		Gas quality at the delivery point	0.12	4	4	4	0.189	0.189	0.189
		Operative flexibility	0.36	2	3	3	0.283	0.425	0.425
2. Fabrication and Installation	0.06								
		Easy to fabricate	0.11	4	3	2	0.024	0.018	0.012
		Easy to Install	0.26	3	3	2	0.044	0.044	0.029
		Availability of drilling equipment	0.63	2	2	3	0.071	0.071	0.107
3. Time to First Production and Cost	0.29								
		Total cost (TC)	0.11	4	3	2	0.125	0.094	0.063
		Utility index (UI)	0.63	4	3	2	0.747	0.560	0.374
		Time to first production	0.26	4	3	3	0.307	0.230	0.230
4. Reliability	0.26								
		Prevention of flow assurance events	0.45	2	3	4	0.234	0.350	0.467
		Insp maintenance and repair (IMR)	0.09	4	3	2	0.093	0.070	0.047
		Redundancy	0.45	3	4	4	0.350	0.467	0.467
		Pair-Wise Rating	Excellent	Good	Average	Poor	**3.08**	**3.33**	**3.22**
		Value	4	3	2	1			

Example: Concept Selection

The concept selection based on economic indexes:

- Tie-Back
- Semi-Sub
- Jacket

The concept selection based on non-economic indexes:

- Jacket
- Semi-Sub
- Tie-Back

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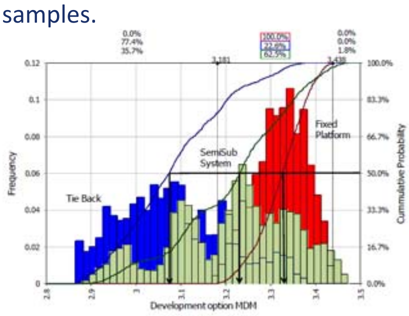
Example: Concept Selection

- In MDM method, engineering judgment is used to define the attributes and weights.
- This can vary depending on the experience of the people, time frame, available information.
- Effect of variation in the attribute weights must be studied with stochastic analysis.
- Define a triangular distribution for attribute weights.
- Performe montcarlo simulation, 10,0000 samples.

Table 13. Attributes weight value range.

Attributes	Lower Value	Base Case	Upper Value
1. Operability	0.18	0.39	0.57
2. Fabrication and Installation	0.03	0.06	0.09
3. Time to First Production and Cost	0.13	0.29	0.53
4. Reliability	0.14	0.26	0.46



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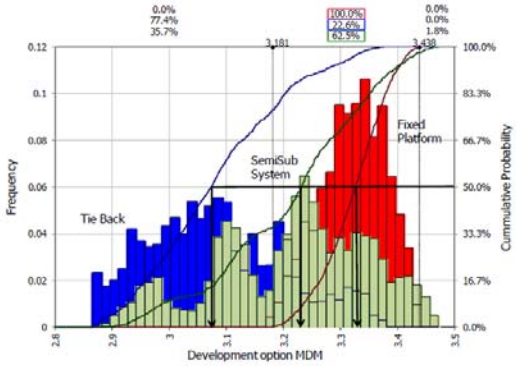
Example: Concept Selection

Ranking MDM results after stochastic analysis:

- ➢ Shows the range of MDM value for each concept and probability.
- ➢ Jacket gives the highest MDM.
- ➢ The median values for all three concepts are:
  - ➢ Jacket = 3.32
  - ➢ Semi = 3.23
  - ➢ Tie-Back = 3.07

This stochastic analysis confirms the deterministic Results.



Example: Concept Selection

Risk Assessment:
To finalize the results from concept selection risk assessment should be performed.
It is a semi-quantitative assessment.

Risk Definition: Probability of occurrence X severity of concequence

Procedure:

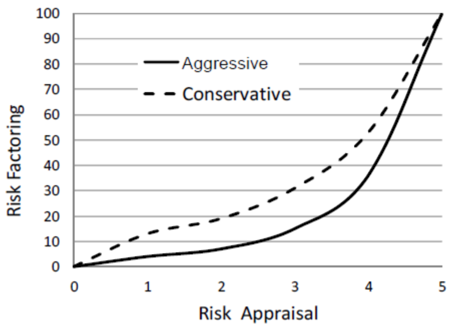
- ➢ Make a list of all possible risk events: previous records or FMEA workshope
- ➢ Determine the probability of occurrence for each event
- ➢ Specify the risk attributes which will be affected by risk events:
  - Health and safety
  - Environment
  - Asset Value
  - Project schedule

Example: Concept Selection

Probability of occurrence:
Use a scale of 1 to 5.
For qalitative probability assignment risk taker are divided into to group:

- Aggresive risk takers
- Conservative risk takers

A risk factoring profile is defined to distinguish risk takers.



Example: Concept Selection

Impact severity of risk events on attributes is apprised by a group of experts from the established guideline and operator's safety policy.
Impact severity appraisal is also weighted by the same factoring curve.

Impact Severity Appraisal	Health and Safety	Environment	Asset Value	Project Schedule
Exceptional (5)	Fatalities/Serious impact on public.	Major or extended duration/Full scale response	20% or more of total asset value	Schedule impacted more than 2 years
Substantial (4)	Serious lost time injury to personnel/ Limited impact on public	Serious environmental damages/ Significant resources needed to respond	5% to <20% of total asset value	Schedule impacted more than 6 month but less than 2 years
Significant (3)	Restricted work case/Minor impact on public	Moderate environmental damages/ Limited resources needed to respond	1% to <5% of total asset value	Schedule impacted more than 3 month but less than 6 months
Moderate (2)	Medical treatment for personnel/ No impact on public	Minor impact/No response needed	0.1% to <1% of total asset value	Schedule impacted more than 1 month but less than 3 months
Negligible (1)	Minor impact on personnel	No damages	<0.1% of total asset value	Insignificant schedule slippage: <1 month

Example: Concept Selection

The resulted table will be: Weighted probability of occerrence X weighted impact severity X Weight of the attributes. The mean square root gives final risk weight of each event.

Table 9. Risk assessment for tie back development option.

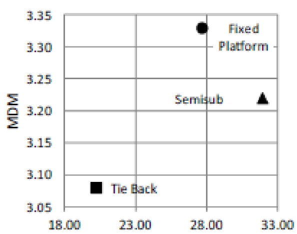
FIELD DEVELOPMENT OPTION: TIE BACK			RISK ATTRIBUTES Risk event impact severity on attributes (Appraisal)				Weight of risk event impact severity on attributes (Factoring)				RISK ASSESSMENT OF EVENTS				
			0.25	0.25	0.25	0.25									
RISK EVENT	Probability of Ocurrence (Appraisal)	Weight of Probability of Occurrence (Factoring)	Health and Safety	Environment	Asset Value	Project Schedule	Health and Safety	Environment	Asset Value	Project Schedule	Health and Safety	Environment	Asset Value	Project Schedule	RISK EVENT WEIGHT
1. Change of reservoir information, well type and future growth.	4	36	1	1	3	2	4	4	15	7	36	36	135	63	16
2. Damage to pipelines / umbilicals due to mooring lines or anchors failure.	3	15	3	3	4	3	15	15	36	15	56	56	135	56	17
3. Equipment failure during commissioning and starting up.	3	15	3	3	3	3	15	15	15	15	56	56	56	56	15
4. Infrastructure / pipelines failure during installation.	3	15	3	3	3	3	15	15	15	15	56	56	56	56	15
5. Delay of infrastructure to start up	4	36	1	1	3	3	4	4	15	15	36	36	135	135	18
6. Problems during well construction	4	36	3	3	3	3	15	15	15	15	135	135	135	135	23
7. Control system failures during operation	3	15	3	3	3	3	15	15	15	15	56	56	56	56	15
8. Flow assurance problems (plugs formation)	4	36	3	2	4	4	15	7	36	36	135	63	324	324	29
9. Slug catcher flooding	3	15	3	2	3	3	15	7	15	15	56	26	56	56	14
10. Hurricanes	5	100	3	3	3	3	15	15	15	15	375	375	375	375	39
											OPTION RISK WEIGHT				20

Example: Concept Selection

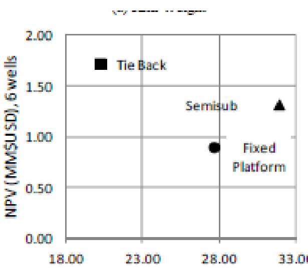
The previous procedure will be performed for all concepts.
The rsults from risk assessment can be combined with multi-atribute decision model and NPV calculation for final selection

Table 11. Summary of risk weights and MDM evaluations.

Development Option	Risk Weight	MDM
Tie Back	20.24	3.08
Fixed Platform	27.65	3.33
Semisubmersible	31.90	3.22



(a) Risk Weight



(b) Risk Weight

Conclusions

- Concept selection for deep water field development is a multidisciplinary task and needs contribution from: Subsurface, drilling and completion, surface facility, operation and maintenance, management and commercial team.
- A structured methology to generate, screen and select the right development concept is required.
- Concept selection is performed when the uncertainty in the critical parameters which determine the commercial success of the project is high. Addressing subsurface data uncertainty in the facility design phase is important.
- Deepwater facility design is highly depends on subsurface data.
- Success of FDP highly depends on: Quality of information, skills of subsurface team, technology and reservoir modeling.

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Questions ?