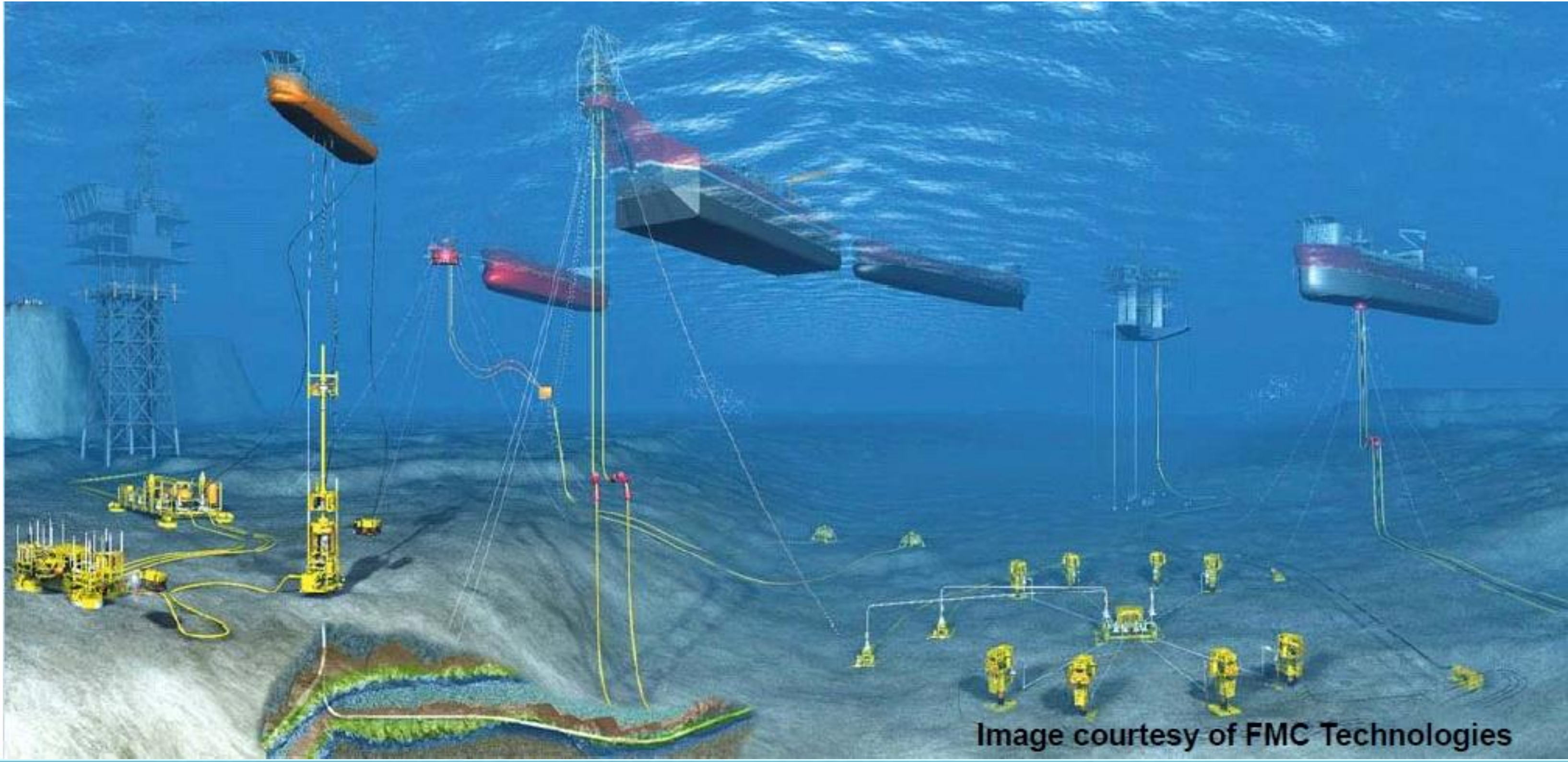


Offshore platform FEED

Yutaek Seo

Introduction

- Combine engineering calculations and up-to-date cost data to deliver lifecycle cost estimates for upstream oil and gas projects
  - CAPEX / OPEX / Decommissioning

- Go through the field development process
  - Regionally adjusted technical algorithms

- Performs preliminary sizing of all field development items
  - From drilling to processing to export options

- Estimates the cost of the defined items
  - Up-to-date, regional cost data giving global coverage

Typical studies

- Prospect evaluation
  - Quickly generate lifecycle cost estimates to assist with prospect screening
- Concept screening
  - Compare multiple concepts ensuring a consistent estimate basis
- Conceptual engineering
  - Develop a preliminary design
- Project benchmarking
  - Produce regional cost benchmarks
- Asset evaluation
  - To aid asset acquisition and divestiture

Prospect Evaluation

Research

- Reserves estimates – P_{10}, P_{50}, P_{90}
- Field properties – Field location, export options

Identify

- Development scenarios – Viable concepts
- Special considerations – Acid gas, extreme environment

Evaluate

- Cost estimates – CAPEX, OPEX, decommissioning
- Economic evaluation – Product price, cost inflation, fiscal terms

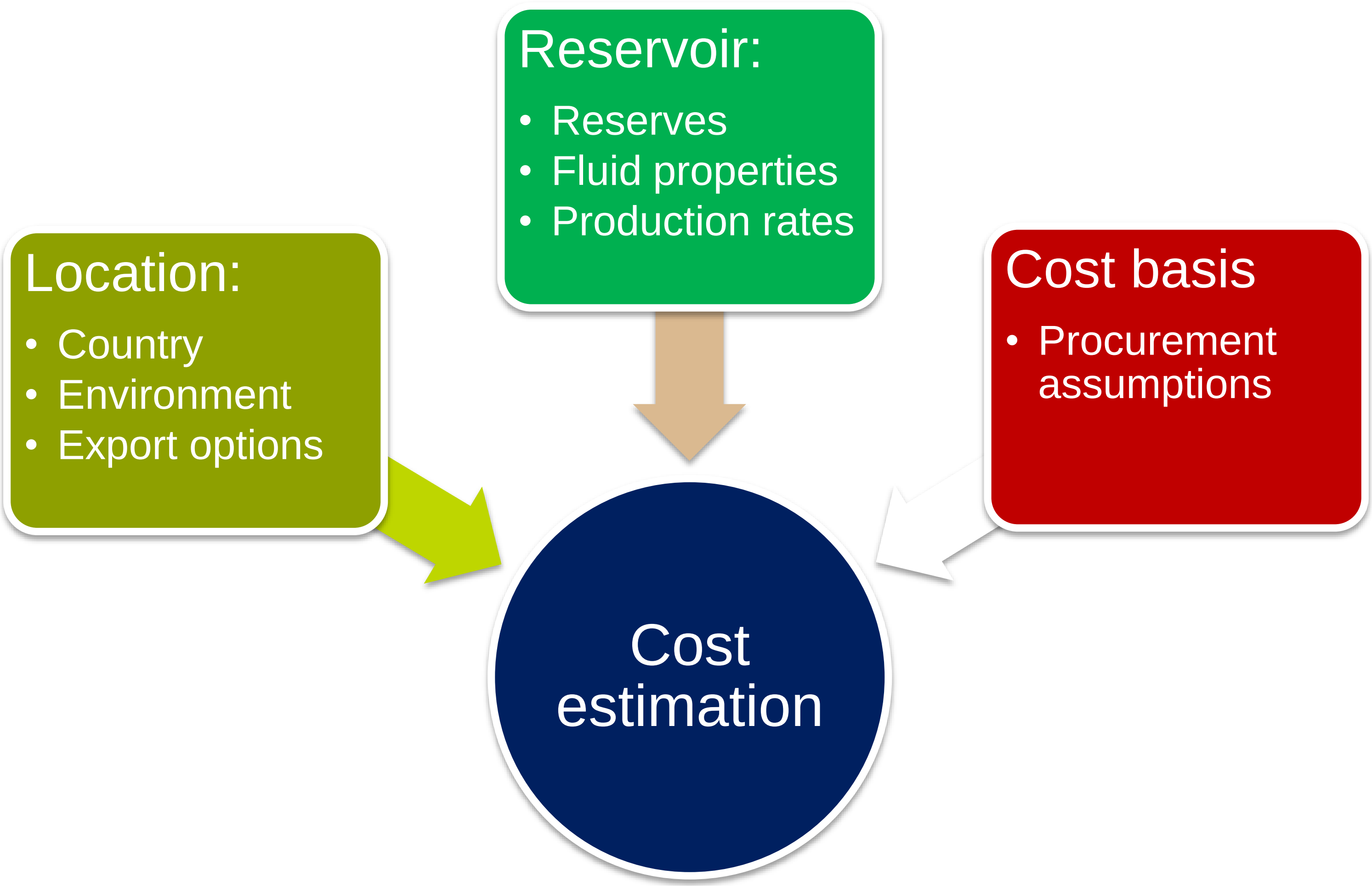
Decide

- Economics – Expected returns, investment levels
- Risk – Political risk

Cost Estimation Methodology

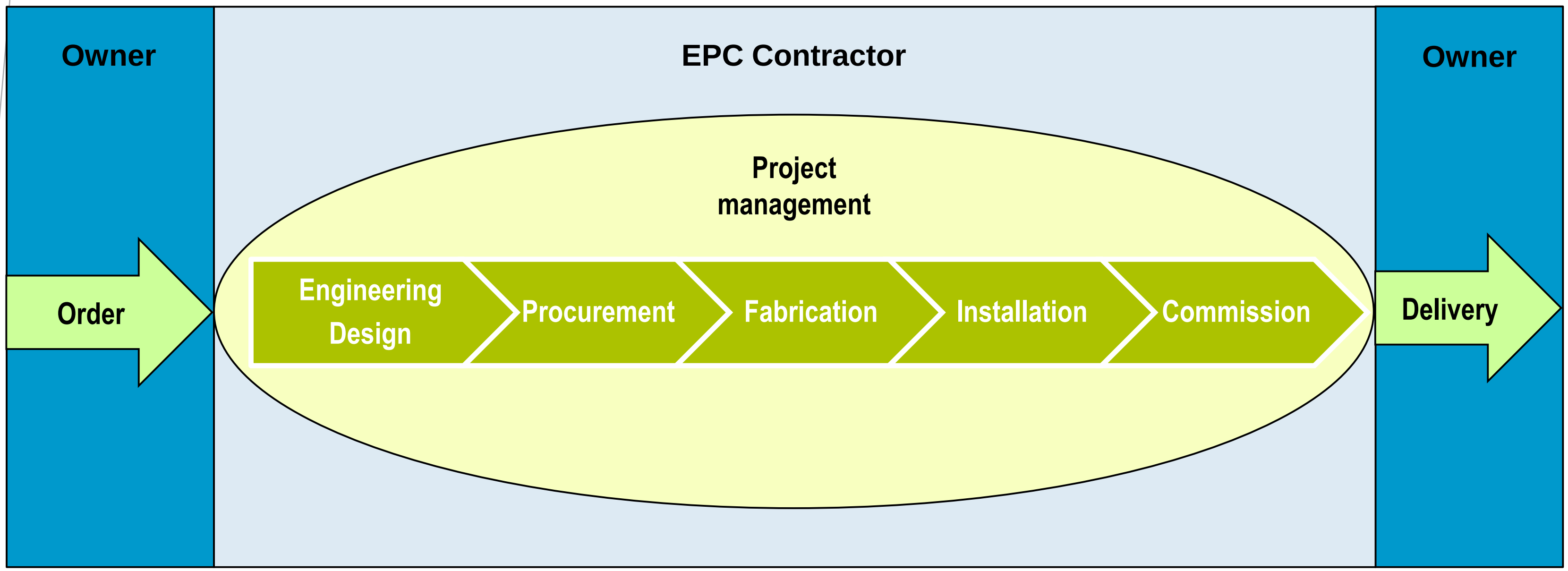
- All costs in "Real", i.e. non-escalated terms
  - Pre-tax costs
  - No cost inflation / discounting
- Costs built up by cost centre using Quantity x Unit rate
  - Equipment
  - Materials
  - Fabrication
  - Installation / Construction
  - Hook-Up and Commissioning (Offshore)
  - Design and Project Management
  - Insurance and Certification
  - Contingency
    - : In the range 10-25% to bring the estimate to the P_{50} level

Typical Required Inputs

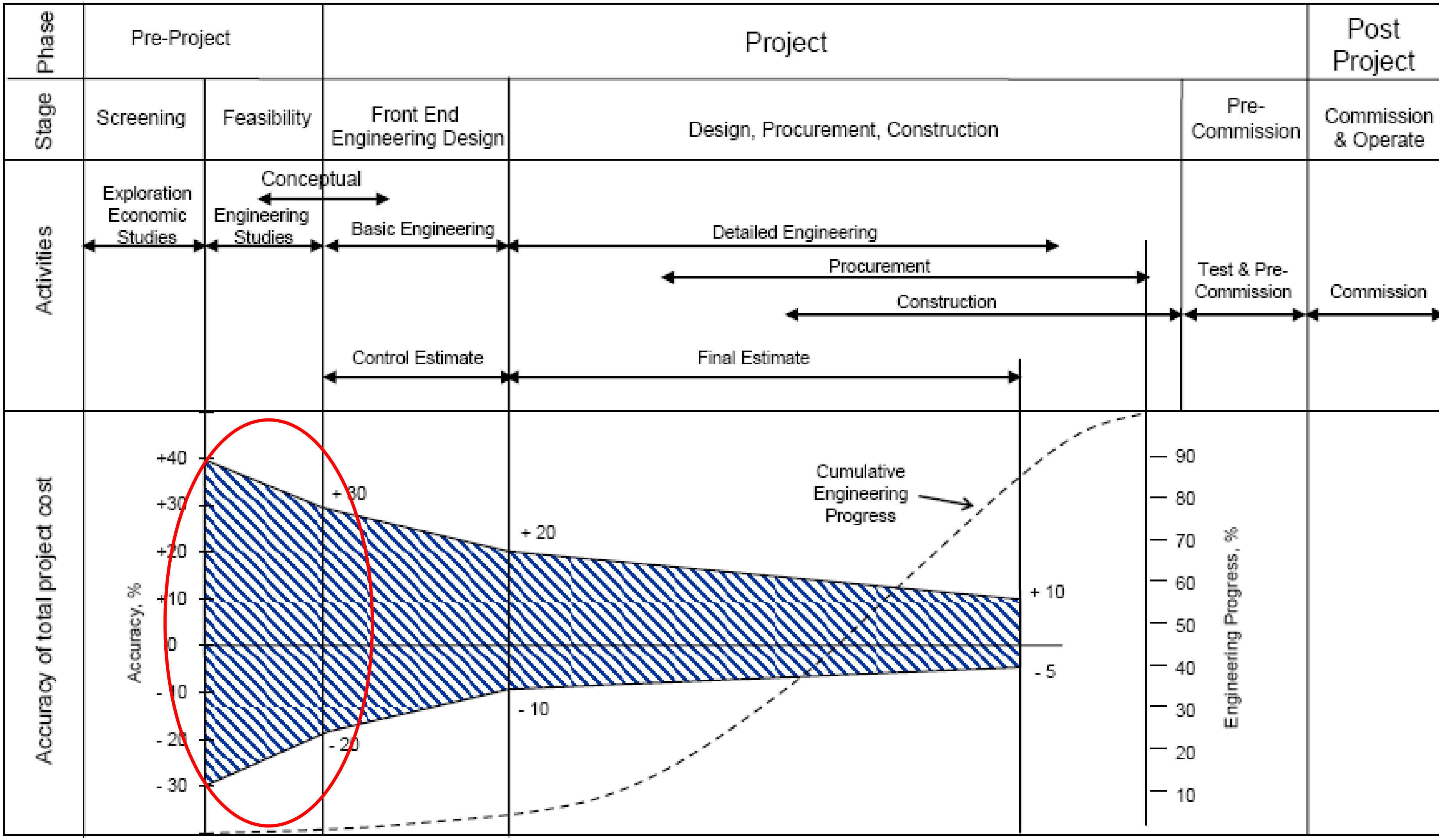


Estimate Scope - CAPEX

- Targeting "Middle of the Road" EPC (Engineering, Procurement & Construction) contract cost
  - Pre-sanction costs can be optionally added
    : (FEED study, Environmental studies)
  - Post-sanction, e.g. Owner's project management can be optionally added

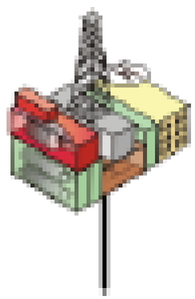


Project Cost Estimation

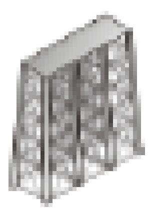


Component Listing - Offshore

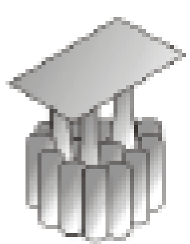
Offshore Components



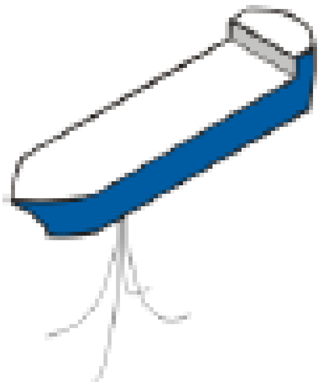
Topsides: can range from a small well protector platform weighing a few hundred tonnes, to a large drilling platform including processing, compression and quarters and weighing more than 30,000 tonnes. The main process systems can be specified together with the associated utilities, quarters and drilling and estimates equipment and bulk weights, material and fabrication costs, installation durations, design, management and HUC man-hours to produce an overall cost estimate.



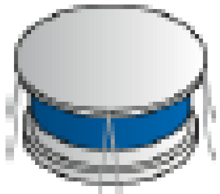
Jackets: traditional steel-piled jackets with three, four, six or eight legs can be selected based on the topsides weight, installation method and local environmental conditions. For topsides operating weights up to 1,600 tonnes and water depths up to 90m lightweight structures including guyed caissons, braced monotowers and lightweight jackets can be selected.



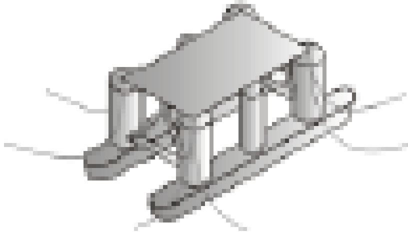
Gravity based structures (GBS): concrete GBS either conventional or monotower can be selected with or without storage. Typically used in the Norwegian sector of the North Sea.



Floating production storage and offloading (FPSO): can be either new build or converted monohull tankers up to 300,000 deadweight tonnes. Used in water depths down to 4,000m.



Cylindrical hull: A new build floating vessel that can be used for production and storage.



Semi-submersible: second to fifth generation new builds and second to fourth generation converted semi-submersibles can be selected with or without rigs. Used in water depths down to 4,000m.

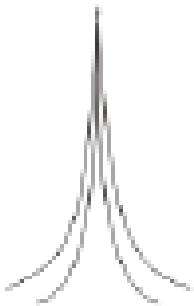
Component Listing – Offshore cont'd.

Tension leg platform (TLP): conventional and mini TLPs can be selected. Used in water depths down to 4,000m.

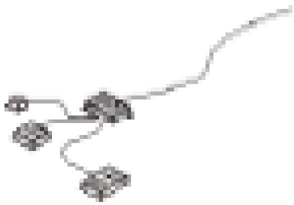
Spars: caisson, truss and cell spar buoys can be selected. Used in water depths down to 4,000m.

Barge: similar to tankers but of a much simpler design and without propulsion. Only suitable for shallow water (up to 50m) with mild environments.

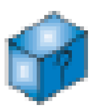
Offshore loading: a single-point mooring system with or without permanent tanker storage that provides an alternative to pipeline export of liquids.



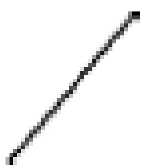
Drilling: exploration/appraisal and development drilling from a platform rig, jackup or semi-submersible. Includes all associated well costs; Xmas tree, wellhead, completions, production tubing, casing, conductors, rig hire, labour and consumables.



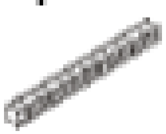
Subsea: template or cluster wells linked to manifolds, covers flowlines, umbilicals and risers. Includes features such as diver or diverless installation, steel or flexible flowlines, round trip pigging, trawl protection structures and new or retrofit risers. Used in water depths down to 4,000m.



User defined: a blank cost sheet into which any item not covered in the components listed above can be input for inclusion in cost summaries and schedules.



Pipelines: are defined by size, wall thickness, material and installation. The cost includes for risers, pipeline tie-ins and shore approaches. Used in water depths down to 4,000m.



Bridge link: a square or triangular section bridge that can be used between two fixed platform topsides. The bridge can transport process flows, utilities and power

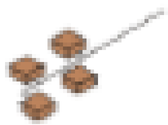
Component Listing – Offshore cont’d.

Subsea Toolbar

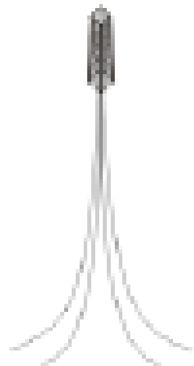
	Cluster manifold for four, six, eight, ten or twelve slots with wells connected by flexible jumpers. Click the arrow to display a dropdown list which enables you to change the number of wells in the cluster.
	Template structure, for four, six, eight, ten or twelve slots. Click the arrow to display a dropdown list which enables you to change the number of wells in the template.
	Satellite well – green for production, red for gas injection and blue for water injection.
	Commingling or distribution manifold, flowrates are combined.
	Flowline group - represents a bundle of flowlines, umbilicals and control and power cables.
	Hide/Show labels - click to toggle between hiding or showing all subsea item and link labels.
	Notes can be added to the subsea schematic using the annotation icon.
	Redraw configuration – reverts back to the QUE$TOR default layout
	Clear all – removes all subsea items and links (except for the root component)

Component Listing - Onshore

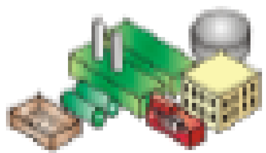
Onshore Components



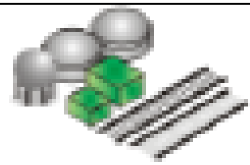
Wellpad groups: specifies the equipment at the wellhead together with the flowlines required to transport the produced fluids to a production facility and/or injection fluids to the wellhead. The costs can include manifolding at the wellhead, test facilities, pumps, power generation and power distribution. Wellpads are grouped for CAPEX scheduling purposes.



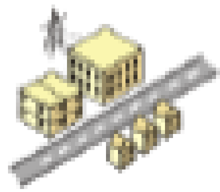
Drilling:covers appraisal and development drilling. The drilling rig characteristics and well type can be specified. The costs include rig hire and drill crews, Xmas trees, casing, production tubing and consumables.



Production facility: can range from manifolding for flowlines, to a large facility including manifolding, processing and compression. Processing, product storage, export pumping, gas compression, metering, water injection, produced water treatment, power generation, power distribution, utilities and controls & communications can all be specified.

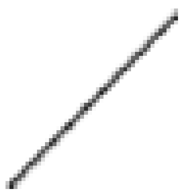


Terminal: can handle crude oil or any liquid derivative of oil or gas - NGL, LNG, Gasoline. The facility includes all storage and export systems. Export can be by road, rail, pipe or ship.



Infrastructure: includes all infrastructure requirements including roads, rail links, airstrips, camps and buildings.

User defined: a blank cost sheet into which any item not covered in the components listed above can be input for inclusion in cost summaries and schedules.



Pipelines: calculation of pipeline size and wall thickness, material, installation and design costs. The cost of booster or compressor stations can be added when required.

Case study: Gas field development

- Concept development phase
  - Concept selection weight & cost estimating basis
- Cost estimating methodology
  - Drilling
  - Subsea Facilities and Risers
  - Topsides
  - Semi-submersible/TLP Substructures
  - Floating Storage and Offloading Vessels
  - Floating Production Storage and Offloading Substructures
  - Jacket/Pile Substructure
  - Self-Installing Fixed Substructures
  - Concrete Gravity Substructures
  - Transfer Pipeline System (CPF or CGS to FSO)
  - OPEX
  - Currency Exchange Rates
  - Presentation of Cost Data

- Costing basis
  - Indirect Costs
  - Drilling
  - Subsea Facilities
  - Topsides
  - Semi-Submersible/TUP Substructures
  - Floating Storage and Offloading (FSO) Vessel
  - Floating Production Storage and Offloading Substructures
  - Jacket/Pile and CGS Substructures
  - Contingency

Definition

- Direct cost

  : Direct costs include all costs not associated with design, engineering/project management and third party duties/charges, that result in installed and commissioned field facilities.

  : Direct costs include, but are not limited to:

  - Materials;
  - Fabrication/Mechanical Completion;
  - Hook-up and Commissioning;
  - Mobilisation/Demobilisation
  - Transport;
  - Installation; and
  - Weather Allowance.

- Indirect cost

  : Indirect costs include those associated with design, engineering/project management, third party duties/charges, that result in installed and commissioned field facilities.

  : Indirect costs include, but are not limited to:

  - Detail Design/Engineering;
  - Contractor Project Management;
  - Customs Duties (where applicable); and
  - Freight/Inspection.

- EPC cost (Contractor’s cost)

  : EPC Costs are defined as the installed cost of the field of facilities excluding Insurance, Certification, Owners Costs and Contingency.

  : This definition also applies to the term Contractor Costs where presented in the cost estimate tables.

- Owner’s cost

  : These are defined as Project Management Team and Parent Company Overhead costs, including, for example:

  - Direct allocated costs;

  - Indirect allocated costs; and

  - Third Party Service Agreements.
- Certification and insurance

  : Defined as costs incurred by INPEX for Certifying Authority services and Insurances (including self insurance allocated costs).
- Contingency

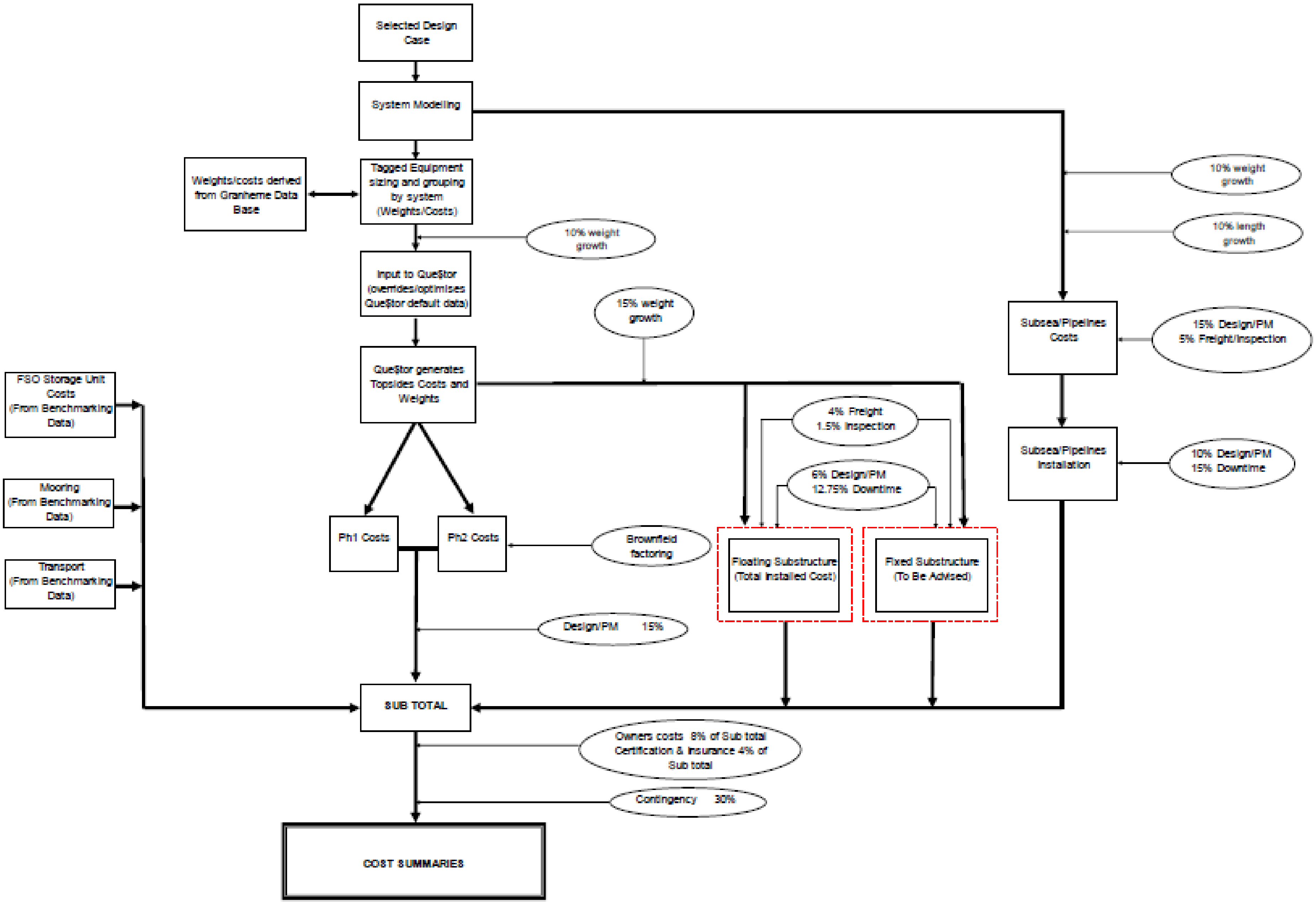
  : Defined as a factored sum intended to provide for outcome costs of facilities and services not currently in the scope of each concept case, that may eventuate through the project execution.

Project overall cost:
Sum of EPC cost + Owner’s cost + Certification and insurance + Contingency

Cost estimating methodology

- The cost estimates have been defined at a level of detail sufficient to establish a +/- 30% accuracy, consistent with the work method and accuracy
- The nominal accuracy stated is intended to convey that the Project Overall Cost estimates would be mid range estimates and could vary significantly up or down from the numbers presented.
- No specific probabilistic assessments have been undertaken as part of the estimating method.
- The overall approach to costing is illustrated in Appendix I ‘Cost Estimating Workflow’.

Cost Estimating Workflow Diagram



- Drilling

: Drilling costs have been addressed separately by INPEX and are not included in the cost estimate methodology presented in this report.

- Subsea facilities and risers

: The subsea facilities costs include the manifold and flowline termination structures, piping/valves, controls, umbilical and equipment to connect to the risers at the production facility.

: CAPEX costs for future brownfield subsea work is also included for the replacement of carbon steel pipelines and the replacement of flexible risers at Infield locations.

: The estimates (including materials and installation) have been developed using a ‘building block’ approach which enabled similar cases to be costed efficiently.

- Topsides

: The basis for input to costing is the items on the major process equipment list for the process facilities (developed via process simulations and equipment sizing routines).

: The equipment list also includes the load requirement for process support and utility systems (cooling, heating and electric power).

: The estimate is then built up as follows:

- Given the defined process equipment, the process support and utility equipment is estimated using Que$tor, generating the total equipment estimate;
- Based on this the bulk materials are factored in;
- Other ancillary items, e.g. flare, are estimated using Que$tor;
- The weight of the accommodation module has been estimated based on in-house benchmarked data. A weight of 960 tonnes has been applied for 80-man modules, and 600 tonnes for 40-man modules;
- A Que$tor generated margin (5-10%) has been applied to the dry weights calculated to obtain operating weights. This margin allows for process fluids loads and live loads (such as containers); and
- A 15% weight factor is then applied to estimate the predicted gross dry/operating weights used for substructure design.

: The topsides estimate is then built up in a logical fashion with unit rates applied for procurement and fabrication.

: The estimates make provision for load out of the topsides and mating/integration/inshore HUC as required for floating substructures and then transportation/installation/offshore HUC of the completed unit in the field.

: For concepts where the topside cannot be integrated with the substructure in or adjacent to the fabrication yard (e.g. jackets) the topside(s) are assumed to be transported to the field location where all integration/HUC would take place.

: The topsides estimate includes all components above the substructure. For semisubmersibles, this is the top of columns.

- Semi-submersible/TLP substructures

: For the production facility hull, the costs have been based on a previous study which considered a semi-submersible and TLP substructures for a range of topsides operating weights.

: The total installed cost versus topsides operating weight is an approximately linear relationship, with TLP's costing approximately 15% more than semi-submersibles, and having similar hull weights.

: Previous result shows the breakdown of semi-submersible weight and cost used for Concept Selection. Where required TLP substructure costs would be considered using the 15% uplift.

- Floating Storage and Offloading Vessels

: For the FSO, a high level cost based on the storage capacity and thus total light ship weight of the vessel has been used. A rate per tonne lightweight has been used to establish the total fabricated cost of the vessel.

The mooring system and transport and installation costs are fixed based on previous project estimates. A fixed cost uplift for increased fatigue life is added to cover the cost of modifying a standard build trading tanker specification to a permanently located in-field vessel.

- Floating Production Storage and Offloading Substructures

Where FPSO substructure costs have been estimated, these have been based on the lightship weight determined and using the same cost basis as the FSO hull. Costs for swivel, turret and mooring systems have been assessed and included on a case by case basis.

- Jacket/Pile Substructure

: Jacket and pile weights and costs have been based on previous project experience and the CDP structural design premise

- Self-Installing Fixed Substructures

: These types of facility substructures have not been assessed during Concept Selection, and will be addressed for any fixed facilities remaining in the Refine phase.

- Concrete Gravity Substructures

: Company B have provided screening level input to generate weight and cost estimates for CGS substructure and storage options, as required by the case matrix.

- Transfer Pipeline System (CPF or CGS to FSO)

: Transfer lines between the CPF or CGS and FSO have been estimated using the cost method used for the subsea facilities.

- OPEX

: Operating costs (per annum) have been estimated using factors based on CAPEX.

: The following factors have been used:

- Wells 6%
- Subsea Facilities 3%
- Flowlines 1%
- Topsides 5%
- Substructure (Fixed) 5%
- Substructure (Floating) 5%
- FSO 5%

Costing basis

- Subsea facilities

: The subsea costs include the manifolds, flowline termination structures, flowlines, risers and umbilicals.

: Equipment is specific for each phase of installation depending on well counts and functionality.

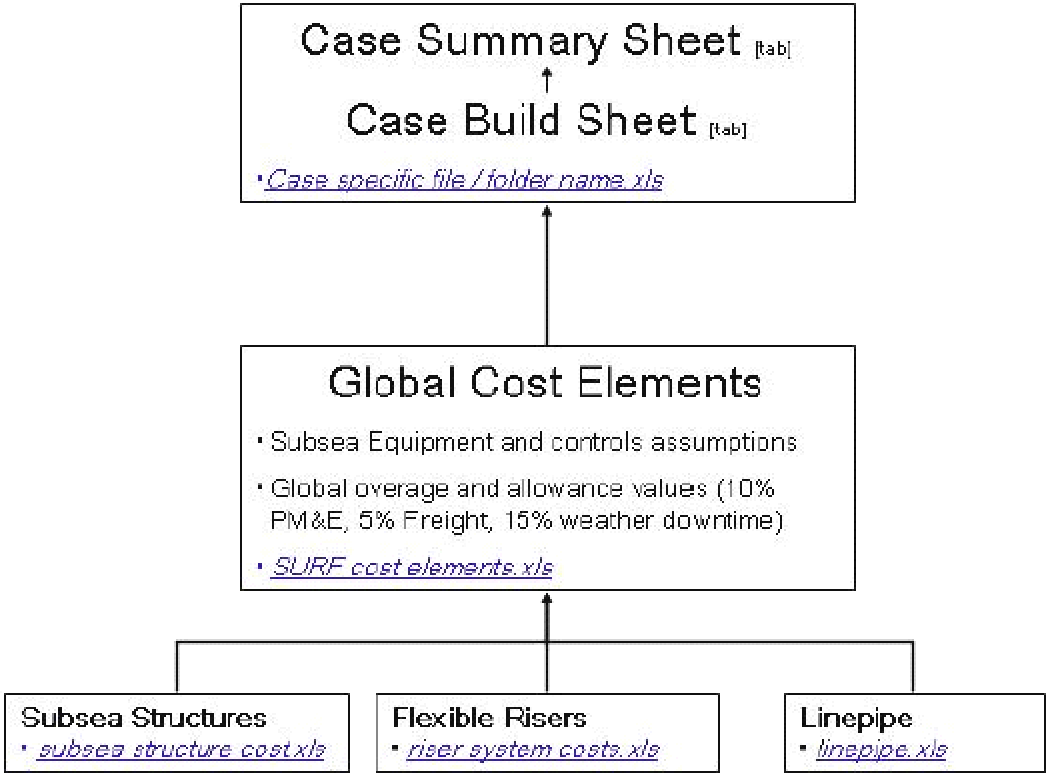
: The installation cost has been determined by assessment of the vessel spread required, the durations of the vessels and day rate then gives the cost.

: The subsea costs have been presented as Subsea Umbilicals Risers and Flowline (SURF) costs and Installation costs for each phase of development

SURF Common Overages/Allowances

Description	Percentage, %	Of
Flowline and Umbilical Overages	10	Direct lengths
Subsea Structure Weight Allowances	10	Calculated Weights

- The overall cost estimating methodology used for the subsea systems



- Subsea material cost ranges

Description	Cost (US$)	Basis
CRA Material Cost – 316L	5,100-6,300	Per tonne, 4" to 26"
CRA Material Cost – 825	7,600-10,080	Per tonne, 4" to 32"
Carbon Steel Material Cost	1,300	Per tonne, all sizes
Insulation Coating	333,000-794,000	Per km, for 12" to 32"
Manifolds	2.8-5.2 Million	4 slot to 10 slot
Infield Gathering Manifold (18")	8.8 Million	6 x 18" tie-ins.
Umbilical	$170-$310 per m	2-10 well cluster sizes
12" Flexible Riser	2.4 Million	Complete with ancillaries
Riser Bases	1.0-3.2 Million	4" to 26"
PLETs	0.2-4.7 Million	4" to 34"
Main Jumpers	532,000	18"
Well Jumpers – Solid Duplex	810,000 -889,000	6"-8", included Multiphase Meter

- Subsea installation cost ranges

Description	Cost (US$)	Basis
Lay Barge	450,000	Per Day
Lay Barge Mob/demob	15 million	Per Campaign
MSV	200,000	Per Day
MSV Mob/demob	4 Million	Per Campaign
Survey	1,000,000	Per Campaign
CRA Pipelay rates	0.8-1.8	km/day, 36" – 4"
Carbon Steel Pipelay Rates	2.3-4.5	km/day, 36" – 4"

- Topside

: Topsides process equipment has been defined according to the relevant process design (the specific simulations predicting the required equipment duties) and the weight estimated per equipment item.

: This allows the process equipment costs to be assigned per equipment item. A 10% allowance has been added to the weights for cost estimating purposes.

: The non process equipment quantities and costs have been estimated based on the defined process support loads (electric power, seawater, cooling medium and heating loads).

: Costs for individual pieces of equipment have been itemised in the equipment lists developed for each case under evaluation during the concept screening process. The costs of individual equipment items have been grouped by system and a unit cost rate per system is established.

- Topside bulk materials

: The estimate of bulk materials has been built up from factors applied to the equipment weights. The bulk materials typically apply to areas such as piping, electrical and instrumentation.

: The weight of the bulk materials has been compared against recent (similar) projects and the following factors derived and applied directly to the predicted equipment weight:

- Piping 62% of the equipment weight;

- Instruments 16% of the equipment weight;

- Electrical 11% of the equipment weight; and

- Other bulks 20% of the equipment weight.

: Bulk (Primary and Secondary) steel weights are specific to the proposed development option, e.g. inte.g.rated deck or modular deck on a jacket or semi-submersible substructure. The bulk steel weights have been calculated using Que$tor and range typically from 35% to 50% depending upon the topsides considered.

: The costing basis used for the topsides bulk is based on a labour cost of US$ 30/manhour.

Thank you!