Chapter 1

Field Development Plans

1.1 What is a field development plan?

During the exploration phase, companies drill exploration wells to determine whether the petroleum reservoirs exist. If a discovery is made (i.e. the well encounters a petroleum accumulation or "reservoir"), the company enters an appraisal phase to better understand the size of the field (grouping of multiple reservoirs), subsurface risks and to determine if it can be technically and commercially developed. If the company determines that it is a "commercial discovery", the next step is to decide how the field will be developed.

A Field Development Plan (FDP), outlines how a company intends to develop a petroleum field, manage the impact on the environment and society, as well as forecasts for production and costs. This involves complex issues such as how to manage the reservoir, how to bring the petroleum to surface (wells), process (facilities), transport to markets (e.g. pipelines, tankers, storage) and sell the various products. It is the outcome of a complex and long process of evaluating multiple development concepts for a field and selecting the best option that successfully manages risks and delivers the greatest value to its shareholders.

Why is it important?

Developing a petroleum field requires the safe and efficient execution of complex, technical, multi-billion[1]-dollar projects. The FDP is the blueprint for how this will be done and is therefore critical for both the company and the country to maximise value and minimise risks from an oil and gas project. In most countries it is unlawful to develop petroleum without the government's approval of an FDP.

A company will not ramp up activities on a project until it has received government approval of its proposed plans given the significant risks and investment. In many instances, the ability to secure financing will be conditional upon receiving such approval.

From the country's perspective, an FDP will have significant implications for the economy (e.g. government revenues and local content) the environment and communities. In most countries, petroleum resources are vested in the State on behalf of its citizens. For a developing country, an FDP which produces a

1 The average cost US$6 – 11 billion "Spotlight on Oil and Gas Megaprojects" Ernst and Young report

successfully executed project has the potential to significantly increase GDP and increase government revenues.

A well-designed FDP is a necessary but not sufficient condition for the oil and gas project to contribute to economic development while minimising social disruption and environmental harm.

A Government's regulatory role is to ensure the company's proposed plan aligns with the governmental strategies for the sector and the selected development concept ensures the safe, sustainable, optimal development of the country's finite resources. However, the view on what is "*optimal*" may not necessarily be the same bewteen the company and the government. It is therefore imperative that the regulator ensures the country's interests are adequately incorporated into how the resources will be developed. Once approved, all future activities on the field should be consistent with the FDP.

The FDP is therefore one of the most important approvals in an oil and gas project.

1.2 How do companies create a field development plan?

Bringing petroleum discoveries to production requires the safe and efficient execution of extremely complex, technical multi-billion[2]-dollar projects. These projects have significant risks and, if poorly executed, can result in environmental disasters, severe financial repercussions and reputational difficulties for the companies involved.

As such, oil and gas companies have developed processes to manage risks and maximise returns from projects. The FDP is a critical part of this process.

The company processes are based on the principle that good planning is fundamental for the success of a project. It is well known that the ability to affect outcomes without significantly impacting costs is highest at the start of the project and decreases as the project moves towards completion. Costs and staffing levels are relatively low at the beginning of a project and will ramp up significantly once design decisions are made as materials and expertise etc. need to be procured for actual construction. Without effective planning, rectifying errors or making changes later is costly, difficult and may jeopardise the project's goals.

This is often referred to as the cost-influence curve (shown in Figure 1.1) and illustrates that opportunities for value optimisation are greatest in the planning and design phases of a project.

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2 The average cost US$6 – 11 billion "Spotlight on Oil and Gas Megaprojects" Ernst and Young report

Figure 1.1 Project Cost/Influence Curve

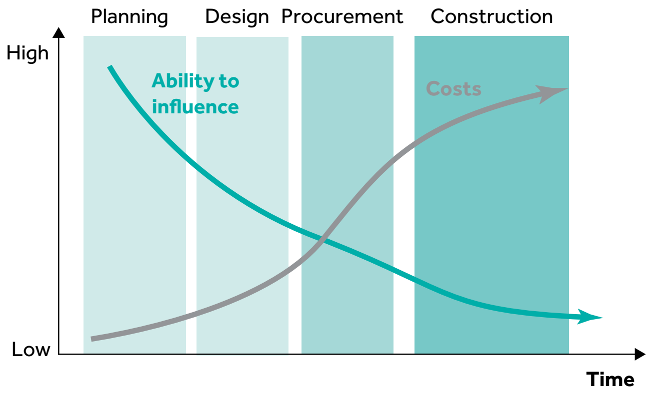
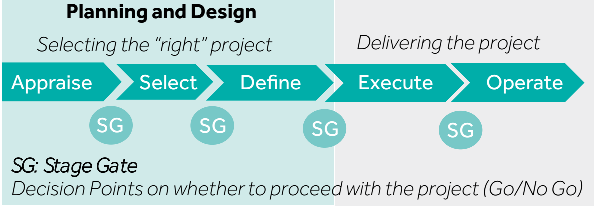


Figure 1.2 Stage Gate Process



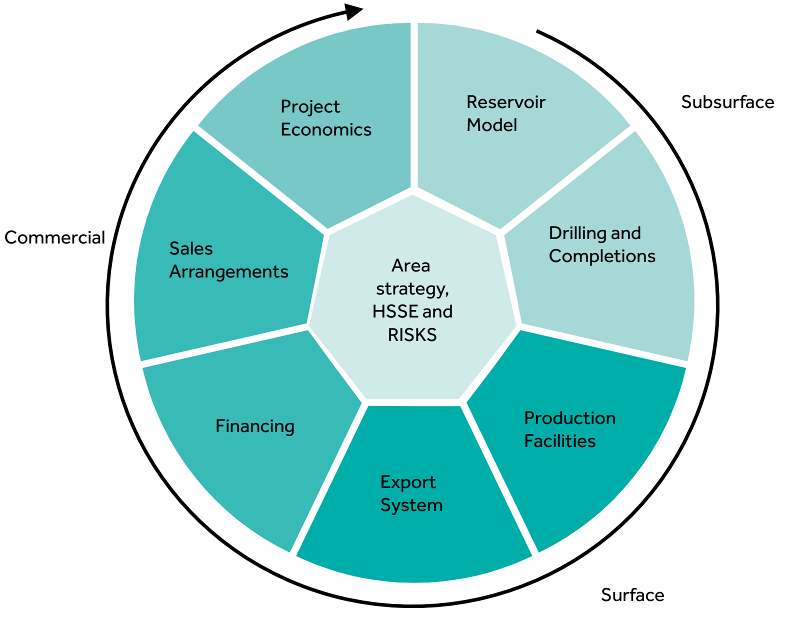
Oil and gas companies apply this concept to the progression of a discovery to production by using a phased or "stage gate" (SG) process. The terminology used for this project management system varies among companies, but typically consists of the Appraise, Select, Define, Execute and Operate phases. At the end of each phase, senior management reviews project progress (via standardised reports, metrics etc.) and makes a decision on whether the project can proceed to the next phase or if it should be dropped, delayed or requires further work. During the planning and design stage, the focus is on "selecting the right project" and thereafter it is around implementation, as illustrated in Figure 1.2.

This structured approach ensures that senior management has sufficient oversight and control on the project before committing further company resources to the project. The typical activities in each phase are as follows:

- *Appraise*: Post-discovery, an appraisal programme is developed to assess the size of the discovery which will carefully balance the need and cost of additional information with the additional benefit it brings. Efforts are focussed on data collection (e.g. seismic surveys/drilling additional wells) and analysis to assess the amount of oil and gas (volumes of hydrocarbons in place) and crucially how much can be recovered. Data is also collated on its characteristics, drilling hazards and potential production levels (reservoir and well performance uncertainties may influence this). This culminates in a decision as to whether it is technically and economically viable to develop the field – i.e. if it is a "commercial discovery".

- *Select*: Different options to develop the field are created, evaluated and a preferred concept is selected. This involves complex issues such as how to manage the reservoir, the design and management of various aspects required to bring the hydrocarbons to surface (e.g. wells/facilities), transportation to markets (e.g. pipelines, tankers, storage and export systems), financing and sales arrangements. Determining the optimal plan that minimises the risks and maximises value is an iterative process that requires multi-disciplinary collaboration to ensure an integrated approach to developing the field. (as illustrated in Figure 1.3). This involves specialists such as geologists, geophysicists, engineers (petroleum, reservoir, drilling, completion, facilities) HSE and commercial teams.
- *Define*: The selected development concept is optimised, and a detailed project plan is developed. Costs begin to ramp up as the project team is expanded and long-lead items are procured. Technical specifications (Front End Engineering and Design ("FEED"), cost estimates, contracting strategies, risk management (identification and mitigation) and the project schedule are developed to an appropriate level of detail to freeze the scope of the project. The detailed engineering and benchmarking will result in a more comprehensive understanding of the project and forecasts of production and costs etc. At the stage-gate review, if senior management is confident the project has met all the necessary technical assurance requirements, that it is value accretive and controls are in place to deliver the project on time and budget, it will be "sanctioned" and progress to the next phase. This is referred to as the Final

Figure 1.3 Integrated Field Planning – Multi-disciplinary Iterative Process



Investment Decision (FID) and is the company's commitment to invest money (often billions of dollars), people (project teams will include several technical disciplines) and other resources into the project. FID will therefore also depend on the company's ability to fund the project, as well as how the project ranks among other investment options.

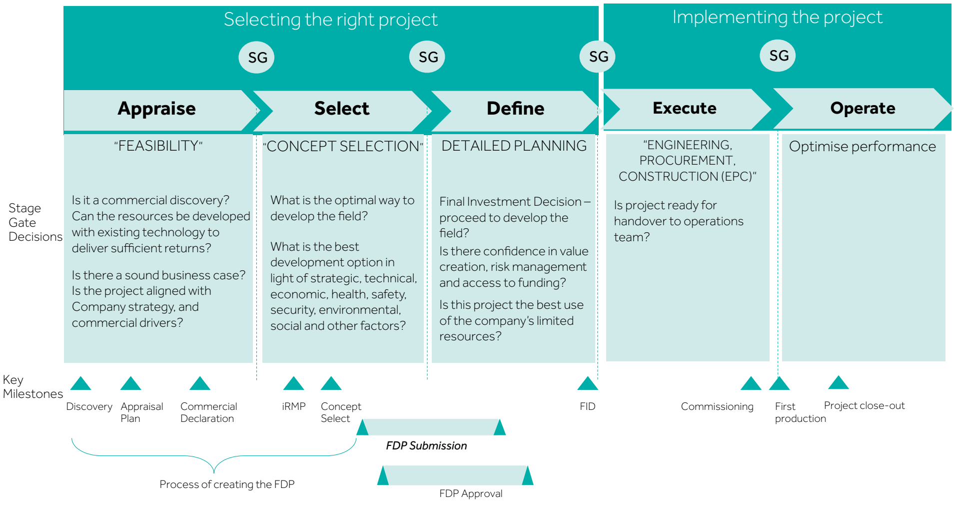
- *Execute*: Activities are executed per the project plan with the oil and gas company in the role of 'project managers' as the work is carried out primarily through specialist firms. Most of the project expenditure is incurred as EPC (Engineering, Procurement and Construction) contracts are signed, wells are drilled and facilities are built, installed and commissioned. Ability to meet project cost and schedule will depend heavily on the quality of pre-sanction preparation.
- *Operate*: Production begins, revenues are generated and the asset is managed to maximise returns. The economic life of a field can extend to 20–40 years and production methods used will depend on the reservoir characteristics and the age of the field. Initially, petroleum is brought to the surface from the natural pressure of the reservoir combined with artificial lift techniques such as pumps (primary recovery). When the pressures fall as the field matures, injecting water or gas to displace and drive the hydrocarbons into the well can increase production levels (secondary recovery). There are also tertiary recovery methods which can extend a field's productive life such as introducing heat, gas (e.g. natural gas, nitrogen, carbon dioxide) and chemicals. Given the long lifespan of the asset, it will require significant maintenance over its useful life (e.g. wells – workovers, pipelines – pigging, facilities - turnarounds). When it is no longer economical to produce the field, it will have to be decommissioned (i.e. wells plugged and abandoned, facilities removed, the site restored and monitored). Planning for decommissioning is an integral part of the overall field development process and should be considered during the design phase.

The FDP submission to the government is the outcome of the integrated field planning that occurs during the appraise, select and define phases. It is the documentation of the company's decisions, the rationale and initial forecasts for an oil and gas project including its impact on the environment and society. It is the critical mechanism that ensures there is shared understanding between the company and government on how petroleum resources from a particular discovery will be produced, monetised, risk managed and its inherent value shared.

Depending on the nature of a project, the company's project management process, its risk appetite as well as regulatory requirements, an FDP could be submitted during either the Select or the Define phase. It is often the case that companies will seek governmental approval of the FDP prior to any significant increase in costs during the Define phase.

A summary of the stage-gate process, the key decisions and the linkage with the FDP is illustrated in Figure 1.4 below.

Figure 1.4 The stage-gate process and the FDP



iRMP, initial Reservoir Management Plan; FID, Final Investment Decision

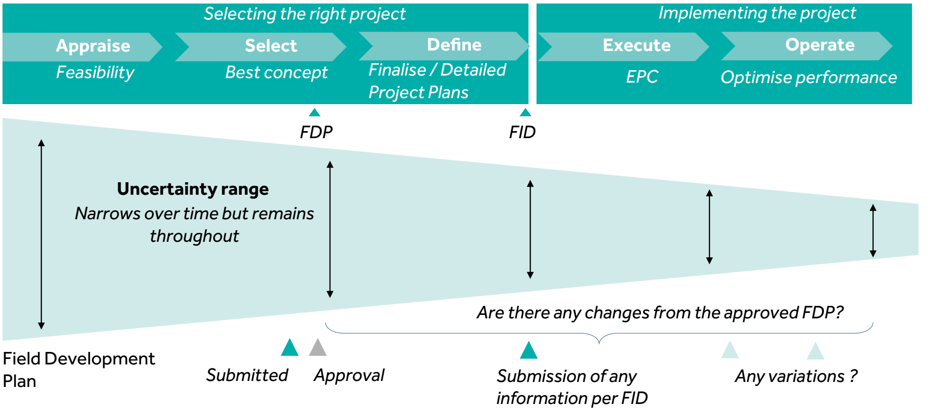
1.3 The challenge of developing FDPs – decision-making under uncertainty

The FDP should consider the entire life cycle of a field up to and including decommissioning. However, it is often developed across the Appraise and Select phases when there is limited information and a wide range of uncertainty on several critical variables. A robust FDP will consider these risks and uncertainty and include them in the evaluation of various development options.

The subsurface is at the heart of a petroleum project and is the largest areas of uncertainty. Oil and gas are produced from underground reservoirs in depths ranging from 5,000 to over 25,000 feet depending on the location. There is no visibility of the subsurface conditions and it can only be estimated by experts using various technologies – data gathering, evaluation and modelling. It is complex and the ability to make effective predictions will depend on reliability and relevance of information gathered during the Exploration and Appraisal phase.

All other disciplines work with the subsurface assumptions as a critical input. Reservoir conditions such as fluid characteristics, impurities, drive mechanism, and others subsurface factors (e.g. pressure, temperature and shallow hazards) will impact the drilling programme (e.g. type of drilling fluids, number and placement of wells, completion design, safety measures). This in turn will have implications for the design of the facilities and infrastructure (e.g. type of processing/pipeline size). These factors are interdependent and require significant co-ordination to understand how choices made in one area effects the others. The various subsurface and surface disciplines will employ appropriate techniques to establish the risks and determine options for developing a field

Figure 1.5 Uncertainty and the FDP



1.4 What factors influence the FDP?

An oil and gas company will consider several factors when determining the optimal solution for producing oil and gas from a commercial discovery. This involves complex issues such as how to manage the reservoir, the design and management of other aspects required to bring the hydrocarbons to surface (wells/facilities), transportation to markets (e.g. pipelines, tankers, storage and export systems) and sales arrangements. The process of developing the FDP will consider issues such as:

- Safety and environmental considerations
- Alignment with the company's strategy and commercial drivers
- Location: whether the discovery is onshore or offshore and site specifics (e.g. water depth), proximity to infrastructure and other fields, distance to markets, susceptibility to disruptions (e.g. natural disasters).
- Technical factors such as
  - Geology: the reservoir is at the heart of the FDP and influences many other critical design components. Characteristics such as the hydrocarbon type (oil/gas, Gas Oil Ratio "GoR"), the volumes in place (how much oil and gas is underground), recovery factor (how much can be produced from the reservoir), quality (heavy/light, impurities), number and compartmentalisation of reservoirs (stacked or fragmented), pressure and temperature will influence the drilling and completions programme, surface equipment, facility type, processing requirements, export systems capacity and sales arrangements.
  - Available technology and engineering considerations. This will impact various aspects such as drilling, completions, facilities and export systems.

safely. Part of the company's stage-gate approach to decision making will include technical assurance of these decisions. This often includes a review by subject matter experts who are not involved in the project to provide independent assessments, referred to as "peer reviews".

Ultimately, a company will only proceed with a project that is both technically and commercially viable – i.e. can it be developed safely, with available technology? Can it generate sufficient economic returns?

Economics therefore plays a central role in generating and selecting the development option. A project's economic return is dependent on both technical and commercial factors, and there is a large degree of uncertainty across both.

The economics will depend on the amount and timing of the net cash flow from the asset over its useful life. This can extend over 40 years. The net cash flow is the amount of cash that a company expects to receive after deducting costs, taxes and other cash outflows from revenues. Revenues are determined by price (very uncertain and extremely volatile) and production of oil, gas and related products (e.g. natural gas liquids). Deductions would include the cost to develop (capital expenditure, "capex"), operate (operating expenditure, "opex") and decommission ("decom"), as well as payments to the government. In some countries where the fiscal regime is ambiguous, or silent on certain elements, assumptions will have to be made. The project economics therefore encapsulate a project's risk, as it depends on technical, commercial and regulatory factors.

When the FDP is being developed (Appraise/Select), uncertainty is at its highest as there is limited information. Estimates of the project's costs, production and revenue will depend heavily on benchmarking and the judgement of experts (e.g. interpretation of modelling). The FDP's purpose is to document the preferred development concept in light of those uncertainties and the assumptions made. The use of scenarios, and stress testing the project to downside cases is common practice. This helps to understand project returns under a range of outcomes with key variables taken into account.

Uncertainty remains throughout the life of the asset, but as further information is collected and additional technical work is completed (Define, Execute, Operate) the range of uncertainty is smaller.

A well-constructed FDP will consider the uncertainty range but it should not be treated as a static or inflexible document. It may be necessary to update and modify the FDP as circumstances change over the project lifecycle (see Figure 1.5). For example, if the FDP is submitted at the end of the Select Phase, detailed engineering and studies would not yet have been completed. It is possible that during the Define phase, as a consequence of new information and analysis, the FDP may require changes. This may also occur during the Operate phase where, for example, reservoir performance is not as expected (there may be higher or lower rates or different fluid properties) which may require changes to drilling plans or existing processing facilities. Material changes should be reflected in the approved FDP.

  - Operability: track record and reliability of various options as well as understanding of the future operations and maintenance requirements

- Impact on communities
- Time to production: earlier production is generally favourable as in most instances would enhance project economics.
- Flexibility if risks materialise especially adaptability to reservoir and well uncertainty.
- Costs and ability of operator to fund the development: The timing and amounts of capital expenditures (capex) and operating costs (opex) can impact project economics. Depending on the cash flow position and balance sheet strength of the operator access to finance and financing costs may also influence the preferred development option.
- Availability of specialist equipment – for example deepwater drilling rigs, construction yards
- Alignment amongst partners. There are often several owners in an oil and gas project which is usually structured as a Joint Venture (JV). The strategic and commercial drivers may vary amongst owners and the technical perspectives may also be different. The operator will in the first instance need to ensure that there is JV alignment and support for the FDP prior to submission to the Government. In several countries the National Oil Company is often a JV partner.
- National policies and regulatory requirements. The FDP will be subject to a nation's policy and legal framework. These instruments should incorporate the country's strategy for development of the sector and associated conditions and obligations which can influence the FDP e.g. domestic utilisation of oil or gas, contract/license duration, when the FDP needs to be submitted, its contents etc.
- Risk assessment. Risks and uncertainty are at their highest post discovery and, although they narrow over time, they remain a mainstay of any oil and gas field. The nature of risks impacts all aspects of the project and would need to be addressed in the FDP. This includes matters such as technical, HSSE (Health, Safety, Security, Environment), social, legal, commercial and project execution.
- Maximising value. There are various economic indicators that companies consider such as Net Present Value, Internal Rate of Return, Payback Period and Capital Efficiency. The company will consider which concept yields the highest economic returns.

The areas above are not mutually exclusive and require an integrated approach to developing a field. The strategic, technical, economic, social and environmental issues need to be assessed in order to determine the optimal concept.

Figure 1.6 summarises the key factors that will influence the company's choice of how to develop the field.

Ultimately, given the stage-gate approach, for the project to proceed into the Define phase, it will have to meet three key thresholds:

- Can the project be executed safely with existing technology?
- Are the risks well understood and considered in the project plan?
- Are the returns sufficient given the risks and other alternative opportunities?

Figure 1.6 Factors influencing the FDP (optimal development concept)