Oil & Gas Authority

Guidance on the preparation and content of offshore oil and gas field development plans

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Preparation of a Field Development Plan document

Set out below are suggested Field Development Plan (FDP) section headings together with the topics that should be addressed in the FDP. The content of the document should be agreed with the OGA and will depend on the complexity of the field, the degree of interaction with the OGA prior to the submission of the FDP, and the issues identified. The FDP will provide a clear explanation of the commitments that the licensees are making (in terms of facilities, number of wells, provision for Improved Oil Recovery (IOR) or Enhanced Oil Recovery (EOR), provision for third party access hydrocarbon export routes etc) to bring forward a sound development, rather than a detailed technical description of the subsurface reservoir description or required infrastructure. It is anticipated that, for small field developments, for example those involving a subsea tie back to an existing platform, the norm for FDP documentation will be in the region of a maximum of 15 pages of text plus associated figures and tables. More comprehensive or varied text, which some operators might for example choose to submit for partner reasons or internal preferences, will be accepted provided it covers the OGA's information requirements. For larger new field developments, or developments involving more complex or challenging reservoirs, a more comprehensive document may be required.

The operator should discuss the expected scope for the FDP document with the OGA early in the process.

Only very brief summaries will be required for reservoir description (section 2), although operators will be expected to keep their own detailed record of how the reservoir model was arrived at as part of good oilfield practice. The section should also contain sufficient information on the reservoir to enable its suitability for EOR techniques to be assessed.

The form of the development and the basis for field management should be described in section 3 and sufficient detail will be required to permit development and production performance to be measured. Operators are encouraged to refer to internal documents and studies in sections 2 and 3 to keep FDP documentation to a minimum. A list of references can be provided in section 4.

The FDP should be submitted formally by uploading a digital copy (preferably a PDF) as an attachment to the portal application for Development and Production Consent.

Suggested contents of FDP document

The suggested section headings for a FDP document are set out below. Additional details are provided in the following section.

Section 1. Executive summary

Section 2. Field description

- 2.1 Seismic Interpretation and Structural Configuration
- 2.2 Geological Interpretation and Reservoir Description
- 2.3 Geological Model
- 2.4 Petrophysics and Reservoir Fluids
- 2.5 Hydrocarbons Initially In Place
- 2.6 Reservoir Modelling Approach
- 2.7 Reservoir Development, Improved and Enhanced Recovery Processes
- 2.8 Wells Design and Production Technology

Section 3. Development and management plan

- 3.1 Preferred Development Plan, Reserves and Production Profiles
- 3.2 Drilling and Production Facilities
- 3.3 Process Facilities
- 3.4 Project Planning
- 3.5 Decommissioning
- 3.6 Costs
- 3.7 Field Management Plan

Section 4. References

More detail about suggested contents of the FDP document

1. Executive summary

The Executive Summary should state the essential features of the development including:

- a brief description of the hydrocarbon reservoirs, reserves, development strategy, facilities and pipelines
- an outline map showing the field limits, licence boundaries, Field Determination boundary, Development Area boundary (if different from the Determination), Unit Area boundary (if different from the Determination) contours of fluid contacts, existing and proposed wells and licence boundaries
- the licence(s) involved and a statement of licence interests, or Unit interests if the field is unitised
- a central estimate of ultimate recovery, and the minimum, central and maximum hydrocarbon production profiles of:
    - gas, in thousand cubic metres and billion cubic feet per year
    - oil, in thousand metric tonnes and in million US barrels per year
- a statement of intent towards any parts of the field not addressed by the plan, including any commitment to later development of that area, or to the later stages of a phased development. Any provision for the development of other hydrocarbons in the area should also be identified
- the essential elements of the Field Management Plan
- a project schedule and total capital cost
- a statement of the provision for decommissioning and an undertaking that the field will be decommissioned in accordance with the requirements of the applicable international and domestic law in force at the time of decommissioning

2. Field description

The purpose of this section is to present the description of the field on which the development has been based ,and so, provide a baseline for future modifications as development proceeds.

The description should be in summary form and only a brief statement, table or map of the results provided with references to more detailed company-held data where appropriate.

In terms of figures, diagrams and data tables, licensees are encouraged to submit only those maps, sections and tables necessary to define the field adequately but should include at minimum a table of in-place hydrocarbon volumes, a representative cross-section, and top-structure maps for each reservoir. Maps should be in subsea depth at appropriate scales and include coordinates in degrees of latitude and longitude and the standard UTM grid, stating the central meridian used and datum.

2.1 Seismic Interpretation and Structural Configuration

A brief summary of the extent and quality of the seismic survey and the structural configuration of the field should be presented using appropriate figures and maps.

2.2 Geological Interpretation and Reservoir Description

The stratigraphy of the reservoirs, facies variations, the geological correlation within the reservoir and any other relevant geological factors that may affect the reservoir parameters (both vertically and horizontally) and thereby influence reservoir continuity within the field should be described in summary form. Figures and maps should be provided where appropriate.

The geological data provided should reflect the basis of reservoir subdivision, and correlations within the reservoir, and should include the relevant reservoir maps on which the development is based, including a top-structure map and cross sections showing the main reservoir units.

2.3 Geological Model

Describe how the seismic mapping of surfaces and faults, the reservoir subdivision and the log analysis were integrated to build a 3D geological model of the field.

2.4 Petrophysics and Reservoir Fluids

A brief summary of the key field petrophysical parameters should be presented incorporating log, core, Special Core Analysis (SCAL) and well test data. A summary of the field Pressure-Volume-Temperature (PVT) description and fluid analyses should be included.

2.5 Hydrocarbons Initially In Place

The volumetric and any material balance estimates of hydrocarbons initially in place for each reservoir unit should be stated together with a description of the cause and degree of uncertainty in these estimates. The basis of these estimates should be available and referenced.

2.6 Reservoir Modelling Approach

The means of representing the field, either by an analytical method, some form(s) of numerical simulation, or by a combination of these, should be briefly described. Where the reservoir has been subdivided for reservoir modelling into flow units and compartments, the basis for division should be stated. A description of the extent and strength of any aquifer(s) should be given. Where Drill Stem or Extended Well Tests (DSTs or EWTs) have been performed, the implications of these on history matching and predicted production performance should be given.

2.7 Reservoir Development, Improved and Enhanced Recovery Processes

The chosen recovery process should be described (e.g. depletion, pressure maintenance, aquifer support). Remaining uncertainties in the physical description of the field that may have material impact on the recovery process should be described and a programme to resolve these should appear in the Field Management Plan (Section 3.7).

Methods for targeting IOR (either mechanical or operational) should be described. Where none are proposed this should be justified.

For all oil or condensate reservoirs, the potential for application of improved recovery processes beyond conventional methods (EOR) should be described. A summary of all the recovery processes considered and the reasons for the final choice is required. There will be a requirement for operators to justify why EOR processes are not being used or are not planned to be utilised.

Where a field demonstrates economic potential for EOR, licensees should set out their firm plans to implement this. Where definite conclusions cannot be reached, a programme for addressing the outstanding issues during production should be given in the Field Management Plan (Section 3.7) and for ensuring that both wells and production facilities are EOR ready or can be readily made so. The provisions made in the design of the wells and production facilities to enable EOR in the future should be set out under Drilling and Production Facilities (Section 3.2). These provisions will include, amongst other things, weight and space for retrofitting equipment such as desalination equipment for Low Salinity Water Flooding EOR techniques, storage/mixing/pumping for chemical EOR (such as Polymer EOR, Thermally Activated Polymer or Alkali/Surfactant/Polymer (ASP) flooding). Where gas (hydrocarbon or Carbon Dioxide) is available already or becomes available for a Miscible Gas EOR process to be implemented within the life of the field, then additional considerations to equipment requirements should be conducted to allow Miscible Gas Injection to be implemented. If the facilities are not to be made ready for EOR, then an explanation for this must be provided, including indicative costs to make facilities and wells EOR ready retrospectively.

2.8 Wells Design and Production Technology

The basic requirements for well-completion design should be stated, in particular the potential for water shut off, artificial lift and stimulation should be discussed. Progressive technology for reservoir monitoring and remote intervention (e.g. intelligent wells and fibre optic across the reservoir) should also be discussed (either here or in Section 2.7). The potential for scaling, waxing, corrosion, sand production or other production problems should be noted and suitable provision for mitigation made in the Field Management Plan (Section 3.7). Any limitations on recovery imposed by production technology (e.g. flow assurance issues in late field life) or by the choice of production facility or location should be indicated. A reference to a Wells Basis of Design document should be provided.

The methods used to optimise production should be summarised, including reference to the methods used for integrated modelling of wells, flowlines and production facilities.

3. Development and Management Plan

The purpose of this section is to set out the form of the development, describe the facilities and infrastructure, and establish the basis for field management during the construction and production phases. For every element of the plan, the description should be brief and related to the complexity of the facility or strategy concerned. Where a particular topic is not relevant to a development it should be omitted.

The general requirements for the section are set out below. Figures and tables should be used where appropriate and the referencing of existing documents is encouraged, providing these are made available.

3.1 Preferred Development Plan, Reserves and Production Profiles

This section should describe the proposed reservoir development and indicate the drilling programme, well locations, expected reservoir sweep and any provision for a better-than-expected geological outcome. Proposed well locations should be shown on both the maps and cross sections referred to in Section 2.2.

An estimate of the range of reserves for each reservoir should be given (excluding fuel and flare) with a brief explanation of how the uncertainty was determined and explicit statements of probability where appropriate. For more complex reservoirs, in particular where EOR processes need to be considered, the range of reserves for each reservoir flow unit and compartment should be given. The assumed economic cut off should be stated.

Expected production profiles, for total liquids, oil, gas, gas usage and flare, associated gas liquids and produced water for the life of the field are required. Where fluids are to be injected, annual and cumulative injection profiles should be provided. Quantities should be provided in both metric units and in standard oil field units. Information to allow calculation of sales quantities should be provided.

The anticipated date for Cessation of Production (CoP), together with the underlying assumptions, should be provided.

3.2 Drilling and Production Facilities

The drilling section should briefly describe the drilling package and well workover capability. There should be a description of the proposed well-completion philosophy and figure(s) showing casing and completion, with main components’ diameters and depths relative to the lithological main units and reservoir depths. A reference to a wells Basis Of Design (which is consistent with the reservoir development and management plan, section 2.7 and 2,8) should be provided.

The production facilities section should describe the major equipment and infrastructure items and identify the design and operating parameters used as the basis of design. Estimated jacket and topsides weights should be provided for platform developments. A clear indication of system bottlenecks and limitations that can give rise to production constraints should also be given together with details of the contingencies available to maintain production in the event of major equipment failure(s). The scope and flexibility for future modification and expansion to address any potential for upside, incremental and satellite field development should also be identified, including any spare capacity provided for in the facilities/pipelines design to allow for future development (including the application of improved recovery techniques) or third-party tie-ins. The studies forming the basis for the selection of the proposed development option should be referenced.

The section should include a diagram of the structures for the development, whether fixed, floating or subsea and should also include a description of the proposed hydrocarbon transportation system including, where appropriate, any onshore terminal facilities. Any limitations on offshore production resulting from constraints in the transportation and terminal facilities should be identified.

Where a development utilises a floating production storage and offloading vessel (FPSO), a diagram of the anchor pattern should be included. If any of the anchors transgress into neighbouring licensed blocks then it must be stated that the agreement of the licensees of the adjacent block(s) has been obtained and it has been confirmed that this will not interfere with any activities proposed on the adjacent block. If, when an FDP receives authorisation, the anchor pattern is not known then a statement of commitment that such agreements will be obtained should the subsequent pattern be such that they are required, must be included. If the anchors are to be located on unlicensed acreage, the operator should seek clarification from the OGA that this will not interfere with any proposed future licensing activities.

Where a rig is to be located for development drilling such that its anchors temporarily transgress into neighbouring licensed blocks, then it must be stated that the agreement of the licensees of the adjacent block(s) has been obtained and it has been confirmed that this will not interfere with any activities proposed on the adjacent block(s). If the pattern is not known at the time an FDP is authorised, then a statement of commitment that such agreements will be obtained should the subsequent anchor pattern be such that they are required must be included. Where the anchors are to be located on unlicensed acreage, the operator should seek clarification from the OGA that this will not interfere with proposed future licensing activities.

New transportation systems are often designed to service more than one development and may have a longer expected life than the originating field. In this instance, a separate FDP for the transportation system may be necessary.

3.3 Process Facilities

A brief description of the operating envelope and limitations of the process plant should be provided. The use and disposal of separator gas should be described.

The section should also include:

- a summary of the main and standby capacities of major utility and service systems, together with the limitations and restrictions on operation. The design and operating philosophy for key equipment items should be discussed (e.g. first-stage production separator 1 x 100%, Inlet heater to first-stage separator 2 x 100%, Powergen sets 3 x 50%). A process flow diagram should be provided
- a summary of the methods of well testing and metering hydrocarbons produced and utilised
- a brief description of systems for collecting and treating oil, water and other discharges
- a brief description of any fluid treatment and injection facilities
- a brief description of the main control systems and their interconnections with other onshore or offshore facilities
- provision of space or utilities for future EOR facilities or future developments
- expected production efficiency
- a brief description of any new technologies to be deployed

A reference to a facilities Basis Of Design (which is consistent with the reservoir development and management plan) should be provided.

For an FPSO development, a statement on whether it is new (leased or purchased) or refurbished should be given, and, if refurbished, a description of the modifications required should be provided.

3.4 Project Planning

Schedules defining key events and decision dates in the detailed design, procurement, construction and commissioning stages of major elements of the development should be provided.

A separate Project Execution Plan should be prepared and submitted alongside the FDP, as set out in the SE05 Robust Project Delivery Implementation Guide (available at https://www.ogauthority.co.uk/exploration-production/asset-stewardship/expectations/)

Commissioning plans will be discussed in greater detail as the project develops, but it should be noted that the commissioning programme will need to demonstrate a commitment to preventing the unnecessary and wasteful flaring of associated gas and carrying out commissioning operations in an efficient and timely manner.

3.5 Decommissioning

The FDP should confirm that decommissioning options will be fully reviewed and discussed with Department for Business, Energy and Industrial Strategy's (BEIS) Offshore Decommissioning Unit (ODU) and the OGA's decommissioning team during the late field life and decommissioning planning stages. A very brief description of the proposed methods of decommissioning should be included to show the basis for the decommissioning expenditure estimates. Steps taken in the design to facilitate eventual decommissioning of the production facilities should be identified.

3.6 Costs

Cost information is required by the OGA to assess the economics of the development. Capital (capex), operational (opex) and decommissioning expenditure profiles are required, phased by year, to a defined monetary base in UK pounds sterling.

Capex and opex tabulations should be subdivided into:

Pre-project costs (seismic, exploration drilling, appraisal drilling, studies) (money of the day costs are acceptable here)

- drilling capex
- facilities capex
- decommissioning expenditure, subdivided into wells costs and facilities costs
- field opex, excluding tariffs
- tariff opex

A spreadsheet entitled the “Standard Economics Template” (SET) is provided for operators to fill out to aid the OGA in reviewing this data. A link to this spreadsheet can be found at: https://www.ogauthority.co.uk/exploration-production/development/field-development-plans/

Details are required of the tariffing arrangements and gas contracts where applicable and whether these are different to those previously notified to the OGA. Where these arrangements are commercially sensitive, a limited circulation 'side letter' will be acceptable.

The information on tariffs should include:

- total fixed and variable costs for the use of facilities or pipelines, phased annually
- base cost per barrel, escalation factors, and escalation lags

The information on gas contracts should include:

- base gas price (pence/therm), the escalation factors, the lag period, the base values for escalation factors and the contract duration

3.7 Field Management Plan

A Field Management Plan is required that sets out clearly the principles and objectives that the licensees will hold to when making field-management decisions and conducting field operations and, in particular, how economic recovery of oil and gas will be maximised over field life. The plan, as described here and in different sections of the FDP, must show clear and consistent linkage between reservoir development plans, well designs and subsea facilities, and process facilities.

The rationale behind the data gathering and analysis proposed to resolve the existing uncertainties set out in Section 2 and understand dynamic performance of the field during both the development drilling and production phases, should be outlined. The use of unmanned or subsea facilities may set restrictions on data gathering, these should be identified.

The potential for workover, re-completion, re-perforation and further drilling should be described. Where options remain for improvement to the development (e.g. as discussed in Sections 2.7 and 2.8) or for further phases of appraisal or development, the criteria and timetable for implementing these should be given.

Some developments will include common user facilities and may have capacity constraints; the methods to be used to set production priorities should be given. For gas reservoirs the criteria for installation of additional compression should be identified.

4. List of References

The FDP may also contain a list of references, which include (but are not limited to):

- Concept Selection Decision support document
- EOR screening study
- Project Execution Plan
- Supply Chain Action Plan
- Host Facility Addendum (if appropriate)
- Wells Basis of Design
- The OGA's Standard Economics Template (SET)
- Environmental Statement (submitted to BEIS)
- Design or Relocation Notification (if appropriate, submitted to the HSE)

4. Guidance on the Preparation of a Revised FDP

These notes have been prepared to provide guidance to field operators engaged in preparing a revised FDP for producing oil and gas fields. The purpose of the revised FDP is both to advise the OGA of divergence from the authorised FDP and to demonstrate that the field is being managed in a manner that will maximise economic recovery of hydrocarbons. The document should be used to propose revisions to Section 3 (Development and Management Plan) of the original FDP as the understanding of the field improves, or to propose incremental development projects not included in the original FDP. These types of revised FDPs are sometimes referred to as "FDP Addenda".

For the guidance of operators there is a check list attached that identifies the general requirements but operators are encouraged to agree an alternative form of document if this would be more appropriate to the individual field. Internal or partner documentation that satisfies or exceeds these requirements will also be acceptable. The revised FDP is not intended as a detailed data source or account of activities carried out during the period since FDP authorisation but should be used to identify departures from the expected performance and planned development. It is not anticipated that detailed FDP revisions will be required routinely, and operators are encouraged to discuss the level of detail required by the OGA prior to preparing a revised FDP. A Project Execution Plan will still be expected although the level of detail necessary will be dependent on the extent of the proposed revision.

5. Check-list for the contents of a Revised Field Development Plan

1. Introduction

A brief review of the field operations and performance should be set out, with divergence from the FDP noted and discussed in more detail in later sections. Any changes in licence equity should be noted.

2. Field description

2.1 Hydrocarbons initially in place and recoverable reserves
Changes in estimates of hydrocarbons initially in place and reserves should be identified by reference to the FDP base case or to the case in any previous FDP revision.

2.2 Well status and operations
A table summarising changes in well status (e.g. producer/injector, suspended/abandoned, perforated intervals, reservoir identifier, lift provision should be included).

2.3 Geology
Where drilling, seismic reprocessing or other work has had a significant impact on the reservoir model, a summary of the results should be provided together with a map in subsea depth giving the current interpretation of the top structure and showing well locations and fluid contacts (by reservoir if appropriate).

2.4 Field facilities and infrastructure
A brief report on the performance of the field production facilities highlighting features that have impeded operations and also valuable improvements should be provided. A forecast of the changes planned for the facilities and, where appropriate, the related infrastructure, should be provided in Section 3.5 (see below).

3. Development and management plan

3.1 Field management
Changes in development strategy should be reviewed. Important reservoir monitoring results, reservoir monitoring limitations and specific production difficulties should be summarised. Where appropriate, plots of reservoir pressure and voidage replacement should be provided. Future plans for reservoir monitoring should be briefly discussed.

3.2 Studies
Results and relevance of geoscience, and reservoir or facilities/pipeline engineering studies completed during the reporting period should be summarised. Plans and timescale for ongoing and future studies should be discussed.

3.3 Improved Oil Recovery (IOR/EOR)
Where improved recovery has not been addressed in the FDP, the potential should be reviewed, and the results of any studies or operations discussed.

3.4 Forecasting
A comparison between the current forecast and the FDP production and injection profiles (or those agreed revisions made in earlier FDP revisions) and the current production consent should be provided, together with the current estimate of the cessation-of-production date.

3.5 Proposed changes to the FDP

This section provides the means for formally proposing revisions to the development and management plan set out in Section 3 of the approved FDP. Proposed changes to explicit or implicit commitments or to conditions in the authorisation should be set out clearly as should plans to extend the development beyond the Development Area. The need to include other deviations should be discussed with the OGA.

Where appropriate, a summary of longer-term development opportunities within or around the field, including potential for recovering third-party hydrocarbons, should be provided. Progress in developing opportunities already identified, in particular IOR or EOR, should also be reviewed. Where changes in the facilities and infrastructure are planned, the proposed modifications should be summarised, together with estimates of opex and capex. Where an incremental project is planned, the corresponding incremental production should be identified.

The production efficiency (PE) assumed for the production forecasts should be stated, and compared with the current PE for the facility. Where appropriate, measures to improve PE should be stated. Where facility modifications on a host platform are planned for a satellite development for a different operator, the proposed changes should be addressed in a revised FDP for the host field and only a cross reference provided in the FDP for the satellite field. Available topsides or pipeline capacity for any potential future tie-in developments and any associated limiting factors should be described.

3.6 Field capital and operating costs

Capex and opex profiles should be provided on an annual basis, categorised as follows:

- drilling capex
- facilities capex
- decommissioning expenditure, subdivided into wells costs and facilities costs
- field opex, excluding tariffs
- tariff opex

A spreadsheet entitled the “Standard Economics Template” (SET) is provided for operators to fill out to aid the OGA in reviewing this data (available at https://www.ogauthority.co.uk/exploration-production/development/field-development-plans/). For incremental projects, in order to understand the impact of the incremental project, the OGA requires two versions of the SET to be completed: one for the "base case" (no incremental development) and one for the base case plus incremental development. Operators should discuss this with OGA prior to submitting the revised FDP.

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