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PETROLEUM AUTHORITY OF BRUNEI DARUSSALAM

Brunei Darussalam Oil and Gas Exploration and Production Guidelines

Volume 7: Field Development Plan Guidelines

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0	Field Development Guideline	July 2019
1	Field Development Guideline - Transfer of Regulatory Undertaking (Roles to t*he Authority*)	January 2020
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Notice

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Abbreviations

In this Guideline, the following abbreviations are referred:

AAR	After Action Review
ALARP	As Low as Reasonably Practicable
BFD	Basis for Design
CCUS	Carbon Capture Utilisation & Storage
CGR	Condensate Gas Ratio
COMAH	Control of Major Accident Hazard
CPRA	Combined Production Risk Assessment
DoE	Department of Energy, Prime Minister's Office
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EPMA	Environmental Protection and Management Act
FDP	Field Development Plan
FEED	Front End Engineering Design
FID	Final Investment Decision
FMG	Field Management Guidelines
GOR	Gas Oil Ratio
GoB	Government of Brunei
HAZID	Hazard Identification
HCIIP	Hydrocarbon In-Place
HCM	Hydrocarbon Maturation
HSSE	Health, Safety, Security and Environment
IOR	Improved Oil Recovery
JV	Joint Venture
LBD	Local Business Development
MOC	Management of Change
NPV	Net Present Value
OCS	Overall Contracting Strategy
PMA	Petroleum Mining Agreement
PLT	Production Logging Tool
PSA	Product Sharing Agreement
PVT	Pressure Volume Temperature
RF	Recovery Factor
SIMOPS	Simultaneous Operations
VIR	Value Investment Ratio
VOI	Value of Information
WRFM	Well Reservoir Facilities Management
WSHO	Workplace Safety and Health Order

Terminology

In this Guideline, the following terminology are referred:

Agreement	The applicable agreement governing the block or concession area such as a PMA or PSA.
Associated Gas	Associated Gas is a natural gas found in contact with or dissolved in oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Condensate	Condensates are portion of natural gas of such composition that are in the gaseous phase at temperature and pressure of the reservoirs, but that, when produced, are in the liquid phase at surface pressure and temperature.
Crude oil	Crude oil is a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.
Condensate Gas Ratio	Condensate to gas ratio in an oil field, calculated using measured condensate and natural gas at stated conditions
Gas Oil Ratio	Gas to oil ratio in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas oil ratio may be the solution gas oil ratio, symbol R_{si}, produced gas oil ratio, symbol R_p, or another suitably defined ratio of gas production to oil production.
Gas-Cap Gas	Gas-Cap Gas is a free natural gas which overlies and is in contact with oil in the reservoir. It is a subset of Associated Gas.
Natural Gas Liquid	NGL are liquid hydrocarbons recovered from natural gas in separation facilities or gas processing plants, NGL include ethane, propane, butane (normal and iso-), (iso) pentane and pentanes plus (sometimes referred to as natural gasoline or plant condensate).
Non-Associated Gas	Non- Associated Gas is a natural gas accumulation that does not contain quantities of crude oil; usually Gas-Water Contact is observed.
Solution Gas	Solution Gas is a natural gas which is dissolved in oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas.
Primary Gas Cap (NGL)	A primary gas cap is found in saturated oil reservoirs that are initially at the bubble point pressure.
Secondary Gas Cap	A secondary gas cap can form when depletion liberates Solution Gas from the oil and allows free flow of gas through the reservoir to the highest structural point.
Initial water saturation, S_{wi}	Initial water saturation is the saturation of an undisturbed reservoir with no prior production
Irreducible oil saturation, S_{or}	Irreducible oil saturation refers to the portion of oil within a reservoir that cannot be displaced or removed by typical reservoir engineering processes such as water flooding or gas injection
Gas saturation, S_g	Gas saturation refers to the proportion of pore volume within a reservoir that is occupied by gas
Critical Gas saturation, S_{gc}	Critical gas saturation is a concept used in Petroleum Reservoir engineering to describe the minimum gas saturation required for a given reservoir to undergo a particular recovery process effectively. It is a critical parameter that influences the success and efficiency of various enhanced oil recovery techniques, in particularly gas displacement methods
Oil Formation volume factor, B_o	Formation volume factor of Oil is a parameter that describes the changes in volume of a quantity of oil when it is brought from reservoir condition to surface condition.
Upstream Operators	Upstream Operators of Upstream Petroleum Operations as defined under this Guidelines.

Upstream Petroleum Operation	Includes any operation or activity in connection with the exploration, appraisal, development, production, gathering, separation and treatment, storage, and transportation (up to an agreed delivery point) of petroleum and decommissioning, abandonment and restoration operations or activities, including the planning of such operations or activities and, without prejudice to the generality of the foregoing, includes – (a) the search for petroleum by geological, geophysical, or other methods and the drilling of wells in this regard, including, but not limited to, processing work, drilling of exploration wells or appraisal wells, appraisal operations and the performance of the other technical or economic feasibility studies; (b) the engineering, planning, design, construction and installation of facilities for the development or production of petroleum and the drilling of wells in this regard, including, but not limited to, the purchase of materials and equipment, drilling of development or production wells, construction and installation of equipment, lines, facilities, plants and systems in and outside any designated area, which are required for production, treatment, waste disposal, transport, storage and lifting of petroleum and for recycling and other secondary and tertiary projects; (c) all other operations or activities performed in connection with the ongoing and continuous production, treatment, transport, storage and lifting of petroleum and its by products, including, but not limited to, improved or enhanced recovery operations such as injection, recycling, recompression, pressure maintenance, treatment of discharged water, water flooding and abandonment; and (d) all activities required to return any site to its original condition prior to the commencement of any petroleum operation at such site including, but not limited to, proper abandonment of wells or other facilities, removal of equipment, structures and debris, establishment of compatible contours and drainage, replacement of topsoil, re-vegetation, slope stabilization, in-filling of excavations and any other appropriate actions in the circumstances.
WRFM	WRFM refer to Well, Reservoir and Facility Management. This is an integrated management system covering the overall chain of reservoir, wells and facilities. This may include comprehensive evaluations of both the subsurface reservoirs and the surface facilities involved in oil and gas production operations. These reviews aim to assess the performance, efficiency, and integrity of reservoirs and associated infrastructure to optimize production performance, minimize risks, ensure long-term sustainability of operation and compliance with regulatory standards. It can also be referred to Well Interventions and Well Reservoir Management Plan.

1. Introduction

The Field Development Plan (FDP) Guideline is Volume 7 of the Brunei Darussalam Oil and Gas Exploration and Production Guidelines, its main goal is to ensure the hydrocarbon resources of Brunei Darussalam are efficiently and sustainably developed, extracted and managed to maximize value and align with Upstream Directive 1/2011 (Appendix A).

The FDP should be submitted for the Authority's approval after the Notification Exploration or Appraisal Well Commercial Discovery has been declared for new discoveries or green fields and when a Field Development Plan Addendum is submitted due to significant change to the approved FDP.

The FDP needs to clearly define the project's objective with key factors such as timing being crucial to meet contractual obligation and to ensure a secure oil and gas supply. It is recommended that regular development project meeting is held to align and achieve the objectives for both the Authority and the Upstream Operators.

1.1 Objectives

The submission defined in this Guideline, serves as a guide for maturing the hydrocarbon development projects of an oil and gas field and helps Upstream Operators prepare a plan that meets the Authority's requirement as stated in the respective Agreement where the field is located. It is not intended to replicate prescriptive description of actions or practises for the Upstream Operators which have their own detailed FDP operating procedures.

It also outlines the necessary documents and steps that Upstream Operators must follow when preparing and submitting an FDP. The objective is to align and achieve the FDP objectives agreed by the Authority and Upstream Operators and to resolve any areas of conflict before the final FDP is submitted for approval. Upstream Operators in Brunei Darussalam must adhere to the Agreement in accordance with Upstream Directive 1/2011 (Appendix A) while carrying out hydrocarbon development project activities.

In cases of consortium or joint ventures (JV) agreements, the Upstream Operators should seek their respective partners endorsement before obtaining approval from the Authority.

1.2 Roles and Responsibilities

The Upstream Operators are responsible for ensuring compliance with all applicable laws in Brunei Darussalam and Government directives and obligations under their respective Agreements (where applicable).

For the avoidance of doubt, these Guidelines are not intended to substitute any existing obligations which Upstream Operators are liable under any existing laws, regulations and Government directives of Brunei Darussalam to other relevant approving Government ministries/ departments/ statutory bodies or other bodies, and Upstream Operators shall continue to ensure compliance with any such laws, regulations or approval requirements in addition to these Guidelines.

1.3 Scope of Work

This volume provides Guidelines for Upstream Operators in generating FDP documents in Brunei Darussalam during the Development phase of the hydrocarbon lifecycle (Figure 1).

Figure 1: Chart showing hydrocarbon lifecycle phase of resources with emphasis on the Development phase for the Field Development Plan submission.

This Guideline sets out the FDP submission minimum requirement for review and approval by the Authority. Upstream Operators' adherence to this Guideline will be demonstrated through the reporting and timely submission of relevant documents and information.

This Guideline may be revised and amended from time to time upon written notice by the Authority and subject to such revision or amendments being consistent with the provision of applicable laws and Agreements in force in Brunei Darussalam.

All Upstream Operators shall adhere to and comply with generally accepted standards of good petroleum industry practise and all applicable laws in force from time to time.

2. Submission and Approval

2.1 Hydrocarbon Development Project Process

Maturing Hydrocarbon development process can be divided into six stages (Refer Figure 2):

1. Project Identification,
2. Project Assessment,
3. Project Select,
4. Project Define,
5. Project Execution,
6. Project Post Investment Review.

Authority milestone review is necessary at each project of hydrocarbon development process. The Authority will review the Upstream Operator's maturation hydrocarbon development plan to track progress and address any obstacle to achieve the FDP submission. Depending on the project's size, complexity, and schedule, more than one milestone reviews may be combined. Decisions about combining milestones review shall be agreed jointly by the Authority and Upstream Operator.

The Authority may request for a meeting to discuss specific project matters as and when needed. The Upstream Operator shall provide any relevant documentation at least ***three days*** before the meeting. Meeting of minutes shall be recorded by the Upstream Operators and submitted to the Authority not more than ***five working days*** after the meeting.

In the Assess phase, the Upstream Operator must demonstrate a wide range of development options where the maximum life cycle EUR is worked in line with the Upstream Directive 1/2011 must be presented to the Authority before proceeding to the Select phase.

Upstream Operator will submit the FDP after the Select Phase and ensure 1st production as per the Agreement for Authority assessment and approval. Submitting the FDP for the Authority's approval is mandatory before the starting of the full-scale development plan.

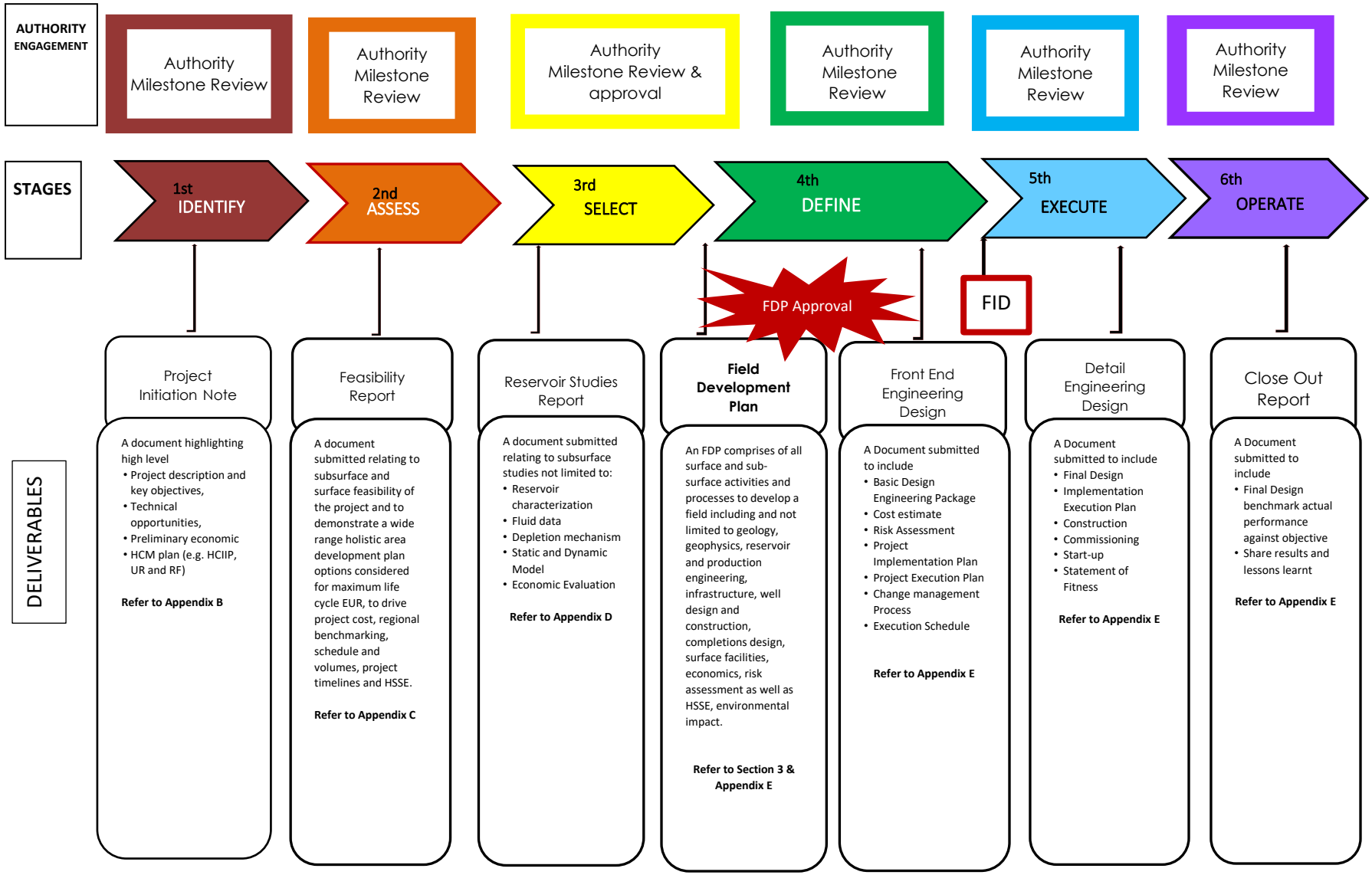

Figure 2: Outline of Activities with Authority Engagement and the essential elements required

2.2 Submission

2.2.1 Document to submit

During the maturation hydrocarbon development phase, the Upstream Operators are required to submit the following documents to the Authority upon completion of each activity:

1) Project Initiation Note (PIN) or Project Premise document,
2) Feasibility Study report,
3) Field Development Plan document,
4) Concept Select report,
5) Basis for Design document and
6) Project Execution Plan.

Any reports submitted must be comprehensive stand-alone documents and must have a complete set of information and references attached. Upstream Operators shall submit to the Authority one (1) electronic copy of the report. Upstream Operators to provide the Final Static and Dynamic Model, Integrated Production Modelling, Economic Model as and when requested by the Authority.

2.2.2 Appraisal Well Programme

Upon Exploration Well Discovery Notification, the Upstream Operators shall within the timeframe stated in the Agreement, submit an appraisal well programme to assess the size of the discovery, the data collection required to support development to the Authority for approval prior to commencement of the Appraisal Well operation. Upstream Operators can also refer to Brunei Darussalam Upstream Oil and Gas Guideline Volume 5 Exploration Guideline for further details.

In the event of an Appraisal Well drilling after the approved FDP and in the production phase, the Upstream Operators is required to notify the Authority and to submit the Final End of Well Report to the Authority upon the completion of the Appraisal Well evaluation.

2.3 Activities Requiring Submission for Approval

Activities listed in Table 1 below is the list of document submission required to the Authority.

ITEM	STAGE	ACTIVITY	INFORMATION REQUIRED	SUBMISSION FOR APPROVAL
2.3.1	**Identify**	▪ Gathering of project information	**Project Initiation Note (PIN) or Project Premise document**. Suggested content of the PIN may refer to Appendix B	**Assess only**
2.3.2	**Assess**	Data Export ▪ Transfer of Information outside of Brunei Darussalam ▪ Transfer of physical data outside Brunei Darussalam (e.g. cores, core plugs, fluid samples, original field tapes)	Submit a detailed data or samples information about to be transferred, destination, recipient, the transfer method and to ensure Confidentiality Agreement in-placed. Approval Timeline: Will be subject to relevant Brunei Governmental agencies.	**Yes**
2.3.3	**Assess**	Feasibility Study ▪ Reserves assessment, preliminary development concepts and the economic viability based on cost and schedules	**Feasibility Study report** to emphasize and demonstrate a wide range holistic life cycle development plan options considered to drive down cost, schedule, and volumes competitiveness including external benchmarking. Suggested content of the report may refer to Appendix C.	**Assess Only**
2.3.4	**Select**	▪ Reservoir Development Study	**Reservoir Studies report** • Complete geological description, resource size and uncertainties identified and addressed. • Complete subsurface aspects including the depletion mechanism, recoverable reserves, expected production profile, type and total number of development wells. Suggested content of the report may refer to Appendix D.	**Assess Only**
2.3.5	**Select**	▪ Pre-Development Activities	**Pre-Development activities** may include: • Site Survey (including pipeline routing, assess drilling location or development risk to shallow seabed hazards) • Soil boring & sampling • Metocean data gathering	**Assess Only**

2.3.6	Select	▪ Concept select & optimization	**Concept Select Report** • Demonstrate that the concept select decision based on a robust integrated opportunity realization process. • Clear, well defined competitive project scope and value drivers, through an effective selection process, supported by decision- based criteria and demonstrated with benchmarking data.	**Assess Only**
2.3.7	**Define**	▪ FDP and FDP addendum	FDP – Refer to section 3 and Appendix E for suggested content and information. FDP Addendum – should immediately inform the Authority on the proposed deviations, or alterations to the approved Field Development Plan. Please refer to section 3.2 for more details. Approval Timeline: The Authority will approve, propose to amend, or deny all or part of the request, within the time limit stated as per the Agreement.	**Yes**
2.3.8	**Define**	▪ FEED	**FEED Document** submission include: i) Overall Contracting Strategy ii) Project Execution Plan iii) Basis for Design • Optimum technology • Operational requirement • Site selection • HSSE assessment • Economic Evaluation • Assurance Review iv) Brief project description & project work scope v) maximise Local Brunei content. Engineering Master Document Register: • Project management • Planning, monitoring & reporting progress • Cost reporting & control • Project schedule • Quality assurance • HSSE	**Assess Only**

2.3.9	**Define**	Trans-boundary field ▪ Development of fields that extend beyond block boundaries within Brunei ▪ Development of fields or reservoirs above or below any depth-limited block boundaries	Collaborative Field Development Plan agreed between all parties involved. The Government of Brunei reserves the right to require a unitization for fields within its territory to avoid competitive development plans that could affect reservoir recovery.	**Yes**
2.3.10	**Define**	▪ Detailed Design	Document or data required: • Detailed design of the facilities. • Procurement of the materials • Fabrication & Installation • Commissioning of all plant and equipment.	**Assess Only**
2.3.11	**Execute**	▪ Project Execution (Fabrication, Construction, Transportation, Installation, Hook-up & Commissioning)	Document or data required: i) Project control • Cost control. • Integrate planning and scheduling • Identified Risk & mitigation plan ii) Monthly progress report including project cost on actual vs plan.	**Assess Only**
2.3.12	**Execute**	▪ Management of Change (MOC)	If there is a deviation during the execution, MOC should be raised. Change request will be recorded.	**Assess Only**
2.3.13	**Execute**	▪ Development well drilling	Refer to Brunei Darussalam Oil and Gas Exploration and Production Guidelines Volume 6 Drilling Guideline.	**Assess Only**
2.3.14	**Operate**	▪ Post Investment Review	Close out report should include, but not limited to; Scope changes, Cost and Schedule breakdown for plan and actual including lesson learnt.	**Assess Only**
2.3.15	**Operate**	▪ Production	Daily and Monthly production report against plan. Refer to Brunei Darussalam Oil and Gas Exploration and Production Guidelines Volume 9 Field Management Guideline.	**Assess Only**

2.3.16	**Operate**	▪ Gas re-categorization and release	Refer to Brunei Darussalam Oil and Gas Exploration and Production Guidelines Volume 8 Gas Cap Development Guideline. For FDP Addendum - should immediately inform the Authority on the proposed deviations, or alterations to the approved Field Development Plan. Please refer to section 3.2 for more details	**Yes**
2.3.17	**Operate**	Secondary and Tertiary Recovery Project	Required Information: Field Strategy Note (Redevelopment Strategy) or FDP Addendum. For Secondary and Tertiary Recovery Project ▪ Implementation of any injection in areas, reservoirs or fields not previously planned in the approved FDP such as Water Injection, Gas Injection or Chemical Injection. ▪ Changes to injection strategy. ▪ Gas dump-flood, internal injection, and crossflow injection.	**Yes**
2.3.18	**Operate**	Full field review	First Full field review engagement should be conducted within 2 years after 1st Hydrocarbon production, and subsequent engagement will be as and when required by the Authority	**Assess Only**
2.3.19	**Operate**	Late Life Strategy	Cascading from higher pressure to low pressure	**Assess Only**
2.3.20	**End of Field Life**	Cessation of Production or Operation	Refer to local Decommissioning and Restoration legislation such as, COMAH, Pipeline Act, EPMA and Brunei Darussalam Oil and Gas Exploration and Production Guidelines Volume 11 Decommissioning & Restoration Guideline.	**Yes**

Table 1. Activities Requiring Submission for Approval

3. Field Development Plan

3.1 Submission Requirement

All Upstream Operators shall submit the FDP for the Authority's review and approval within the time limit stated in the Agreement. All submissions should make a compelling case that the proposed development option will seek to maximise oil, gas and condensate recovery factors and make it positive optimal development of hydrocarbon resources within prevailing economic constraints.

The submission of the FDP must meet the requirements set in Upstream Directive 1/2011 (Appendix A) that briefly summarise as follows:

1. *The discovered field should have a **complete full life cycle**, reserves to contingent resource opportunity evaluated and remaining volumes considered unrecoverable need to be justified. The plans should include on how the contingent and prospective resources to be matured and prudently produced.*
2. *The plan must demonstrate key objective to **maximise economic ultimate recovery** through evaluating the technical limit recovery and must cover secondary and tertiary recovery; sharing where the economic limit and the corresponding recovery factor achieved.*
3. *Any **gas development plan** project to demonstrate similar **maximise economic ultimate recovery** in-line with proper reservoir management practise for not just the natural gas but also its condensate.*
4. *Having a **holistic life cycle area development plan** which include exploration programme that synergise with development plans or options of synergising with existing discovered fields*
5. *To demonstrate **high standard of safety, asset integrity and environmental** consideration are in-place in the field development plan.*

FDP content should entails estimate of oil, condensate and gas recoverable volumes, development concept strategy, ultimate recovery and production forecast, economics, operational philosophy and WRFM plan requirement to meet the maximum economic ultimate recovery.

Details of the FDP submission must consist of but is not limited to information described in Appendix E and all assumptions used as a basis of evaluation should be stated. Technical assessment must be done with certain degree of certainty and quality with proper reservoir management practises.

Before submitting the FDP, technical meetings with the Authority must be conducted. These meetings provide venue to clarify matter, provide upfront involvement, get an early buy in to resolve any potential conflicts such as the preferred development concepts, project scope, approval requirement and expected timeline. The final FDP submission for approval must be accompanied by an official cover letter.

After FDP submission, a meeting with the Authority may be required for the purpose of discussing the proposed development concept. Any recommendation during this meeting shall be documented and

taken into consideration for implementation. If revision to the FDP is deemed necessary, the updated FDP will be submitted to the Authority with an official cover letter.

The time limit for the Authority to review the FDP submission to approval will be in accordance with the provisions of the Agreement where the field is located.

After FDP approval, Upstream Operator to ensure execution of the approved FDP and to achieve first production date. In the event of first production date becomes unlikely due to unavoidable or unforeseen circumstances, Upstream Operators must notify the Authority as soon as possible.

For Associated Gas Development refer to Brunei Darussalam Oil and Gas Exploration and Production Guidelines Volume 8 Gas Cap Development Guideline for further details.

3.2 Field Development Plan Addendum

All Upstream Operators must submit an FDP Addendum for the Authority's approval within the time limit stated in the Agreement. All submissions should inform the Authority of the proposed deviations or alterations to the approved FDP. All FDP Addendum submissions must be accompanied by an official cover letter. Deviations post FDP Approval that will require the submission of a Field Development Addendum includes, but is not limited to:

a) Development of more new reservoirs or the need to assess the areal extent of the field better.
b) Adjustment to the production or depletion strategies (to implement pressure maintenance or introducing new gas sales),
c) Modification to the drainage plan involving the location and how many platforms and development wells.
d) Revision of notional plans based on drilling results from Exploration or Appraisal wells, or
e) Modification to the selected development plan (for example changing the evacuation route, integrated development, adding new facilities) that could impact significant cost, timing, and availability risk.

With regards to FDP Addendums, the specific updates relating to the scope of the required changes will be sufficient for submission.

3.3 Infill Wells

The Upstream Operators required to present and submit a Note for File for infill development wells of producing reservoirs or new reservoirs from an existing platform with no major modification to existing facilities. Table 3 below summarise the submission that should include, but not limited to, the following information:

ITEM	CONTENTS	REQUIREMENT
3.3.1	Executive Summary	▪ A brief description of the infill well(s) from producing reservoirs or new reservoirs. ▪ Incremental recoverable hydrocarbon reserves. ▪ Expected first production.
3.3.2	Reservoir Description	Description should include: ▪ Any New reservoir ▪ Any changes in the producing reservoir extend. ▪ Updated map showing all gas bearing sands, field limits, contours of fluid contacts. ▪ Changes in estimates of hydrocarbon initially in place and reserves. ▪ Subsurface key uncertainties.
3.3.3	Infill Wells	▪ Number of infill wells. ▪ Drainage plan (e.g. number of producers/injectors). ▪ Well Design and Completion. ▪ Production forecast. ▪ Impact on existing producers
3.3.4	Facilities	▪ Description of any facilities modification. ▪ Facilities or pipelines constraint. ▪ Remaining design life of existing facilities. ▪ New technology application.
3.3.5	Economic Evaluation	▪ Capital expenditure, Operation expenditure and Abandonment expenditure. ▪ NPV and VIR.

Table 3: Note for File Requirement

Appendices

In this Guideline, the following appendices are referred:

Appendix A	Upstream Directive No 1/2011
Appendix B	Project Initiation Note
Appendix C	Feasibility Studies Report
Appendix D	Reservoir Studies Report
Appendix E	Field Development Plan Submission Minimum Requirement

Appendix A: Upstream Directive No. 1/2011

UPSTREAM DIRECTIVE NO 1/2011:- FIELD DEVELOPMENT PLAN FOR MATURING HYDROCARBON DEVELOPMENT PROJECTS.

In order to ensure that the hydrocarbon resources of Brunei Darussalam are appropriately explored, developed and managed to maximize its value for the sustained economic benefits of the nation, the Government of His Majesty the Sultan and Yang Di-Pertuan of Brunei Darussalam hereby issues the Upstream Directive No 1/2011: Field Development Plan for Maturing Hydrocarbon Development Projects.

Field Development Plan (FDP) for maturing hydrocarbon development projects must be submitted by each operator to Energy Department at Prime Minister's Office (EDPMO) and are required to meet the following requirements as follows with the exception of well reservoir management (WRM) activities like workovers, repairs and simple re-completion :-

1. Every discovered field in the acreage under the operatorship of an operator should have the **complete full life cycle opportunities as per the SPE Petroleum Resource Maturation System (SPE-PRMS) (Attachment 1) i.e. from reserves up to the contingent resources evaluated and justification for the remaining volumes deemed unrecoverable needs to be provided**. This assessment should be done with a certain degree of rigor and quality inline with proper reservoir management practices. Operators are required to submit plans on how the contingent and prospective resources will be matured and prudently produced. These plans will be visited on an annual basis to track progress and to identify obstacles that prevent progress.

2. **The operator needs to demonstrate that the development project has the objective of maximizing economic ultimate recovery from the target field, blocks or reservoirs**. The plan must first evaluate the Technical Limit recovery taking into account the full reservoir life cycle and must cover secondary recovery

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e.g. water-flooding at start of production and tertiary recovery schemes. It should clearly show where the economic limit is and what is the corresponding recovery factor achieved.

3. **For gas development projects, the emphasis should be same, demonstrating how to maximize economic ultimate recovery of the total hydrocarbon fluids inline with proper reservoir management practices, for not just the natural gas but also its condensate**. In the case of condensate gas fields, if the depletion of the reservoirs results in reservoir pressure decline causing condensate to drop out in the reservoirs resulting in unrecoverable condensate, alternative schemes such as dry gas recycling needs to be considered and presented as an option with the economics fully evaluated.

4. Overall, in the studies operators are required to come up with **holistic, life cycle area development plan,** which include the complete exploration programme, that synergies with the development plans or options of the existing discovered fields. Small discovered accumulations that may not seem to justify anything else other than primary depletion may be part of a cluster development with secondary and tertiary schemes if the exploration prospects and other discovered blocks nearby are taken into consideration.

5. At all time operators are required to demonstrate **high standard of safety, asset integrity and environmental** considerations are in-place in the Field Development Plan.

Issued by:

Office of the Minister of Energy, Prime Minister's Office
Bandar Seri Begawan, BRUNEI DARUSSALAM

Issued on: 22 September 2011

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Appendix B: Project Initiation Note

Suggested content of the Project Initiation Note are as follows:

PROJECT INITIATION NOTE (PIN)					
Project Name					
Project Type					
Field					
Block					
Project Description and Objectives					
To include the Technical Scope, value drivers, general description of possible development concepts.					
Technology Opportunities					
Key Uncertainties, Risks & HSSE Issues					
To include Stakeholders and environmental aspects					
Data Acquisition Plan					
Preliminary Economics					
	Units	Low	Base	High	Comments
Capex					
Opex					
Abex					
NPV					
EMV					
VIR					
Hydrocarbon Maturation Plan					
In-Place Volume		Recoverable Volume		Recovery Factor (RF)	
Further Information					
Work Scope and Deliverables					
Manpower required					

Project Schedule including Critical milestone of special activity			
Milestones	20XX	20XX	20XX
AGREED BY			

Appendix C: Feasibility Study Report

Suggested headings and content of the Feasibility Study Report are as follows:

Executive Summary

- **Background and Introduction**
- **Subsurface description**
  - Seismic Data
  - Structural interpretation
  - Depositional Geology
- **Petrophysical Evaluation**
- **Static Modelling & Hydrocarbon in Place volumes**
- **Near Field Exploration Opportunity & Screening**
- **Geomechanics and Shallow hazards**
  - Well bore stability
  - Sand Failure Prediction
  - Shallow geohazards evaluation
- **Reservoir Engineering**
  - Initial Reservoir Pressure and Temperature
  - Fluid Properties
  - Aquifer strength
  - Capillary Pressure and Relative Permeability
  - Dynamic Reservoir Modelling
  - Upscaling QA/QC
  - Scenario and Sensitivity Analysis
  - Production Forecast
  - Liquid loading Risk Assessment
- **Well Engineering Summary**
  - Well and Completion Design
  - Well Cost Definition
- **Production Technology**
  - Completion strategy
  - Completion Concept
  - Prosper Model
  - Fist Modelling
  - Sand Control Evaluation
  - Material Selection
  - Well Intervention & Workover
  - Well Reservoir Facilities Management/ Production Strategy
- **Surface Development Concept and Process Engineering Overview**
  - Description of Range of Scenarios and Feasible cases
  - Technical Concept Description
- **Development Cost and Schedule**
- **Deliverable and Milestones**
- **Operation and Maintenance Assessment**
- **Evaluation against Decision Criteria**
- **HSSE**
- **External Benchmarking**
- **Technical Risks and Opportunities**
  - Subsurface Risks and Opportunities
  - Surface and Wells Risks and opportunities
  - Technical Risk mitigation plan
- **Conclusions and Recommendations.**

Appendix D: Reservoir Development Studies Report

Suggested headings and content of the Reservoir Development Study Report are as follows:

Executive Summary

- **Background and Introduction including objective**
- **Seismic Interpretation**
  - Seismic & Well Data
  - Well to Seismic Tie
  - Key seismic horizon mapping with fault interpreted
  - Amplitude maps
  - Time depth conversion
  - Uncertainties
- **Qualitative Interpretation**
  - Fluid Predictions
  - Fluid and Contact evaluations
  - Conclusions and Discussion
- **Static Modelling & Hydrocarbon in Place volumes**
  - Objectives
  - Database used
  - Regional & field setting
  - Depositional environment
  - Static Model construction including correlation, structural modelling, fluid contacts, property modelling and volumetric
  - Property Modelling
  - Conclusion & Recommendation
- **Petrophysics**
  - Data availability
  - Core data including Core Analysis, Special Core analysis and Core Data issues
  - Water sample
  - Pressure data
  - Open Hole formation evaluation
  - Saturation Height Function
  - Permeability – Porosity discussion
  - Sums and Averages
  - Uncertainty Analysis
  - Appraisal recommendation and conclusion
- **Formation Pressure Analysis**
  - Available Pressure data
  - Validation of the Pressure data
  - Methodology for determination of Fluid Contacts
  - Uncertainties
  - Hydrocarbon Contact and Ranges
- **Reservoir Engineering**
  - Initial Reservoir condition
  - PVT fluid characterisation
  - Relative permeability Analysis
  - Dynamic Reservoir Modelling
  - Model initialisation and QA/QC
  - Scenario and Sensitivity Analysis
  - Production Forecast
  - Base Case Scenario Model
  - Reservoir Uncertainty Analysis (Tornado Assessment)
  - Subsurface Model Realisations (Low-High) on Base Case Surface Concept
  - Development Scenarios (Surface Concept & Subsurface Realisation)
  - Base Case Surface Development Concept Production Forecasts (Low & High)
  - Conclusions

- **Well Engineering Summary**
  - Well and Completion Design
  - Subsurface target Selection
  - Surface location Selection
  - Well Cost
  - Well Risks
  - Work Plan for Next Phase
- **Production Technology**
  - Reservoir and Fluid Characteristic
  - Sand Control Evaluation
  - Well Modelling
  - Artificial Lift Screening
  - Smart Well Application
  - Material Selection
- **Facility Engineering**
  - Development concepts including Minimum CAPEX, Base Case, Maximum UR Case and Unconstrained Case
  - Further Concept Work
- **Conclusions and Recommendations.**

Appendix E: Field Development Plan Minimum Requirements

The table below serves as a guide and scaling may be necessary based on complexity of the field

ITEM	CONTENTS	FIELD DEVELOPMENT MINIMUM REQUIREMENT AND NOT LIMITED TO
3.1.1	Executive Summary	▪ A brief description of the field, including reservoirs, reserves, development strategy, facilities, overview on the exploration well results. ▪ The project schedules ▪ Total development capital expenditure, operating expenditure, and abandonment expenditure. ▪ Economic Indicators i.e. NPV and VIR
3.1.2	Field Description	▪ Map showing the area of interest including cross section showing all hydrocarbon bearing sands, field limits, contours of fluid contacts. ▪ Gas categories. ▪ A description on the reservoir characterization, deposition system and structural styles
3.1.3	Reserves and Resources	▪ An estimate of the initial oil and gas volume in place. ▪ An estimate of oil, condensate and gas recoverable resources and recovery factors under different development option(s). ▪ Description of in-place Hydrocarbon volumes uncertainty range, the uncertainties of parameters impacting in-place volume.
3.1.4	Data acquisition plan	▪ In the case of an Appraisal well, it shall contain a reasonable description of the planned appraisal activities, estimated investment, time schedule ▪ Plan Pressure Build-up test. ▪ Fluid and Core sample programme & report
3.1.5	Risk and Opportunity Management Plan	▪ Description of project technical subsurface and surface. ▪ Mitigation plan. ▪ Subsurface/Well Risks and opportunities covering Technical, Economical, Commercial, Organizational and Political. ▪ Surface Risks and Opportunities covering Technical, Economical, Commercial, Organizational and Political.
3.1.6	Geophysics	▪ Available Seismic Data and quality. ▪ Seismic interpretation. ▪ Quantitative Interpretation. ▪ Seismic attribute extraction & analysis, depth conversion & uncertainty.
3.1.7	Petrophysics	▪ Available well log data, core data and its quality ▪ Petrophysical Log data used for log correlation ▪ Rock properties ▪ Formation Pressure Analysis and Interpretation ▪ Fluid Contact ▪ Formation temperature ▪ Well test analysis to evaluate well productivities and reservoir characteristics, including flow barriers/fractured systems. ▪ Integrate permeability data from core and/or logs with a well test results.
3.1.8	Geology and Static Modelling for green field	▪ Reservoir Geology & Static Modelling ▪ Volumetric Analysis including the input parameters ▪ Description of how the subsurface static reservoir models are constructed, data used with their uncertainty ranges and alternate realizations.

3.1.9	Reservoir Properties	▪ Aquifer support assumption ▪ Viscosity & Mobility ▪ Log interpreted data – Porosity and Saturation ▪ Net to Gross ▪ Reservoir Temperature and formation water salinity ▪ Core Data- core porosity, vertical and horizontal permeability, initial saturation (Swi, Sor, Sg, Sgc), capillary pressure and relative permeability. ▪ Average reservoir characteristics (porosity, permeability, initial water saturation, capillary pressure, relative permeability). ▪ Rock Mechanical properties ▪ Drainage and imbibition capillary pressure Please indicate if analogues or correlation used for the reservoir properties input.
3.1.10	Reservoir Fluid Data	▪ PVT data summary – indicating if it is Black oil, Volatile oil, dry gas, retrograde gas, Reservoir gas PVT (gas-condensate, wet, or dry) properties. ▪ Initial reservoir and saturation pressure ▪ Reservoir Temperature ▪ Saturated oil density, API, Viscosity, Bo ▪ Oil properties vs pressure at reservoir temperature; Formation volume factors, Gas Oil Ratio, Oil Viscosity. ▪ Solution GOR at saturation pressure and thermal expansion. ▪ Integrate well test analysis used to evaluate well productivities and reservoir characteristic including flow barriers/ fractured system
3.1.11	Depletion Mechanism	▪ Determine the drive mechanism
3.1.12	Dynamic Reservoir Modelling	▪ Geological data input In case of insufficient data available, Upstream Operators should highlight any analogues or correlations used. ▪ Upscaling For input data from static modelling, Upstream Operators should highlight the upscaling process if used. ▪ Model Gridding ▪ Distribution of initial water saturation ▪ Model initialization – any major discrepancy in calculated volume between static and dynamic should be highlighted. ▪ Quality Check (Static and Dynamic models) ▪ Identify key uncertainties having a large effect on ultimate recovery and establish a range of possible values ▪ History Match Ensemble. ▪ Sensitivity Analysis ▪ Simulation Prediction
3.1.13	Ultimate Recovery and Production Forecast	▪ Description of the behavior of the reservoir system using analytical or numerical simulation techniques under different development schemes. ▪ Description of reservoir simulation models used to optimize hydrocarbon recovery and development options and evaluate the impact of key uncertainties. ▪ Assessment of the ultimate recovery from different recovery processes, recommended secondary or tertiary recovery techniques. ▪ Assessment of best-possible, technical limit ultimate recovery (creaming curve assessment of primary, secondary and EOR techniques) with associated assumptions and basis required to achieve highest ultimate recovery.

		▪ Production (and injection) forecasts for all fluids produced and injected with uncertainty ranges, using the appropriate tools and techniques. System constraints, uptime assumptions, schedule, and ramp-up uncertainty for new fields in the forecasting models should be explained.
3.1.14	Development strategy – Preferred Development Concept	• Description of the Possible Development Concepts and the range of possible forecast outcomes • Well designs and completion schemes. • Expected production and injection profiles for the development option. • Quantification of the key uncertainties and risks • Assessment of the potential value of reducing parameter uncertainties and recommendations to reduce uncertainty ▪ Recommended option(s) and reasons for the preferred concept choice ▪ Expected first commercial production of oil, gas, and condensate. ▪ Secondary and tertiary recovery method such as water flooding, gas flooding, polymer flooding, gas recycling if there is a retrograde condensate gas cap in the reservoir. ▪ Technical evaluation of innovative technology to increase the ultimate recovery.
		For Thin Oil Rim development ▪ Reserve volume & project economic cut off ▪ Potential synergy with other oil rims, marginal or within development activity ▪ Proposed well location i.e. distance from gas oil contact ▪ Critical oil production rates ▪ GOR limit
3.1.15	Production Strategy and Operation philosophy	▪ Selected production strategy. ▪ Short and long-term plans, impact on production acceleration and recoverable reserves. ▪ Number of production and injection wells. ▪ Well type including perforation scheme and completion diagram. ▪ Indicative of hydrocarbon bearing sands penetrated. ▪ General Operations and maintenance philosophy for Wells and Surface ▪ Specific to the platform or facilities, accessibility, manning level, maintenance plan, SIMOPS/CPRA procedures must be defined. For oil rim - The following information should be submitted to provide assurance that adequate GOR control is implemented prior to deliberate production of gas cap gas ▪ Gas Production Control Plan for each reservoir. ▪ Solution GOR - based on reservoir characterization, subsurface uncertainties, and field development and production plans ▪ Recommended produced GOR limit ▪ GOR monitoring plan, including Key Performance indicators.
3.1.16	Production Technology and Well Engineering	▪ Well Design Concepts including trajectory and location. ▪ Well cost ▪ Production Technology Completion Design and strategy. ▪ In flow performance prediction. ▪ Sand control and Sand Management.

3.1.17	Surface Facilities and Operating Envelopes	▪ Analysis on optimum hydrocarbon evacuation concept. ▪ Surface facilities requirements. ▪ Decisions taken on the implementation of specific technologies. ▪ Scope should be well defined and competitive in costs ▪ Description of various types of concepts considered ▪ Selected Concept ▪ Concept Selection Criteria ▪ Description of major equipment and infrastructure items and operating parameters. ▪ Platform's basic information o Location & coordinates o Distance to shore & nearby facilities ▪ Facilities reliability, integrity management and corrosion management. ▪ Design life ▪ Facilities design rates- oil, gas, water ▪ Description of Gas venting and flaring ▪ Provision for third party used of infrastructure facilities and services to third party
3.1.18	Project Planning	▪ Apply standard industry practice in integrated project planning – such as scope, time, cost, quality, resources, HSSE, and value. ▪ Apply appropriate project management plan as the following, but are not limited to: o Project Scope o Resources o Cost and Schedule o Procurement o Quality Control o Process improvement o Communications and Stakeholder o Risk and Opportunities ▪ Ensure the competence and compliance of all personnel involved including contractors.
3.1.19	Project Execution	▪ Description of Project management model and resources requirement, Stakeholders engagement plan, Front end engineering design, Contract, and procurement execution model. ▪ Describe the critical path and what are the critical elements that influence the timing of the key milestones. ▪ Explanation related to the basis of Cost estimate and Integrated schedule with benchmarking applied ▪ Apply project management best practices. ▪ Apply use best available tools, technologies, and innovative solutions. ▪ Ensure execution programs in place and assurance on readiness such as material, resources, and logistics etc. ▪ Implement, monitor and control activities to ensure project are executed within time and cost ▪ Organize post execution review upon completion of the activity such as After-Action Review and project closed-out meeting. ▪ Update as-built drawing, associated document, and prepare closed-out report with all asset registers and documentation are consistent. ▪ Ensure asset handover to relevant party meet all requirements that have been agreed.

		▪ Ensure the competence and compliance of all personnel involved including contractors. ▪ Monitor performance and to capture lessons learnt ▪ Promote knowledge sharing and sharing of best practices.
3.1.20	Field Management Plan	Refer to Brunei Darussalam Oil & Gas Guidelines Volume 9 on Field Management Guidelines.
3.1.21	Economic Evaluation	▪ Economic evaluation of each development option ▪ Economic model analysis and evaluation of the economic viability of the development scenarios on the project level. ▪ Description of the accuracy and contingency applied. ▪ Sensitivity analysis ▪ Key commercial parameters that could impact on economics. ▪ Evaluate the economics of a development option to initiate water injection from first oil date rather than waiting for primary depletion.
3.1.22	Health, Safety, Security and Environment (HSSE) Policy	▪ Comply with all Authority requirements. ▪ Define HSSE best practices for safe and sustainable operations ▪ Venting and Flaring must be kept to the minimum that is technically and economically justified. ▪ Ensure that gas is conserved where possible by avoiding unnecessary wastage. ▪ Manage water and wastes disposal. ▪ Ensure the competence and compliance of all personnel involved including contractors. ▪ Review policy performance and capture lessons learnt for HSSE improvement ▪ An HSSE and SP activities plan. ▪ Key activities in the select phase include HAZID, Hazard and Effect management and Environmental Impact Assessment where appropriate and a Green House Gas and Energy Management Plan. ▪ Risk registers and management system incorporated into the integrated project work plan and the assurance plan.
3.1.23	Local Business Development (LBD)	▪ Refer to LBD directives requirement.
3.1.24	New Technology	▪ Surface and subsurface technology application.

3.1.25	Trans-boundary field	▪ All oil and gas development that straddles between two or more petroleum mining agreements, should be refer to the Authority.
3.1.26	Possibility of future tie-in of nearby Exploration prospects	▪ The plan should provide an assessment of the possibilities of future tie-in of neighbouring exploration prospects in the area.