NORWEGIAN OFFSHORE DIRECTORATE

RNB2026 General Guidelines

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1 Reporting Framework

1.1 The Purpose of the Reporting

Pursuant to Section 50a of the Regulations to Act relating to petroleum activities, operating companies shall submit data as input to the revised national budget (RNB):

"The reporting shall include economic company data, projects, resource volumes and prognosis for production, costs and environmental emissions as specified by the recipient".

Every year by 15 October, all operating companies shall submit data and forecasts for their respective operated fields, discoveries, transportation- and utilization facilities (TUF). Note that the economic company data is not part of the RNB reporting and shall be reported to the Ministry of Energy (MoE) in accordance with their deadlines.

The reporting to the RNB comprises part of the basis for the Government's petroleum and environmental policies, as well as the fiscal and national budget. These forecasts are important, and great emphasis is therefore placed on ensuring that high-quality reporting is provided within the stated deadlines.

The Norwegian Offshore Directorate (the Directorate) quality-assures and organizes the data reported by the companies. The Directorate also prepares its own estimates and classifies the resources based on its own knowledge and assumptions. Based on this, the Directorate updates the resource account for the Norwegian continental shelf and prepares overall forecasts. The forecasts are submitted to the MoE and forwarded to the Ministry of Finance.

The forecasts and the resource account are incorporated into several analyses and various publications, such as the "The petroleum resources on the Norwegian continental shelf" and the websites sodir.no and norskpetroleum.no.

The data received will be considered exempted from public disclosure pursuant to Section 13 of the Freedom of Information Act, and to Section 13 of the Public Administration Act, 1st paragraph number 2. Reserves, in-place resources and CAPEX associated to the reserves, are published per field on the Directorate's web site. Recoverable resources are published per reported discoveries.

1.2 Deadlines and Requirements

The operators' deadline for submitting the reports to the Directorate is **15 October**. It is important that you deliver at the deadline, for the Directorate to meet subsequent deadline with the MoE.

The guidelines are provided in English. Please contact the Directorate for any questions regarding the reporting.

If there are significant changes to the reporting due to the budgetary processes in the production licensees' management committees after 15 October, please contact the Directorate as soon as possible to clarify whether there is a need to submit an updated reporting.

Companies submit data to Collabor8 either via API or using an Excel template provided by Offshore Norway. Collabor8 will then convert the submitted data into the JSON exchange format required by the Norwegian Offshore Directorate. The transfer from Collabor8 to the Directorate includes a validation service that checks compliance of the information from both the data phase and the defined scope. Depending on the severity of any validation errors, the report must either be corrected, or the error messages must be addressed with proper comments. Data is not considered received by the Directorate until it has successfully passed validation.

1.3 Content Changes from Last Year's Reporting

There are changes in the Guidelines in the following areas:

- Description of the variables to be reported are available in Collabor8 and as an attachment to this guideline.
- New data types have been introduced. To ensure completeness in CO_2 emissions reporting, venting of CO_2 must now be reported using the parameter "CO2ContributionVenting".
- Variables earlier used solely for calculation of power demand on platforms, recipe of gas, deliveries of gas and liquids, gas lift and injection from main field have been removed.
- Reporting now includes new parameters for the injection of CO_2, natural gas, and water for disposal purposes, separate from the field's resource management activities.
- The previous general description to each Project Group is split into two explanatory parameters. “GeneralDescription” for a description of the activity reported and “VolumeChangesExplanation” for comments on changes in volumes and production/sales profiles from last year’s report.
- Providers of tariff services must be entered as "ExternalReportingObjectReference" from a valid list of objects (NPDID). Tariff costs profiles must be reported separately on different providers, the explanation “TariffCostExplanation” could be used if necessary.
- Objects included in calculation of energy demand, disposal of products and emissions, as well as sources of purchased gas must be entered with a NPDID. This is information only, and there is no need to separate the influence from each object.

1.4 Quality Assurance and Updates from the Operators

It is very important that the operator performs an internal quality check to ensure the high quality of data before submission to the Directorate. If the Directorate identifies errors, lack of information or ambiguities in the submitted report, the issuer of the report will receive feedback. The operator must then either submit a corrected report or respond to the comments.

The person responsible for the operator's reporting shall ensure:

- that the reporting is in accordance with the approved Scope
- that a correct project group is linked to the various projects
- that correct reporting is submitted to the authorities by the deadline stated in the dispatch letter
- that there is consistency between data types
- that contributions from the respective disciplines are quality assured

Quality implies that the reporting is in accordance with the requirements listed in the General Guidelines.

2 What to Report

2.1 Reporting Objects

There are three primary categories of Reporting Objects: Field, Discovery and TUF. These categories are used to structure and classify petroleum resource data in the reporting process. The table below provides formal definitions for each category.

Table 2-1 Definition of main categories

Category	Description
Field	One or more petroleum deposits, which together are comprised by an approved plan for development and operation (PDO) or for which exemption from the PDO requirement has been granted.
Discovery	One petroleum deposit, or several petroleum deposits collectively, which have been discovered in the same wellbore and in which testing, sampling or logging has established the probability of the existence of mobile petroleum (includes both commercial and technical discovery). For discoveries in RC4F, 5F and 7F that are reported as part of a field, the resource estimates will not be published. Several discoveries may be combined in one report, as a development project.
TUF	Transportation and Utilization Facilities includes pipelines, terminals and onshore facilities.

2.2 Projects in Objects

Each Reporting Object (field, discovery and TUF) contains one or several projects. A project in the Norwegian Offshore Directorate's resource classification system (see section 3 below) refers to an initiative aimed at developing and producing petroleum resources. Projects are categorized based on their maturity and the level of knowledge about the petroleum volumes involved.

All recoverable petroleum volumes must be assigned to a project. A project represents the connection between a petroleum volume and the decision process, including budget allocation. A project will have a specific level of maturity regarding a decision to whether to proceed (i.e., to invest money). An additional project in a field or a mature discovery can represent development of one or more new deposits, or it can represent a specific measure to optimise production on a field.

Projects also apply to TUF. An additional project can for example be a new pipeline or a new compressor. Each project should be placed in a resource class based on its maturity.

For mutually exclusive projects (targeting the same volume), only the most probable project should be reported.

3 Guidelines for Reporting Petroleum Resources

The percentage of resources attributed to Norway (normally 100 per cent) must be clearly stated. For those cases where the resources extend into another country's continental shelf, use the latest official allocation of resources between Norway and the respective country. For discoveries, please state the existing agreement between the parties involved.

3.1 Originally in Place Resources

The resource overview shall be completed for all fields and discoveries, unless otherwise agreed with the Directorate. Fields and discoveries often have projects also in higher resource classes with associated resources.

- Expected resource class as of **31 December** of the current year shall be used as a basis for the reporting.
- Only the Norwegian percentage of the resources is stated according to the distribution provided in the Scope.
- For reporting objects where several discoveries are reported, resources for each individual discovery should be given separately.

Hydrocarbons originally in place shall be reported for each deposit available on the reporting object. The hydrocarbons are categorised into oil, associated liquid (condensate), associated gas and/or free gas, independently of the sales products. Gas volumes shall be reported at the actual calorific value. All estimates shall be given with uncertainty: high (P10), low (P90) and base estimate (expected value).

In the reporting of hydrocarbons originally in place, condensate should be reported as associated liquid, regardless of the sales product.

3.2 Recoverable Resources

Recoverable resources shall be stated for all projects reported on the object.

The resources should be reported as sales products; oil, NGL, condensate and gas. The sales products shall, to the greatest extent possible, be reported in the same way as they will be reported to the Directorate (DISKOS – Saleable Production) in the regular monthly reporting. This means that condensate sold as oil should be reported as oil, and associated liquid from gas fields shall be reported as oil if the liquid is sold as oil. Recoverable gas comprises quantities which are sold, physically delivered, or planned to be delivered from the asset.

If there are any changes to the definition of sales products during the operating period of a field, the date of the change should be reflected in the RNB reporting. This means the change should be reflected in the same way as it is reported to DISKOS (Saleable Production).

Gas flared or used for fuel shall not be included in the resource base.

For all projects the high (P10), low (P90) and base estimate (expected value) shall be reported for recoverable resources.

Table 3-1 Uncertainty categories

Uncertainty category	Definition	Explanation
Low estimate (L)	Low estimate of petroleum volumes that are expected to be recovered from a project.	The low estimate must be lower than the base estimate. The probability of being able to recover the indicated estimate or more must be shown (e.g., P90). Compared with the base estimate, the low estimate should express potential negative changes with regards to mapping of the reservoir, reservoir/fluid parameters and/or recovery rate.
Base estimate (B)	Best estimate of petroleum volumes that are expected to be recovered from a project.	The base estimate must reflect the current understanding of the scope, properties, and recovery rate of the reservoir. The base estimate will be calculated using a deterministic or stochastic method. If the base estimate was calculated using a stochastic method, the base estimate shall be stated as the expected value.
High estimate (H)	High estimate of petroleum volumes that are expected to be recovered from a project.	The high estimate must be higher than the base estimate. The probability of being able to recover the indicated estimate or more must be shown (e.g., P10). Compared with the base estimate, the high estimate should express potential positive changes with regards to mapping of the reservoir, reservoir/fluid parameters and/or recovery rate.

RC1-5
For projects in RC1-5, the recoverable resources are normally equivalent to the sum of the reported sales profiles. However, some fields and discoveries with commercial agreements for swaps/borrowing/deferral of volumes need special handling (see section 4.3.1.6 below for more information).

At least one Project Group shall be prepared for each resource class in which a project is reported.

In total, the field/discovery should not report negative resource estimates, but fields and discoveries can have projects with negative resource estimates.

Reporting of historical production from fields where production has ceased has been challenging to get correct. Fields that have ceased production shall report the total production for the prior production period as a separate project with RC0, where the production for all products is identical to what has been reported to DISKOS (Saleable Production). Fields without potential for further activity and where all cessation costs have been spent before the previous year, should not be reported.

RC6 and RC7:
For projects in RC6 and 7 only report recoverable resources including information about evaluations that have been performed, and further plans for the project are provided in the explanation “RC6-7Description”.

RC7A:
For projects in RC7A, the resource estimate should reflect a long-term expectation of the final recovery factor for the field/discovery due to anticipated technological development. The low estimate should reflect a long-term expectation of the final recovery factor for the field/discovery assuming a moderate technological development. The high estimate should reflect a more optimistic, long-term objective for the final recovery factor for the field/discovery assuming an expansive technological development.

RC8:
Estimates must be provided for recoverable resources in prospects located within separate production licences or unitized fields that, if discovered, will highly likely be tied into the field or discovery in which they are reported in. Prospects that extend into adjacent production licences must be reported with the total estimated volumes. It must be ensured that the same prospect is not reported simultaneously by other fields/discoveries. The resource estimate must be risk-weighted and should reflect the estimated volumes multiplied by the probability of making a discovery.

Explanation and comments about changes in the reserve- and resource estimates:
Changes in the reserve- and resource estimates compared to the previous RNB reporting must be entered in "ResourceExplanation"**.** If the change in reserves for oil and gas is ± 0,5 million Sm^3 o.e. or more, the reasons for the change must be described. As a minimum, these reasons should include whether the changes are due to development decisions, well decisions or updates to the model and assumption.

Changes in total recoverable resource estimates of more than 5 per cent are considered significant and must be explained.

4 Requirements for Reporting Project Groups

4.1 Definitions

Project Groups: are entities as they are defined in the Scope that contain one or more projects on which the operator must report profiles for. Each Project Group is identified by its name, a unique “ProjectGroupID” and the Reporting Object to which it belongs. All Project Groups in RC0-5 must include profiles.

Profiles: are different data items (yearly or monthly data) that the operator must report on.

Time horizon: The operator should report complete profiles for the projects, assuming profitable operations continue beyond the expiry of the licence. Relevant columns for costs and emissions related to production, shall be filled inn. If the profitability of a project depends on other projects, such as in case of uneconomic tail production, this dependency should be clearly stated in a comment section for the project.

Norwegian part: If the ownership of a field or discovery is shared with another country, only the Norwegian part must be reported in the profiles, except for environmental data which shall be reported 100 per cent if the emissions take place in Norway.

NOK-values: Costs and income for the previous calendar year shall be reported in actual NOK values for that year. No adjustments for inflation or deflation shall be applied to the cost numbers for previous years. All future costs and income shall be reported in real NOK terms using the current calendar year as the reference year.

Costs: To the extent possible, reported operating costs should be distributed among the various cost components and correspond with the operating period. For next year, the RNB reporting should be in accordance with the proposed licence budget as of **October 1st**. Any discrepancies between reported estimate and the operator’s proposed investment budget shall be commented in the relevant “ChangeExplanaition” for the Project Group.

4.2 Information and Explanation of Changes in Project Groups

Each Project Group includes Description and Explanation of variables. Please use this extensively for information about the Project Group.

Change explanations are to be used if there are significant changes compared to the previous RNB reporting, such as:

- Changes exceeding 5 per cent in total recoverable resource estimates.
- Changes in any single year within the next ten-year period that exceed 10 per cent or more than 1 million Sm^3 o.e.
- Changes in total investment exceeding 5 per cent or changes of more than NOK 500 million in a single year.
- Changes in operating costs exceeding NOK 300 million per year.
- As regards “Disposal costs and Other income”, changes in the total estimate greater than NOK 300 million must be explained.

The Description and Explanation of variables can be used to explain significant variations in the profiles reported this year. For projects reported with operating costs in basis profile, the Description and Explanation of variables in this profile sheet is used to explain nonconformities. Deviations from proposed budget should also been explained.

4.3 Overview of Profile Types in Project Groups

For fields, discoveries and TUF in RC0, 0+1, 1, 2, 3, 4 and 5, data must be reported annually. Monthly sales quantities for the upcoming year must be reported separately.

The ‘Profiles’ tab in the Project Groups template includes the following data types:

- Production and injection data
- Sale of petroleum and other revenues
- Physical rich gas/dry gas deliveries
- Costs (investments, operating costs, tariffs, and other costs)
- Environmental data

4.3.1 Profiles for Petroleum

The following section provides guidance on how to report liquid and gas profiles. Please consider the points below:

- Reporting is requested for the **sales product**, for example condensate sold as oil should be reported as oil.
- For individual profiles **negative rates** can occur in some years, for example, a profile for a project that entails acceleration of the oil production or increased gas injection, however the sum of all profiles for a field or discovery should be positive.
- Reporting of **commercial agreements** involving swaps/borrowing/deferral of volumes are described in section 4.3.1.6 below.

4.3.1.1 Production and Injection Data

The profiles in the subgroup "ProductionAndInjection" refer to volumes that are produced and injected in the deposits in the same field. They do not include injection into other fields.

4.3.1.2 Sale of Oil, NGL and Condensate

For oil, annual base (expected) estimates must be reported with uncertainty estimates if the project is in RC (0+1) - 4. For NGL and condensate, only annual base (expected) estimates are to be reported.

The high and low estimates must describe the sample space for the relevant calendar year including both general reservoir uncertainty and operational uncertainty. Operational uncertainty shall reflect the progress in well drilling, the productivity of the wells, production capacity in processing facilities, etc.

The total of low estimates for annual production will typically be lower than the low estimate for the resource estimate. This is because uncertainty in annual volumes includes factors that are not correlated from year to year—such as operational regularity. It is also unlikely that the low estimate will occur every year. Similarly, the total of annual high estimates will generally exceed the high estimate presented in the resource overview.

4.3.1.3 Transport, Sale, and Purchase of Gas

Transport and sale of gas must be reported independently of the granted production permit. If the expected volumes exceed the existing production permit, this must be clearly stated.

Note that some of the gas data is to be reported according to calendar year (1 January – 31 December), while other data is to be reported according to gas year. The gas year (n) runs from 1

October in year (n) to 1 October in year (n+1). If it is difficult to convert between gas year and calendar year, please contact the Directorate.

The Directorate collaborates with Gassco on the reporting process. It is important that profile information submitted to the Directorate is identical to the data reported in the Gas System.

All gas that the licensees may seek transport rights for in Gassled, shall be reported both in "ProductionVolumes" and in the Gas System.

Gas received as compensation for services (such as storage, treatment, and transport), is not defined as purchase and shall not be reported.

For reporting of uncertainty and production start-up, the same principles as for oil are used as a basis (see section 4.3.1.2 above).

The table below summarizes the reporting of different gas types.

Table 4-1 Overview of gas types

Product	Profile name				
	DryGasLow DryGasBase DryGasHigh	PhysicalDryGas	PhysicalRichGas	SaleableGasCalenderYear	SaleableGasGasYear
Dry gas	δ	δ		δ	δ
Rich gas	ρ	ρ	δ	ρ	ρ
Condensate	χ			χ	χ

δ *Gas delivered directly from the installation*

ρ *Expected volumes of dry gas at sales point after processing*

χ *Dry gas separated from the liquids at the terminal and sold*

4.3.1.4 Monthly Profiles and Accumulated Values

Monthly sales quantities for the upcoming year must be reported separately for all products in "OilBaseMonth", "SaleableGasMonth", "NglBaseMonth" and CondensateBaseMonth". The expected value is to be reported for all Project Groups with expected sales volumes the upcoming year and the total monthly figures must match the annual totals reported for each respective Project Group. It is important to account for differences in the number of days per month, as well as any planned workovers.

Accumulated quantities must be reported for production volumes; covering all years with historical sales and transport of petroleum prior to the start of yearly profiles. The numbers will make up the totals for different products and will be checked against the saleable resources in the projects included in the Project Group.

4.3.1.5 Gas Blow-down

For these types of projects, it is preferable to obtain gas and associated liquid profiles, as well as investment profiles in a separate Project Group. Operating costs and environmental profiles can still be reported in the main project, unless the project involves new power-generating equipment.

4.3.1.6 Resources and Profiles Regarding Commercial Agreements

Gas purchased from other fields for injection purposes, which will later be exported, should not be included in the buyer's resource base. These volumes should be listed in a separate row in the resource overview as negative numbers.

If gas is delivered to another field/discovery for injection or other use, please specify the actual field/discovery. If the gas is given away as payment for a service or if the gas is sold, this should be explained in "ResourceChangeExplanation" per object.

When products are delivered in kind to other fields, the recipient should list the volumes in a separate row in the resource overview, if these volumes will be sold. Note the following:

- For accounting it is crucial that the different parties report the same effect of the commercial agreement, ensuring that the total effect is zero. If the agreements are not ready for RNB reporting, the Directorate can ask for the commercial effects in a separate Excel file. Please comment in "ProjectGroupDataDescription" on whether the other field/discovery is expected to report.
- The gas columns reported should be based on the same definitions as in Table 4.1.
- The sum of all profiles reported should give the correct total income profiles corresponding to the total resources. The project resource included in a Project Group should correspond to the sum of the sales profiles in the same Project Group.
- In total the field/discovery should not report negative total resources. If it is expected that a development of a discovery will reduces total saleable products, please report physical products separately from the total effect. Total saleable can then be adjusted in Project Group for commercial agreements.
- "ProjectGroupDataDescription" should be used to describe commercial setups and assumptions.
- Bilateral agreements between individual companies (e.g., shipper agreements) should not be reported.

4.3.2 Profiles for Costs and Income

The Joint Operating Agreement (JOA), which is an appendix to the Licence Agreement, specifies which cost items the licensees are obliged to report in their budgets, work programs etc. The JOA consists of 9 main items with sub-items (and sub-sub-items).

Reporting to the Directorate should primarily be in accordance with the item structure outlined in the JOA. In some cases, operators may be asked to provide more detailed reporting than what is specified in the JOA. In other cases, operator may be requested to report more aggregated data. This applies to both investment costs and operating costs.

4.3.2.1 General Price Increases

The general price increase represents the operator's assumption for converting nominal NOK to real NOK. For RNB2026 the reference year is 2025. Therefor the general price increase should be used to convert nominal figures for 2026 and beyond into 2025 values. Figures for the year 2024 should be reported in nominal values.

4.3.2.2 Investments (JOA, item 5)

Reporting to the RNB regarding investment costs differ on certain items from the structure in the JOA. The table below shows where this is applicable.

Table 4-2 Investment costs

Structure in the JOA	Profile name in the RNB
5.1 Development investments	Development investments shall be reported separately for: - NewSubseaFacilities - NewFloatingFacilities - NewFixedFacilities - Pipeline - LandFacility - OtherDevelopment
5.2 Operating investments	Investment Modifications
5.3 Production drilling	Investments in development wells shall be reported separately for: - DevWellsMobileDrilling - DevWellsPermanent Drilling - ProductionDrilling

4.3.2.3 Development Investments (JOA, item 5.1)

Development investments refer to capital expenditures related to the development of new petroleum resources. According to the JOA:

"*Development investments concern the development of new resources. There will always be concept studies before such an investment is made. The budget for the project is sanctioned by an approved PDO/PIO. Some projects are exempted from the PDO requirement."*

The profile "OtherDevelopment" is used as a general profile that includes all other remaining development investments.

Please ensure consistency between the type of development investment and the development solution reported in the Scope for projects in the Project Groups for RC3-5.

Different investment profiles are expected and will, to some extent, be part of the validation when uploading data to the Directorate. For example, investments in subsea development must be divided between subsea equipment, pipelines and necessary investments in host facilities. For more details, please refer to the document outlining the validation rules.

4.3.2.4 Operating Investments (JOA, item 5.2)

This will normally be investments in operating equipment that have been put to use (after the project investment was made) and that are not classified as maintenance. We refer to the JOA which states what to be included in item 5.2.

4.3.2.5 Development Wells (JOA, item 5.3)

The reporting regarding development wells must differentiate between wells drilled from fixed and mobile facilities.
Please note that the Directorate uses the term "development wells" instead of "production wells" and "development drilling" rather than "production drilling". Investments related to development drilling that cannot be directly attributed to specific wells, such as seismic surveys and associated activities mentioned above, must be reported separately and kept distinct from well-specific investments.

For more details, we refer to the JOA.

Number of development wells: New wells include all wellbores that receive their own designation in accordance with the Directorate's rules for naming wells and wellbores Well Classification. Please note that a side-track and each branch in a multilateral well shall count as a separate wellbore. Development wells must be reported as follows:

- Both production and injection wells must be included in number of development wells and associated costs.
- Pilots and observation wells drilled to establish an efficient wellbore should not be included in the number of development wells. However, costs related to these wells must still be reported. This ensures that the calculation of average well cost reflects the total cost of achieving one functional well.
- If the purpose of a well changes, it does not count as a new well. The number of wells remains unchanged, but the costs related to the conversion must be reported.
- Exploration wells (wildcat and appraisal wells) must NOT be included in the number of development wells nor in the well cost reporting.
- Disposal wells must be included in both the number of development wells and costs.

The number of development wells from mobile and permanently placed facilities must be reported. The following definition applies:

- A mobile drilling facility is a drilling facility intended for use on multiple fields.
- A permanently placed drilling facility is intended to remain on a specific field during the production period, even if it is physically movable. This includes floating facilities and jack-up rigs equipped with drilling and processing equipment, provided they are intended to stay in place throughout production.

The classification is therefore not based on whether the facility can physically be moved, but rather on its intended use during the production period.

Well costs: Costs associated with development wells; disposal wells and costs related to pilot and observation wells shall be reported.

The number of wells drilled from fixed and mobile facilities each year must align with the costs reported for development wells. The number of wells may be reported as a decimal figure (e.g.,3.2) if the wells are not completed within the calendar year.

4.3.2.6 Operating Costs, (JOA, item 6)

The reporting to the RNB regarding operating costs differs on certain items from the structure in the JOA. The table below shows where this is applicable.

Table 4-3 Operational costs

Structure in the JOA	Profile name in the RNB
6.1 Operational preparations	OperationalPreparations
6.2 Operating costs and support activities **6.2.1 Operation (ordinary operating costs)** **6.2.2 Maintenance** **6.2.3 Well maintenance** **6.2.4 Modifications** **6.2.5 Subsea operations and maintenance** **6.2.6 Platform services** **6.2.7 Administration** **6.2.8 HSE** **6.2.9 Reservoir management and development** **6.2.10 Business development**	 OrdinaryOperatingCosts Maintenance WellMaintenance OperatingModifications SubseaOperationsAndMaintenance PlatformServices Administration HSE ReservoirManagementAndDevelopment BusinessDevelopment
6.3 Logistics **6.3.1 Maritime operations** **6.3.2 Air transport** **6.3.3 Supply bases** **6.3.4 Preparedness**	LogisticsCost
6.4 Tariff costs	See section 4.3.4.2
6.5 Other operating costs	Operating costs (part of item 6.5) Gas purchase (part of item 6.5)

For more details, we refer to the JOA.

Shared Facilities (Costs): Some fields or development projects share common facilities to achieve cost-efficient resource management. Typical cases are:

- Development of deposits in different production licences sharing common facilities
- Power from shore projects involving different fields

For such projects, all investments and operating costs should be reported by the operator of the shared facilities. Other fields or discoveries that pay for the use of these facilities should only report their share of investment or operating cost under “TariffCostsCostSharingCapex” or “TariffCostsCostSharingOpex”. For RC1 and RC2 the shared costs are to be reported by the operator of the shared facilities.

When different projects within a specific field share new common facilities, all investments and operating costs related to the new facilities must be reported in a single Project Group. In such cases, no cost sharing should be reported.

Distribution of a field’s total operating costs on individual projects: Projects that result in significant changes in operating costs cannot be reported in the basis profile. Examples of such projects include new facilities, new expensive equipment/drainage strategy and cost reduction project.

It is not necessary to report separate operating costs for a project on a field if no significant changes are expected in the operating costs on the facility. Examples of such projects include well work (e.g. interventions or maintenance), optimizations within reservoir management, facility upgrades, etc.

If any of these projects result in extended lifetime for the field, the total operating costs must also be extended accordingly.

4.3.2.7 Shut Down and Removal (JOA, item 8)

Costs associated with shutdown and final disposal shall be reported. The time schedule for the activity must be practically possible to carry out. In a supplementary project that can extend the lifetime of the same field, costs related to shut down and removal/disposal may be postponed. Shutdown- and final disposal costs are then subtracted from the Project Group for the supplementary project and added to the year(s) the removal/disposal of facility is taking place. An example is given below:

A project in RC1 is shown in the left table. The right table illustrates a supplementary project in RC5 that can extend the lifetime of the field, thereby delaying shutdown and final disposal costs.

Table 4.4 Shutdown and removal costs-example case

OtherCosts		
Year	ShutDownCosts JOA 8.1	FinalDisposalCosts JOA 8.2
	million NOK	million NOK
Total	1400	1000
2027	700	500
2028	700	500
2029		
2030		
......		
2035		
2036		
2037		

OtherCosts		
Year	ShutDownCosts JOA 8.1	FinalDisposalCosts JOA 8.2
	million NOK	million NOK
Total	0	0
2027	-700	-500
2028	-700	-500
2029		
2030		
......		
2035	700	500
2036	700	500
2037		

4.3.3 Profiles for Environmental Data

The environmental forecasts include emissions to air and/or discharges to sea from the production facilities on the respective fields and their connected fields.

Alternative power projects related to existing infrastructure must be reported with associated costs and emissions if they have passed or are expected to pass, DG0 in the current year. These projects must be reported in a separate profile including emission reductions for both the main field and any associated fields, as well as for power-from-shore solutions if applicable. The decision to terminate separate reporting for such projects must be made during the scope phase.

Main principles:

- For reserves (RC1-RC3), environmental data must be reported for fields, transport systems and land facilities where emissions or discharges physically occur. Fields with only subsea installations are exempt from reporting environmental data beyond drilling-related emissions. Forecasts must reflect emissions and discharges based on current technology and any reduction measures implemented by the licensee.
- A different principle applies to RC4 and RC5. Environmental emissions and discharges, along with the underlying assumptions, must be reported for the respective field or discovery, unless reporting is covered by an agreement with the proposed host. Emissions and discharges must be reported as the projects "net contribution" to the environment.
- Associated fields that are included in the calculations of disposal, consumption, discharge and emission forecast shall be listed. Both the host and the satellite field must indicate whether the reporting is included in other objects. Use:
    - "ROsIncludedInEnvironmentalAssumptions" for objects reporting environmental influence from included objects.
    - "EnvironmentalAssumptionsIncludedInROs" for objects where emissions will be realized on another object.

  This information must be reported using NPDID, name and type for the objects, in the "AssosiatedObjects" sheet of template. Forecasts must be based on current plans. Any potential measures under consideration that could lead to emission/discharge reductions, beyond what can be achieved using current technology, must be described in the comments for environmental data.
- Border fields/discoveries with facilities located entirely on the Norwegian shelf, must report the total amount of emissions/discharges.

4.3.3.1 Emissions

Emissions of CO_2 and NOx

Total emissions of CO_2 and NOx from fuel gas, flaring and diesel include emissions from permanent facilities, mobile facilities linked to a permanent facility in production (activities subject to the CO_2 tax) and facilities that are not covered under the CO_2 Tax Act.

For reserves (RC1-3), the total CO_2 and NOx emissions shall be divided between the contributions from fuel gas, flaring, diesel, and activity from mobile facilities.

For RC4 and RC5 it is required to report the total prognosis for emissions of CO_2 and NOx, respectively. When possible, please specify these emissions according to contributions from fuel, flare, diesel, and activity from mobile facilities.

Emissions from activity related to exploration wells shall not be reported.

Emissions of nmVOC and CH_4

Total emissions of nmVOC and CH_4 from diffuse emission sources, cold venting and combustions (vent, turbines, motors, boilers, furnace, well tests, well cleaning or others) shall be reported. The sources of these emissions will be facility specific. Emissions of natural gas from all systems that handle hydrocarbons shall be included. Total emissions reported in “nmVocOther” and “CH4Other” should be sum of all sources, except for storage and loading reported separately as in Footprint.

Emissions associated with storing and loading of oil/NGL/condensate shall be reported in accordance with adopted measures or as planned by the operator (in cases where a final decision has not yet been made).

For facilities that carry out storage and loading for other fields, these volumes and their associated emissions shall also be included.

4.3.3.2 Energy demand for power-from-shore

Use of power-from-shore in the petroleum industry will have consequences for the whole power system onshore. Information regarding both energy requirements and power demand (GWh and MW) from the sector of the petroleum industry that gets power from shore is necessary, both to secure an effective operation of the power system onshore, and to help plan for prudent development over time.

It is important when planning to have the best possible overview and knowledge of both energy consumption and power demand. Power demand from the onshore grid, measured as maximum load during a year, from the installations that get power from shore will vary over time. This applies to both facilities that receive power from shore via subsea cables and land facilities that are directly connected to the domestic power grid. It is the power demand that regulates the dimensioning requirement of the transmission capacity in the power grid.

4.3.4 Profiles for Tariff Income and Cost

Tariff income and tariff costs shall be reported, assuming that they entail a payment obligation.

Tariffs per field: Tariffs shall be equivalent to 100 per cent of the field (or 100 per cent of the Norwegian share). If all licensees do not receive the same tariffs/have the same tariff costs, an estimate must be calculated, e.g., calculated as the operator's tariffs / the operator's share in the joint venture.

Reporting period: Tariff income/tariff costs shall, as for the Project Group, be reported for the entire licence period for the project, or for as long as income/costs are expected to occur for the project (longest period).

4.3.4.1 Tariff Income

Tariff income must be reported for fields that receive tariff from other fields/projects and shall normally include tariff income from projects in RC1-2. Tariff income from projects in RC3-4 shall normally not be included by the receiving party but shall be reported as tariff cost by these projects, ref section 4.3.4.2 below. In certain cases, tariff income from RC3-5 must be reported by the receiving party, this must be agreed upon with the Directorate and described in the respective “TariffIncomeExplanation”.

The Directorate requires actual payments to be reported, broken down by tariff provider and tariff type. This information must be entered in the “TariffIncome” sheet of template. Note that the tariff providers are identified by their NPDID, name and type of each provider.

Tariff revenues may also include reimbursement of operating costs resulting from cost-sharing agreements with associated fields. Free text and additional details can be added in the "TariffIncomeExplanation" sheet per profile reported.

Delimitation
Tariff income shall include all payments for services provided to other fields or to facilities outside the Norwegian continental shelf, related to the processing, transport, storage, modulation, etc. of petroleum. It shall also include any reimbursement of operating costs/investments that the relevant project has incurred and that are covered by other parties under agreements for the treatment and/or transport of petroleum.

4.3.4.2 Tariff Costs
Tariff costs must be reported for projects in RC3-4 where such costs apply. If data related to OPEX sharing and/or CAPEX sharing is available for RC5, it is encouraged to include this as well. The information must be entered in "TariffCosts" sheet of template. Service providers must be identified by their NPDID, name and type of each provider. Free text and additional details may be added in the sheet "TariffCostExplanation" per project group reported.

Except for tariffs on foreign installations, tariff costs for RC0-2 should not be reported. Tariff costs to Norwegian installations, associated with the projects in RC0-2, will be accounted for when the relevant fields report income from third-party processing. In addition, pipelines and terminals will provide estimates of their income. The Directorate will incorporate and allocate this income as costs for the relevant fields as part of the comparison of the figures associated with National Budget Reporting.

Definition and Delimitation
Tariff costs must include all payments for services provided by other fields on the Norwegian shelf related to the treatment, transport, storage, modulation and similar activities involving petroleum.

- Only tariff costs that are or will be included in the licence budget should be reported. Costs that only occur in the operator's internal accounts should not be reported.
- For the purposes of this reporting, imported tariff services (i.e. use of foreign installations) refer to payments for access to foreign facilities and pipelines. The Directorate receives a calculation basis for Norpipe UK and Norsea Pipeline; therefor tariffs paid to these systems should not be reported.

Note that import of tariff services (i.e., use of foreign installations), meaning costs associated with the use of transport or processing facilities that are either geographically or, under the Petroleum Act, outside the Norwegian continental shelf area, but which are still deductible for petroleum tax purposes, shall be reported. for both RC0‑2 and projects in RC3‑4.
Any tariff costs incurred after the expiry of the licence period for a project may be reported as an estimated annual amount, for example, based on the level prior to licence expiry.

Only the Norwegian part of the tariffs shall be reported.
If there are other significant operating costs beyond tariffs/rebates that are not covered by the joint venture or equivalent budgets, relevant information must be provided separately, if applicable. Operating costs are considered significant if they exceed NOK 50 million per year or NOK 300 million in total over the next ten years.