Brown Field Allowances (DECC, 2 February 2015)[1]

The Government announced on 7 September 2012 that it would introduce a Brown Field Allowance (BFA). This note gives information on the BFA qualification criteria and the process for BFA cost verification. Companies undertaking incremental projects that might be eligible for a BFA are advised to ensure they are familiar with this process if they wish those projects to qualify for the allowance.

Qualification criteria and amount of allowance

- Qualifying project – an incremental project increasing expected production from a wholly offshore oil or gas field as described in a revised consent for development which is authorised by the Department of Energy and Climate Change (DECC) on or after 7 September 2012 and has verified expected capital costs in excess of £60 per tonne of incremental reserves. Where a project forms part of a wider development,[2] all elements of the development must receive authorisation on the same day.

- The total field allowance for a qualifying project is calculated as £50 per tonne of incremental reserves (i.e. tax relief of £15 per tonne at the current 30% rate of supplementary charge) for projects/wider developments with a verified expected capital cost per tonne of incremental reserves of £80 or greater, with a straight-line taper to no allowance at an expected capital cost of £60/tonne.

- The maximum available allowance is £250 million for a single project or projects forming part of a wider development (with any reduction in allowance due to the cap being applied in equal proportion to pre-cap allowances). A company's share of the total BFA for a field is in proportion to its share of the expected incremental reserves for the project but with a further rule that, if the company reasonably expects to pay Petroleum Revenue Tax (PRT) in respect of production from the field during the expected period of increased production from that field as a result of the incremental project, for the purposes of calculating the total amount of the BFA at field or wider development level the cap is £500 million rather than £250 million.

- The field allowance for a project is available at a maximum yearly rate of 1/5 of the total allowance as from the accounting period in which incremental production

1. i.e. field allowances for "additionally-developed oil fields" - see Corporation Tax Act 2010 Part 8 Chapter 7 as amended and The Additionally-developed Oil Fields Order 2013.

2. A wider development may, for example, comprise a new field and an incremental project if they are mutually dependent or involve projects in more than one existing field e.g. if activity in one field increases reserve recovery in another and that is part of the value driver for the activity; all such projects need to be covered by an FDP or FDP addendum.

is expected to start (as set out in the Field Development Plan (FDP) addendum for the project[3]) as long as "a substantial amount of work has been done in relation to the project", which should be taken to mean completion of all "key elements" (if any) identified in the FDP addendum for the project.

- For the purpose of computing the amount of allowance activated where a company already holds another field allowance for the field, the amount of the company's relevant income from the field is reduced by the amount of any earlier field allowance activated for the accounting period.

- Because of concerns around cost apportionment across the upstream/downstream boundary, projects involving enhanced oil recovery using carbon dioxide are not eligible for the allowance at this stage, though the Government will keep this under review.

- **Costs:**

  - Incremental capital costs to reflect recovery of the incremental reserves (compared with a baseline case) as described in the approved FDP addendum for the project (FDP addendum(s)/FDP(s) for a wider development).

  - Central estimate of nominal undiscounted incremental capital expenditure, excluding decommissioning, interest and sunk costs, in sterling. Capital expenditure is not defined in statute but, as a general rule, for BFA purposes it would include expenditure that would attract 100% first year capital allowances. The costs of well workovers and other similar repair and maintenance activities would normally not be treated as capital expenditure but the expected cost of ESP and pipeline replacements would, but in the

3. Companies will disqualify an incremental project from a BFA if they do not submit an FDP addendum for it; the usual FDP approval procedures apply as described at https://www.gov.uk/oil-and-gas-fields-and-field-development#process-for-oil-and-gas-field-development-plans. Even if an FDP addendum would not otherwise have been required, as long as a project for which DECC consent is required has not already received consent, DECC will not prevent operators from submitting one if they wish to do so in order that a project can qualify for a BFA. However, DECC approval of a project remains subject to the usual criteria e.g. that the project is the one that maximises economic recovery of hydrocarbons. Projects should also represent a coherent set of activities and not, for example, cherry pick some but not all of a planned series of wells to maximise the amount of BFA. All activities should be necessary or add pre-tax value to the project. The need for/nature of future capital expenditure ("capex" e.g. "life of field" or "field life extension" capex) needs to be justified and set out in appropriate detail with no "ballpark" estimates that are not capable of being verified as reasonable.

case of ESPs only where these form part of a bigger project. The capitalised value of expected FPSO lease costs should be treated as capital expenditure.

- Operators may seek advice from HMRC, as final arbiters of what is capital expenditure for tax purposes, if they or DECC have concerns over the capital nature of project costs. They should allow sufficient time for HMRC advice/clearance in project approval timetables.

- Costs may include reasonable contingencies where appropriate (but contingencies must not exceed 20% on any individual line item), reflecting the degree of uncertainty associated with the cost estimates.

- The central estimate of incremental capital costs must be verified by a suitable independent third party.[4] The verified nominal costs must be reconciled to the constant price costs reported in the Common Reporting Format (CRF) spreadsheets which give cost and production profiles for the "with" and "without" project scenarios. The following table illustrates one way of reconciling the various estimates.

	Pre-contingency capital expenditure ("capex")	Uncapped contingency	Capex for CRF	Sunk and other non-verified costs	Verified capex	Contingency capped at maximum of 20%	Verified capex with capped contingency	Escalation (inflation assumption)	Estimate of remaining capex for BFA	Escalation factor
	£ million (2013 prices)	*%*	*£ million (2013 prices)*	*£ million (2013 prices)*	*£ million (2013 prices)*	*%*	*£ million (2013 prices)*	*%*	*£ million (nominal)*	
2012 sunk	10.000		10.000	10.000						1.000000
2013 sunk	30.000		30.000	30.000						1.000000
2013 other	100.000	25.0	125.000		125.000	20.0	120.000		120.000	1.000000
2014	150.000	15.0	172.500	10.000	162.500	15.0	162.500	2.0	165.750	1.020000
2015	20.000	10.0	22.000		22.000	10.0	22.000	2.0	22.889	1.040400
2016	50.000	30.0	65.000	5.000	60.000	20.0	55.000	2.0	58.366	1.061208
Total			**424.500**		**369.500**				**367.005**	

- As implied by Step 5 below, cost verification reports (CVRs) are subject to agreement by DECC.

- **Reserves**

  - Central estimate of incremental reserves consistent with approved FDP addendum (FDP addendum(s)/FDP(s) for a wider development).

  - Conversion factor for gas in cubic metres to oil equivalent in tonnes: 1,100 cubic metres of gas at a temperature of 15 degrees Celsius and pressure of one atmosphere ≡ 1 tonne of oil.

4. Operators may seek advice from Oil & Gas UK (Claire Ralph; 020 7802 2411; cralph@oilandgasuk.co.uk) on suitable independent third parties able to verify capital costs.

- The estimate of incremental reserves will generally be equal to the cumulative sales volume expected as a result of the project(s) with an economic rather than technical cut-off applied; production which is used for fuel gas will count as reserves in the field from which it is produced to the extent that it displaces UK gas production which can thereby be sold into the market.

- In the case of trans-boundary fields, costs and reserves will be assessed at field level, but the allowance available to UK licensees will reflect the UK share of incremental reserves.

- Projects have to target different reserve increments from projects that have previously qualified for a BFA.

Process for BFA cost verification

As noted in footnote 3 above, projects will require an approved FDP addendum to qualify for a BFA.

STEP 1: Operator to submit draft FDP addendum to the relevant field team at DECC. This will include:

- Project definition (i.e. defined base case and incremental opportunity)

- Central estimates of incremental oil and gas reserves

The operator should also send completed CRF files to Mike Earp at DECC giving:

- Cost and production profiles (reflecting "with" and "without" project scenarios).

STEP 2: DECC to confirm that it is happy with brownfield project definition and estimate of incremental reserves in the *draft* FDP. If the final FDP addendum is significantly different to the draft, steps 1 and 2 may need to be repeated.

STEP 3: Operator to obtain formal verification of the estimated incremental capital costs of the project (i.e. those associated with the incremental reserves) from an independent third party.[5] Where projects form part of a wider development, all relevant capital costs for the development as a whole must be verified. Verification should include:

- Assessment that work scope, concept selection and project definition are consistent with and appropriate for the incremental opportunity identified.

5. It is strongly recommended that operators obtain an assessment of the expected incremental capital costs as at the date of FDP addendum approval from an external cost verifier only after DECC has agreed the scope of the project and that it seems likely to qualify for a BFA (which means DECC having early sight of CRFs for the project).

- Assessment that the estimate of incremental project costs is robust and consistent with the incremental opportunity identified, and verification of the uncertainty range associated with those costs. Projects will qualify for a BFA only where any contingencies on individual line items do not exceed 20%; 20% is a maximum, not a target, and any contingencies need to be justified.

- Confirmation that expected incremental capital expenditure excludes operating and decommissioning costs and that interest and sunk costs (i.e. costs which have already been incurred or committed prior to FDP addendum approval to the extent they are not recoverable – for example, by way of alternative use or by way of sales proceeds – if the project does not proceed) have been excluded; the cost verification report (CVR) should focus on non-sunk costs as at the expected date of FDP addendum approval.

STEP 4: Operator to submit final draft of FDP addendum and evidence of cost verification to DECC.

STEP 5: If DECC wishes to query cost estimates/evidence of verification, it will do so before approving the FDP addendum. Prior to FDP addendum approval, DECC will advise the operator that it has no outstanding queries and give its view of the verified expected capital costs and incremental reserves for the project/wider development. It should be assumed that HMRC will not treat any other estimates as reasonable once they have been confirmed by DECC at Step 6.

STEP 6: Licensee(s) sanction(s) project (via Board letter(s) submitted to DECC). DECC gives final FDP addendum approval and issues a revised Development and Production Consent, together with confirmation of the expected incremental reserves and capital costs in a BFA "side letter".

STEP 7: Licensees submit tax returns under the Corporation Tax Self Assessment (CTSA) process. Where they are reflecting a BFA, it would be helpful if they submit with their tax returns a copy of the side letter showing the expected incremental reserves and capital costs as confirmed at Step 6. They should also confirm when a substantial amount of work was done (i.e. when the key elements were completed) in relation to the project.

STEP 8: To help with future adjustment/lessons learned, operators of projects receiving a BFA are strongly encouraged to submit details to DECC of the actual costs incurred in delivering the work scope.

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