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| **Title:** Post Implementation Review of the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 (S.I. 2015/386) | Post Implementation Review |
| **PIR No:** DESNZ002(PIR)-24-OPRED | **Date: 29/01/2024** |
| **Original IA/RPC No:** | **Type of regulation: Domestic** |
| **Lead department or agency:** Department for Energy Security and Net Zero | **Type of review: Statutory** |
| **Other departments or agencies:** Maritime & Coastguard Agency | **Date measure came into force: 19/07/2015** |
| | **Recommendation: Keep** |
| **Contact for enquiries:** Andrew Taylor, OPRED, 01224 254080 | **RPC Opinion:** Choose an item. |

**1. What were the policy objectives of the measure?** (Maximum 5 lines)

The policy objective of the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 ("the OPRC15") was to transpose relevant provisions of EU Directive 2013/30/EU (amending Directive 2004/35/CE[1]) on the safety of offshore oil and gas operations - referred to as the Offshore Safety Directive ("the OSD"). The OPRC15 amended the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 ("the 1998 Regulations") by inserting the new requirements of the OSD.

The main changes to the existing regime were the addition of definitions to comply with the OSD; the requirement for Non-Production Installation owners to hold an Oil Pollution Emergency Plan (OPEP); the addition of Schedule 2 (Requirements for an OPEP in respect of an offshore installation) to the 1998 Regulations; and improved clarity on maintaining equipment and expertise relevant to an OPEP.

Further information is detailed in the Explanatory Memorandum to the OPRC15, which is available at: http://www.legislation.gov.uk/uksi/2015/386/memorandum/contents.

**2. What evidence has informed the PIR?** (Maximum 5 lines)

This Post Implementation Review (PIR) has focussed on the OSD requirements transposed by the OPRC15, the costs of transition to the new requirements and early views on the impacts of the OPRC15. A multi-method approach was used and included online surveys with Responsible Persons[2]; workshops with three key industry bodies; and follow up questions with individual Responsible Persons to clarify survey responses.

[1] Directive 2004/35/CE on environmental liability with regard to the prevention and remedying of environmental damage ("the Liability Directive").

[2] Responsible Person means the operator of a production installation, the owner of a non-production installation or a well operator as defined in OPRC15.

**3. To what extent have the policy objectives been achieved?** (Maximum 5 lines)

The PIR found that the overarching oil pollution response regime remains appropriate and has achieved its objective of maintaining existing standards while incorporating the additional requirements as set out in the OSD. There is evidence that the OPRC15 also minimised any adverse impact of changes on the oil and gas industry, while achieving the obligation to transition all installations to the OSD requirements by July 2018.

Sign-off for Post Implementation Review: Chief economist/Head of Analysis and Minister

***I have read the PIR and I am satisfied that it represents a fair and proportionate assessment of the impact of the measure.***

Signed: **Rt Hon Graham Stuart MP, Minister of State for Energy Security and Net Zero**

Date: **29/01/2024**

## Further information sheet

Please provide additional evidence in subsequent sheets, as required.

**4. What were the original assumptions?** (Maximum 5 lines)

The PIR assessed one-off costs only as the ongoing steady state has not yet been reached. One-off costs to Responsible Persons are estimated to have been between £3.4 - £4.6m. This is around £5 - £6m less than estimated in the original Impact Assessment ("IA"). One factor in this was that fewer OPEPs were transitioned or required approval (496) than the IA anticipated (1,335), even though in some cases actual costs for some activities were likely higher than estimated in the IA. See Tables 1-6 in the estimated costs report for details. Also, some Responsible Persons' costs were less than the IA estimated due to the establishment of templates which helped simplify OPEP development and assessment.

The evidence from the PIR also supports the assumptions in the IA that the OPRC15 did not substantially change the existing UK arrangements for pollution response, primarily as the OSD was largely based on the UK's offshore oil and gas regulatory regimes.

**5. Were there any unintended consequences?** (Maximum 5 lines)

The PIR did not identify any significant unintended consequences from the implementation - via the OPRC15 - of the relevant OSD requirements. However, responses to the survey highlighted additional costs around consideration of whether a pollution event from a major accident would result in a Major Environmental Incident (MEI) as defined in the Liability Directive. These additional costs were not covered by the IA and delays in producing Guidance to provide clarity to industry possibly meant these costs were higher than they might have been. Responses to the survey indicated that these additional costs were in the order of £1.989m but are not related to the implementation of the OSD. MEI assessments are included in the installation Safety Case or notification of Well Operations.

**6. Has the evidence identified any opportunities for reducing the burden on business?** (Maximum 5 lines)

The PIR has not identified any opportunities for reducing burdens on the offshore oil and gas industry by amending or revoking any regulations at this time. The OPRC15 transposed EU Directive requirements into the existing domestic regime for pollution response and the PIR findings have confirmed that this is still the most effective way to manage pollution response.

**7. For EU measures, how does the UK's implementation compare with that in other EU member states in terms of costs to business?** (Maximum 5 lines)

The European Commission reviewed member states' efforts and experiences of implementing the OSD in 2019 and the report was published in November 2020.[3] The report concluded that the OSD had been implemented satisfactorily across the EU, though there was significant variation in some areas due to the differing ways in which Member States implemented the OSD. While the report identified some areas the EU would consider strengthening, none of them related to those aspects of the OSD that were implemented by the OPRC15. A technical report prepared by the EC Joint Research Council concluded that the UK had fully complied with the requirements for an External Offshore Emergency Response Plan as required by Article 29 and Annexes VII and VIII of the OSD.

[3] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2020:732:FIN

# Post Implementation Review

## The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 (S.I 2015/386)

## Contents

## Introduction

1. This report, published by the Department for Energy Security & Net Zero (DESNZ), presents the conclusions of the Post Implementation Review (PIR) of the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 ("the OPRC2015"). These Regulations came into force on 19 July 2015.

2. There is a statutory requirement, under the Small Business, Enterprise and Employment Act 2015 to review domestic regulations at least every five years and publish a report on the review findings. This is the first review of the OPRC15 and was due by 19 July 2020.

3. Due to work priorities within the Offshore Petroleum Regulator for Environment & Decommissioning (OPRED) which undertook the review on behalf of DESNZ (BEIS[4] at the time) during the Covid-19 pandemic and the recovery from that during 2021-2022, the PIR was delayed and picked up again in 2023 along with several other PIRs that were to be undertaken by OPRED.

4. Regulation 16 of the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015 ("the OPLR15") sets out the scope of the review and states that the report must in particular:
   - *set out the objectives intended to be achieved by the regulatory system established by these Regulations;*
   - *assess the extent to which those objectives are achieved; and*
   - *assess whether those objectives remain appropriate and, if so, the extent to which they could be achieved with a system that imposes less regulation.*

5. The OPRC15 implemented Articles 14 and 28 from Directive 2013/30/EU on safety of oil and gas operations ("the Directive") which set out the requirements relating to pollution response as part of an installation's Internal Emergency Response Plan.

6. The OPRC15 added the new Directive requirements into the existing regime established under the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 ("the OPRC98"). The OPRC98 had implemented, in part, the International Convention on Oil Pollution Preparedness, Response and Co-operation, 1990. The OPRC98 already required that all offshore installations, where there is a risk of pollution from oil, must have an Offshore Pollution Emergency Plan (OPEP). The UK had set out administratively through guidance what the content of an OPEP must include.

7. The OPRC15 brought a number of those administrative requirements into law and further extended some of the requirements for an OPEP.

8. Regulation 16 of the OPLR15 also includes a requirement to consider, as far as is reasonable, how the Directive has been implemented in EU Member States.

## Impact Assessment and extent of this PIR

9. The OPRC15 is one of several regulations implemented to transpose the Directive into domestic law. The Directive contained requirements relating to licensing, environmental protection and safety and was a cross-government exercise. The transposition was jointly led by the Department of Energy and Climate Change (now DESNZ) and the Health & Safety Executive (HSE), The Department for

[4] Department for Business, Energy & Industrial Strategy

Environment, Food and Rural Affairs and the Department for Transport was also involved. The Impact Assessment for the implementation of Directive 2013/30/EU (IA No.0088) (IA) covered the whole transposition (see below for Northern Ireland) with separate sections for the different government departments and respective regulations.

10. The Department for Energy and Climate Change (DECC) (subsequently BEIS and now DESNZ) was responsible for transposing the Directive's requirements for pollution response arrangements into UK legislation and these were implemented in the OPRC15. DECC was also responsible for transposing the Directive's requirements in relation to licensing, operator appointment and financial liability arrangements which was implemented through the OPLR15 and which is managed by the Oil and Gas Authority (now the North Sea Transition Authority (NSTA)) as the licensing authority in the UK. This PIR therefore covers the OPRC15 only. The relevant sections of the IA are Sections 1 to 7 (Background and approach); 8.5 and 8.7.1 on changes to DESNZ environmental legislation to implement the Directive; and 9.4 and 9.8 on costs to industry for complying with changes to DESNZ environmental legislation.

11. The Transposition Note for Implementation of Directive 2013/30/EU provides details on the full UK transposition and the regulations introduced or amended by government departments in order to implement all requirements. PIRs for other regulations covered in the IA will be undertaken by the responsible departments as appropriate and published alongside the relevant legislation.

12. The Directive also required EU Member States to establish a competent authority to oversee industry compliance with the offshore oil and gas major hazard regime. In the UK this requirement was fulfilled by establishing the Offshore Safety Directive Regulator (OSDR), rebranded as the Offshore Major Accident Regulator (OMAR) following EU exit. This is a partnership competent authority between the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), which is part of DESNZ, and HSE (involving HSENI if any oil and gas operations start up in NI waters). OPRED is responsible for oversight of environmental aspects and HSE for health and safety aspects.

13. Depending on the context, this PIR refers to OMAR as the partnership competent authority for the offshore major hazard regime; OPRED as the regulator specifically responsible for environmental aspects and HSE as the regulator specifically responsible for worker's health and safety within that partnership. It is usual practice to refer to OMAR when discussing the regime as a whole but it may be more relevant to refer to the individual departments when discussing respective regulations.

14. OMAR was set up administratively and is governed by a Memorandum of Understanding and Working Agreements. As it is not a legal requirement of the OPRC15, this PIR does not cover how OMAR was set up or how it functions. The OMAR Senior Oversight Board agreed to conduct a separate survey to specifically capture Oil and Gas Industry (Industry) views of OMAR which was undertaken following the research gathered for this PIR.

## PIR approach

15. In accordance with Government guidance on PIR's, and as the IA estimated that the annual cost to Industry for the introduction of the OPRC15 requirements would be less than £5million p.a., the costs met the sub-De Minimis threshold and a light touch approach could be adopted.

16. Advice from DESNZ's Spending Evidence Guidance & Analysis Unit and Better Regulation Unit was that the regulation could be considered controversial as it dealt with pollution response to major oil/gas spillages, and as such a medium level of evidence and resourcing might be more appropriate.

17. Policy officials agreed that a medium level of evidence and resourcing was proportionate for this PIR, however, the OPRC15 only amended existing regulations (the OPRC98) and associated guidance which had been in place since 1998. Furthermore, a number of the additional requirements set out in the Directive were already in place in the UK and as such it was decided that while greater evidence

would be gathered, it would not be necessary to submit the PIR to the Regulatory Policy Committee (RPC) for an opinion prior to the PIR being approved / signed off at Ministerial level and subsequently published on the Legislation UK website..

## Proportionality

18. The IA estimated the Equivalent Annual Net Direct Costs to Business (EANDCB) for implementing the OPRC15 to be £2.3 million in 2009 prices. This is below the minimum threshold of £5 million for low level PIRs and several other factors were considered:

    - It was possible to draw on evidence from various sources such as in-house management information and data, joint industry/OMAR working groups and the European Union Offshore Oil and Gas Authorities Group (EUOAG).

    - The new requirements were integrated within the existing regulatory regime, some of which had already been introduced administratively. The changes proposed were agreed with Industry throughout the transposition period so there was nothing controversial or unexpected.

    - The OPRC15 did not impact a large number of businesses and while some were small businesses, the close scrutiny of the UK offshore industry, particularly following the Deepwater Horizon disaster, meant that it was crucial that all businesses operating offshore, regardless of size, are subject to the same regulatory regime to ensure that they continue to provide a high level of protection for the safety of the workforce and the marine environment. The Industry is a homogenous group, represented by key Industry bodies, and is actively engaged with OMAR.

    - Early in the process, it became clear that more time was needed for the OPRC15 to embed before the full impact, particularly any ongoing costs, could be evaluated (see section on timing below).

    - The OPRC15 implemented the requirements of an EU Directive, so there was limited scope for the Government to change regulations while the UK remained a member of the EU.

19. On balance, while the OPRC15 could be considered controversial due to their subject matter, the OPRC15 amended existing regulations that had been in place since 1998 and the EANDCB would be below the threshold for a light touch approach. As such it was considered appropriate that while greater evidence would be gathered a RPC opinion was not needed.

## Timing

20. The OPRC15 allowed a three-year transition period from July 2015 to July 2018. OMAR and Industry agreed a staggered transition programme to allow all Oil Pollution Emergency Plans (OPEPs) to be submitted and approved within the tight timescale. The research for the PIR was left as late as possible (July 2019) giving owners and operators of installations between 1 and 4 years' experience of complying with the OPRC15 depending on when they had transitioned. In early discussion with OMAR and Industry, there was a consensus that it was too soon to effectively evaluate the full impact, particularly the ongoing impact and costs. It was agreed that at least five years' experience of complying with the OPRC15 would be necessary for owners and operators to provide meaningful data. It was therefore decided that this PIR would focus on the transition to the OPRC15 and the experiences of Industry in achieving compliance with the new requirements.

21. The Commission has conducted a review of EU Member States' efforts and experiences of implementing the Directive. This was required under Article 40 and to be completed by 19 July 2019. OMAR issued an official response to the Commission consultation in December 2018 stating that because the transition of all installations was only completed on 19 July 2018, the UK considered it too

early to meaningfully evaluate the effectiveness of the Directive. The PIR approach is consistent with that statement and the agreed position with Industry.

## Background to the OPRC15

22. The OPRC15 apply to oil and gas operations in 'external waters'; that is the United Kingdom territorial sea and Continental Shelf. The OPRC98 continue to apply in the United Kingdom's internal waters.

23. The primary aim of these Regulations is to ensure that an appropriate emergency response to an oil pollution incident is in place for the operations being undertaken and that the response is detailed within an approved OPEP.

24. The OPRC98 made provision for certain facilities in the United Kingdom's internal waters, territorial sea and Continental Shelf to have an OPEP. The amendments effected by the OPRC15 apply the requirement to have an OPEP to non-production installations in the territorial sea and the Continental Shelf and apply further requirements to installations and their connected infrastructure which are carrying out offshore oil and gas operations, including well operations, in the territorial sea and the Continental Shelf, but not in internal waters.

25. The key recommendation was that all owners and operators of offshore installations must prepare an OPEP and submit it to OPRED for assessment and approval. It is an offence to operate an offshore installation without an approved OPEP.

26. The explosion on the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 resulted in the death of eleven workers and the loss of 4.9 million barrels of oil to the sea, the largest ever spill in US waters. The UK Government asked Professor Geoffrey Maitland to chair an Independent Review to ensure that findings from the official reports into the incident had been fully considered, and actioned where relevant, by the UK Industry and regulators. The review panel recognised that the UK regime for pollution response was robust, but that improvements could be made to increase exercise frequency of response cells and increase the frequency for response contractors to demonstrate their capability. This later requirement was included within the Directive.

27. The Industry was fully involved in negotiating the Directive and in developing the approach for transposing the requirements into domestic law. It was widely acknowledged that the Directive requirements in regard to pollution response drew upon the UK regime established under the OPRC98. At 'town-hall' style events and during the comprehensive public consultation it was overwhelmingly agreed that the OPRC98 should be maintained as far as possible with new requirements 'woven' in. It was considered that this would maintain the existing pollution response arrangements and would keep burdens of new regulations to a minimum.

28. The OPRC15 maintained all requirements from the OPRC98 and added in new requirements as necessary to transpose the Directive. In most cases new requirements were meshed into existing OPRC98 regulatory provisions but a few (e.g. additional offences and specifying what must be included in an OPEP) were completely new and 'copied out' from the Directive. A table of the new requirements is provided at Appendix 1.

## Transition to the OPRC15

29. The OPRC15 allowed a one-year transition period for non-production installations and new production installations and a three-year transitional period for existing production installations. To facilitate the submission, assessment and acceptance of all OPRC15-compliant OPEPs by the EU deadline, OMAR introduced a staggered transition programme. Industry supported this approach and fully cooperated with the programme despite the challenges it posed. This was particularly difficult for those submitting OPEPs very early in the process, or for owners of non-production installations to develop OPEPs where

previously they had not required them. As a result of these efforts by OMAR and Industry, 293 installations successfully transitioned to the OPRC15 regime by the deadline of 18 July 2018, as well as OPRED reviewing and approving a further 195 OPEPs for onshore response arrangements, combined operations or well operations during the transition period, but excluding subsequent variations to these.

## What were the Policy Objectives for the measure?

30. The primary aim of the OPRC15 was to implement the Directive requirements by transposing the pollution response requirements of the Directive into domestic legislation while ensuring that the existing regime, which was in place under the OPRC98, was maintained and the additional burden on industry minimised.

31. The policy objectives set out in the Impact Assessment were to fully transpose the Directive requirements into domestic legislation by July 2015 in a way that:

    - minimised the adverse impact of any changes on the oil and gas industry and UK interests by adopting the least burdensome approach;
    - maintained, or improved upon, the levels of pollution response arrangements which were in place under the OPRC98; and
    - was open and transparent and ensured consistency with current regulations.

## What evidence has informed the PIR?

32. A PIR plan was developed in order to identify the evidence required and how that would be sourced. These sources included OPRED and OMAR management information and data, Commission reports and primary research with key stakeholder groups. Industry bodies helped to facilitate the information gathering process by hosting workshops and reviewing survey questions.

33. Prior to conducting the research, initial discussions were held with policy managers from Industry bodies to check that methods were appropriate and the questions suitable. A survey was subsequently developed for the Industry bodies. Information was also sourced from OPRED staff relating to costs recovered from Industry.

34. The research method comprised an industry survey undertaken from 7 June to 12 July 2019; workshops held on 12 & 16 September 2019 to further explore identified themes or issues with all groups; and further clarification from individual survey respondents to seek clarification where needed. The research explored the views and experiences, of both Industry and the OMAR, of the transition to the OPRC15 and Industry duty holders were also asked about transitional costs to provide evidence for the cost-benefit analysis.

35. OMAR conducted a survey and held workshops with key industry groups to cover both the OPRC15 and the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015. This allowed OPRED and HSE to share information where there were regulatory overlaps as well as reduce burdens on business. OPRED and HSE were seeking information on actual costs of the transition process to compare against the cost estimates in the IA as well as feedback on what had gone well or not, and any unintended consequences from the implementation of the OSD via domestic legislation. Once the research was completed, the findings were analysed by the individual departments so that separate reports could be produced and published with the relevant legislation.

36. OMAR engaged with duty holders through the key industry bodies: Oil and Gas UK (OGUK), now Offshore Energy UK (OEUK); the International Association of Drilling Contractors (IADC); and the British Rig Owners Association (BROA).

37. The details on the survey questions and responses, as well as a summary of the workshop discussions are provided in Appendix 2 to this report.

## To what extent have the policy objectives been achieved?

### General overview

38. The evidence demonstrates that the OPRC15 are still fit for purpose with the vast majority of the 25 respondents to the industry survey considering the Regulations to be the most effective way to manage the pollution response from an oil and gas installation.

39. There was also consensus that the OPRC15 allowed the existing regime established under the OPRC98 to continue by maintaining the consistency of approach and effective pollution response arrangements. It was considered that the OPRC15 had not necessarily improved the offshore oil and gas pollution response arrangements.

40. It was largely agreed that OPRED did minimise the adverse impact of any changes by adopting the least burdensome implementation approach. Some respondents, however, focussed on some requirements of the Directive e.g. Major Environmental Incident assessment, which is not directly related to the OPRC98, and their negative experiences of certain aspects of the transition process.

### Objectives

***To fully transpose the Directive requirements***

41. The Directive requirements relating to pollution response arrangements as set out in Articles 14 and 28 were transposed into UK legislation by the deadline set by the Commission. Following Parliamentary scrutiny of the transposing legislation, the respective regulations came into force on 19 July 2015. The Transposition Table for Directive 2013/30/EU provides details of all regulations and measures in place to fully transpose the Directive requirements.

42. A notification to the Commission was also made under Article 27(5) of the Directive to confirm that the UK had national measures in place regarding access to knowledge, assets and expert resources, including formal agreements with appropriate agencies or bodies for the provision of specialist expertise to support the OMAR in carrying out its regulatory functions under the Directive.

***Minimising the adverse impact of any changes on the oil and gas industry and UK interests by adopting the least burdensome approach***

43. The implementation approach was to merge the new pollution response requirements of the Directive into the existing regulations (the OPRC98).

44. The Commission initially proposed a direct-acting EU Regulation to strengthen the EU offshore oil and gas regulatory system. UK stakeholders (Industry, offshore workforce representatives and ministers) successfully argued for a Directive as a new EU Regulation would have resulted in the need to revoke the UK's existing offshore oil and gas regulations. Industry argued that this would create excessive burdens and a potential reduction in safety and environmental protection standards. The Commission also claimed to be using the UK's offshore regulatory system as a template for the proposals so it seemed most sensible to maintain the existing UK regime and integrate any new requirements into it.

45. During the consultation on the regulatory proposals to implement the Directive, Industry agreed that this approach was least burdensome. Throughout the implementation process Industry representatives were involved, at workshops and town-hall style meetings, and some modifications were made to address concerns. This included changes to consideration of who the Regulations applied to, amending guidance to make clear what would be expected in submissions to transition to OSD requirements and avoiding gold plating.

46. One of the changes introduced by the Directive was that non-production installations (NPI) were required to have an OPEP, which they didn't previously require. The non-production owners and their trade body, the International Association of Drilling Contractors (IADC), discussed at length the requirements for this and the content of an NPI OPEP that would meet the Directive requirements. The IADC developed a template for an NPI OPEP which was widely used by their members and feedback from IADC members at the PIR workgroups confirmed that this eased the transition process by reducing time / costs in drafting NPI OPEPs. The template also made it easier for OPRED to review and approve NPI OPEPs as they all followed the same format reducing time and costs for the approval process.

47. The PIR survey responses were largely positive and when followed up at workshops it was agreed that this had been the least burdensome approach, especially compared with the alternative of a completely new direct acting EU Regulation. However, the research did highlight issues concerning some aspects of the transition regarding guidance relating to the identification of Major Environmental Incidents and associated modelling. This transitional issue is addressed in paragraphs 54 to 57.

***Maintaining, or improving upon, the levels of pollution response arrangements which were in place under the OPRC98***

48. The original objective in the IA covered all new regulations being implemented to transpose the Directive requirements in respect to the protection of both worker's safety and the environment. For this PIR, the survey question was restricted to maintaining the consistency of the existing regime in regard to pollution response in order to measure any specific impact.

49. All the OPRC98 requirements were retained in the OPRC15 so it was a reasonable assumption that the existing pollution response arrangements would at least have been maintained. All survey groups agreed that existing levels of pollution response have been maintained and other than the administrative burden of transitioning, there hasn't been a negative impact. This was reinforced during the follow-up workshops.

***Is the OPEP system established under the OPRC15 the most effective way to set out pollution response arrangements for offshore oil and gas operations?***

51. There was majority agreement that the regime established under the OPRC15, which built on the existing regime under the OPRC98, was the most effective way to implement the Directive requirements for pollution response. 68% of Industry agreed with this, while 32% neither agreed / disagreed or were not sure / didn't know. Nobody indicated that the OPRC15 wasn't the most effective way to implement the Directive requirements.

## Feedback on new requirements and regime established under the OPRC15

50. The survey and workshops invited open feedback on all new requirements in the OPRC15 and on the OPEP regime generally. A table of new requirements is provided at Appendix 1.

51. There was a view, shared across all groups, that not much has changed under the OPRC15: there were no obvious benefits but equally no obvious disadvantages. There were a few areas, however, that individual companies identified as benefits or disadvantages.

<u>Benefits</u>

52. **NPI OPEP Template**: While there was some disagreement from the IADC and NPI owners about the need for NPI owners to have installation OPEP's, the IADC created a template approach for NPI OPEPs which OPRED accepted, and this greatly helped the drafting of OPEPs as well as in their review and approval. While some cost was associated with the creation of the template, it has

significantly reduced the cost of developing new OPEP's and feedback from the IADC workgroup was that this approach was successful and greatly minimised costs, far below the costs expected in the IA.

Guidance

53. OPRED published guidance to support the OPRC15 'Guidance Notes for preparing Oil Pollution Emergency Plans'. Industry largely agreed that the guidance and assessment templates helped to clarify what was required in an OPEP, while only 10% disagreed that the guidance was helpful. The guidance was updated during the transition period to address feedback and comments from Industry and OPRED staff approving OPEP's and has continued to be updated as required.

Disadvantages

54. **Major Environmental Incident (MEI)**: The Directive requires that duty holders and well operators identify all their major accident scenarios, which might include a MEI as the result of a precursor major accident. These major accident scenarios, including potential for a MEI, are to be described in the Safety Case. Determining the potential for a MEI required operators to make assessments of the environmental consequence from certain major accidents and potentially run additional pollution modelling. MEI assessments would typically be undertaken as part of any Environmental Impact Assessment (EIA) under the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999[5]. The outcome of the assessment could then be used in the EIA for the OPEP to ensure appropriate pollution response is in place and for inclusion within the safety case or notification of well operations.

55. While EIAs did consider worst-case pollution scenarios, they did not make an assessment as to whether this constituted a MEI under the definitions set out in the Directive. As a result, all such worst-case pollution scenarios needed to be reconsidered as to whether they constituted a MEI in each transitional safety case and all notification of well operations.

56. While this was not a requirement set out in the OPRC15, responses to the survey included the additional costs of MEI assessments as a negative impact due to delays in producing guidance and the additional modelling required to make the assessment.

57. The IA had not considered any additional costs of MEI assessment, so this was an unexpected consequence of the transition process when implementing the Directive.

## What were the original assumptions?

58. The original IA estimated both one-off and ongoing costs from the implementation of the OPRC15. The consensus of OMAR and Industry was that the phased transition to the requirements of the OPRC15 and the five-year thorough review cycle meant it was too early to evaluate ongoing costs, which have not yet reached a steady state. As such, this PIR has focused on one-off costs and the next PIR will evaluate ongoing costs.

59. The IA estimated that the following number of OPEPs would need to be drafted or revised and approved over the three-year period to meet the OPRC15 requirements:

    a. 45 OPEPs submitted for existing installations expecting to be decommissioned;
    b. 92 OPEPs for existing production installations would need to be revised to meet the OPRC15 requirements;
    c. 45 existing OPEPs would need to have their five-year review brought forward;

[5] Since replaced by the Offshore Oil and Gas Exploration, Production, Unloading and Storage (Environmental Impact Assessment) Regulations 2020.

d. 12 new production installations would require OPEPs;
e. 106 existing non-production installations would require an OPEP;
f. 15 new non-production installations would come into the UKCS and require an OPEP.

60. In addition to the above, the IA assumed that 300 OPEPs would be submitted for well operations each year and 40 OPEPs would be submitted for combined operations each year.

61. The IA also estimated costs for the five yearly review of production and non-production OPEPs, however, these five yearly reviews had not commenced at the time the PIR data was being gathered, so have not been considered at this time.

## What were the actual costs?

62. Details of the responses to the surveys and a more detailed breakdown of the costs are given in Annex 1 - Estimated Costs of the OPRC15 Transition at the end of this report. A summary of the costs is provided below.

63. The total costs to Industry for transitioning to the additional requirements under the OPRC15 was estimated in the IA to be £9.3m based on a forecast of the number of OPEPs to transition. The actual estimated costs as assessed by this PIR was £4.3m as an upper limit if the full cost of NPI OPEPs is used. If the possible lower cost for NPI OPEP development is considered then the actual estimated costs are closer to £3.1m.

64. In either case, the cost is significantly lower than estimated in the IA. This is primarily due to the overestimation of the number of OPEPs that would be transitioning or submitted in the original IA and the overestimation of some per-OPEP costs. The IA estimated that 300 well operation OPEPs would be submitted per year which would cost the Industry £5.1m over the transition period. The actual number of well operation OPEPs received was 68 with a cost of £388k, a £4.7m difference which accounts for the majority of the difference between the PIR assessed costs and the IA estimated costs. There were also reduced costs from decommissioning OPEPs as again fewer were received than expected (45 estimated vs 9 received) saving £450k. These reduced Industry costs more than offset some higher incurred costs from transitioning existing PI OPEPs and bringing forward some OPEPs for early review to align with safety case thorough reviews.

65. In addition to the compliance costs for Industry to transition their OPEPs, there would be a cost to Industry for the work OPRED did in reviewing OPEPs for approval. The IA estimated these costs would be approximately £438k based on a forecast of the number of OPEPs to transition. The actual estimated costs as assessed by this PIR was £282k. The PIR identified that OPRED's per OPEP costs for reviewing existing PI OPEPs that required transition (£1,094) and review of well operation OPEPs (£520) were higher than the IA estimates (£453 & £229 respectively). The PIR also identified OPRED's per OPEP costs for reviewing NPI OPEPs (£399) were much lower than the IA estimated (£916) due to the development of the IADC template which made the review process easier.

66. The significantly lower actual total OPRED costs are primarily due to the much lower number of well operation OPEPs that were submitted compared to the numbers estimated in the IA (300 per year estimated vs 68 actual) despite the higher per OPEP cost of review. It is also worth noting that the transition period coincided with a downturn in the oil and gas industry which significantly curtailed offshore oil and gas exploration activity and hence well operations thus reducing the number of well operation OPEPs that were submitted.

67. The total costs to Industry, accounting for Industry's own costs and OPRED costs recovered from Industry, were estimated to be £9.7m in the IA. From the evidence gathered the actual estimated costs are in the range £3.4m - £4.6m.

## Where there any unintended consequences?

68. The PIR has not identified any direct examples of unintended consequences relating to the OPRC15. There were issues related to assessment of MEIs which were mentioned at paragraphs 54-57, however, these were not as a result of the OPRC15 regulations. Once the guidance on MEI assessments was published the assessment process became easier, though additional modelling was often still required for duty holders to make MEI assessments. The potential extra costs incurred for undertaking MEI assessments, along with the additional modelling required are estimated to have been at a worse case of £2m, however, this is not associated with the costs of transitioning to the OPRC15 requirements.

## Has the evidence identified any opportunities for reducing the burden on business?

69. The PIR has not identified any opportunities for reducing burdens on the offshore oil and gas industry at this time.

70. The OPRC15 implemented the Directive requirements into the proven regime that had been established as part of the UK's implementation of the OPRC Convention. This regime ensures that offshore oil and gas installations (and ships) have suitable pollution response arrangements in place in the event of an incident. The PIR provided strong evidence that the OPRC15 is still the most effective way to achieve this.

71. The PIR sought to highlight any areas of concern with the new requirements introduced to transpose the Directive. No significant issues were identified.

## For EU measures, how does the UK's implementation compare with that in EU Member States in terms of costs to business?

72. Regulation 16 of the OPLR includes a requirement to consider, as far as is reasonable, how the Directive has been implemented in EU Member States.

Directive 2013/30/EU (Offshore Safety Directive)

73. The European Commission ("the Commission") undertook a review of the Directive as required under Article 40. The review took account of the efforts and experiences of competent authorities and assessed their experience of implementing the Directive. The Report has been published[6]. The Report concluded that the OSD had been implemented satisfactorily across the EU, though there was significant variation in some areas due to the differing ways in which Member States implemented the OSD. While the Report identified some areas the EU would consider strengthening, none of them related to those aspects of the OSD that were implemented by the OPRC15.

74. The research undertaken for the Commission review included a roadmap, comprehensive consultation with EU Member States and workshops for members of the European Union Offshore Oil and Gas Authorities Group. This is a forum for the exchange of information and expertise on all issues relating to major accident prevention and response in offshore oil and gas operations. Regulators responsible for offshore oil and gas are formal members of this forum and officials from OMAR had attended meetings. Since leaving the EU the UK has not been invited to attend EUOAG meetings but instead has an annual meeting with the Commission under the EU / UK Trade and Cooperation Agreement, part of which discusses offshore safety.

[6] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2020:732:FIN

75. Separately the Commission reviewed Member States' implementation of the Directive and the UK received a letter from the Commission in March 2019 detailing where it believed the UK had not fully implemented the Directive. None of the matters raised were in relation to the requirements that needed to be implemented in relation to pollution response as amended by the OPRC15.

76. The Commission's Joint Research Council published a technical report on EU Member States' efforts to comply with Article 29 and Annexes VII and VIII of the Directive, which related to national emergency response plans (External Emergency Response Plans). The report concluded that the UK had fully complied with the Article 29 and Annex requirements for external emergency response plans.

## Annex 1 - Estimated Costs of the OPRC15 Transition

## Introduction

1. This Post-Implementation Review (PIR) of the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 ("the OPRC15") has sought to assess how accurate the transitional costs estimated in the original Impact Assessment (IA)[7] have proven to be. The IA cost estimates were made against the baseline of the compliance costs of the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 ("the OPRC98").

2. The original IA estimated costs for the transposition of the Offshore Safety Directive[8] in totality and thereby estimated several costs that are out of scope of this PIR, which will focus on the costs of the OPRC15 only.[9] This PIR will focus only on:

    a. the costs to industry to comply with the new requirements in the OPRC15;

    b. the costs recovered from industry by the Competent Authority, the Offshore Major Accident Regulator (OMAR), to assess additional submissions made under the OPRC15; and

    c. the benefits of the new requirements in the OPRC15 (discussed in the Evidence Review, which discusses whether the objectives of the OPRC15 have been met).

3. The IA assessed both the transitional and ongoing additional costs of the OPRC15. However, this PIR will evaluate only the one-off costs as the industry only finished transitioning in the summer of 2018 (approximately six months before research on this PIR began) and the Regulations have a natural cycle around the five-year review of the Oil Pollution Emergency Plan (OPEP). As such, the industry has not yet reached a steady-state equilibrium of average ongoing costs that we could evaluate – this is the view of OPRED, OMAR and of industry itself. Consequently, ten-year NPV costs estimated in the IA are not evaluated fully in this PIR (see paragraph 79) as the OMAR had not started to receive any OPEPs for their five yearly reviews at the time of preparing the PIR, other than those 'brought forward', so it was not possible to assess the costs at the time.

4. We have prioritised the costs in the IA but allowed a route in our question sets for respondents to tell us about any other costs encountered if they chose to.

5. The research method undertaken included an industry wide survey followed by workshops with industry in Aberdeen (where the bulk of industry members have their offices) to delve further into the evidence. The survey was arranged in discussion with the three trade bodies[10] for operators of production installations and owners of non-production installations who could ensure all their members were aware of the survey. The survey was managed via Survey Monkey[11] and publicly available. The workshops were organised through the trade bodies with an open invitation to their members to attend in person. There was also further evidence gathering with survey respondents to probe and challenge answers for greater understanding.

6. Prior to conducting the research, we discussed our proposed methods with industry trade bodies to check that our methods would be appropriate, and that industry could answer the questions we posed. This guided the wording of our questions as well as the timing of the research to ensure we would be able to get the largest response possible.

[7] http://www.legislation.gov.uk/uksi/2015/386/impacts
[8] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32013L0030&from=EN
[9] The areas of cost in the IA that this PIR will and will not evaluate are summarised in Appendix 3.
[10] Oil & Gas UK (now Offshore Energy UK), International Association of Drilling Contractors and the British Rig Owners Association.
[11] https://uk.surveymonkey.com/r/OSDR_PIR_Survey2019

7. The IA estimated ranges of costs with a single ‘best estimate’. The trade associations we discussed the questions with advised that the questions probe whether the best estimate only was ‘about right’ or not, rather than the range. Where respondents disagreed with the best estimate, they were invited to give a new estimate and the analysis that follows assesses these responses (plus the follow-up workshop and interviews) against the best estimates and the ranges.
8. The costs in the original IA were estimated on a per-OPEP basis and assumed that each installation had a single OPEP. The costs for different types of OPEP were estimated to be different in the IA, due to the different types of OPEPs required for differing oil and gas activities or the differing costs estimated to update an existing OPEP to the OPRC15 requirements vs creating a brand new OPEP. Estimating average per-OPEP costs allows for extrapolation to total costs for the industry and this PIR has followed this method.
9. While the IA assumed that each installation had a separate OPEP, Responsible Persons would often create a single OPEP for a field (a field OPEP) which may cover multiple installations. As a consequence, the estimated number of OPEPs in the IA and what was submitted for review during the transition period were different.
10. Further the IA estimated the costs for changes to existing OPEPs for the inclusion of the additional requirements of the Directive. When reviewing OPEPs during the transition period this included information already required by the OPRC98 as well as the additional information required by the OPRC15. As a result, it is not possible to extract the costs purely for the changes brought about by the OPRC15 from the costs that would have been incurred under the OPRC98, particularly for new OPEPs. Consequently, the costs, in particular for new production installation (PI) OPEPs, will be higher than estimated as most of the information in the OPEP was required already.
11. Except in relation to well operations and combined operations OPEP addenda, responses to questions about costs in the PIR survey have been weighted according to the number of installations each respondent transitioned to under the OPRC15 requirements according to OMAR data. Therefore, when considering whether costs were about right, too high or too low, then the number of installations the responding company had was totalled to give a weighted response[12]. In some cases, this has meant excluding responses where the company did not identify themselves or there was no evidence that they had transitioned any installations – this affected only a small number of responses.
12. For well operations and combined operations OPEP addenda, responses to questions about costs in the PIR survey have been weighted according to the number of OPEP addenda submitted for review and approval by each respondent as this was more relevant than the number of installations a company may have. This is because some companies with a small number of installations may be much more active in terms of well or combined operations than a company with more installations. Therefore, it was better to consider the level of activity that respondents to these particular questions undertook.
13. Respondents represented in total around 125 transitioned OPEPs, which is 50% of the total of 250 OPEPs that transitioned. Respondents comprised 100 PI and 25 Non-Production Installation (NPI) OPEPs. In addition, given the respondents included PI operators, non-production installation (NPI) owners, trade associations, well operators and verification bodies, not all respondents responded to every question. Further in some cases, PI operators classified some of their PI which had ceased production as a NPI, even though they would be classified as a PI under the OPRC15 in terms of requirements. This has been noted where relevant in the report.

## Numbers of Installations and OPEPs Transitioning

[12] For example, if two respondents with five PI between them thought costs were too low, while five respondents with one PI each thought costs were about right and one respondent with five PI thought costs were too high, this would be considered as the same weight in each category as the costs applied to five installations each. Respondents with no PI, in this example, would not be considered.

14. The original IA estimated that the following numbers of OPEPs would require to be prepared and submitted for review to meet the OPRC15 requirements:

    a. 45 PI OPEPs for decommissioning (15 per year over three-year transition period),
    b. 92 existing PI OPEPs,
    c. 45 PI OPEPs brought forward over three years to align five-year review period with Safety Case thorough review cycle,
    d. 12 new PI OPEPs (4 per year),
    e. 106 new OPEPs for existing NPIs,
    f. 15 new OPEPs for new NPIs (5 per year)

15. In total the IA estimated that 315 OPEPs would either need to be prepared and submitted to meet the requirements of the OPRC15 based on installation numbers at the time and regulator expectations of industry change. Of these 315 OPEPs, 194 were estimated to be PIs and 121 NPIs.

16. In addition to the above numbers, the IA estimated that approximately 300 OPEP addenda would be submitted each year for well operations and a further 40 OPEP addenda would be submitted for combined operations each year.

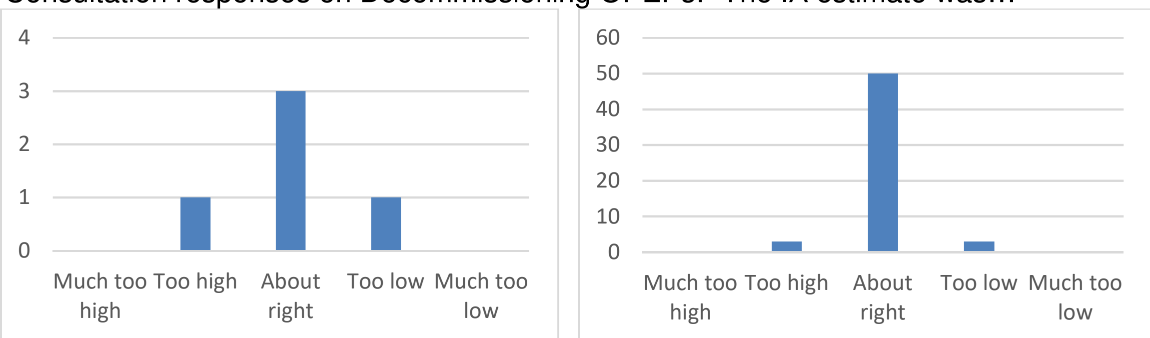
17. Data from the OMAR shows that in fact only 250 OPEPs transitioned, of which 119 were PIs and 115 were NPIs. There were a further 16 onshore OPEPs which were submitted for review. In regard to OPEP addenda over the three-year period, only 68 well operations addenda and 127 combined operations addenda were submitted. It is evident that the estimates in the original IA for numbers of OPEPs to review was too high, particularly for well operations. The discrepancy may be due in part to a reduction in oil and gas exploration and production in the UK in recent years, impacted by the low oil price and downturn in the market, leading to installations being decommissioned; as well as life-cycle cessation of production for older assets.[13]

## Decommissioning OPEPs

18. OPEPs for new decommissioning activity would need to be submitted and comply with the new requirements set out in the OPRC15. This would generally require an update to an existing OPEP that would have been in place for the production operations but amended to account for any change in oil spill scenarios and to include the new OPRC15 requirements. There was uncertainty as to the number of OPEPs that would be submitted over the transition period as this is based on oil price and economics of the field, however the IA estimated that 15 OPEPs per year would be submitted for decommissioning operations.

19. The IA estimated that the cost of preparing and submitting a decommissioning OPEP would be around £10k to £15k, with a best estimate of £12.5k per OPEP.

Figure 1: Consultation responses on Decommissioning OPEPs: “The IA estimate was…”




Consultation responses

Consultation responses weighted by installations

[13] https://oilandgasuk.co.uk/wp-content/uploads/2019/09/Economic-Report-2019-OGUK.pdf; and direct discussion with OEUK.

20. As shown in Figure 1, out of 25 respondents only 5 answered this question, possibly due to limited submissions of OPEPs for decommissioning from their operations. Responses indicated that this estimate was about right, particularly when considering the weighted responses.

21. Respondents who did not think the best estimate was about right were asked to provide a more reasonable figure instead. The responses ranged from a low of £5k to a high of £17k, which are just outside the range of the original IA.

22. The number of OPEPs submitted for installations moving into decommissioning was much lower during the three-year transition period than originally estimated and OPRED received only 9 OPEPs for installations moving into decommissioning operations rather than the 45 estimated in the IA.

23. With consideration of the evidence that has been gathered, the range of the Decommissioning OPEPs estimate being between around £10k to £15k per OPEP, with a best estimate of around £12.5k, is found to be about right.

## Existing Production Installation OPEPs

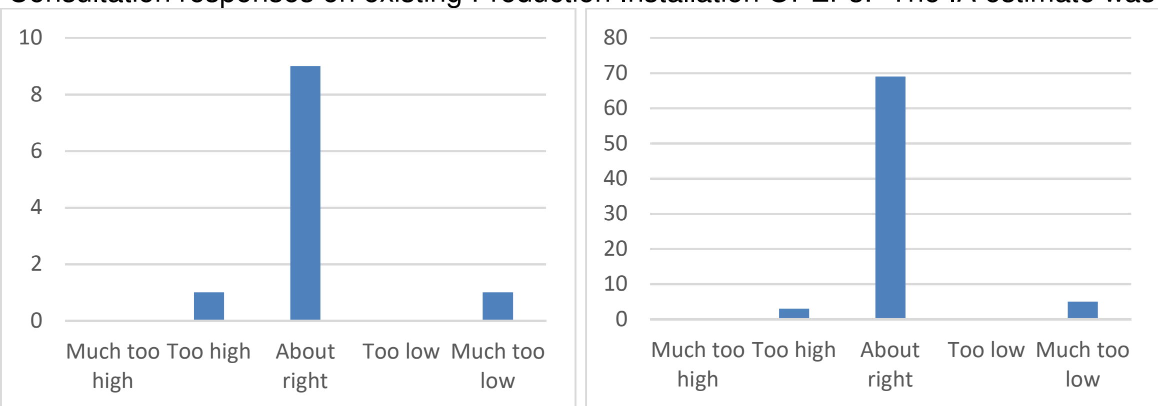
24. Existing production installations who already had approved OPEPs under the OPRC98 would need to update their OPEPs with the new requirements of the OPRC15. The new requirements included:

    a. Responsible Persons to take account of the risk assessment undertaken during preparation of the safety case submitted under the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015,
    b. description of the potential worst-case oil spill scenario,
    c. arrangements for limiting risks to the environment,
    d. a description of the equipment and resources available to respond to a release of oil to the sea,
    e. the measures in place to ensure that the response equipment and procedures are maintained in an operable condition,
    f. an assessment of oil spill response effectiveness.

25. Production installation (PI) OPEPs could also cover one or more fields and include all the PIs within those field(s). At the time of the IA there were estimated to be 101 PI OPEPs, but it was anticipated that by 2018, 9 installations would be removed by decommissioning resulting in 92 OPEPs for updating and review.

26. The IA estimated that the average cost of updating a PI OPEP would be around £10k.

Figure 2: Consultation responses on existing Production Installation OPEPs: “The IA estimate was…”




Consultation responses

Consultation responses weighted by installations

27. As shown in Figure 2, 11 respondents answered this question. Responses indicated that this estimate was about right, particularly when considering the weighted responses.

28. Respondents who did not think the estimate was about right were asked to provide a more reasonable figure instead. The respondent who thought the estimate was too high estimated the cost at £5k. The respondent who thought the estimate was too low did not provide an estimated cost but commented that the cost did not consider the cost of a third-party consultant to reassess the oil spill scenarios to meet the Major Environmental Impact (MEI) criteria.

29. While the Offshore Safety Directive ("the OSD") does require a MEI assessment to be undertaken of the various major accident hazard scenarios, this is not part of the OPRC15 requirements, and this cost was not included in the IA.

30. The number of PI OPEPs for existing installations submitted for review during the three-year transition period was 111. This was higher than provided for in the IA, possibly due to some inaccuracies in how existing PI OPEPs were counted at the time. Further, some Responsible Persons submit an OPEP to describe the oil spill response arrangements offshore along with the installation details and submit an Onshore OPEP to describe the response arrangements managed by the Responsible Persons' emergency response teams and the supporting oil spill response contractors. This resulted in a further 14 onshore OPEPs for review. The number of OPEPs submitted for production operations was therefore higher than estimated in the IA.

31. With consideration of all the evidence that has been gathered, the estimate for PI OPEPs of approximately £10k each is found to be about right.

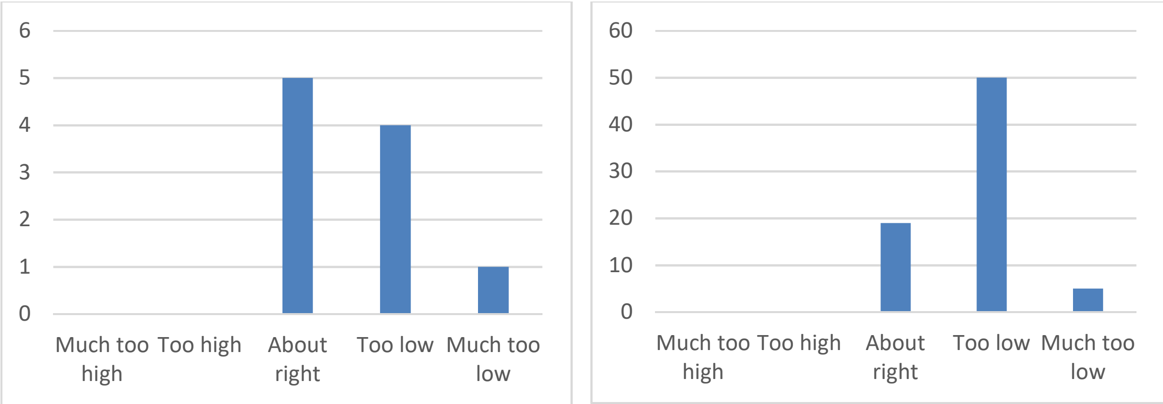
## 'Bringing forward' Production Installation OPEP reviews

32. The OSD makes the Internal Emergency Response Plan part of the Report on Major Hazards. For the UK implementation the Report on Major Hazards was the Safety Case and the OPEP was part of the Internal Emergency Response Plan. As part of the transition to the new Regulations and implementation of the OSD, it was proposed to align the five yearly review cycle of the installation OPEP safety case with the five yearly thorough review of the installation safety case.

33. While all OPEPs were reviewed on a five yearly basis already, to align with the safety case review cycle some OPEPs would need to be reviewed and be updated with the OPRC15 requirements earlier than they would otherwise. This introduced an additional cost to Responsible Persons (Production Installation operators) during the transition period as these costs came earlier than anticipated.

34. The IA estimated that the average cost for bringing forward a review would be approximately 10% of the cost of developing a brand new OPEP, including the addition of the OPRC15 requirements. This estimated the cost to be between £2.3K and £2.8k, with a best estimate of £2.5k.

Figure 3: Consultation responses on ‘bringing forward’ a Production Installation OPEP review: “The IA estimate was…”




Consultation responses

Consultation responses weighted by installations

35. As shown in Figure 3, out of 25 respondents to the survey, 10 answered this question and their responses conclude that the best estimate was too low.

36. Respondents who did not think the estimate was about right were asked to provide a more reasonable figure instead. From the survey results, operators provided estimates ranging from £5k for the operator with the largest portfolio of installations up to £25k, which was the cost for a brand new OPEP, including the addition of the new OPRC15 requirements, estimated in the IA.

37. At the workshops the cost of bringing forward a production installation OPEP was estimated to be about £8k, but this was the view from a single operator.

38. With respect to ‘bringing forward’ an OPEP review, the IA considered the NPV cost of submitting an OPEP for review earlier than would otherwise have been the case, as all existing OPEPs would have been required to be updated to meet the OPRC15 requirements at some point within the three-year transition window. The cost for updating an existing production installation (PI) OPEP was included within the IA and considered in section 4 above, and estimated at approximately £10k, and the costs provided by some respondents for bringing forward an OPEP review of between £5k - £8k possibly reflects that.

39. However, in the survey questionnaire this earlier cost was probably not made clear, and respondents provided the cost for updating and submitting an OPEP to meet the new requirements. This is reflected in one of the respondent’s comments that the cost was the sum of the previous OPEP costs brought forward in date. In addition, this earlier work may not have been budgeted for.

40. The number of OPEP reviews brought forward are difficult to determine from the data now available as the programme for the transition of all OPEPs did not identify which were brought forward. Data indicates that 28 PI Safety Cases had thorough review dates during the first year of transition when the OMAR was reviewing Non-Production Installations Safety Cases and OPEPs. These 28 Production Installations would also have had an OPEP for review at the same time so could be assumed to have been brought forward. The IA estimated that 45 existing OPEPs would have their review date brought forward and given that other PI may have also been brought forward during the two-year transition window for existing PI, for the purposes of the review, this will be the number assumed to have been brought forward.

41. Given the uncertainty in the responses to the question and costs provided for ‘bringing forward’ an OPEP it is unclear what the actual costs of an earlier review were. However, taking a conservative cost from most of the respondents who gave a cost of between £2.5k to £8k, this would give an average cost of £5.25k per OPEP brought forward.

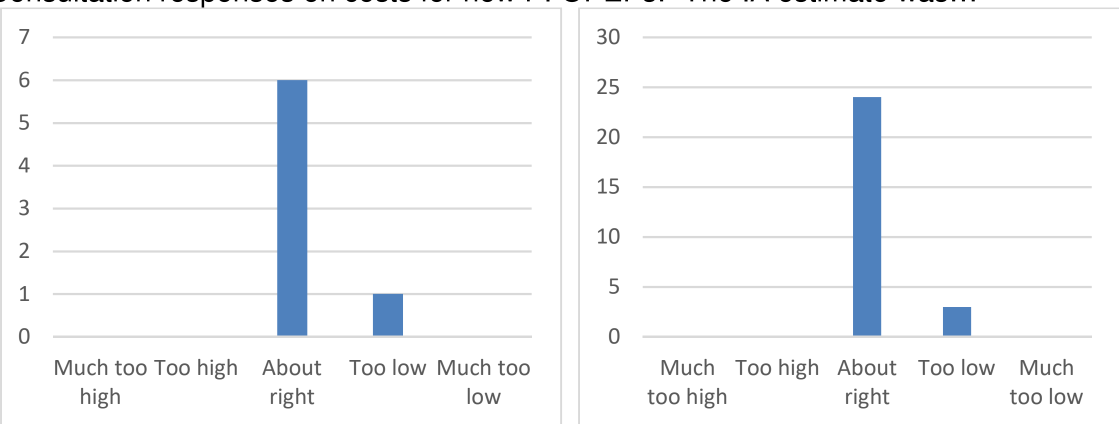
42. The IA estimated the ten-year present value cost to industry from bringing forward the reviews of OPEPs, with a best estimate of around £39.5k (see sections 467-475 of the IA). Given that the estimated costs from respondents on the cost of bringing forward OPEPs results in an average cost of £5.25k per OPEP rather than £2.5k per OPEP, the best estimate for this would now be £82.9k. While significantly higher than the IA estimate this would be seen as a one-off cost from bringing forward OPEP reviews that would have been done within five years in any case. For some installations this may also mean that an extra five yearly review may be required before decommissioning of the installation allowed for the OPEP to be withdrawn. Despite the costs being higher than the estimate in the IA the cost of bringing forward OPEPs was only 5% of the overall transition costs for industry. This also assumes that all 45 OPEPs that were estimated to be brought forward were, which may be an overestimate.

## New Production Installation OPEPs

43. It was estimated in the IA that approximately four new oil and gas fields would be developed each year for which each production installation (PI) would require an OPEP. As the PIs would have required an OPEP under the OPRC98, it was the additional costs of including the new OPRC15 requirements that were considered.

44. As set out in the IA the industry research group estimated that the additional costs would amount to £10k per OPEP.

Figure 4: Consultation responses on costs for new PI OPEPs: “The IA estimate was…”




Consultation responses

Consultation responses weighted by installations

45. As shown in Figure 4, there were 7 respondents to this question with the majority confirming that the estimated costs were about right, particularly when considering the weighted responses. Several of the respondents had new PI for which new PI OPEPs were required during this time.

46. The respondents who did not think the estimate was about right were asked to provide a more reasonable figure instead, and their estimate was £15k per new OPEP. As it was not possible to identify who the respondents were, it wasn’t possible to determine if they had submitted any new OPEPs during the transition period.

47. With consideration of all the evidence that has been gathered, the estimate for new PI OPEPs of approximately £10k each is probably about right or was possibly a little low.

48. The number of new PI OPEPs submitted during the transition period was 8, which was less than the 12 estimated over the transition period given in the IA. Total costs to industry over the period were therefore lower than the IA estimated.

## OPEP’s for existing Non-Production Installations (NPIs)

49. Prior to the introduction of the OPRC15, oil and gas operations involving NPIs were covered by an addendum to an existing PI OPEP, field OPEP or onshore OPEP. The OSD required that all offshore installations required their own OPEP, so this was extended to NPIs operating in the UKCS. It was

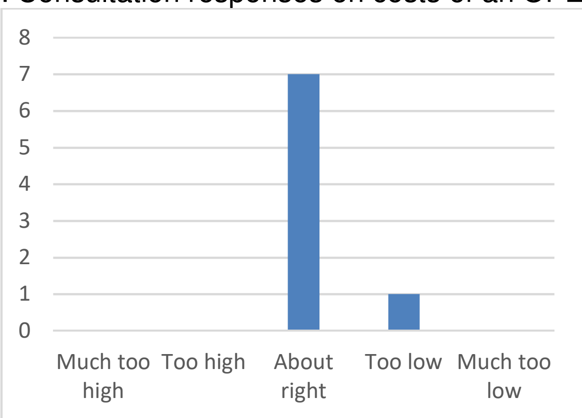
recognised that due to the nature of NPI work that no location specific information could be provided in an NPI OPEP (including worst case oil spill scenarios and associated spill modelling) as this would be operation and location specific. As such the NPI OPEP was a document with limited scope which would be supplemented by a Communication and Interface Plan (CIP) to another existing OPEP, typically a PI OPEP when an NPI was working in the same field as a PI; or be supplemented by a Temporary Operations OPEP (TO OPEP) which provided the location specific oil spill information and pollution response arrangements where these were not otherwise available, typically for well operations.

50. For the purposes of this PIR and reviewing the IA, a TO OPEP is assumed to be a well operations OPEP addenda, while a CIP is assumed to be a combined operations OPEP addenda.

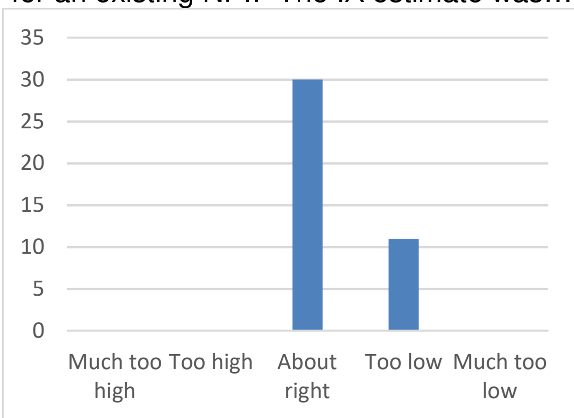
51. All NPIs required OPEPs and the IA estimated that there were 106 NPIs with UK accepted Safety Cases. . As set out in the IA, industry estimated that the cost of preparing and submitting a NPI OPEP was between £10k and £15k with a best estimate of £12.5k. However, it was recognised that this may be an overestimate as industry was anticipating that an OPEP for a NPI would be done to the same requirements as that for a PI, which turned out not to be the case as some of the information required to be in a PI OPEP is not available to the NPI owner. This additional information that would be required is included in a CIP or TO OPEP and provided by the well operator at the time of the proposed well operations.

52. There was significant discussion with the NPI owners Trade Associations (the IADC and BROA) about the content of a NPI OPEP and the IADC proposed developing a template format that all their members could use and which could also be shared with BROA members. OPRED agreed to this approach which made the drafting of NPI OPEPs and their review much simpler and made the cost of preparing, submitting and reviewing them much lower than expected.

Figure 5: Consultation responses on costs of an OPEP for an existing NPI: “The IA estimate was…”




Consultation responses




Consultation responses weighted by installations

53. As shown in Figure 5, of the 25 respondents to the industry survey, only 8 responded to this question with the majority of views being that the costs were about right. It should be noted that three respondents with no NPIs responded to this question and in further discussion it was identified that they had mistakenly considered PIs that had ceased production to be an NPI. When excluding these responses all the NPI Owners that responded considered that the costs were about right.

54. In the workshop discussions with the IADC and BROA, the use of the NPI OPEP template to prepare and submit NPI OPEPs was discussed and it was agreed by respondents that the template greatly eased the time and subsequent cost both of preparing and reviewing NPI OPEPs. Given that the IA assumed that the content of a NPI OPEP would be the same as for a PI OPEP, which turned out not to be the case, it was questioned what the cost was. One respondent advised that using the template now allowed them to prepare a NPI OPEP in less than two hours compared to the 174 hours estimated in the IA. Allowing

for any additional time submitting the OPEP and responding to queries, this would put the cost of a NPI OPEP at around £1k - £2k.

55. The number of OPEPs for existing NPIs received during the transition period was 103, which was slightly lower than estimated in the IA.

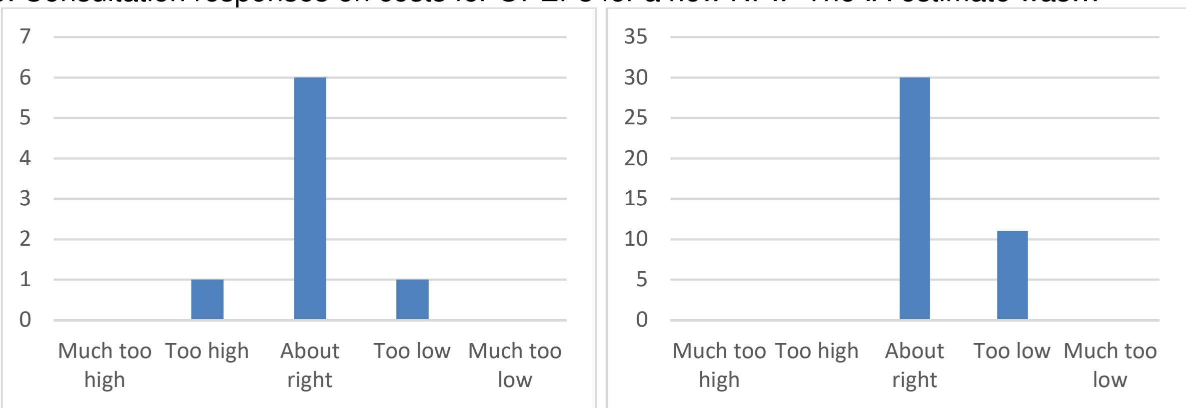
56. To conclude, there is evidence which supports the IA range of between around £10K and £15k per NPI OPEP, with a best estimate of around £12.5k being about right, however, there is also evidence that the cost was much lower for NPI OPEPs once use of the NPI OPEP template was established and may have been about £2k.

## OPEPs for new Non-Production Installations

57. As described in paragraph 49 & 50, OPEPs for NPIs was a new requirement under the OPRC15. In addition to requiring OPEPs for existing NPIs, OPEPs would be required for any new NPIs coming into the UKCS who did not have Safety Cases.

58. As set out in the original IA, Industry estimated that the cost of preparing and submitting an OPEP for a new NPI was between £10k and £15k with a best estimate of £12.5k. Industry also estimated that five new OPEPs for NPIs would be required each year, though this could be an overestimate as NPIs move around the UKCS and would be dependent on oil and gas exploration and other drilling activity.

Figure 6: Consultation responses on costs for OPEPs for a new NPI: “The IA estimate was…”




Consultation responses

Consultation responses weighted by installations

59. As shown in Figure 6, of the 25 respondents to the survey, only 8 responded to this question with most views being that the costs were about right. It should be noted that as with the previous question, four of the respondents were not NPI owners. When excluding these responses all the NPI Owners that responded considered that the costs were about right.

60. During the workshop discussions held with the IADC and BROA there was discussion about the cost of developing the template which assisted in the preparation of NPI OPEPs. The cost of this was deemed to be much less than £10k (about the cost of one NPI OPEP), but by using it the time spent to create a new NPI OPEP was, according to one respondent, less than two hours which is significantly less than the 174 hours estimated in the IA for preparing and submitting an NPI OPEP. Given this estimate, and as set out in paragraph 54 above, this would put the cost of a NPI OPEP, once use of the NPI OPEP template was established, to have been about £2k. Taking account of the benefits of using a standardised template for NPI OPEPs which reduced the time and cost for developing these then the overall costs for industry would have been much lower than that estimated in the IA.

61. It is not possible to reconcile this response with the survey responses. However, given there is significantly less information to be provided in a NPI OPEP, and no modelling required, it would be reasonable to say that the estimated cost in the IA for a NPI OPEP is an overestimate, despite the survey responses.

62. The number of new NPI OPEPs received during the three-year transition period was 12, which was slightly lower than the 15 estimated in the IA.

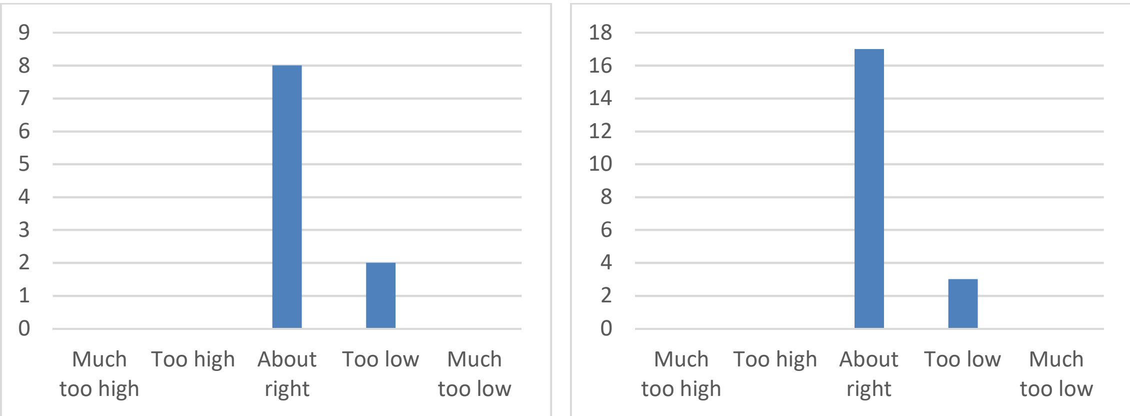
63. To conclude, there is evidence which supports the IA range of between around £10k and £15k per NPI OPEP, with a best estimate of around £12.5k being about right. However, there is also evidence that the cost was much lower for new NPI OPEPs once use of the NPI OPEP template was established and a best estimate might be around £2k.

## OPEP Addenda for well operations

64. As set out in the IA and as mentioned in paragraph 49 & 50 above, when undertaking well operations an addendum to an existing OPEP is required to provide the specific pollution response scenarios and response arrangements if not already provided. This would provide details of the NPI being used, oil spill scenarios and spill modelling, etc. The IA estimated that based on the number of applications that were being received at the time, that approximately 300 OPEP addenda would be submitted annually for well operations.

65. As set out in the IA the industry research group gave a wide range in the time required for preparing and submitting a well operation addendum and it was estimated that the average cost would be in the region of £1.44k to £10k, with a best estimate of £5.7k per well addenda OPEP.

Figure 7: Consultation responses on costs for addenda to OPEP for well operations: "The IA estimate was…"




Consultation responses

Consultation responses weighted by number of well ops addenda submitted

66. As shown in Figure 7, 10 respondents answered this question. They indicated that the original best estimate was either about right or too low, though when weighted by the number of well operations addenda each respondent submitted there is more evidence that the costs were about right.

67. The respondents who did not think the estimate was about right were asked to provide a more reasonable figure instead. One respondent, who submitted two well operations addenda, advised that the cost was approximately £10k which did not include the costs of additional modelling. Modelling costs had been estimated by a different respondent during follow up questioning to the survey to be approximately £5k. The other respondent, who had submitted one TO OPEP advised a range of £3k for a CIP up to £25k for a brand new TO OPEP.

68. There were no additional cost estimates provided at the workshops.

69. The number of well operations addenda submitted over the transition period was much lower than anticipated, which was likely due to the downturn in the industry and low oil price. Rather than 300 well addenda per year, OPRED received 68 well operations addenda over the three-year period, giving an average of 23 per year.

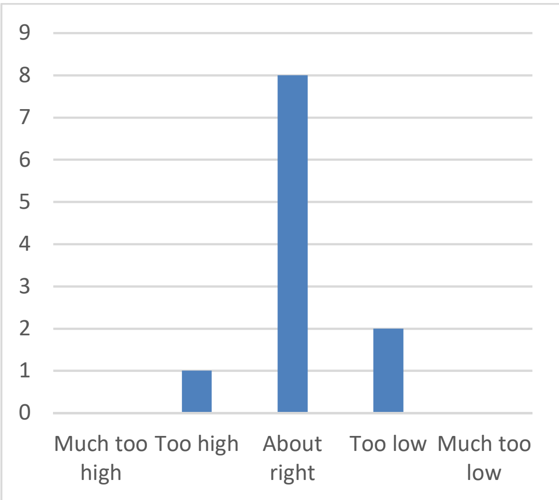
70. To conclude, the range of costs of £1.44k to £10k, with a £5.7k best estimate is probably about right given the evidence available and that the respondents who submitted the most well operations addenda thought the costs were about right. The higher range given in the IA reflects to some degree the higher costs reported by two of the respondents, however, there is insufficient quantitative evidence to support a re-estimation. As such we estimate that a range of between around £1.44k and £10k, with a best estimate of around £5.7k, might be reasonable.

## OPEP addenda for combined operations

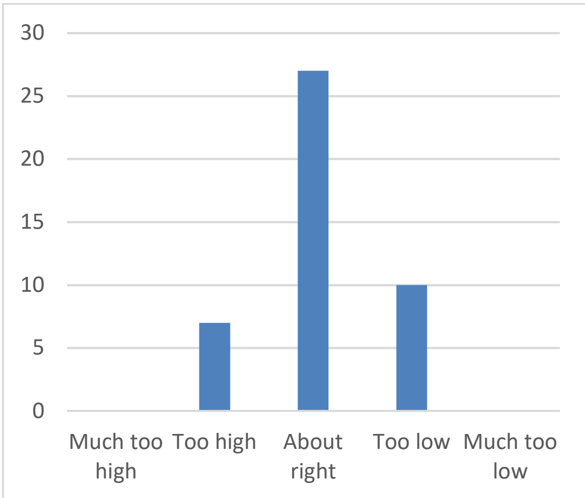
71. As set out in the IA and mentioned in paragraphs 49 & 50 above, when undertaking combined operations an addendum to an existing OPEP is required to provide the additional pollution response scenarios from the NPI and any changes to response arrangements between the NPI and PI OPEP. The IA estimated that based on the number of applications that were being received at the time, that approximately 40 OPEP addenda would be submitted annually for combined operations.

72. As set out in the IA the industry research group gave a wide range in the time required for preparing and submitting a combined operations addendum and it was estimated that the average cost would be in the region of £5k to £10k, with a best estimate of £7.5k per combined operations addenda OPEP.

Figure 8: Consultation responses on costs for addenda to OPEP for combined operations: "The IA estimate was…"




Consultation responses




Consultation responses weighted by number of combined ops addenda submitted

73. As shown in Figure 78, 11 respondents answered this question. While some respondents considered that the estimate was either too low or too high the majority, particularly when weighted by the number of combined operations addenda submitted, considered the cost about right.

74. The respondents who did not think the estimate was about right were asked to provide a more reasonable figure instead. One respondent who thought the costs were too low but who didn't submit any CIPs, estimated the cost to be approximately £10k, which did not include the costs of additional modelling. Modelling costs had been estimated by a different respondent during follow up questioning to the survey to be approximately £5k. The other respondent, who thought the costs were too low, but submitted 10 CIPs, advised a range of £3k for a CIP (which is what, for the purposes of the PIR, we consider a combined operations addenda to be) up to £25k for a brand new TO OPEP.

75. The respondent who thought the costs were too high, and had submitted 7 CIPs, said the costs were about £3k for a CIP, which was about half the estimated cost in the IA of £7.5k.

76. With two respondents, who had submitted the most CIPs, advising that costs were closer to £3k for a CIP, this would suggest that the estimate in the IA was an overestimate. Given that a CIP is a much smaller document than a TO OPEP this would be expected. If the lower cost for a CIP is to be taken as

£3k rather than £5k as given in the IA, and the upper range remains at £10k, then the best estimate for a combined operations addenda could be considered to be £6.5k rather than £7.5k.

77. The number of combined operations addenda submitted over the transition period was as anticipated. OPRED received 127 CIPs over the three-year period, giving an average of 42 per year.

78. To conclude, the range of costs in the IA of £5k to £10k, with a £7.5k best estimate, is probably slightly overestimated. Given the evidence available and that the respondents who submitted the most combined operations addenda thought the costs were either about right or too high, a lower best estimate of around £6.5k might be reasonable. Given the lower cost for a CIP compared to the estimate in the IA, but 7 more CIPs were assessed than estimated, then the transition costs to industry were approximately £75k less than estimated.

## Impacts not assessed in the original IA

79. In addition to the one-off costs discussed above, the IA assessed the five-yearly review of PI and NPI OPEPs over a ten-year period. As this PIR is only reviewing the costs of the transition period, and the OMAR had not started to receive any OPEPs for their five yearly review at the time of preparing the PIR, other than those ‘brought forward’, it is not possible to assess the costs at this time. As such these costs are not included in the PIR.

80. We asked an open question in our consultation, workshops and interviews as to whether respondents had incurred any transitional costs other than the ones discussed above to capture any significant impacts in these other areas. Respondents raised the additional costs of undertaking Major Environmental Impact assessments.

81. The Directive required that duty holders and well operators identify all their major accident scenarios, which might include a major environmental incident (MEI) as the result of a precursor major accident. These major accident scenarios, including potential for a MEI, are to be described in the Safety Case. Determining the potential for a MEI required operators to make assessments of the environmental consequence from certain major accidents and potentially run additional pollution modelling. MEI assessments would typically be undertaken as part of any Environmental Impact Assessment (EIA) under The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999[14]. The outcome of the assessment could then be used in the EIA; for the OPEP to ensure appropriate pollution response is in place; and for inclusion within the safety case or notification of well operations.

82. While EIAs did consider worst-case pollution scenarios, they did not make an assessment as to whether this constituted a MEI under the definitions set out in the Directive. As a result, all such worst-case pollution scenarios needed to be reconsidered as to whether they constituted a MEI in each transitional safety case and all notification of well operations.

83. While this was not a requirement set out in the OPRC15, responses to the survey included the additional costs of MEI assessments as a negative impact due to delays in producing guidance and the additional modelling required to make the assessment.

84. From the survey, four respondents indicated that there were additional costs associated with undertaking MEI assessments and modelling. The costs ranged from £5k per installation up to £20-£30k per installation. Another respondent indicated they had a one-off cost of £15k and then a further £3k per OPEP, of which they had submitted four over the transition period for PI and a further 8 for well or combined operations. One respondent indicted that there were no additional costs associated with MEIs as they didn’t have any identified from their major accident scenarios.

[14] Since replaced by the Offshore Oil and Gas Exploration, Production, Unloading and Storage (Environmental Impact Assessment) Regulations 2020.

85. Given the wide range in costs provided, an average MEI assessment per production installation (PI) could be taken from the costs provided by respondents for the number of installations they each have. This would give an average estimated MEI assessment, including modelling cost, of around £9k per PI transitioned. As the MEI assessment and description needed to be provided in the safety case, as opposed to in the OPEP, and 221 PIs transitioned, the total cost to industry might be estimated at a worse case of £1,989k, however, this is not associated with the costs of transitioning to the OPRC15 requirements.

## Total transitional costs

### Per-OPEP transition costs

86. The original IA estimated the transitional costs for the various types of OPEP which would be required to be submitted to OPRED. The analysis above now gives us an opportunity to re-estimate these figures.

87. As summarised in Table 1, the PIR analysis indicates that the IA underestimated the costs of bringing forward PI OPEPs, however, the cost of this was relatively insignificant in the total cost for industry. The analysis shows that the IA slightly overestimated the costs for OPEP addenda for combined operations. There is evidence which suggests that the costs of OPEPs for NPIs was also overestimated, but this is based on possibly limited evidence.

**Table 1: Summary of the OPRC15 transition costs per OPEP (£)**

| OPRC15 OPEPs | IA estimate (£Ks) | | | PIR conclusion – | PIR re-estimate (£Ks) | | |
|---|---|---|---|---|---|---|---|
| | Low | Best | High | IA estimate is… | Low | Best | High |
| Decommissioning OPEPs | £10 | £12.5 | £15 | About right | £5 | £12.5 | £17 |
| Existing PI OPEPs | £9 | £10 | £11 | About right | £5k | £10 | £15 |
| Bringing forward PI OPEPs | £2.3 | £2.5 | £2.8 | Too low | £2.5k | £5.25 | £8k |
| New PI OPEPs | £9 | £10 | £11 | About right | £9 | £10 | £11 |
| OPEPs for existing NPIs | £10 | £12.5 | £15 | About right -Too high[15] | £10 | £12.5 | £15 |
| OPEPs for new NPIs | £10 | £12.5 | £15 | *About right – Too high[16]* | *£10* | *£12.5* | *£15* |
| OPEP addenda for Well operations | £1.44 | £5.7 | £10 | About right | £1.44 | £5.7 | £10 |
| OPEP addenda for combined operations | £5 | £7.5 | £10 | Too high | £3 | £6.5 | £10 |

### Aggregate transition costs

88. As described in paragraphs 14 & 15, the original IA estimated that 315 OPEPs would either need to be prepared and submitted to meet the requirements of the OPRC15 based on numbers at the time and regulator expectations of industry change in the three years from July 2015 to July 2018. In addition, the IA estimated that approximately 300 OPEP addenda would be submitted each year for well operations and a further 40 OPEP addenda would be submitted for combined operations each year.

89. Based on the per-OPEP costs estimated in the IA discussed above, this gives a total one-off transitional cost for the OPRC15 of:

[15] There is evidence to suggest that once the NPI OPEP template was introduced the average costs for a NPI OPEP were in the region of £1k - £2k.

[16] There is evidence to suggest that once the NPI OPEP template was introduced average costs for an NPI OPEP were in the region of £1k - £2k.

**Table 2: Estimated costs to Industry in the original IA for transition period (£)**

| OPRC15 OPEPs | IA estimate (£Ks) | Estimated Number of OPEPs | Total cost (£Ks) |
|---|---|---|---|
| Decommissioning OPEPs | £12.5 | 45 | £562.5 |
| Transitioning existing OPEPs for Production Installations | £10 | 92 | £920 |
| Bringing Forward OPEPs | £2.5 | 45 | £112.5 |
| OPEPs for new production Installations | £10 | 12 | £120 |
| Transitioning existing non-production Installations to have an OPEP | £12.5 | 106 | £1,325 |
| OPEP's for new non-production Installations | £12.5 | 15 | £187.5 |
| Well Operation OPEPs | £5.7 | 900 | £5,130 |
| Combined Operations OPEPs | £7.5 | 120 | £900 |
| **Total** | | | **£9,257.5** |

**Table 3: Actual total costs to Industry as determined by the PIR for OPEPs (£)**

| OPRC15 OPEPs | Actual average cost | Actual number of OPEPs | Total cost (£Ks) |
|---|---|---|---|
| Decommissioning OPEPs | £12.5 | 9 | £112.5 |
| Transitioning existing OPEPs for Production Installations | £10 | 124 | £1,240 |
| Bringing Forward OPEPs | £5.25 | 45 | £236.25 |
| OPEPs for new production Installations | £10 | 8 | £80 |
| Transitioning existing non-production Installations to have an OPEP | £12.5* | 103 | £1,287.5 |
| OPEP's for new non-production Installations | £12.5* | 12 | £150 |
| Well Operation OPEPs | £5.7 | 68 | £387.6 |
| Combined Operations OPEPs | £6.5 | 127 | £825.5 |
| **Total** | | | **£4,319.35*** |

*There is some evidence to suggest that Industry costs for transitioning NPI OPEPs and for new NPI OPEPs were in the range of £1-£2k. Taking £2k as a conservative lower figure then costs for all NPI OPEPs (transitional or new) would only amount to £230k rather than £1,437.5k. This would give the total transition cost at £3.112m. Some costs as noted in paragraph 79 have not been fully assessed.

90. This indicates that the IA overestimated the one-off transition costs of compliance by between around £5m, and possibly as much as £6m, if the lower NPI OPEP costs are considered.

91. This overestimate is due to two causes: the overestimation of the number of OPEPs that would be transitioning in the original IA (discussed in paragraphs 14 & 15); and the overestimation of some per-OPEP costs (discussed throughout this report).

## Costs recovered by OMAR

92. In addition to the compliance costs discussed above, the original IA also estimated that each OPEP would be charged by OPRED for assessments relating to submissions for the OPRC15 transition. Assessments

were carried out by OPRED specialists and estimates in the IA were made by the team setting up OMAR at the time.

93. It is worth noting that OMAR data is recorded for the purposes of invoicing Responsible Persons, rather than for assessing the costs of the OPRC15 transition. As such, the cost data contains some assessment costs where we have had to disentangle charges for assessment work from other administrative issues and to account for multiple installations that may have been recorded under one field OPEP. The IA only took account of specialist time in reviewing OPEPs and did not include associated administrative costs. For the purposes of comparison to the IA the actual administrative costs have also not been considered in the PIR.

94. The amount estimated in the IA for reviewing OPEPs varied depending on the type of OPEP and the research identified the average cost for each of the OPEP types, which is set out in Table 4. The cost estimates were about right for decommissioning OPEPs and new PI OPEPs, but other costs were either too high or too low. Notably the costs for assessing NPI OPEPs was significantly lower than estimated and this is likely to be a result of NPI OPEPs following a standard template developed by the IADC which made reviewing easier and the content of a NPI OPEP was far less than that assumed by the IA.

95. Average OPEP costs for transitioning PIs were higher than estimated partly as a number of transitioning OPEPs were field OPEPs covering multiple installations or were onshore plans covering broader emergency response arrangements which increased the average cost versus a single installation OPEP. OPEP costs were higher than estimated for well operation OPEPs (TO OPEPs) as these contained more information than was estimated by the IA so took longer to review.

**Table 4: Estimated costs recovered by OPRED in the original IA per OPEPs (£)**

| OPRC15 OPEPs | IA estimate (£s) | IA estimate is… | PIR re-estimate (£s) |
|---|---|---|---|
| Decommissioning OPEPs | £916 | About right | £1094 |
| Transitioning existing OPEPs for Production Installations | £453 | Too low | £1094 |
| OPEPs for new production Installations | £916 | About right | £1094 |
| Transitioning existing Non-Production Installations to have an OPEP | £916 | Too high | £399 |
| OPEP's for new Non-Production Installations | £916 | Too high | £399 |
| Well Operation OPEPs | £229 | Too low | £520 |
| Combined Operations OPEPs | £229 | Too low | £362 |

96. The IA used a ten-year present value to estimate the total cost to industry, however, given the timeframe for transition and differences in the number of OPEPs submitted in comparison to the IA the per OPEP type, cost has been used for comparison against the IA rather than using a ten-year NPV. This is summarised in Table 5 and 6**Error! Reference source not found.**.

**Table 5: Estimated costs recovered by OPRED in the original IA for transition period (£)**

| OPRC15 OPEPs | IA estimate (£s) | Estimated Number of OPEPs | Total cost (£Ks) |
|---|---|---|---|
| Decommissioning OPEPs | £916 | 45 | £41.2 |
| Transitioning existing OPEPs for Production Installations | £453 | 92 | £41.7 |
| OPEPs for new production Installations | £916 | 12 | £11 |
| Transitioning existing Non-Production Installations to have an OPEP | £916 | 106 | £97.1 |
| OPEP's for new Non-Production Installations | £916 | 15 | £13.7 |
| Well Operation OPEPs | £229 | 900 | £206.1 |
| Combined Operations OPEPs | £229 | 120 | £27.5 |
| **Total** | | | **£438.3** |

**Table 6: Actual total costs recovered by OPRED for OPEPs (£)**

| OPRC15 OPEPs | Actual average cost (£s) | Actual number of OPEPs | Total cost (£Ks) |
|---|---|---|---|
| Decommissioning OPEPs | £1094 | 9 | £9.8 |
| Transitioning existing OPEPs for Production Installations | £1094 | 124 | £135.7 |
| OPEPs for new production Installations | £1094 | 8 | £8.8 |
| Transitioning existing Non-Production Installations to have an OPEP | £399 | 103 | £41.1 |
| OPEP's for new Non-Production Installations | £399 | 12 | £4.8 |
| Well Operation OPEPs | £520 | 68 | £35.4 |
| Combined Operations OPEPs | £362 | 127 | £46 |
| **Total** | | | **£281.6** |

97. The costs recovered by OPRED vary between the IA estimate and the actual costs for individual OPEP types, in particular for transitioning existing PI OPEPs and well operation OPEPs, which were much higher than estimated and for NPI OPEPs which were much lower than estimated. However, the actual total costs recovered based on the OMAR data – (£282k) is much lower than the total cost estimates in the IA (£438k). This is primarily due to the much lower number of well operation OPEPs submitted compared to the numbers estimated in the IA (300 per year estimated vs 68 total received) despite the actual higher cost recovered per well operations OPEP. It is worth noting that the transition period coincided with a downturn in the oil and gas industry which significantly curtailed offshore oil and gas exploration activity and hence well operations.

## Appendix 1 – OPRC15 Summary of New Requirements

| Key Changes | |
|---|---|
| **Regulation** | **New requirements** |
| 2<br><br>Definitions | Defined those entities required to have an oil pollution emergency plan (OPEP) for installations in offshore waters as Responsible Persons, which means the operator of a production installation and the owner of a non-production installation. |
| 4<br><br>Oil Pollution Emergency Plans | Existing requirement for the operator of an offshore production installation to have an OPEP extended to include owners of non-production installations in order to meet the Directive requirements.<br><br>Copy out of Directive requirements that every Responsible Person would be required to:<br>• maintain equipment and expertise relevant to their plan;<br>• ensure that such equipment and expertise is available for use at all times;<br>• make such equipment and expertise available to the authorities responsible for the execution of the National Contingency Plan;<br>• undertake exercises to maintain relevant expertise for the implementation of the plan, including interaction with the National Contingency Plan;<br>*Note: already required under existing guidance and from Maitland review*<br>• retain evidence of those exercises, such evidence to be provided to the Secretary of State on request.<br><br>Some elements of these requirements were already being undertaken through administrative means. |
| 7<br><br>Offences | Copy out of Directive.<br><br>Introduced new offences for failing to comply with the new requirements of the Regulations. |
| Schedule 2<br><br>Requirements for an oil pollution emergency plan in respect of an offshore installation | There were already requirements set out in guidance as to what was required to be demonstrated in an installation OPEP under the OPRC98 and new requirements were added to these. |

| | |
|---|---|
| | The OPRC15 changes:<br>• Responsible Persons to take account of the risk assessment undertaken during preparation of the safety case submitted under the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015;<br>• a description of the potential worst-case release of oil to the sea from the installation arising from the scenarios identified in the safety case;<br>*Note: The existing guidance already required that the worst-case scenario be described and modelled in the OPEP, which in some cases were worse than the scenarios described in the safety case.*<br>• arrangements for limiting risks to the environment;<br>• a description of the equipment and resources available to respond to a release of oil to the sea;<br>• the measures in place to ensure that the response equipment and procedures are maintained in an operable condition;<br>• an estimate of the oil spill response effectiveness. |
| **Other Changes** | |
| **Regulation** | **New Requirement** |
| 4<br><br>Oil Pollution Emergency Plans | Where there are material changes to an installation Safety Case as per the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, the Responsible Person would be required to amend the existing OPEP or submit a new OPEP. |

# Appendix 2 – Evidence Summary

The evidence review considered information from the following:

- Explanatory Memorandum for the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015, S.I. 2015/386.
- Impact Assessment for Implementation of Directive 2013/30/EU on the safety of oil and gas operations and on updating UK oil and gas legislation, IA No: 0088, 11th December 2014.
- Industry survey on Offshore Major Accident Regulator (OMAR) Post-Implementation Reviews, June 2019.
- OPRED costs for review and approval of OPEPs during the transition period July 2015 – July 2018.

The OPRC15 apply to all offshore installations where there is a risk of pollution from oil and a survey was developed for the Industry bodies and their members. Following receipt of survey results, further information gathering was undertaken from individuals who had responded to seek further clarification on some responses. Workshops were also held after survey results were received in order to further refine the information provided. The workshops were attended by the Industry trade body representatives as well as members. The key Industry bodies and their members were from Oil and Gas UK (OGUK) - now Offshore Energies UK (OEUK); the International Association of Drilling Contractors (IADC); and the British Rig Owners Association (BROA).

Of the 59 companies that hold offshore installation OPEPs, 26 responses were received to the combined survey on the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 ("the SCR15") and the OPRC15. However, one response was from a verification company that only responded to the SCR15 questions, and there were either duplicate responses or no responses on the OPRC15 from six other organisations. Consequently, for the OPRC15 we received responses from 19 organisations which comprised 13 (of 35) production installation operators, four (of 24) non-production installation owners, one well operator only and one trade association.

The respondents did however represent in total 125 transitioned installations, which is 50% of the total of 250 OPEPs that transitioned to the new regulatory requirements. Respondents comprised 100 production installations and 25 non-production installations.

Further details of the online survey are provided below including the number of responses, length of time the online survey was live and demographics of respondents:

<table>
<tr><th>Title of survey</th><th>Date undertaken</th><th>No. of respondents</th></tr>
<tr><td>Duty-holders survey</td><td>7th June to 10th July 2019</td><td>n = 26 (full or partial responses to survey)</td></tr>
<tr><td colspan="3">Details of Respondents<br>Size of organization:<br><br>*15% (4) <50 employees<br><br>*4% (1) 50 – 99 employees<br>*12% (3) 100-249 employees<br>*65% (17) 250+ employees<br>*4% (1) No response<br><br>Organisation type (in what capacity are you responding):<br><br>*62% (16) Production installation operator</td></tr>
</table>

| Title of survey | Date undertaken | No. of respondents |
|---|---|---|

| | |
|---|---|
| *19% (5) | Non-production installation owner (other than Flotel[17]) |
| *8% (2) | Other (please specify below)<br>• *'Trade Association for Rigs (drilling, accommodation)'*<br>• *'Trade Association'* |
| *4% (1) | ICP[18] (verification scheme or well examination scheme) |
| *4% (1) | Well operator only |
| *0% (0) | Flotel |
| *0% (0) | Union or worker representative |
| *4% (1) | No response |

How many of the following does your organisation either own and/or operate:

| | Production installation | Non-production installation |
|---|---|---|
| 1 | 2 | 3 |
| 2-4 | 8 | 4 |
| 5-10 | 7 | 2 |
| 10-15 | 0 | 1 |
| 16-20 | 0 | 0 |
| 21-30 | 0 | 1 |
| More than 30 | 1 | 0 |
| Not applicable (N/A) | 1 | 3 |

Comments:

The survey was hosted on SurveyMonkey with the link sent to contacts at BROA, IADC and OGUK for them to circulate amongst their members.

Some production installation operators responded that they had non-production installations, however, they meant production installations that had ceased production as opposed to a non-production installation such as a drilling rig, dive support vessel or flotel.

Alongside the online surveys, a number of workshops were held with BROA, IADC and OGUK to clarify and expand on the findings of the aforementioned survey. Details of these workshops are as follows:

| Stakeholder group(s) in attendance | Date workshop held | No. of attendees |
|---|---|---|
| Members of BROA / IADC | Thursday 12th September 2019 – 10am to 4pm | 11 |
| Comments: | | |

[17] Flotel, a portmanteau of the terms floating hotel, refers to the installation of living quarters on top of rafts or semi-submersible platforms. They tend to be used as accommodation at the sea for crews working in the high seas' drilling industry (https://www.marineinsight.com/types-of-ships/what-is-a-flotel/).

[18] Independent competent person (ICP) (see https://www.hse.gov.uk/offshore/verification.htm).

| Stakeholder group(s) in attendance | Date workshop held | No. of attendees |
|---|---|---|
| Attendees were asked to comment on areas which were unclear within the survey findings or where we wanted to explore emerging themes; this included costs estimates. | | |

| Stakeholder group(s) in attendance | Date workshop held | No. of attendees |
|---|---|---|
| Members of OGUK | Monday 16th September 2019 – 10am to 4pm | 5 |
| Comments:<br>Attendees were asked to comment on areas which were unclear within the survey findings or where we wanted to explore emerging themes; this included costs estimates. | | |

Alongside the workshops, there were seven follow up dialogues with specific companies in order to clarify aspects of their survey responses and to ask about the costs and benefits figures which were provided. Five companies provided further clarification.

### To what extent have the policy objectives been achieved

In addition to questions in the survey about the costs incurred, details of the responses to which are in the OPRC15 estimated costs supplement, respondents were asked about various aspects of the implementation of the Directive and whether it achieved the policy objectives.

Respondents to the online survey were asked whether they agreed or disagreed with the statement "*The OPRED implementation approach minimised the adverse impact of any changes on industry.*"

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, 70% (14) agreed or strongly agreed that OPRED's approach to implementing the OPRC15 minimised the adverse impact of the changes on Industry. A further four (20%) neither agreed nor disagreed or didn't know or were unsure. Only two respondents (10%) disagreed providing different reasons. One respondent indicated that "*OPRED were extremely slow to provide guidance on the meaning of the term 'Major Environmental Incident', which led to wasted effort, increased costs and delays in producing safety and environmental critical element (SECE) assessments*". The other response was that "*BEIS took the opportunity to demand more changes than was required under the new Regulations*". |

The consensus from the online survey was largely positive. Of the two negative responses provided, one referred to the need to undertake assessment as to whether the potential environmental impact from a major accident may result in a ‘major environmental incident’ (MEI) in order to complete the Safety Case. OPRED had not published guidance on MEIs for the first few months of the transition period and consequently there were some delays in completing assessments. However, the requirement to undertake the MEI assessment is not required by the OPRC15 and so the response does not fully apply to how OPRED implemented this aspect of the Offshore Safety Directive, though it does identify some unintended consequences in the way the Directive as a whole was implemented.

The other negative response was that BEIS took the opportunity to demand more changes than was required under the new Regulations. On further clarification from the respondent, this was in regard to how OPEPs were required for well operations. Under the OPRC98, any well operations being undertaken within the scope of an existing installation, field or onshore OPEP was covered by an annex to that plan and there was no requirement for non-production installations to have an OPEP under the OPRC98. The Directive was clear that internal emergency response plans were required as part of the safety case. These internal emergency response plans included both the response for health & safety as well as pollution response as provided within an OPEP. As such all offshore installations, including non-production installations, were required to have an OPEP and the interface for arrangements between the NPI OPEP and an installation, field or onshore OPEP was set out though a communication & interface plan (CIP) or Temporary Operations OPEP (TO OPEP).These were new arrangements put in place by OPRED in order to be able to implement the Directive fully, which the respondent considered as unnecessary.

Respondents to the online survey were asked whether they agreed or disagreed with the statement “*The OPRED implementation approach maintained the consistency of the regime established under the OPRC 1998*”.

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, over half (58%, 11) agreed that OPRED’s approach maintained the consistency of the existing regime established under the OPRC98. A further seven respondents (37%) neither agreed or disagreed or didn’t know or were unsure. Only one respondent (5%) disagreed. The one respondent who disagreed provided the same response as per the previous question that *“BEIS took the opportunity to demand more changes than was required under the new Regulations*”. |

The consensus was mostly that the existing regime largely stayed the same, minimising changes to the OPRC98. The one respondent who disagreed gave the same response and further clarification as discussed above in regard to how OPRED implemented the Directive with regards to NPI OPEP arrangements.

OPRED also sought to find out whether the new requirements which implemented the Directive improved the existing regime. Respondents to the online survey were asked whether they agreed or disagreed with the statement “*The new requirements in the OPRC15 improved the offshore oil and gas pollution response arrangements*”.

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, less than half agreed or strongly agreed (37%, 7), while four (21%) neither agreed or disagreed and three (16%) didn't know or were not sure. Five respondents (26%) disagreed that the pollution response arrangements had been improved, providing the same common reason. This was that *"the arrangements stayed largely the same"*; "*it didn't change anything that was already being done*"; "*the arrangements have not changed significantly since the OPRC15*"; "*increase in admin only, no material improvements to response capability*"; and "*Prior to implementation of the OSD the UK already had a mature and well understood goal-setting regime that was effective in controlling the risks of major accidents on offshore installations. Overall the changes introduced by the OSD have made minimal improvements to the effectiveness of that regime*". |

While a significant minority (36%) believed that pollution response arrangements had improved, a number of respondents also replied that the Directive did not improve existing arrangements as the UK already had a high standard of pollution response arrangements.

OPRED sought to minimise the impact of implementation by ensuring that guidance was updated, assessment templates were available to make it clear what was required to be submitted and that engagement with industry was effective during implementation and the transition period. Respondents to the online survey were asked whether they agreed or disagreed with the statement "*The new guidance, assessment templates and engagement make it clearer what was required to be provided in an OPEP*".

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, well over half agreed or strongly agreed (63%, 12), while four (21%) neither agreed or disagreed and one (5%) didn't know or were not sure. Two respondents (11%) disagreed with the statement. One respondent replied with "*Very ambiguous and left open to interpretation with inconsistencies between operators*" while an NPI respondent replied that "*Main template for NPI was developed / provided by industry IADC*" |

The consensus was that OPRED guidance, assessment templates and engagement helped to make it clear what was required in OPEPs to be submitted. OPRED updated its guidance in August 2015 to ensure Responsible Persons complied with the new requirements for the OPRC15. The guidance was further updated in December 2016 and October 2017 to address queries from Industry and changes to the manner in which OPEPs were submitted to OPRED. There were also a number of workshops prior to the OPRC15 coming into force and during the transition period to assist with any queries. It is therefore not clear what ambiguity was seen by the respondent in this regard as no further follow up was possible. With regard to the NPI respondent comment, the IADC did create a template for NPI OPEPs which OPRED reviewed to confirm that if used it would meet the requirements for an NPI OPEP. Workshop discussions also agreed that the template greatly eased the time and subsequent cost both of preparing and reviewing NPI OPEPs, much reducing the time, and the cost, estimated in the IA.

OPRED also sought Industry views on whether the OPRC15 had effectively implemented the Directive requirements for pollution response. Respondents to the online survey were asked whether they agreed or disagreed with the statement "*The objective of effectively implementing the pollution response requirements of the OSD through the OPRC2015 remains appropriate?*"

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, well over half agreed (68%, 13), while three (16%) neither agreed or disagreed and three (16%) didn't know or were not sure. There were no respondents who disagreed with the statement. |

The consensus was that the OPRC15 remains the appropriate mechanism for implementing the Directive requirements for pollution response.

OPRED also sought views on whether the Directive requirements could have been implemented by reducing the burden on business. Respondents to the online survey were asked whether they agreed or disagreed with the statement "*Do you believe that the objectives of meeting the OSD requirements for pollution response could be achieved effectively via a system that imposes less regulation?*"

| Research instrument | No. of respondents | Evidence |
|---|---|---|
| Duty-holders online survey | *n* = 26 (full or partial responses to survey) | Of the 19 respondents to this question, the majority (58%, 11) did not know or were unsure, while 32% (6) replied No. Only two respondents were of the view that the objectives could have been achieved effectively by imposing less regulation. Only one comment was provided which was that "*we have no MEIs, so the existing legislation was fit for purpose*." |

The majority of respondents were unsure or didn't know if there were other ways of meeting the Directive requirements through a less burdensome approach. Those who had a view agreed that there was not an easier way of meeting the Directive requirements. Of those who indicated that there was, one did not provide any comment in the survey and did not provide a further clarification after the survey. The one response in regard to MEI is not relevant for the OPRC15 as MEIs are not required to be identified under those Regulations.

## Appendix 3 – Cost areas of IA evaluated in this PIR

**The original IA for the transposition of the Offshore Safety Directive is available on [legislation.gov](legislation.gov).**

| Section of IA | Area of cost | Evaluated in this PIR? | Reasons |
|---|---|---|---|
| 9.1 | Setting up the OMAR | **No** | Setting up the Offshore Competent Authority is not a requirement of the OPRC15. |
| 9.2 | Operating the OMAR | **No** | Running the Offshore Competent Authority is not a requirement of the OPRC15. |
| 9.3 | OMAR assessments related to OPRED legislation to implement the Directive | **Yes** | Costs incurred as part of the transposition of the OPRC15 as detailed in:<br>• 9.3.3 Internal Emergency Response Plans. |
| 9.4 | OMAR assessments related to DECC Environmental Legislation to implement the Directive | **Yes** | Costs incurred by OPRED as part of the implementation of the OPRC15 to cover the costs of reviewing OPEPs, **with the exception of**:<br><br>• 9.4.2 Financial Liability arrangements which would be regulated under the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015. |
| 9.5 | OMAR and Licensing Authority assessments related to changes to DECC licensing legislation to implement the Directive | **No** | North Sea Transition Authority (NSTA) legislation will not be evaluated by DESNZ. The costs related to updating IT systems is outside the scope of the OPRC15. |
| 9.6 | Complying with changes to HSE legislation to implement the Directive | **No** | HSE legislation will not be evaluated by OPRED as not their responsibility. |
| 9.7 | Maintaining existing standards and gold-plating of HSE legislation | **No** | HSE legislation will not be evaluated by OPRED as not their responsibility. |
| 9.8 | Complying with changes to DECC environmental legislation to implement the Directive | **Yes** | Costs to industry for amending and submitting OPEPs to transition to the OPRC15 requirements, **with the exception of:**<br><br>9.8.2 Financial Liability arrangements which would be regulated under the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015. |
| 9.9 | Complying with changes to DECC licensing legislation to implement the Directive | **No** | NSTA legislation will not be evaluated by OPRED as not their responsibility. |
| 9.10 | Maintaining existing standards of DECC legislation | **Yes** | Covered in the PIR. |
| 9.11 | Complying with legislation to implement Article 38 | **No** | Defra legislation will not be evaluated by OPRED as not their responsibility, |
| 9.12 | Complying with changes to update additional HSE legislation | **No** | HSE legislation will not be evaluated by OPRED as not their responsibility. |
| 9.13 | Benefits | **Yes** | Only section 9.12.1 has been assessed qualitatively in the Evidence Review of this PIR, as the other sections are not related to the OPRC15. |