Oil & Gas Authority

Analysis of UKCS Operating Costs in 2016

December 2017

Contents

Executive summary

Operating costs (OPEX) in the United Kingdom Continental Shelf (UKCS) fell in 2016 in terms of both total OPEX and average unit operating cost (UOC), measured per barrel of oil equivalent (boe).[1]

In 2016, UKCS total operating costs were 14% lower than in 2015, with an approximate £1.1 billion reduction in OPEX. Total oil and gas production rose by 5% to 598 million boe in 2016 compared with 571 million boe in 2015. Consequently, average UOC fell in 2016, for the second consecutive year, to £12/boe.

This report shows progress towards strengthening the operational cost base in the UKCS. The reduction in UOC, driven by a combination of lower costs and higher production volumes, is a positive story of success for the UKCS in what has been a difficult operating environment in recent years and a lower oil price.

There was high variation in unit costs and OPEX reductions between operators, with the highest UOC over 12 times more than the lowest UOC. While in part this is a product of the varying operating environments and infrastructure, it is important that operators continue to collaborate and share lessons learned to sustain the lower cost base.

Total OPEX reduction in the UKCS was dominated by four operators which achieved 60% of the total OPEX reduction in 2016.

Some operators have forecast cost increases, which indicates that some earlier reductions may have been the result of activity deferment and may be unsustainable.

UKCS total operating cost	Approximately £1.1 billion OPEX reduction in 2016 14% lower than 2015 Over 50% of operators secured OPEX reductions	
UKCS unit operating cost	**£** **£12/boe in 2016** 18% lower than 2015 35% lower than 2014	**US$** **$16/boe in 2016** 27% lower than 2015 47% lower than 2014
Offshore Field OPEX	Manned platforms, on average, cost 33% less to operate than the equivalent floating facility Older developments on average require less discretionary OPEX Overall OPEX reduction in the UKCS dominated by four operators	

[1] See methodology notes.

1. Introduction

The purpose of this report is to analyse, benchmark and provide insights into UKCS operating costs. It is one of a suite of benchmarking reports using data collected through the OGA's 2016 UKCS Stewardship Survey (2016 survey).[2]

The report is split into a discussion of total OPEX, offshore field OPEX and UOC, which together provide an insight into the operating cost landscape in the UKCS.[3]

The offshore field OPEX benchmarking highlights the operating cost base for the UKCS. It provides operators with a field-specific perspective on the cost of operating (based on size and complexity).

UOC analysis provides a comparison of costs on a per barrel of oil equivalent basis and is a useful indicator of the extent to which operators have been containing costs, especially when benchmarked against other similar fields and/or against an overall industry unit operating cost index.

UOC is also a major consideration in determining the economic life of a field. Unit cost at field level will depend on the rate of production, which will typically decline over time thus increasing UOC.

The analysis contained in this report will be used to support the OGA's asset stewardship process by providing cost benchmarking that aids peer group comparison.

Within the analysis of OPEX and UOC, a variety of categories such as facility type, asset location and proximity to cessation of production (COP) were analysed to allow for such peer group comparisons.

By taking account of characteristics that may account for cost differentials, the OGA is able to identify cost-efficient assets/operators to help drive further improvements in the overall operating cost landscape of the UKCS.

An analysis of operating costs and unit costs will allow industry to benchmark its performance over time in a clear, consistent and quantifiable way to ensure that cost benchmarking drives efficiencies into operations whilst maintaining high standards of health, safety and environmental management.

Table 1: UOC/Production/OPEX

	2015	2016	2017 (forecast)
UOC (£/boe, nominal prices)	15	↓ 12	↔ 12
UOC ($/boe, nominal prices)	22	↓ 16	↔ 16
UKCS total production (million boe)	571	↑ 598	↑ 603
UKCS total OPEX (£ billion)	8.3	↓ 7.2	↑ 7.3

[2] Recovery Factor Benchmarking and UKCS Production Efficiency reports can be found on our website https://www.ogauthority.co.uk/news-publications/publications/
[3] Please refer to the methodology notes (section 8) for definitions used within the report.

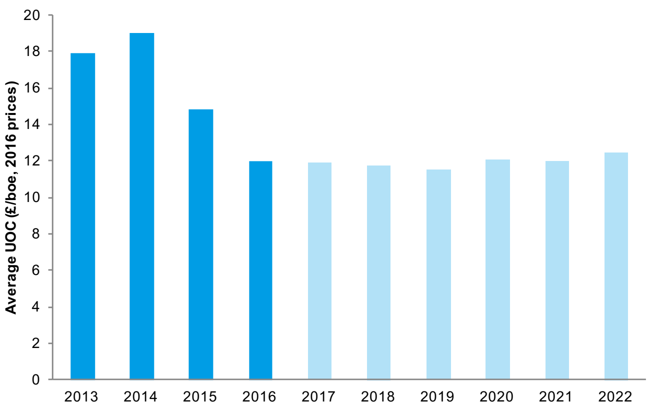
2. UKCS unit operating costs

The 2016 survey has revealed a slowdown in the pace of cost reduction. UKCS average UOC was £12/boe in 2016, an 18% reduction from 2015, which was 22% below the average in 2014. UOC is now over a third lower than the peak seen in 2014.

The OGA's projections suggest the outlook for the medium term is for unit costs to remain close to £12/boe in 2016 prices.

Figure 2 shows average UOC for each operator from the highest to the lowest, with the width of the bars scaled to reflect relative shares of total production. The largest producers generally had the lowest UOC in 2016.

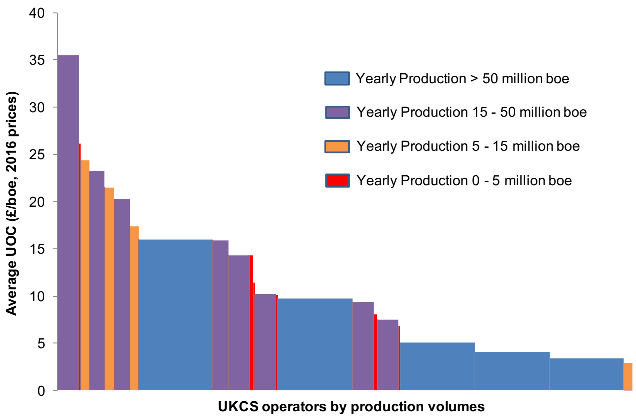
Figure 1: UKCS UOC over time



Although UKCS average UOC declined between 2015 and 2016, that fall masked the fact that some operators saw their UOC increase. The reduction in UOC in the basin was driven by 50% of UKCS operators with the rest showing no change or an increase in UOC, highlighting further scope for improvement.

The unit cost drivers over the last decade can be seen in Figure 3, which shows that the steep rise in UOC through to 2014 was driven by both rising OPEX and declining production.

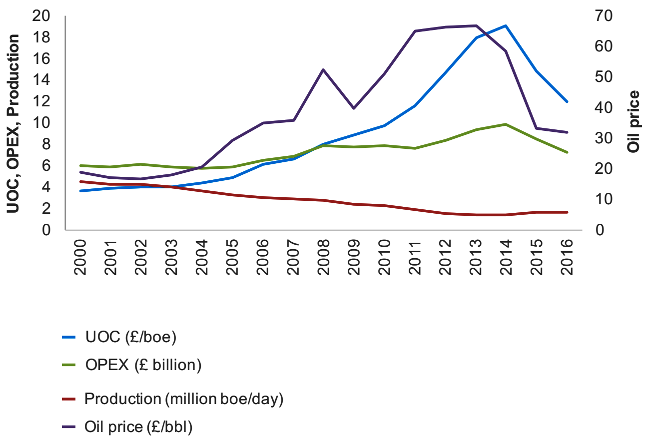
Figure 2: 2016 UOC and hydrocarbon production by operator



The improvement in unit costs from 2014 to 2016 was largely driven by cost reduction, as total OPEX declined at a much faster rate than the increase in production volumes (Figure 4).

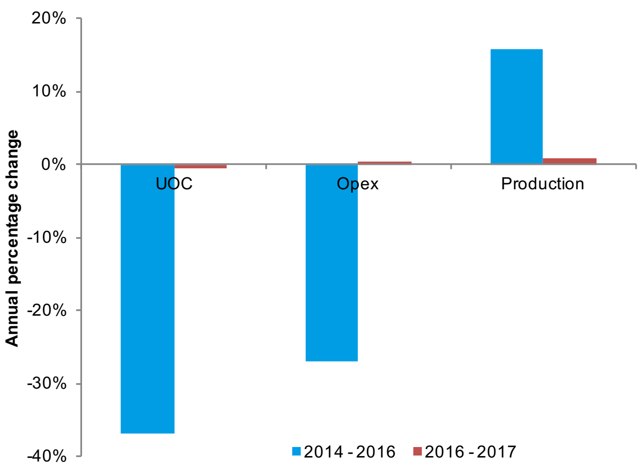
Over the last decade and a half, UOC has moved broadly in line with the oil price (Figure 3), indicating more cautious spending habits in periods of low oil price.

Figure 3: Unit cost drivers[4]



The OGA projects a modest increase in total OPEX in 2017. This is predominantly driven by 16 fields estimated to start up in 2017. These fields are forecast to have an average UOC of only £7/boe in 2017. Excluding new field start-ups and decommissioning fields, total OPEX is expected to be flat between 2016 and 2017.

Figure 4: UOC/OPEX/production annual growth rates



[4] UOC, OPEX and oil price are in 2016 prices.

2.1 UOC by operator

There was a high variation in costs between operators, as illustrated in Figure 5, with the highest UOC over 12 times more than the lowest UOC. There is a wide range of operating environments and infrastructure which partly explains the range of operator UOCs. However, there remains significant scope for cross-learning and further collaboration to continue to reduce costs. Lessons learned from the biggest improvers in the basin are being shared with operators through the OGA's asset stewardship process.

Figure 5: UOC by operator for 2015 and 2016

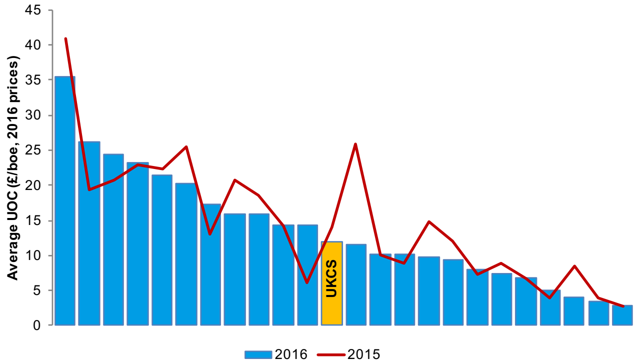


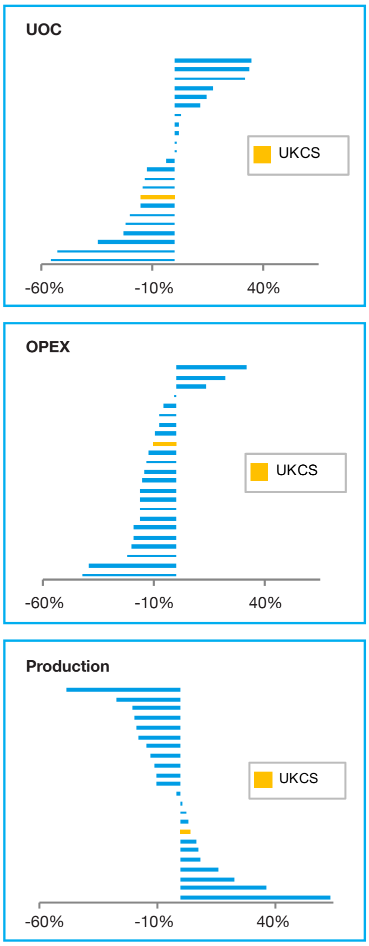
Table 2 shows the diverse mix of companies operating on the UKCS – from majors to national oil companies (NOCs), diversified independents and niche players. This diversity is also reflected in the top performing operators (on a UOC basis) as there is little evidence that the type of operatorship has a significant impact on average unit costs.

Table 2: UKCS top performing operators, 2016

Ranking	Operatorship	UOC (£/boe)
1st	New entrant	<£5/boe
2nd	NOC	<£5/boe
3rd	Major	<£5/boe
4th	Independent	£5/boe - £7/boe
5th	New entrant	£5/boe - £7/boe

Although start-up fields and fields which are ceasing production have been excluded from Figure 6, the charts show significant changes, both positive and negative, in UOC. Extremely low unit costs could be influenced by large changes in production as fields reach peak production. Conversely, a high UOC does not always signify inefficiency as it might highlight a lag between OPEX spend and production. For instance, there is an expected lag between well interventions that require invasive techniques (e.g. workovers on casing, replacing a damaged production tubing) and when the benefits of the work are realised.

Figure 6: UOC/OPEX/production by operator (2015 to 2016 percentage change)



2.2 UOC by area

An analysis of UKCS fields has highlighted that, in 2016, the Central North Sea (CNS) had the lowest UOC in comparison to the other areas in the UKCS.[5] This was driven by a reduction in OPEX which was accompanied by production growth in 2016.

Regional comparisons should be interpreted with caution as there are multiple factors that influence unit operating costs for a geographical region. For instance:

- Many Northern North Sea (NNS) fields are very late life.
- The Southern North Sea (SNS) is experiencing declining production rates, with a high proportion of late life assets.
- The NNS has harsher weather conditions/deeper water depth and consequently bigger/costlier infrastructure.
- The NNS is more likely to have bigger platforms which is reflected in associated OPEX.
- The NNS has more onerous logistical requirements which can drive higher costs.
- The CNS had major improvements made during the CRINE era and has continued to capitalise on savings made then.[6]
- There are regional variations in heavy oil versus gas fields.

Figure 7: UOC/OPEX/production by geographical region (2015 to 2016 percentage change)

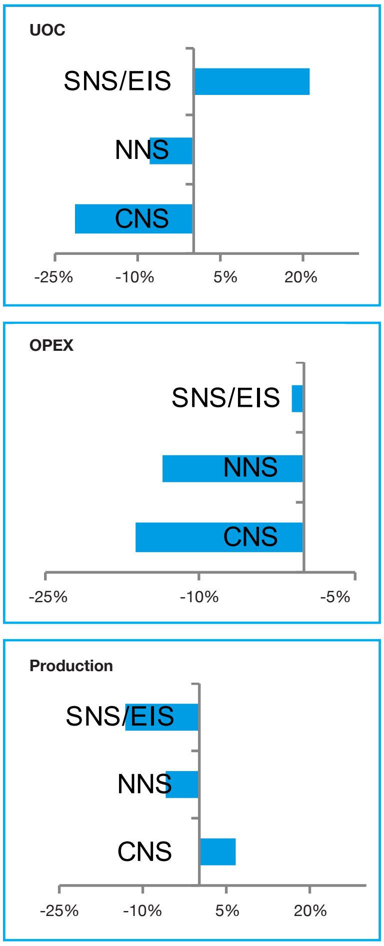


Figure 7 shows annual growth of UOC, production and OPEX by region of the UKCS. It shows unit operating costs decreased in the CNS and NNS, driven by large reductions in OPEX in both regions and a growth in production in the CNS. Note that the CNS is the largest producing region in the North Sea (making up approximately 60% of UKCS oil and gas production) and therefore a given percentage increase in CNS volumes can offset similar or even larger percentage decreases in other areas.

Although the NNS saw a reduction in production in 2016, this was offset by a larger reduction in operating costs. The SNS has been grouped with the East Irish Sea (EIS) due to the small number of EIS fields. This group saw the only increase in average UOC. There was a modest reduction in unit costs in the SNS/EIS which was offset by a large decrease in production reflecting the natural rate of production decline in the region.

[5] Excluding West of Shetland, as a significant proportion of the production in 2016 came from start-up fields.
[6] CRINE is the acronym for an industry initiative known as Cost Reduction in the New Era.

Figures 8 and 9 show the distribution of UOC at field level and illustrate the fact that regional performance can be mixed at field level, with significant variation in UOC observed.

The heat map highlights a positive story for the UKCS as it shows a significant proportion of fields recorded a decrease in unit operating costs between 2015 and 2016. It also highlights a few areas where the UOC has increased and, to this end, the OGA will explore these areas further to determine the drivers of rising UOC.

Figure 8: UKCS UOC percentage change (2015 – 2016)

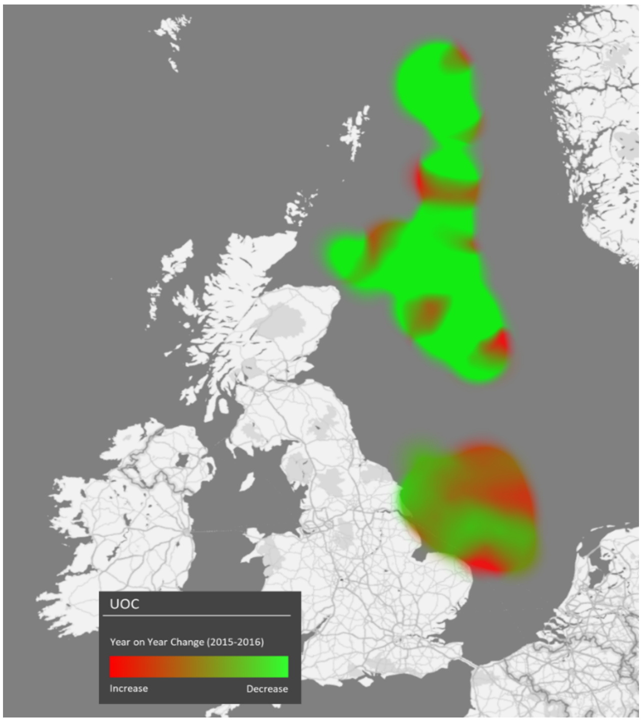
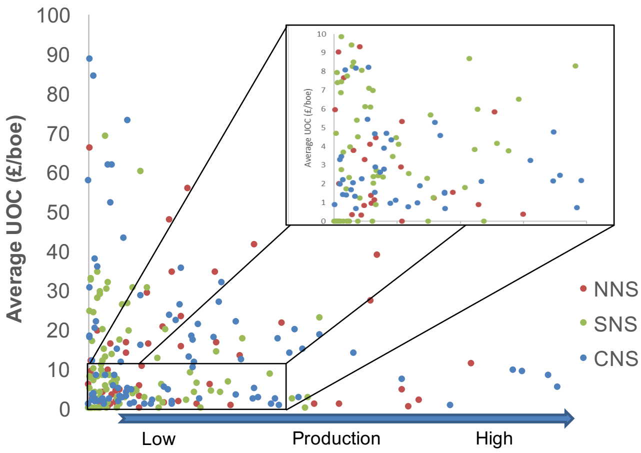


Figure 9 shows the highest UOCs in the UKCS (greater than £45/boe) are mostly found in small producing fields distributed across the basin. While declining production is inevitable for mature assets, a focus on maintaining efficient levels of production is required.

Figure 9: UOC by field (2016)



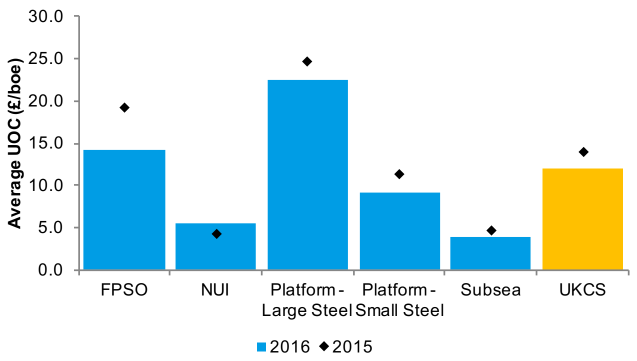
2.3 UOC by facility type

The type of facility used for production activities is driven by a range of factors including:

- Water depth
- Weather
- Well type (i.e. exploration or production)
- Geographical location
- Heat and pressure of the well
- Geology and reservoir make up
- Field design

These factors mean that some facilities will invariably cost more to run due to their underlying structure. However, it is still useful to observe how the costs of facility types have evolved over the past year and how they compare with the UKCS average.

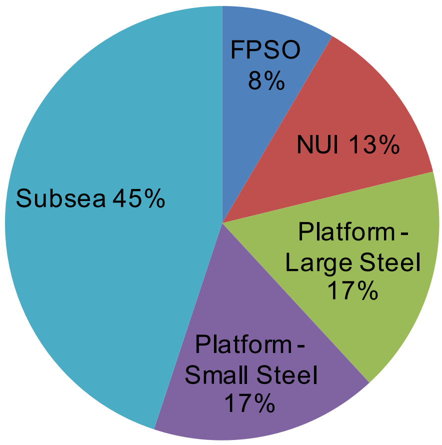
Figure 10: UOC by type of facility



It is useful to bear in mind the production capacity of the different types of facility groups as illustrated in Figure 11. In 2016, small steel platforms and subsea facilities accounted for over 60% of total production in the UKCS.

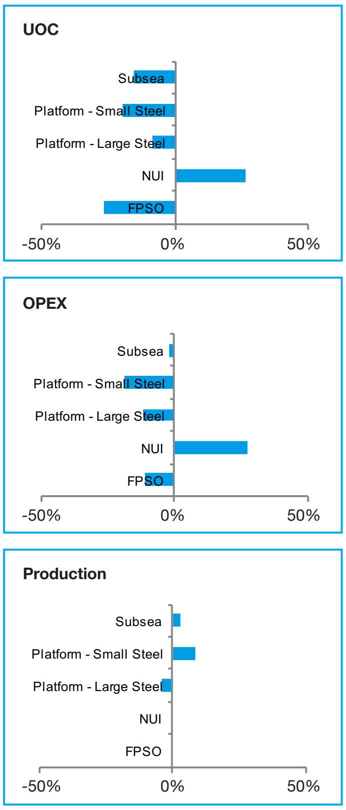
Many fields act as hubs for other (user) fields, recovering some of their operating costs from the user fields through tariff or cost share arrangements. The 2016 survey collected data on operating costs where they were incurred rather than where they eventually ended up through these tariff or cost share arrangements. Consequently, operating costs for hubs (typically, fixed platforms or Floating Production Storage and Offtake 'FPSO' vessels tend to be overstated and, correspondingly, operating costs for user fields (typically, subsea tie-backs) are understated.

Figure 11: UKCS total production volumes (2016) by facility types



The largest annual percentage fall in unit costs between 2015 and 2016 was in FPSOs, where unit costs fell by a quarter in 2016. The unit operating costs of small steel platforms and subsea facilities were lower than the UKCS average, while Normally Unmanned Installations (NUIs) recorded the only growth in unit operating costs among the five broad facility types, with an increase of 26% from 2015 to 2016. This increase in costs for NUIs can, in many instances, be explained by the influence of one-off events such as interventions in NUIs.

Figure 12: 2015-2016 UOC/OPEX/ production by facility type



2.4 UOC by age of platform/COP

To some extent, the older an offshore asset, the more expensive it is to run, due to increased maintenance costs. Furthermore, older fields often have larger facilities which translate to higher running costs. However, this can be offset by efficient practices. For example, if there is infrastructure that can be shared by multiple parties in the area, then the burden of operating costs can be shared. Additionally, the organisational culture of an operator towards efficiency also influences attitudes towards cost management. This therefore means there is no clear-cut relationship between the age of a platform and its UOC. Figure 13 shows that some of the oldest assets in the UKCS have a comparable UOC to newer assets, and that there are some medium aged assets in the North Sea that have a higher UOC than the oldest assets.

There is also evidence that older assets have succeeded in achieving much lower unit costs where there is an economically-driven late life asset strategy.

The changing operator landscape in the UKCS has contributed to fresh investment and a boost in production in mature fields. The renewed focus on late life asset management has also delayed cessation of production (COP) for many fields and consequently contributed to the observed reduction in unit operating costs for some mature fields.

Project lifecycle implications are shown in Figure 14. While it is inevitable that unit costs will increase towards the end of field life, the rate of increase can be mitigated through adequate late life asset management, as observed in some mature fields that remain among the top quartile performers in the UKCS.

Figure 13: Average UOC by Cessation of Production (COP) date

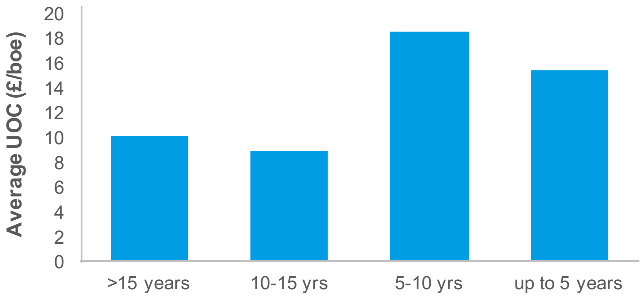
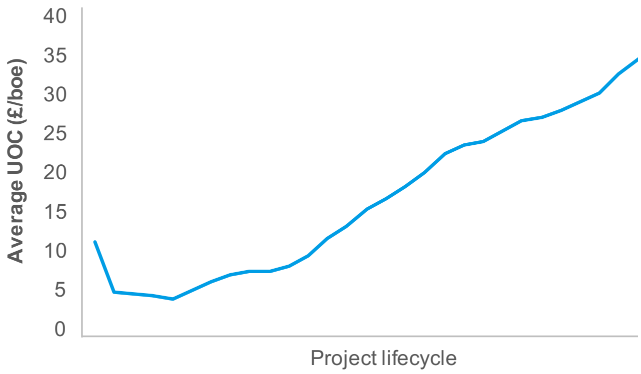


Figure 14: Average UOC over time for an illustrative field



2.5 UOC by production efficiency

The OGA has adopted a data-driven approach to enhanced stewardship and a leading performance indicator is for the UKCS to achieve a target of 80% production efficiency (PE) by 2018.

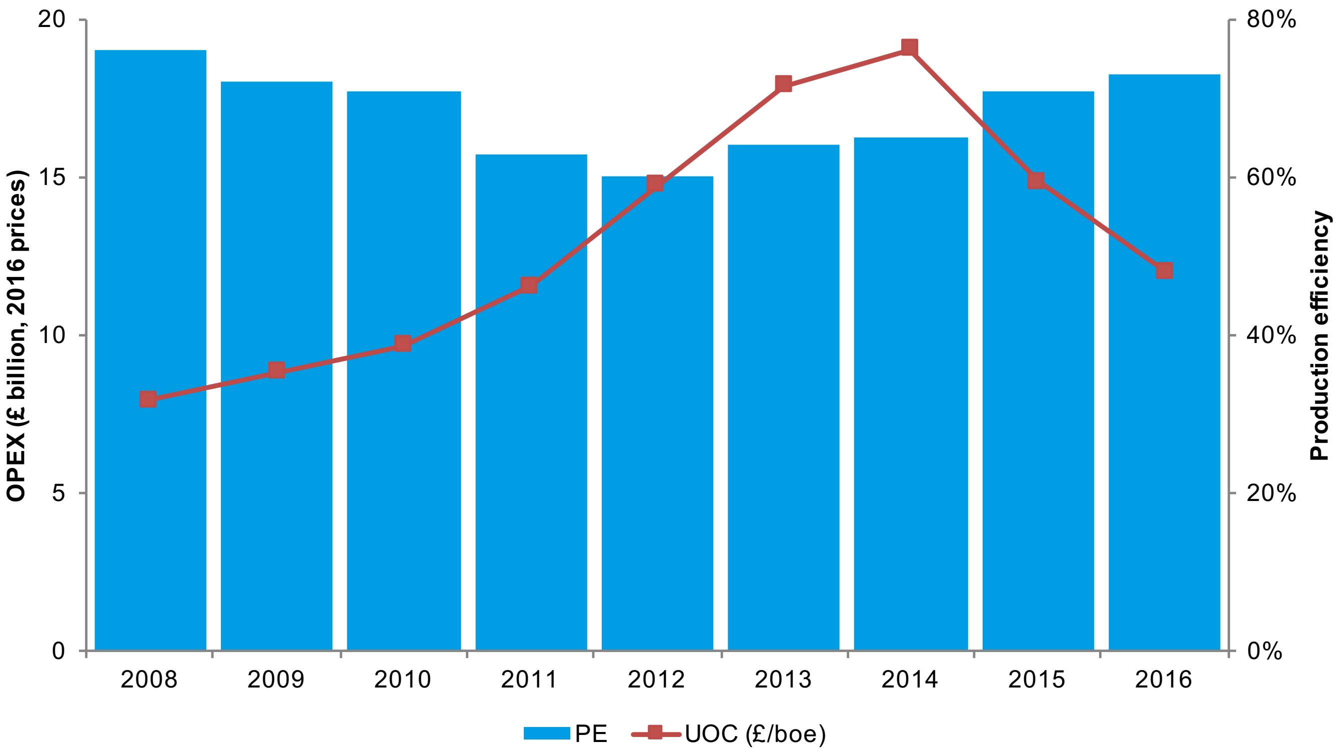
There is an observed inverse relationship between productive efficiency and the unit cost of production i.e. the higher the observed PE, the lower the UOC. The most productive efficient producers on average incur a lower cost of production per barrel. This is demonstrated in Figure 15 which shows that the recent decline in UOC from its 2014 peak which coincides with a steady increase in PE.

When looking at PE at an operator level, the top quartile operators (UOC basis) also have corresponding high PE (average of 84%). The OGA's asset stewardship reviews with operators have highlighted that simple behaviour-led practices to increase productivity in the workplace lead to an increase in production and consequently lower unit costs.

Among the lower quartile operators, there is a small number of operators that have some of the highest unit operating costs in the UKCS despite very high PE (greater than 80%). For these operators, the OGA is working with them to understand cost drivers.

Improvements to PE are expected to translate to lower unit costs for the basin in the long-run. Although increasing PE may sometimes require significant spend (e.g. a compressor upgrade), the corresponding increase in production means that costs are kept manageable on a per barrel basis.

Figure 15: UOC by PE



3. Total OPEX performance

Total OPEX for the UKCS was £7.2 billion in 2016 compared with £8.3 billion the previous year.

Prior to 2014, OPEX was escalating in the UKCS, exacerbated by the low oil price environment that saw over 50% reduction in Brent crude price from its peak of around £70 per barrel between 2011 and 2013, to average just over £30 per barrel in 2016.

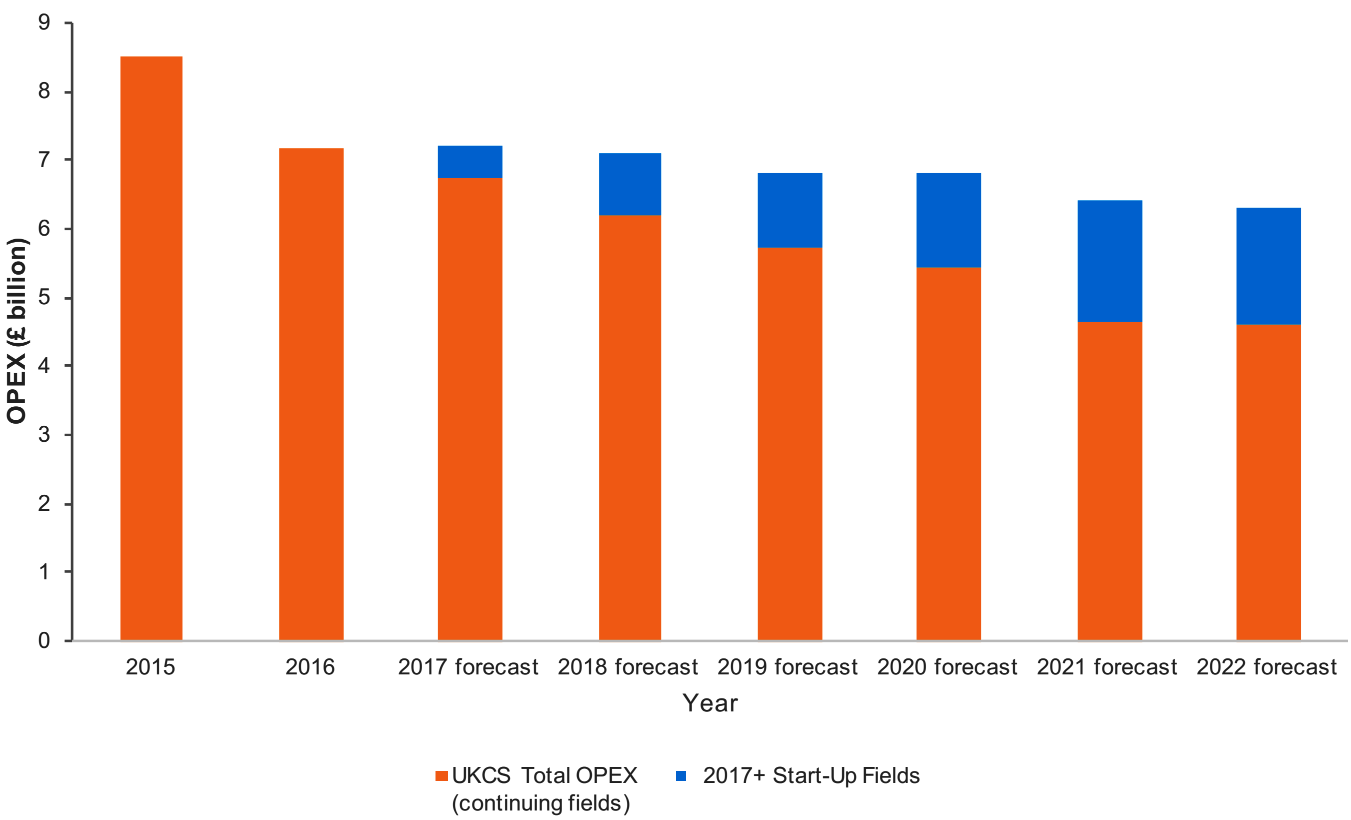
UKCS operators responded to the low oil price environment by pursuing targeted cost reductions, driving down overall operating costs by over 25% (£2.4 billion reduction) between 2014 and 2016.

Reductions have been observed since 2015 as shown in Figure 16 with total OPEX reducing by approximately 14% from 2015 to 2016. Total OPEX is expected to remain relatively constant in the near term to 2022; sustained notably by OPEX relating to 16 new fields coming onstream from 2017 onwards whilst OPEX for existing fields continues to decline albeit more modestly.

The forecast reduction in OPEX from existing fields illustrated in figure 16 includes the impact of a number of fields which are forecast to COP during the period 2017 to 2022. The net reduction in OPEX for continuing fields excluding these COP fields is therefore a more modest downward trend. Figure 17 overleaf illustrates the effect of COP fields on Field OPEX.

The overall OPEX reduction in 2016 was dominated by four operators which achieved 60% of the total reductions in the period, with most others making more modest contributions.

Figure 16: Forecast OPEX, UKCS £ billion



4. UKCS offshore field OPEX

This section of the report provides a more detailed analysis of UKCS offshore fields OPEX which excludes costs relating to onshore fields, subsea fields, offshore pipelines and terminals and therefore enables a more direct comparison of OPEX spend by a range of parameters including facility type and asset location. In 2016 UKCS offshore field OPEX was £5 billion.

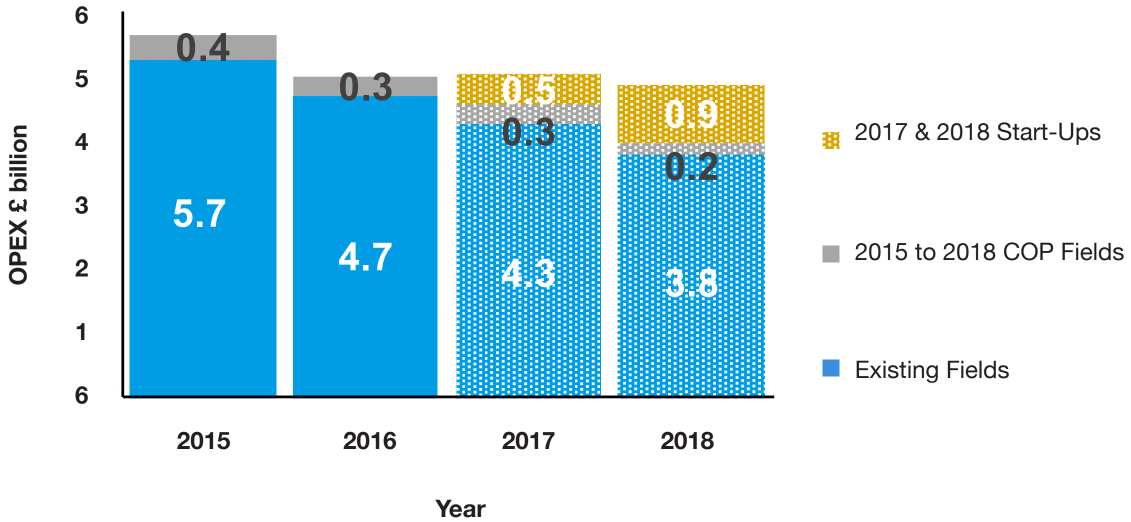
Following the recent fall in oil price, many operators have reviewed core business objectives and operating models, focusing on transformational change such as delivering operational excellence across the production lifecycle, which have significantly improved efficiency and international competitiveness.

Overall, offshore field OPEX fell by 13% from 2015 to 2016. On a like-for-like basis, when excluding the impact of the cessation of production, offshore OPEX is assessed to have fallen by approximately £700 million.

Offshore field OPEX is forecast to remain flat in 2017 and 2018 on a like-for-like basis.

There is significant variation in offshore field OPEX across the UKCS reflecting the diversity of facilities, for example, £0.5 million per annum for some relatively simple subsea tie-back through to £150 million per annum for some complex multi-platform offshore facilities.

Figure 17: Offshore fields OPEX 2015-2018



4.1 Offshore field OPEX by facility type

The wide variation in offshore field OPEX across the UKCS is in part driven by the type of facility located on the field. Figure 18 shows field OPEX for 2016 for manned, unmanned and floating facilities.

Figure 18: Facility analysis of platforms and floating facilities

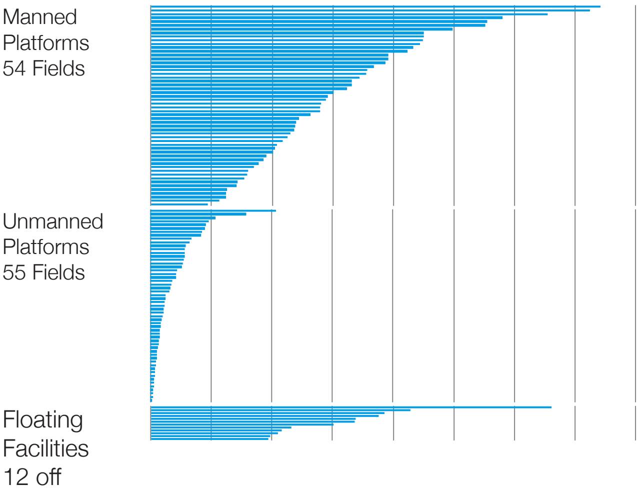
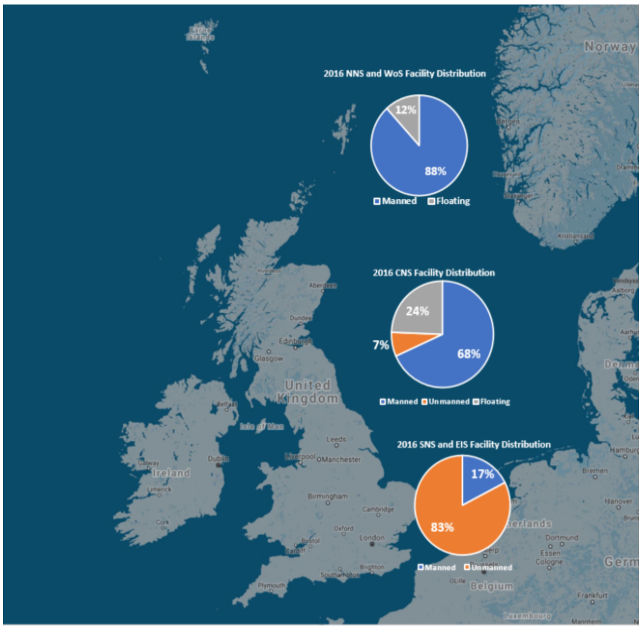


Figure 19 illustrates the location of the different types of facilities in the UKCS.

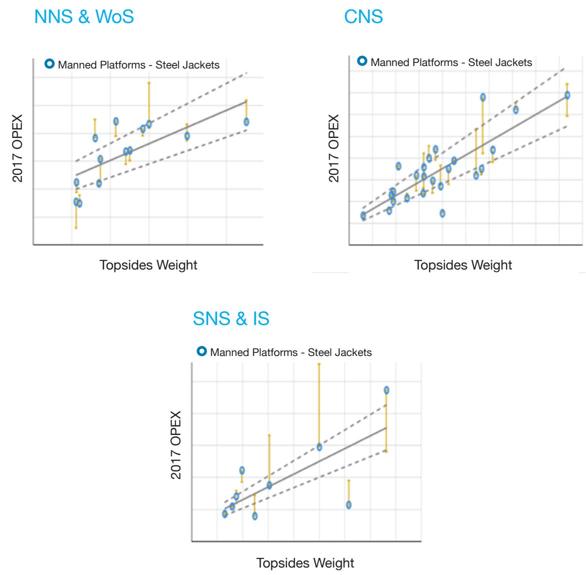
Figure 19: 2016 UKCS asset type location



Manned platforms

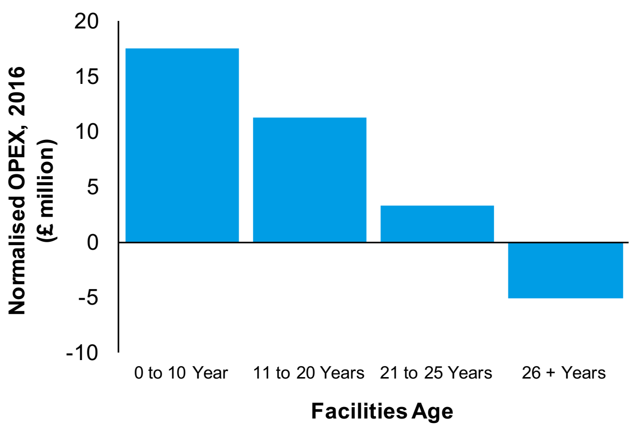
An analysis of manned platforms determined a clear correlation with topside weight and provides the OGA with a reasonable basis for peer group comparisons as part of the stewardship review process.

Figure 20: Manned platform OPEX vs. topsides weight



Analysis was also conducted on the age of manned facilities in relation to field OPEX. Newer manned platforms report higher OPEX than older platforms due to value-adding activities such a well work or plant reliability. Figure 21 shows that, whilst this is the case for newer platforms, older platforms attract less discretionary OPEX as they approach COP. This includes the optimisation of maintenance spend ahead of the expected end of operating life.

Figure 21: Ageing impact

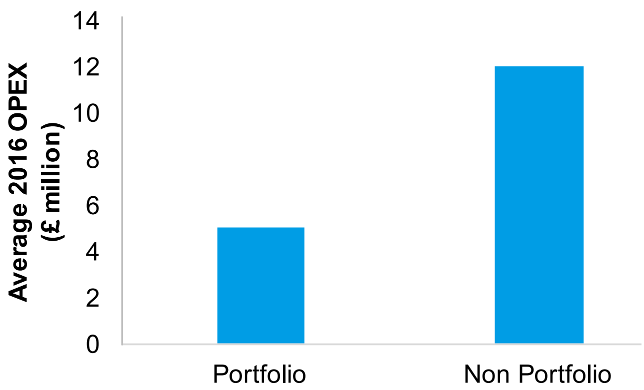


Unmanned platforms

NUIs reported offshore field OPEX ranging from less than £1 million to £40 million in 2016. Unlike manned platforms, there is limited correlation between topsides weight and OPEX.

There is, however, strong evidence to suggest that greater cost efficiencies for operators with increased numbers of unmanned platforms may be achieved. The ability to operate an unmanned platform as part of a portfolio allows materially reduced OPEX. There may also be further scope for collaboration on cross company portfolios to reduce OPEX.

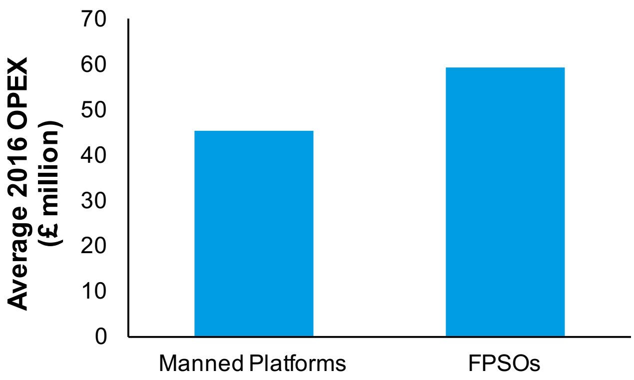
Figure 22: Operating cost NUIs – portfolio vs non-portfolio assets



Floating facilities

A comparison of the average OPEX for both manned platforms and floating facilities of similar liquids processing capacity (~110kbbl/d) shows that manned platforms on average cost 33% less to operate than the equivalent floating facility (Figure 23).

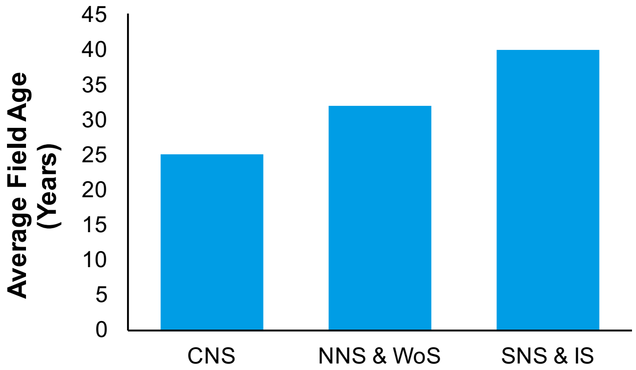
Figure 23: Facility analysis – floating facilities



4.2 Offshore field OPEX by area

There is significant variation in field OPEX across the UKCS. Similarly, the distribution of asset type varies across the UKCS locations as illustrated in Figure 19. This distribution will continue to vary as new developments are commissioned and older facilities decommissioned.

Figure 24: Area analysis



On average, assets in the CNS have the highest OPEX whilst those in the SNS and EIS have the lowest OPEX as shown in Figure 24. The CNS had lower floating facilities OPEX spend compared to the NNS and West of Shetland (WOS).

Differences between the three categories may be accounted for by several factors:

- Differences in processing complexity, with increased complexity associated with gas condensate platforms in the CNS and reservoir support common across the NNS & WoS and CNS.
- A prevalence of CRINE facilities in the CNS, where capital expenditure (CAPEX) was aggressively targeted, with subsequent impact on OPEX profiles.
- Relative age and maturity of facilities, with CNS manned platforms on average seven years younger than those in the NNS & WoS and 15 years younger than those in the SNS & EIS.
- Differences in logistics requirements, with shorter travelling distances common in the SNS & EIS and the NNS & WoS often accessed by fixed wing and subsequent helicopter travel.

5. Benchmarking field OPEX

The lower oil price environment has stimulated reductions in OPEX and UOC as operators have adjusted to the new operational and commercial environment. The 2016 survey shows a reduction in total OPEX in 2016, however, this is forecast to increase by a small amount in 2017 with that higher level maintained into 2018.

It is, therefore, important that operators collaborate and learn from others that are attaining significant cost reductions, while being mindful that overly-aggressive cost reductions in the short-term can result in cost increases and exposure in the medium to long term. For instance, headcount reduction, while offering immediate OPEX reduction, is not often a long-term solution to managing costs.

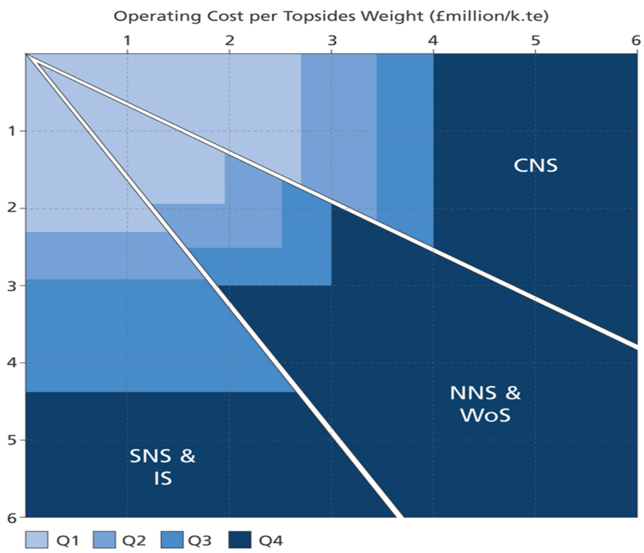
As part of this report, the OGA has undertaken and performed a quartile analysis which will be used as part of the asset stewardship process and operator engagement to assess operator performance in relation to peer groups.

The approach has been developed by assessing operating costs across the UKCS normalised for topsides weight and geographical location.[7]

Representative peer groups for each facility type and location may be used to highlight potential opportunities relative to other operators.

Operators will be able to identify how they perform in comparison to others by calculating their OPEX (£ million) per Topsides Weight (kte) for each manned platform as shown in Figure 25. Based on the location of the facility, the cost per tonne identifies which performance quartile they reside in. Quartile 1 (Q1) has the lowest OPEX per topsides weight and quartile 4 (Q4) the highest.

Figure 25: Manned platforms: cost per tonne (£MM/kte), quartile performance by location



[7] The appendix provides more detail into how the cost benchmarking tool was derived.

6. Insights

Creating a more sustainable cost base for the UKCS will enable industry to withstand future oil price fluctuations and be more profitable in periods of stability and growth. The OGA is keen to learn of successful cost reduction initiatives and is encouraging the sharing of best practice.

Table 3 shows a selection of insights shared during the 2017 tier 1 asset stewardship process. It provides evidence of the introduction of cost reduction initiatives, shows more effective contract management with the supply chain and reinforces industry's progress towards achieving MER UK.

A further selection of success stories and case studies on MER UK in practice can be found on the OGA website.

Table 3: Insights from OGA tier 1 asset stewardship process

Targeted Cost Reduction Campaigns and improvements	Cross Learning Opportunities and Collaboration	Innovative Technology and Techniques	Late Life Asset Management Strategies	Risk Management and process improvements
Reduction in cost of helicopter and vessel transport through sharing Reducing TARs from every year to once every 3 or potentially 5 years Clear understanding from offshore workforce of requirement to improve efficiency reinforced by regular senior management visits	Collaborative thinking utilising scale on well inventories Collaborative salt management approaches	Use of technology in data transmission, failure diagnostics, sensors, drones (outside), robots (inside) and non-intrusive inspection Shared learnings on hot-tapping technologies	Facilities management and asset life extension increasing returns Well abandonment cooperation programmes	Reducing cost of services by renegotiating costs and innovative contracting strategies Improved planning of offshore operations e.g. preventative maintenance and restructured onshore teams Key roles such as OIM classed highly competent with period of onshore working

7. Next steps

The UKCS outlook from 2017 onwards is for OPEX to remain relatively flat, suggesting a requirement for industry to continue to focus on sustainable improvements, through productivity and efficiency.

Sustainable improvements could come from several methods, including:

- Continuous improvement in production efficiency whilst maintaining high standards of health, safety and environmental management.
- Continued industry focus on improving the efficiency of business and operational processes, and the introduction and widespread adoption of simplified standards across the basin, drawing on the output of industry led collaboration such as the Oil & Gas UK Efficiency Task Force.
- Further consolidation of assets and infrastructure across the UKCS, consistent with the OGA's promotion and enabling of the right assets in the right hands.
- The MER UK Technology Leadership Board and the Oil & Gas Technology Centre (OGTC) working closely to support the development and deployment of technologies which can deliver further operational cost efficiencies.

As a mature basin which requires effective late life asset management strategies, the UKCS must continue to maximise the economic recovery of its oil and gas resources.

UOC is an integral component of the profitability of fields and to a large extent can influence COP dates. It is therefore important that unit costs are kept under control as part of an economically driven late life asset strategy.

The OGA is continuing to use OPEX and UOC benchmarking as part of the UKCS Stewardship Survey to support industry's efficiency improvement efforts.

Vision 2035, developed with industry and government, indicates a considerable prize of nearly £140 billion of additional revenue from UKCS oil and gas production. Achieving this vision requires, in part, a continued focus on cost management and promoting behaviours that support MER UK.[8]

[8] For further information visit our website https://www.ogauthority.co.uk/about-us/vision-2035/

Methodology Notes

Definitions

1. OPEX assessments:

    1.1. For the purposes of this report, total OPEX is based on the total cost incurred by offshore facilities, onshore terminals and trunk pipelines as reported in the 2016 survey.

    1.2. Costs for 2015 and 2016 were reported in nominal terms with costs for later years reported in constant 2016 prices.

    1.3. The assessment of OPEX at field level specifically excludes OPEX tariffs paid to third parties for transportation and processing, and the costs of onshore terminals and major offshore trunk pipelines. At the UKCS level, tariff payments and receipts and cost share payments and receipts are all included as they cancel each other out.

    1.4. Total OPEX as presented in section 3 is an aggregated measure of operating costs for the UKCS and includes field OPEX, pipelines & terminals OPEX and shared costs.

    1.5. The analysis in sections 4 is based on offshore field level OPEX and consequently does not include subsea fields, offshore pipelines or shared costs. Field level OPEX is further broken down by asset type, geographical location and asset age.

2. Unit operating costs (UOC):

    2.1. Unit operating costs are calculated as the sum of operating costs divided by the number of barrels of oil equivalent produced.

    2.2. In this report, production volumes refer to a combination of crude oil, natural gas liquids and gas, added arithmetically to provide an oil-equivalent volume. Gas volumes are converted to oil equivalent using an industry gas conversion factor where 5.8 thousand standard cubic feet of gas (mscf) equals one barrel of oil equivalent.

    2.3. UOC is presented in this report in pounds sterling as the 2016 survey is conducted in the domestic currency.

3. Life extension projects typically associated with ageing infrastructure, including flotel campaigns, are excluded from this analysis. Furthermore, such activities are more likely to be categorised as capital expenditure.

4. The OPEX benchmarking tool (section 5) was developed looking at the OPEX of manned platforms across the UKCS. The following parameters were tested as part of the correlative analysis:

    - fluid type;
    - location;
    - water depth;
    - operator;
    - installation age;
    - number of tie-backs.

    Topsides weight was determined to be the strongest correlative index, (with a correlation coefficient of 0.7 for NNS & WoS, 0.8 for CNS and 0.7 for SNS and EIS facilities), and therefore a reasonable basis for peer group comparisons.

    Benchmarking was performed for manned platforms by assessing the operating costs normalised for topsides weight.

    Quartile performance ranges were derived for all manned platforms and show that top quartile performance is demonstrated by an OPEX of ≤£2.5 million per kte of topsides weight.

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