



Oil & Gas
Authority

UKCS Operating Costs in 2017

September 2018



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Cover page image: The North Promise Offshore Supply Vessel, returning to Aberdeen harbour from the Everest field – photo courtesy of Jamie Vince

Executive Summary

UKCS level operating expenditure (OPEX) and the average unit operating cost per barrel of oil equivalent (UOC), both rose marginally (+2%) in 2017 to £6.9 billion and £11.6/boe respectively¹, according to the Oil and Gas Authority's (OGA) annual UKCS Stewardship Survey.

In 2017, an additional £130 million was spent on UKCS oil and gas operations compared to the previous year, an increase of approximately two per cent. Due to oil and gas production remaining flat from 2016-2017 (at 1.63 million boe/day) the resulting average UKCS unit operating cost grew slightly by £0.3/boe to £11.6/boe.

Gross operating costs for offshore fields grew slightly by 2%, whereas those for pipelines and terminals fell 20% and 11% respectively. Out of these three kinds of infrastructure, fields comprise nearly 90% of total costs incurred spent operating the UKCS as a whole.

On an operator basis, over half of the companies surveyed saw a reduction in their total field OPEX from 2016 to 2017. Whilst the majority saw a rise in their unit operating cost, this was primarily driven by a fall in production, rather than an inflation of operating costs.

The relative stabilisation of UOC is an encouraging sign, at a time when the oil price is rallying and operating costs may also have been expected to increase. This trend is expected to continue with projections showing only a marginal rise in UOC into the early 2020s.

Evidence suggests that a proportion of costs incurred from 2016-2017 are having direct impacts on improved long term asset integrity, which will in turn, have a beneficial effect on future operating costs.



UKCS Total OPEX

£6.9 billion
+ £120 million from previous year
28% lower than the 2014 high



UKCS UOC

£11.6/boe | \$15.0/boe
+ £0.3/boe | - \$0.4/boe
37% | 51% lower than 2014 high



Offshore Field OPEX

£5.9 billion
5% increase from 2016
Downward trend post 2018

¹ This is on a nominal basis. Note that in real terms, OPEX and UOC remained flat in 2017.

1. Introduction

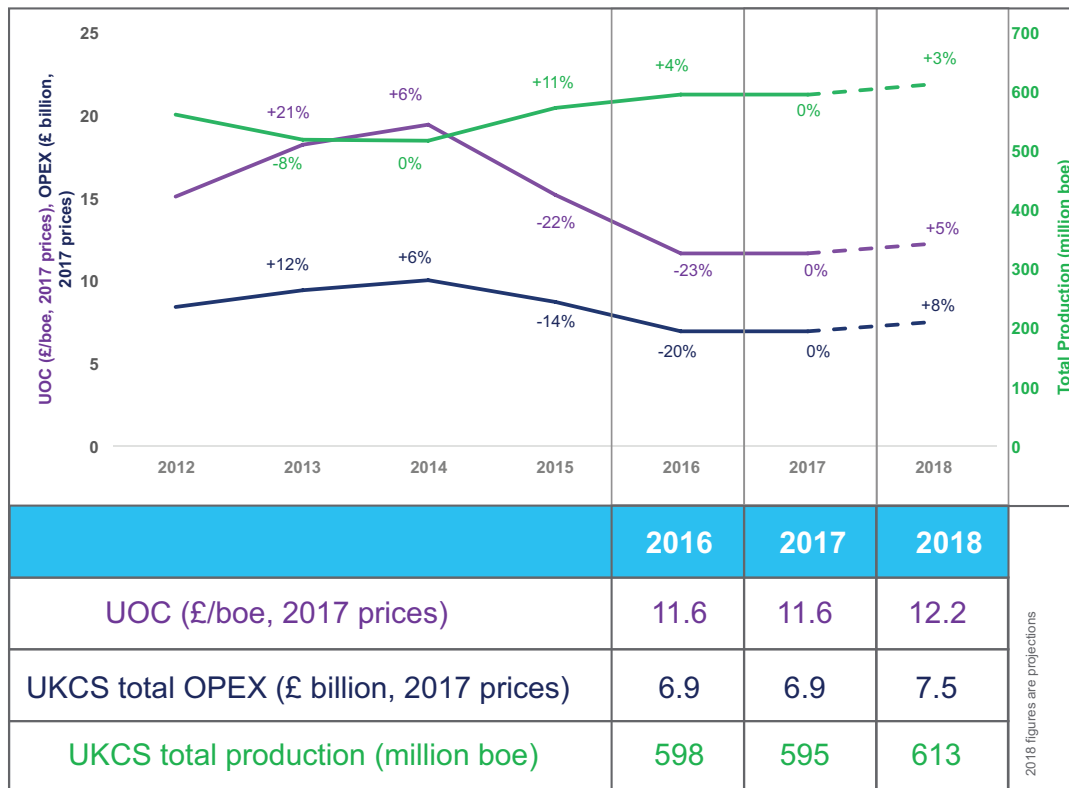
Since the high cost operating environment of 2014, OPEX has fallen significantly. This, coupled with the marked increase in production has led to a drop in unit operating costs of over £7.5/boe (real terms, 2017 prices).

Figure 1 (overleaf) highlights the recent rise of production on the UKCS, alongside the combined fall in OPEX and UOC.

Looking to the future, production is expected to rise in 2018. If this is the case, it will be the fifth consecutive year without a significant drop in oil and gas production. Operating costs are also anticipated to rise but at a slighter greater rate. This is partly due to new costs created by the recent start up fields which are causing the growth in production. As a result nominal UOC is projected to rise by 80 pence a barrel, from £11.6/boe in 2017 to £12.4/boe in 2018.

This report will focus on three main distinctions of operating costs. Firstly, total UKCS OPEX as represented in Figure 1 (blue), then direct costs associated with operating offshore fields, then finally, a commentary on the unit operating cost per barrel of those fields. Following on from this, benchmarking metrics and further insights will be explored.

Figure 1. UKCS UOC, production and OPEX



2. Total UKCS Operating Costs

Total OPEX for the UKCS was £6.9 billion in 2017, £120 million and 2% higher than the previous year. OPEX for offshore fields made up 89% of the gross total, with the remainder comprised of facilities and pipelines OPEX.

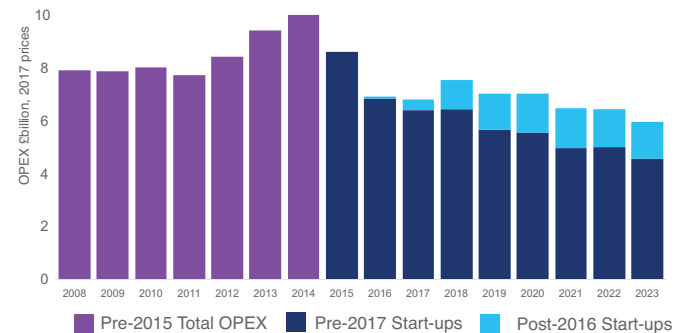
Following a sharp fall in UKCS OPEX from 2014-2016, total OPEX from 2017 onwards is now projected to be relatively flat, (aside from an isolated increase in 2018), indicating that the recent period of pronounced cost reduction may be over. Across the UKCS around 45% of operators are still recording modest reductions in total OPEX. However, this is offset by (on average) larger increases from 55% of operators leading to a slight net increase in the near term future profile. This will be further explored in section 4.2.

Following 2018, total OPEX is expected to fall at an average rate of 4% per annum to 2023. This decline is lessened by costs to over 30 new projects coming onstream from 2017 onwards*. It is estimated that these new projects will comprise 14% of the total UKCS OPEX to be incurred from 2017 to 2023. It is worth noting that production from these projects is estimated to be just over one billion barrels of

oil equivalent over the same time span (around 29% of the UKCS total), highlighting the cost efficiency and relative size of modern developments. This forecast in reduction of OPEX from existing fields, and the supplementation by new fields/ projects is illustrated in Figure 2.

OPEX in the UKCS continues to be dominated by six main operators, which comprise approximately half of OPEX spend in both 2016 and 2017 (out of 31 operators with operating costs in these years).

Figure 2. Historic and projected UKCS OPEX



*New/ redeveloped fields estimated to start production from 2017-2023 that have sanctioned OPEX profiles in 2017 Stewardship Survey.

Figure 3. Composition of 2017 UKCS OPEX

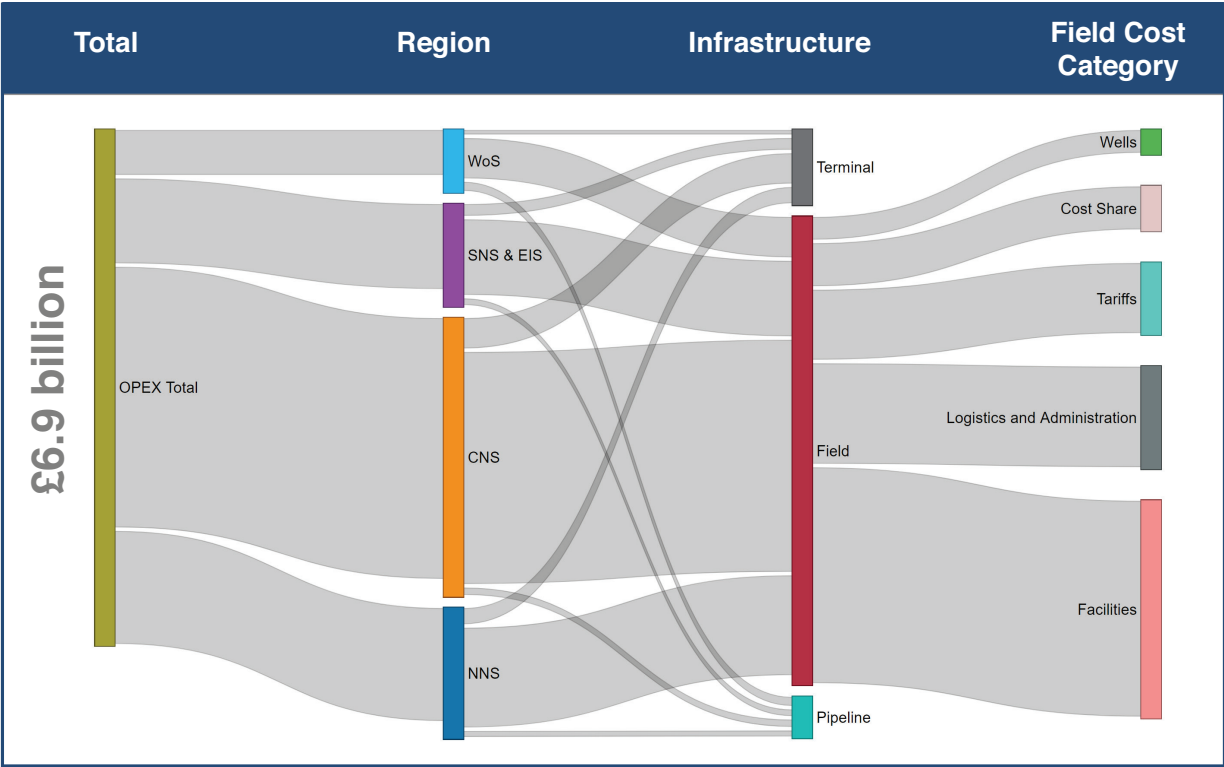


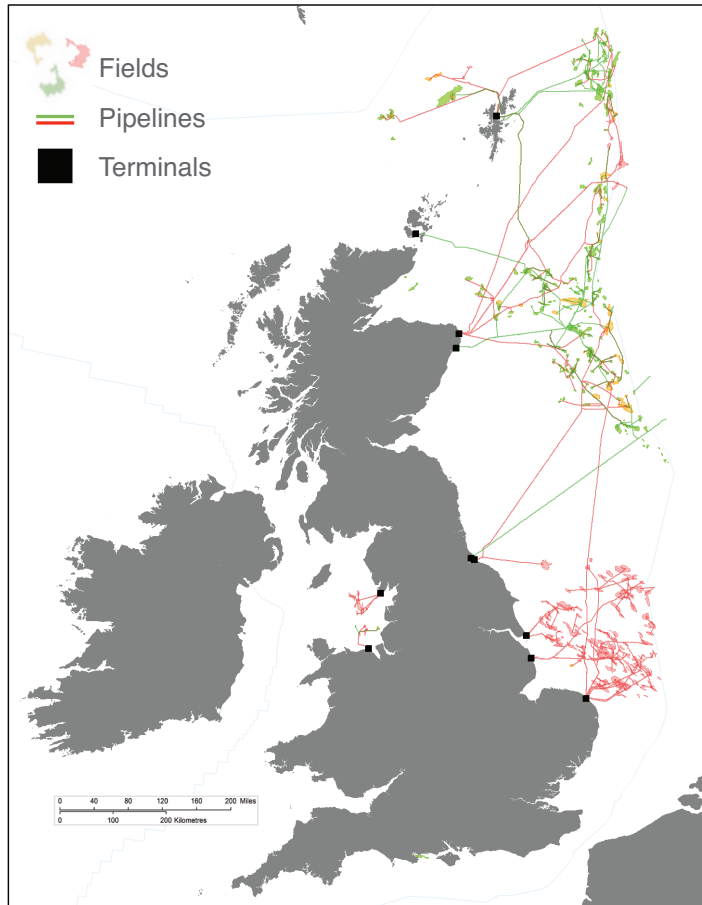
Figure 3 depicts the composition of total UKCS operating costs, incorporating divisions by geography, infrastructure and activity cost allocation. The majority of costs are concentrated in Central North Sea (CNS) fields. The CNS also comprises the majority of terminal costs, however pipeline costs are fairly equally divided between each of the four geographic sectors.

2.1 Total OPEX by Infrastructure Category

As shown in Figure 3 (previous page), UKCS OPEX data is collected within three distinct infrastructure categories: Field OPEX (subsurface, subsea and/or topsides operating costs), Pipeline OPEX (trunk lines) and Terminal (onshore receiving) OPEX. Figure 4 shows the geographic distribution of the pipelines and terminals surveyed.

As previously stated, in 2017 operating expenditure linked to offshore fields comprised the majority of costs, at 89% of the total. Pipelines made up 9% and terminals the remaining 2%. As well as incurring costs, fields can generate income through tariff income and cost share payments. This is the same for pipelines and terminals, which together made up 72% of all the tariff/ cost-share income generated on the UKCS. When this operating income is taken away from the gross costs we establish the net costs. For 2017, the total UKCS OPEX figure of £6.9 billion highlighted in this report, is the net number, with the total gross cost being over £300 million higher.

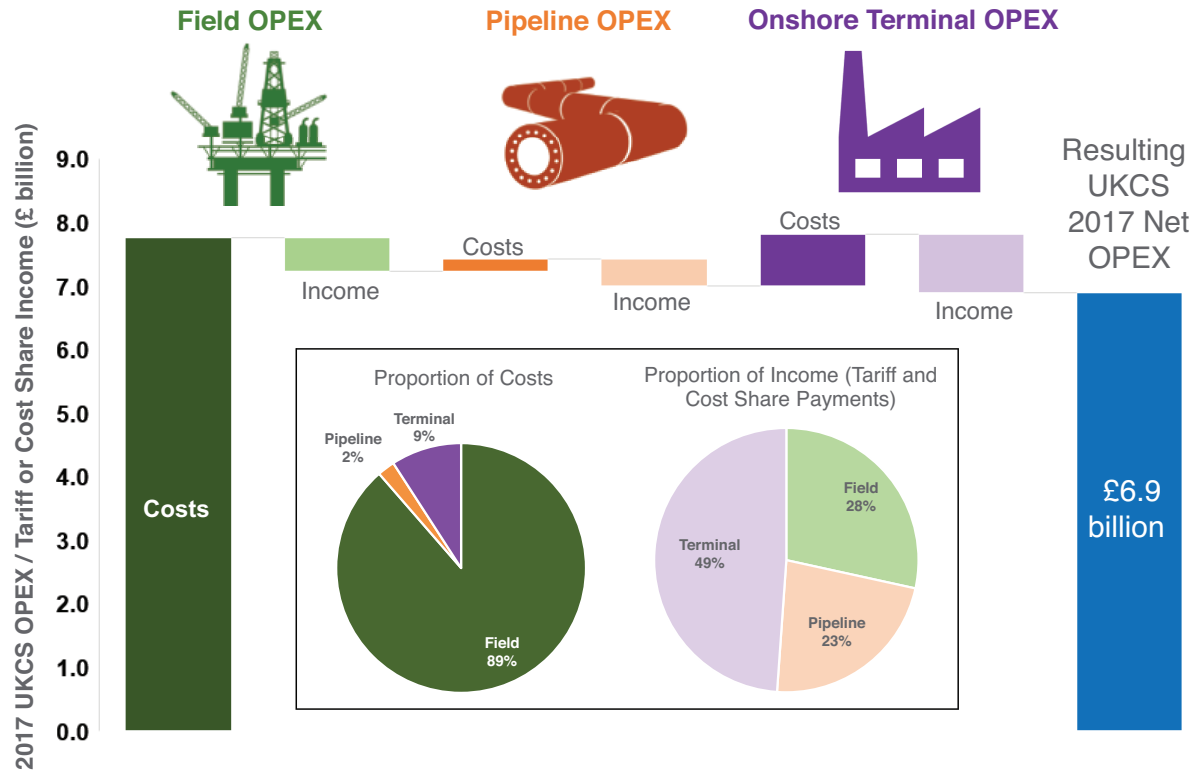
In the 2017 UKCS Stewardship Survey, 15 pipeline systems were surveyed. The total cost to operate these was £118 million, an average of £7.9 million per pipeline system. Gas pipelines were on average slightly cheaper to operate than oil pipelines at £7.3 million and £9.5 million respectively per pipeline. Taking into consideration the size of the pipeline network enables benchmarking between systems. The 2017 UKCS average cost per km of pipeline is £39,000. The range is considerable, from just under £3,000/km to over £100,000/km.

Figure 4. UKCS infrastructure

The 2017 total net operating cost associated with onshore receiving terminals was £748 million. Oil terminals accounted for two thirds of this total at £494 million, whilst gas terminals (the other 34%) costed £254 million.

Total incomes from tariffs, cost-share and transportation and processing services for both terminals and pipelines were higher than their respective costs, resulting in -£210 million OPEX for pipelines and -£100 million for terminals. See Figure 5 for a breakdown of 2017 costs and incomes for pipelines, terminals and fields.

Figure 5. UKCS infrastructure income and costs in 2017



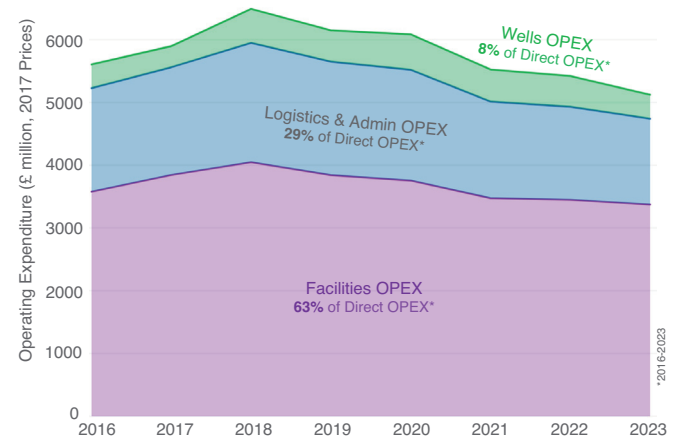
3. UKCS Field OPEX

This chapter focuses on the largest tranche of UKCS OPEX that associated with operating offshore fields. The amount spent on direct field OPEX² in 2017 was £5.9 billion.

Overall, direct field OPEX increased 5% from 2016 to 2017. Facilities and logistics & administration (L&A) OPEX both rose by 7% and 4% respectively, whilst wells OPEX fell by 11%. Going forward, all three categories are projected to grow in 2018 with wells OPEX seeing a 61% increase. Following 2018, the trend is projected to be downwards. Without OPEX attributed to new (post 2016 start-up) fields, direct OPEX would be expected to fall by third from 2018 to 2023. Costs on these new fields limit the decrease to 21%.

As shown in Figure 6, direct OPEX is set to peak in 2018 primarily due to new OPEX created for new fields, rather than costs inflating in older fields. This mirrors the picture seen for overall OPEX (Figure 2).

Figure 6. Direct Field OPEX by Cost Category (2016-2023)



In order to understand the drivers of OPEX for a UKCS field, three variables will be investigated:

- Facility type
- Field age
- Region

² Direct OPEX is defined as the sum of Wells, Facilities and Logistics & Administration (L&A) OPEX. Excludes tariffs and cost share payments.

Figure 7. Facility type makeup and 2017 OPEX by area

3.1 Offshore Field OPEX by Facility Type

On the UKCS, hydrocarbons are produced via a range of facility or infrastructure types. The most common field facility type is a subsea tieback (SST). These SSTs are then usually connected to an adjacent platform which can either be manned or unmanned and come in a range of sizes. Excluding extended reach drilling (ERD) field developments, the remaining infrastructure types on the UKCS are FPSO (Floating Production Storage and Offloading) vessels and FPS/FPV (Floating Production Systems/ Vessels).

The relevant abundance of these facilities and their respective proportional costs across the UKCS is shown in Figure 7. SSTs are the most common type of development in the West of Shetland (WoS), Northern North Sea (NNS) and CNS whilst the Southern North Sea and East Irish Sea (SNS & EIS) favour small steel manned platforms. The cost efficiency of SSTs is apparent throughout the UKCS. Basin wide, subsea tiebacks make up half of the infrastructure, but only 14% of the operating costs in 2017. The opposite is the case for heavy steel platforms, which in each area comprise a lower proportion of the total infrastructure than of the total costs. In the NNS they make up a fifth of the infrastructure but nearly two-thirds of the costs.

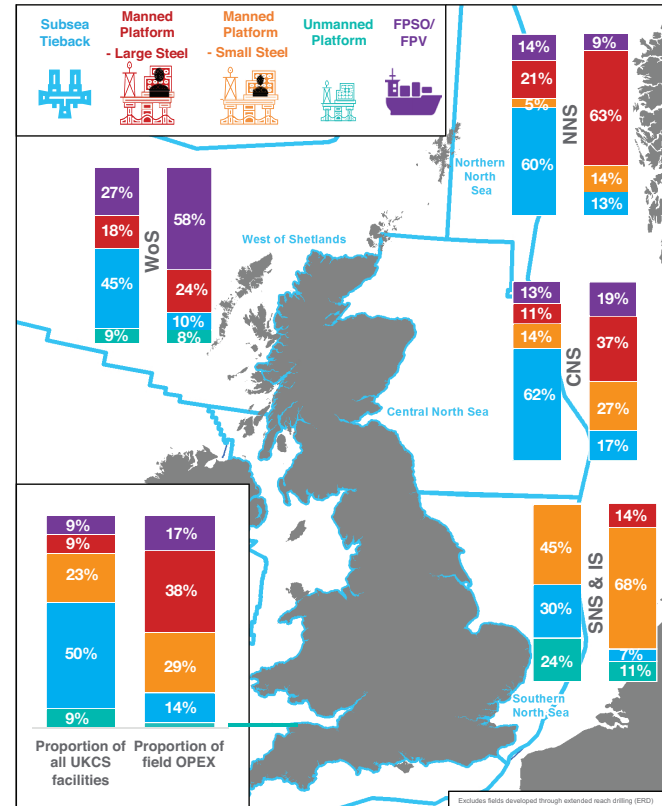
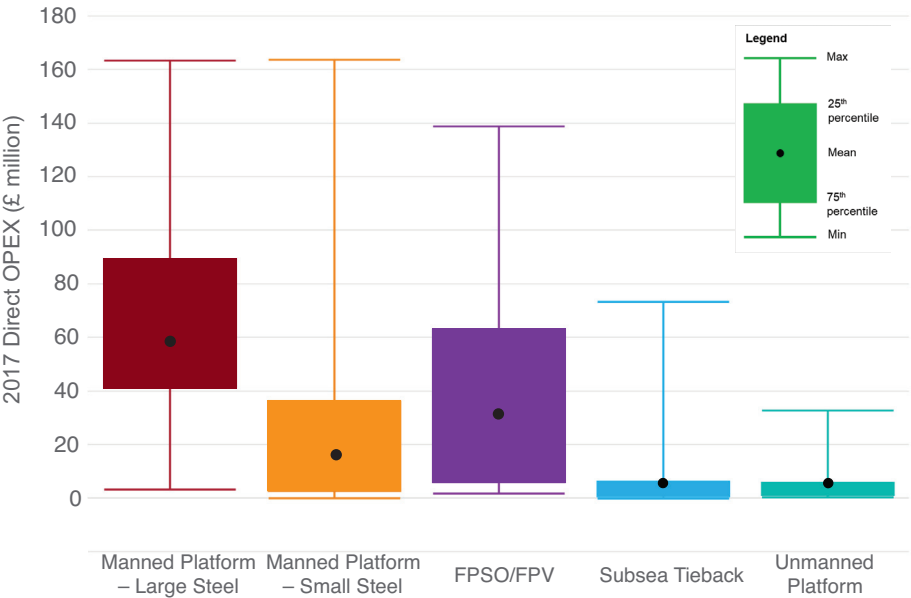


Figure 8. Direct OPEX distribution of UKCS facility types in 2017



There is a significant range in operating costs across the different facility types. In 2017, SSTs and unmanned platforms were the cheapest to operate at an average of £4 million/ year. Small steel manned platforms are the next cheapest at around £18 million/ year, then FPSO/ FPVs

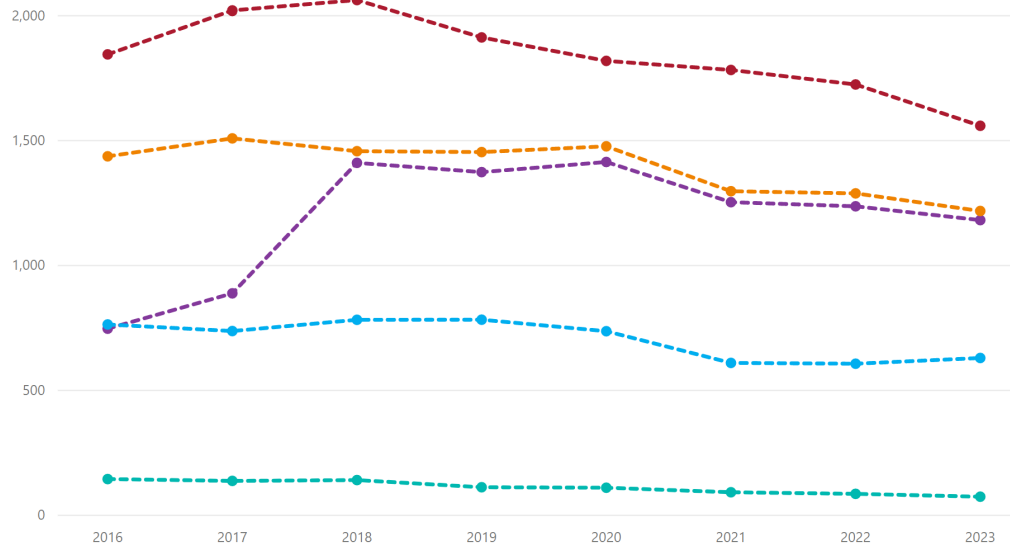
(£30 million/ year), and then large steel manned platforms at over £50 million/ year.

Within each category there is a considerable spread (Figure 8), highlighting the non-uniformity of costs on the UKCS, even for fields of a similar development type.

Figure 9. Estimated direct OPEX of UKCS facilities from 2016-2023

Direct OPEX (£MM) by Year and Infrastructure Type

Infrastructure Type ● FPSO/FPV ● Manned Platform - Large Steel ● Manned Platform - Small Steel ● Subsea Tieback ● Unmanned Platform



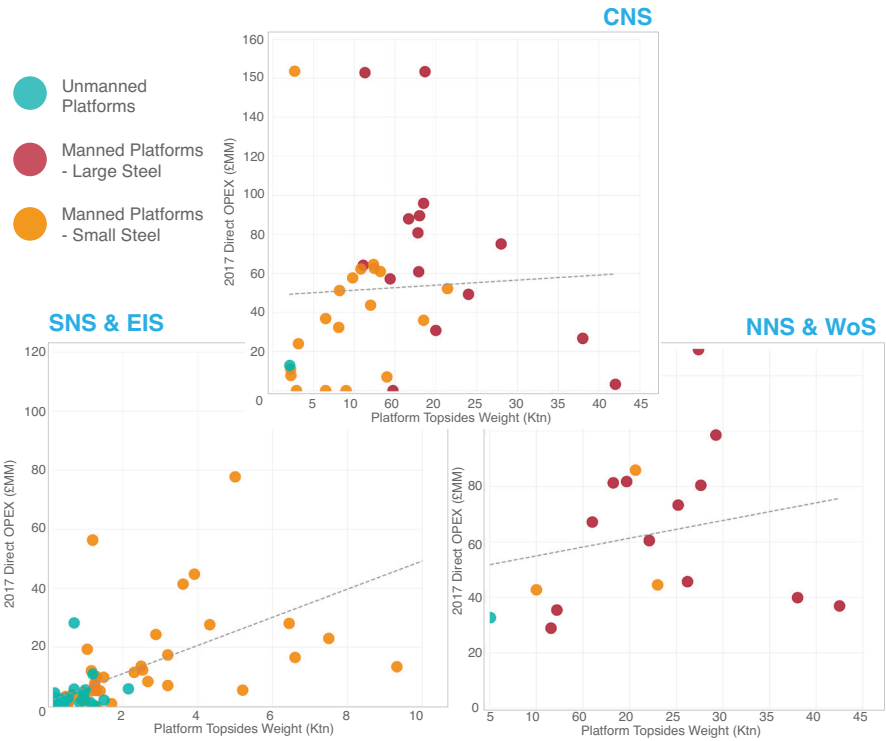
The current ranking of total costs by facility type is anticipated to remain uniform from 2017 to 2023 (Figure 9). Except for FPSO/FPVs, total costs for each facility type are expected to decrease over this time period, with short term increases expected for large manned platforms, small

manned platforms and subsea tiebacks. The significant rise in OPEX for FPSO/FPVs from 2017 to 2018 is primarily due to costs associated with recent floating installation developments, however, pre-existing fields using floating facilities have also seen increases in OPEX from 2016-2017.

3.1.1 Fixed Platforms

An analysis into the 2017 direct OPEX and topsides weight of platforms reveals a positive correlation. As Figure 10 shows this especially clear in the SNS & EIS due to their make up of small manned and unmanned platforms, which both exhibit stronger cost-tonnage correlations than large manned platforms (see Manned Platform – Large Steel distribution for NNS & WoS and CNS). These data provide the industry with a basis for peer group cost benchmarking comparisons which be used as part of the OGA’s stewardship review process.

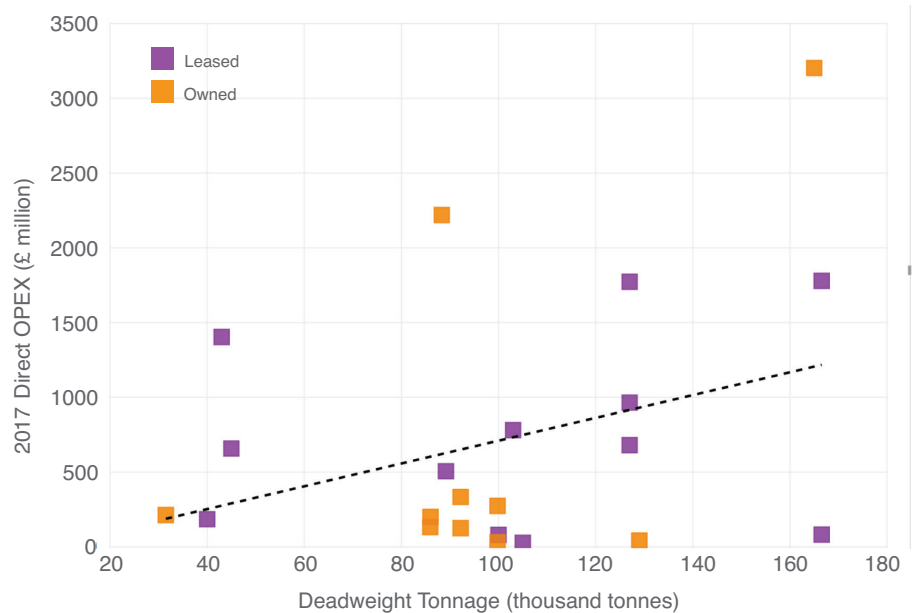
Figure 10. Manned platform 2017 OPEX vs topsides weight



3.1.2 Floating Facilities

With regard to floating installations, a proxy which can be used to indicate size of a facility is the vessel's deadweight tonnage (DWT) - a measure of a ship's carrying capacity. Comparison of direct OPEX and floating installation DWT shows a positive correlation (Figure 11). Categorising floating facilities by their ownership status reveals those which are owned by the operator are generally cheaper to run than those on lease, with a couple of outliers. Note that for 2017 there is actually a negative correlation, however this is due to several large FPSOs still being in the lower operating cost pre-production phase. Once these come onstream, the overall correlation becomes positive.

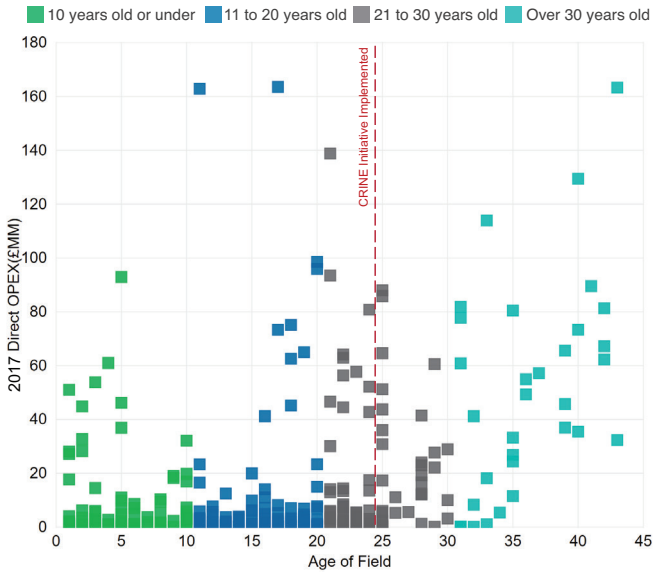
Figure 11. Floating facility total OPEX vs deadweight tonnage



3.2 Offshore Field OPEX by Field Age

As illustrated in Figure 12, the age of a facility has a marked impact on its operating costs in 2017. Older fields are much more likely to have higher costs with only 16% of >30 year old fields being under the average 2017 direct OPEX amount of £12 million. Fields which began production before 1994 (the year the CRINE initiative began) are subject to a wide distribution of 2017 operating costs. With regard to fields which started up post 1994, whilst there are a few with 2017 direct OPEX of over £20 million, the vast majority are condensed at the lower end of the distribution with costs of under £10 million.

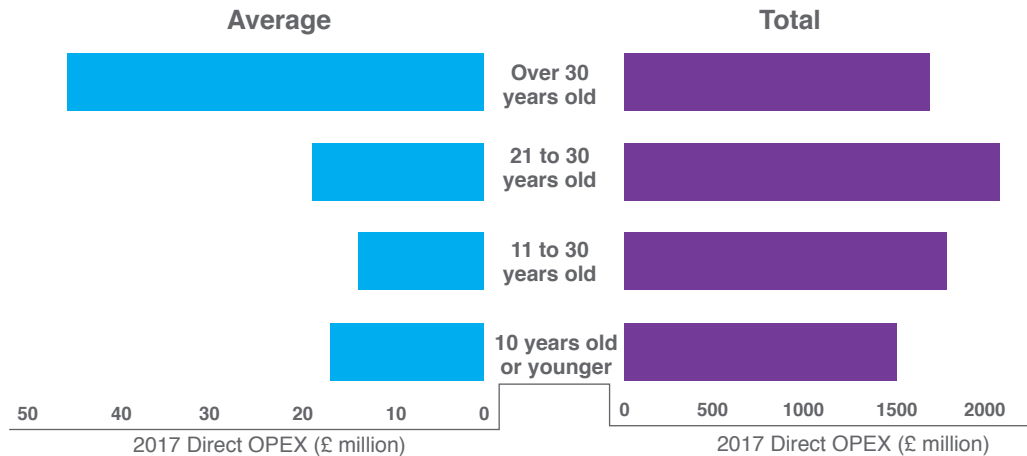
Figure 12. The field age and 2017 OPEX



When divided into the categories highlighted in Figure 13, in 2017, fields under 10 years old were the cheapest to run on an aggregated basis, then those which are the oldest at over 30 years, then 11 to 20 years and 21 to 30 years. On an average basis, the oldest fields are overwhelmingly the

most expensive. The reason for these fields placing second cheapest on an aggregated basis is that there are relatively few of these facilities compared with newer ones.

Figure 13. Average and total 2017 OPEX for four age groups



3.3 Offshore Field OPEX by area

As highlighted in Figure 14 there is high geographic variability in direct OPEX on the UKCS, both in terms of aggregated totals and averages. The CNS by far has the highest total spend of any area, however this is to be expected, given that over 40% of fields are located within this region. The NNS on the other hand contains less than half the fields of the SNS & IS but roughly double the costs (2018 direct OPEX). This is determined heavily by the make up of facility type in each area (see Figure 15). On an average by field basis, the WoS is by far the most expensive region with costs per field set to peak in 2021.

Figure 14. Direct OPEX by area and year

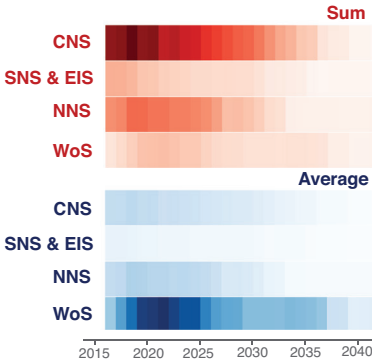
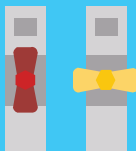



Figure 15. Factors influencing OPEX in different regions




Extraction Complexity

Increased complexity of processing associated with gas condensate platforms in the CNS and reservoir support common across the NNS, WoS and CNS. Gas rich SNS fields generally requires less complex extraction.




CRINE Initiative

A prevalence of CRINE era facilities in the CNS, where capital expenditure (CAPEX) was aggressively targeted, with potential for subsequent impact on OPEX profiles.



Relative Age

CNS manned platforms are on average seven years younger than those in the NNS & WoS and 15 years younger than those in SNS & IS.



Logistics

Marine and air distance/travel times to offshore infrastructure are shorter in the SNS & EIS than other areas. NNS and WoS facilities are often accessed by fixed wing and subsequent helicopter travel.

4. UKCS Unit Operating Costs

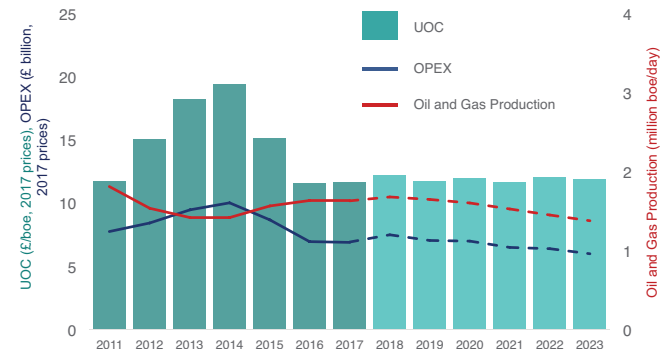
The 2017 Stewardship Survey has revealed that from 2016 to 2017 unit operating costs rose by 2 per cent in nominal terms and stayed flat in real terms. At £11.6/boe, UKCS average UOC is still over a third lower than the peak seen in 2014.

The OGA's medium term projections suggest slight fluctuations and ultimately a small rise in UOC (2% increase) by 2023. This is due to a slightly higher forecast decline rate for production than for OPEX (Figure 16).

UOC is defined as the total cost of field operations for a given time period, divided by the amount of hydrocarbons produced in that same timespan. It is beneficial in its ability to enable the benchmarking of similar fields or against an overall industry unit operating cost index. It is also a useful indicator of the extent to which industry is containing its costs.

The following subsections will explore UOC on a field level by the following categories: field operator, area, facility type, field age and relationship to production efficiency

Figure 16. Historic and projected UKCS UOC, Production and OPEX



4.1 UOC by Field

UOC at field level varies significantly due to a combination of factors including differing geographical locations, facility types, age of infrastructure, operational efficiency and the operational culture in each facility – driven by operatorship. Figure 17 shows the distribution of field unit operating costs in 2017. Nearly 40% of fields in 2017 had a UOC of £10/boe or lower. The 31% of fields operating at Over £20/boe require further attention.

Figure 18 highlights the range in unit costs and how they are related to overall OPEX and production levels. As shown there is a wide array in production/ OPEX relationships which is why the resultant spread in UOC is so large.

Figure 17. Distribution of 2017 field UOC

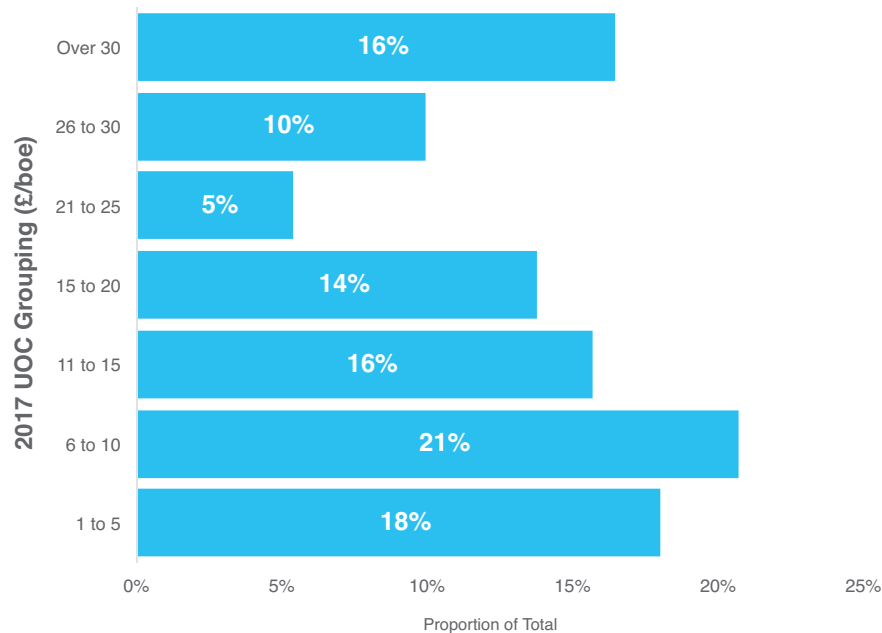
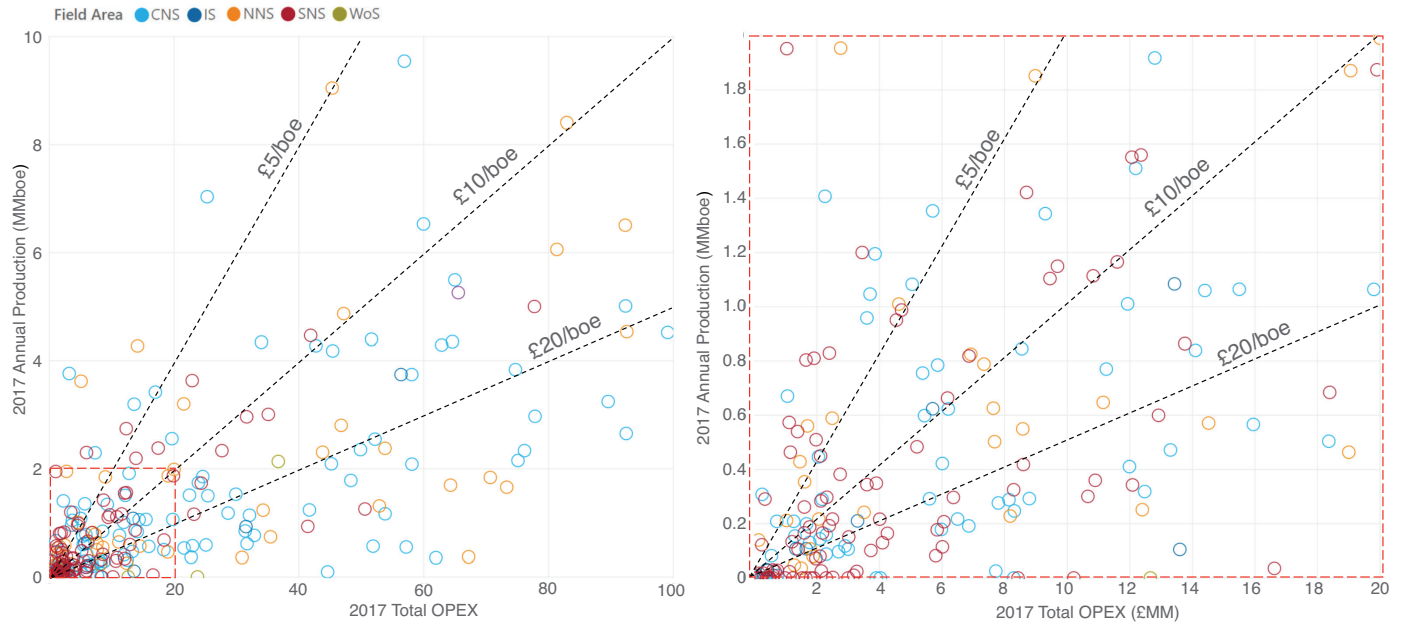


Figure 18. 2017 OPEX, Production and UOC by Field and Region

4.1.1 UOC for recent start up fields

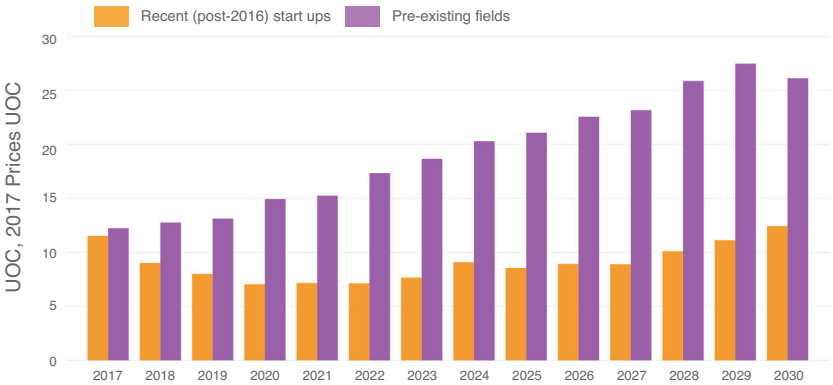
As stated in section 2, newer (post 2016 start up) fields are collectively more cost efficient than their older counterparts. This is highlighted further in Figure 19, where there is a consistent divide in the cost efficiency between newer and older fields. Despite the 2022 UOC low point of around £7/boe for newer fields (reflecting the average production plateau phase of these fields) the rate of UOC increase thereafter is marginal compared to older fields. This is indicated by the fact that the largest difference in UOC between older and newer fields is estimated

to be in 2027. At this point this newer generation of fields are expected to have unit operating costs of 2.6 times lower than pre-existing fields.

From 2020 to 2029 the increase in UOC of newer (post 2016 start up) is expected to be 58%, compared to 84% for older fields.

For recently sanctioned fields, which are still in their pre-production phase, their estimated life of field unit operating costs range between £9/boe and £13.50/boe.

Figure 19. Projected UOC by field start up date



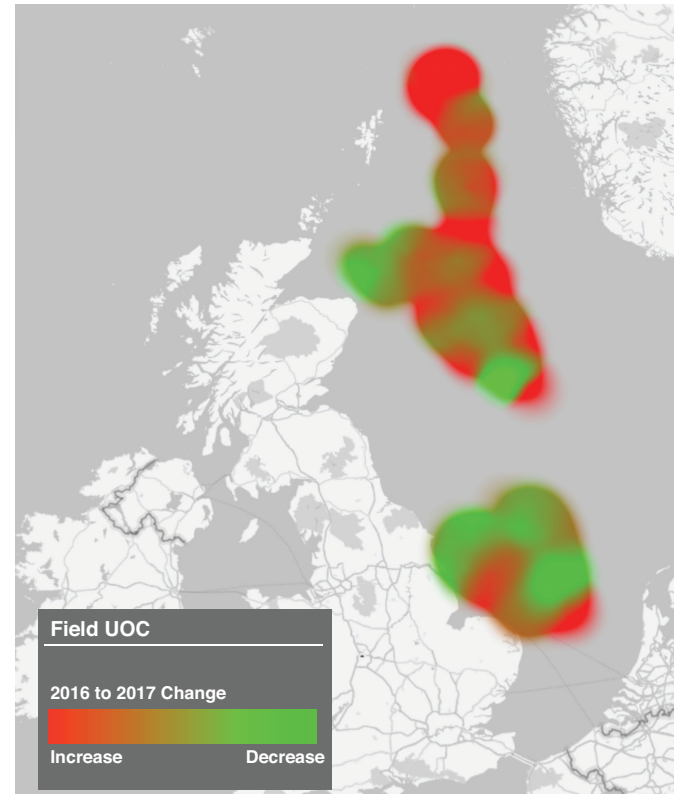
4.1.2 UOC field annual change

Of all the UKCS fields evaluated for their UOC in this report, roughly two thirds saw an increase from 2016 to 2017. The average increase of these fields was just under £6/boe. The average change for fields which saw a decrease was a £5/boe fall.

Figure 20 maps the rough geographic distribution of these 2016-2017 changes in UOC across the UKCS. Note that fields WoS, in the EIS and in other geographically isolated locations have been omitted.

The SNS stands out for having a consistent mix of fields which have decreased their unit operating costs. This is also shown by the fact that the split of annual change in this region is 50/50, compared to the CNS and NNS which mirror the UKCS split of 66% increase to 34% increase. The CNS exhibits geographic pockets of improvement such as in the Outer Moray Firth and the southern end of the Central Graben

Figure 20. Field UOC Change (2016-2017)



4.2 UOC by Operator

The 2017 average UOC for the UKCS was £11.6/boe, with performance varying significantly at an operator level. UOC by operator ranged from over £30/boe to less than £6/boe on the other end of the scale.

Figure 21 shows the distribution of 2017 average UOC for each operator, with the width of the bars scaled to reflect the amount of gross operated production. As illustrated, the largest producers generally had the lowest UOC in 2017. This is broadly consistently with 2016 UOC data.

Although UKCS average UOC was flat between 2016 and 2017, at an operator level, over 60% of companies saw their average UOC increase (Figure 22). At first glance this may seem that on an operator basis costs are starting to rise again, however, when analysed further it seems the reason for the majority rise in UOC amongst operators is due to decreasing production, rather than increasing OPEX.

Figure 21. 2017 UOC and Production by Operator

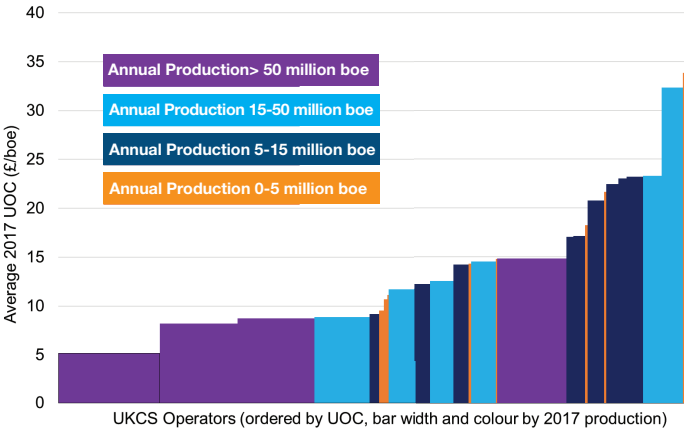


Figure 22. UOC by operator for 2016 and 2017

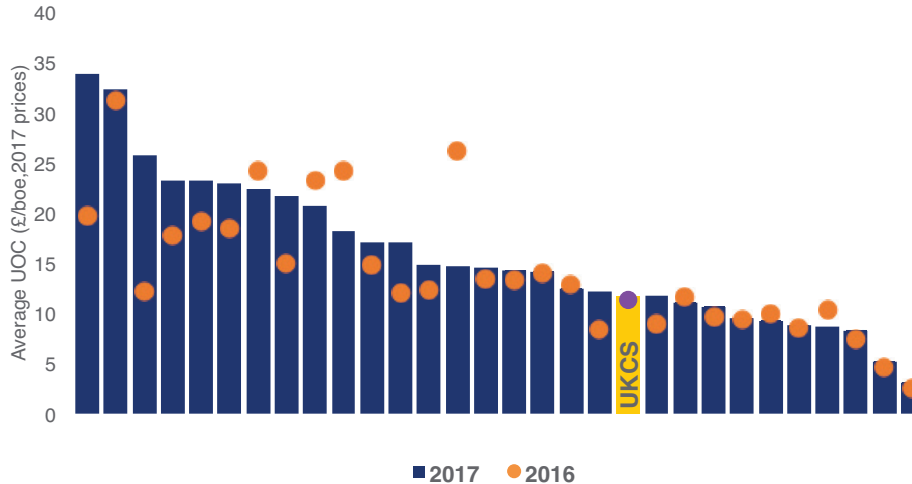
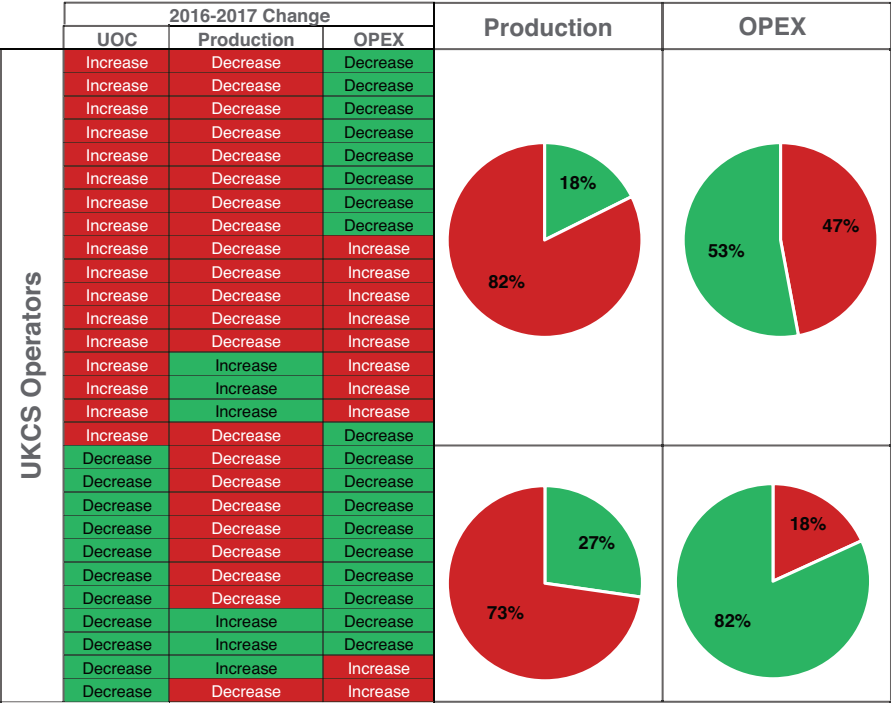


Figure 23 indicates that amongst the 60% with a 2016-2017 UOC increase, less than half actually saw OPEX inflation, whilst over three-quarters saw a fall in production. For the remaining 40% whose UOC decreased, over four-fifths saw OPEX reductions. Across the board 64% of surveyed operators reported a reduction in OPEX. This illustrates that on an operator level, most are still reporting a decrease in both costs, and production.

Figure 23. 2016-2017 change in UOC, OPEX and Production by Operator (2017 prices, only includes field data)



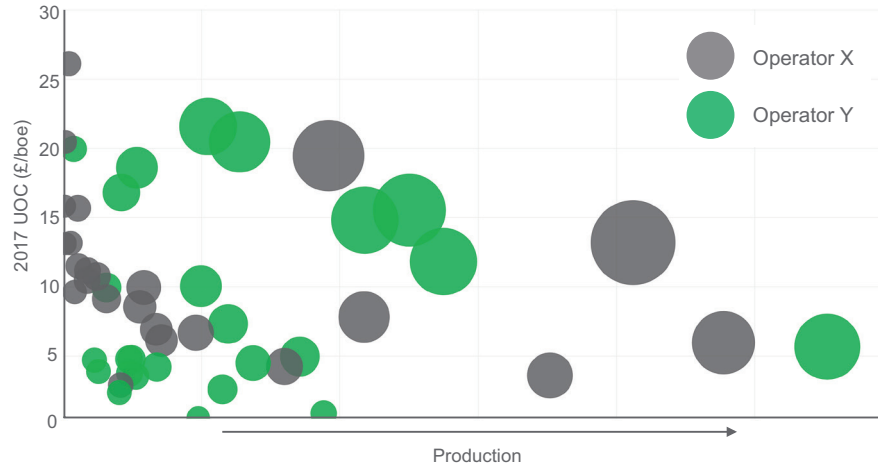
A good example of UOC decrease driven by cost reduction is where an operator achieved >40% decrease in UOC between 2016 and 2017 (from £26/boe to £15/boe). This large reduction in UOC was controlled entirely by OPEX reductions as production remained flat.

UOC at operator level is useful for identifying where each operator sits relative to the UKCS average and to other operators, especially within their peer group.

UKCS operators have a diverse range of assets capable of producing varying amounts and are subject to a variety of operating costs. As illustrated in Figure 24 below, two UKCS

operators, both with an average UOC of £9/boe operate a wide array of fields with regard to UOC and production volumes.

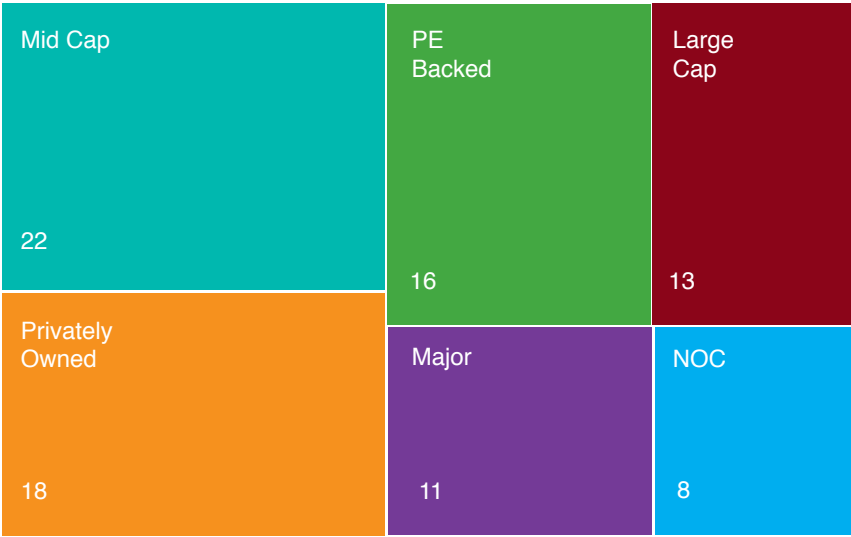
Figure 24. UOC by field for two operators with organisational average of £9/boe – bubble size is OPEX



A recent trend in the commercial landscape in the UKCS is that of a change towards an ever greater diversity of organisation types. These companies range from majors to national oil companies (NOCs) to a now growing number of smaller, private equity funded firms. Looking at UOC by organisation type (Figure 25) shows a diverse mix, with

Mid Cap E&P companies having the highest unit operating cost on average. At the other end of the scale, National Oil Companies then Large Cap Independents and Majors have the lowest unit operating costs. Newly established PE backed companies lie somewhere in the middle, driven by a large range of UOC within this organisation type.

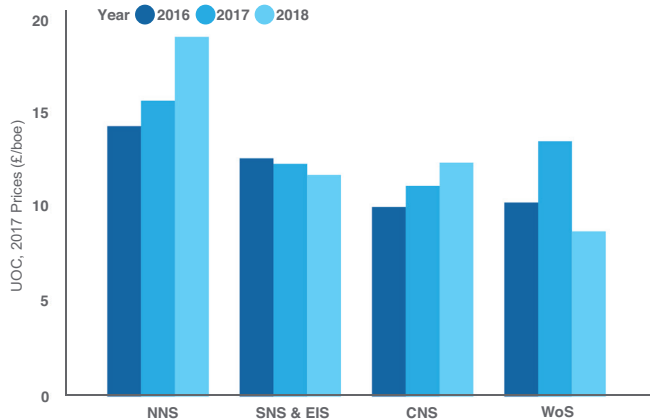
Figure 25. 2017 UOC (£/boe) by organisation type (asset operator)



4.3 UOC by Area

When analysed at area level, average UOC fluctuates across the UKCS, with slightly more variability observed in 2017 compared to 2016. This range is expected to increase into 2018 as the NNS becomes significantly less cost efficient, with the opposite occurring to the WoS region (Figure 26).

Figure 26. Actual and forecast (2018) UOC by UKCS region



The Central North Sea (CNS) had the lowest UOC in comparison to the other areas in the UKCS for the second consecutive year.

The SNS & EIS recorded the only average fall in OPEX of any UKCS geographical region in 2017. The SNS fall in OPEX offset its production decline, leading to the sole annual reduction in UOC among the geographical regions from 2016-2017. This is anticipated to fall further into 2018 and even 2019, driven by OPEX falling at a greater rate than production. From 2016 to 2018, eight fields in the region are projected to have overall production growth and OPEX reduction.

The WoS saw a 31% increase in UOC from 2016-2017. Whilst this seems alarming, it is explained by operators in the region incurring pre-production OPEX from new developments in the region. Once production starts the UOC is estimated to drop, as shown in Figure 26.

The NNS saw a UOC increase of 10% from 2016 to 2017 and is predicted to increase 22% from 2017 to 2018. The widening gulf between the NNS and the next least cost-efficient area is driven by falling levels of both OPEX and production and the rate of fall of OPEX exceeding that of production. This is to be expected in an area as mature as the Northern North Sea.

4.4 UOC by Facility Type

The type of facility used for developing an offshore oil or gas field is determined by a range of factors such as:

- Water depth
- Meteorological/ oceanographical conditions
- Number of wells needed/ field life expectancy
- Fluid type
- Geographical location
- Heat and pressure of the reservoir
- Subsurface geological conditions
- Export proximity/ availability

For example, a small, shallow water, gas field in the SNS which is close to surrounding infrastructure may only require a single subsea tieback. In contrast, a large, geologically complex, deep water oil field West of Shetland, which is tens of kilometres away from the nearest pipeline, will most likely require a floating installation with tanker offloading.

These factors mean that some facilities will invariably cost more to run due to their underlying structure. It would be assumed that the costlier the infrastructure, the greater the produced volumes, (which would result in a relatively uniform UOC between facility types). Whilst over the life of a field this is broadly the case, in a snapshot of unit operating costs for 2016 and 2017 we can see there is a degree of variability.

In 2017 there is a £7.5/boe range between the costliest type of facility (FPSO/FPV) and the cheapest (Unmanned Platform). Despite floating installations having the highest UOC, they were the only facility type to keep their unit operating costs flat from 2016 to 2017. The other facilities all saw an increase in UOC of at least 6% (Figure 27).

This UOC ranking distribution for facility type is similar to that of Direct OPEX, however the FPSO/FPV and Large Manned Platform categories are swapped. This is because there have been many recent FPSO developments which have incurred OPEX but have yet to reach peak production. The UOC for floating installations is expected to significantly decrease in 2018 as production on these facilities ramps up.

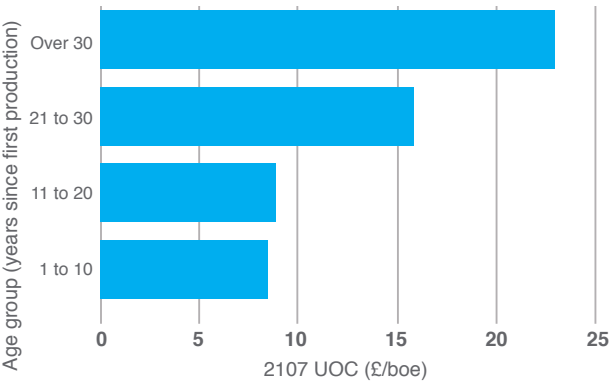
Figure 27. 2016 and 2017 UOC by facility type



4.5 UOC by Field Age

On a per barrel basis, newer facilities are generally cheaper to operate than older ones. When categorised into the age groupings shown in Figure 28, it shows there is a large difference of nearly £15/boe in the average UOC between the newest and oldest fields. Note the similarity in UOC of the first two groupings, which both include post-CRINE initiative fields. This trend is primarily due to increased maintenance costs and due to the fact older fields often have larger facilities (e.g. manned large steel or concrete platforms) which translate to higher running costs. However, these prerequisites can be offset

Figure 28. 2017 Average UOC by field age



by efficient practices and attitudes towards cost management. This is evident in that nearly a fifth of >30 year old facilities operated under the UOC average in 2017. (Note that the CRINE initiative was implemented 24 years ago.)

In terms of average field production in 2017, fields either 1 to 10 years old or over 30 years old are extracting more hydrocarbons than those 11 to 30 years old. This is because newer fields are more likely to be in their plateau phase and the oldest fields are generally the biggest so their decline phase production profiles are still significant. This in turns helps to explain why the newest fields have the lowest UOC and why the oldest fields' unit operating costs are not higher.

While the average UOC for older assets is much higher than the UKCS average, it important to point out that at an operator level, there are very good examples of operators with mature portfolios and average UOC of less than £10/boe. This demonstrates that with an economically-driven late life asset strategy and the right commercial mindset, it is possible to achieve competitive unit costs in the UKCS. This aligns with the OGA's vision of having the right assets in the right hands. The 2017 survey shows that some mature fields remain among the top quartile performers in the UKCS.

4.6 UOC and Production Efficiency

There is an observed inverse relationship between operational efficiency (PE) and cost efficiency (UOC), i.e. the higher the observed PE, the lower the UOC (Figure 29). The most operationally efficient operators generally incur a lower cost of production per barrel than those with low PE values on their hubs.

There are a small number of operators that have some of the highest unit operating costs in the UKCS despite PE of around 80%. For these operators, the OGA is working with them to understand the associated cost drivers. The OGA's asset stewardship reviews with operators have highlighted that the increased use of existing data and creating a culture of efficiency in the workplace has led to an increase in production efficiency and consequently lower unit operating costs.

Figure 29. 2017 UOC and PE by Operator

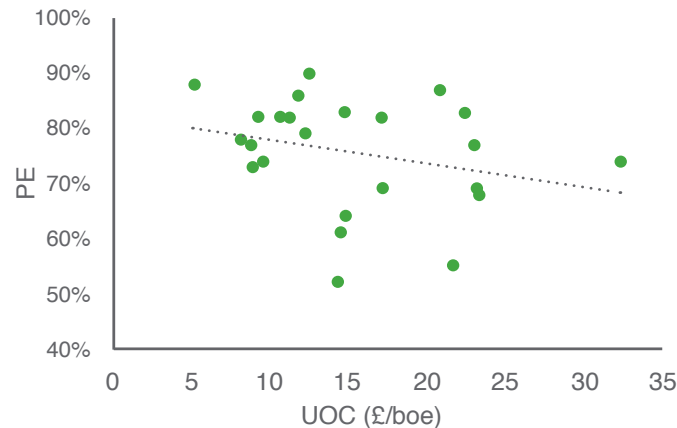
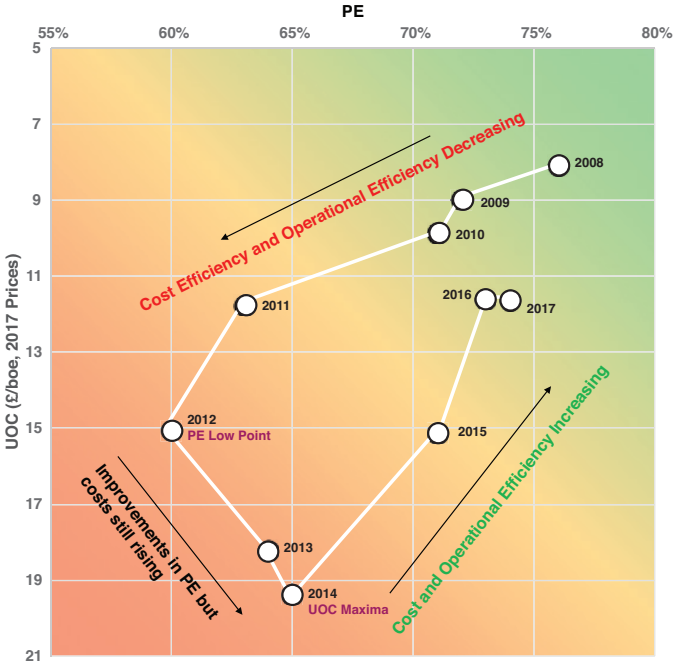


Figure 30 demonstrates this UOC/ PE relationship on a UKCS level over nearly a decade between 2008 and 2017. From 2008 to 2012 both cost and operational efficiency fell substantially (85% and 21% respectively). After 2012, whilst UOC still increased, PE then began to rise until 2014, where after both efficiencies have continued to increase. With PE marginally rising by 1% in 2017 and UOC remaining flat, the industry must be careful to not let slip the efficiency gains which have been made since 2014.

Figure 30. Historic UKCS level UOC and PE



5. Field OPEX Benchmarking

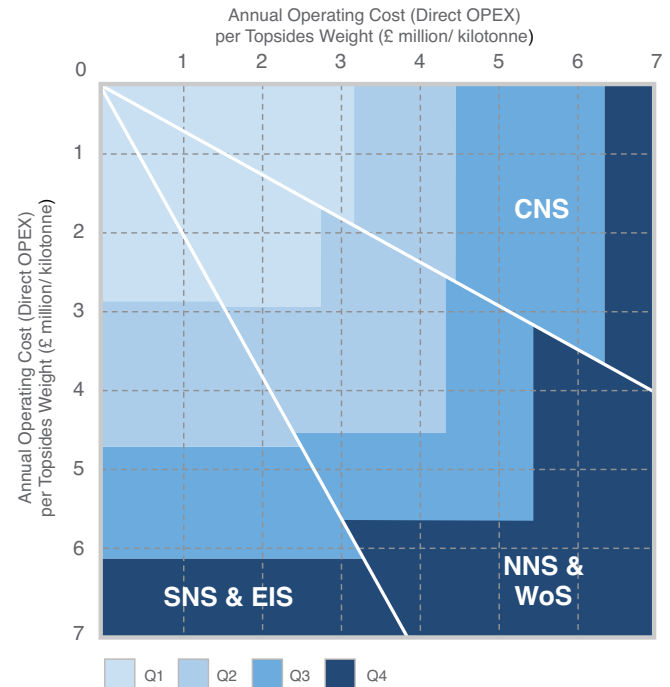
The OPEX per tonnage quartile analysis performed in the OGA's 2016 UKCS Operating Cost report has been updated using 2017 data.

As stated in last years report, manned platforms exhibited a strong correlation between OPEX and topsides weight, therefore these metrics have been combined to produce a benchmarking tool. Figure 31 is an updated version of the tool which allows operators to identify how they perform with regard to their costs on fields developed using manned platforms.

Quartile boundaries between each of the three regions represented are similar, with platforms having annual costs per tonne of under £3 million/kte generally breaking into the top quartile. ~£4.5 million/kte gets into upper quartile and anything above roughly £6 million/kte in the lower quartile. Any platform with a cost per tonnage higher than this falls into the bottom quartile.

The largest regional difference observed is that between the CNS and NNS/WoS for the Q3/Q4 boundary. This difference equates to nearly a £1 million per kilotonne of topsides weight.

Figure 31. Manned platforms - cost per tonne (£MM/kte), quartile performance by region. 2017 data.



6. Insights

6.1 UOC and the Oil Price

As illustrated in Figure 32, there is an obvious positive relationship between UKCS UOC and the oil price, albeit with UOC lagging a couple of years behind Brent Crude. When UOC is taken as a percentage of the oil price (right hand axis), this acts as proxy for cost efficiency with respect to the oil price environment (at the time). From 2000 to 2011 UOC averaged 16% of the Brent Crude Price. Following 2011, this proportion started to rise, even with the oil price surging in value, reflecting the significant cost inflation during this period. Due to the lag between the fall of the Brent Crude Price and UKCS UOC, this proportion peaked at over 40% in 2015, leading to an extremely unsustainable situation. Despite the fact that in recent years UOC has fallen to a more sustainable level, in 2017, when taken as a percentage of Brent Crude it is still 28%.

With the recent upwards trend of the oil price, the industry needs to maintain focus on efficiency to prevent potential future OPEX inflation. The OGA will be

benchmarking operators on their OPEX and will be following up with individual companies through asset stewardship engagements.

Figure 32. UOC and Brent Crude



6.2 Offshore field revenue

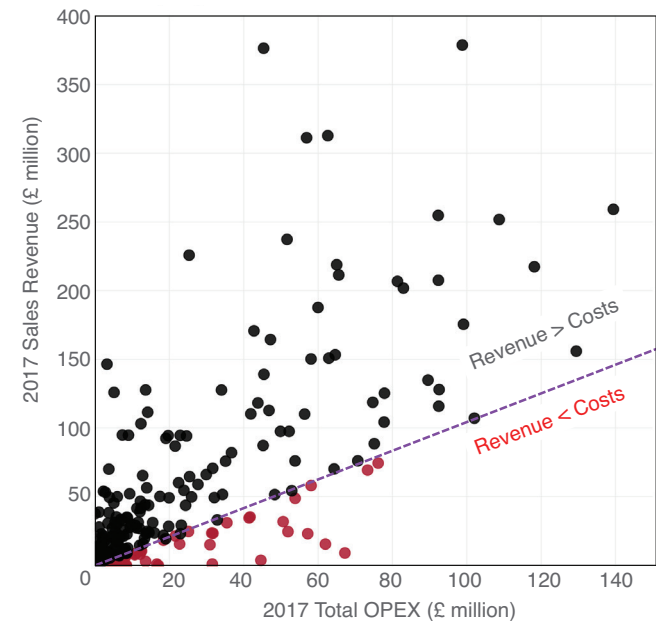
During the 2015-2016 and 2016-2017 financial years, UKCS tax revenue was negative for the first time in the basin's history. This was due to the decreased profitability from offshore fields caused by the sharp decline in the oil price and the relatively high cost environment at the time. From 2017 to 2018, tax revenue returned to positive at £1.2 billion. Figure 33 goes towards supporting this fact, showing that in 2017, 59% of UKCS fields had greater revenues than total operating costs. To retain anonymity, the Y axis has been restricted to a maximum of £400 million. Note, the data displayed still represents over 90% of UKCS fields.

Whilst this position is undoubtedly better than the past couple of years, there are still many fields which are operating at a negative net revenue. It is noted that since these data were collected, the oil price has steadily risen (which will aid the situation), however Figure 33 is another signal that operating costs need to be controlled to ensure the economic health of assets in the basin.

Total UKCS revenue for the 2017 calendar year is estimated to have been just over £20 billion, compared to total UKCS

OPEX of £6.9 billion. Note this revenue is significantly affected by a select few high value fields.

Figure 33. 2017 Revenue against operating costs by field



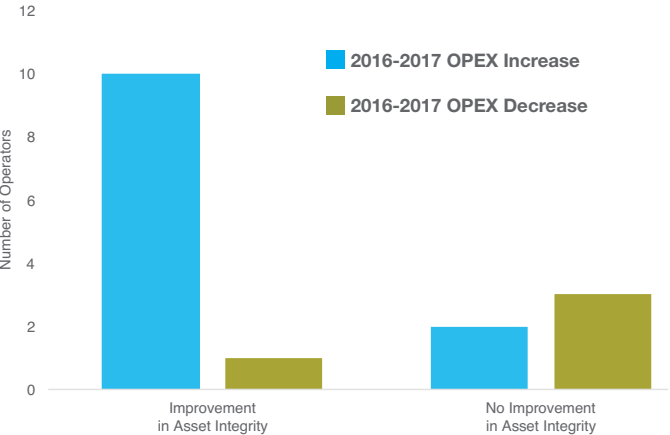
6.3 Costs and Asset Integrity

Figure 34 shows that out of 10 offshore operators who spent more operating their offshore assets in 2017 than 2016, 83% considerably reduced their maintenance backlog over the same time span. In contrast, of the few operators who did not improve on their assets’ integrity, the majority saw cost reductions.

Technology has a significant part to play in delivering these facilities management cost efficiencies. The 2017 Stewardship Survey shows that companies are including a growing number of technologies in their maintenance operations. For example, operators are now exploiting the benefits of 4G offshore by deploying wearables and wireless technologies. These, along with asset visualisation, condition based maintenance technologies and using composites for structural repairs, have provided cost, operational and process efficiency gains. Looking ahead, very promising NII (non-invasive inspection) technologies for hard to reach areas are being piloted by the OGTC Asset Integrity Solution Centre, in addition to remote and autonomous technologies that will deliver further safety and cost benefits.

Both Figure 34 and these examples of the use of innovative technology, highlight that high levels of upfront operating expenditure are not necessarily a detriment, as costs spent performing critical maintenance will lead to increased operational efficiency in the future, supporting the objective of the OGA, the industry and the government to maximise economic recovery from the UKCS.

Figure 34. Changes in asset integrity from 2016 to 2017



7. Glossary and Notes

Definitions

- **UKCS:** United Kingdom Continental Shelf. Term given to describe the region of waters surrounding the UK to which the UK has mineral rights.
- **OPEX:** Operating Expenditure. The costs incurred running and maintaining (offshore) infrastructure. Comprised of the following:
 - **Wells OPEX:** Costs incurred keeping wells producing hydrocarbons. Example projects include completions workovers or wellhead maintenance.
 - **Facilities OPEX:** Expenditure that goes towards keeping the surface facility operating.
 - **Logistics and admin (L&A OPEX):** Includes marine and air logistics to the facility as well other cash payments such as insurance.
 - **Tariff payments:** Payments to a third party for transportation and processing of produced hydrocarbons on a fixed cost basis.
- **Cost share payments:** Like tariff payments but on a shared proportional cost basis.
- **Direct OPEX:** Wells + Facilities + L&A OPEX
- **UOC:** Unit Operating Cost. Sum of operating costs divided by the sum of barrels of oil equivalent produced (over the same time span). Presented in this report in pounds sterling per boe, as the 2017 Stewardship Survey is conducted in this domestic currency.
- **BOE:** barrels of oil equivalent. The combination of crude oil, natural gas liquids (NGL) and natural gas. Gas volumes are converted to oil equivalent using an industry gas conversion factor of 5.8 thousand standard cubic feet of gas to one boe.
- **Heavy steel platform:** Those platforms where the jacket weighs 10,000 tonnes or more. Also includes a small number of concrete gravity based structures.
- **Small steel platform:** Those platforms where the jacket weighs less than 10,000.

- **Jacket (platform):** the subsea frame supporting the deck and topsides of a fixed offshore platform.
- **Topsides (platform):** the surface section of an offshore structure, outside of the splash zone, on which all of the operational equipment, accommodation and other facilities are located.
- **Production efficiency:** The AWP (actual wellhead production) divided by the EMPP (economic maximum production potential) of an offshore hub. A measure of what a hub produced against what it could (economically) theoretically produce.
- **Trunk pipeline:** production pipelines outside of a field area, generally travelling long distances from fields to either an onshore terminal or to a connecting trunk pipeline.



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