havenpower
A Drax Group company

Third Party Costs newsletter

Issue 9 – Q1 2018

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Introduction

Since our last issue, some significant events have affected the energy industry. Dieter Helm published his independent review into the cost of energy - in a report that the UK Government commissioned. And, while November's Budget was light on energy announcements, various changes regarding Third Party Costs (TPCs) have occurred.

In the wholesale markets, a number of problems - the availability of French nuclear generation, gas supply disruptions in Austria, and interruptions to UK oil pipelines - all contributed to prices rising. As of March 1st, the price for Summer 2018 baseload was £42.95/MWh , up from £41.60/MWh at the end of Q3 2017.

However, relatively mild temperatures have led to demand out-turning at a lower level year on year. Renewable generation made up a smaller proportion of the total, due to the increasing call on fossil fuels as demand rose with winter approaching. This trend will reverse as we head into spring.

After failing to secure a contract in the recent T-1 Capacity Market auction, Eggborough power station announced its closure, leaving the UK with only seven coal-fired power plants.

In advance of the Autumn Budget, the energy industry avidly awaited the promised changes to the Levy Control Framework. The Chancellor confirmed there'll be no new low carbon electricity levies until there's a fall in the burden of such costs; on current forecasts, not before 2025. Investors were also looking for clarity on carbon prices, and the Budget confirmed the Government's belief that the Carbon Price Support is set at the correct level.

The Budget also revealed that electric vehicles appear to be a key priority, with funding earmarked for battery charging infrastructure to support their use. In addition, from April 2018, there'll be no 'benefit in kind' fee for employers to pay on electricity that's used to charge employees' electric vehicles.

Against this background, and for a more complete view of the energy market, it's important to grasp the nature, role and purpose of TPCs - and to understand how we forecast these costs and assess their impact upon end users..

Dieter at the helm

Dieter Helm delivered his independent cost of energy review at the end of October 2017, concluding that prices are too high. The report's author blames legacy costs and the complexity of regulation as the major causes of rising costs.

Helm also found that consumers aren't gaining the maximum benefit from the falling costs of traditional fuels (gas and coal) and renewables, nor from network and supply efficiency gains. His suggestions from the report include:

- Simplifying Government interventions, and including fewer details in policy
- Merging the legacy costs from the Renewables Obligation (RO), Feed in Tariff (FiT) and Contracts for Difference (CfD) charges, then ring-fencing them and making them an explicit charge on bills, with exemptions for industrial customers
- Harmonising carbon taxes, to lower the cost of the existing multiple interventions
- Phasing out and merging FiTs and other low carbon CfDs into one capacity auction, to place the cost of intermittency on the generators and encourage investment into alternative technologies
- Establishing an independent National System Operator (NSO) and Regional System Operator (RSO), and opening up these functions to competitive auction as far as possible

Helm recommends following a roadmap of simplicity and notes that markets work best in clear structures. To what extent the Government implements his 60+ recommendations remains to be seen; some industry commentators fear that the Government will single out certain policies at the expense of making more difficult decisions.

Executive Summary

Here's a summary of the key updates to TPCs since our last newsletter:

- Final tariffs for both Distribution Use of System (DUoS) - 2018/19 and 2019/20 - and Transmission Network Use of System (TNUoS) - 2018/19 only - were published. TNUoS may be revised upwards depending on the outcome of an outstanding judicial review (page 3)
- TNUoS transmission losses will be calculated zonally. For most customers, the impact will be negligible. (page 4)
- DCP161 means that, from April 2018, the excess capacity charge can be up to three times the amount of the capacity charge. However, Extra High Voltage (EHV) connections will not be affected. (page 11)
- Renewables Obligation (RO) levels have been set for 2018/19 at £22.10/MWh. This figure includes the Energy Intensive Industry (EII) exemption cost (page 7)
- It's our understating that EIIs will be exempt from up to 85% of the indirect costs of the RO from 1st April 2018 (page 7)
- Parliament agreed Contracts for Difference (CfD) EII exemptions in October 2017, and certificates were issued immediately after. The Department of Business, Energy & Industrial Strategy (BEIS) has not made a statement yet regarding RO exemption. However, Haven Power believes that any qualifying business with a CfD exemption certificate will automatically qualify for the RO exemption from 1st April 2018 (page 8)
- The T-1 Capacity Market (CM) auction for delivery in 2018/19 cleared at £6.00/kW/year, delivering almost 6 GW of volume. The T-4 auction cleared at £8.40/kW/year – significantly lower than the 2020/21 clearing price – delivering over 50 GW of volume (page 11)

For further information on EIIs, go to:
https://www.havenpower.com/help/energy-intensive-industry-exemption/

Make-up of a bill

The Government's policy-driven charges under the Levy Control Framework (LCF), plus other charges, are likely to form an increasing proportion of the end user's bill. The table and graph below use out-turn data, published rates and forward-looking estimates to provide a guide to the make-up of a typical energy bill in the future.

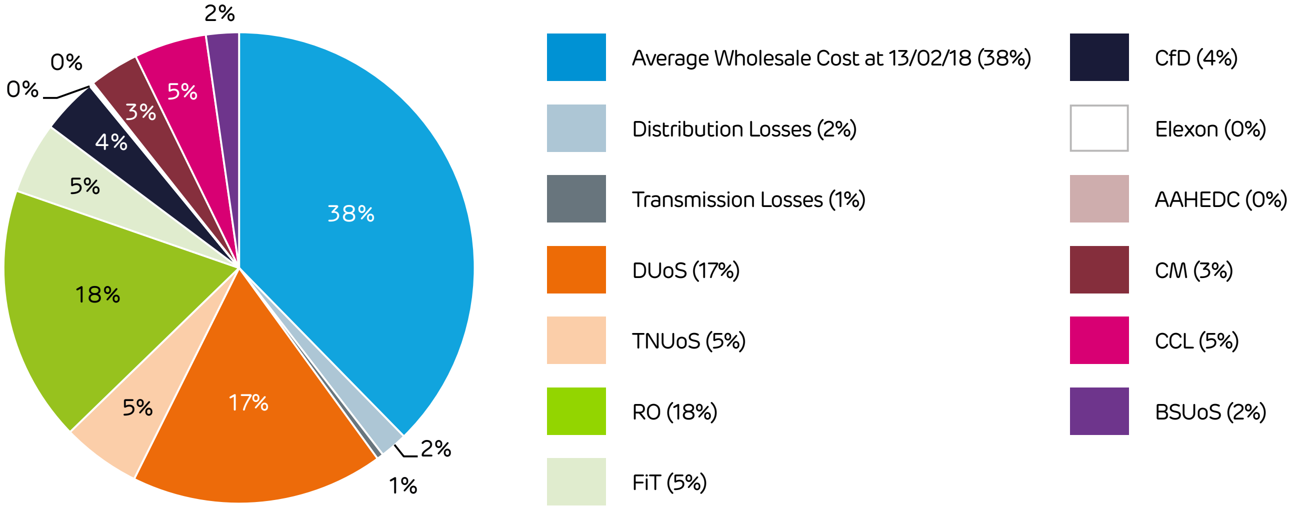
We included a similar breakdown in the previous newsletter and have updated the figures below. You should only use these figures for indicative purposes.

	Charge (£/MWh)	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**
Energy	Average Wholesale Cost at 13/02/18	45.33	46.03	42.93	41.56	42.02
Losses	Distribution Losses	2.27	2.30	2.15	2.08	2.10
	Transmission Losses	0.54	0.55	0.52	0.50	0.50
Distribution/ Transmission	Distribution Use of System (DUoS)	22.22	20.33	21.75	22.62	23.75
	Transmission Use of System (TNUoS)	5.58	5.46	6.16	6.78	7.46
Levy Control Framework charges	Renewables Obligation (RO)	18.64	22.10	23.31	24.39	25.53
	Feed in Tariff (FiT)	5.24	5.70	6.25	6.50	6.80
	Contracts for Difference (CfD)*	2.21	4.80	7.25	10.90	12.00
Other charges	Elexon	0.07	0.07	0.07	0.07	0.07
	AAHEDC	0.23	0.27	0.29	0.31	0.34
	Capacity Market (CM)	1.40	3.72	4.00	5.00	2.23
	Climate Change Levy (CCL)**	5.68	5.83	8.47	8.90	9.34
	Balancing Service Use of System (BSUoS)*	2.50	2.60	2.85	3.10	3.40
	Total	**111.96**	**120.04**	**126.35**	**133.11**	**136.00**

* National Balancing Point (NBP)

** Haven Power forecast from 2020/21 onward

Cost Breakdown for 2018/19



Transmission Network Use of System (TNUoS)

TNUoS charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore.

TNUoS charges for 2018/19 were finalised at the end of January 2018, and average Half Hourly (HH) decreases were around 2.2% less than 2017/18 final tariffs. The difference in charges ranged from a decrease of 11% to an increase of 0.5% across the 14 charging zones. Average Non Half Hourly (NHH) charges dropped by around 4% on last year's tariffs (ranging from a decrease of 44% to an increase of 11%).

Please note that the final TNUoS tariffs for 2018/19 aren't yet locked-in, since there are still on-going appeals (CMP264/265 - see below) that could increase the published tariffs mid-year.

We've highlighted all of the relevant Connection and Use of System Code (CUSC) Modification Proposals (CMPs) below:

CMP264 & CMP265 - Charging arrangements for embedded generation (on-going appeal)

Approved for implementation from 1st April 2018, this modification phases out the majority of the embedded generation Triad benefit over the next three years. The approval resulted in demand tariffs reducing by 12% on average. If the judicial review is successful, charges could increase by the same amount - we're expecting a decision by May 2018.

CMP261 – Ensuring EU compliance

This is to check that the TNUoS charges paid by British generators in charging year 2015/16 comply with the €2.5/MWh annual limit set by EU Regulation. This modification was rejected in November 2017, although the Competition and Markets Authority (CMA) raised an appeal against the decision to recover the revenue that generators felt they overpaid in 2015/16. On 26th February 2018, the CMA upheld the original decision (by the Office of Gas and Electricity Markets: Ofgem) to reject the modification. Therefore, no changes are required to the 2018/19 TNUoS tariffs published on 31st January 2018.

CMP251 – Removal of error margin

This would remove the error margin in the cap on total TNUoS recovered by generation, and introduce a new charging element to ensure compliance with the EU Regulation (€2.5/MWh cap). The modification has been delayed, pending a decision on the appeal of CMP261.

CMP282 – The effect of negative demand on Zonal Locational Demand Tariffs (approved)

Approved, without appeals, for implementation from 1st April 2018, this modification changed the calculation for TNUoS demand tariffs by lowering Northern Scotland (Zone 1) and increasing the other areas.

There are also two other issues that could have an impact on TNUoS charges:

Significant Code Review – Targeted Charging Review

This focuses on the residual charge for the transmission and distribution network - for generation and demand - along with any other embedded benefits that may be distorting the market.

Here are our projected increases, shown as a range of possible outcomes:

	2017/18	2018/19	2019/20	2020/21	2021/22
TNUoS High Case			20%	15%	15%
TNUoS Middle Case	Actuals	Actuals*	13%	10%	10%
TNUoS Low Case			7%	0%	5%

* Dependent upon outcome of judicial review

P350 – Introduction of a seasonal Zonal Transmission Losses scheme

The Competition and Markets Authority (CMA) concluded that the lack of geographical pricing for transmission losses has an adverse effect on competition and leads to higher consumer bills. With P350 to be implemented from April 2018, the CMA forecast a total saving of £130m to £160m between 2017 and 2026. For most customers, the change will be negligible.

Distribution Use of System (DUoS)

DUoS charges are paid to the Distribution Network Operator (DNO). Each supply meter is on a network run by the DNO for that relevant geographical area, and there are 6 DNOs operating across 14 regions in the UK. DUoS charges cover the cost of installing, operating and maintaining a safe and reliable electricity supply within each DNO region.

DUoS rates for 2019/20 were published in December 2017. All main connection types increased by around 7% across all areas; 6.87% for small non-domestic customers and 7.5% for large non-domestic customers.

And, as mentioned in an earlier newsletter, the introduction - effective from April 2018 - of DCP 228 will change how DUoS charges are calculated. It revises the weightings applied to unit rates, reducing the peak (red) rate and increasing off-peak (amber and green) rates.

The Office of Gas and Electricity Markets (Ofgem) has introduced a new measure, DCP 161, to ensure that all Half Hourly supplies - except those using Extra High Voltage (EHV) meters - pay more to the Distribution Network Operator (DNO) for exceeding their agreed capacity. The measure takes effect from April 2018.

Before this date, the capacity charge and excess capacity charge were set to the same rate - effectively removing any incentive for customers to adhere to, or adjust, their agreed capacity. In contrast, under DCP 161, the excess capacity charge may be up to three times the amount of the capacity charge. This makes it vitally important for all parties that the DNO gets the correct information.

Beyond 2019/20 – using the DNOs' revenue estimates and most recent data available from the DCP 066 statements – we project future average tariff increases (excluding EHV) as follows:

<table>
<tr><th></th><th>2017/18</th><th>2018/19</th><th>2019/20</th><th>2020/21</th><th>2021/22</th></tr>
<tr><td>DUoS High Case</td><td rowspan="3">Actuals</td><td rowspan="3">Actuals
+0.2% to
+36%*</td><td rowspan="3">Actuals
+6% to
+8.5%*</td><td>10%</td><td>10%</td></tr>
<tr><td>DUoS Middle Case</td><td>4%</td><td>5%</td></tr>
<tr><td>DUoS Low Case</td><td>-1%</td><td>-1%</td></tr>
</table>

*Actual rates are known – charges for individual customers will vary depending on geographical location and usage pattern

Balancing Services Use of System (BSUoS)

Computed half hourly, BSUoS charges are imposed equally on generators and suppliers. The charge recovers the cost (to the System Operator, National Grid) of operating and balancing the electricity system.

BSUoS charges continue to be volatile; particularly when demand is low and intermittent generation, such as wind turbine output, is high.

The BSUoS charge since April 2017 has averaged £2.56/MWh against a National Grid forecast of £2.07/MWh. Total costs are out-turning lower than we expected (see our previous middle case) but these gains have been, in practice, offset due to a reduction in chargeable demand. Combining out-turn to date and future estimates, our current assumption is that BSUoS will out-turn at £2.56/MWh between April 2017 and March 2018.

The costs for "black start" - the procedure to recover from a shutdown of the transmission system without requiring start up power from the grid - are recovered through BSUoS charges. The 2016/17 charge has increased by over £0.10/MWh per annum, following the recovery of black start costs from the April to September 2016 RF (Final Reconciliation) volumes. The industry is awaiting confirmation of the contracts agreed for 2018/19.

In December 2017, a circular from National Grid requested feedback on how it should recover the 2017/18 Balancing Services Incentives Scheme (BSIS) costs, which Ofgem had only recently agreed. (The agreement usually happens much earlier in the year.)

The circular offered two options:

1. Smear the whole cost over the remaining SF (Initial Settlement) data runs for December 2017 to March 2018
2. Collect part of the cost over the remaining SF runs, and the year to date proportion of the costs from the RF settlement run

The first option proved most popular and the costs announced at the time were £5.3m. However, in December's Monthly Balancing Services Summaries (MBSS) report, the figure increased to £8.1m. Based on this, and the published eligible BSUoS volumes for the relevant months, the cost works out at around £0.04/MWh.

We've shown our projections in the table below, taking into account black start costs. These differ from the previous newsletter, due to changes in our future cost forecasts.

£/MWh*	2017/18	2018/19	2019/20	2020/21	2021/22
BSUoS High Case	2.90	3.20	3.80	4.50	5.60
BSUoS Middle Case	2.50	2.60	2.85	3.10	3.40
BSUoS Low Case	2.20	2.30	2.40	2.45	2.50

* Time weighted at National Balancing Point (NBP)

Here are the BSUoS out-turns for the last period and for this year to date (@ NBP):

£/MWh	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total/Ave
2015/16	1.32	2.59	2.44	2.02	2.38	1.47	1.56	2.88	2.92	2.35	1.77	1.43	2.10
2016/17	1.63	2.20	2.23	2.79	2.99	3.10	2.43	3.70	2.65	2.25	2.33	1.85	2.51
2017/18	1.86	2.14	3.43	2.80	3.18	2.31	3.07	2.03	2.20				2.56

Levy Control Framework

The Government manages its support for renewable energy through charges added in to electricity bills. The amount of funding is capped through a budget - known as the Levy Control Framework (LCF) - that sets the cap while ensuring that renewable targets are met.

Spending under the LCF was originally expected to increase from £3.2bn in 2013/14 to over £7bn by 2020/21, in 2011/12 prices. This would cover the costs of the Renewables Obligation (RO), small scale Feed in Tariff (ss-FiT) and the Contracts for Difference Feed in Tariff (CfD FiT) schemes – all of which we explain in more detail below.

Renewables Obligation (RO)

The RO was the main support framework incentivising the generation – and associated construction – of large-scale renewable electricity in the UK, before it closed to all new generation in 2017. Eligible generators receive a prescribed amount of Renewables Obligation Certificates (ROCs) for every MWh of renewable generation.

Suppliers fulfil their requirements by presenting Renewables Obligation Certificates (ROCs, sourced from the aforementioned market) to the Office of Gas and Electricity Markets (Ofgem). Alternatively, they can pay Ofgem a published Buy-Out price per ROC for any short-fall. Funds arising from Buy-Out payments are channelled into a "recycling" arrangement and distributed to eligible renewable generators.

The RO scheme closed to all new generating capacity on 31st March 2017 (with the exception of grace periods). Therefore, although there will be some increases for 2018/19 due to generation under these grace periods, the cost of the RO will start to level out from 2019/20 onwards.

Licensed suppliers are obliged to source an increasing proportion – the "Renewables Obligation" – of electricity from renewable sources. This is specified each October for a given April-March year to follow (the Compliance Period, or CP).

The RO for 2018/19 was set in September 2017, and subsequently revised in December - to implement an Energy Intensive Industry (EII) exemption - at 46.8% for Great Britain. This percentage - representing the Government's target for the proportion of UK generation from renewable sources - is a substantial increase from the previous level of 40.9%. The rise has been driven by the expectation of new offshore wind capacity coming online – and therefore generating ROCs. This wouldn't have been fully operational in the previous compliance period.

The table below shows out-turn and our projected RO costs in terms of £/MWh of electricity supplied (based on a valuation of ROCs at projected Buy-Out prices, and for non-EII exempt customers). We've updated our RO costs since the previous newsletter, having revised our ROC production forecasts and EII assumptions following the recent Department for Business, Energy & Industrial Strategy (BEIS) Consultation response.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
RO High Case			25.00	27.10	29.30
RO Middle Case	Actuals* 18.64	Actuals* 22.10	23.31	24.39	25.53
RO Low Case			22.50	22.75	23.10

* Actual published rate including EII (buy-out price forecasted)

Small Scale Feed in Tariffs (ssFit)

The ss-FiT subsidy is recovered from suppliers and paid to smaller generators of eligible low carbon and renewable power. The majority of these generators use photo-voltaic (PV) panels on rooftops, although a significant proportion of the power comes from "solar farms" and wind farms in the countryside.

The Office of Gas and Electricity Markets (Ofgem) administers the ss-FiT scheme, collecting a sum from each supplier based on their market share in each quarter. In the September following a given financial year, an annual reconciliation – or "truing up" – occurs, when more information is available about generation levels and suppliers' market shares. The principal factors affecting the charges to suppliers in any period are the levels of insolation (the amount of sunshine) and the installed PV capacity.

We previously reported that ss-FiT costs increased well-above levels anticipated by the Department of Energy & Climate Change (DECC) – now called the Department for Business, Energy & Industrial Strategy (BEIS). The increase occurred as implementation costs (particularly PV) dropped, making generation tariffs for suppliers relatively generous. In December 2015, following a consultation by DECC, it was announced that the scheme would continue, but with budget/deployment caps for new installations and reduced tariff bands. PV tariffs average a 68% reduction from pre-consultation rates, hydro 9% and wind 44%.

In the Autumn Budget, the Government announced that the Feed in Tariff scheme wouldn't be affected by the new levy framework and that it would close to new applicants from April 2019.

Thanks to the department of Business, Energy & Industrial Strategy (BEIS) cost control measures, the scheme's annual costs are now starting to level out at around £1.4 billion.

On average, costs have out-turned £30m lower than expected for Q3 and Q4 2017. The reasons include lower than average load factors and less new capacity, with a lower than expected tariff rate.

The scheme continues to be over-subscribed, triggering deployment caps. These result in the FiT tariff for the specific category reducing by 10% for the new installations accrediting in the following quarter. From Ofgem's weekly 'Queued Capacity' report, we can see that stand-alone photovoltaic (PV) panels has at least reached its deployment cap up to Q2 2018 and that wind is between 100kW and 1.5MW into Q2 2019.

The Energy Intensive Industry (EII) exemption for small scale FiT is still awaiting EU state aid approval. This may not be received until the scheme closes to new applicants from April 2019.

Seasonal fluctuations in FiT levels are evident, and swings of over £1/MWh from quarter-to-quarter are quite common. The table below shows quarterly costs since 2014.

£/MWh	Q2 (Apr-Jun)	Q3 (Jul-Sep)	Q4 (Oct – Dec)	Q1 (Jan-Mar)	Value including Annual Rec
2014/15	3.23	4.27	3.05	2.50	3.39
2015/16	4.55	5.70	3.90	3.15	4.47
2016/17	4.95	6.55	4.25	3.42	4.80
2017/18	5.96	6.81	4.57		

Here are our projections, which differ from the previous newsletter due to changes in our future cost forecasts.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
ssFiT High Case	5.35	6.10	7.00	7.75	8.50
ssFiT Middle Case	5.24	5.70	6.25	6.50	6.80
ssFiT Low Case	5.15	5.30	5.50	5.50	5.50

Contracts for Difference Feed in Tariff (CfD FiT)

The CfD FiT scheme is the framework designed to encourage new low carbon power generation in the UK. It replaces the Renewables Obligation (RO) mechanism, which has now closed, as the main vehicle for long-term investment into renewable electricity.

Generators enter into a contract with the Low Carbon Contracts Company (LCCC) under the auspices of the Department for Business, Energy and Industrial Strategy (BEIS). The generators sell their renewable power into the wholesale market as usual, but crucially pay or receive an amount for each MWh. This amount is equal to the difference between an individually agreed and fixed "strike" price and the relevant market price (the "reference" price) for that MWh.

Therefore, if the market price is below the strike price, the generator receives a "top up" price for the energy produced. However, the generator has to make a payment if the market price is above the strike price in any period. The arrangement means that generators can rely on receiving the strike price for their output.

Before each quarter, the LCCC estimates how much Contracts for Difference (CfD) generation will occur in the following three months. It then uses each agreed strike price to calculate total net payments to all CfD FiT generators. This will be used to compute a published interim rate; a guide to how much the CfD FiT scheme will cost per MWh for that quarter.

The LCCC will charge suppliers this interim rate for their accredited volume each day. At the end of each quarter, the LCCC will reconcile with each supplier the daily difference between the interim rate and actual cost of the CfD scheme.

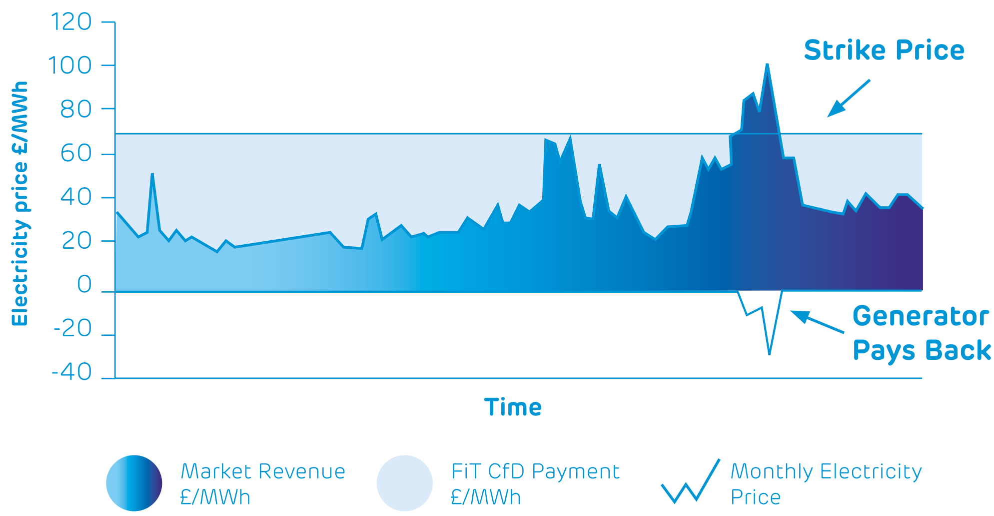
The first generation under this scheme came on over a year ago, along with the first payments. We've since seen costs increase quarter on quarter as more and more generators come online.

As the CfD FiT scheme's costs are dependent upon wholesale prices, predicting costs (or income) for generators is difficult. Should wholesale prices increase, scheme costs will fall as lower top-up payments are required. The opposite holds true if wholesale prices fall. Wind generation may also affect scheme costs; if high wind production pushes wholesale prices lower, eligible generators will require top-ups.

At the time of publication, the latest LCCC-published Interim Levy Rate (ILR) of £2.52/MWh for the last quarter of 2017 was amended mid-quarter to £1.57/MWh. This followed delays to the implementation of two schemes under the CfD.

The graph below is a simple illustration of how generators are compensated.

The LCCC will also recover its operational costs (from suppliers) through an Operational Cost Levy - set at £0.052/MWh for 2017/18. As the scheme costs continue to rise (from around £15m in 2017/18 to over £17m in 2020/21), the Operational Cost Levy will follow - albeit from a low base. Our forecast cost for 2020/21 is currently £0.061/MWh.



Source UK Government White Paper, July 2011, licensed under the Open Government License v1.0

Below, we've set out our projections of CfD FiT costs for the next four years. We constantly review our forecasts, taking into account power prices, possible changes to commissioning dates, revisions to wind forecasts, and adjustments for implementation date and volumes falling under the Energy Intensive Industry (EII) scheme.

2017/18 rate in £/MWh	**Q1**	**Q2**	**Q3**	**Q4**
CfD Interim Levy Rate	1.51	1.55	2.04	2.64*
Average Outturn ILR	1.44	1.44	1.78	N/A
2018/19 rate in £/MWh				
CfD Interim Levy Rate	3.82	4.17	4.57	4.44
Average Outturn ILR	N/A	N/A	N/A	N/A

* Time weighted average, due to the CfD Interim Levy Rate changing mid-quarter. Before the change, it was £2.86/MWh. On 23rd February 2018, it became £2.33/MWh.

As part of the LCCC's commitment to transparency, it publishes forecasts for the coming 15 months – along with the assumptions underpinning estimates - on its website.

Below, we've set out our projections of CfD FiT costs for the next four years. We constantly review our forecasts, taking into account power prices, possible changes to commissioning dates, revisions to wind forecasts, and adjustments for implementation date and volumes falling under the Energy Intensive Industry (EII) scheme.

£/MWh	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**
CfD FiT High Case	2.43	5.70	9.75	12.70	14.25
CfD FiT Middle Case	2.21	4.80	7.25	10.90	12.00
CfD-FiT Low Case	1.79	4.00	5.50	7.65	10.00
Operational Cost Levy	**0.053**	**0.057**	**0.059**	**0.061**	**TBC**

Capacity Market (CM)

The introduction of a CM within the Electricity Market Reform (EMR) arrangements is to ensure that the UK has sufficient capacity on the grid to cover peak demands. Historically, this was an issue on winter weekdays. Under the CM, reliable generating sets (e.g. coal-fired or gas-fired plant) not remunerated through other schemes* are eligible to commit to being available at peak times in the future, in return for a payment. This also applies to demand that can be reduced with notice. The level of payment is set via an auction process.

* This includes schemes such as Contracts for Difference (CfD) and Renewables Obligation (RO)

Two Capacity Market (CM) auctions were held in early February 2018, with the T-1 2018/19 auction occurring before the T-4 winter 2021/22 auction.

Looking to secure 50.5GW, the T-4 out-turned contracting 50.4GW at a clearing price of £8.40/kW (2016/17 money). This was more than a 60% reduction from the 2020/21 clearing price of £22.50/kW.

The T-1 was looking to secure 6GW; it out-turned contracting 5.78GW at a clearing price of £6/kW (around a 13.6% decrease from the 2017/18 clearing price). Combined Cycle Gas Turbines - CCGT - and Open Cycle Gas Turbines - OCGT - dominated the auction, securing over 60% of the awarded capacity. This takes the total amount of capacity secured to 53.31 GW, costing in the region of £1bn, and equates to an average clearing price of £19.35kW.

Unlike the Levy Control Framework charges that fall across all periods and run from April to March each year, the CM supplier charge runs from October to September. This monthly payment to National Grid is based on each supplier's expected market share during periods of high demand (4pm – 7pm, Monday to Friday, from November to February). Once the out-turn supply of each supplier is known, the charge is reconciled back.

From 2018/19 onwards, the charge will be calculated at gross demand (rather than at net demand, as at present). This will remove the embedded benefit for small scale generators, which has the effect of decreasing the cost to demand customers.

We've recently reviewed our assumptions on future CM clearing prices, and our estimates of future CM costs are set out in the table below. These costs include a Haven Power inflation forecast.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
CM High Case	1.60	3.78	4.60	5.25	2.40
CM Middle Case	1.40	3.72	4.00	5.0	2.23
CM Low Case	1.35	3.00	3.10	4.20	1.90
Operational Costs	**0.025**	**0.026**	**0.026**	**0.026**	**TBC**

ELEXON

Each Balancing and Settlement Code (BSC) party compensates National Grid Company (NGC) for the trading and settlement duties it has performed, paying its share of the costs based on the volume supplied/traded. Effectively, the more involved the BSC party, the larger the share it has to pay.

Our Elexon figures remain unchanged.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
ELEXON	0.07	0.07	0.07	0.07	0.07

Assistance for Areas of High Electricity Distribution Costs (AAHEDC)

Assistance for AAHEDC is levied on all suppliers, with the funds passed on to Scottish Hydro Electric Power Distribution Limited. This reduces the Distribution Use of System (DUoS) charges for the North of Scotland.

We previously revised our forecast from 2020/21 onwards, on the back of the Shetland New Energy Solution (SNES) proposal put forward by National Grid and Aggreko. Since our last newsletter, the Office of Gas and Electricity Markets (Ofgem) has rejected the proposal. Ofgem cited changes to the emissions targets timeline proposed by the EU Industrial Emissions Directive (IED) for engines on 'small isolated systems'. Therefore, we've reverted to our previous forecast.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
AAHEDC	0.231	0.249	0.291	0.314	0.341

Climate Change Levy (CCL)

The CCL is an energy tax that encourages business users to reduce carbon emissions and improve energy efficiency. Before August 2015, Levy Exemption Certificates (LECs) backed generation from renewable sources (such as biomass or wind) and customers on renewable energy were exempt from paying CCL. Since that date, the charge has applied to all business users.

CCL rates show modest increases until 2019/20, at which point they jump 46% to £8.47/MWh. This significant rise is because the Government wants to make up for the shortfall in revenue from the end of the Carbon Reduction Commitment (CRC) scheme in 2019. HM Revenue & Customs (HMRC) has not published CCL rates for any period after 2019/20.

£/MWh	2017/18	2018/19	2019/20	2020/21	2021/22
CCL	5.68	5.83	8.47	8.90	9.34

For further information on Third Party Costs, please contact your Account Manager.

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