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Credit and collateral in the GB energy markets

Phase 1

Volume 1—main report

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Strategic energy market intelligence

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- regulation and public policy within both electricity and gas markets;
- electricity and gas market design, governance and business processes; and
- market entry.

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Control sheet

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Contents

1 Introduction and summary

This Section explains our brief and the approach we have adopted to delivering it. It then summarises our main conclusions.

1.1 Need for collateral

Credit risk and the requirement to post collateral is a key feature of all commodity trading arrangements.

This is no less the case for electricity and gas, indeed collateral is required in three key areas of Great Britain (GB)'s energy market. These are principally to cover:

- energy purchase (or buy back) in a market where participants will consume energy irrespective of whether they have a contractual entitlement to do so;
- use of networks, which are paid for in arrears; and
- liabilities that arise under government low-carbon policy support schemes to recover costs.

In the GB market licensed players must post collateral under several industry codes, as well as under new government obligations. There are additional requirements where market participants engage in trading in a variety of forward markets (bilaterally and through exchanges).

1.2 Objectives

The Department of Energy and Climate Change (DECC) Energy Markets and Consumers Team commissioned Cornwall Energy in late December 2013 to conduct a review of credit and collateral arrangements in the GB markets for gas and electricity.

This report will be used by DECC to enhance its understanding of:

- the interaction between levels of credit and collateral and the costs faced by different types of participants in different segments of the energy markets; and
- the impact of credit and collateral arrangement on competition and effective market functioning in the retail and wholesale gas and electricity markets.

The report defines and assesses the current baseline of credit and collateral amounts and costs faced by market participants. The report is referenced on May 2014, and predates DECC's final decision on Electricity Market Reform (EMR) dated 30 June.

In turn, this Phase 1 report is divided into two volumes:

- Volume 1 (this document) sets out our method, headline analysis and findings. It is accompanied by a series of technical annexes; and
- Volume 2, available separately, provides analysis of credit requirements under individual codes and orders.

A full glossary of terms and acronyms can be found at the end of Volume 2.

Volume 1:

- establishes the segmentation of credit by amount and cost, by different rules, codes and orders, and by current and existing requirements, which we term "frameworks";
- assesses the impact of credit arrangements on different types of market participants;
- quantifies the inter-relationship between different forms of collateral and their application under the different frameworks; and

- considers how the overall burdens of credit and collateral might be impacted by proposed future policy changes.

The Phase 2 report addresses less burdensome but proportionate alternative options to the current requirements by:

- presenting and assessing options for alternative arrangements to address the most significant findings of the Phase 1 analysis as they apply to current requirements; and
- creating a framework of alternative approaches that could be used to inform more detailed work with relevant stakeholders on how options that are attractive in principle might be taken forward in practice.

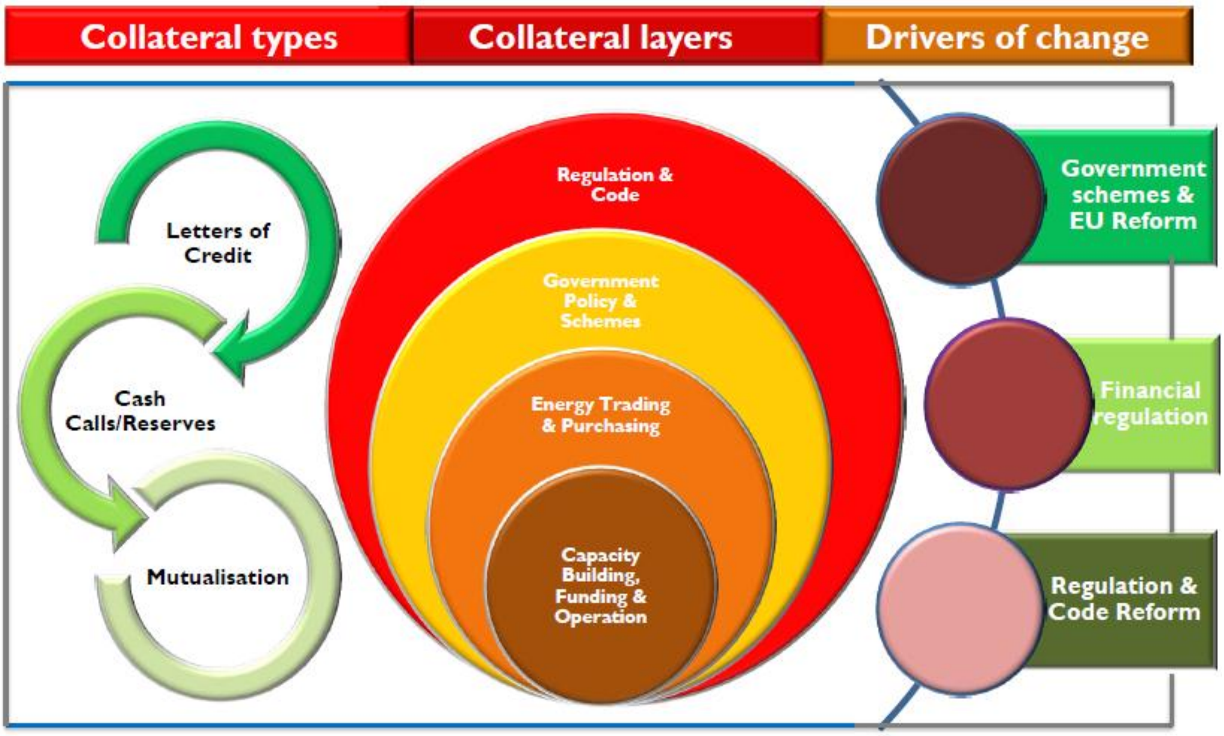
1.3 Approach

Our approach in this Volume 1 report involves a combination of desktop data gathering and analysis, engagement with key industry stakeholders and validation of what we term the framework and benchmark maps (*more on these below*).

Posting of credit in the energy markets arises under a series of obligations on individual companies to secure payments and charges, which are levied under different rules, codes and orders that govern key areas of financial and operational activity. These rules, codes and orders specify the value and types of permitted collateral. They can be complex and subject to change, both through industry modifications and changes brought about by the government, code authorities and the regulator.

These various elements are represented in Figure 1.1.

Figure 1.1: Map of credit and collateral in GB energy markets



The credit and collateral (terms which are used interchangeably in this report) demands placed on participants reflect the types of credit instruments they are allowed to post under the different frameworks, the number of "layers" of the frameworks that participants are exposed to as a result of their type of participation in the energy market, and the influence that reforms and changes to market, policy and regulatory arrangements will have on the levels and forms of credit that participants must post in order to carry out business.

Figure 1.1 shows the most common forms of credit types that participants are exposed to, including letters of credit and cash deposits, linking these to a range of different layers of activity that demand credit to be posted. It also identifies possible material drivers of change for credit arrangements, including new government policies and regulatory and code reform.

The report is framed around two key outputs that have been designed to deliver both a top-down and bottom-up perspective on credit and collateral in the GB energy markets. These are:

- the framework map, which focuses on the individual codes and arrangements (e.g. the Balancing and Settlement Code (BSC)), and which synthesises the main credit rules and quantifying instruments and costs they give rise to; and
- the benchmark map, which sets out a series of representative participant profiles, allows us to quantify typical costs of collateral at the individual participant level, thus identifying differences in the net cost of meeting the prudential requirements in doing business in the GB energy market.

The interaction between these two maps is represented in Figure 1.2.

1.4 The framework map

1.4.1 Purpose

The map quantifies and segments industry collateral by amounts and cost, by different codes and policies and by the permissible forms of collateral available to market participants. We have populated it following close liaison with code administrators and officials.

Figure 1.2: Top-down and bottom-up evaluation of credit and collateral

Top Down—Framework map

Detailed analysis of code rules.

Data from code governance authorities/policy teams.

Profiling and segmenting aggregate collateral

Authentication and challenge through dialiogue with stakeholder contacts

Cross feeds into benchmark mapping.

Current and future drivers of change

UNDERSTANDING CREDIT AND COLLATERAL ARRANGEMENTS

Bottom Up—Benchmark map

Creation of representative hypothetical companies

Modelling of credit and collateral exposures

Validation with appropriate market participants

Current and future drivers of change

Variant profiles to relfect choices/constraints of different business models

1.4.2 Codes and obligations

The framework map comprises a review of seven different arrangements. These elements we refer to as frameworks, and these frameworks can be split into two:

- baseline frameworks—regulation, code and policy-related credit and collateral rules that participants in the energy markets are obliged to face at the date that this report was originally commissioned. These are:
  - the BSC, which sets out the rules for balancing electricity under the central trading arrangements, and settlement of transactions under them, including payments for uncontracted electricity;
  - the Connection and Use of System Code (CUSC), which contains the rules for access to electricity transmission networks in GB, but which also includes arrangements for recovering costs of balancing services procured by National Grid;
  - the Distribution and Use of System Code (DCUSA), which likewise sets out commercial rules for use of the 14 electricity distribution systems and recovery of the associated costs; and
  - the Unified Network Code (UNC) for gas, which fulfils in a single document the same functions as the previous three codes for gas balancing and network use at all pressures;

For each code we have estimated costs for each of 2011, 2012 and 2013 in collaboration with code administrators, to arrive at annualised average estimates for both suppliers[1] and generators.

- new frameworks—certain regulation, code and policy-related credit and collateral rules that participants in the energy markets will be obliged to face in the future. These are:
  - the Contract for Difference (CfD) regime and its cost recovery mechanism under statutory orders yet to pass into legislation;
  - the new Capacity Market (CM), together with an obligation on electricity suppliers to fund it. Again the implementing orders have yet to be enacted; and
  - the Smart Energy Code (SEC). The SEC is now live, but the costs incurred under the code have yet to be fully established.

The credit and collateral proposals for the CfD and Capacity Market are yet to be finalised and the steady-state costs are not as yet known. The rules relating to credit under these frameworks are therefore subject to change and the report should be read with this in mind.

The report refers to representative years for new frameworks (CfD, Capacity Market and SEC). We have assumed (for comparative purposes) that these estimated collateral amounts are retrospectively posted each year during the period 2011-13 so the impact can be seen in addition to credit required under the baseline frameworks and compared against them.

To do this:

- for the CfD we have modelled the supplier levy and associated credit amounts and used a representative year of 2020 using the information from the 23 October 2013 DECC impact assessment[2];
- for the Capacity Market we have taken the capacity market payments figure for 2019 from the 24 October 2013 DECC impact assessment[3], and calculated the associated security value; and
- for the SEC we have taken the total costs cited for the Data and Communications Company (DCC) for the period of assessment in the DECC impact assessment from 30 January 2014[4] and derived an annual cost, calculating from this an associated security value.

1.4.3 Trading

Additionally, in the benchmark map, we have extended the assessment to consider credit requirements for energy trading—both bilateral and exchange-based trading in power and gas. Again we have estimated costs for each of 2011, 2012 and 2013, to arrive at annualised average estimates.

We have modelled the amount of credit that we estimate is required to cover settlement risk under bilateral contracts for power and gas and have estimated credit required to be posted under power

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[1] The analysis assumes that where any of our benchmark companies have gas customers or are pure gas suppliers then they are also a gas shipper. It is not unusual for suppliers with meaningful activities in gas supply also to operate a gas shipping business. Hence, they face the burden of amounts and costs of collateral directly, rather than these being passed through more opaquely through commercial arrangements between suppliers and shippers.

[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252273/131022_IA_-_Supplier_Obligation__final_for_publication_21_10_2013_.pdf

[3]www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

[4]www.gov.uk/government/uploads/system/uploads/attachment_data/file/276656/smart_meter_roll_out_for_the_domestic_and_small_and_medium_and_non_domestic_sectors.pdf

exchanges, based on credit rules for the N2EX platform. In both cases this is based on assumed volumes of trading by different benchmarks through these types of trading channels.

In reality, there are a range of possible energy trading routes available to market participants, and in bilateral trading in particular credit arrangements will be set based on commercial negotiation between parties, with the details of such arrangements being commercially sensitive and often highly bespoke. As a result, our estimated credit amounts and costs associated with trading are supplemented substantially by qualitative views obtained from active market participants.

1.4.4 Health warnings

The report does not quantify known changes where it is not possible accurately to assess the implications on levels of credit and collateral because the detailed design elements are not known[5].

In the case of the CfD regime and the supporting supplier objective, the analysis we have conducted does not reflect the final design decisions[6].

The analysis of the credit impacts on participant companies in the power and gas markets associated with trading strategies is also hampered by lack of access to confidential and commercially-sensitive information relating to volumes and costs.

1.5 The benchmark map

1.5.1 Purpose

The benchmark map creates a representative set of hypothetical companies from different segments of the GB energy market. Through numerical modelling of data from the period 2011-13, it estimates credit and collateral amounts and costs attributable to each participant benchmark in each year of that period under each framework. These estimates are then averaged for the 2011-13 period.

As with the framework map, it achieves this by assuming that the credit costs of the new frameworks were also incurred based on representative years but in the same period of analysis (2011-13).

The benchmark map further examines costs faced by different participant types when they engage in trading of gas and power. However, the ability to access confidential information on how credit requests underpin individual trading arrangements means that this analysis is less developed than the analysis under the baseline and new frameworks.

The benchmark map splits into two—a map for suppliers and a map for generators. This reflects the material differences in collateral demands faced by these two types of participant. In both cases, the report also includes profiles for alternative benchmarks to reflect choices/constraints of different business models or stages of business evolution. In particular, this analysis has focussed on new entry and acquisitions. It also considers collateral calls associated with energy trading for the larger suppliers, including “mark-to-market”.

[5] These include (but are not limited to): cost recovery for new balancing services through BSUoS charges (influencing credit levels under the CUSC); Ofgem’s review of gas transmission charging and cost recovery methods; implementation of market splitting or locational pricing as part of the European Target Model; CMP224 potentially varying the rates of transmission usage charges recovery from generators and suppliers; CMP201 potentially removing BSUoS charges from generators; and implementation of EMIR and MIFIDII. These changes also include the gas significant code review where rule changes have yet to be brought forward. We have attempted to factor the electricity balancing significant code review (EBSCR) into the benchmark map, which takes into account marginal prices, as we have assumed suppliers are posting collateral based on the most extreme system buy and sell prices to avoid credit default. Modelling the full impact of EBSCR in the future is unlikely to reveal any useful comparison as this would involve modelling a supplier’s balancing position, which would be outside the scope of this report, and would include speculative assumptions surrounding prices, imbalance and behaviour.

[6] The final design does not include the insolvency fund and the main reserve fund has been reduced in size. It will therefore reduce the costs associated with the supplier obligation.

1.5.2 Participant types

To translate these collateral amounts into amounts per participant, we have produced a series of benchmarks based on a range of typical market participants. In each case we have developed a profile of key assumptions on market participation. The benchmarks we have selected have been agreed with DECC and are set out in Table 1.1 and Table 1.2.

Table 1.1: Core supplier benchmarks and variants

Core supplier benchmark	
Intermediate domestic supplying electricity and gas	New entrant and acquisitive market entrant
Niche domestic electricity supplier	
Industrial and commercial electricity supplier	
Small and medium-sized enterprise electricity supplier	
Industrial and commercial gas supplier	
Small and medium-sized enterprise gas supplier	
Large vertically integrated undertaking (VIU)[7] supplying gas and electricity to domestic and non-domestic consumers	"Mark-to-market"
Large domestic gas and electricity supplier	

Table 1.2: Core generator benchmarks and variants

Core generator benchmark	
800W CCGT operator	New build
100MW biomass operator	
600MW dedicated biomass conversion operator	
500MW offshore wind operator	
50MW onshore wind operator	
10MW solar operator	None

A brief description of each benchmark is included in Table 1.3.

[7] Such as the Big Six companies, who are British Gas, EDF Energy, E.ON UK, RWE npower, Scottish Power and SSE.

Table 1.3: Description and shorthand references for benchmarks[8]

Supplier type	Graph/table shorthand	Description
Intermediate domestic supplying electricity and gas	Intermediate domestic	An intermediate domestic supplier of both electricity and gas (in a ratio of 55:45 per customer), with 500,000 domestic customers.
Niche domestic electricity supplier	Niche domestic	A small electricity supplier to domestic customers from niche forms of generation (such as purchasing all power from green generation), with tariff offers differentiated on that basis, with 50,000 customers.
Industrial and commercial electricity supplier	I&C electricity	An electricity supplier to large industrial and commercial business customers (no domestic customers or smaller business customers), with 95 customers.
Small and medium sized enterprise electricity supplier	SME electricity	An electricity supplier to small and medium sized business customers (no domestic customers or larger industrial or commercial customers), with 16,799 customers.
Industrial and commercial gas supplier	I&C gas	A gas supplier to large industrial and commercial business customers (no domestic customers of smaller business customers), with 1,000 customers.
Small and medium sized enterprise gas supplier	SME gas	A gas supplier to small and medium sized business customers (no domestic customers or larger industrial or commercial customers), with 40,000 customers.
Large vertically integrated utility (VIU) supplying gas and electricity to domestic and non-domestic consumers	Large VIU	A large electricity and gas supplier (in a ratio of 60:40 per customer) to domestic and industrial and commercial customers, but the supply arm is part of a wider business with access to power purchasing options from their own generation fleet and through Power Purchase Agreements (PPAs) entered into with third party generators. 8.5mn customers.
Large domestic gas and electricity supplier	Large supplier	A large electricity and gas supplier to domestic customers (in a ratio of 60:40 per customer). It has no generation fleet as part of its wider group but has the ability to source power through writing PPAs with third party generators, with 6mn customers.
800MW CCGT operator	CCGT	An operator of a generating plant utilising combined cycle gas turbines with a nameplate generating capacity of 800MW. The fuel input is gas.
600MW dedicated biomass conversion	Large biomass conversion	An operator of a generating plant that has converted from coal fired generation units to biomass generation, with a nameplate generating capacity of 600MW. The fuel input is biomass.
100MW biomass operator	Biomass plant	An operator of a generating plant using dedicated biomass to fuel generation with a nameplate capacity of 100MW.
500MW offshore wind operator	Offshore wind	An operator of a generating plant using wind power for generation, with turbines located offshore and a nameplate capacity of 500MW.
50MW onshore wind operator	Onshore wind	An operator of a generating plant using wind power for generation, with turbines located onshore and a nameplate capacity of 50MW.
10MW solar operator	Solar	An operator of a generating plant using solar power, with panels and inverters located onshore and a nameplate capacity of 10MW.

[8] To get the per customer ratio we have weighted the distribution of customers for each fuel for each supplier.

More details on the input assumptions we have utilised in modelling credit results for these benchmarks can be found in the annex to this report.

We have included one large vertically integrated utility benchmark. Despite similarities in business model, each Big Six utility will have varying degrees of vertical integration, hedging strategies, the extent to which they trade financially and also self-supply. Our large VIU supplier benchmark is not designed to mimic any established player or to be generally representative of all Big Six utilities. We do nevertheless explore more generally in this example the benefits of integration to participant costs in the analysis, which we believe are considerable.

In summary, using these benchmarks, the map:

- estimates in nominal terms the collateral amounts and costs in the period 2011-13 facing the 13 'core' benchmarks;
- displays credit amounts and costs for supplier benchmarks under alternative circumstances reflecting relevant choices and constraints;
- considers the current collateral demands faced by these benchmarks from current frameworks as well as those arising from new frameworks; and
- demonstrates the extent of correlation between the size of participant, date of market entry, their financial standing and the amounts and costs of collateral required.

1.5.3 Stakeholder liaison

To ensure the data contained in this report is representative of actual levels of credit and collateral in the GB energy markets, we participated in a series of discussions with market operators, code administrators and market participants. We have validated the information in both the framework and benchmark maps with these various stakeholders.

Specifically:

- with regard to the framework map, we have received data from, and discussed the topic of credit and collateral with National Grid, Xoserve, Elexon; and Electralink; and
- with regard to the benchmark map, we have discussed the outputs of our desktop data analysis and related themes and issues with a range of energy market participants, including Hudson Energy, Haven Power, Co-operative Energy, Opus Energy, Spark Energy, Good Energy, First Utility, and BES (the trading name of Business Energy Solutions Ltd.). This took the form of structured interviews based around data sets sent to market participants in advance.

1.5.4 Credit instruments

We have considered the following main types of instruments of credit and collateral:

- letters of credit/bank guarantees—typically on-demand promises to pay up to a specified value, issued to code authorities on behalf of energy market participants by strongly rated banks or financial institutions, collateralising the financial obligations of the energy market participant under the code;
- cash—typically placed on deposit with code authorities, collateralising the financial obligations of the energy market participant under the code;
- parent company guarantees (PCGs)—a guarantee of payment or performance obligations of a subsidiary company by a direct or indirect parent company, issued to code authorities on behalf of the subsidiary company;

- insurance performance bonds—a surety bond issued by an insurance company on behalf of an energy market participant to code authorities, guaranteeing performance of the energy market participants obligations under the code; and
- unsecured credit allowance—an allowance as a proportion of otherwise collateralised charges and liabilities that the CUSC, DCUSA, UNC transmission and distribution, and SEC framework credit rules allow participants to individually utilise based on their financial standing (established through third party credit rating), their history of making full and timely payments, or both factors.

For each framework we specify the applicable instruments that are allowable under the detailed rules. Permissible credit instruments under each framework differ. They are set out in Table 1.4 below.

Table 1.4: Overview of credit instruments

Framework	Letter of credit	Bank guarantee[9]	Cash deposit[10]	PCG	Bilateral insurance	Prepayment agreement	Unsecured rating	Unsecured payment history
BSC	✓	×	✓	×	×	×	×	×
UNC Balancing	✓	×	✓	×	×	×	×	×
CUSC	✓	✓	✓	✓	✓	✓	✓	✓
DCUSA	✓	✓	✓	✓	×	×	✓	✓
UNC Tx/ Dx	✓	✓	✓	✓	×	✓	✓	✓[11]
CfD	✓	×	✓	×	×	×	×	×
Capacity Market	✓	×	✓	×	×	×	×	×
SEC (DCC)	✓	✓	✓	×	×	×	✓	×

1.6 Headline findings

The headlines that emerge from this analysis are summarised below.

1.6.1 Framework map

The figures for the baseline frameworks are derived from data provided by code governance authorities. The code authorities have not been able to provide data that splits collateral by participant type.

As we have noted, the data for the new frameworks is taken from the relevant DECC impact assessments referenced in section 1.4.2 of this report. In the case of the new frameworks, the data is calculated for a reference year in the future and then expressed as average annualised amounts and costs over the period 2011-13 to assist comparability.

The total collateral amounts across baseline and new frameworks are shown in Figure 1.3 below and they sum to £4.2bn.

[9] Including performance bonds.

[10] Including escrow.

[11] Only for the first two years after signing up to the code.

Figure 1.3: Average annual framework collateral 2011-13 (£mn)

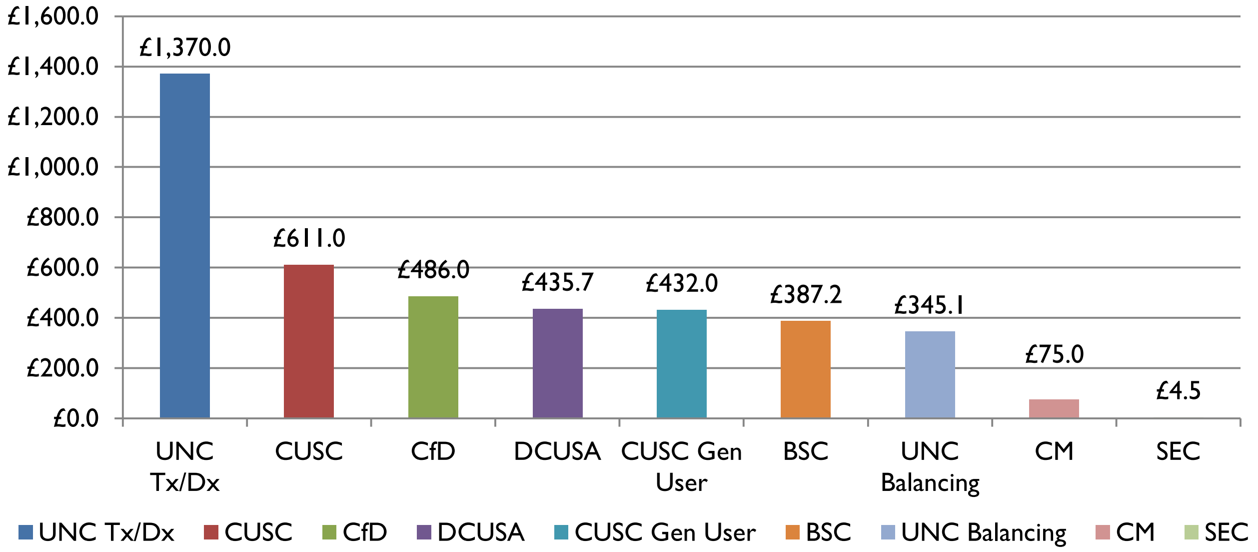


Figure 1.4 illustrates the relationship between collateral amounts and collateral costs.

- **credit amounts** refer to the monetary value of posted credit across participants; and
- **credit costs** refer to the monetary costs of financing the credit amounts again across participants, and are derived from multiplying the value of different component instruments of the credit amounts (cash or letters of credit) by a set of financing cost assumptions.

Figure 1.4: Correlation annual average amounts to annual average costs, 2011-13 (£mn)

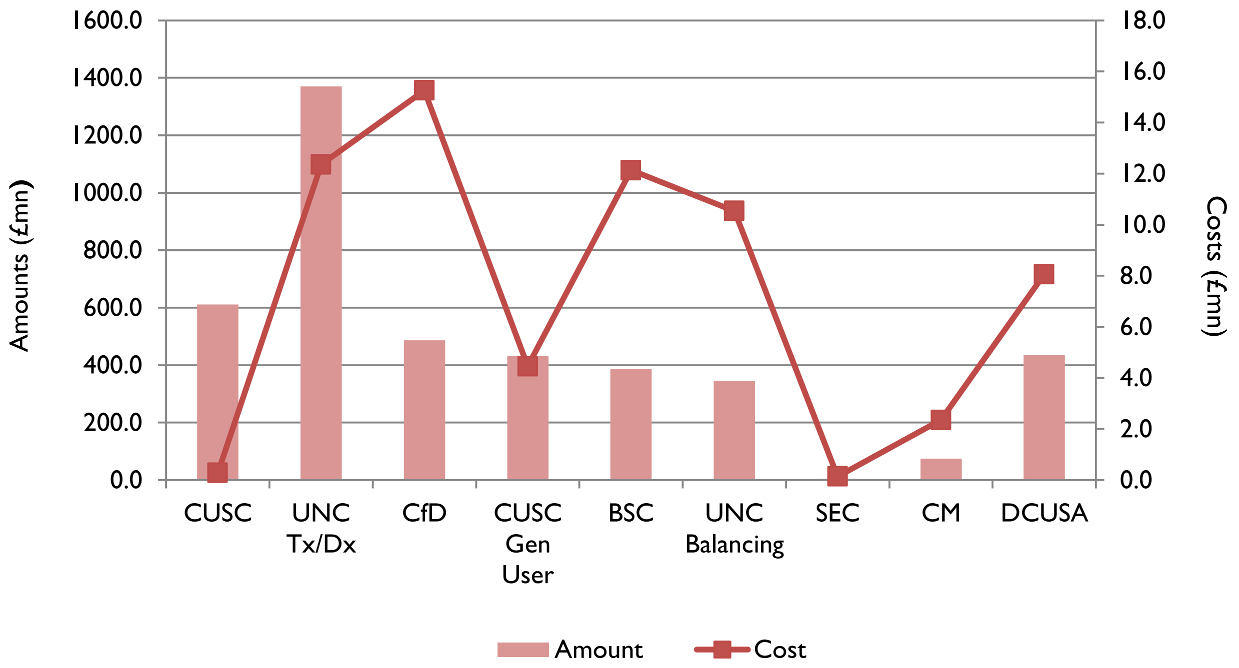


Figure 1.4 shows the strong relationship between the scale of credit amounts and credit costs in balancing frameworks and the new frameworks, and the weak relationship in transmission and distribution frameworks across both gas and electricity. These effects are a result of balancing and new frameworks predominantly being collateralised by letters of credit and cash, which attract direct credit costs, and transmission and distribution frameworks allowing the use of unsecured credit allowances and PCGs.

The key findings from our analysis of the framework map relevant to our terms of reference include:

- credit arrangements are set out in a number of codes, regulations and laws, with different governance bodies. The implementing arrangements are fragmented and complex. They are subject to frequent change through industry, government or governance authority driven modifications;
- it is challenging for all participants, but smaller participants in particular, to engage with these complex arrangements, and it is difficult for possible new entrants to assess the implications of credit arrangements on the costs of new entry;
- even after taking into account the ability to take advantage of unsecured credit allowances under transmission and distribution frameworks, credit amounts are still material for suppliers, and in particular electricity suppliers, reflecting the demands they face under the BSC, bilateral power trading and new demands to be set under the CfD and Capacity Market;
- the total average annualised collateralised amount required across industry codes and arrangements is £3.6bn (baseline frameworks) and £0.6bn (new frameworks), summing to £4.2bn;
- the new frameworks will add 16% to collateralised amounts;
- the majority of collateral amounts and therefore costs under baseline frameworks arise under electricity arrangements (52%), a position that will be reinforced with the roll-out of new frameworks (rising to 58%), given that they almost exclusively relate to electricity suppliers;
- the majority of collateralised amounts for baseline frameworks and virtually all for new frameworks will be borne by suppliers, and in particular electricity suppliers;
- the design of credit arrangements differs from framework to framework and there are certain inconsistencies with the same types of risk from the same community of participants being covered in different ways;
- features of existing credit arrangements of some baseline frameworks in the market have been replicated in the design of new frameworks, but in some cases with the addition of strengthening the protections for the beneficiaries of credit;
- balancing codes create some of the most costly credit obligations of the current baseline frameworks, particularly by cost per pound of credit posted. The posting of collateral is some way in excess of calculated indebtedness particularly under power balancing for the BSC. Under both the BSC and UNC credit instruments are limited to letters of credit and cash;
- the majority of collateral by value is concentrated on activities relating to electricity and gas transmission and distribution. However, the cost to participants is offset by the ability to issue PCGs;
- the transmission and distribution frameworks also allow participants to access an unsecured credit allowance based on their credit rating or good payment history. The net result is a much lower collateral cost for transmission and distribution than for balancing activities;
- in contrast, for those frameworks like the BSC and UNC balancing activities, the CfD, the Capacity Market and the SEC, where letters of credit (or bank guarantees) and cash are the only methods of collateralisation, there is a strong correlation between collateral amounts and collateral costs; and
- the CfD will be the most credit-intense by cost of all regulatory and policy frameworks, once the majority of the expected number of CfDs have been entered into. This position reflects the expected value of settlements under this scheme relative to other frameworks. It is also a consequence of the

multiple levels of collateral being required to protect against different types of risks, and the costly nature of the obligated credit instruments.

1.6.2 Supplier benchmark map

Turning to the distribution of costs between participant types, Figure 1.5 illustrates the allocation of collateral amounts, across the different supplier benchmarks we have developed.

Figure 1.5: Supplier benchmark map, annual collateral amounts, 2011-13

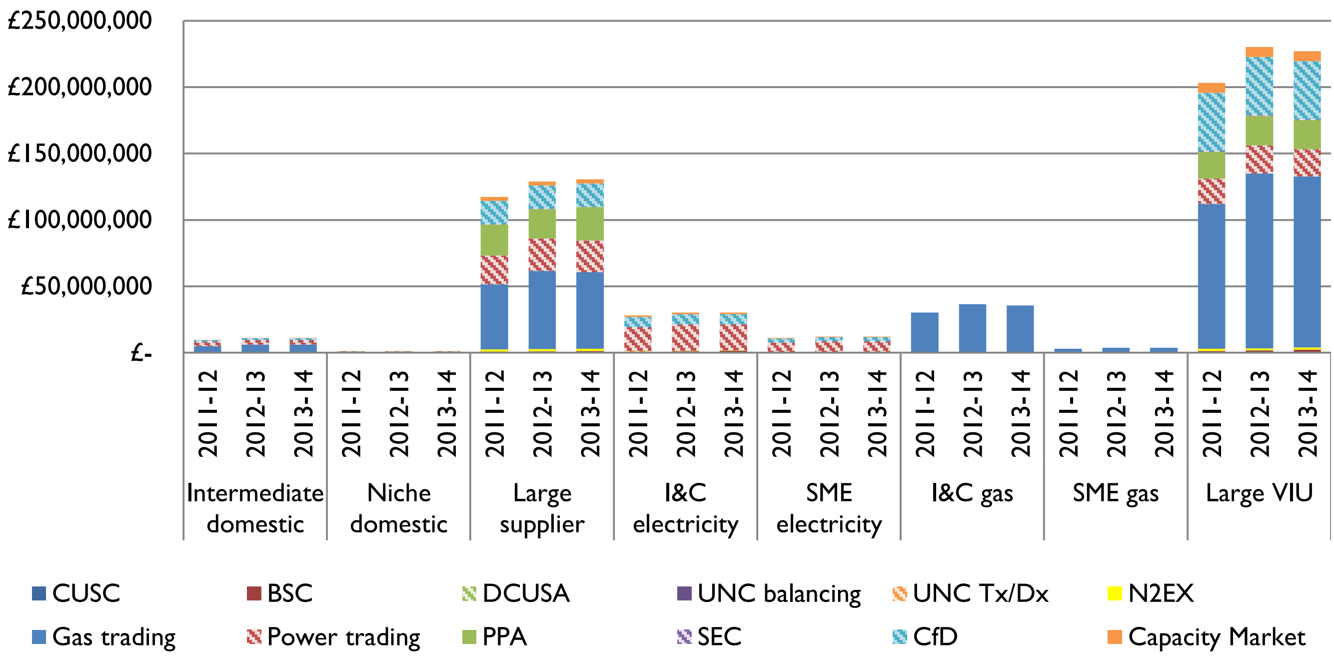
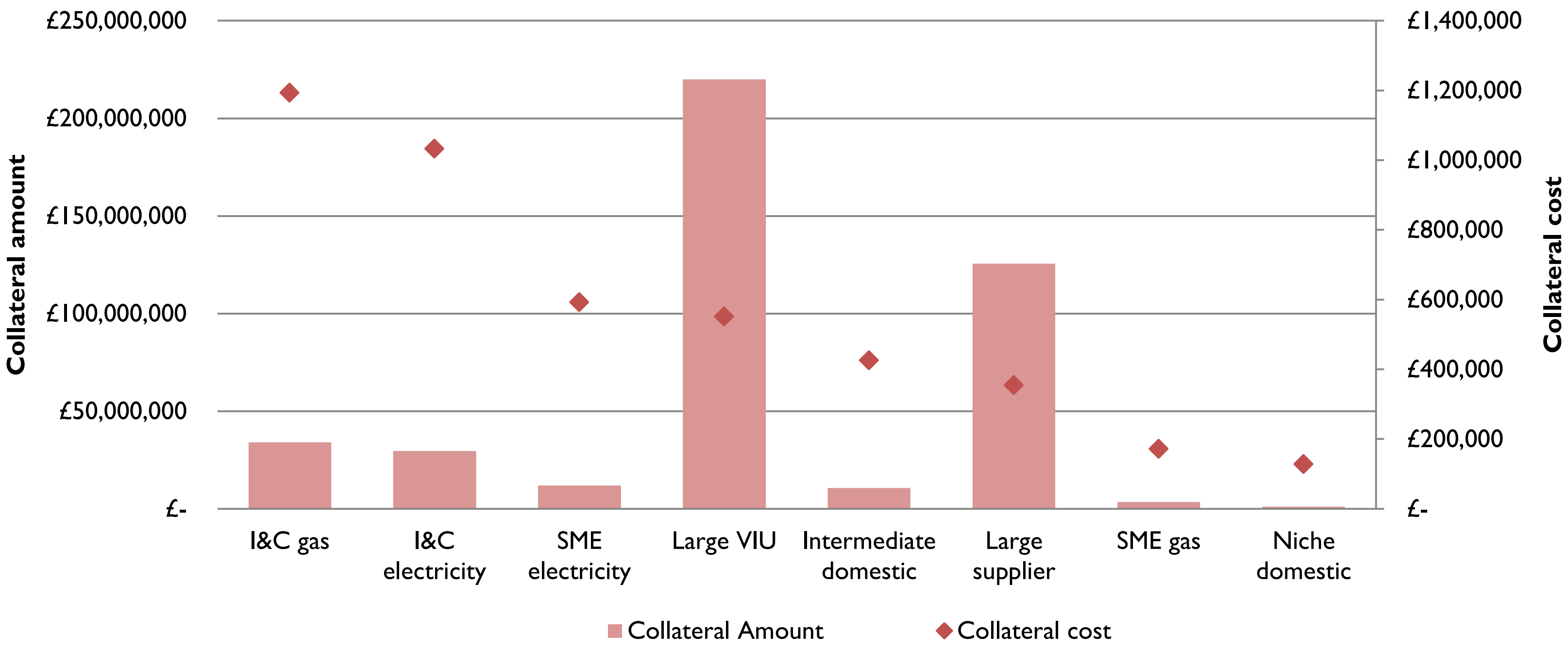


Figure 1.5 shows that the size of credit amounts are heavily driven by the scale and volumes of activity of suppliers. All relevant frameworks require suppliers to post credit based on either volumetric charges or market share. Credit costs are however not strongly correlated in this fashion, revealing financial advantages to larger suppliers who have greater choice over how to collateralise obligations in transmission and distribution in both gas and electricity, and they also face cheaper credit costs for balancing and new frameworks.

Figure 1.6: Core supplier benchmark ranking by annual average credit cost (£) vs. ranking by annual average credit amount, 2011-13



This finding is reinforced by Figure 1.6, which illustrates the relationship between annual average credit amounts and costs for different suppliers for the period 2011-13. Amounts are measured on the right hand axis, with costs measured on the left.

The relationship is asymmetrical because of the different cost of collateral faced by the different types of player assessed under the detailed framework rules, but clearly disadvantages smaller players who see higher costs relative to their size. This differential arises as a function of both scope and scale.

To illustrate the average cost per customer we calculate that for the large VIU supplier is 4p/customer; for the large supplier of domestic gas and electricity it is 6p/customer but for the niche domestic electricity supplier it is £2.60/customer.

The first differential is a consequence of the large VIU supplier's larger customer base and lower financing costs, which outweigh the fact that they are being required to post collateral across a wider range of customer activities than the other supplier benchmarks. With regard to the large supplier, its advantage over the niche supplier is a reflection simply of its lower financing costs that arise from its established position and better credit standing.

In addition to the supplier benchmarks for existing players, we also present some alternative cases examining the impact on credit amounts and credit costs of different types of new entry (both new entrants and acquisitive entrants). We also explore "mark-to-market" risk under power and gas trading for a large VIU supplier with domestic and non-domestic supply and a large domestic supplier.

Headlines from our analysis of the supplier benchmark map relevant to our terms of reference include the following:

Existing players:

- nominal collateral demands fall heaviest on suppliers. For example, the peak of credit amount and cost postings across the supplier benchmarks are £220mn (for the Large VIU) and £1.2mn (industrial and commercial gas supplier) respectively. The equivalent numbers for the generator benchmarks are £12.7mn and £190,000 (for the CCGT operator);
- for suppliers, the prevalence of "headroom" in the credit posted under the BSC reflects fear of the consequences of BSC default, and the complicated nature of the credit cover calculation;
- power exchanges like N2EX and APX are not widely used by smaller suppliers for purchasing as the costs, amounts and volatility of collateral required are seen as prohibitive, which in turn is reflected in low collateral costs simply because of less trading;
- bilateral trading is also credit-intense, especially for smaller suppliers. Varying attitudes to collateral, in particular in electricity arrangements, are apparent depending on the nature of the counterparties entering into trades;
- as a consequence typically credit arrangements are a barrier to trading for smaller suppliers;
- this context has prompted innovation, with the entry of financial players, aggregators and large industrials providing a route for suppliers to trade without large collateral demands. This innovation allows some smaller suppliers access to trade with longer maturities, in return for a margin and in some cases a minority equity holding in the supplier's business by the aggregator; and
- the introduction of the CfD will materially increase the volume and cost of credit for all electricity suppliers once it has reached scale.

New players:

- collateral demands for new market entrants who enter supply with limited customers are immediate and relatively large. The combination of setting collateral requirements against a future expectation of market activity, along with the comparative financial weakness of the respective new entrant, and hence high costs of finance, creates a working capital squeeze;
- for these new entrants, the ability to manage these unavoidable costs through pricing of tariffs to customers is limited;
- their ability to hedge risk is also compromised by difficulty in posting the required amount of credit to support trading at different points on the maturity curve;
- transmission and distribution activities are also much more credit-intense for new entrant suppliers as they typically cannot access unsecured credit allowances. These activities create hurdles for new market entry and consequently could contribute to a reduction in competitive tension in the market;
- external financial support from shareholders or owners during the first one to two years of new entry appears essential. Without it, new entrant suppliers would be required to make difficult choices about which frameworks and activities they collateralise in preference to others, in effect reducing their ability to trade. Their ability to grow their business will almost certainly be compromised;
- acquisitive new entrants face similar demands, but with a scale of existing operation that allows them to manage these demands better than new entrants. Nonetheless, these demands impose important

additional costs on new entrants relative to their peers, which can dilute their ability to compete effectively; and

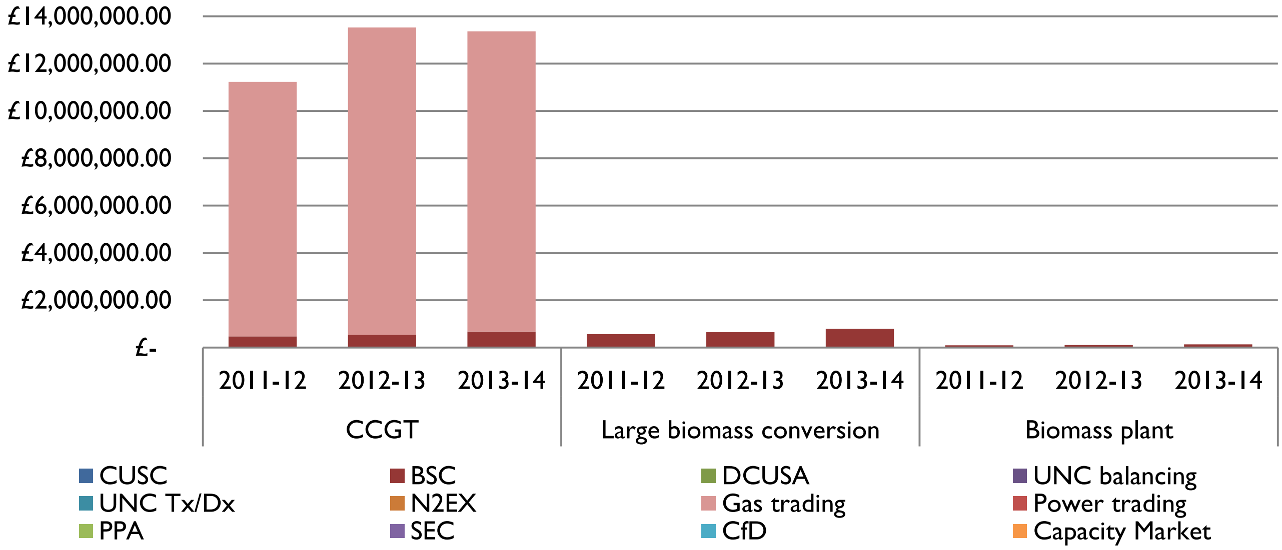
- these factors facilitate a scenario in which acquisitive new entrants tend to come from established energy market participants in other countries[12].

1.6.3 Generator benchmark map

Figure 1.7 illustrates the allocation of collateral amounts, across different generators, and by framework and trading activity between 2011-13. It shows that generators are much less widely exposed to credit demands than suppliers. Renewable generators with no fuel purchasing requirements are generally insulated from needing to post credit amounts as a result of entering into Power Purchase Agreements (PPAs), where offtakers as meter registrant assume credit responsibilities on the generator's behalf in return for a fee.

A CCGT plant incurs a higher cost and amount of collateral in proportion to its size (MW) than other plant. This is as a result of being required to post large amounts of collateral to support gas trading—biomass and biomass conversion will also face "hidden" collateral from sources not covered in our benchmark map.

Figure 1.7: Generator benchmark map, annual collateral amounts, 2011-13



We also present some alternative cases examining the impact on credit amounts and credit costs of new entry.

Headlines from our analysis of the generator benchmark map relevant to our terms of reference include the following:

<u>Existing players:</u>

- the collateral costs and amounts across the core generator benchmarks are far less than for suppliers. For example, the peak of credit amount and cost postings across the generator benchmarks are

[12] Most notably Iberdrola acquiring Scottish Power, RWE acquiring npower, E.ON acquiring Powergen, EDF acquiring London Electricity. Other new entrants in supply have been UK arms of established larger continental utilities such as GDF, Gazprom and DONG Energy.

£12.7mn and £190,000 (for the CCGT operator) respectively. The equivalent numbers for the supplier benchmarks are £220mn and £1.2mn;

- this disparity reflects simpler process and the linear business model associated with baseload energy production;
- some generator benchmarks also see limited collateral exposure by virtue of the fact that they do not trade their output. For many smaller players PPAs insulate them against credit demands, but for a fee; and
- biomass plant will need to secure medium to long-term fuel supply contracts (or invest in their own fuel supply chain) in order to operate and finance their plant. Due to the degree of uncertainty and non-standard nature of fuel supply arrangements, we have not modelled these fuel supply collateral arrangements. But such arrangements will impose collateral demands on these benchmarks in practice.

New players:

- credit timing rather than amounts is key for new build generation. Under both the CUSC and the Capacity Market, collateral is required to be posted at a stage where there is no generating revenue, the project is in development, and therefore if the project does not proceed for any reason any draw-downs on issued collateral are likely to be written off in full; and
- for independent developers seeking third party finance at this stage of a project's life, this is likely to create a financing challenge, which supplements other credit demands they may face to secure contracts for critical equipment for the construction of the project.

1.7 Structure of report

Following this introductory and summary chapter, the rest of Volume 1 of this report is structured as follows:

- Chapter 2 sets out the framework map and established collateral requirements across current and future frameworks;
- Chapter 3 sets out the methodology for compiling the supplier benchmark map and sets out findings from the application of this method to our range of supplier benchmarks; and
- Chapter 4 sets out the methodology for compiling the generator benchmark map and sets out findings from the application of this method to our range of supplier benchmarks.

Annexes to Volume 1 have been included separately. These include the detailed supplier benchmarks (Annex C) and detailed generator benchmarks (Annex D).

This analysis is supplemented by further data and detailed background on the individual codes and orders specifying credit and collateral rules. This is included in Volume 2. A summary of each baseline and new framework is included for ease of reference in Section 2 of this report.

2 The framework map

This Section of the report describes the framework map. It establishes the amounts and costs of collateral posted under different codes, regulations and policies, both now and in the immediate future.

2.1 Purpose

The framework map describes:

- the entities requiring and administering the different types of collateral in the GB energy markets;
- the individual frameworks under which the collateral is demanded, including brief commentary on the rationale behind the need for the type and amount of collateral sought;
- the segments (electricity or gas, transmission, distribution or balancing etc.) into which these fall;
- the types of permissible collateral and other protections that might exist alongside collateral in mitigation of loss; and
- in nominal terms, the total amounts demanded between 2011-2013 and the estimated cost of collateral provision under each framework[13].

2.2 Quantifying collateral amounts and cost

For the seven framework arrangements, we:

- present data sourced from the code administrators on collateral amounts posted in the period 2011-13, but averaged to produce an annualised reference amount;
- split these amounts out by instrument based on this data; and
- use financing cost assumptions to establish a representative estimate of the cost of credit in aggregate for individual frameworks, and for all frameworks as a whole in the period 2011-13.

2.3 Summary of framework credit arrangements

Below in Tables 2.1 to 2.9 we summarise the key parameters and metrics from each of the seven frameworks. In each case we summarise the purpose of the credit arrangements, amounts posted, types of collateral accepted, its breakdown between instruments, triggers and other defining features.

[13] Given the basis of calculating liabilities and charges that underpin credit demands across different frameworks, inflation has an inconsistent influence on the movement in the level of charges and credit requirements across different codes. Hence in our view presentation in real terms could distort meaningful analysis.

Table 2.1: Key BSC credit parameters

Who is impacted?	Electricity suppliers and generators	
Purpose	Trading parties may have debts (or be due payments) in respect of trading charges incurred, on average, over the previous 29 days. These primarily relate to energy imbalance charges The purpose of credit and collateral under the BSC is to ensure that, should a trading party default, there is liquid collateral available to pay defaulted debts	
Average annual credit amounts	2011—£424mn 2012—£383mn 2013—£354.5mn	Annualised average £387.2mn
Type of collateral accepted	Letter of credit from an A rated financial institution (with duration of at least three months) or cash	
Split between instruments	2011 £351.4mn letter of credit, £72.6mn cash 2012 £329.5mn letter of credit, £53.5mn cash 2013 £307.0mn letter of credit, 47.5mn cash	
Period/ level of cover required	29 days of charges; indebtedness estimates based on actual and projected charges	
Unsecured credit criteria	None	
Other protections	Mutualisation payments relating to a defaulting trading party that cannot be covered by the posted letter of credit, or cash, by that defaulting trading party	
Trigger for call	Non-payment default. There are specific grades of default for failure to comply with credit rules (level 1 and level 2) linked to the amount of indebtedness as a percentage of liabilities, which can also lead to BSC suspension and eventual exclusion if not remedied within the terms of the rules	
Total scheme cost	2011—£13.7mn 2012—£11.8mn 2013—£10.9mn	

Table 2.2: Key CUSC credit parameters—TNUoS and BSUoS

Who is impacted?	Electricity suppliers and generators	
Purpose	To cover unsecured losses from non-payment of transmission use (TNUoS) and balancing (BSUoS) charges; to recover funds from the termination of a party's participation in CUSC	
Average annual credit amounts (TNUoS and BSUoS)	2011—£597mn 2012—£626mn 2013—£610mn	Annualised average £611mn
Type of collateral accepted	Letters of credit; insurance performance bonds/ bilateral insurance policies provided by an A-rated institution; independent security arrangement; parent company guarantee; and cash in an escrow account	
Split between instruments	2011—£2mn letter of credit; £3mn cash, £592mn PCG 2012—£3mn letter of credit, £3mn cash, £620mn PCG 2013—£5mn letter of credit, £3mn cash, £610mn PCG	
Period/ level of cover required	Amount based on value at risk CUSC—29 days BSUoS—32 days	
Unsecured credit criteria	An independent credit assessment score or credit rating allows for up to 2% of National Grid's RAV to be awarded as unsecured credit (the maximum unsecured credit limit). Good payment history can allow the participant to access lower levels of unsecured credit (capped at 2% of the maximum unsecured credit limit)	
Other protections	None	
Trigger for call	Payment default or failure to pay cancellation charges	
Total scheme cost	2011—£0.25mn 2012—£0.28mn 2013—£0.33mn	

Table 2.3: Key CUSC Generator User Commitment credit parameters[14]

Who is impacted?	Generators only	
Purpose	To recover costs of stranded investments	
Average annual credit amounts	2011—£417mn 2012—£468mn 2013—£411mn	Annualised average £432mn
Type of collateral accepted	Performance bond or letter of credit from a qualified bank; a cash deposit in a bank account; and/or a performance bond or guarantee from a qualified company	
Split between instruments	2011—£95mn letter of credit; £22mn cash, £300mn PCG 2012—£136mn letter of credit; £18mn cash, £314mn PCG 2013—£150mn letter of credit; £17mn cash, £244mn PCG	
Period/ level of cover required	Amount based on rules relating to the proximity to the date of plant commissioning	
Unsecured credit criteria	A credit rating for long term debt (A- and A3) as set by S&P or Moody's; an indicative long term private credit rating (A- and A3) as set by S&P or Moody's; or a short term rating by S&P or Moody's that correlates to a long term rating of A- and A3 respectively	
Other protections	None	
Trigger for call	Termination of a connection agreement or failure to pay the invoiced cancellation charge	
Total scheme cost	2011—£3.86mn 2012—£4.61mn 2013—£4.90mn	

[14] The credit numbers pre-date any impact of CMP228 as they cover 2011-13.

Table 2.4: Key DCUSA credit parameters

Who is impacted?	Electricity suppliers and embedded generators	
Purpose	Security for payments of charges under DCUSA relating to distribution network use	
Average annual credit amounts	2011—£413mn 2012—£435mn 2013—£459mn	Annualised amount £435.7mn
Type of collateral accepted	Letter of credit or equivalent bank guarantee (available for an initial period of not less than six months), escrow account deposit; cash deposit; qualifying guarantee or other as agreed	
Split between instruments	2011—£179.5mn letter of credit, £47.7mn cash, £185.9mn PCG 2012—£189mn letter of credit, £50.2mn cash, £195.7mn PCG 2013—£199.4mn letter of credit, £53mn cash, £206.5mn PCG	
Period/ level of cover required	Total value at risk plus 15 days	
Unsecured credit criteria	An independent credit assessment score or credit rating allows for up to 2% of a Distribution Network Operator's RAV to be awarded as unsecured credit (the maximum unsecured credit limits). Good payment history can allow the participant to access lower levels of unsecured credit (capped at 2% of the maximum unsecured credit limit)	
Other protections	None	
Trigger for call	Payment default	
Total scheme cost	2011—£7.71mn 2012—£8.11mn 2013—£8.37mn	

Table 2.5: Key UNC balancing credit parameters

Who is impacted?	Gas suppliers and gas shippers	
Purpose	To cover the risk of payment default on UNC energy balancing charges	
Average annual credit amounts	2011—£300.62mn 2012—£357.76mn 2013—£376.85mn	Annualised average £345.1mn
Type of collateral accepted	Highly rated letter of credit (supported by smearing/mutualisation) or cash, accompanied by a deposit deed	
Split between instruments	2011—£261.4mn letter of credit; £39.2mn cash 2012—£311.1mn letter of credit; £46.7mn cash 2013—£327.7mn letter of credit; £49.2mn cash	
Period/ level of cover required	One month	
Unsecured credit criteria	None	
Other protections	After two months outstanding balances will be recovered through the smearing process. Money received as a result of directed recovery steps will be shared back to users on a prorate basis	
Trigger for call	Payment default	
Total scheme cost	2011—£9.1mn 2012—£10.9mn 2013—£11.5mn	

Table 2.6: Key UNC transmission and distribution credit parameters

Who is impacted?	Gas shippers and gas suppliers	
Purpose	To ensure gas network operators have access to working capital to cover non-payment of gas network use charges in the event of a user failure	
Average annual credit amounts	2011—£1348mn[15] 2012—£1396mn 2013—£1366mn	Average annual credit amounts £1370mn
Type of collateral accepted	Letters of credit, deposit deed, cash or pre-payment agreement	
Split between instruments	2011—£234mn letter of credit; £10mn cash, £144mn other secured, £930mn PCG 2012—£302mn letter of credit; £10mn cash, £148mn other secured, £936mn PCG 2013—£538mn letter of credit, £10mn cash, £6mn other secured, £802mn PCG	
Period/ level of cover required	One month	
Unsecured credit criteria	An independent credit assessment score or credit rating allows for up to 2% of a Gas Distribution Network Operator's RAV to be awarded as unsecured credit (the maximum unsecured credit limits). Good payment history can allow the participant to access lower levels of unsecured credit (capped at 2% of the maximum unsecured credit limit)	
Other protections	None	
Trigger for call	Payment default	
Estimated annual average financing cost	2011—£10.87mn 2012—£11.92mn 2013—£14.27mn	

[15] UNC transmission and distribution credit amounts, costs and segmentation numbers are based on actual data received from National Grid for the four of the gas networks it operates. We have then extrapolated out these numbers for the remaining four gas networks using the share of total customer numbers attributable to the National Grid gas networks to establish a factor for resolving the amount of total credit across all networks.

Table 2.7: Key CfD credit parameters[16]

Who is impacted?	Suppliers only
Purpose	Collateral for 21 calendar days of supplier levy payments, to ensure the CfD counterparty has working capital to pay generators in the event of non-payment of charges under the supplier obligation Reserve fund to cover levy forecasting errors, and daily mismatches between amounts collected from suppliers and payments made to generators Insolvency reserve fund to provide funds in the event of supplier insolvency in circumstances where the supplier 'collateral has been exhausted and mutualisation amounts are yet to be received from non-defaulting suppliers.
Average annual credit amounts	Representative year (2020)—£486mn
Type of collateral accepted	For the collateral for 21 calendar days of supplier levy payments, letters of credit from a financial institution or cash. For the reserve fund, cash For the insolvency reserve fund, cash or letters of credit
Period/ level of cover required	21 calendar days (rolling) for collateral for supplier levy payments Additional funding obligations prior to the obligation period for the reserve fund and the insolvency reserve fund
Unsecured credit criteria	None
Other protections	The regime is underpinned by mutualisation arrangements
Trigger for call	For the collateral for 21 calendar days of supplier levy payments, a supplier payment default For the reserve fund, to cover levy forecasting errors and to smooth out payment flows as a result of daily mismatches that might occur between sums collected from suppliers and payments to generators under a fixed £/MWh levy For the insolvency reserve fund, to cover the CfD counterparty's working capital requirements between a supplier's 21 calendar days collateral being exhausted and mutualisation amounts being received.
Total scheme cost	Representative year (2020)—£15.3mn

[16] Based on the 23 October 2013 impact assessment. See footnote 2.

Table 2.8: Key Capacity Market credit parameters[17]

Who is impacted?	Electricity suppliers only
Purpose	To cover the risk of the Capacity Market Settlement Agency not having working capital to pay generators under the supplier obligation
Average annual credit amounts	Representative year (2019)—£75mn
Type of collateral accepted	A-rated letters of credit or cash
Period/level of cover required	One month plus 10%
Unsecured credit criteria	None
Other protections	None
Trigger for call	Payment default
Total scheme cost	Representative year (2019)—£2.35mn

Table 2.9: Key SEC credit parameters[18]

Who is impacted?	Suppliers and networks
Purpose	To cover charges levied by the DCC and estimated charges during the invoice settlement period
Average annual credit amounts	Representative year—£4.5mn
Type of collateral accepted	Letters of credit, bank guarantees or cash
Period/ level of cover required	1.4 multiple of the monthly invoice amounts for eligible DCC charges
Unsecured credit criteria	An independent rating or a PCG, subject to the parent having a suitable credit rating
Other protections	None
Trigger for call	Payment default
Total scheme cost	Representative year—£0.1mn

Further details on each framework are set out in Volume 2.

2.4 Scheme costs

2.4.1 Assumptions

For each framework we have assessed the total cost of collateral—the monetary costs of financing the credit amounts. These are derived by multiplying the value of different component instruments by a set of financing cost assumptions.

[17] Based on the 24 October 2013 impact assessment. See footnote 3.

[18] Based on the 30 January 2014 impact assessment. See footnote 4.

The following key technical assumptions underpin our analysis:

- the analysis of collateral amounts includes PCGs. However, the analysis does not include a nominal collateral cost for posting PCGs. These do not attract a direct financing charge, but equally they are not cost free. Issuing PCGs will have impacts on the credit assessment, by a rating agency or financial institutions, of the issuing company. The total PCG values are captured in the aggregate figures for the amounts of collateral posted but the credit financing cost estimates focus only on letters of credit and cash only, or other collateral instruments (such as performance guarantees or insurance products) that attract a direct financing cost;
- we have not included unsecured credit allowances in collateral amounts. Technically, according to the terms of certain codes where they apply, these unsecured credit allowances are included as a contributory value in the calculation of total credit requirements. However, as they attract zero cost, we have excluded them from the analysis;
- for the Capacity Market and the SEC, we have taken into account the relevant, real term values directly from the relevant DECC impact assessments; and
- CfD estimates are based on Cornwall Energy's own modelling of the size of the CfD supplier levy in a representative year.

2.4.2 Financing costs

The framework map analysis is based on a set of financing assumptions. We make a number of simplifying but logical assumptions.

First we establish a representative assumption for the average credit rating for energy market participants. We assume that the "average" credit rating for the energy market is Standard and Poor's (S&P) rating BBB or equivalent. This is a reasonable assumption reflecting the dominant role played by larger, strongly credit rated companies in the energy market—particularly the supply market[19].

Based on the average credit rating assumption, a distinction in financing costs is then made for the different types of credit instruments posted under each framework. Letters of credit are cheaper than cash as, unlike cash borrowings, they are not priced by banks with a margin over an underlying interest rate. Instead they are priced on the basis of a regular fee charged against their face value. We assume the annual fees to be 2.5%, charged annually on the face value of letters of credit that are posted under each framework[20].

For cash posted as credit, we assume an annual financing cost of 6.744%. This figure has been derived from DECC's assumptions on electricity market weighted average costs of capital that was used in the 23 October 2013 *Impact Assessment for Electricity Market Reform—Supplier Obligation*[21]. DECC's stated assumptions were that cost of financing was 6% for larger suppliers and 12% for smaller suppliers. These financing costs were then converted into a weighted average rate for the industry as a whole of 6.744%.

Financing costs across the period in question were relatively volatile. This variability reflected both the impact of the credit crunch and the European banking crisis. A chart capturing debt pricing for syndicated loans across the period is at Annex A, which illustrates this volatility.

It is important to note that total real costs will be higher than the figures represented in this report. Wider costs are not captured. Letters of credit, for example, attract arranging and renewal fees as they reach their maturity and need to be replaced. These may be reasonably material, for example assuming a 0.5% renewal

[19] In generation, plant seeking to raise finance would target and typically expect to achieve a similar equivalent credit rating. This assumption is based on Cornwall Energy personnel's previous experience of financing energy projects in the GB markets.

[20] It should be noted that different banks will price letters of credit at different levels. We sourced two confidential benchmark standby letter of credit price windows for BBB-rated companies from two large UK banks to arrive at this assumption.

[21] https://www.gov.uk/government/consultations/proposals-for-implementation-of-electricity-market-reform

fee was charged annually on the average amount of letters of credit posted under the BSC between 2011-13, this would add £1.7mn additional cost a year. For certain companies they may be asked to counter-indemnify banks that issue letters of credit on their behalf, or partially cover the face value amount through cash held by the bank to cover any risk of demand. This can substantially increase the financial burden of issuing letters of credit where it occurs. We do not include commitment fees on bank cash lending facilities.

There is also a substantial opportunity cost associated with issuing letters of credit, posting cash credit and issuing PCGs. All will use up the overall borrowing or investment capacity of a company, taking financing away from working capital or business investment purposes, although cash and letters of credit will have more tangible effects than PCGs. The cost to companies is the lost return on alternative investments. We have not attempted to capture the value of this cost in the modelling, but they are nonetheless likely to be significant costs that should be considered alongside direct financing costs.

2.5 Summary analysis

Table 2.10 sets out the summary amounts and costs of collateral across the different frameworks in the period 2011-13. It shows an annual average collateral amount of £3.6bn across existing frameworks—rising to £4.2bn after the inclusion of the new frameworks. It illustrates an annual average central case cost of credit of £47.8mn for the baseline frameworks and £65.6mn for all frameworks.

Table 2.10: Estimated framework collateral amounts and costs

	Collateral amount (£mn)				Collateral cost (£mn)			
Baseline framework	**2011**	**2012**	**2013**	**Average**	**2011**	**2012**	**2013**	**Average**
BSC	424.0	383.0	354.5	387.2	13.7	11.8	10.9	12.1
CUSC (TNUoS, BSUoS)	597.0	626.0	610.0	611.0	0.3	0.3	0.3	0.3
CUSC (Generator User)	417.0	468.0	411.0	432.0	3.9	4.6	4.9	4.5
DCUSA	413.2	434.9	459.0	435.7	7.7	8.1	8.4	8.1
UNC Tx/Dx	1348.0	1396.0	1366.0	1370.0	10.9	11.9	14.3	12.4
UNC Balancing	300.6	357.8	376.9	345.1	9.2	10.9	11.5	10.5
Subtotal	3499.8	3665.7	3577.3	3580.9	45.6	47.7	50.3	47.8
New frameworks[22]			**RY**				**RY**	
CfD			486.0	486.0			15.3	15.3
CM			75.0	75.0			2.4	2.4
SEC			4.5	4.5			0.1	0.1
Subtotal			565.5	565.5			17.7	17.7
Total			**-**	**4146.4**			**-**	**65.6**

Figure 2.1 shows the average amounts over the three year assessment period attributable to individual frameworks, by relative size.

[22] These frameworks are not fully legislated yet, hence these figures are estimates based on a future reference year.

Figure 2.1: Average annual framework collateral 2011-13 (£mn)

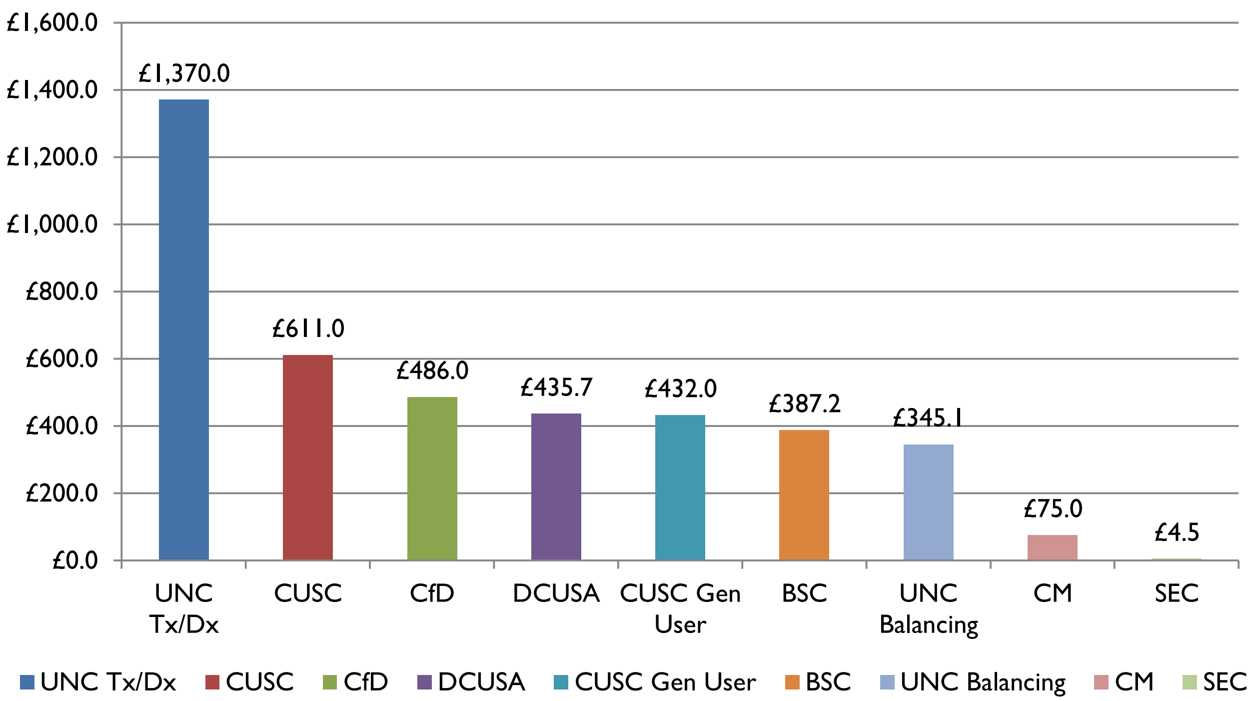
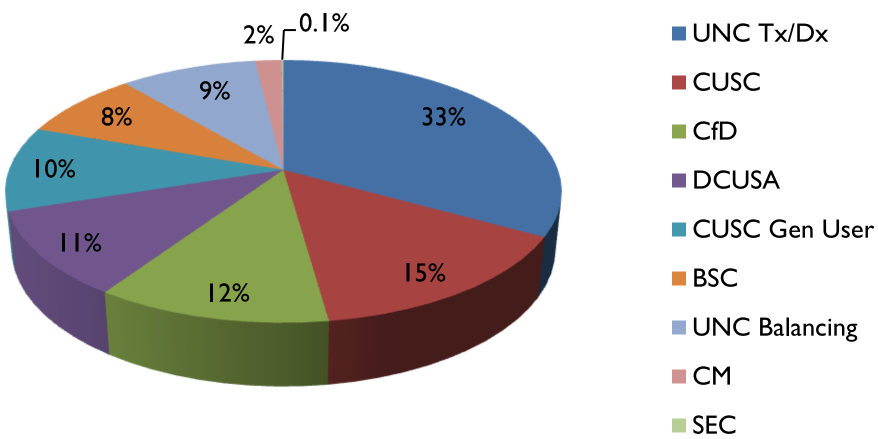


Figure 2.2 shows the collateral amounts under each framework as a percentage of collateral under all frameworks.

Figure 2.2: Average annual collateral amounts 2011-13 (% of total amounts)



Taking these numbers, and the segmentation we have adopted for types of collateral posted, we have calculated collateral costs by framework.

Figure 2.3 illustrates the costs of collateral under each framework as a percentage of total estimated collateral costs.

Figure 2.3: Average annual collateral costs 2011-13 (% of total amounts)

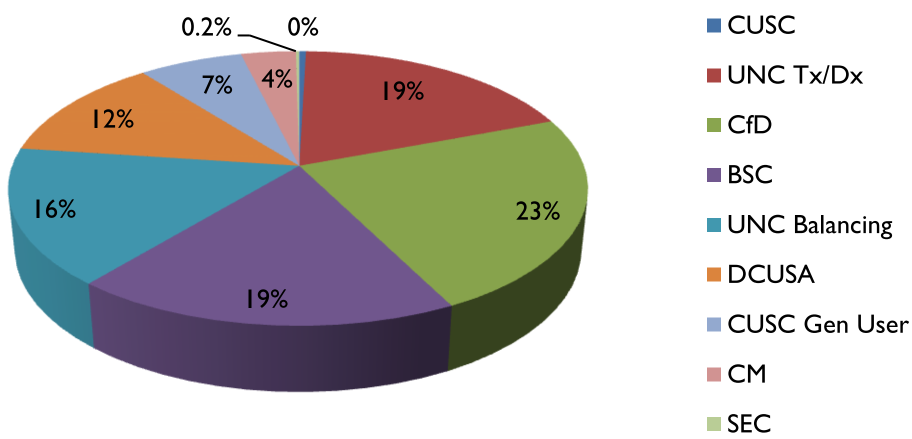


Figure 2.4 illustrates the relationship between the annual average amounts and the annual average costs, showing the extent of any correlation between the two.

Figure 2.4: Correlation annual average amounts to annual average costs, 2011-13 (£mn)

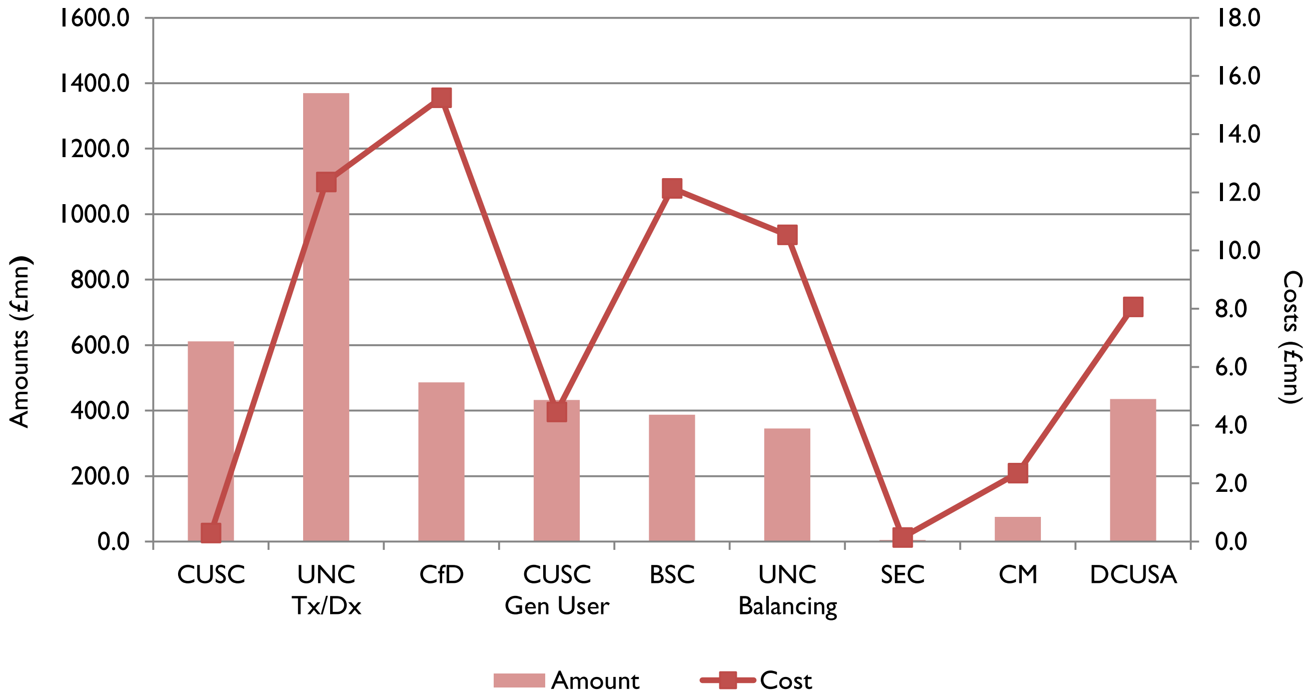


Figure 2.4 shows the strong relationship between the scale of credit amounts and credit costs in balancing frameworks and the new frameworks, and the weak relationship in transmission and distribution frameworks across both gas and electricity. These effects are as a result of balancing requirements and new frameworks predominantly being collateralised by letters of credit and cash, which attract direct credit costs, and transmission and distribution frameworks allowing unsecured credit allowances and PCGs.

2.6 Headlines

The headlines from the framework analysis are summarised below:

- existing credit amounts and costs under frameworks vary widely;
- they are generally more onerous in electricity frameworks than those under gas frameworks;
- transmission and distribution credit is high in volume but low cost;
- energy balancing incurs the highest credit costs under the current baseline. Of this electricity balancing under the BSC is the most costly framework;
- additional collateral from future frameworks is unavoidable;
- the introduction of the supplier obligation under the CfD regime will significantly increase collateral requirements;
- there are significant differences in the design of prudential requirements for future frameworks; and
- collateral arrangements under future frameworks have tended to increase credit requirements for suppliers.

These points are explained more fully below.

2.6.1 Credit costs and amounts under the different arrangements vary widely

Credit arrangements are set out in a number of codes, regulations and laws, with different governance bodies. For example, credit rules are contained in seven separate codes, some of which refer to further guidance or rules documents—five in electricity (BSC, CUSC, DCUSA, CfD, Capacity Market), one in gas (the UNC) and one straddling both sectors (the SEC). Taking into account new frameworks, there are over 30 bodies or business units across a multitude of different companies involved in the processes for modifying, administering and implementing these credit arrangements in the GB energy markets. Some credit arrangements are part of a national code, implemented by a single body for the whole market (such as the BSC) whereas others are unified codes based on regional administration and implementation of credit rules.

No two codes are identical in their credit rules. There are though some similarities in principles in defined areas such as balancing or transmission and distribution (reflecting Ofgem's best practice guidelines, issued in 2005). The rules and procedures for administration are subject to continual change through industry, government or governance authority driven modifications. Against this backdrop, it is challenging for smaller market participants—particularly smaller ones in the electricity supply sector, and certainly for dual fuel suppliers—to properly engage with these complex arrangements. It is also difficult for potential new entrants to assess the implications of credit arrangements on the costs of new entry.

2.6.2 Electricity frameworks require more credit than gas

More collateral is required under electricity arrangements than gas under the existing frameworks, and the weighting is set to shift further towards electricity under the new frameworks. The split between electricity and gas is 52%-48% under current frameworks; this will change to 58%-42% with the addition of the new frameworks. This weighting is an effect of the larger market size and the manner in which collateralised activities are divided between balancing and transmission and distribution frameworks.

2.6.3 Transmission and distribution credit is high volume but low cost

The majority of collateral is concentrated on activities relating to transmission and distribution in the gas and electricity markets. Collateral across the CUSC (TNUoS and BSUoS), DCUSA and UNC for transmission and distribution accounting for 68% of collateral amounts of the baseline frameworks, and 59%

across all frameworks. However, this is offset by the allowance in these markets to collateralise through the issuance of PCGs, rather than purely through cash or letters of credit.

The net result is a much lower collateral cost for transmission and distribution than for balancing activities, relative to the amounts of collateral that are required. Hence, the costs of this collateral for the CUSC, DCUSA and UNC transmission and distribution are far lower at 43% of the baseline frameworks and 32% across all frameworks.

By contrast, for those frameworks where letters of credit (or bank guarantees) and cash are the only methods of collateralisation (like the BSC and UNC balancing activities, the CfD, the Capacity Market and the SEC), the correlation between collateral volume and value is strong and well established.

2.6.4 Energy balancing incurs high credit costs amongst the baseline frameworks

Despite the BSC and UNC balancing accounting for only 8% and 9% of the annualised average of credit amounts across all frameworks for the period 2011-13, the collateral costs are 19% and 16% respectively. Put another way, the annualised average credit cost for each pound of credit posted under the BSC and UNC Balancing is 3p in the period 2011-13, compared to just under a penny across on average across the CUSC, DCUSA and UNC transmission and distribution.

The explanation for the high credit costs (relative to credit amounts) in the BSC and UNC for different market participants is explained by:

- both frameworks accepting only letters of credit and cash as acceptable forms of collateral;
- the fact that a failure to maintain certain thresholds of collateral are specific events of default;
- the complexity of the formula used for calculating indebtedness (particularly under the BSC); and
- the extent of volatility in charges and indebtedness that drive credit postings.

The combination of these elements means that balancing credit involves costly instruments that are often posted at a level with some allowance for "headroom" to avoid the risk of default.

2.6.5 The CfD significantly increases collateral requirements

If implemented in line with the policy proposals current at the time of our analysis, the CfD, Capacity Market and SEC regimes will add a further £565.5mn to collateral amounts in the GB energy markets[23]. This is a 16% increase in the average annual collateral amounts, from £3,581mn to £4,146mn. Predominantly, this increase arises through the collateral requirements that will emerge under the CfD[24].

Overall, the CfD, Capacity Market and SEC collateral comprise 14% of the total amount of collateral under all frameworks. The majority of this is attributable to the CfD, which accounts for 12% of the total amount of collateral under all frameworks.

Based on the reliance of new schemes on cash or letters of credit as security, the increase in collateral costs is higher than the increase in the amount of credit. The CfD, Capacity Market and SEC will add a further £17.7mn of collateral cost. This is a 37% increase in credit costs.

The new frameworks therefore account for 27% of total collateral costs across all frameworks, with a 23% share of total collateral costs attributable to the CfD.

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[23] This is for the period 2011-13. It assumes that the collateral amounts for the representative years for each of the CfD, Capacity Market and SEC DCC are overlaid onto this period for comparative purposes even though these costs did not exist at that point in time.

[24] As noted the government has since published final proposals, which will reduce the amount and cost of collateral required from suppliers.

Once the CfD reaches scale, it overtakes all other frameworks in terms of the cost of collateral, and will constitute the third largest amount of collateral of all frameworks. The amounts and costs associated with CfD collateral are partly attributable to the fact that there will be a relatively large value of settlements under the CfD.

Unlike other frameworks, where collateral is supporting settlement, generators will be raising finance off the back of payments to them by the CfD counterparty. This means generators need confidence in the ability of suppliers to fund the levy payments used to make payments under CfDs.

Under DECC's October proposals, there are three layers of collateral to be provided under the CfD:

- letters of credit and cash (or a combination of the two) for collateralisation of the CfD supplier obligation payments;
- insolvency reserve fund to protect against the risk of suppliers defaulting on the CfD supplier obligation; and
- a reserve fund to protect against the risk of shortfalls in money available to make payments under CfDs[25].

The combination of these factors means the CfD is likely to be a credit-hungry scheme relative to other frameworks.

2.6.6 Collateral from future EMR frameworks is unavoidable

Collateral postings under the CfD and the Capacity Market are unavoidable to licensed suppliers, and are calculated by reference to market share[26].

By contrast, in the balancing markets, it is possible to reduce credit exposure through better balancing (in practice, this relies on the scale and level of integration of the participant's business model). In the case of transmission and distribution, collateral postings can be reduced through acquiring a stronger credit rating over time and to a far lesser extent through demonstrating good payment history.

2.6.7 Differences in future frameworks design

The CfD and the Capacity Market have two different approaches to covering the risk of supplier default in making payments under the levy. The same community of companies are bearing the costs of supporting the levy in both instances; hence the risk of levy payments not being made is equal in both schemes. The levies in both cases are being used to support payments to generators that seek to encourage investment in new generating capacity. Hence, the generators tolerance for non-payment risk by the settlement body in both instances will be broadly equal under both schemes.

Despite these similarities in purpose, under the CfD the risk of non-payment is collateralised in two distinct ways: suppliers posting letters of credit or cash and the insolvency reserve fund[27]. It is supplemented by mutualisation and safeguards such as the Supplier of Last Resort (SoLR) process and Energy Supply

[25] The amount, which is collected through the £/MWh rate, will rarely match the CfD payments to generators on a particular day. The RF is there to smooth this cash flow and will also account for forecast errors.

[26] The method for calculating the market share of suppliers is likely to differ. In the case of the CfD regime and SEC, this is expressed as MWh supplied; for the Capacity Market the share is based on the share of maximum demand. For the capacity market, a supplier's share at the time of system peak demand will initially be calculated by the settlement agent based upon a forecast collected from licenced suppliers not less than three months prior to the start of the delivery year. This forecast will be of the average electrical demand that the supplier expects its customers will be drawing across the three TRIAD peak periods of the delivery year. The forecasts provided by all suppliers shall be used by the settlement agent to determine each supplier's market share and therefore the size of each supplier's Capacity Market charge.

[27] As noted, the insolvency reserve fund is not part of the final design. However, the reserve fund is.

Company Administration (ESCA). By contrast, the approach to credit under the Capacity Market is to rely only on cash or letters of credit and mutualisation. Again it is supplemented by SoLR and ESCA, but there are no additional cash reserves being raised from suppliers.

According to DECC the reason for the difference in scheme design is because of the different nature of the schemes – the CfD is a scheme whose cost is inherently unpredictable in advance, as it depends on volume of generation and market prices, whereas the Capacity Market is a scheme with a much more predictable cost as it is simply a £/kW of capacity payment (that is that it doesn't depend on market prices or generation volume).

2.6.8 "Strengthening of credit" bias

There have been conscious attempts to replicate elements of existing credit arrangements in the design of new schemes. However, this seems to have trended towards a "replicate and strengthen" approach. For example, the CfD credit arrangements contain features of the BSC collateral arrangements in terms of standing collateral and mutualisation. But they are supported by reserve funding arrangements to cover forecasting error on the fixed levy rate. DECC believes these are additional risks that require supplemental protection.

Under the credit cover arrangements for the SEC, there are similarities with the provisions in transmission and distribution arrangements to assess creditworthiness based on a user's credit rating. However, the approach in transmission and distribution arrangements whereby an unsecured credit allowance is established is not reflected in the SEC given both the pass through nature of costs within the DCC's financial structure as an asset light organisation and the allocation of unsecured bad debt to SEC parties rather than DCC.

3 Supplier benchmark map

This Section sets out a series of supplier benchmarks and evaluates the allocation of collateral amounts and costs between them. It also establishes the impact on these benchmarks of the frameworks discussed in Section 2. Finally, it evaluates the collateral amounts and costs associated with market entry for new or acquisitive suppliers and concludes by looking at exposure to "mark-to-market" under gas and electricity trading as a sensitivity.

3.1 Key assumptions

We listed eight core supplier benchmarks in Section 1. The key metrics used for each supplier benchmark are set out in Table 3.1 below.

Table 3.1: Core supplier benchmark metrics

Type	Power/gas split (%)	Daily power (MWh)	Daily gas (MWh)	Annual power (MWh)	Annual gas (MWh)	Market share (%)
Intermediate domestic supplying electricity and gas	55	2,411	8,322	880,000	3,037,500	0.28
Niche domestic electricity supplier	100	438	-	160,000	-	0.05
Small and medium sized enterprise gas supplier	-	-	5,479	-	2,000,000	0.63
Industrial and commercial gas supplier	-	-	54,795	-	20,000,000	1.57
Small and medium sized enterprise electricity supplier	100	5,479	-	2,000,000	-	0.63
Industrial and commercial electricity supplier	100	13,699	-	5,000,000	-	1.57
Large domestic gas and electricity supplier	60	31,562	88,767	11,520,000	32,400,000	3.62
Large vertically integrated utility (VIU) supplying gas and electricity to domestic and non-domestic customers	60	58,959	198,356	21520000	72,400,000	9.00

For the core supplier benchmarks we assume that:

- each company is well-established in the energy markets. Each benefits from unsecured credit allowances in the light of their independent credit assessment score, credit rating or their good payment history under the CUSC, DCUSA and UNC transmission and distribution frameworks. As a result of their independent credit assessment score or credit rating they derive unsecured allowances that are in excess of their indebtedness that would otherwise have been applied under these frameworks;
- suppliers of gas also have involvement in gas shipping and face the amounts and costs of UNC transmission and distribution collateral directly as well as the costs for gas balancing;

- for all but the large suppliers (15% of all demand) and the large VIU suppliers (25% of non-domestic demand), the volume of trading on exchanges is low (5% of all demand). In reality large suppliers and large VIU suppliers will trade higher or lower volumes than this;
- the large supplier is a domestic supplier, supplying gas and electricity. It has no non-domestic customers. By contrast, the large VIU supplier runs both a domestic and non-domestic gas and electricity business; and
- the large VIU supplier sources power for its domestic customer base from its own generation fleet. This means that a proportion of exchange trading, bilateral trading and PPAs applies to its non-domestic electricity supply volumes.

We have also assessed the differentiated credit costs for each of our benchmarks. To do this we assume:

- all of our core supplier benchmarks (other than the niche domestic electricity supplier, large domestic gas and electricity supplier and large VIU domestic and non-domestic gas and electricity supplier) will post letters of credit rather than cash because it is cheaper for them to do so;
- the niche domestic electricity supplier has more difficulty in getting banks to issue letters of credit, so they post cash as security;
- the large domestic gas and electricity supplier and the large VIU domestic and non-domestic gas and electricity supplier have a strong, recognised credit rating and where permitted under framework rules they will post PCGs. This assumption partly explains the much lower costs of collateral that they incur, particularly with regard to trading and access to exchanges; and
- the large VIU domestic and non-domestic gas and electricity supplier has the lowest financing cost by virtue of its scale and its financial capability. It can therefore collateralise its trading activities outside of exchanges through PCGs.

A range of assumed financing costs are summarised at Annex B. These are based on taking the BBB typical cost of 2.5% for issuing letters of credit used in the framework map, and then applying estimated discounts or premiums to this rate to arrive at different levels of financing costs based on a generalised assumption of the credit strength of companies occupying each segment[28]. By applying these cost assumptions to the core supplier benchmarks, we have estimated costs/participant type under each framework.

A more detailed explanation of our benchmark assumptions and the supplier benchmark profiles are in Annex C2. These include where relevant results under alternative cases for new entry, acquisitive new entry and “mark-to-market”.

3.2 Summary analysis—existing suppliers

Table 3.2 sets out the ranking of supplier benchmarks by the average modelled collateral amounts for 2011-13. The amounts range from just over £1mn for the niche domestic electricity supplier to over £200mn for the large VIU domestic and non-domestic gas and electricity supplier. These are the aggregated totals taken from Table C.1 in Annex C.

[28] It should be noted that in reality there are a wide range of companies operating in these different segments, with different levels of financial capability and hence financing costs. The analysis does not reflect all of these permutations.

Table 3.2: Supplier benchmark hierarchy by annual average posted credit amounts, 2011-13

Rank	Benchmark supplier	Collateral amount (£)
1	Large vertically integrated utility (VIU) supplying gas and electricity to domestic and non-domestic customers	220,060,282.65
2	Large supplier domestic gas and electricity	125,572,490.81
3	Industrial and commercial gas supplier	34,084,079.35
4	Industrial and commercial electricity supplier	29,503,090.80
5	Small and medium sized enterprise electricity supplier	11,836,408.46
6	Intermediate domestic supplying electricity and gas	10,636,969.17
7	Small and medium sized enterprise gas supplier	3,422,302.76
8	Niche domestic electricity supplier	1,064,433.36

These amounts broadly reflect relative size and market share.

Table 3.3 shows the relationship between average annual collateral amounts and average annual costs posted for all eight supplier benchmarks across the different frameworks and through trading where relevant.

Table 3.3: Average annual percentages of collateral amounts and costs across supplier benchmarks, 2011-13

Framework	Collateral amounts (%)	Collateral costs (%)
BSC	3.4	4.1
DCUSA	0.0	0.0
UNC balancing	0.1	0.1
UNC Tx/Dx	0.0	0.0
N2EX	0.5	1.5
Gas trading	43.5	31.0
Power trading	30.9	27.5
PPA	3.6	0.0
SEC	0.2	0.5
CfD	15.2	30.2
Capacity Market	2.6	5.1

Table 3.3 also demonstrates that a large part of estimated credit amounts and costs for supplier benchmarks can be attributed to power and gas trading activities. Of the non-trading current activities, power balancing under the BSC incurs the greatest level of credit amounts and costs for all supplier benchmarks, even though this is only applicable to those benchmarks with interests in electricity supply (gas supply benchmarks incur no credit amounts or costs under the BSC). The table also illustrates the significant impact of the CfD once it is introduced on both collateral amounts and costs, and this has a particular impact on electricity suppliers. These observations are evaluated further in the headlines.

Figure 3.1 illustrates the allocation of collateral amounts, and provides a breakdown by framework and different types of trading for the different benchmark types[29].

Figure 3.1: Supplier benchmark map, annual collateral amounts (£)

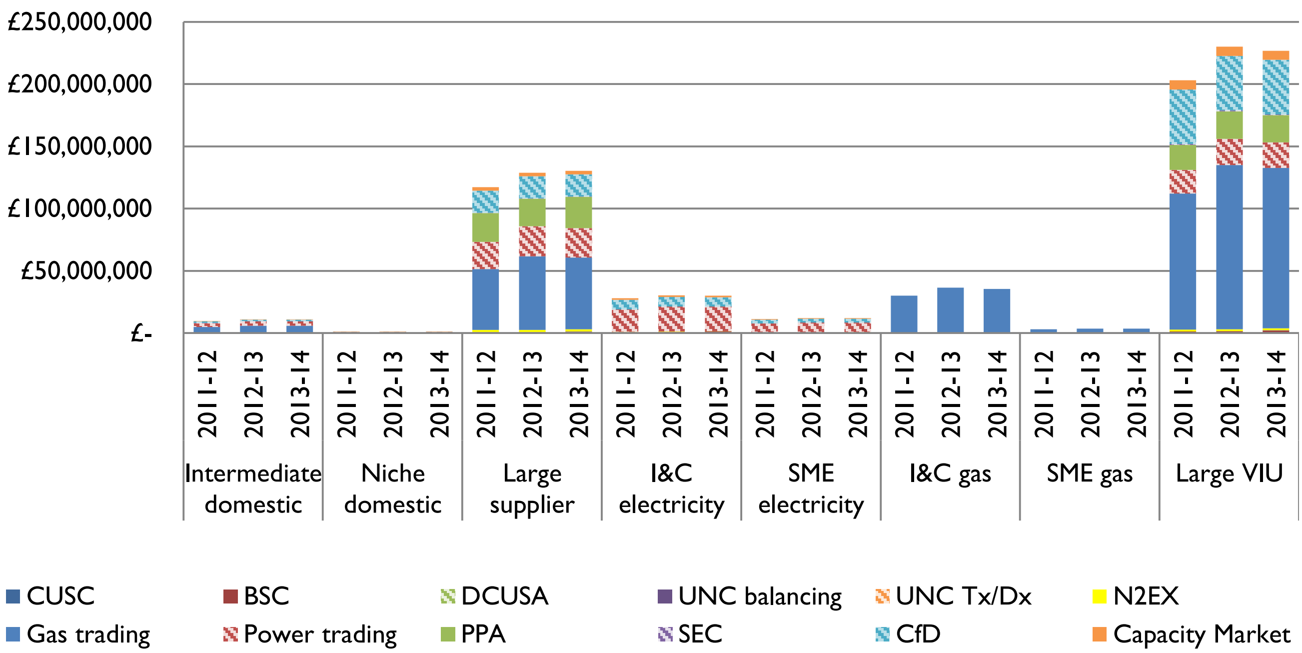


Figure 3.1 shows that the size of credit amounts is heavily driven by the scale and volumes of activity of suppliers. All relevant frameworks require suppliers to post credit based on either volumetric charges or market share. Credit costs are however not strongly correlated in this fashion, revealing financial advantages to larger suppliers who have greater choice over how to collateralise obligations in transmission and distribution in both gas and electricity, and face cheaper credit costs for balancing and new frameworks.

3.3 Headlines—existing suppliers

The headlines from the supplier benchmark map are:

- collateral costs are a significant cost to all supply businesses;

[29] DCUSA, CUSC and UNC Transmission and Distribution are not shown because all benchmarks access an unsecured credit allowance by virtue of good payment and rating that is higher than their value at risk.

- existing supplier benchmark companies post framework collateral in proportion to volumes of activity or market share;
- bilateral trading is credit intense;
- barriers to bilateral trading are driving divestment to secure routes to market;
- the cost of exchange collateral credit is a significant barrier to direct participation in exchange trading for most supplier market participants;
- transmission and distribution in gas and electricity is "credit light" for established players;
- BSC balancing attracts the highest cost of non-trading policy baseline frameworks;
- mainly larger suppliers write and collateralise large volumes of PPAs; and
- amounts and costs of credit increase for all suppliers following the introduction of the CfD.

These findings are explained in more detail below.

3.3.1 Supplier benchmarks post framework collateral in proportion to volumes of activity or market share

The basis of establishing the amount of credit to be posted under baseline and new frameworks is either charges based on a company's volume of use of the framework (in the case of baseline frameworks) or on their market share (in the case of the new frameworks). As a result, the size of a company in terms of their share of the market or extent of operations is a major driver of the amounts of credit demanded from them.

As all frameworks are mandatory activities for suppliers, there is no way of avoiding credit calls—it is part and parcel of doing business. However, in certain frameworks rules prescribe ways in which the impact of volumetric credit calculations can be reduced through demonstrating financial capability—either through their independent credit assessment scores, their credit rating or to a lesser extent good payment history.

3.3.2 Collateral costs are significant to all supply businesses

With the imminent introduction of new frameworks, a small niche domestic electricity supplier with 50,000 customers can be expected to cover credit amounts in excess of £1mn. For an intermediate domestic electricity supplier with 500,000 customers, the credit amount increases to over £10mn. Established existing suppliers even with a good payment record see credit amounts in excess of £220mn.

3.3.3 Bilateral trading is credit intense

Challenging exchange trading and inability to write PPAs mean that all supplier benchmarks will trade power and gas predominantly through bilateral contracts. Consequently, power and gas trading accounts for on average 31% and 44% of credit amounts and 27% and 31% of credit costs across all supplier cases.

Gas trading collateral makes up a significant proportion of overall collateral costs for those supplier benchmarks with sole interests in supplying gas. Similarly amongst electricity suppliers power trading is by far the most costly and credit-intense activity. The exceptions in power trading are the large domestic gas and electricity supplier and large VIU domestic and non-domestic gas and electricity supplier benchmarks, which are assumed to collateralise their bilateral trading activities using PCGs.

Trading parties told us that the ability to secure manageable and economically viable credit terms through bilateral trading was mixed. It can depend on the attitude and strategic perspective of the larger trading counterparty to helping their competitors (or future potential competitors) trade power and manage risk optimally.

Bilateral trading can involve having to post collateral to cover not only the risk of non-payment upon delivery but also potentially volatile "mark-to-market" exposures. For "mark-to-market" risk, the issue is not so much the size of the required collateral (although depending on price movement, this could be large), but the speed at which collateral may be required or increased. The collateral arrangements can affect smaller players' ability to hedge their positions over a longer maturity, as "mark-to-market" and delivery credit demands will increase with the maturity of the contract. Where larger counterparties are more flexible to facilitating bilateral trading, trading collateral will be weighted more towards delivery risk, with less credit burden associated with "mark-to-market" exposure.

3.3.4 Barriers to bilateral trading are driving divestment to secure routes to market

Participants suggested a significant volume of the bilateral trading outside of the larger suppliers is being channelled through financial or industry aggregators. Aggregators are prepared to trade with reduced collateral requirements in return for a margin. In some cases they have asked for a minority equity stake in the supply businesses. This gives them a more predictable cost for trading and allows for a greater ability to access longer dated hedging products. Consequently, suppliers can grow their customer base and develop their tariff offers.

3.3.5 Exchange collateral credit is a barrier to participation

Only the large domestic gas and electricity supplier and the large VIU domestic and non-domestic gas and electricity supplier benchmarks are well placed to post collateral against trading on exchanges. This introduction reflects the high levels of collateral and the risk of exposure to "mark-to-market" calls associated with this activity. Other suppliers consequently make very limited use of exchange trading, particularly for forward trades.

This position was borne out by discussion with suppliers. They cited the obligation to post letters of credit and cash as a significant barrier to trading. These credit demands supplement existing demands for letters of credit or cash posting under the balancing frameworks and the financing capacity of suppliers have finite limits. In this context, posting of credit under regulatory codes is non-discretionary, so it is exchange-based trading that is most likely to bear the effect of any working capital squeeze.

3.3.6 Transmission and distribution is "credit light" for established participants

The amount of collateralisation for transmission and distribution in both gas and electricity is assumed to be zero for our core supplier benchmarks. This is by virtue of an assumption of their independent credit assessment score or credit rating under the UNC transmission and distribution, CUSC and DCUSA activities, which affords an unsecured credit allowance that is in excess of indebtedness.

Even after allowing for the ability to take advantage of unsecured credit allowances under transmission and distribution frameworks, credit amounts are still material for suppliers, reflecting the demands they face under the balancing, bilateral power trading and new demands for electricity suppliers under the CfD and Capacity Market. For example, total annualised average credit amounts for electricity-related activities across the suppliers are £214mn and £221mn for gas. Even the comparatively small niche domestic electricity supplier is posting £1mn of credit a year, which equates to £20 per customer.

3.3.7 BSC is the most demanding of the baseline frameworks

Despite only being applicable to suppliers with electricity customers, the BSC attracts relatively large levels of collateral as a share of the non-trading baseline frameworks for all core supplier benchmarks, and the second highest amount across the benchmarks attributable to the baseline and new frameworks.

Whilst credit demands under the BSC are low when compared to the CfD, in aggregate, as a proportion of total collateral across trading, baseline and new frameworks, the BSC accounts for 3.4% of average collateral amounts posted by our supplier benchmarks on average in the period 2011-13, and 4.1% of average collateral costs.

The differences in the size of collateral posted for balancing is based on differing abilities to balance, which in part reflects the benchmark company's size and degree of vertical integration.

Imbalance percentages for each supplier have been set based on experience from an examination of average imbalance percentages across the market:

- the Big Six imbalances typically range between 0.5%-1.5%. As such the large domestic gas and electricity supplier and large domestic and non-domestic gas and electricity VIU supplier benchmarks are assumed to have 1% imbalance; and
- smaller suppliers have larger imbalance percentages as they are less able to balance owing to their relative lack of diversity and integration. In this report:
  - the intermediate domestic gas and electricity supplier is assumed to have an imbalance percentage of 6%;
  - the niche domestic electricity supplier is assumed to have an imbalance percentage of 12%; and
  - the two larger non-domestic suppliers (I&C gas and electricity suppliers) are better able to balance their positions and are both assumed to have a 3% imbalance percentage.

Table 3.4 illustrates the average amounts and costs of collateral for BSC balancing relative to the total average collateral amounts and costs across the supplier benchmarks for the period 2011-13.

Table 3.4: BSC balancing average credit amounts and costs as a share of total credit amounts and costs, 2011-13

Benchmark	BSC collateral amounts (%)	BSC collateral costs (%)
Intermediate domestic supplying electricity and gas	3.9	3.9
Niche domestic electricity supplier	14.2	14.2
Large supplier domestic gas and electricity	0.7	3.8
Industrial and commercial electricity supplier	4.0	4
Small and medium sized enterprise electricity supplier	4.0	4
Large vertically integrated utility (VIU) supplying gas and electricity to domestic and non-domestic customers	0.8	3.1

There are factors that drive the spread of collateral across supplier benchmarks under the BSC. Discussions with trading parties identified a tendency to post BSC collateral with a pessimism bias. This is in part driven by the calculation of required credit cover being relatively complex (in comparison with other frameworks).

The approach is also driven by the nature of the consequences of default under the BSC, which involve considerable reputational and financial damage. At the extremes, default could see a party being unable to manage its imbalance because it can be barred from submitting contracts. In turn this could lead to all metered volumes being subject to imbalance pricing, which can quickly lead to insolvency.

Smaller, independent suppliers also indicated that monitoring the level of indebtedness as a proportion of credit cover (and hence an awareness of the proximity of credit defaults) is not a straightforward task.

3.3.8 PPAs are the domain of larger suppliers

Only the large suppliers and the large VIUs write and collateralise PPAs with merchant thermal and renewable generators. This reflects the current difficulty for smaller suppliers, as a consequence of their lesser credit standing, in offering acceptable PPAs to banks.

Typically, bankable PPAs have concentrated on off-takers and suppliers with strong investment grade credit ratings (BBB+ and above).

The ability of smaller suppliers to write bankable PPAs may change once the government has introduced the Offtaker of Last Resort (OLR) mechanism. But the potential speed and extent of market adaption to these proposals remains unclear.

3.3.9 CfD collateral will exacerbate these issues—concentrating burdens on electricity suppliers

All core electricity supplier benchmarks (and those involved in both gas and electricity supply) will see a material increase in collateral amounts as a result of the introduction of the CfD and Capacity Market. The CfD cost alone could represent 15% of average total collateral amounts across all core supplier benchmarks, but accounting for a much higher share (30%) of average total credit costs.

Amounts and costs of credit increase for all electricity suppliers following the introduction of the CfD. However, there is a material impact for larger suppliers too. This is as a result of the low starting base of requirements to issue letters of credit under other frameworks and activities given their ability to collateralise through PCGs.

This position is illustrated in Table 3.5, which shows the CfD percentage share of average collateral amounts and costs across all core supplier benchmarks notionally applied in the period 2011-13.

Table 3.5: CfD average credit amounts and costs as a share of total credit amounts and costs for each core supplier benchmark, 2011-13

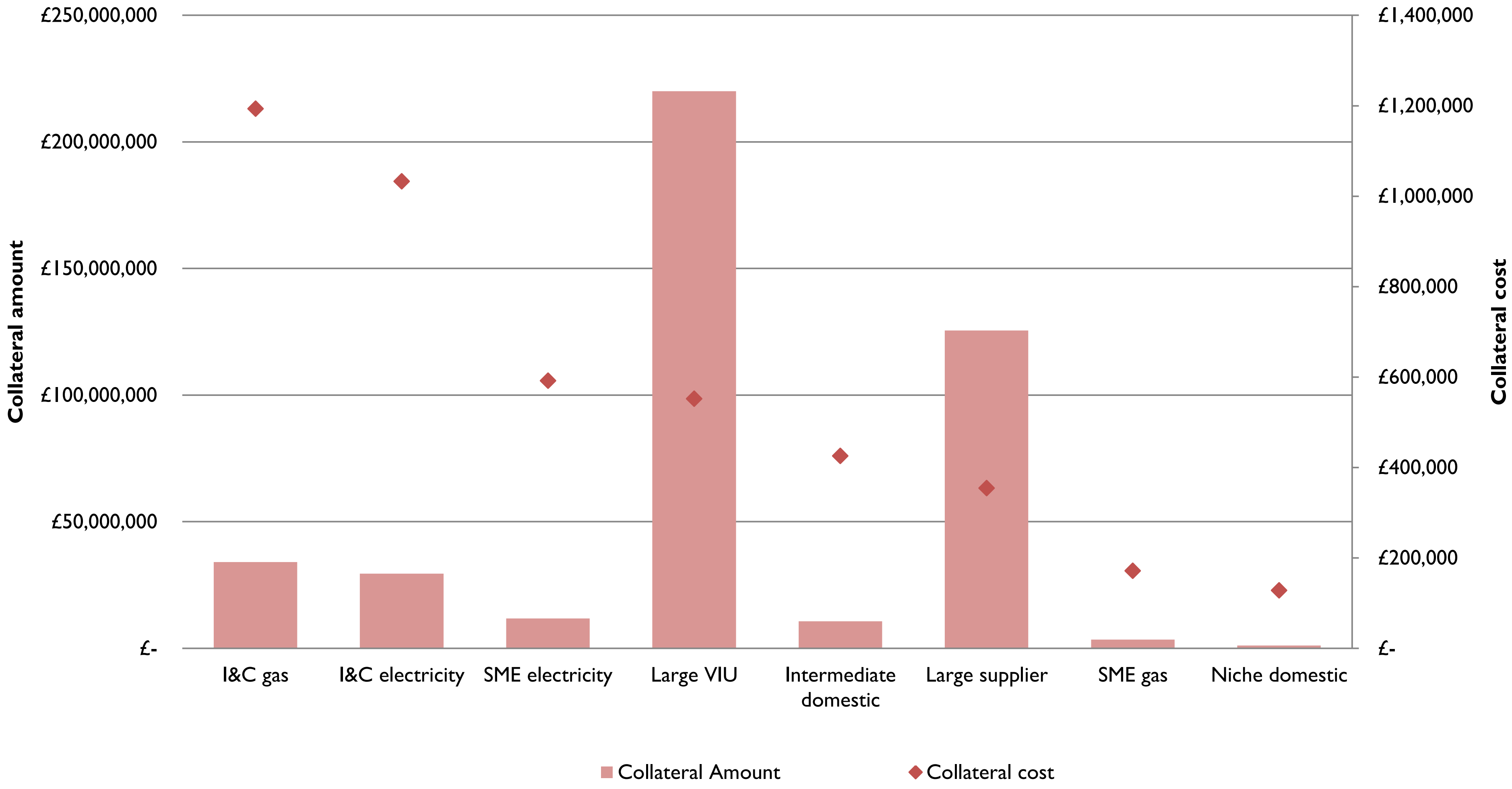
Benchmark	CfD collateral amounts (%)	CfD collateral costs (%)
Intermediate domestic supplying electricity and gas	12.7	12.7
Niche domestic electricity supplier	23.0	23.0
Large supplier domestic gas and electricity	14.0	74.6
Industrial and commercial electricity supplier	25.9	25.9
Small and medium sized enterprise electricity supplier	25.9	25.9
Industrial and commercial gas supplier	0.0	0.0
Small and medium sized enterprise gas supplier	0.0	0.0
Large vertically integrated utility (VIU) supplying gas and electricity to domestic and non-domestic customers	19.9	79.3

However, given smaller suppliers have to post letters of credit or cash already under the BSC, the introduction of the CfD obligation will put pressure on electricity suppliers' available financing facilities and add additional cost to their businesses. For example, the niche domestic electricity supplier and the industrial and commercial electricity supplier could face a 25% increase in credit amounts and costs.

3.3.10 Scale drives large credit amounts, but vertical integration reduces the burden of amount and cost

Figure 3.2 shows the ranking of supplier benchmarks by annual average cost, and the ranking by the amount of credit posted to show the extent of correlation between the two expressed as an annualised amount over the period 2011-13.

Figure 3.2: Core supplier benchmark ranking by annual average credit cost (£) vs. ranking by annual average credit amount 2011-13



Generally speaking there is a correlation in ranking between collateral amounts and collateral costs for the supplier benchmarks, with the exceptions of large VIU supplier and the large domestic gas and electricity supplier benchmarks. They are able to raise their required collateral at the fourth and the sixth highest cost of the eight benchmarks, despite ranking first and second in terms of the collateral amounts they post.

Vertically integrated suppliers are unable to avoid being captured by the volumetric basis of calculating liabilities that underpins most credit and collateral arrangements. Hence, they are still required to post materially higher amounts of collateral than other parties. Owing to the different levels of involvement of large VIUs in fields such as upstream gas and gas storage, it has not been feasible to develop a general assumption on the benefits this brings in terms of reduced quantum of collateral being required under the UNC, or in terms of trading gas through bilateral contracts or exchanges. We have nonetheless attempted to reflect how access to a large fleet of generation and the ability to write PPAs might reduce the necessity to source power through bilateral trading and exchanges and have reflected the benefit of vertical integration in imbalance assumptions.

It is clear that large VIUs have a number of advantages that allow them to reduce the costs of posting collateral, even if the volumes posted are relatively high compared to other market participants. These include:

- a strong credit rating, which allows the large VIU supplier to avoid posting cash or letters of credit where frameworks allow (such as in transmission and distribution frameworks). This advantage also allows the large VIU supplier to raise such instruments at a cheaper cost, even where they are obligated to post such instruments (such as under the BSC and UNC balancing frameworks);
- a strong credit rating is also capable of being leveraged to support trading activity at longer dated maturities than other, less financially secure counterparties. Large VIU suppliers have the ability to collateralise trades through the strength of their own balance sheets;
- a greater degree of scale, skill, resources, and technological capability to reduce their exposure to costs under balancing frameworks, including the ability to net exposures; and
- an ability to spread costs of collateral across a wider customer base—including SME and I&C gas and electricity suppliers—maximising their scale to enhance and embed their competitive position.

The impact of these advantages can be usefully represented by displaying both amounts and costs of collateral across the domestic electricity and supplier benchmarks on a per customer basis[30]. This is shown in Figures 3.3 and 3.4.

[30] We have chosen the domestic gas and electricity market as the most topical illustrative example of large VIU benefits. In this analysis we include in the VIU customer base their SME and I&C customers. It should be noted that of the comparator benchmarks the niche supplier is the only one that does not engage in the supply of both gas and electricity.

Figure 3.3: Average collateral amounts per customer, large VIU supplier versus domestic supplier benchmarks, 2011-13 (£)

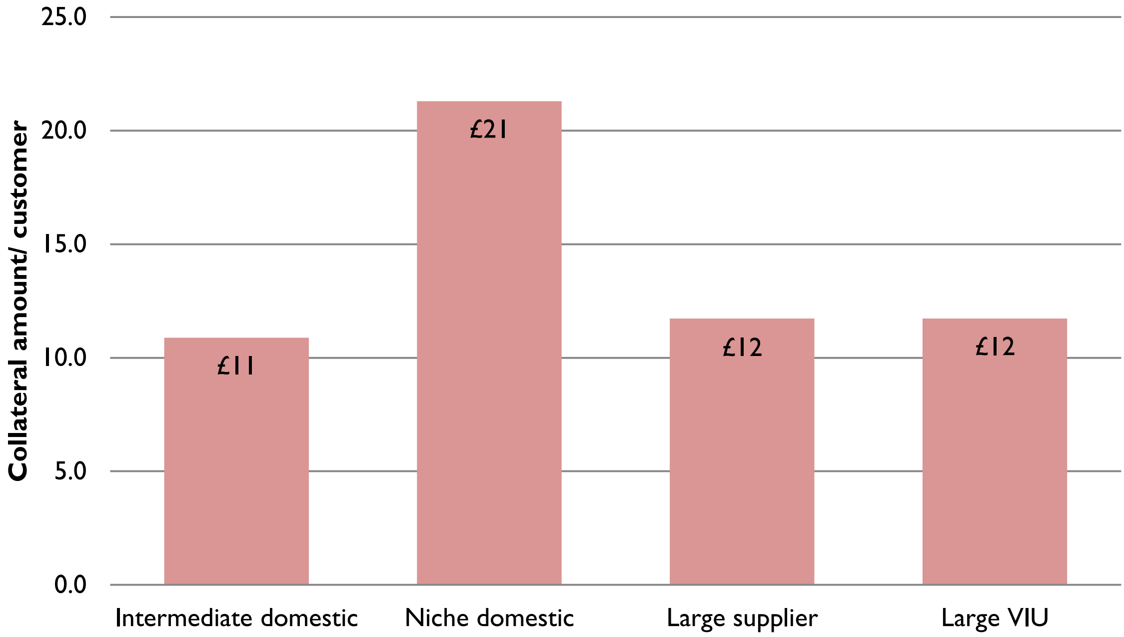


Figure 3.4: Average collateral cost per customer, large VIU supplier versus domestic supplier benchmark comparators, 2011-13 (£)

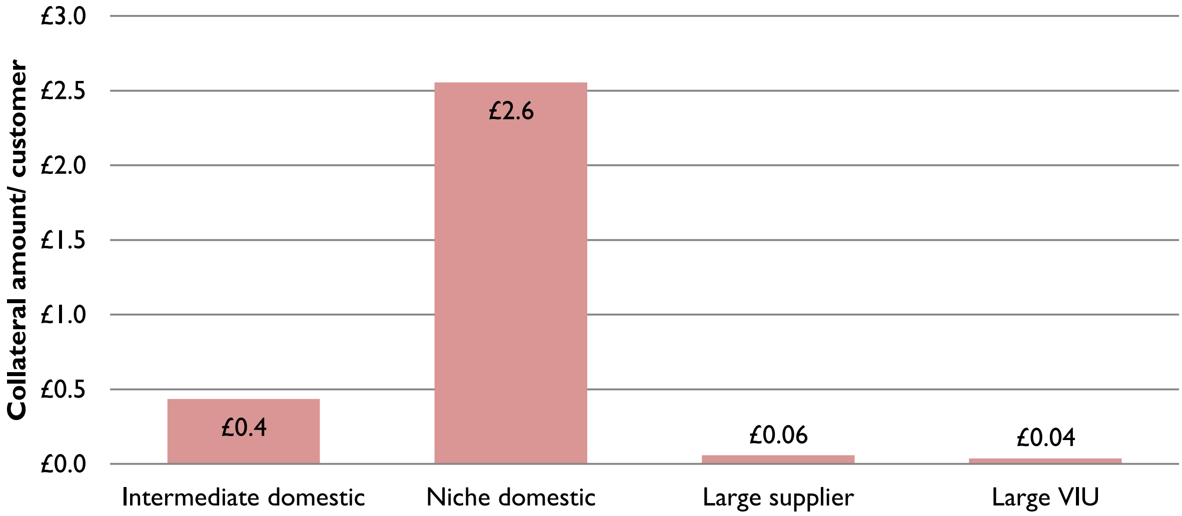


Figure 3.3 illustrates that the amount of collateral per customer for the large VIU and large supplier benchmarks are lower than the comparative group. Despite being required to post collateral volumetrically, both benchmarks enjoy benefits which allow them to reduce credit demands, including ability to source power from its own generating fleet and PPAs, and it is assumed to have a lower exposure to balancing costs under the BSC and UNC.

The costs of collateral per customer for the large VIU are lower than for its competitors, as Figure 3.4 illustrates. This is a consequence of the large VIU's broader customer base and lower financing costs.

3.4 New entrant cases

3.4.1 Purpose

We have also established two new cases in order to examine the impact of credit arrangements on supplier new entry. We consider a new market entrant case and acquisitive market entrant case for each of our core supplier benchmarks.

3.4.2 Key assumptions

This part of the analysis is based on the following assumptions for the new entrants:

- it is one month after market entry;
- these suppliers are weakly credit-rated, reflecting that they are start-ups in the market, and are not supported by a strong financial parent;
- these suppliers are unable to benefit from unsecured credit allowances under transmission and distribution frameworks as they do not have a strong enough independent credit assessment score, or credit rating or an established good payment history; and
- they face a higher cost of finance than the core benchmark.

Each of our new entrants are compared to benchmarks a quarter of the original size[31] (but with all other assumptions held the same) of their relative core benchmark to provide a fair basis for comparison of the increased burdens of credit[32].

For the acquisitive entrants:

- each new entrant has acquired a company of exactly the same market share, customer number and operating parameters as the relevant core benchmark;
- the analysis takes a snapshot of the collateral demands and costs these new entrants would face upon market entry. They too would not benefit from unsecured credit allowances under transmission and distribution activities as a result of good payment history[33]; and
- the analysis assumes these case benchmarks are financially capable, but not supported by parent companies. A "new entry risk premium" is added to the finance assumption that has been used for their respective core benchmark comparator.

In both cases the financing assumptions are at Annex C (2).

3.5 Summary analysis—new entrants

Table 3.6 shows the full collateral amounts the new market entrant variants would be required to post. It then shows these amounts as an increase against established benchmark profile of the same size.

[31] Thus for the niche domestic electricity supplier, the new entrant has 12,500 customers rather than 50,000.

[32] Volume of activity and numbers of customers are a critical driver of collateral amounts under the various frameworks.

[33] They may also benefit from unsecured allowance through independent credit assessment scores or credit ratings but this cannot be guaranteed, so in this analysis we have assumed that they do not.

Table 3.6: Annual average increases in amounts and costs, new market entrant vs. scaled down core benchmark, 2011-13

Benchmark	New market entrant (£)	Increase in collateral (%)	Increase in collateral cost (%)
Intermediate domestic supplying electricity and gas	3,397,506.8	27.8	91.6
Niche domestic electricity supplier	328,784.5	23.6	44.1
Industrial and commercial electricity supplier	9,043,478.0	22.6	92.7
Small and medium sized enterprise electricity supplier	3,538,082.8	19.6	67.4
Industrial and commercial gas supplier	10,149,221.2	19.1	87.2
Small and medium sized enterprise gas supplier	1,040,039.6	21.6	70.2

Table 3.7 shows the full collateral amounts the acquisitive new entrants would be required to post. It also shows these amounts as an increase against the relevant established benchmark profile scaled to the same size.

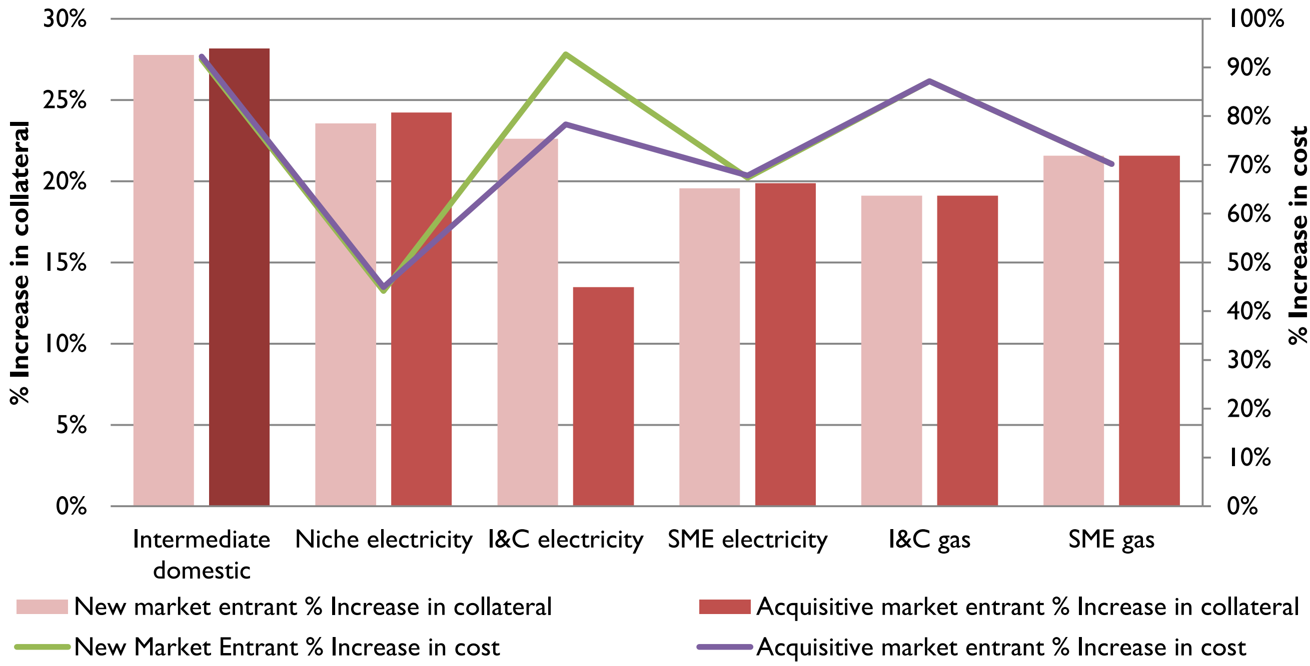
Table 3.7: Annual average increases in amounts and costs, acquisitive new entrant vs. core benchmark, 2011-13

Benchmark	Acquisition new entrant (£)	Increase in collateral (%)	Increase in collateral cost (%)
Intermediate domestic supplier of electricity and gas	13,629,708.74	28.1	92.2
Niche domestic electricity supplier	1,322,352.83	24.2	44.9
Industrial and commercial electricity supplier	33,481,320.83	13.5	78.3
Small and medium sized enterprise electricity supplier	14,188,405.15	19.9	67.8
Industrial and commercial gas supplier	40,596,884.86	19.1	87.2
Small and medium sized enterprise gas supplier	4,160,158.24	21.6	70.2

For both new market entry cases, there is an immediate demand for collateral upon market entry. There is a marginally bigger increase in collateral for new entrants (on average 22% relative to the equivalent core supplier benchmark) than for the acquisitive market entrants (on average 21% relative to the equivalent core supplier benchmark). The largest increase in both cases occurs for the intermediate domestic gas and electricity supplier. Costs rise considerably relative to comparators, on average increasing by 75% across new entrant suppliers and 73% across acquisitive suppliers. Again the intermediate domestic gas and electricity supplier incurs the highest increase in cost. The increase in credit amounts occur in particular under transmission and distribution frameworks.

Figure 3.5 illustrates the increases in collateral amounts and costs for both brand new entrants and acquisitive new entrants in the period 2011-13. The left axis represents percentage increase in collateral amount. The right axis represents percent increase in collateral cost.

Figure 3.5: Acquisitive and new market entrant vs. core benchmarks, 2011-13 annual average credit amount and cost, summary changes (%)



3.6 Headlines—new entrants

The headline findings from the analysis of the new entrant and acquisitive entrant cases are:

- the problems faced by the core supplier benchmarks are compounded;
- there is an optimism bias in establishing collateral levels as they assume fast growth;
- a pessimism bias also exists in financing arrangements;
- there are additional financial barriers to hedging for new market entrants;
- customer pass-through is limited, particularly for new market entrants; and
- external support can be critical for success.

These findings are discussed in more detail below.

3.6.1 The problems faced by the core supplier benchmarks are compounded

The largest increase in both cases occurs for the intermediate domestic gas and electricity supplier. Costs rise considerably relative to comparators, on average increasing by 75% across new entrant suppliers, and 70% across acquisitive suppliers.

3.6.2 Optimism bias in establishing collateral levels

According to our discussions with trading parties, collateral limits and postings (in balancing frameworks in particular) can often be set for new suppliers assuming growth in charges will occur, rather than incrementally increasing levels of collateral to match business growth as it occurs. This creates an unavoidable cost of business that is out of proportion to the revenues being earned and can result in a margin and working capital squeeze. This constraint limits the ability for entrants to grow their customer base as quickly as they would otherwise be able to do.

3.6.3 Pessimism bias in financings arrangements

For new entrants, working capital pressure is increased by limited access to affordable banking facilities. We were told that many companies who have entered the market found it difficult to access bank financing in the first 12-18 months of trading and that the costs of alternative sources of finance were very high[34]. In some instances, without working capital, new entrants would choose to pay on receipt of invoice (effectively is prepaying for energy) rather than finding themselves in breach under various frameworks for an inability to post collateral.

For acquisitive entrants, the financing challenges are less stark, although (depending on the background of the acquiring company) we have assumed that it is likely that any investors would apply some form of risk premium to account for the lack of local market experience of the acquiring company.

3.6.4 Limitations on hedging for new market entrants

Greater financial uncertainty also faces new entrants as credit acts as a barrier to enter into any bilateral trades that might help them to hedge the risk of supplying customers. In both the domestic and non-domestic sectors, fixed tariffs (one year) are now a stock part of a supplier's offer. The competitive position of a new entrant would be compromised if it were unable to offer this product, but the entrant's ability to hedge its position in doing so is more questionable if it were unable to enter into bilateral forward trades in reasonable volumes.

We also heard that, owing to credit constraints, new entrants frequently find themselves trading more than they would otherwise wish to on the day-ahead markets—effectively leaving themselves exposed to volatile short-run prices. From a risk management perspective, due to vulnerability to spikes in wholesale energy costs, this is not a sustainable position for any supply business engaged in longer-term tariff offers[35].

3.6.5 Customer cost pass-through is limited, particularly for new entrants

It is very challenging for new entrants to pass-through the costs of credit to customers. In simple terms, they have to pro-rate a far higher cost than their direct peers and competitors across their smaller customer base. This differential is disadvantageous to their competitive position and inhibits their prospects for growth.

[34] Such as venture capital equity, which we heard had been offered at a fixed coupon of around 14%.

[35] Zest Energy in 2006 and Electricity4Business in 2008 became insolvent following acquisition of new customers but exposure to rising short-run prices.

Recent entrants have spoken about a "tipping point" when an increase in customer numbers leads to the ability to access greater levels of unsecured credit. This "tipping point" will be different for each individual business, but in general terms market participants have spoken about a period of around 18-24 months. But this means having navigated this period successfully in the first place.

Whilst the challenges are less than those faced by new entrants, the enhanced volume and costs of collateral will make it challenging for acquisitive entrants to grow their acquired business as a result of facing higher marginal costs, which must in turn be reflected in the margin they can earn.

3.6.6 External support critical for success

The working capital conditions facing new entrants are extremely challenging and often necessitate seeking external support. We were told of many instances where recent entrants needed to rely on repeated and large levels of investment from their shareholders and parent companies to navigate the first 18-24 months of business. This means that success is most likely where there are strong backers or where the entrant submits to some form of trading or ownership consolidation with more established market players.

Acquisitive entrants are most likely to be backed by strong financial and industry operators in their own right already, either in the GB market or with a presence in international energy markets.

3.7 "Mark-to-market" sensitivities

3.7.1 Purpose

Large suppliers and large VIU suppliers face unique risks as a result of greater volumes of trading through bilateral agreements at longer-dated maturities. Forward trading exposes these suppliers to a greater level of "mark-to-market" risks.

These risks arise for a seller of power when the underlying commodity price falls from the point at which the trade was struck—assuming the buyer is unable to settle the trade. If the supplier were unable to fulfil the trade obligation, the seller of the power would face a loss in replicating a sale for the same volume of the commodity in the open market. As a result, the seller will make collateral calls to cover this risk.

We have modelled exposure to "mark-to-market" risks for different maturities of bilateral power and gas trades. We have not however established a "mark-to-market" sensitivity for exchange trading on N2EX as the majority of these trades are "prompt" or day ahead and do not create large "mark-to-market" exposures for trading parties.

3.7.2 Key assumptions

To obtain a representative level of possible commodity price reductions, we have used historic data to capture decreases in prices actually seen in the power markets. We have chosen the reductions seen between September 2008-September 2009. During this period contract prices reduced by approximately10% month-on-month, and around 50% over the year. The significant reductions in commodity prices in this period were unusual and significant. These scenarios should therefore be considered extreme and towards the worst case in the range of possible events that could lead to "mark-to-market" risks for suppliers. Supporting data is at Annex E.

The sensitivity analysis focusses on two "mark-to-market" scenarios:

- first, for one month all power and gas traded bilaterally by the large domestic gas and electricity supplier and large VIU domestic and non-domestic gas and electricity supplier is through month-ahead contracts (delivery and settlement a month out from entering the trade). Prices reduce by 10% between the date of entering the trades and the date of settlement in one month during the 2011-13 period. Hence the suppliers are exposed to "mark-to-market" risk on a month of month-ahead trades, in proportion to the 10% reduction in prices; and

- second, for one month all power and gas traded bilaterally by the large domestic gas and electricity supplier and large VIU domestic and non-domestic gas and electricity supplier is on a year-ahead basis. Prices reduce by 50% at one point between the date of entering the trades and the date of settlement. The suppliers are exposed to "mark-to-market" risk on a month of year-ahead trades, in proportion to a 50% reduction in prices. Whilst suppliers may hedge certain proportions of gas and power for longer than one year, we have selected a year ahead basis as this maturity of trading will be a core part of a large suppliers hedging strategy.

These scenarios reflect actual market conditions over the recent past. It is hard to say whether they are typical, through recent price movements have ended these trends. The analysis uses the same cost of finance assumptions for the large domestic gas and electricity supplier and large VIU domestic and non-domestic gas and electricity supplier as used for the core supplier benchmarks in Annex B.

3.8 Summary analysis—"mark-to-market"

The following cost of credit analysis is based on the "worst case" assumption that in these circumstances the trading counterparty would wish to receive liquid and strong collateral from the supplier in the form of letters of credit. In reality, this may not be the case, and requirements will depend on the terms of the bilateral contract and the appetite for risk of the seller.

Table 3.8 shows the additional average annual credit amount resulting from "mark-to-market" exposure, together with its impact on the total credit required from the large domestic gas and electricity supplier.

Table 3.8: Large domestic gas and electricity supplier collateral average annual credit amount profile with "mark-to-market"

Benchmark	Large supplier	Large supplier "mark-to-market" 50%	Large supplier "mark-to-market" 10%
"Mark to market" (£)	-	41,586,108.77	3,904,097.59
Total (£)	125,572,490.81	167,158,599.58	129,476,588.40
Increase (%)	-	33	3

Table 3:9 shows the same information in terms of the annual average credit costs.

Table 3.9: Large domestic gas and electricity supplier collateral annual average cost profile with "mark-to-market"

Benchmark	Large supplier	Large supplier "mark-to-market" 50%	Large supplier "mark-to-market" 10%
"Mark to market" (£)	-	623,791.63	58,561.46
Total (£)	354,251.06	978,042.69	412,812.52
Increase (%)	-	176	17

The make-up of "mark-to-market" collateral between gas and electricity bilateral trading is 70% to 30% gas to electricity in the year-ahead sensitivity, and 75% to 25% gas to electricity in the month-ahead sensitivity.

This reflects the fact that the large domestic gas and electricity supplier can source power from exchanges (reducing reliance on bilateral trading). However, as we assume the supplier has no interests in up-stream gas storage or supply, they must purchase all of their gas demand from third parties.

Table 3.10 (average annual credit amount) and Table 3.11 (annual average collateral cost) show the same information for the "mark-to-market" exposure for a large VIU domestic and non-domestic gas and electricity supplier.

Table 3.10: Large VIU domestic and non-domestic gas and electricity supplier collateral average annual credit amount profile with "mark-to-market"

Benchmark	Large VIU supplier	Large VIU supplier "mark-to-market" 50%	Large VIU supplier "mark-to-market" 10%
"Mark to market" (£)	-	76,048,720.45	7,383,940.37
Total (£)	220,060,282.65	296,109,003.10	227,444,223.02
Increase (%)	-	35	3

Table 3.11: Large VIU domestic and non-domestic gas and electricity supplier annual average collateral cost profile with "mark-to-market"

Benchmark	Large VIU supplier	Large VIU supplier "mark-to-market" 50%	Large VIU supplier "mark-to-market" 10%
"Mark to market" (£)	-	1,140,730.81	110,759.11
Total (£)	477,368.71	1,692,349.52	662,377.82
Increase (%)	-	254	39

3.9 Headlines—"mark-to-market"

The principal conclusions we have reached are:

3.9.1 "Mark-to-market" risk is significant

The analysis highlights the materiality of "mark-to-market" credit exposure in bilateral trades, particularly if longer-term trades are adopted. For shorter-term trades the risk is more limited. Smaller suppliers are not in a strong position to shoulder the potentially rapid escalations of credit amounts and costs that might arise from "mark-to-market" risks, and the limited credit standing of smaller players exacerbates this.

In reality, large and large VIU suppliers will have the benefit of being able to trade a range of contract maturities depending on their individual hedging strategies by virtue of a typically more robust credit standing. They will most likely adjust the profile of their trading activities based on projections of future prices and demand and so can attempt to mitigate exposure to the concentration of "mark-to-market" risks.

We have assumed an exposure to "mark-to-market" risk based on exposure to specific contracts over fixed durations. In practice the supplier would most likely face a series of "mark-to-market" calls across a range of maturities. Hence, in simple terms the actual level of "mark-to-market" exposure in circumstances of commodity price reductions equivalent to those factored into these sensitivities is likely to be somewhere between the results for the 10% and 50%.

3.9.2 It is a barrier to smaller players in particular

Large suppliers may have the trading breadth of access to different trading products to alter and refine hedging strategies and avoid material exposure to "mark-to-market" risks. In practice, however, this is unlikely to be available to smaller suppliers given the challenges they have in accessing trading options at different maturities. So, even if small suppliers were able to meet the credit requirements associated with "mark-to-market" risk, their ability to adapt and refine their trading in response to price movements is constrained.

4 Generator benchmark map

This Section of the report develops a series of generator benchmarks and evaluates the allocation of collateral amounts and costs between them. It analyses the impact of the application of credit rules for the frameworks discussed in Section 2. The Chapter further evaluates the collateral amounts and costs for new build generator variants of the generator benchmarks.

4.1 Key assumptions—existing generators

The key metrics of the five core generator benchmarks are set out in Table 4.1.

Table 4.1: Existing generator benchmark volume assumptions

Benchmark	Capacity (MW)	Load factor (%)	Annual output (MWh)	Daily output (MWh)	Connection	Location[36]
CCGT	800	0.5	3504000	9600	Transmission	England
Large biomass conversion	600	0.8	4204800	11520	Transmission	England
Biomass plant	100	0.8	700800	1920	Transmission	England
Offshore wind	500	30	1314000	3,600	Transmission	Offshore England
Onshore wind	50	27	118260	324	Transmission	Scotland
Solar	10	11	9636	26	Embedded	South West England

Other key assumptions that underpin the analysis of core generators are as follows:

- our core generator benchmarks (other than solar) are operating electricity power stations owned by large vertically integrated utilities;
- for CCGT, biomass conversion and biomass, the generating stations comprise baseload power units. 50% load factor is an upper estimate of load for a CCGT[37]. Load factors for onshore wind, offshore wind and solar are taken from DECC figures used for underpinning strike price setting under the CfD;
- it is unlikely that dedicated biomass would operate as flexible plant, as the illiquidity and immaturity of the fuel supply markets means they are likely to pre-buy and store fuel on site against a planned and predictable level of load. The Renewables Obligation Certificate (Roc) provides an additional incentive

[36] Location is relevant to the level of tariff underpinning CUSC generator user commitment credit.

[37] Observed load factors for CCGTs over the last three years have been 20%-25%, but in the case of a new CCGT they would be running mid-merit and at or around loads of 50% due to their greater efficiency factors. The future load factor for CCGTs will depend on the prospects for the running and eventual closure of coal plant.

to maximise running. Large biomass converters would also face similar incentives but would be further constrained by the fact that the underlying technology being converted is inflexible coal generation. This homogeneity of operating models limits collateral exposure under the BSC and (where applicable) to fuel sourcing and trading;

- for CCGT, biomass conversion and biomass, the generating stations are trading directly in the markets and participate directly in balancing mechanisms—they do not have PPAs. For the CCGT plant this also means they face the costs of collateral in the gas supply value chain (they source their own gas through physical trading). As such we allocate an amount and cost of collateral in terms of gas trading;
- for wind, the projects have PPAs. In offshore wind this reflects the joint venture arrangements that utilities are increasingly entering into with independent partners, who require PPAs to raise finance against their share of the generating assets; and
- we assume that (to the extent they were required to in circumstances where the reference price is higher than the strike price) they would be "good-payers" under the CfD, and would not be required to post collateral upon a non-payment event.

For the purposes of assessing financing costs, we have assumed that all of our core generator benchmarks will post letters of credit rather than cash. Further, we assume a consistent 1.5% letter of credit fee for each benchmark (other than for solar PV), on the basis that they are financed not through project finance but by their large VIU owners. 1.5% is lower than the average letter of credit fee we assume in the framework map for BBB companies (2.5%). This difference is to take account of the potential credit rating of utilities underwriting these investments[38], which will be above BBB. For solar PV we assume a financing cost of 2.5%, reflecting based on our experience an estimate of the cost of issuing letters of credit under a project finance structure.

Generator benchmark profiles are contained in Annex D2. These set out the key assumptions we have used to determine credit amounts and credit costs and display the results of our analysis for each benchmark, including where relevant results under alternative cases for generator new build.

4.2 Summary analysis—existing generators

Figure 4.1 and Table 4.1 illustrate the allocation of collateral amounts across our core generator benchmarks, including a ranking to demonstrate the relative demands on different types of generator market participants.

Our core generator benchmarks post less collateral than supplier benchmarks. This position reflects generators' more limited exposure to the costs of transmission and distribution of electricity and gas. It also reflects independents' ability to find routes to market—and avoid the direct costs of collateralisation in electricity balancing—through PPAs or tolling arrangements.

[38] The Big Six typically have had credit ratings between BBB+ and A- in the 2011-13 period.

Figure 4.1: Core generator benchmark map, annual collateral amounts for baseline and new frameworks 2011-13 (£)

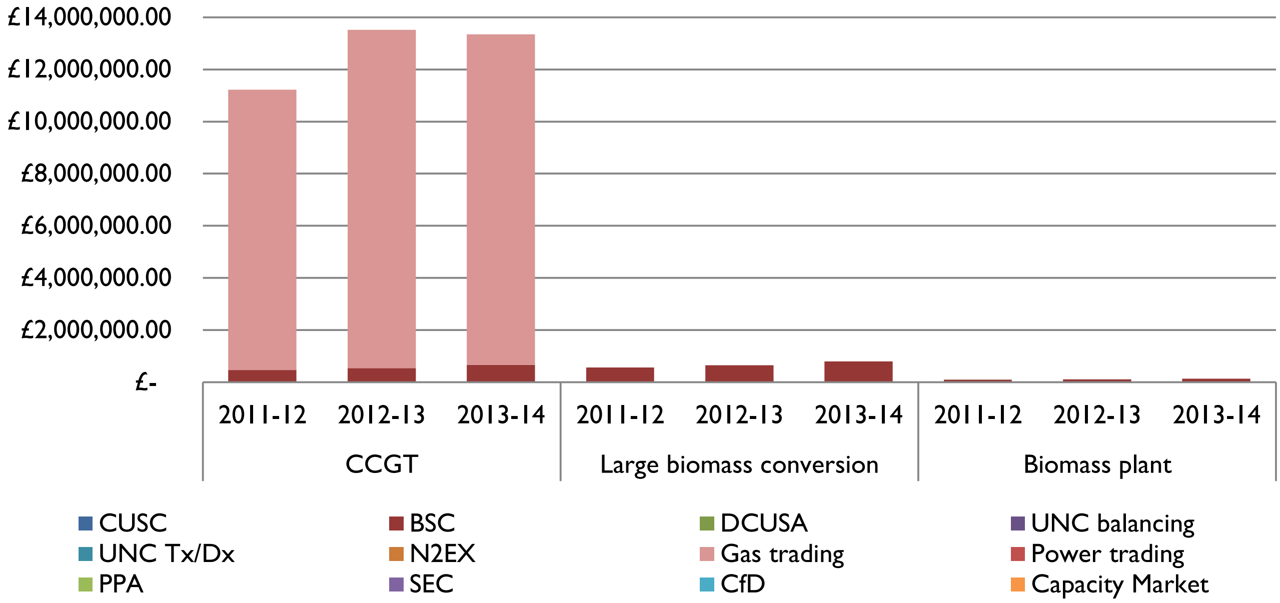


Table 4.2: Existing generator benchmark ranking by credit amount, annual average 2011-13

Rank	Generator	Collateral Amount (£)
1	CCGT	12,699,619
2	Large biomass conversion	668,946
3	Biomass plant	111,491

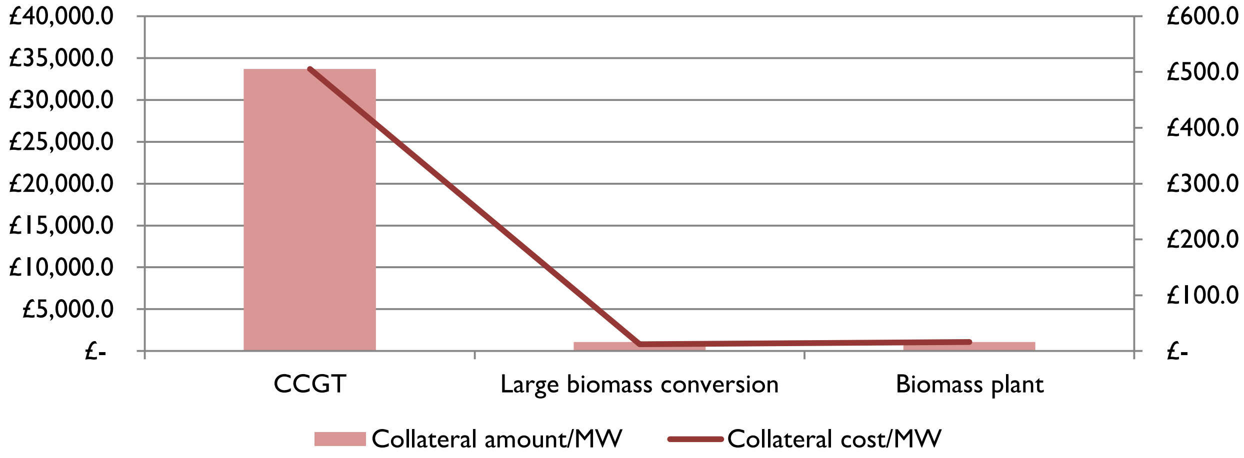
Table 4.3 shows the ranking of generator benchmarks by annual average cost, and displaying the ranking by the amount of credit posted to show the extent of correlation.

Table 4.3: Existing generator benchmark ranking by credit cost and amount, annual average 2011-13

Rank on Cost	Generator	Collateral Cost (£)	Rank on Amount
1	CCGT	190,494	1
2	Large biomass conversion	8,388	2
3	Biomass plant	1,672	3

This information can be expressed as an amount and cost per MW, which is represented in Figure 4.2.

Figure 4.2: Existing generator benchmark annual average amounts and costs of collateral per MW



4.3 Headlines—existing generators

The key findings from the analysis of the generator benchmarks are:

- there is less credit required in generation than in supply;
- a CCGT would be exposed to gas trading and the associated credit costs;
- biomass faces additional collateral for fuel supply; and
- PPAs insulate against credit requirements but at a cost.

These findings are explained in more detail below.

4.3.1 Lesser amounts and cost of credit in generation than in supply

The collateral costs and amounts across the core generator benchmarks under specific frameworks are far less than for suppliers. This disparity reflects the more simple process and linear business model associated with baseload energy production. It also indicates the more limited exposure to different burdens (relative to suppliers) from transmission and distribution activities, and to collateralisation under the CfD.

4.3.2 CCGT is exposed to credit costs associated with gas trading

A CCGT plant incurs a higher cost and amount of collateral in proportion to its size (MW) than other plant. This is as a result of being required to post large amounts of collateral to support gas trading—as compared to biomass plant, which only faces credit under the BSC.

4.3.3 Biomass and biomass conversion will face "hidden" collateral

Biomass plant will need to secure medium to long-term fuel supply contracts (or invest in their own fuel supply chain) in order to operate and finance their plant. This is an illiquid, opaque and under-developed market compared to sourcing gas, and contractual terms (including those relating to collateralisation of payment commitments for fuel) are unlikely to be standardised. The credit arrangements will depend on the requirements and profile of the counterparties striking the contract. For example, some large biomass converters, such as Drax, have developed their own international fuel supply and processing capability, which will demand very different credit arrangements than entering into a long-term contract with a third party for the supply and shipping of fuel[39].

Equally, sources of fuel may be from the international market[40]. Such trade potentially necessitates the entry into currency hedges (with banks), which in turn will need to be collateralised. In some cases, fuel supply contracts will have an indexed price with part of the index being linked to oil prices (reflecting the cost of transit), again incentivising some form of hedging of oil prices. Due to the degree of uncertainty and non-standard nature of fuel supply arrangements, we have not modelled these fuel supply collateral arrangements for biomass and large biomass conversion benchmarks. But such arrangements will impose collateral demands.

In contrast, for CCGT plant, gas markets are highly liquid and established, with long standing commercial practice around posting credit to support settlement and "mark-to-market" risks across a range of products. Therefore, it is possible to capture possible collateral arrangements that will be required to support this activity.

4.3.4 PPAs insulate against credit demands, but for a fee

For offshore and onshore wind as well as solar, the core generator benchmarks show no collateral exposure. This is because under our assumptions these benchmarks have entered into PPAs where the provider of the contract (typically a utility) offers the generator the service of providing them a route to market in return for a fee or margin. Therefore, whilst no numbers are shown for the posting of collateral, the generators are likely to face a PPA discount instead.

Typically, a main driver of the margin (typically expressed as a percentage discount to the various elements being sold under the PPA, such as wholesale power, Rocs, Levy Exemption Certificates and embedded benefits) will be the exposure to imbalance costs faced by the counterparty in taking on intermittent or variable generation.

Theoretically, by writing PPAs, the counterparty, who usually will be a utility, may face greater risk of charges (and hence have to post more collateral) under the BSC. The extent to which a utility faces imbalance costs from these activities obviously depends on the scale of its PPA portfolio, but typically imbalance discounts in long-term[41] PPAs have ranged between 10%-25% of the market value of power[42]. These costs are far lower than the costs and risks that an individual generator would face if they participated directly as a trading party to the BSC, where variability in actual versus notified output could see them having to post large amounts of collateral to cover their exposures.

4.4 Key assumptions—new build generators

To show the possible impact of credit and collateral arrangements on new build generation in the GB energy markets, we have established a new build entrant case for each of our core generator benchmarks.

Now that 10MW solar has been excluded from this new build case analysis on the basis that they would be classified as a distributed generator, and (depending on the nature of their connection) they would not directly have to post CUSC Generator User Commitment security. Instead DNOs may pass through security requirements or costs in the grid connection agreements they enter into with distributed

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[39] In these instances the third party supplier may be using the fuel supply contract as security to raise finance to invest in their own capital assets to support fuel aggregation and transport, and hence may demand stringent collateral to support fuel payments by generators.

[40] For example, large amounts of wood chip are being sourced from the US.

[41] 15-year PPAs are considered typical as they are necessary to support generators in raising long-term debt finance.

[42] Typically the price paid for power under PPAs is at a percentage of a reference price, usually a well-established data source (for instance the London Energy Brokers Association) or against a liquid contract price in the market (day-ahead or season-ahead).

generators, reflecting the fact that that the DNO must post security under the CUSC for an equivalent amount. The arrangements adopted by different DNOs are not consistent, and can be discretionary. It should be noted that they would face credit posting requirements of some form[43].

We have made the following assumptions:

- new build cases have been run for all core generator benchmarks other than large biomass conversion (this is because large biomass conversion plant are exiting plant) and the solar plant as noted above;
- each relevant variant has to post credit applicable to new build generation. This requirement includes credit under the CUSC Generator User Commitment arrangements. It assumes this is the post-consent level of collateral (10% of their liability under CUSC charging arrangements) and that transmission costs make up 5% of the project's total cost[44]. All variant benchmarks they are transmission connected and so will have to post credit directly as part of their grid connection agreement[45]. As it is not in receipt of low-carbon support, the new build CCGT benchmark is in a position to bid into the Capacity Market, and hence posts security as required[46]. The other variant new build benchmarks are all supported by renewables measures (Rocs) and hence are prohibited at this stage from participating in the Capacity Market; and
- the analysis does not change the financing costs from our core generator benchmarks as any credit is being posted by the utility owners, from credit facilities that they have sourced for general purposes (i.e. they are not linked to the risk of the individual project).

4.5 Summary analysis—new build generators

Tables 4.3 and 4.4 show the nominal amount and amount per MWh of collateral that each new build variant generator benchmark would be required to post.

Table 4.4: New build generator variants: annual average amounts of collateral 2011-13

Benchmark—new build	CUSC (£)	Capacity Market (£)	Total (£)
CCGT	1,148,302.3	10,092,000.0	11,240,302.3
Offshore wind	789,268.9	-	789,268.9
Biomass plant	134,907.0	-	134,907.0
Onshore wind	513,321.22	-	513,321.2

[43] For example, in an effort to introduce a greater degree of standardisation of CUSC Generator User Commitment security pass-through arrangements to distributed generators, a modification to the CUSC has been proposed. Further detail on the nature of CUSC Generator User Commitment can be found in Chapter 4, Volume 2.

[44] Using data taken from the Mott Macdonald report commissioned by DECC in 2010 on *UK Generation Costs* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65716/71-uk-electricity-generation-costs-update-.pdf.

[45] For solar, if wider reinforcement or grid works are required as this is an embedded generator connecting through a distribution network, then the DNO will bear the cost. DNOs are regional monopolies, the DNOs may pass this cost through to the solar generator.

[46] Details of Capacity Market security rules are set out in Chapter 9 of Volume 2.

Table 4.5: New build generator variants: annual average amounts of collateral, 2011-13

Benchmark—new build	CUSC (£/MW)	Capacity Market (£/MW)	Total (£/MW)
CCGT	1,435.38	12,615.00	14,050.38
Offshore wind	1,315.45	-	1,315.45
Biomass plant	269.81	-	269.81
Onshore wind	10,266.42	-	10,266.42

Tables 4.5 and 4.6 show the data for cost of collateral.

Table 4.6: New build generator variants: annual average costs of collateral, 2011-13

Benchmark—new build	CUSC (£)	Capacity Market (£)	Total (£)
CCGT	17,224.5	151,380.0	168,604.5
Offshore wind	11,839.0	-	11,839.0
Biomass plant	2,023.6	-	2,023.6
Onshore wind	7,699.82	-	7,699.8

Table 4.7: New build generator variants: annual average costs of collateral, 2011-13

Benchmark—new build	CUSC (£/MW)	Capacity Market (£/MW)	Total (£/MW)
CCGT	21.53	189.23	210.76
Offshore wind	19.73	-	19.73
Biomass plant	4.05	-	4.05
Onshore wind	154.00	-	154.00

4.6 Headlines—new build generators

The headlines from the analysis of new build generator benchmarks are that:

- credit timing, rather than amounts, is key; and
- the challenges are locational.

These are explained in more detail below.

4.6.1 Credit timing rather than amounts is key

Under both the CUSC and the Capacity Market, it is not the amount or cost of collateral that is necessarily an issue. Collateral is required to be posted at a stage where there is no generating revenue, the project is in development, and therefore if the project does not proceed for any reason any drawdowns on issued collateral are likely to be written off in full. For independent developers seeking third party finance at this stage of a project's life it is unlikely they will be able to convince banks to post credit on their behalf unless they have a strong enough underlying business (outside of the project) that can be used to counter-indemnify the bank.

This issue needs to be considered in light of other wider collateral demands that developers may be facing at this time. For example (depending on turbine supply market conditions) an onshore or offshore wind developer may be required to place a down-payment or issue a letter of credit to turbine suppliers to secure a delivery date. If payment security in the form of a letter of credit or bank guarantee is required then for the period 2011-13 this could have ranged between 20%-25% of the overall turbine supply contract value. For a 50MW onshore wind farm, this may therefore equate to £10mn[47]. For offshore wind developers, at a similar stage in project development, they may also be required to place deposits on long-lead time items such as HVDC cabling for connection of the generating turbines to the onshore grid. For a 500MW offshore plant this may necessitate spending up to £50mn to secure cabling capacity[48].

4.6.2 New build generation face locational challenges

The amount of credit required to be posted under the CUSC Generators User Commitment arrangements are partly dependent on locational derived charges. Where projects are built will have a material bearing on the burdens created by the CUSC generator user commitment credit arrangements.

Liabilities for CUSC Generator User Commitments are driven in part by the wider liability element of connection charges, which are linked to the grid cancellation tariffs in each charging zone across the GB market. For example, the cancellation tariff in North West Scotland (Zone 1) for 2013-14 is £29/MW, whereas in London (Zone 14) it is £960/MW. The result is that security posted for connections will vary dramatically by region, even for the same technology, as they are locational driven system charges rather than technology driven.

This can often run contrary to other incentives to build in certain locations. For example, for wind projects it is likely those in the north of the GB markets will enjoy better capacity factors than those in the south and operationally will be more efficient and better value for money overall, even after taking into account the need to post security under the CUSC pre-commissioning.

However, the higher credit requirements at an early stage of a project increases the barriers to build for the more efficient wind farms. This is because, as already set out, it is challenging for these projects to enjoy any benefit of their future operational efficiency in terms of accessing credit from banks. Banks are not likely to change their lending behaviour given the early stage of development, and the inherent completion risks for the project, even if they are expected to be efficient projects once operational.

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[47] Assuming a turbine supply agreement contract cost to the order of £50mn.

[48] Validated with an offshore wind generator.