An assessment of the potential impact on consumers of connect and manage access proposals

A REPORT PREPARED FOR OFGEM

November 2009

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Executive Summary

The Department of Energy and Climate Change (DECC) is currently consulting on proposals to improve access to Britain's electricity transmission network. Three models of access have been proposed and, whilst there are numerous substantive differences between the models, they are all based on what is termed a "connect and manage" approach. Ofgem have commissioned Frontier Economics to assess the potential impact for consumers of a connect and manage approach. This report presents our conclusions.

The current transmission access regime can be described as "invest then connect". Generation is only connected to the network once the transmission system has been upgraded to the extent required by the planning standards. In practice this has tended to mean that, for some parts of the system, the connection of significant generation capacity can only occur once the transmission system has been upgraded. A move to a "connect and manage" regime would mean generation could be connected ahead of transmission investment. This could result from an acceleration of generation connections or a delay in transmission investment projects, or indeed both.

The possibility of a disconnect between generation and transmission investment has a number of potential implications. If generation connections are faster than under the existing access regime, then wholesale prices may fall (if the new generation is low cost) but congestion costs will rise. If generation connection timings remain unchanged but transmission projects are delayed, congestion costs will rise with no offsetting reduction in wholesale prices.

The incidence of congestion costs will depend on the exact design of the transmission access regime. However, at least one of the proposals set out by DECC would see congestion costs borne in their entirety by customers, rather than potentially by a combination of generation and customers.

Based on data provided by Ofgem, we have modelled some possible scenarios of generation acceleration and transmission investment delay under a "connect and manage" regime. We have compared these outcomes to an estimate of potential congestion costs and wholesale prices under the existing enduring arrangements. These results are not forecasts – rather, they are aimed at understanding the potential risks which could be borne by customers if they bear the cost of congestion. Under all our scenarios we assume that the UK meets (and in some cases exceeds) its renewables targets.

Our results show that the costs which customers could face under a "connect and manage" regime could be very material:

- our transmission investment delay scenario would see an additional congestion cost of £1.9bn (on an NPV basis to 2020) being borne by customers.

- our generation acceleration scenario would see an additional £2.9bn of congestion costs. While our modelling shows that there could be an offsetting wholesale market cost reduction of around £2.7bn, we note that since we do not model the link between the wholesale price and the level of generation investment, there is a risk that the price reductions would deter investment and that therefore not all of this benefit would materialise. Given the modelled load factors on newer CCGT plant reduce from 85% in 2010 to 30% in 2020, this risk could be significant. Alternatively, the reduction in thermal capacity factors due to increased wind generation means that investors will require higher mark-ups above short run marginal cost in order to enter – negating some of the wholesale market cost reduction.

- our combined generation acceleration and transmission investment delay scenario would see an additional £3.5bn of congestion costs, mainly as a result of differences in the early and middle part of the modelling horizon. This would be greater than the offsetting wholesale market cost reductions of around £2.7bn (the same issues arise in relation to the risk of these reductions failing to materialise).

It is also important to note that, as the volume of wind generation connected to the transmission system increases, the level of congestion becomes highly correlated with the level of wind production. It is therefore highly variable. In windy years, the level of congestion observed could be significantly greater than the averages reported here.

The level of congestion costs is also uncertain because the behaviour of market participants affects costs. In particular, if competition for the provision of balancing services were less effective in future, the level of congestion costs for any given volume of congestion could be higher than our estimates. Such a development could increase the NPV of congestion costs by about £0.5bn for all scenarios. The adverse effect of market power on the *incremental* cost of connect and manage would be more pronounced in a situation where connect and manage causes a greater congestion volume that is under the influence of market power. This could happen if generation concentration in key areas increases, for example, as a result of advanced connection of plant by certain players, or transmission being delayed.

The outturn levels of congestion and wholesale prices will depend on a range of inputs. However, this analysis makes clear that the potential sums at stake are significant, and there are possible scenarios under which a "connect and manage" regime will result in customers bearing a significant additional burden. Careful consideration should clearly be given to any move towards a "connect and manage" policy. The detailed specification of the regime will be critical if the risk of certain generators securing significant benefit at the expense of customers is to be avoided.

1 Introduction

In their consultation "Improving Grid Access"[1], the Department of Energy and Climate Change (DECC) have suggested three possible models for enduring reform of the arrangements for transmission access. These models differ in a number of respects, but they are all fundamentally based on a "connect and manage" approach.

Ofgem wished to explore the potential implications for the risks being borne by customers of the implementation of models based on a connect and manage approach. We were therefore commissioned to explore the implications of such models for customers under a variety of possible scenarios for generation and transmission development.

In this short report, we set out:

- in **Chapter 2**, the overall approach to our analysis;
- in **Chapter 3**, an overview of our modelling approach and the data inputs that we have used; and
- in **Chapter 4**, the results obtained.

The Annexe provides some further details of our modelling approach.

1 See http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx for DECC's consultation document

2 Approach to assessing the impact of the proposals

Historically, the transmission access arrangements in place in the GB market have been based on an "invest then connect" approach. These arrangements have been varied from time to time[2], most recently by Ofgem's decision (set out in their open letter of 8 May 2009) to "extend the period of over-selling for an interim period until, and subject to, the timely and successful implementation of enduring access arrangements".

All of DECC's proposals are based on an alternative approach to "invest then connect", typically referred to as "connect and manage".

In this chapter, we briefly outline the differences between the two approaches and then describe our approach to analysis of the implications of a move to connect and manage for customers.

2.1 Invest then connect

Under an invest then connect regime, the date of connection for any generator is determined by the need for transmission system investment.

Upon receipt of a request for connection by a generator, the GBSO and the relevant TO(s) consider the transmission system investment which would be required in order to connect that generator while continuing to meet the transmission system planning standards. This investment analysis relates not to the "local" assets required to connect the generator to the transmission system, but investment "deep" in the transmission system required to accommodate the changes in flow patterns which could be caused by the connection of the generator.

If no investment is required for the planning standards to continue to be met following connection, the generator is allowed to connect to the network immediately. However, if transmission investment is required, the generator is only allowed to connect once this transmission investment has been completed[3].

This regime effectively means that the timing of connection of new generation is driven by the time lags associated with transmission system investment. And

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2 For example, as part of the implementation of BETTA, NGET and SP Transmission Ltd were granted a derogation from the GB Security and Quality of Supply Standards, permitting the overselling of transmission capacity (relative to the volume which would be consistent with an invest then connect regime) in relation to certain generators.

3 There are exceptions to this rule. For example, the generator may be allowed to connect to the system if it is fitted with devices which allow the GBSO to disconnect the generator if specific events occur ("intertrips").

given the planning issues associated with new transmission system lines or transmission upgrades, this could mean significant delay in the connection of new plant – including new renewables.

2.2 Connect and manage

Under a connect and manage regime, the link between deep system reinforcement and generation connection is broken. Generation is permitted to connect to the system at a given time (under the proposals under discussion, a maximum of four years after having applied for the connection) irrespective of whether the transmission system complies with planning standards at that time. Plant connection is therefore not held back by delays in upgrading the transmission network.

One of the important implications of such a regime is that there is a greater risk of congestion on the network, because of connection of new generation ahead of transmission reinforcement. There are two aspects to this risk:

- generation is likely to be allowed to connect earlier than would have been the case given expected transmission investment lead times; and
- transmission investment projects themselves involve significant risks of delay (for example, due to difficulties in securing all the required planning approvals) – therefore actual completion may lag the expected lead times.

The incidence of this congestion cost depends on the precise definition of the regime. However, at least with the "Connect & Manage (Socialised)" option, it would fall entirely on customers. Other connect and manage options may differ in this regard – however, without further specification (e.g. in particular, in relation to the proportion of congestion costs charged back to those considered to have "caused" them), it is not possible to be precise as to the incidence.

The fact that some or all of congestion costs are likely to fall on customers is an important aspect of these regimes. It effectively means that, relative to the current situation, end users bear risk associated with the difference between generation and transmission investment lead times, and with the potential for delays in transmission capital projects.

2.3 Comparison of the regimes

Ofgem wishes to understand the potential implications for customers of a move (on an enduring basis) from an invest then connect regime to one based on connect and manage.

The costs borne by customers are made up of a number of elements. These include:

- commodity cost;
- network costs – both those associated with physical assets and with the costs of system operation (including management of congestion);
- retail cost; and
- the cost of subsidy and levy arrangements (including, for example, the costs of the Renewables Obligation).

A move to a connect and manage regime will, as noted above, encourage the connection of generation to the system faster than would otherwise be the case. This is likely to have an impact on three of the above cost areas:

- commodity costs will change both in the short run and the long run:
  - in the short run, if the new generation has low or zero marginal costs, it can be expected that the wholesale price of energy will reduce as more expensive thermal generation is pushed out of merit more frequently;
  - in the long run, the change in the commodity prices will impact on investor decisions and influence the type of plant that connects to the network, which in turn, impacts the commodity price;
- network costs will change because network investment will be required to connect new plant, and because the costs of system operation will increase. As noted above, congestion cost will increase, but the cost of holding reserve is also likely to increase if the new generation is intermittent; and
- the cost of subsidy arrangements are likely to increase, if the new generation is renewable.

In this report, we focus on the changes in congestion and commodity costs only, and consider the net effect on customers under a range of scenarios.

Over the period 2009-2020, to understand the risks borne by customers as a result of a potential change in transmission access philosophy, we compare these costs under four scenarios:

- **Scenario 1 ("invest then connect"):** a generation and transmission scenario which would be consistent with an invest then connect regime (in other words, in which there has been sufficient transmission investment to accommodate the generation scenario);
- **Scenario 2 ("connect & manage: accelerated generation"):** a scenario under which generation connection is accelerated, in line with the presumed effect of a connect and managed regime;

- **Scenario 3 ("connect & manage: delayed transmission"):** a scenario under which generation connection remains unchanged but transmission investment is delayed. This will help understand the magnitude of the potential risks to customers associated with connect and manage even if generation connection is not accelerated; and
- **Scenario 4 ("connect & manage: accelerated generation and delayed transmission"):** a combination of scenarios 2 and 3.

In each scenario, the pattern of generation investment we assume is based on work by the Energy Network Steering Group (ENSG). In all cases we assume that renewable targets are met (and in scenario 2 exceeded) by 2020.

3 Modelling approach and data inputs

In this chapter, we summarise our approach to modelling commodity costs and congestion costs and then describe our data inputs. A more detailed description of our modelling approach is set out in the Annexe to this report.

3.1 Overview of our modelling approach

In the GB electricity market, participants trade with each other on a national basis. Therefore the prices established in the markets operating prior to Gate Closure do not take into account transmission constraints. Assuming traded markets are efficient, commodity costs will therefore be defined by the least cost operating profile of plants on the GB system ignoring all transmission constraints (the unconstrained schedule). Specifically, the wholesale price at any point in time should be based on the operating costs of the marginal unit in the unconstrained schedule.

Congestion costs are a function of the extent to which this running profile has to be modified to ensure that transmission constraints are not breached. The volume of congestion relieving trades required is determined by the difference between the unconstrained schedule and the least cost operation profile given transmission capacity (the constrained schedule). Congestion cost is then determined by multiplying these volumes by the price at which generators offer to deviate from their planned schedules through the Balancing Mechanism.

To estimate these costs, we therefore use a despatch model of the GB system to estimate, for a given demand level:

- the unconstrained schedule; and
- the constrained schedule.

The despatch model uses estimates of plant short run marginal costs (SRMC) to determine the least cost operating profile. This ignores the need to recover plant fixed and non-output related operating costs. While we present results based on this SRMC-based modelling, we also model more realistic costs by:

- making a (simplistic) adjustment to the modelled cost of the marginal unit in the unconstrained schedule to reflect the difference between modelled costs and observed electricity wholesale market cost levels; and
- making an adjustment to the cost at which generators are assumed to offer to deviate from their unconstrained running profiles to reflect estimates of the mark-up on SRMC in Balancing Mechanism offers and offers implied by today's observed congestion cost levels.

If competition for the provision of balancing services were less effective in future than it is today, the level of congestion costs could be higher than we estimate. However, this may or may not result in a greater incremental cost of connect and manage.

3.2 Data inputs

In this section, we set out the key data inputs used in our analysis across scenarios. We note that the scenarios we model are not intended to be forecasts. Rather, they represent possible outcomes which introduce a disconnect between generation and transmission investment.

Table 1 below provides a high level overview of the inputs that define each scenario.

Table 1. Overview of inputs

Scenario	Demand, BM mark ups over SRMC, Fuel prices	Generation	Transmission
1. Invest then connect	Demand: NG central estimate for Gone Green	As per ENSG "gone green" scenario	As per TO submissions to Ofgem, plus Eastern HVDC project (effectively the ENSG transmission investments)
2. Accelerated generation	BM bids and offers: mark-ups / downs against SRMC based on Ofgem's observed E&W behaviour, adjusted so that 2009/10 modelled congestion costs equal to 2009/10 expected outcome	Acceleration of ENSG "gone green" scenario by 3 years, plus continued renewables growth from 2017	As per TO submissions to Ofgem, plus Eastern HVDC project (effectively the ENSG transmission investments)
3. Delayed transmission	Fuel price scenarios: coal and gas prices linked to oil prices in long term. Oil prices follow DoE AEO 2009	As per ENSG "gone green" scenario	1 year delay on all proposed transmission expansions
4. Accelerated generation and delayed transmission		As scenario 2	As scenario 3

Source: Frontier Economics

As Table 1 illustrates some data inputs are common to each scenario, whereas some vary to define the scenario we have modelled. We describe each set of data inputs in turn.

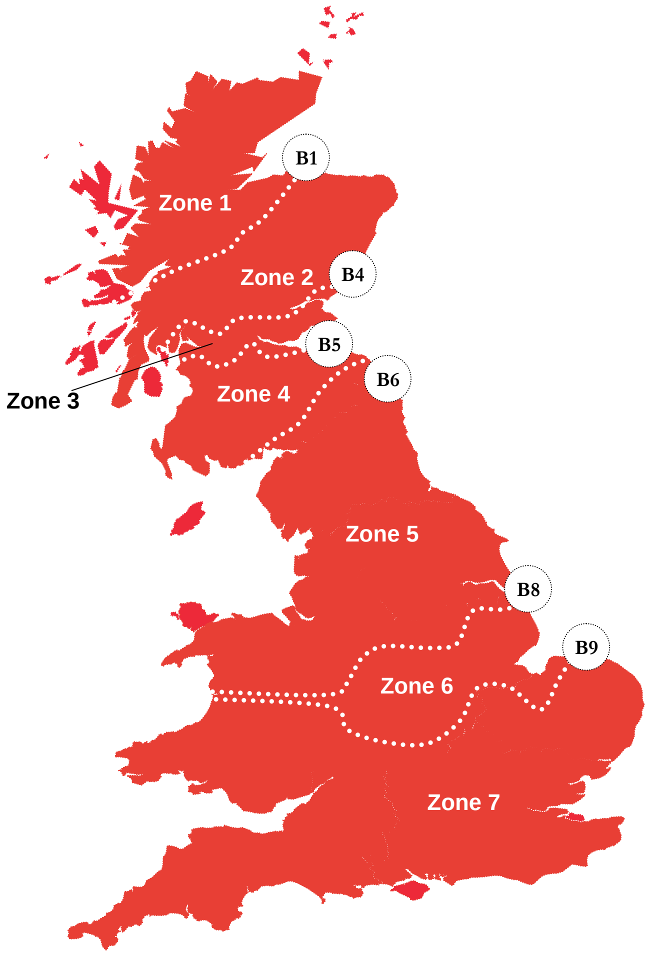
3.2.1 Common data inputs

The data inputs which are common to all scenarios relate to the definition of the zones, demand, fuel prices and assumptions on BM bids and offer price levels. We outline each in turn below.

Zonal definition

For all scenarios, we represent the GB electricity system by a 7 zones and 6 boundary model. The boundaries adopted are a subset of those used by the GBSO and the TOs for network planning and operational purposes. We understand from National Grid that this depiction of the system captures between 90% and 95% of congestion costs. The zonal boundaries are shown below in Figure 1.

Figure 1. Representation of the GB transmission system



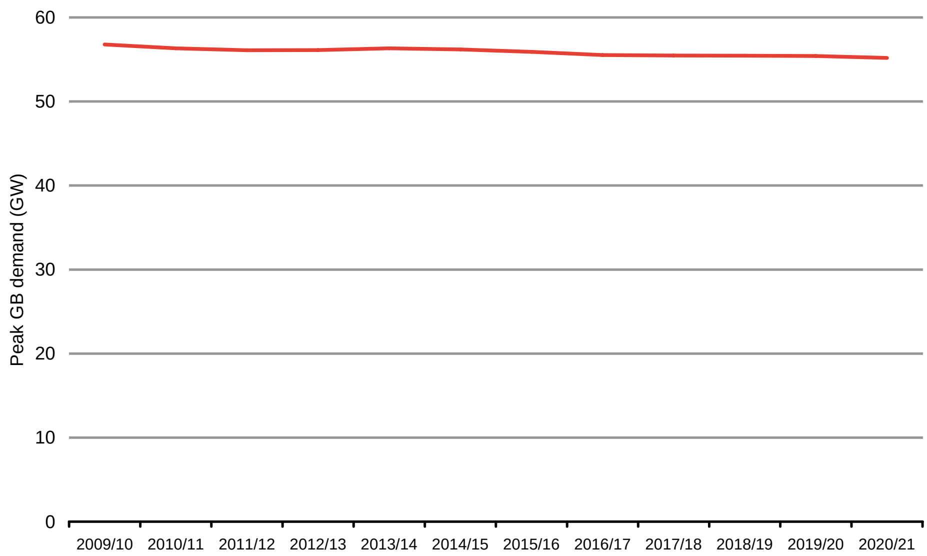
Source: Frontier Economics

Demand

The demand applied in our modelling is based on National Grid's estimate for the Gone Green scenario of demand to be met by imports from other countries, transmission connected generation and large embedded generation, excluding exports to other countries, station load and pumping load. We apply one set of demand assumptions to all scenarios assessed.

As a result of an assumed increase in embedded generation and ongoing low economic growth, peak demand declines from 56.8 GW in 2009/10 to 55.2 GW in 2020/21, as shown by Figure 2.

Figure 2. Evolution of peak demand

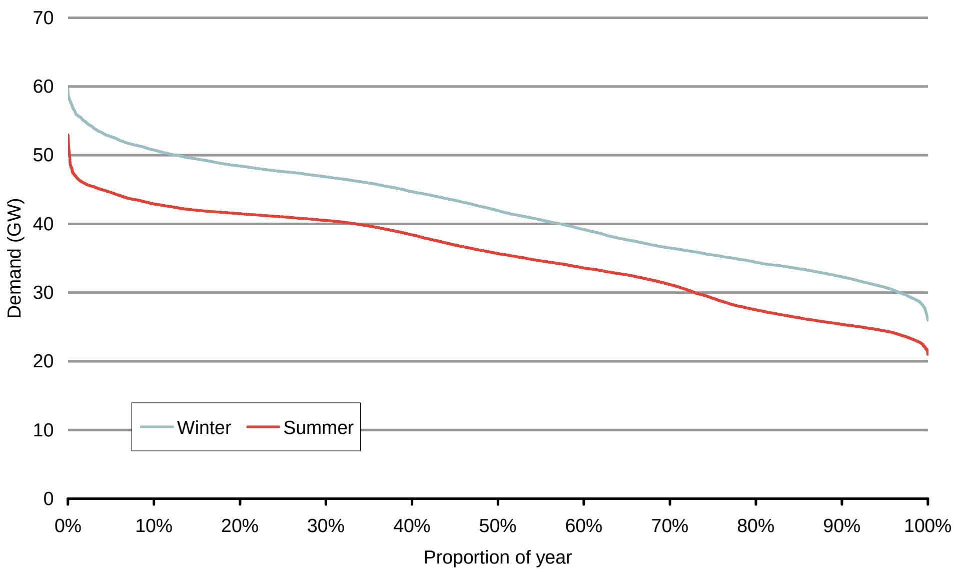


Source: Frontier based on data provided by National Grid

Our model represents demand as a series of eight load steps for each of three seasons: winter, summer (transmission intact) and summer (transmission outage). Winter represents the five month period from November to March, Summer intact represents a five month period during the months April to October and Summer outage represents a two month period during the months April to October.

The heights and durations of the demand steps are derived from the shape of half-hourly demand as published by National Grid for the 2008 calendar year, with the heights and durations of the eight demand steps being the same for the two summer seasons. The demand shape is shown in Figure 3.

Figure 3. Demand shape



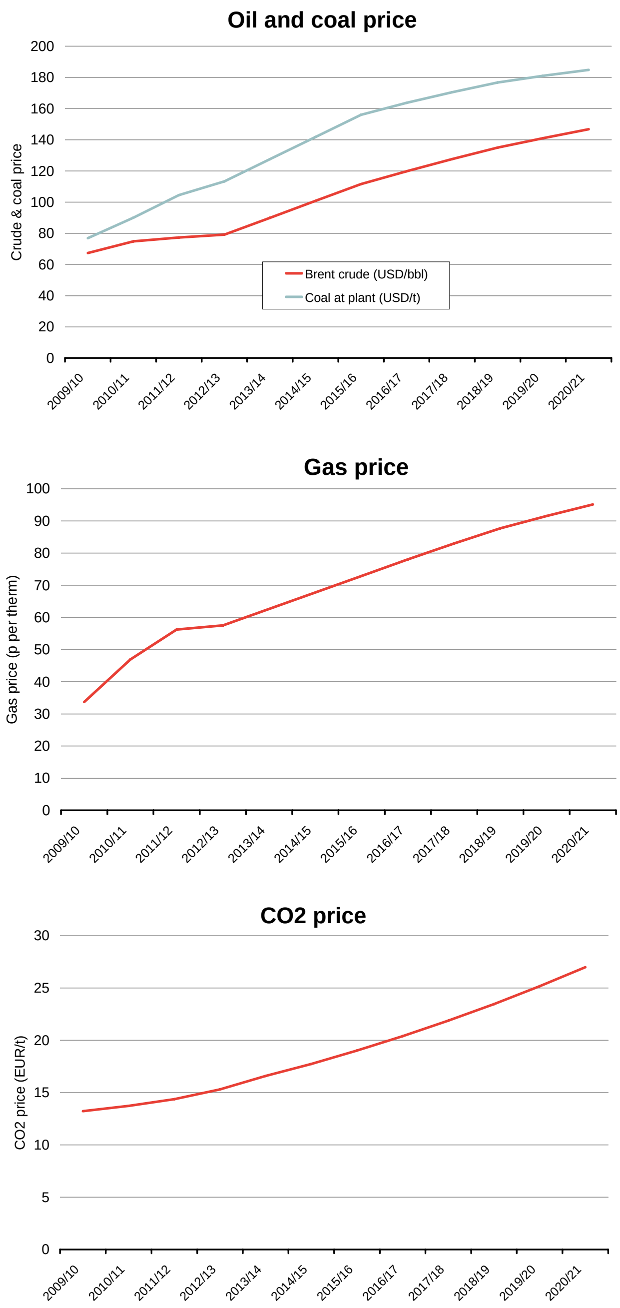
Source: Frontier based on NG data

Demand is depicted separately for each of the seven transmission zones modelled. The breakdown of peak demand between zones is based on data provided by National Grid and we apply the same demand shape to all zones and over time.

Fuel prices

Our assumptions on the evolution of fuel and carbon prices across the modelling horizon are the same for all of the three scenarios that we model. The fuel price assumptions reflect the short term global recessionary outlook, and sustained demand into the medium term driven by growth in demand from the developing world. Our assumptions on carbon prices reflect an assumed tightening of emission caps in Phase III of the EU ETS. The fuel prices used are set out below in Figure 4.

Figure 4. Fuel and carbon price assumptions



Source: Frontier Economics

Balancing mechanism prices

The quantity of congestion is calculated by running a constrained dispatch of our seven zone model of the British power system and by running an unconstrained dispatch of the British power system. The output of the two runs is then compared on a plant by plant and period by period basis. The difference is the volume of constrained on generation or constrained off generation for each plant and each period.

We assess the cost of congestion by applying two different sets of prices to the constrained off and constrained on volumes:

- SRMC based congestion costs – we apply the short run marginal cost (SRMC) of generation of each power plant to value the constrained on and constrained off volumes. This means that the cost of congestion is determined by the spreads between the SRMCs of the constrained on generators and the SRMCs of the constrained off generators.

- Balancing Mechanism (BM) bids and offers – we apply a mark-up to SRMC in the case of constrained on generation and a mark-down to SRMC in the case of constrained off generation. The mark-ups and mark-downs applied vary by plant type and are based on Ofgem's observed BM behaviour in England and Wales, adjusted such that modelled congestion costs in 2009/10 equal expected outturn congestion costs for 2009/10 (approximately £190 million). We apply the same mark-ups and mark-downs to England & Wales and to Scotland. The BM offer and bid mark-ups and mark-downs against SRMC are set out in Table 2 below. If competition for the provision of balancing services were less effective in future than it is today, the level of congestion costs could be higher than our estimates. To test this effect, we estimate congestion costs for a sensitivity whereby coal and gas bid mark-downs in Scotland are £40/MWh and £25/MWh, respectively.

Congestion costs calculated on the basis of our BM bids and offers are significantly greater than congestion costs calculated on the basis of generators' SRMCs.

Table 2. Assumed balancing mechanism prices by generation technology

Generation technology	Bid – mark downs from SRMC	Offer – mark ups from SRMC
Wind	50	N/A
Nuclear	50	N/A
Coal	5	35
Hydro	50	N/A
Gas	15	35
Pumped Storage	50	N/A
Heavy Oil	50	100
OCGT	50	250

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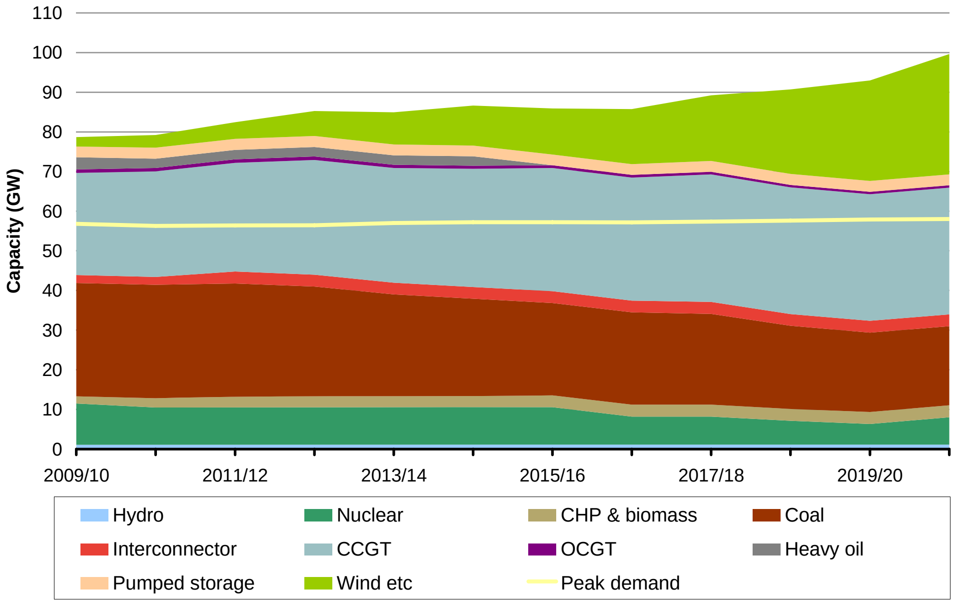
3.2.2 Scenario 1 – "invest then connect"

Under our first scenario we assume that the generation capacity evolves on the GB system to be consistent with GB's 2020 renewables targets. The split of generation technologies for this scenario is based on NG's view for the "Gone Green" scenario. Figure 5 below illustrates the assumed change in generation capacity by technology. Clearly the most notable feature is the large projected increase in wind generation – 29GW is anticipated to connect to the network by 2020 under this scenario.

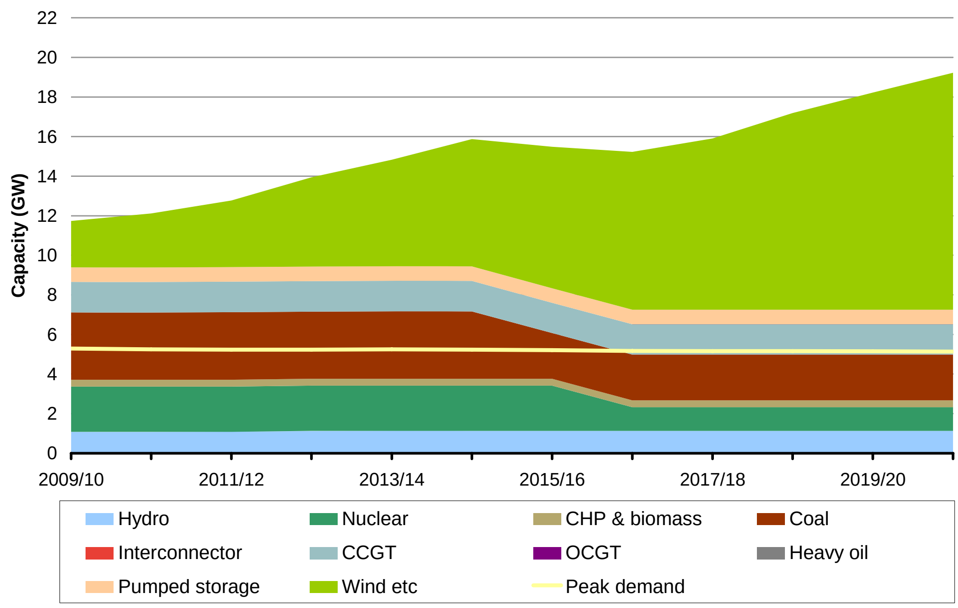
Figure 5. Assumed evolution of GB generation capacity for Scenario 1



Source: Frontier Economics based on data from NG, SP and SHETL

To model the impact of changes in generation, it is clearly important to come to a view on how generation capacity evolves for each of the 7 zones that we modelled. Ofgem provided us with information submitted to them by the three transmission owners on their expectations for generation connection in their transmission areas under a gone green scenario. This allowed us to subdivide the ENSG gone green generation scenario into the 7 zones of our transmission model. To preserve confidentialities we do not depict that breakdown by zone in this report. However, Figure 6, below sets out our assumed evolution of generation capacity for Scotland, which represents an aggregate of generation capacity for Zones 1 to 4 of our transmission model.

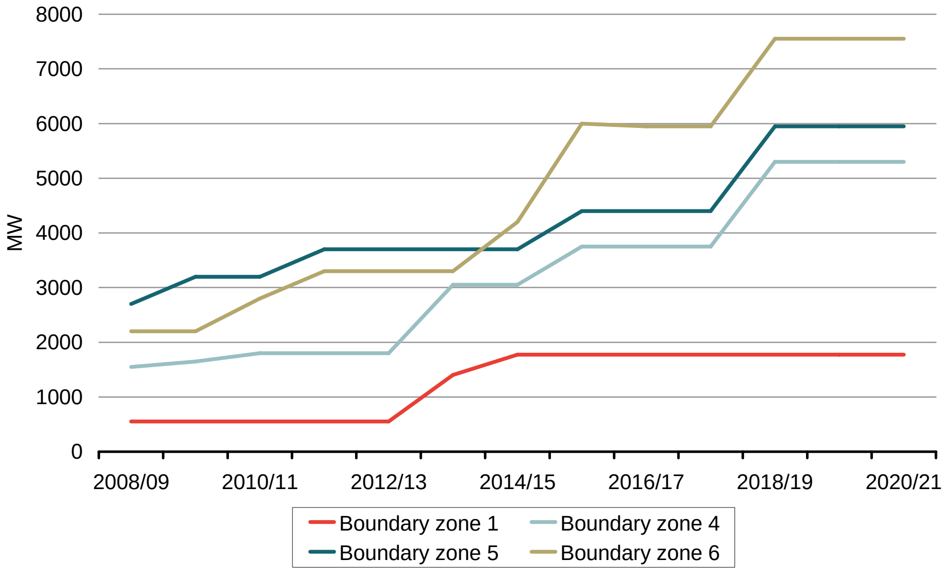
Figure 6. Assumed evolution of Scottish generation capacity for Scenario 1



Source: Frontier Economics based on data from NG, SP and SHETL

Under the "invest and then connect" scenario, we assume that sufficient transmission capacity is constructed to meet the predicted increase in generation capacity. We therefore model expansions in the boundary capabilities over time as depicted below in Figure 7 for the critical boundaries of B1, B4 , B5 and B6.

Figure 7. Assumed winter transmission boundary capabilities for GB system for key boundaries under Scenario 1



Source: Frontier Economics based on data from NG, SP and SHETL

The key changes in the transmission network considered in the assumed profiles of boundary capabilities illustrated in Figure 7 above include:

- completion of the Beauly-Denny line in 2012-13;
- upgrade to the transmission lines between Scotland and England in 2014-15; and
- completion of the offshore eastern and western HVDC projects towards the end of the next decade.

3.2.3 Scenario 2 – "connect & manage – accelerated generation"

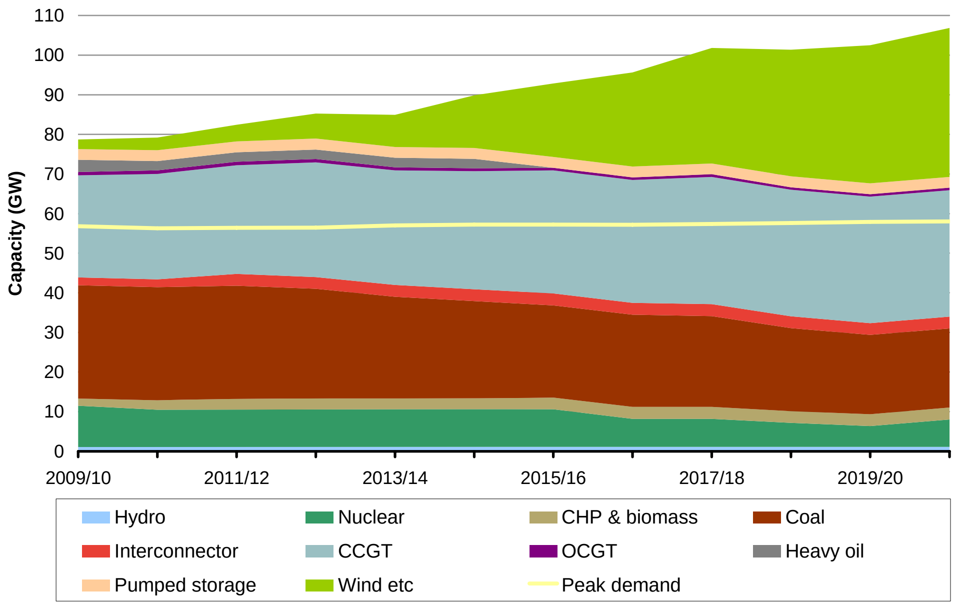
Under this scenario we assume that the proposed connect and manage regime is implemented and that this allows for an accelerated connection of generation across GB. We assume that the transmission background remains as per Scenario 1.

Figure 8 and Figure 9 below depict our Scenario 2 assumptions for generation capacity for GB and for Scotland respectively. Effectively we assume that wind generation connection is accelerated by 3 years from 2014[4] and continues to

4 Assuming implementation of the connect and manage regime in 2010, generation which applied to connect today could, at the latest, be connected to the network in 2014 given the proposed 4 year maximum lead time. Ofgem have provided us with data indicating that, on average, the

grow after 2017 so that by 2020 there is an additional 10GW of wind generation connected to the network relative to Scenario 1.

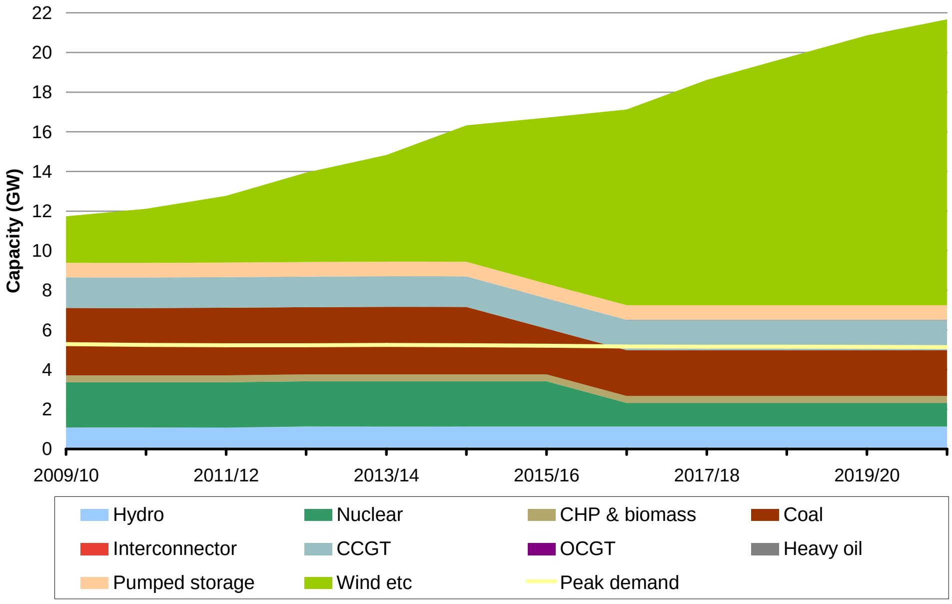
Figure 8. Assumed evolution of GB generation capacity for Scenario 2



Source: Frontier Economics

"aspirational" connection date for new projects is around 3 years ahead of the currently proposed connection dates.

Figure 9. Assumed evolution of Scottish generation capacity for Scenario 2



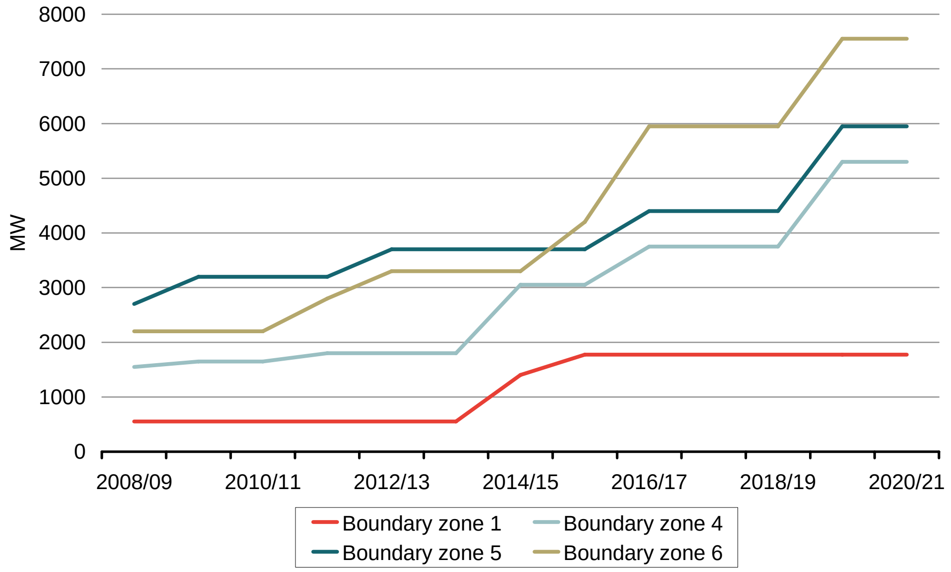
Source: Frontier Economics

3.2.4 Scenario 3 – "connect & manage – delayed transmission"

Under Scenario 3 we assume that the planned transmission investments, as outlined above under Scenario 1, are delayed by one year. Under a connect and manage regime we assume that this delay would not reduce the rate at which new generation could connect to the transmission grid and therefore assumes that the generation profile remains as per Scenario 1.

Figure 10 below illustrates our assumptions on transmission boundary capabilities for Scenario 3.

Figure 10. Assumed winter intact transmission boundary capabilities for key boundaries under Scenario 3



Source: Frontier Economics

3.2.5 Scenario 4 – "connect & manage – accelerated generation and delayed transmission"

The inputs for scenario 4 are a combination of the inputs for scenario 2 in terms of generation investment and those for scenario 3 in terms of transmission investment.

4 Results of our analysis

In this chapter, we set out the results of the modelling analysis described above. We first present an overview of our results across scenarios before providing more detailed results for each scenario separately[5].

It is worth emphasising that none of the results set out here constitute forecasts of likely congestion costs, system marginal costs or wholesale prices. The purpose of the analysis is to consider the implications for these variables – and hence for risks borne by the consumer – of different scenarios for generation and transmission investment, consistent with different transmission access regimes.

4.1 Overview of results

In this section, we provide a brief overview of the results of our analysis.

For any scenario, our estimated congestion cost levels will vary over time. We therefore compare the estimated congestion costs arising in each scenario, evaluated at BM bid and offer prices, in NPV terms. We also present the estimated 2020 level.

For commodity costs, we make the simplistic assumption that wholesale prices are at around £45/MWh in 2010. We then assume that a constant percentage mark up is maintained over modelled system marginal costs throughout the period and compare 2020 estimated wholesale prices between scenarios.

Table 3 presents an overview of our results on this basis.

As we discuss in more detail in the remainder of the chapter, the generation and transmission data provided to us by Ofgem and considered consistent with an invest then connect regime results in significant congestion towards the back end of the period (over the B1 boundary in north Scotland). This is arguably not consistent with the invest then connect philosophy. Therefore we have modelled a sensitivity in which the transmission boundary over which this congestion occurs is assumed to be unconstrained[6]. These sensitivity results are presented in parentheses in the table.

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5 In order to assess the sensitivity of our results to fuel prices, we have carried out sensitivity analysis based on the invest then connect scenario at lower fuel prices than those presented in Chapter 3. The pattern of observed flows and congestion is not materially different to that observed with the base fuel prices.

6 We note that in reality, even under invest and connect, some level of congestion could be expected on the B1 constraint. It may therefore be argued that this sensitivity underestimates the overall cost of congestion. However, by modelling the B1 boundary as unconstrained, we are likely to have increased the level of congestion on other boundaries to the south beyond that which could be expected (as a greater volume of electricity is modelled as being exported from zone 1). This will mitigate the extent of any cost underestimate.

Table 3. Overview of results

Scenario	Congestion costs at estimated BM prices		Commodity costs in 2020 assuming price level in 2010 of £45/MWh	tCO_2 displaced by wind generation [3]	
	NPV 2009-2020 [1] [2]	2020 level		Total 2009-2020	2020 level
1. Invest then connect	£2.4bn (£1.2bn)	£815m (£75m)	£81.30/MWh	213,805 (217,621)	42,231 (43,915)
2. Accelerated generation	£4.1bn (£1.8bn)	£1.2bn (£228m)	£79.30/MWh	292,790	51,168
3. Delayed transmission	£3.1bn	£818m	£81.30/MWh	213,705	42,231
4. Accelerated generation and delayed transmission	£4.7bn	£1.2bn	£79.30/MWh	292,649	51,168

Source: Frontier Economics

1. The NPV has been calculated using a social discount rate of 3.5%, as recommended in the HMT Green Book.

2. Figures in parentheses are results where the B1 boundary is assumed not to be binding. No sensitivity was performed in relation to B1 for scenario 3 or scenario 4.

3. Assuming average CO_2 intensity of 460.5gCO_2/kWh, based on a fuel mix of 25% coal, 65% gas and 10% nuclear.

For the invest and connect scenario, since significant structural congestion is arguably not consistent with the philosophy of the regime being modelled, we believe it is more appropriate to focus on the sensitivity where the B1 boundary is not assumed to be binding.

This is not the case for the connect and manage regime, where we believe it is more appropriate to focus on the model runs where the B1 boundary is assumed to have limited capacity. This is because, for a connect and manage regime, it would be perfectly consistent to see significant generation connection north of B1 without any upgrades to the B1 boundary taking place. While the boundary may subsequently be upgraded in response to these high levels of congestion, the timing of any such upgrade would be decoupled from the new connections themselves. Customers would bear the risk in the mean time.

On this basis, the results point to a number of conclusions.

First, it is clear that if a disconnect between generation and transmission investment were to arise, as under scenarios 2 and 3, customers could face a significant increase in congestion costs. The scenarios we have modelled indicate potential increases of £1.9bn-£3.5bn on an NPV basis.

Second, if the disconnect comes about through accelerated connection of renewable generation, wholesale prices may fall as a result, creating an offsetting benefit. Assuming flat GB demand of 340TWh throughout the period, the modelled benefit of the reduction in wholesale prices between scenario 1 and scenario 2 is some £2.7bn.

While clearly significant, this would not quite be sufficient to offset the estimated increase in congestion costs of £2.9bn between these two scenarios.

There is a significant level of uncertainty associated with the cost of congestion for any given congestion volume. This is because the cost of managing congestion depends upon the behaviour of generators for the provision of balancing services, e.g. the pricing behaviour in the Balancing Mechanism. Less effective competition for the provision of balancing services would increase congestion costs of connect and manage. We estimate that the increase to the NPV of congestion costs under our invest and connect and connect and manage (generation acceleration) scenarios to be about £0.5bn. The adverse effect of market power on the *incremental* cost of connect and manage would be more pronounced in a situation where connect and manage causes a greater congestion volume that is under the influence of market power. This could happen if generation concentration in key areas increases, for example, as a result of advanced connection of plant by certain players, or transmission being delayed.

Equally, there is a level of uncertainty associated with this reduction in wholesale prices. There is a risk that such a price reduction would deter some of the projected investment in thermal generation plant (generation investment is an exogenous input to our model). In this regard, we note that load factors for some of the more efficient CCGT plant on the system are modelled as falling to 30% by 2020 under an accelerated generation scenario, with significant volatility around this average level. Alternatively, the reduction in thermal capacity factors means that investors would require higher mark-ups above short run marginal cost in order to enter – negating some or all of the wholesale market cost reduction.

Were some thermal plant investment to be discouraged, while levels of congestion (largely driven by the location of wind plant) would be unlikely to be affected, the level of wholesale price reduction could be lower. Therefore there is a material risk that the net costs to customers would be higher than the £200m indicated by this result.

Third, the highest level of risk to customers is likely to come from a scenario in which generation connections are accelerated by a connect and manage regime, but at the same time transmission investments are delayed. If developments followed our scenario 3, it could result in additional congestion costs of £3.5bn. The offsetting wholesale price benefits would be similar to those from scenario 2. We estimate these at £2.7bn, not high enough to offset the congestion costs.

If transmission outages were greater than we assumed (e.g. due to outages during the construction of the significant new transmission capacity) congestion costs would be higher.

The issues raised above regarding the uncertainty of these benefits would also apply under this scenario.

Finally, we note that to the extent that more wind generation is constrained off in scenario 3 than scenario 1 (if the B1 constraint is assumed to be non-binding), the displacement of CO_2 emissions by renewables generation is commensurately lower (by around 4,000 tonnes over the period).

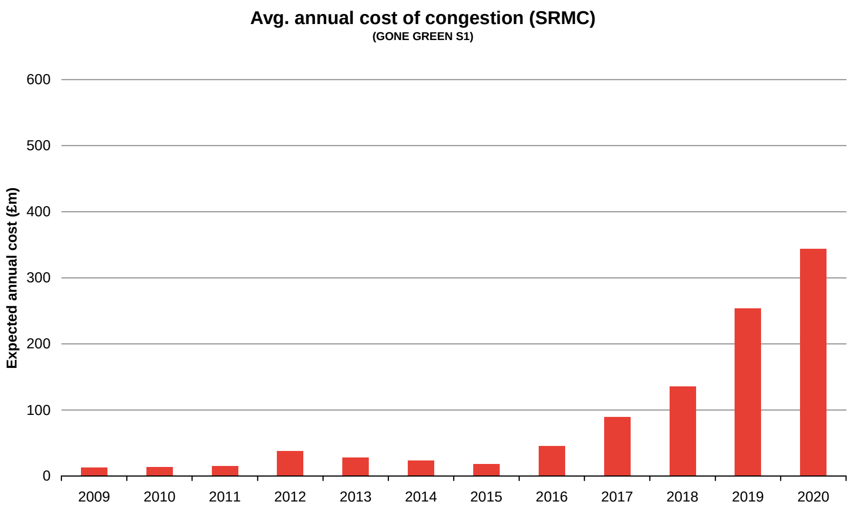
On the basis of these results, we conclude that a move to a connect and manage based regime could involve customers taking on material financial risks resulting from a disconnect between generation and transmission investment.

4.2 Results: "invest then connect"

4.2.1 Congestion costs

Figure 11 shows our estimates of constraint costs under the invest then connect scenario, evaluated at SRMC.

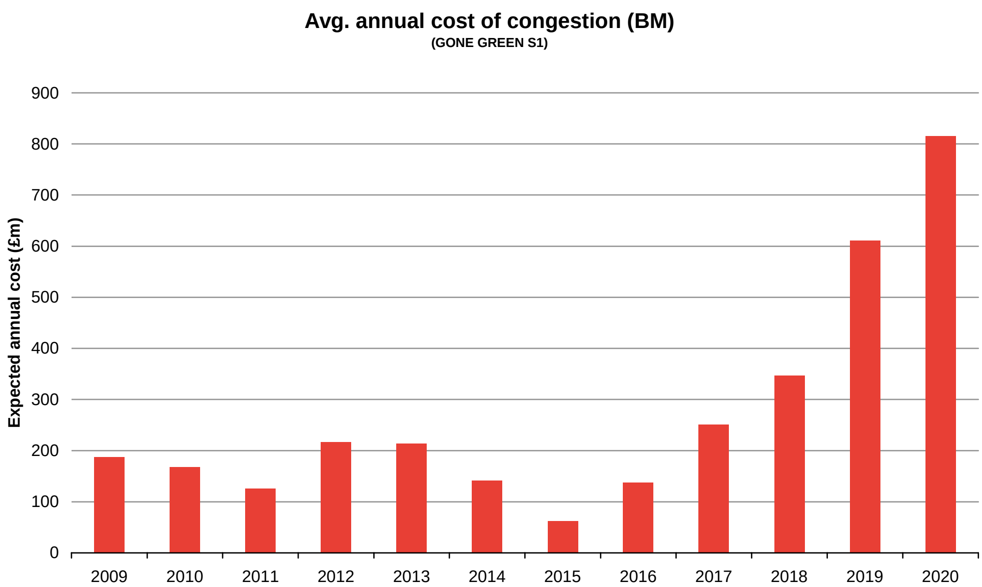
Figure 11. Constraint costs evaluated at SRMC



Source: Frontier Economics

Figure 12 shows these estimates evaluated at our estimated BM bid and offer prices.

Figure 12. Constraint costs evaluated at BM prices



Source: Frontier Economics

It is notable from these results that there is a sharp increase in estimated congestion costs towards the end of the period. Congestion costs evaluated at BM bid and offer prices reach over £800m p.a.

This is arguably inconsistent with an invest then connect philosophy, as it is a strong indication that generation has connected to the network without sufficient reinforcement being undertaken[7]. With an invest then connect regime, it is difficult to see how this outcome would arise. In reality, either:

- the generation assumed to be connecting would not be allowed to connect (part of the reason DECC are considering a move to a connect and manage regime); or
- the transmission system would be reinforced to accommodate the generation connection.

To assess the cause of this congestion, we examined the flows on the key transmission boundaries in our model. Figure 13 shows the estimated flows on transmission boundaries B1 (in the north of Scotland) and B6 (the boundary between Scotland and England).

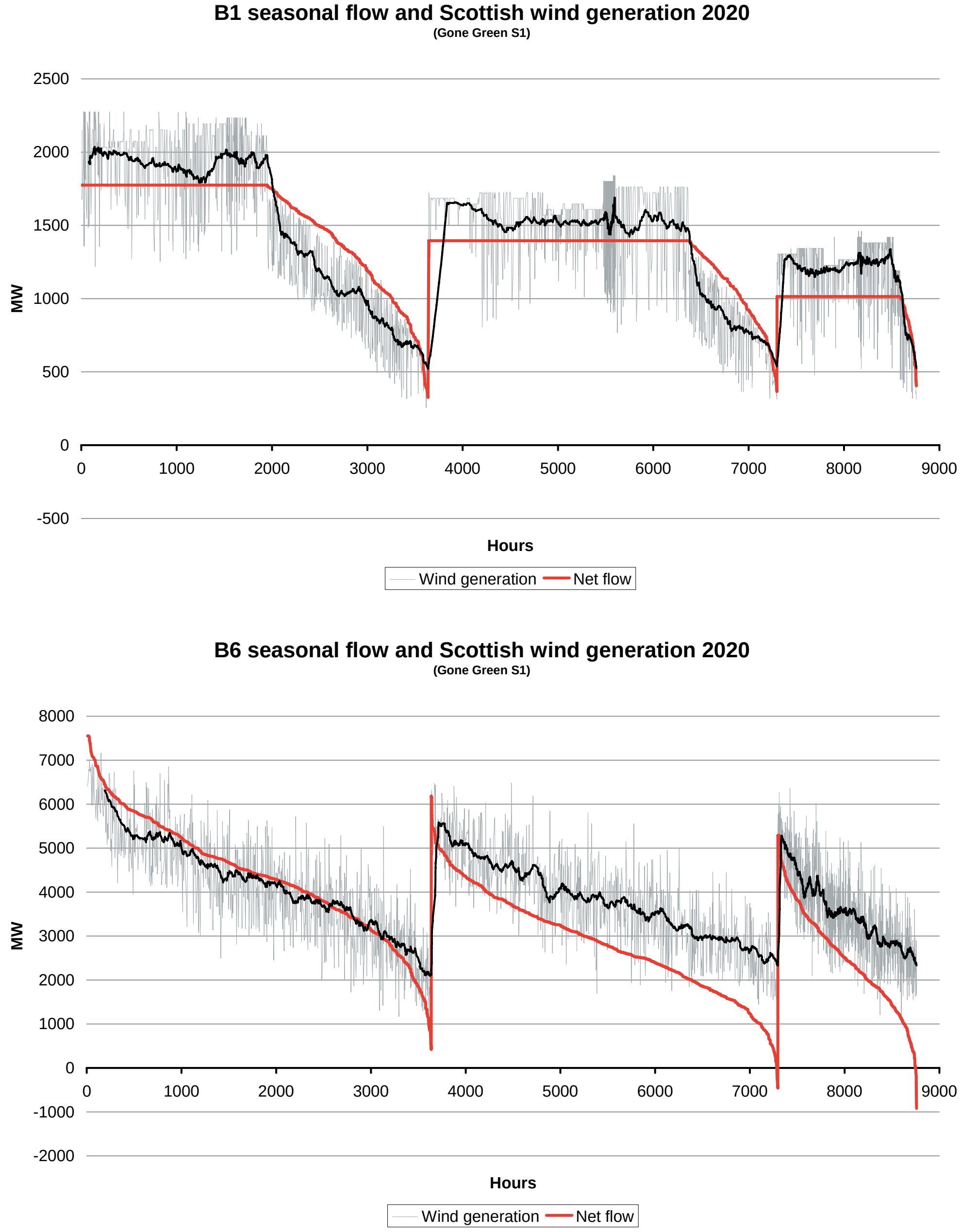
The figure shows the flow duration curves for each boundary over three periods, one in winter and two in summer. The two summer periods are distinguished by the extent of significant outages on the transmission system. Reading from the left of the diagrams, when the red line in the diagrams is horizontal it indicates congestion, because the flow estimated on the boundary is equal to the capability of the line. When the red line starts to fall away, it indicates that the boundary is becoming uncongested.

The grey line shows the level of wind output, and the black line is a moving average of wind output. It is clear from the graphs that boundary flow is strongly correlated with wind production by 2020.

The figures show that boundary B6 is not estimated to be congested, largely as a result of the significant transmission reinforcements in place by 2020. In contrast, however, boundary B1 is congested for a significant part of the year.

[7] On the other hand, this would be consistent with the physical generation and transmission assumptions made for scenario 1 but a connect and manage transmission access regime in place, as this would imply the possibility of a disconnect between generation and transmission investment.

Figure 13. Boundary flows on B1 and B6 - 2020



Source: Frontier Economics

Similar graphs for 2014 show significantly less B1 congestion. Congestion on B1 starts to increase from 2017.

The data provided to us by Ofgem indicate that few of the transmission reinforcements proposed by the TOs towards the end of the period impact on the capacity of the B1 boundary. One of three conclusions can therefore be drawn from our modelling in relation to the invest then connect scenario:

- the data provided to Ofgem by the TOs underestimates the impact of reinforcements on the B1 boundary;
- the connection of the levels of renewable generation considered in this scenario would be accompanied by further transmission reinforcement than has been modelled – which would in turn reduce congestion costs; or
- the connection of the levels of renewable generation considered would not be possible within the time horizon considered[8] – again, reducing congestion costs.

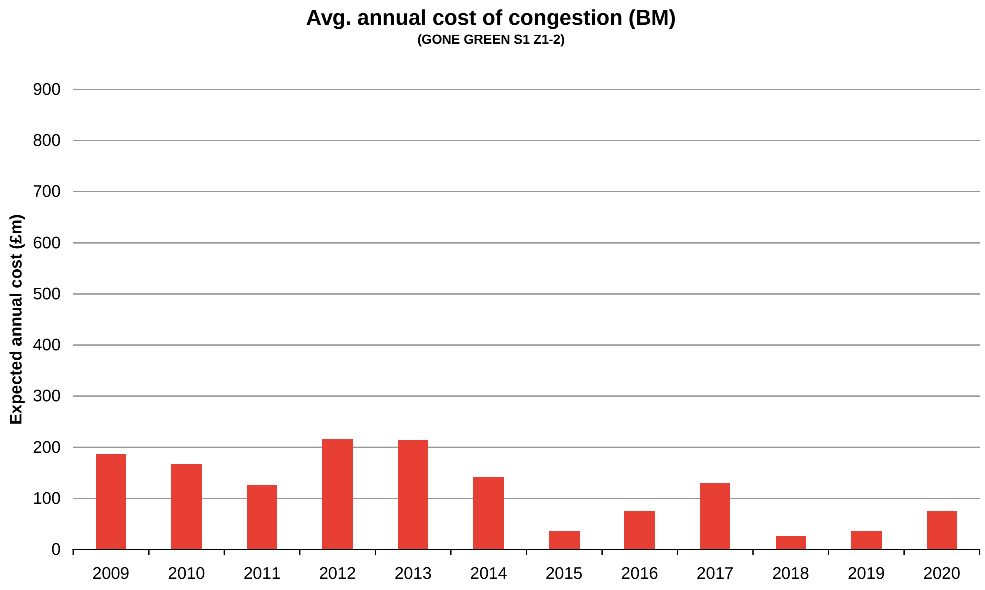
We therefore conclude that the strong increase in congestion cost estimates from 2017 onwards are not consistent with the invest then connect philosophy. Little weight should therefore be placed on them in comparing the relative impact of connect and manage and invest then connect philosophies.

In order to attempt to estimate how congestion costs would look were the B1 boundary not a constraint, we ran a sensitivity merging zones 1 and 2 (effectively assuming that there were an infinite capacity over the B1 boundary). This is consistent with the assumption that the generation connections in the scenario are maintained, and as a result the transmission system needs to be reinforced.

Constraint cost estimates for this sensitivity, evaluated at BM bid and offer prices, are shown in Figure 14.

8 We note that in deriving the generation background for 2020, we have had to make a number of assumptions as to the location of wind projects which are at present relatively speculative and were simply stated to be somewhere in SHETL's area. Our approach involved a simple pro-rating of these projects between zones based on the level of identified wind projects in each zone. This estimation may have resulted in an overestimate of realistic generation connection levels north of boundary B1.

Figure 14. Constraint costs evaluated at BM prices - with no B1 constraint



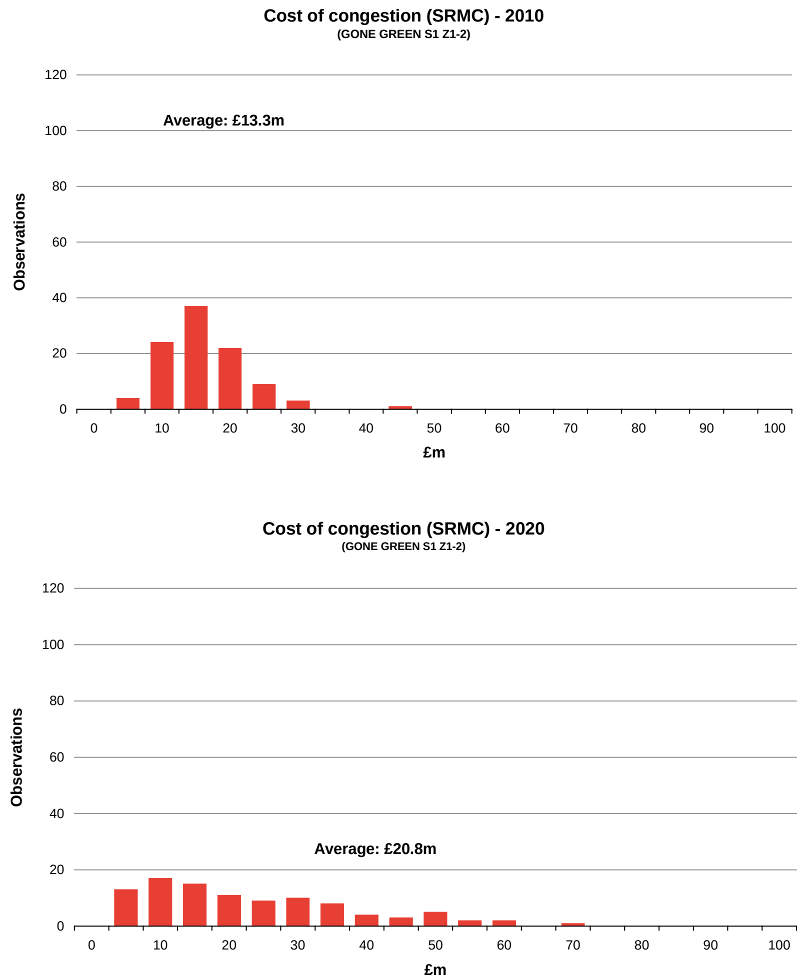
Source: Frontier Economics

As expected, the levels of constraint costs in this sensitivity are significantly lower – arguably much more consistent with an invest then connect philosophy.

Finally in relation to congestion costs, we note that even though congestion costs may be expected to be relatively low on average under an invest then connect scenario, the strong correlation with wind production towards the end of the period means they could be highly variable from year to year.

Figure 15 shows the modelled distribution of congestion costs in 2010 and 2020 (valued at SRMC). It is clear that, by 2020, there is significant potential variance to congestion cost levels as a result of variability in wind production.

Figure 15. Distribution of congestion costs - 2010 and 2020



Source: Frontier Economics

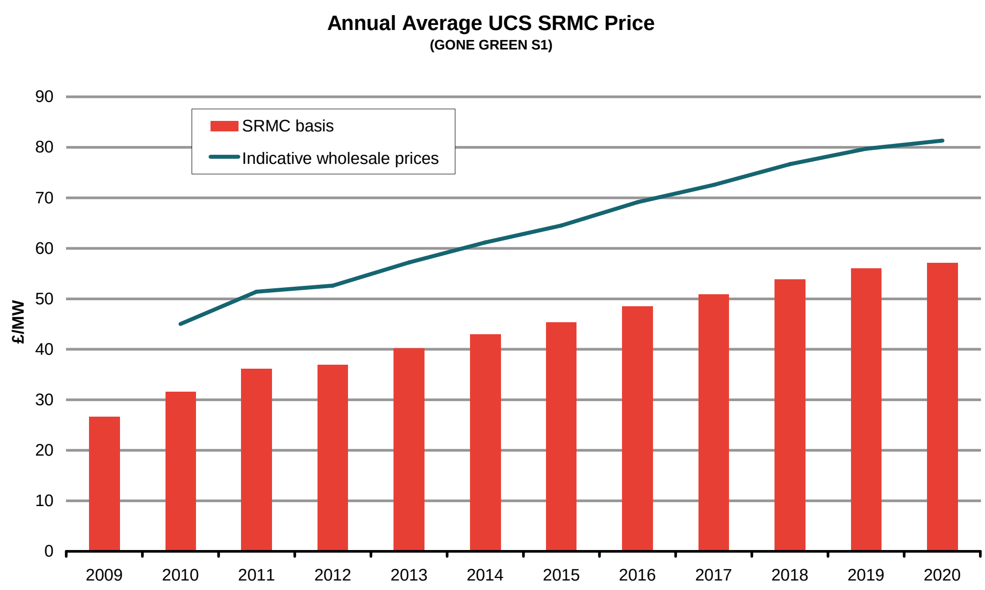
4.2.2 System marginal costs

Under the invest then connect scenario assumptions for generation and demand, we show the average annual costs of the marginal plant on the unconstrained system in each year of the modelling horizon in Figure 16 below.

For the purposes of indication, we also show on the graph an estimate, based on this level of system marginal costs, of the potential evolution of wholesale prices assuming:

- a starting level of wholesale prices in 2010 of £45/MWh; and
- that there is a constant percentage mark-up of annual average wholesale prices over system marginal costs.

Figure 16. Estimated system marginal costs and indicative wholesale prices over time



Source: Frontier Economics

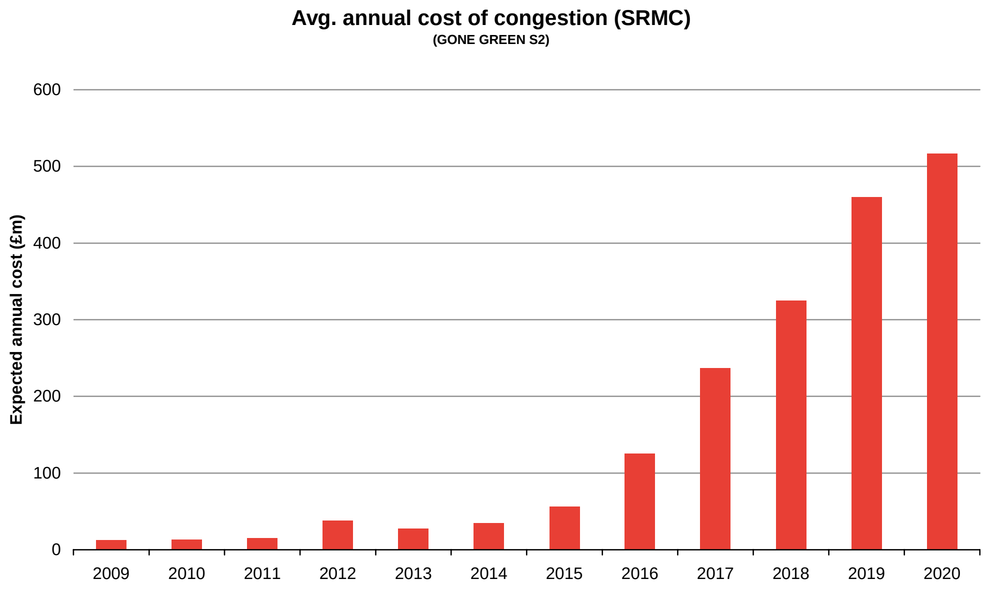
These estimates should be unaffected by the considerations in relation to the B1 boundary discussed above, as they are derived from an unconstrained despatch schedule. In other words, they represent the average cost over the year of the marginal plant used to meet demand *ignoring transmission constraints*.

4.3 Results: "connect & manage – accelerated generation"

4.3.1 Congestion costs

Figure 17 shows our estimates of constraint costs under scenario 2, evaluated at SRMC.

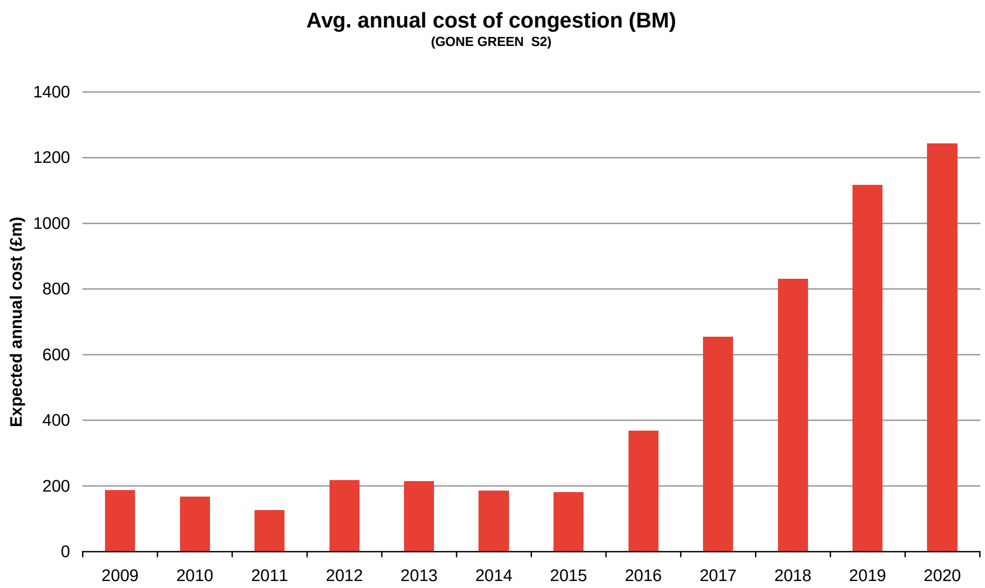
Figure 17. Constraint costs evaluated at SRMC



Source: Frontier Economics

Figure 18 shows these estimates evaluated at our estimate BM bid and offer prices.

Figure 18. Constraint costs evaluated at BM prices



Source: Frontier Economics

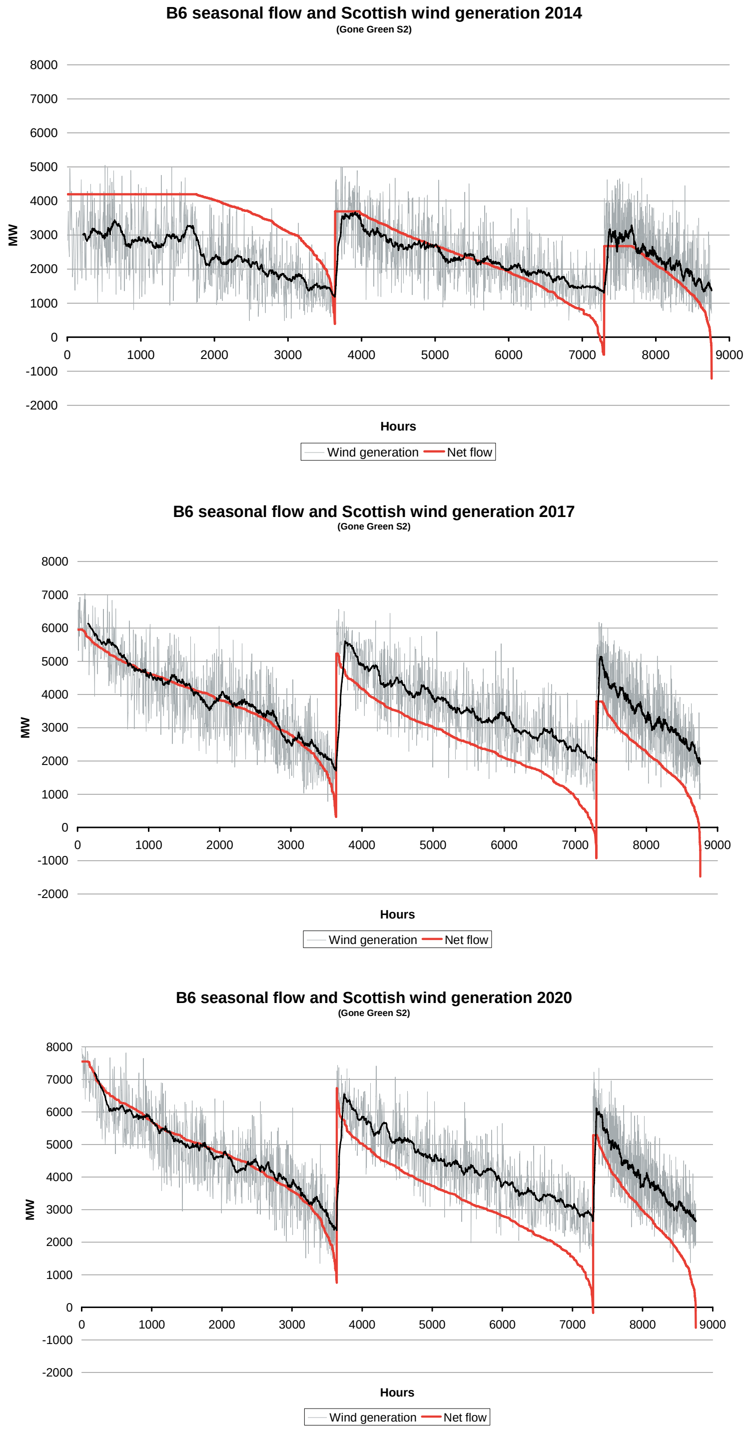
Results of our analysis

It is clear that, under this scenario, there is a significant increase in the congestion costs incurred by the system operator. Under our invest then connect scenario, congestion costs were highest in 2020 at a cost of £815m. Under our sensitivity assuming infinite capacity on the B1 boundary, which is arguably more consistent with invest then connect, congestion costs peaked at £217m. These estimates compare with congestion costs at up to £1,242m under this connect and manage scenario.

Again, it is important to understand the likely source of this congestion.

In Figure 19 we present the estimated flows over the B6 boundary (between Scotland and England) over time. It is clear that, while in the early years of the modelled horizon, there is congestion on B6, the boundary is relatively uncongested in later years.

Figure 19. Estimated B6 boundary flows - 2014, 2017 and 2020

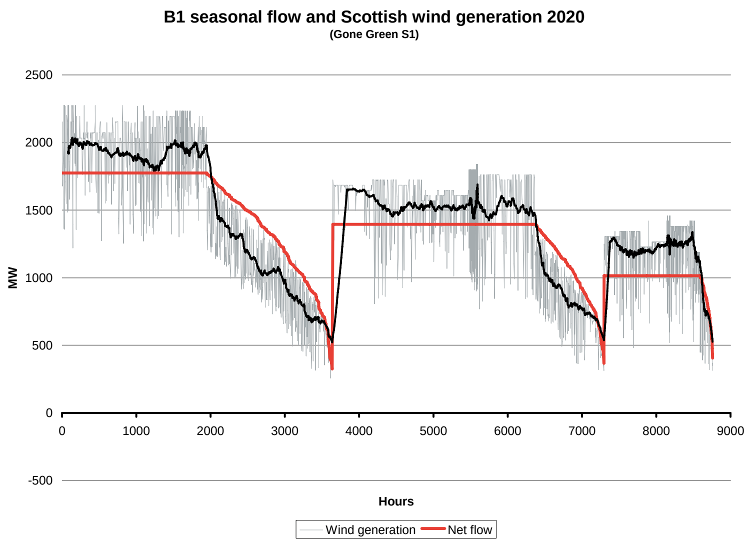


Source: Frontier Economics

Again, it is boundary B1 which is contributing to the congestion towards the back end of the period, as is shown in Figure 20.

Results of our analysis

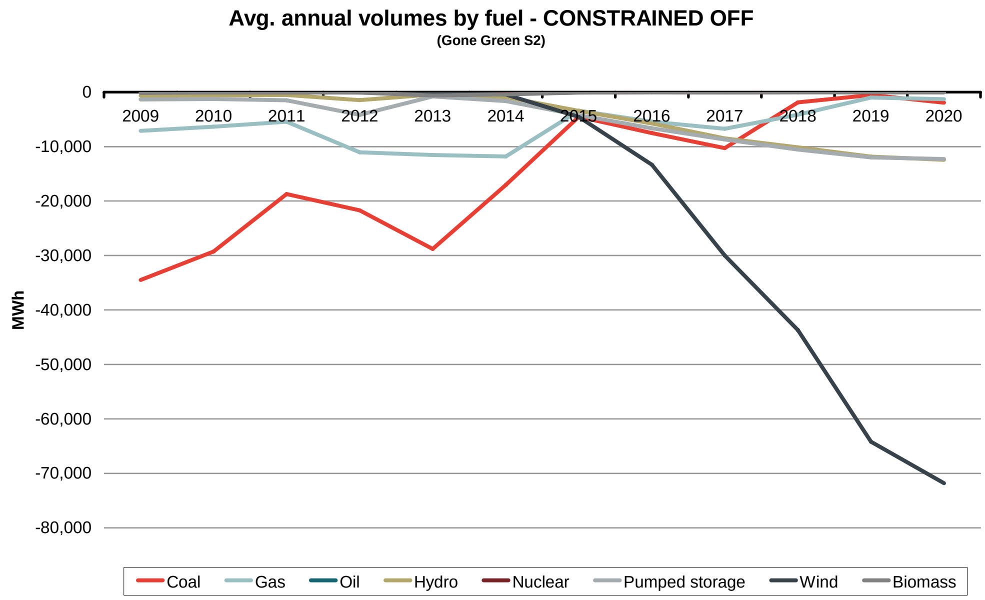
Figure 20. Estimated flows over boundary B1 - 2020



Source: Frontier Economics

As a result of congestion across B1, there is a significant volume of wind generation which is constrained off towards the back end of the modelling horizon. That is to say, based on the generation background we are using, wind plant connects to the system north of boundary B1 which is then unable to produce as a result of the lack of capacity over B1. As a result this wind generation has to be constrained off. The extent of this effect is illustrated below in Figure 21.

Figure 21. Constrained off volume by fuel type



Source: Frontier Economics

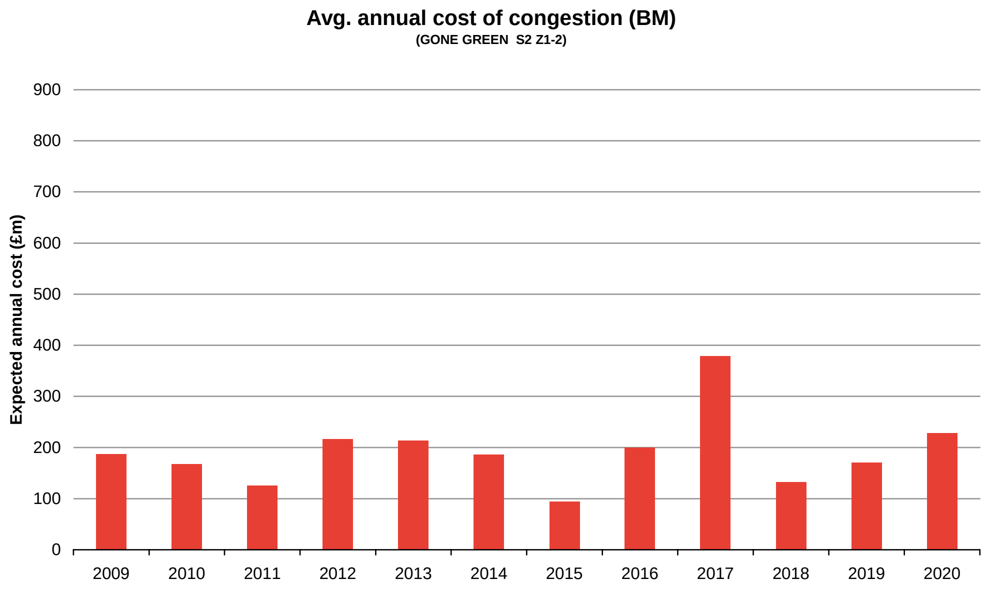
In contrast to scenario 1 which represented an invest then connect philosophy, significant generation connection north of boundary B1 without accompanying transmission reinforcement is entirely plausible under a connect and manage regime.

However, we have also estimated the potential congestion costs under scenario 2 which might arise were either:

- significant reinforcements to take place on boundary B1; or
- the generation projected to connect north of the boundary actually to connect south of it.

The congestion costs, valued at BM bids and offers, which would result in such a case are shown in Figure 22.

Figure 22. Constraint costs evaluated at BM prices – assuming no B1 constraint



Source: Frontier Economics

While these are significantly lower than those in which a B1 boundary constraint binds, they are still higher than those under the invest then connect scenario. At a 3.5% discount rate, the estimated NPV of constraint costs over the modelled period assuming no B1 boundary constraint are:

- under an invest then connect scenario, £1.2bn; and
- under a connect and manage – accelerated generation scenario, £1.8bn.

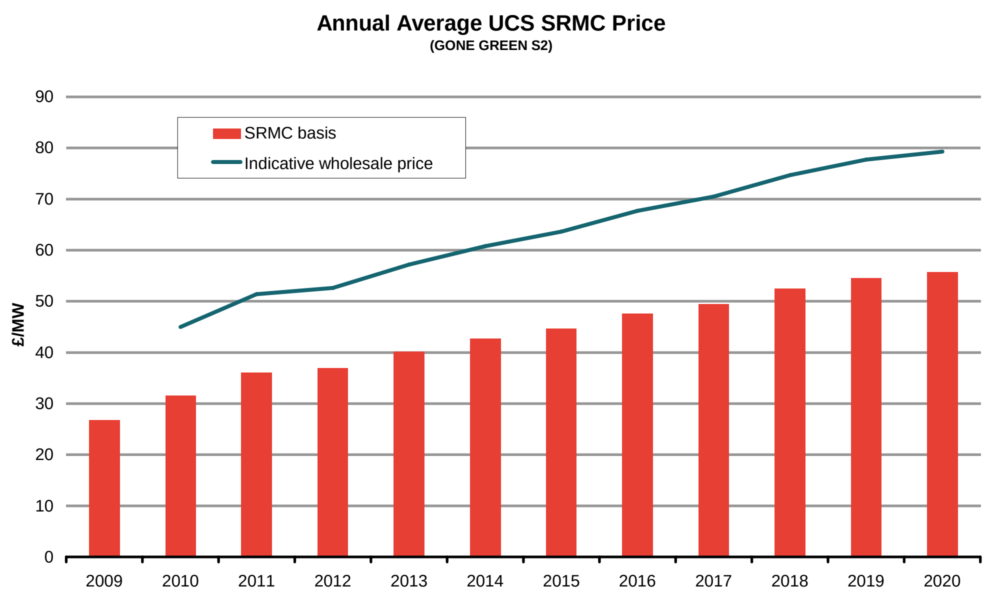
4.3.2 System marginal costs

Under scenario 2 assumptions for generation and demand, we show the average annual costs of the marginal plant on the unconstrained system in each year of the modelling horizon in Figure 23.

For the purposes of indication, we also show on the graph an estimate, based on this level of system marginal costs, of the potential evolution of wholesale prices assuming:

- a starting level of wholesale prices in 2010 of £45/MWh; and
- that there is a constant percentage mark-up of annual average wholesale prices over system marginal costs.

Figure 23. Estimated system marginal costs and indicative wholesale prices over time



Source: Frontier Economics

Relative to the indicative wholesale price levels under the invest then connect scenario, prices under this scenario:

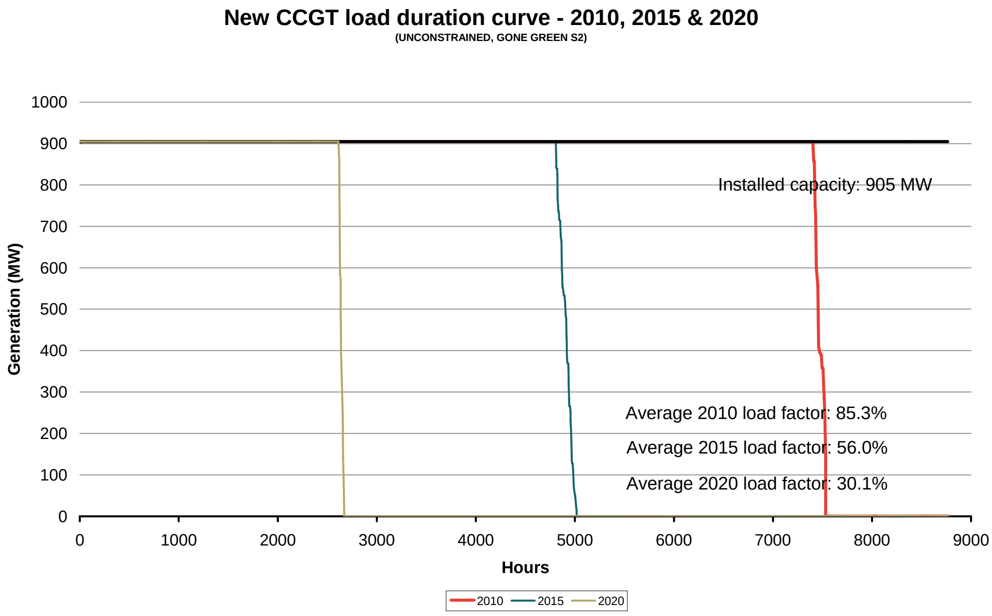
- are practically unchanged up to around 2014; and
- are around 2% lower by 2016, and fall to 2.5% lower by 2020.

However, it is important to note that a degree of uncertainty should be attached to these wholesale price reductions, because they do not take into account the impact of falling wholesale prices on investment incentives.

As additional wind generation connects, existing thermal plant load factors will fall as will price levels. This will reduce the ability of existing plant to cover their fixed costs and will reduce the incentive for new plants to connect. The impact of this effect is marked. Figure 24 shows the modelled annual load duration curve for a relatively new CCGT plant on the system under scenario 2 through time[9]. If new investors project similar load factor declines for their new plant, they may decide not to enter – in which case, the wholesale price would fall less.

9 The reduction in load factor is a result of both wind entry and new CCGT entry. New CCGT entering towards the end of the modelled period, with higher assumed efficiencies achieve higher load factors. However, since the improvement in efficiency is likely to be relatively low, the margin on these additional running hours could also be expected to be low. Their higher load factors may therefore not necessarily imply significantly greater incentive to invest.

Figure 24. New CCGT load duration curve, scenario 2



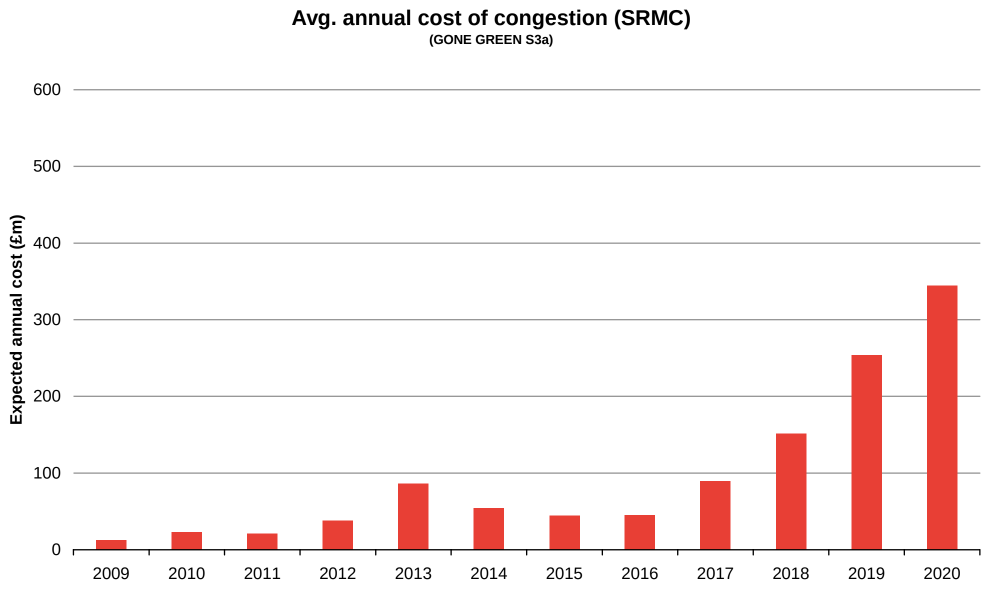
Source: Frontier Economics

4.4 Results: "connect & manage – delayed transmission"

4.4.1 Congestion costs

Figure 25 shows our estimates of constraint costs under scenario 3, evaluated at SRMC.

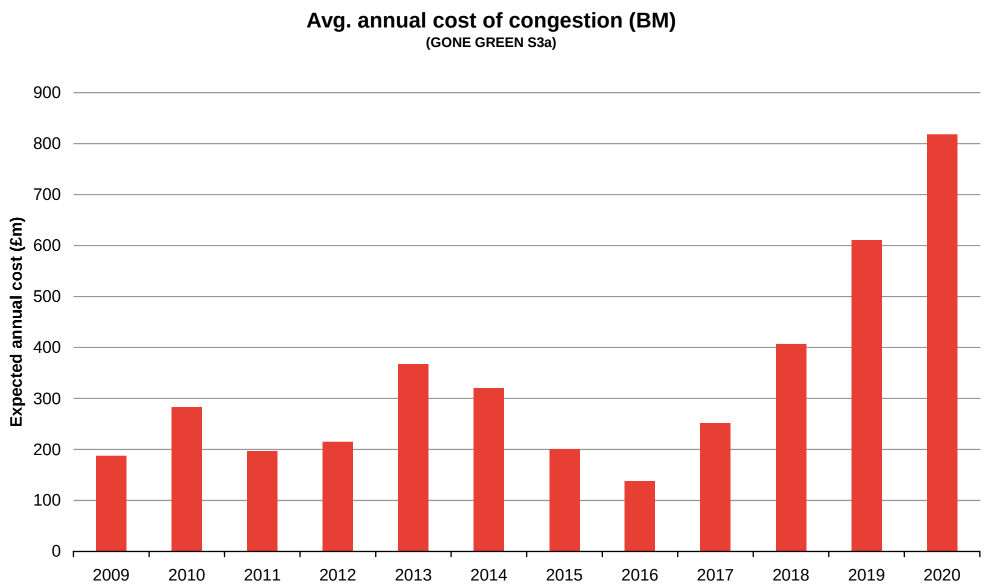
Figure 25. Constraint costs evaluated at SRMC



Source: Frontier Economics

Figure 26 shows these estimates evaluated at our estimate BM bid and offer prices.

Figure 26. Constraint costs evaluated at BM prices



Source: Frontier Economics

Results of our analysis

Again, relative to the invest then connect scenario, there is a significantly higher level of congestion. The overall level is lower than that under the accelerated generation scenario, though this is not surprising as the transmission projects are only assumed to be delayed by a year (compared to an advance of 3 years on generation connections).

While the impact of accelerated generation connections is principally felt towards the back end of the period (as the acceleration is only expected to happen from 2014 onwards), the impact of delayed transmission is apparent in the middle of the period. This is because there are significant transmission expansions projected to be commissioned in 2012-15 (e.g. Beauly-Denny, England-Scotland upgrade works).

Towards the back end of the period, the congestion is again caused by the B1 boundary.

4.4.2 System marginal costs

The generation background used for the connect and manage – delayed transmission scenario is identical to that used for the invest then connect scenario. The difference between the scenarios lies entirely in the assumptions in relation to the transmission system capability.

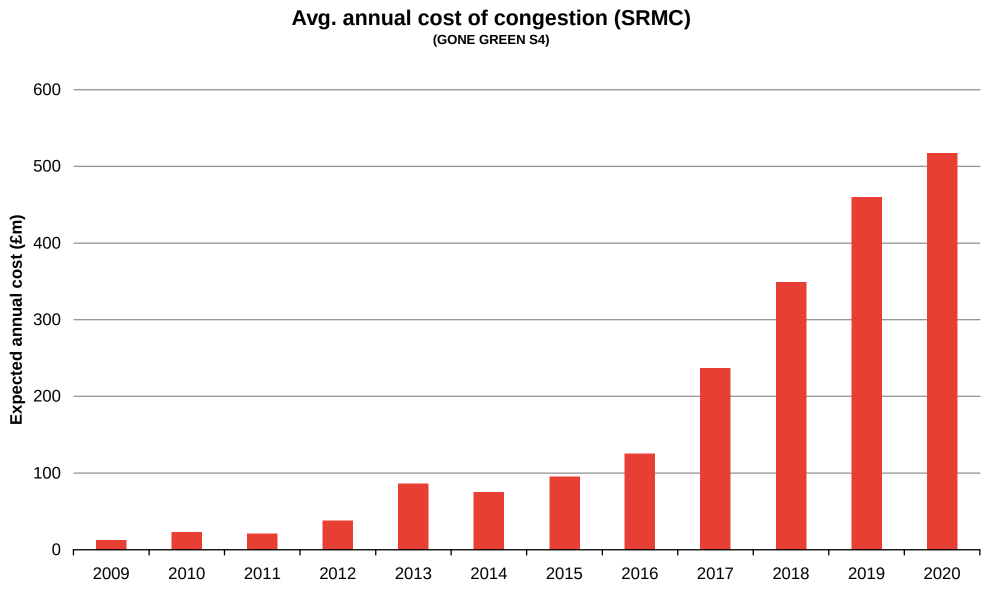
Since the system marginal cost and the wholesale price is set by the unconstrained schedule (i.e. ignoring transmission constraints), they are identical to those estimated under the invest then connect scenario (i.e. scenario 1).

4.5 Results: "connect & manage – accelerated generation and delayed transmission"

4.5.1 Congestion costs

Figure 27 shows our estimates of constraint costs under scenario 4, evaluated at SRMC.

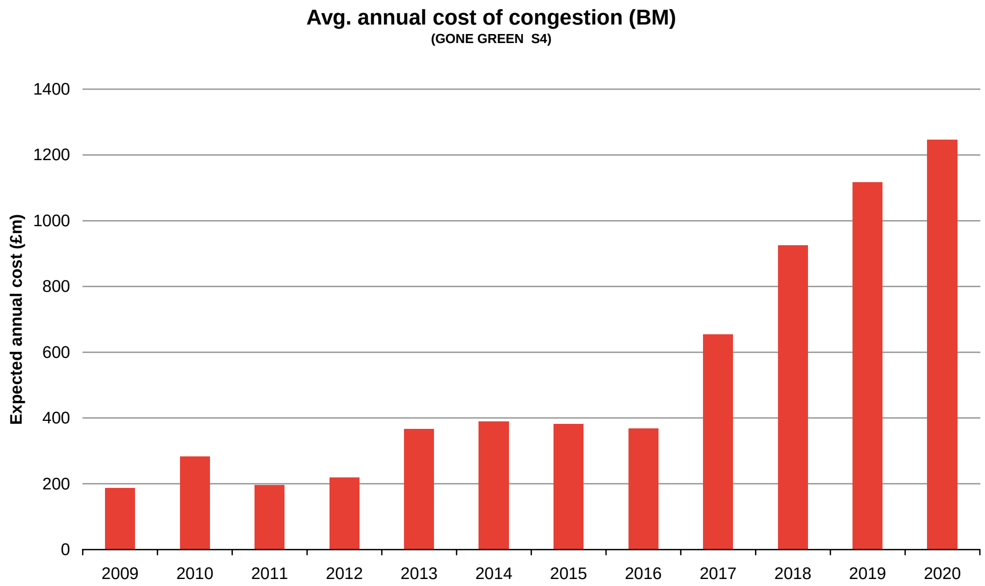
Figure 27. Constraint costs evaluated at SRMC



Source: Frontier Economics

Figure 28 shows these estimates evaluated at our estimate BM bid and offer prices.

Figure 28. Constraint costs evaluated at BM prices



Source: Frontier Economics

Results of our analysis

As could be expected, relative to both the invest then connect scenario and the other two connect and manage based scenarios, modelled congestion is higher:

- congestion in the early and middle part of the period is higher than under scenario 2 because of the combination of accelerated generation and delayed transmission (for example, congestion in 2010 is modelled as £282m, compared to £168m in scenario 4 – similarly, congestion in 2013 is modelled as £390m in scenario 4, compared to £186m in scenario 2); and

- congestion at the end of the period is higher than under invest then connect because of the accelerated generation connections causing significant constraint costs over the B1 boundary. The congestion cost in 2020 is not significantly different to that under scenario 2 because we are only modelling a one year delay in transmission, and our transmission investment assumptions do not involve significant expansions in the last year of the period.

4.5.2 System marginal costs

The generation background used for the connect and manage – accelerated generation and delayed transmission scenario is identical to that used for scenario 2. The difference between the scenarios lies entirely in the assumptions in relation to the transmission system capability.

Since the system marginal cost and the wholesale price is set by the unconstrained schedule (i.e. ignoring transmission constraints), they are identical to those estimated under scenario 2.

Annexe 1: Description of the model

In this annexe we provide further details of our modelling approach. We describe in turn the solution process we adopt, our approach to modelling seasonality and demand, our representation of the GB transmission system of GB's generation capacity and its availability and finally how we model the operation of the balancing mechanism.

Solution process

Our dispatch simulation model of the British power system is a linear optimisation program that selects the least cost set of outputs from each power station or power station unit and transmission flows in order to meet demand in each region and during each period of time.

The least cost dispatch is determined according to the estimated SRMC of production for each power station or generating unit. These same costs are used to derive the unconstrained schedule and also the constrained schedule. This approach is a reasonable representation of reality as long as the merit order derived from the estimated SRMCs is similar to the actual merit order of generation, including the actual merit order of BM bids and offers.

To keep the modelling problem manageable, inter-temporal features of the power system such as restrictions on the speed at which generators are able to change production levels, start costs, serial correlation of plant availability etc are ignored. This enables the model to treat each period of time as an independent dispatch problem.

The model can be applied to any period. Changes to transmission and generation capacity are exogenous inputs to the model and demand and fuel prices evolve over the period of analysis.

Seasons

Each year is split into three seasons:

- winter;
- summer intact (i.e. when there are no transmission outages); and
- summer outage (i.e. when transmission maintenance outages are taken).

Winter represents the period November to March and summer represents the remaining seven months of the year. Summer is in turn split into a period when the transmission system is intact (23 weeks) and a period when planned outages of the transmission system are undertaken (8 weeks).

Demand

The demand applied to the dispatch model represents end user demand to be met by transmission connected generation and large distribution embedded generation, plus grid losses. Pumping load and exports are not included within demand.[10]

Demand is represented in the model as an eight step load duration curve for each of the three seasons in a year, with the summer intact and summer outage seasons having a load duration curve with the same shape. The load duration curves used in the dispatch model were derived by sampling the actual summer and winter load duration curves for 2008.

The sample is made such that the height of the steps between each demand level remains constant but that the number of hours which each step represents varies. This means that peak and off-peak steps in the sampled load duration curve represent fewer hours than steps in the middle of the load duration curve. The shape of the load duration curve is kept constant for each zone (see the description of transmission below) and from one year to the next.

The dispatch simulation model is therefore applied to 24 separate periods in each year (3 seasons x 8 demand steps). When aggregating results for each year, each of the 24 unique dispatches is given a weight according to the proportion of the year that the dispatch represents.

Transmission

We represent the British power system in the dispatch model as comprising seven zones with constrained boundary transfer capabilities, as depicted in Figure 1 of the main report. Zones 1 to 4 are located in Scotland and zones 5 to 7 are located in England and Wales.

The capacity of the transmission system is highest in winter and lowest during the summer outage season.

Generation capacity

We explicitly represent in the dispatch model each individual power station that is "seen" by the transmission operator, i.e. all power stations directly connected to the transmission and large distribution embedded power stations. The production of small distribution embedded power stations has been factored into the demand information provided to us.

---

10 In the case of the Moyle interconnector and the proposed East-West interconnector linking Wales and Eire, we increment demand according to the full export capacity of these links. We then include two generators in the model at a price equivalent to the estimated marginal cost of generation in Ireland and whose dispatch represents the export flows being reduced.

Very large power stations are represented as individual generating units in the dispatch model, with the exception of large power stations that have chosen to "opt out" in accordance with the Large Combustion Plant Directive (LCPD). The units of these opt out power stations are aggregated according to the number of individual stacks at the power station.[11] Smaller power stations are represented in the model as a single generating unit.

Generation availability

We derive the availability of generation for each dispatch period from random draws from a probability distribution that varies by type of generator. We run the dispatch model 100 times for each demand step and apply a different random draw for each generator or generation unit for each run. Therefore, we apply 2400 different dispatches for a year (i.e. 3 seasons x 8 steps x 100 random draws).

The distributions of availability are set out in Table 4 below. In general, the availability of conventional plant is assumed to be lower in summer than it is during winter. These are the same distributions of availability that National Grid applied for the GB SQSS consultation.

---

11 Power plants that have opted out under the LCPD have a 20000 running hour limit over the period 2008 to 2015. The limit is applied on a stack basis rather than on a unit by unit basis. This means that a firm with an opt out power station has an incentive to take off line all units associated with a stack whenever one of the units associated with the stack is out of service for planned or unplanned maintenance.

Table 4. Distribution of capacity availability

Fuel type	Distrib-ution	Min.	Most likely	Max.	Winter mean	Summer mean	Std dev.
Wind	Tri-angular	5%	20%	80%	35%	35%	
Nuclear	Binomial				80%	70%	
Gas	Binomial				90%	85%	
Coal	Binomial				85%	75%	
Link	N/A				100%	100%	0%
Hydro[12] (1-4), (5-8)	Normal				60%, 10%	60%, 5%	4%
Pumped storage (1-4), (5-8)	Binomial				90%, 25%	90%, 15%	
Oil	Binomial				95%	85%	
GT	Normal				95%	95%	3%

Source: National Grid

We do not apply serial correlation to the random draws. However, we apply a 60% correlation between the wind availability of different zones. We apply 100% correlation of wind availability for all wind parks within a zone. We also apply 100% correlation of hydro generation availability within a zone.[13]

When we run the dispatch model to estimate the constrained schedule and re-run the model to estimate the unconstrained schedule, we do so with precisely the same random draws of plant availability. This ensures that any change to the dispatch volumes for each plant is related solely to the change in assumptions about transmission capacity and are not related to random variations in availability. Likewise, when we undertake sensitivity analysis we ensure that we apply precisely the same random draws that were applied in the base case.

Generation SRMCs

We estimate the SRMC for each generator or generation unit and use that as the basis for deciding how to operate each plant in order to arrive at a least cost dispatch for each dispatch period.

12 The numbers in brackets refer to steps in the load duration curve, i.e. the availability of hydro and pumped storage plant is assumed to vary between peak and offpeak periods.

13 This does not apply in the case of pumped storage hydro whose availability is drawn from a binomial distribution separately for each power station or generation unit.

To estimate the SRMC of each generator, we apply a fuel price forecast plus an estimate of fuel transportation cost and the forecast cost of CO_2 permits to an estimate of each plant's thermal efficiency. The efficiency is assumed to vary by commissioning date, with newer plants being more efficient than older plants. We then add an estimate of the variable O&M cost to arrive at the estimate of SRMC for each generator.

LCPD opt out coal plants have a running hours limit which averages out at about 2500 hours per annum. This limit has the effect of increasing the opportunity cost of generating from these units to be equivalent to the dark spread these plants could achieve during the "best" 2500 hours of a year. We proxy this effect by setting the SRMC of LCPD opt out coal plants in the model equal to the SRMC of an efficient gas fired CCGT plant in winter.

We include the interconnectors with France, the Netherlands and Ireland in the merit order. We first increment demand to mimic all interconnectors running at full export load at all times. We then include in the generation merit order a tranche of capacity for each interconnector which represents the interconnector exports being reduced. In the case of France and the Netherlands, we include two additional tranches of capacity in the merit order at a higher price that represent these interconnectors importing power into Great Britain.

In the case of Peterhead, we assume that the CCGT components of this power station are powered by gas which has a price half that of conventional gas.

Hydro and wind powered generation are assumed to have a zero SRMC. Nuclear generation is assumed to have a SRMC of about £11/MWh.

BM bid and offer prices

We estimate the cost of congestion by first estimating the volume of generation that is constrained on and constrained off (where the dispatch order in the constrained and unconstrained schedule is determined according to the SRMC of each plant). We then apply either the plant specific SRMCs to those volumes or a plant type specific estimate of BM bid and offer prices (based on a mark-up on SRMC for offers or a mark-down on SRMC for bids) to those volumes to estimate the cost of congestion.

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