CRA Insights:
Energy

CRA Charles River Associates

December 2016

The investment case for CCGTs in the GB power market

The investment case for CCGTs is dependent on energy market margins

How can a new combined cycle gas turbine (CCGT) compete successfully against peaking capacity? With total fixed costs for a CCGT around £55-70/kW-yr[1] as compared to £40-55/kW-yr for an open cycle gas turbine (OCGT) or reciprocating engine, new CCGTs are likely to be undercut in the Capacity Market *unless* they are able to reduce their Capacity Market offers with the benefit of substantial energy market margins.

Clean spark spreads for Summer/Winter 2017 have improved to £5-6/MWh, which is around their highest level for many years. This is partly explained by increases in expected gas prices together with the tightening reserve margin over the next few winters for which National Grid has prepared with its purchases of Supplementary Balancing Reserves (SBR). However, futures prices and spreads then fall back again in 2018 with the release of SBR back into the energy market.

For CCGT investors to be able to back competitive offers into the next T-4 Capacity Market auction for delivery year 2020/21, they need to be able to rely on the drivers of energy margins, including:

- the impact of rising loss of load probabilities (LOLPs) on cash-out prices; and
- the achievement of increased load factors by low efficiency, price-setting peaking plant.

At the same time, the case for CCGT investment will be helped if investors in competing peaking plant are cautious about the extent of revenue contribution they anticipate from ancillary services.

[1] This comprises capital expenditure including interest during construction and fixed operating and maintenance costs.

The sources of improved energy market revenues

Contribution from LOLP-based pricing

With the new cash-out pricing mechanism, as LOLP rises and Short-term Operating Reserve is utilised, prices are set equal to LOLP multiplied by the capped level of the Value of Lost Load (VOLL). This capped VOLL has been fixed at £6,000/MWh, for now. Further, National Grid determines the target capacity in the Capacity Market such that the Loss of Load Expectation (LOLE) is 3 hours. This by itself may be expected to provide, on average, a boost of £18/kW-yr (3 hours times £6,000/MWh) to energy market revenues provided that the out-turn, de-rated reserve margin is consistent with National Grid's target capacity at not much more than 4% of average cold-spell peak demand.

However, LOLP-based revenues do not by themselves support the case for CCGTs. This is because these revenues are equally available to low load factor, and low capacity cost plant, and so also allow them to reduce their required Capacity Market offers. Alternatively, such low efficiency plant may provide ancillary services at prices close to or even above £18/kW-yr.

Contribution to energy market margins from low efficiency plant

OCGTs have recently had a load factor of less than 1.5%.[2] However, over the last two capacity auctions, over 2 GW of new gas or diesel reciprocating engines have been awarded contracts. At the same time, since 2014 around 6 GW of large-scale conventional coal- and gas-fired plant have been retired.[3] Given further retirements by 2020/21, low efficiency plant may comprise some 10% of total conventional plant.

Moreover, assuming that by 2020/21, the overall supply-demand balance has 'stabilised' such that the de-rated reserve margin is around 4%, then in terms of marginal cost, the most expensive plants can expect to be price-setting a greater amount of the time. In the example in Table 1, OCGTs are assumed to achieve a load factor of between 3% and 5%. This by itself would increase the spreads for new entrant CCGTs significantly, contributing an extra £6-9/kW-yr to intra-marginal plant (or slightly less if reciprocating engines are at the margin with slightly lower marginal costs due to their exemption from the EU Emissions Trading System (EU-ETS)).

---

[2] National Grid, "Draft Annual Load Factors for 2016/17 Generation TNUoS Charges", 4 December 2015.

[3] Department for Business, Energy & Industrial Strategy, "Digest of UK Energy Statistics Table 5C", p. 122, July 2016. The figure includes 'mothballed' Lynemouth & Uskmouth and excludes capacity converted to biomass.

Table 1: Energy market contribution (excluding LOLP payment)

	New CCGT	Old CCGT	OCGT
Efficiency (HHV)	54%	49%	35.1%
Gas price p/therm	50	50	50
Carbon compliance costs £/tonne	23	23	23
Marginal cost £/MWh	42.3	46.3	63.7
Margin vs New CCGT £/MWh		4.0	21.3
Assumed price setting hours		3679-3942	263-438
Contribution for New CCGT £/kW-yr		15-16	6-9

In addition, new CCGTs can expect to run ahead of older CCGTs due to their higher thermal efficiencies. This means that new CCGTs can expect to earn an additional margin where market prices are set by older CCGTs. This could be as much as £15/kW-yr where plant retirements (and limited addition of renewables) allow for an increase in the load factors of existing CCGTs, up to 50% from their current levels of around 40%, and projected gas prices increase.

Ancillary service revenues

The prices for ancillary services are determined in competitive auctions and exhibit a significant range. For example, in 2014/15 National Grid reports average STOR availability payments of £18.5/kW-yr and average utilisation payments at £120/MWh.[4] In contrast the recent Enhanced Frequency Response saw 201 MW purchased at a cost of £327/kW. In Table 2, an indicative range of ancillary service revenues is shown; this is lower for CCGTs given that the same kW cannot, for the most part, earn both energy market margins and ancillary service revenues.

Target Capacity Market Contribution

The main sources of revenue to contribute towards the recovery of fixed costs are summarised in Table 2. This shows that with the benefit of ancillary service revenues, OCGTs and reciprocating engines may be able to sustain Capacity Market bids at £20-30/kW-yr. CCGTs can be competitive with this by relying on energy margins without LOLP payments only where investors in OCGTs and reciprocating engines attach significant risk factors to their prospective ancillary service revenues. Otherwise, CCGT investors need to rely, in addition, on a contribution from LOLP-based payments. However, these LOLP-based payments are likely to be variable and as such, may not constitute a revenue source on which investors are prepared to place any substantial reliance, at least until there is established experience on how these payments vary in practice. A reliance of 50% is placed on these revenues in the illustrative table below.[5]

---

[4] National Grid, "Short-term Operating Reserve Annual Report 2014-15", p. 1.

[5] LOLP-based payments in the energy market may be expected also to impact forward contract prices that hedge energy prices. So, it is not necessary for generators to be fully exposed to spot prices to access the benefits of any LOLP-based energy market payments.

The figures in Table 2 are provided only for indicative purposes in order to illustrate the potential relative magnitude of different revenue drivers.

Table 2: Target Capacity Market Contribution

	CCGT	OCGT/ Gas-fired reciprocating engine
Costs		
Total Fixed Cost (£/kW-yr)	55-70	40-55[1]
Revenue Sources		
1. LOLP x VOLL x 50% (£/kW-yr)	9	9
2. Ancillary Services (£/kW-yr)	0-5	10-20
3. Peaking plant contribution (£/kW-yr)	6-9	
4. Old CCGT contribution (£/kW-yr)	15-16	
Target Capacity Market Contribution		
2+3+4 Without LOLP revenues (£/kW-yr)	25-49	20-45
1+3+4 With LOLP revenues (£/kW-yr)	21-40	31-46

Note: 1. Fixed cost estimate for reciprocating engine does not include allowance for network benefits.

Is it 'optimistic' to assume increased load factors for low efficiency plant?

There are a number of critical factors to assess in determining the likelihood that load factors of low efficiency plant will increase.

Existing plant retirement

Some 53.2 GW of existing capacity (de-rated) has pre-qualified for the T-4 2020/21 Capacity Market auction which is 1.5 GW in excess of the target capacity of 51.7 GW (de-rated). However, the pre-qualified capacity includes 7.7 GW of coal-fired capacity that even with additional LOLP-based payments from the energy market, may make it challenging to recover fixed costs and start-up costs from reduced operating hours.[6] In any event, all coal-fired plant remaining are expected to be closed by 2025.

Interconnectors

National Grid in its latest capacity report assumed a range for peak interconnector flows of some 3-6 GW in the early 2020s, narrowing only to around 6-8 GW by the end of the 2020s.[7]

---

[6] Department of Energy & Climate Change, "The EMR Panel of Technical Experts' Final Report on National Grid's Electricity Capacity Report", June 2016 notes at p. 21 that there may be 4.5-10 GW of coal plant closures by 2020/21.

[7] National Grid, "National Grid EMR Electricity Capacity Report", Figure 17, p. 53, May 2016.

To date, there has been limited experience of interconnector performance during periods of coincidentally narrow margins under market coupling. However, capacity surpluses in France, the Benelux and Germany are expected to be largely eliminated by the beginning of the 2020s leading to a markedly different operating environment which may limit the scale of GB's net imports. This means that, even with de-rating, expected interconnector contributions may be over-stated.[8]

Renewables

Further additions of renewables will limit the load factors of other conventional, non-nuclear generating plant. However, the availability of wind plant is, of course, highly variable. For this reason, National Grid estimates the equivalent firm capacity for wind at 21% of its technical capacity. Moreover, as wind capacity grows, the security of supply risk from wind variability increases due to the correlation of wind speeds across wind plant.[9]

Batteries

2 GW of batteries for storage have pre-qualified for the 2020/21 Capacity Market auction and may offer themselves as price-takers where they are confident of covering most of their costs from other sources of revenue. This may include contracting for additional frequency response as well as providing benefits to distribution network operators.

Can LOLP-based payments be relied upon?

A sustained capacity imbalance (relative to the LOLE target of 3 hours) need only be quite small to have a substantial effect on the LOLP-induced component of energy prices. This can be seen in the 'LOLP Look-up table' currently being used by Elexon.[10] It provides an estimation of the LOLP value that is applied for a given margin of available generation at Gate Closure. This will, in due course, be replaced with a dynamic calculation of LOLP. But on the assumption that the dynamic calculation will not depart too much from the static values in the look-up table, then this shows that the margin which is expected to be sufficient to deliver 3 hours LOLE is only 2370 MW. At this level of margin, a reduction of 250 MW increases the LOLE to just over 10 hours, while an increase of 250 MW reduces LOLE to 0.8 hours. These changes represent a range of £60/kW-yr to £4.8/kW-yr. However, the current dependency of market participants (except possibly batteries) on Capacity Market revenues provides some mitigation of the risk of LOLP volatility. This because the Capacity Market limits capacity agreements to the target capacity which, in turn, significantly reduces the risk of excess entry. However, some risk of excess capacity still remains from procurement outside the capacity mechanism of renewables and

---

[8] *See supra* note 5 at p. 25 which notes that in relation to occasions when VOLL caps are reached "there remains a level of uncertainty in the amount of de-rated capacity that can be delivered in this manner until TSO's at either end of each interconnector draw up and publish rules that govern such out-of-market actions".

[9] National Grid, "Winter Outlook Report 2016/17", at p. 23, October 2016.

[10] Elexon, "CVA CC247 Loss of Load Probability lookup table", 17 August 2015, available at https://www.elexon.co.uk/release-circular/cva-cc247-loss-of-load-probability-lookup-table/

interconnect capacity that may serve to depress peak prices or, indeed, from lower out-turn demand.

Conclusions

On the assumption that with coal retirements, some 5+ GW of new capacity is required in the next T-4 Capacity Market auction, then it is probable that CCGTs will need to out-compete reciprocating engines (after batteries and DSR clear) to be successful. This is only likely to occur if investors in reciprocating engines discount the continuation of network pricing benefits and take a cautious approach to banking on prospective ancillary service revenues, while investors in CCGTs are convinced of prospective energy margins and/or LOLP-based payments.

Contacts

Robin Cohen
Vice President
London
+44-20-7959-1444
rcohen@crai.com

Ana Barillas
Associate Principal
London
+44-20-7959-1547
abarillas@crai.com

CRA Charles River Associates