ELEXON

P229 follow-up CBA queries

This document sets out the responses from the P229 CBA consultants, London Economics (LE) and Ventyx, to queries from Ofgem. The aim was to clarify Ofgem's understanding of the P229 CBA study and to facilitate a model benchmark exercise.

Page references are to the October 2009 LE/Ventyx CBA report. Responses in **green** are from LE, and pertain to cost-benefit analysis and reporting; **blue** answers are from Ventyx, and concern modelling.

Seven Year Statement (SYS)

- Please confirm which edition/update of National Grid's SYS was used as the primary source for transmission powerflow data (see p15).

The 2008 SYS was referenced as the primary source for powerflow data.

Renewables

- Can LE/Ventyx provide more detail on the amount of renewable generation assumed in their model?
    - What assumptions on annual renewables output were made in the Reference scenario?

We have used the following annual load factors for the different renewables category. For the non-wind categories, we have taken the yearly forecast annual capacities (in MW), multiplied by the annual load factors (below) and modelled them as must-run.

Landfill gas	64%
Biomass	57%
Sewage gas	45%
Hydro	43%
Other	10%
On-shore Wind	27%
Off-shore Wind	36%

For wind – see below - Ventyx has used two aggregated wind units to represent on-shore and off-shore wind in the GBEM. The historical generation and installed capacity of a number of wind farms were obtained from the BMRA web site. The capacity factor for each hour was derived for each hour of the historical data for these BM units. These capacity factors were than averaged to create a "typical" year of load factors. The typical capacity factors were scaled up to equate to a yearly average of 27 percent for the on-shore wind and 36 percent for off-shore and multiplied by the forecasted installed capacity for the on-shore and off-shore wind. The resulting hourly MW values were input to the database for the 25 year period and modelled as non-dispatchable generation in the forecast. This methodology captures some of the impact of volatile wind on the commitment/dispatch of the generation fleet and on the market clearing prices.

- - What is the volume of electricity generated from Renewable Energy (RE) sources, and how does this compare to the Governments 2020 commitment for 20% of all energy to derive from RE sources, which approximates to about 35% of electricity being generated from RE?

The modelling of renewables for the P229 study was based, as agreed in our proposed approach and presentations outlining assumptions to the steering committee for P229. The foundations of this were the

Autumn 2008 Renewables forecast with the government targets as reflected at that time. From the Ventyx Autumn 2008 report we get 58 TWh (Autumn 2008). It should be noted that the new Government targets were introduced after our report was written and right around the time of when our final presentation made.

- Please provide the assumptions for onshore wind capacity each year in the Reference scenario?

MW	On-shore Wind Capacity Assumptions Spring 2009
2011	3448
2012	3698
2013	4098
2014	4498
2015	4978
2016	5458
2017	5708
2018	5908
2019	6108
2020	6308

- The LE/Ventyx Report states that additional wind-power generation is "added by increasing wind capacity proportionally at existing sites". Does this assumption only apply to on-shore wind? If it does, what assumptions were made with respect to the distribution of offshore wind? For example, did LE/Ventyx assume that offshore wind would be distributed according to the capacities of the offshore licensing rounds held by the Crown Estate?

Onshore and offshore wind expansion was located at existing wind sites and also located at specific busses on the system, derived from the Table 3.5 in the 2008 National Grid Seven Year Plan. Please refer to the answer to the question below, providing regional onshore and offshore wind location.

- Please provide a regional breakdown of the wind capacity assumptions?

Wind capacity was located at specific at busses on the powerflow system according to National Grid information on wind farm locations. The regional summary of the onshore and offshore wind capacity is shown below.

Wind Farm Locations by Zone:

2011 Offshore	
Zone	% of Capacity
A_East	50
G_NorthW	25
P_Nscotl	25

2011 Onshore	
Zone	% of Capacity
N_SScotl	75
P_Nscotl	25

2020 Offshore	
Zone	% of Capacity
A_East	21
D_Mersey	24
G_NorthW	7
J_SouthE	15
L_SouthW	22
M_Yorksh	4
P_Nscotl	7

2011 Onshore	
Zone	% of Capacity
N_SScotl	60
P_Nscotl	40

- What assumptions were made regarding renewables development besides wind?

The following capacities were used. Load factors were estimated and units modelled as must run.

MW	Landfill Gas	Biomass	Sewage Gas	Hydro	Other
2008	823	275	85	605	1
2009	861	325	86	610	2
2010	880	375	87	615	2
2011	861	425	88	620	37
2012	842	825	89	625	38
2013	823	875	90	630	39
2014	805	925	91	635	74
2015	786	975	92	640	75
2016	767	1075	93	645	76
2017	749	1175	94	650	111
2018	711	1275	95	655	111
2019	692	1375	96	660	111
2020	655	1475	97	665	136
2021	636	1575	98	670	161
2022	618	1675	99	675	186
2023	580	1775	100	680	211
2024	561	1875	100	685	236
2025	524	1975	100	690	261
2026	505	2050	100	695	286
2027	487	2125	100	700	311
2028	468	2200	100	705	336
2029	449	2275	100	710	361
2030	430	2325	100	715	386
2031	412	2375	100	720	411
2032	393	2425	100	725	436
2033	393	2425	100	725	436

- Was biomass co-firing modelled?

Biomass co-firing was not modelled as separate renewable units, but its impact in reducing the CO_2 emissions from coal-fired generation was estimated.

We have also taken into account its contribution to the renewables targets using the assumptions below.

GWh	Co-fired Biomass
2011	2200
2012	3200
2013	3500
2014	3800
2015	4100
2016	4000
2017	3900
2018	3800
2019	3700
2020	3600

- What assumptions were made on annual wind capacity factors in different locations (see p14)?

Annual capacity factors were applied as 27% for all onshore wind farms, and 36% for all offshore wind farms.

- Did the "hourly profiles" assumed for wind units vary by month or season, and were the profiles correlated between locations (see p14)?

The hourly profiles used for wind generation varied by hour throughout the year, with 8760 separate hours modelled. Two 8760 hourly profiles were modelled, one applied to onshore wind farms and the second applied to offshore wind farms. This hourly shape applied to the variability of the wind hour-to-hour, while the energy output for each wind farm was also related to the installed capacity of the farm and the applied capacity factor.

- To what extent is the variability of wind output addressed in LE/Ventyx's model? Do all wind farms have the same hourly output pattern? Does the pattern vary by month or only by time of day? (see answer above)

Embedded generation

Please clarify the treatment of embedded generation (described on p71):

- Did LE/Ventyx "explicitly model all renewable generation going forward to enable comparisons with set targets" or was it the case that "only the non-embedded generation resources were modelled"?

We explicitly modelled only non-embedded generation in the simulations, this included renewable and thermal generation resources. We assumed new renewable generation resources as non-embedded, so they were explicitly modelled. Implicitly, our demand forecasts should take account of some embedded gen, as should our existing demand data and load profiles—which were based on actual load data.

Our methodology for modelling embedded generation was the following:

Embedded generation is typically smaller generation such as Combined Heat and Power (CHP) or renewable generation: small hydro, wind, or biomass. The generation from such plant is netted off from the demand forecast made by NGC. On the other hand, NGC's forecasts explicitly include demand served by large *embedded generation. As such, any large embedded generation (which includes significant wind generation in Scotland) is explicitly modelled in the GBEM[1] database. For the forecast, Ventyx chose to explicitly model all renewable generation going forward to enable comparisons with set targets, whereas embedded CHP continued to be netted from the forecast demand.*

- Was embedded generation treated differently in the TLF validation and the forecast exercises?

Embedded generation was treated the same in both the TLF validation simulation and the cost / benefit simulations.

- Was all new renewable generation effectively treated as transmission-connected?

Yes, all new / future renewable generation was treated as transmission-connected.

- Did the treatment of embedded generation require LE/Ventyx to adjust the nodal demand information from National Grid's SYS?

The nodal demand information used in the study was from Elexon metered volume data, not from the National Grid's SYS, so only included the non-embedded generation and load. No adjustment was necessary.

Fuel parameters

- Please confirm that a calorific value of 30 GJ/t was applied for coal (see p51) - Is the starting point for the Ventyx coal price forecast values in £/GJ or £/tonne? (We assume that it is the £/GJ figures that are actually used in the modelling.) We are interested only because the assumed calorific value (30 GJ/tonne) seems high.

Our standard calorific value assumption is 6,000 Kcal/Kg which is approximately equal to 25 GJ/ metric ton. We are not clear where they are getting the 30 GJ/tonne figure?

- What assumptions were made on emission production rates for SO_2, NO_x and CO_2 (see p15)?

Individual plant effluent rates were used from Ventyx's UK database, derived from historical data from plants, including fuel types, thermal efficiency, etc. Emission production rates were modelled for SO_2, NO_x and CO_2.

We modelled the emission rates at the plants for all 3 effluents based on historical.

Industrial Emissions Directive

- What assumptions were made about the impact of the proposed EU Industrial Emissions (Integrated Pollution Prevention and Control) Directive on the operating regime or retirement of coal and gas-fired plant from 2016?

There was no clarity on the details of IED at the time that we developed our core database for the study, so we did not model the impact of IED.

[1] An installed capacity of approximately 4.9 GW (mainly from biomass, landfill gas, sewage gas, and small hydro) is currently considered as "embedded" in Great Britain, i.e., connected to the distribution grid and netted off from the total GB demand. The GB database takes into account this capacity through the load. On the other hand, this capacity is explicitly considered for the installed capacity (renewable and total) reporting below. Ventyx has modelled future renewable generation additions through the aggregated generation units, assuming this capacity will be connected to the transmission grid.

Merit order

- How did LE/Ventyx derive hourly load shapes for each zone? Is the assumption that the hourly pattern in all zones is the same and, if not, how is it derived?

We did not assume the hourly load shapes to be the same across zones. Hourly load patterns were derived from metered volume data provided from Elexon for zonal demand. Each zone was modelled with a separate hourly pattern.

- Please provide annual plant load factors for the Reference scenario (Base and Change cases) in order to facilitate model benchmarking.

LE/Ventyx will not be able to provide these results, as the load factor for each individual plant was beyond the scope of the original study and the results are not available.

- It is possible that differences in heat rate assumptions for certain plant will have a material impact on model benchmarking: will it be possible to compare assumptions with LE/Ventyx in this event?

The heat rate assumptions in the database were derived on a plant-by-plant basis and is part of the proprietary Ventyx UK database. As such, Ventyx will not be able to provide this information. We do not believe individual plant heat rate assumptions are likely to be a material matter for the model benchmarking.

Interconnector flows

- Can you provide more information on your assumptions on interconnector flows? For example, were there net imports or exports on each interconnector and did these vary significantly by season? (see p69)

Energy and schedule on Interconnector flows were derived from historical flow data provided by Elexon. Two years of data were provided to LE/Ventyx. For each month, the average monthly energy of the two years was modelled as net energy (import or export). This energy was applied as a "peak shave" or "valley fill" type hourly schedule depending on the characteristic direction and average daily schedule of the particular interconnector.

Transmission congestion and contingency

- We would like to confirm with regard to the treatment of congestion that all three cases that are run (Base case, loss optimised case, Change case) include the effects of congestion.

All cases run in the study were treated identically with regard to transmission congestion. The transmission constraints modelled on the system were the same for all cases.

- When you say that the Base and Change cases do not include the optimisation of losses, does this mean that losses have no impact on the nodal prices or simply that there is no redispatch to minimise losses.

The latter is the case – the simulation was conducted to purposefully not fully optimise losses, as the "optimisation" is market-based, based on the market participants' reactions to the new TLF charging regime. Thus the modelling was rather to simulate the market rules by applying the corresponding annually-updated, zonal-seasonal input TLF to the overall generation commitment and dispatch.

- Please clarify the extent to which transmission constraints (e.g. contingency limits) were modelled on key boundaries (e.g. the B6 Cheviot boundary between England and Scotland), in addition to the individual line ratings:

Transmission constraints were modelled to the extent that congestion occurred on system boundaries or transmission lines within each grid. (see note on N-1 contingency analysis below).

- Please confirm that "BETTA is modelled as a single transmission zone, so only external transmission constraints are included" (see p18)

Transmission constraints were modelled within the separate grid systems as well. Wherever there were issues with transmission overloads on any grid within the BETTA market, transmission constraints were developed and modelled.

- Please clarify the reference to "contingency data for congestion modelling was developed through independent analysis" (see p15)

Ventyx conducted N-1 contingency screening analysis in a powerflow model over the full network to derive a set of contingency events for this study.

Transmission upgrades

- What were the assumptions regarding transmission expansion beyond the SYS horizon (see p72)?

Transmission expansion beyond the NGET Seven Year plan was not modelled, as it is our opinion that this would have been a highly speculative assumption.

- What assumptions and parameters were modelled for the proposed ENSG reinforcements (e.g. the Eastern and Western offshore HVDC "bootstraps")?

This particular system reinforcement plan was not addressed explicitly in this study.

Operating reserve

- Was operating reserve modelled in the unit commitment process (see p17)?

Yes, spinning reserve was modelled as a system level constraint in the unit commitment and dispatch.

- If so, what assumptions were made about present and future reserve requirements?

The reserve requirements were modelled as a 1300MW operating reserve requirement. This assumption was not modified for future years in the study.

Demand Response

- How was demand response to price changes handled? Are we correct in assuming that it was an ex post adjustment rather than being incorporated into the detailed modelling?

Yes. Demand response was not modelled explicitly in the simulation.

Prices

- Are all prices quoted in real 2009 terms?

Yes.

- Did LE/Ventyx undertake any 'backcasting' to check if the model could accurately re-produce historic electricity prices and generating patterns across the year? For example by inputting 2009 fuel/carbon prices and demand into the model, and comparing the resulting electricity prices and despatch patterns to outturn prices and despatch? This is of particular importance if we are correct in assuming that all the modelling is carried out on a constrained basis since wholesale prices in GB do not include the effect of constraints.

We do regular calibration exercises before running our forecasts. For the GB, we have fed real fuel and emission prices as well as historical load for 2007, 2008 and Q1 2009.
We would note a few factors. Our analysis was not seeking to model prices explicitly, but rather TLFs and the pattern of despatch/transmission losses. We focused our benchmarking efforts on the TLFs. We agreed competitive pricing assumptions with the steering committee in advance. As such, market-based-bid-mark-ups would be part of actual historical prices, and not part of our prices. It was our opinion that our approach would be conservative (in the sense of not overestimating the benefits of P229), in that the "marginal value of losses saved" from P229, would then not include generator bid-mark-ups.

Plant Entry and Exit

- Could you provide more information regarding which LCPD opt-out plant close in each year. Did you consider whether zonal TLFs might have an impact on the order in which the plants close?

LCPD opt-out plant retirements were scheduled based on independent research and information known at the time of the study. It was considered that zonal TLFs would be different based on when particular plants were retired, but absent perfect intelligence on the schedules, LE/Ventyx used best judgment to place the retirement schedules with no preferential treatment to any company or zone.

- Could you provide us with information on plant closures by zone and year?

Year	Zone	MW Cap Retired
2012	F_Northern	900
	N_South of Scotland	1200
2013	F_Northern	900
	H_Southern	1900
2014	F_Northern	1200
	G_North Western	1200
	J_South Eastern	40
	M_Yorkshire Electricity	2900
2015	A_Eastern	1000
	C_LE Distribution	1500
	E_Midlands	1000
	H_Southern	1100
	J_South Eastern	1400
	M_Yorkshire Electricity	1000
2016	L_South Western	1300
	N_South of Scotland	1300
2017	B_East Midlands	500
2018	B_East Midlands	1000
	J_South Eastern	1100
2019	B_East Midlands	4500
	C_LE Distribution	200
	P_North of Scotland	700
2020	D_Merseyside & North Wales	500

Other

- We are unclear about the relationship between Tables 4-8 and 4-10. Are the values in Table 4-10 assumed to be additional to those in Table 4-8 or not? For example, more "generic nukes" appear in Table 4-8 than are included in Table 4-10. If the tables are cumulative, in which zones are the generic plant assumed to be added?

The term 'cumulative' in Table 4-8 is with respect to the accumulated total capacity over all generating unit additions in all zones. Table 4-8 does not include retirement capacity. Tables 4-9 and 4-10 are specific to plant retirements.

- Are all the data (fuel prices, CO2, demand etc.) shown on a calendar year basis or on a financial year basis?

The question is a bit too vague to answer specifically: for example, in general, demand has an hourly basis. In general, information in the assumptions is on an annual (calendar year) basis, and the CBA tables were done on the financial year basis.