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BEIS: CCUS TECHNICAL ADVISORY – REPORT ON ASSUMPTIONS
prepared for
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SUMMARY

This report provides documentation on the methodology used to provide the BEIS Dynamic Dispatch Model with best available estimates for the costs and performance of three selected CCUS technologies:

- Combined cycle gas turbine (CCGT) with post-combustion capture and storage
- Oxy-fuel combustion, with carbon capture and storage
- Hydrogen generation with carbon capture and storage, intermediate hydrogen storage, and hydrogen turbines data,

It includes associated assumptions and limitations, and comments on the expected behaviours of each technology.

Power generation plus capture is considered in turn for each technology for a 'first of a kind' (FOAK) unit. Transport and storage are then considered. These are treated in the same way for each technology. A discussion on the transition between FOAK and NOAK ('nth of a kind'), and a section on other assumptions made, is also included in the report.

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CONTENTS

Page

ABBREVIATIONS

1 INTRODUCTION 1

2 NOTES ON CURRENCIES, COUNTRIES AND INFLATION 1

3 FIRST OF A KIND CAPEX AND OPEX ASSUMPTIONS 1
3.1 CCGT with post-combustion capture 1
3.2 Oxyfuel 2
3.3 SMR + H2 storage + H2-fired CCGT 3
3.4 Transport and Storage 4

4 COMMENTS ON THE FOAK COSTS 4

5 TRANSLATION FROM FOAK TO NOAK COSTS 5

6 OTHER ASSUMPTIONS 6

7 REFERENCES 8

ABBREVIATIONS

CPI	Consumer Prices Index
ESP	Electrostatic Precipitators
ETI	Energy Technologies Institute
SMR	Steam Methane Reformer

1 INTRODUCTION

The UK Government department for Business Energy and Industrial Strategy, BEIS, is undertaking an analytical project looking at the role of CCUS within the UK electricity system. The work aims to update the representation of Power CCUS within BEIS internal modelling tools and to use these tools to assess the role of CCUS. Uniper Technologies Limited (UTG) was contracted to provide technical advice in support of the project. The main objective being to provide the BEIS Dynamic Dispatch Model with best available estimates for the costs and performance of three selected CCUS technologies:

- Combined cycle gas turbine (CCGT) with post-combustion capture and storage
- Oxy-fuel combustion, with carbon capture and storage
- Hydrogen generation with carbon capture and storage, intermediate hydrogen storage, and hydrogen turbines

This report provides documentation on the methodology used to provide the data, including associated assumptions and limitations, and comments on the expected behaviours of each technology.

Power generation plus capture is considered in turn for each technology for a 'first of a kind' (FOAK) unit. Transport and storage are then considered. These are treated in the same way for each technology. This is followed by a discussion on the transition between FOAK and NOAK ('nth of a kind'), and a discussion on other assumptions made.

2 NOTES ON CURRENCIES, COUNTRIES AND INFLATION

Different sources quoted costs based on different years; different currencies; and different build locations. These were normalised into 2014 £ as follows:

- Currencies were converted to UK £ using the average exchange rate for the year of the currency reference.

- Conversion to 2014 was done using UK CPI inflation rates. This inflation adjustment is simplistic as labour, steel, cement and other materials all have their own indices. As a cross-check the CPI rate was compared to the Chemical Engineering Process Cost indices. In all cases, it was within 10% and generally within 5%. Given the accuracy of these costs, that is considered sufficient.

- There was no adjustment for differences in build costs between the UK, mainland Europe and the USA (the main data sources) other than the currency conversion.

3 FIRST OF A KIND CAPEX AND OPEX ASSUMPTIONS

3.1 CCGT with post-combustion capture

In this case the focus was on the additional cost of capture, including the efficiency penalty. The existing BEIS data for the unabated CCGT were used to avoid artificial differences between abated and unabated plant due to selection of different CCGT technology.

For capture, there are multiple sources for costs and efficiency impact. The sources used directly were the AMEC study (AMEC 2018); the CCS Cost Reduction Taskforce (CRT 2013); cost update report for the GCCSI (GCCSI 2017); a paper by E S Rubin (Rubin 2015); Costs of CCS report by ZEP (ZEP 2011); and cost from the ROAD Project (to be published soon). Some internal Uniper reports were also used to guide selection of the best external sources.

The efficiency penalty for CCS on gas ranged from 8% (GCCSI 2017) through 7.4% (AMEC 2018) to 6% (ROAD, adjusted for gas CO_2/MWh). The AMEC figure was selected as being achievable. The ROAD figure, although the most accurately engineered and costed, was based on capturing CO_2 from a coal-plant flue gas, which has a higher CO_2 concentration, and therefore may not be achievable with flue-gas from a CCGT. Hence the efficiency chosen with capture was 7.2% lower than for the unabated CCGT.

The costs of the CCGT part of the plant are quoted in £/kW where the kW refers to overall net plant output. Therefore, the cost of the CCGT part of the plant with capture is scaled to take into account the reduced net output of the plant with capture.

For capital costs of capture (in 2014 £/kW), figures ranged from 627 (ROAD) through 570 (GCCSI 2017), 567 (ZEP 2011), 507 (CRT 2013) to 278 (AMEC 2018). Excluding the AMEC result, which is clearly an outlier and is not considered achievable, the remaining estimates lie in a comparable range. Although ROAD is for coal flue-gas, this will not have a big impact on costs. A wet ESP was required for ROAD which a CCGT can avoid, but the absorber must be larger for flue-gases from a CCGT due to the lower CO2 concentration. We selected £570/kW (based on the ZEP and GCCSI reports) as this is mid-range of the credible sources.

For CCGT operating costs, again they are scaled by the change in net output, with the exception of connection and use-of-system charges. These grid charges presented on a £/MW/year basis are constant for all technologies.

For capture plant fixed and variable operating costs, the AMEC 2018 values are used (fixed = £ 10250 /MW/year, variable = £0.93/MWh). The total for baseload plant aligns well with the ROAD estimates (within 5%), but ROAD did not attempt a realistic split between fixed and variable costs – the split proposed by AMEC is considered reasonable. Other sources either did not give a separate operating cost for capture, or included electricity and steam in their results.

3.2 Oxyfuel

For oxyfuel, the CCGT and carbon capture must be considered together as a single entity. Therefore, costs are given for CCGT plus capture combined.

Here, we only have two sources, the published information from NET Power (NET power) on the technology, which is mostly high-level. There is a high quality technical report, but this avoids cost data. The only reference to costs in the NET power material is the claim that costs and performance will (for the optimised design) will be comparable with an existing unabated CCGT. This seems optimistic, but we propose to use this assumption for the nth of a kind unit to represent “breakthrough” technology.

For comparison, the approx. 30MW pilot now being demonstrated was quoted in a 2017 news report as costing \$140M, leading to a cost of \$4667/kW.

We therefore used the AMEC costs estimates for the CAPEX and OPEX of the FOAK oxyfuel plant, with one qualification. In this case AMEC has assumed almost all operating costs were fixed. Given that the core of the plant is a GT, and that tends to be dominated by operating costs due to the high temperature blade replacement, this should also apply to the oxyfuel plant, so we have moved some OPEX costs from fixed to variable.

3.3 SMR + H2 storage + H2-fired CCGT

For this technology option, we assume (agreed with BEIS) that the CCGT is the same size as for other technology options but it runs for 12 hours per day only. The SMR operates continuously and is therefore sized to provide 50% of the hydrogen flow required by the CCGT. This gives the buffer storage capacity – namely 12 hours output of the SMR.

For a hydrogen-fired CCGT, we were unable to find reliable external sources. This has been studied in collaborative R&D projects that Uniper has been involved with (e.g. Dynamis) but the reports are covered by confidentiality constraints. The practical conclusion of this work is that a hydrogen-fired CCGT is very similar to a conventional natural gas CCGT except that:

- Nitrogen or water must be added to control NOx, as pre-mix flame technology used for natural gas NOx control is not yet developed for hydrogen. We assumed water would be used as we have no low-cost nitrogen source.

- The higher water content in the flue gas increases the heat transfer to the gas turbine blades so the combustion temperature must be reduced to preserve blade life.

These effects reduce the CCGT efficiency by about 2%, compared to an equivalent CCGT firing natural gas – so we used 57.8% (2% less than the BEIS reference unabated CCGT efficiency).

We made no other changes to the capital or operating costs of a FOAK hydrogen-fired CCGT.

The SMR must be sized to provide 50% of the hydrogen requirement of the CCGT – which gave an SMR size of 30t/h hydrogen (1000MWth). The costs for the SMR were taken from the AMEC 2018 report. This assumed a 300MWth SMR, so we applied a scaling factor (0.7 power scaling) to get the estimated capital costs for the SMR.

The non-fuel operating costs of the SMR were also scaled in the same way as the capital costs (0.7 power law scaling). While this is generally true for industrial processes, it is not always true (for example, maintenance costs for advanced gas turbines scale approximately linearly with the number of units). Therefore, this is an area of uncertainty.

Cost for hydrogen storage were taken from ETI 2013. We had to make assumptions on the type of storage, which depends on the location. Here we chose a 105 bar salt cavern which is typical of East Cheshire, and is mid-range for the costs of on-shore storage. We assumed off-shore hydrogen storage (which is more expensive) would not be necessary, although there is an untested public acceptance risk for on-shore hydrogen storage.

The ETI report assumed the hydrogen was produced using an auto-thermal reforming process with oxygen, and that the nitrogen by-product of the oxygen production would be used for NOx control in the CCGT. They therefore included nitrogen storage. For our technology selection, this is not necessary, making the storage requirement smaller and cheaper. We estimate that a single 200 000 m^3 cavern will be required for the hydrogen storage, and have scaled the costs from the ETI report based on this.

3.4 Transport and Storage

Transport and storage costs are very site dependent. As such, sources are either project specific, or quote very general numbers. For example, AMEC 2018 gives T&S costs as £8-31/t with a central case of £19/t. Quoting costs in this way places all the costs of T&S into variable operating costs, which can be true if a third party is providing T&S as a service, for example as a regulated business. However, this model is unlikely for a FOAK plant.

Therefore, we chose to include a realistic CAPEX estimate for T&S. For this, we had two sources. ROAD has a T&S CAPEX of £205/kW and ZEP 2011 gave £325/kW. Given that ROAD has an unusually cheap T&S system due to the short pipeline distance and re-use of platform infrastructure, we took the ZEP number as more representative.

For operating costs, we have also taken the ZEP 2011 number for consistency, which scaled to £3.34/MWh or about £10/t. Again, this is higher than the ROAD value of about £1.5/MWh.

Translating all these costs into a £/t cost would give about £23/t of CO_2 stored, so these costs are a little higher than the AMEC central case of £19/t. Given that this is the FOAK plant, this seems reasonable.

4 COMMENTS ON THE FOAK COSTS

The costs estimated for the different technologies are summarised in the following table.

Summary table	Units	CCGT unabated	CCGT + CCS	Oxyfuel	SMR+H_2 CCGT
Unit size	MW	1200	1056	850	1160
Efficiency		59,80%	52,60%	55,20%	38,88%
CAPEX					
Total CAPEX	£/kW	540	1508	1693	1328
OPEX					
Fixed	£/MW/year	12240	24159	30783	54974
Variable (non-fuel)	£/MWh	3,33	8,05	6,51	11,84
Insurance	£/MW/year	2064	2345	2345	2135
Connection and UoS charges	£/MW/year	3280	3280	3280	3280

From this, it is apparent that both oxyfuel and the SMR option are currently more expensive than post-combustion capture on a CCGT. The oxyfuel (Allam cycle) has an efficiency advantage that will provide significant compensation, but the SMR process is also much less efficient. This has been tested with Uniper experts and supported based on experience in other studies.

In particular, the SMR approach is essentially a form of pre-combustion capture, and this is known to be much less efficient than post-combustion capture on natural gas due to the energy loss in converting the natural gas to hydrogen (about 33% for the SMR applied by AMEC). A conventional SMR process is also regarded as inefficient when combined with carbon capture even for pre-combustion capture technologies. We suggest considering auto-thermal reforming with oxygen, which we expect to be more efficient for this application. This is because it allows separation of CO_2 at high concentration and high pressure, whereas a conventional SMR must apply post-combustion capture. We expect the use of auto-thermal reforming would increase the overall cycle efficiency by 6-7% points, so to about 45-46% and optionally provide a source of nitrogen for CCGT NOx control. However, that would still leave it significantly less efficient than post-combustion capture and oxyfuel technologies.

5 TRANSLATION FROM FOAK TO NOAK COSTS

In developing our costs for the "nth of a kind" (NOAK) cases, we started from the FOAK costs and made the following assumptions:

- The CCGT was assumed to be NOAK already, and therefore costs and performance for the CCGT component of the plant were unchanged. This also matched the assumption used by BEIS for the unabated CCGT

- For post-combustion capture, we assume a capital cost reduction of 30% and a modest efficiency improvement (from 52.6% to 53.3%). The most comparable technology (FGD) achieved 50% CAPEX reductions from the first units in the early 1980s to the routing construction in the late 1990s, but there were also market and commodity price reductions, so such as steep cost reduction is considered unlikely to be achieved. The efficiency improvement is based on a 20% reduction in steam use by the capture plant but with other works power (e.g. compression power) unchanged. It thus represents the effect of the use of advanced solvents but assumes other technical advances result in cost reductions rather than performance improvements. For comparison, CRT 2013 expected no CAPEX cost reduction, but a greater improvement in efficiency (by 2% points between 2013 and 2028). Given the trade-off between costs and performance, this is also a credible scenario.

- For transport and storage we also assume 30% CAPEX reduction, consistent with the assumption for capture. Here there is much better agreement with CRT 2013, which assumed 38% reduction across transport and storage from 2013 to 2028. Again, assumptions on shared infrastructure and storage locations can give large changes to this number.

- For capture, transport and storage, we assume that operating costs scale with capital costs. For transport and storage, this would place the combined cost at around £16/t, so a little lower than the AMEC central estimate.

- As noted above, we have used the NOAK oxyfuel case as representing a "breakthrough" technology, and therefore assumed that NET Power's promotional claim of "similar costs and performance to an unabated CCGT" is actually achieved. We therefore use the BEIS unabated CCGT data for the CCGT and capture plants combined, and assume unchanged efficiency. Transport and storage costs are then added as for the post-combustion capture case above.

- Although SMRs are relatively proven technology, we still assume a comparable learning curve as for post-combustion capture because the technology can be adapted to the carbon capture case. Therefore, we assume 30% lower CAPEX and a thermal conversion efficiency of 70% rather than 67%. Given the comments above on the efficiency advantages of auto-thermal reformers, it may be that a change of technology is more realistic for the NOAK plant, but we did not have reliable cost estimates immediately available to use for this alternative case.

- Salt cavern storage is assumed to be established technology, and therefore has no technology learning.

- For a hydrogen-fired CCGT we assume that the pre-mixed flame technology is developed, so the efficiency penalty of 2% can be removed. Thus, a hydrogen-fired CCGT is just as efficient as a natural gas CCGT. No other learning is assumed since CCGT technology is already NOAK. We believe this is another area with scope for potential breakthrough technology, in that hydrogen fuel-cells may give a step-change efficiency improvement to circa 70%. However, this is very uncertain, and we already have the oxyfuel NOAK plant at low cost to represent breakthrough technology.

6 OTHER ASSUMPTIONS

Here we briefly discuss other assumptions not discussed above:

- <u>Insurance.</u> We are not clear what is covered here. Large utilities often either self-insure, or do not insure at all. The decision on what to insure depends on the commercial policy of the investors and on their ability to take risk. To avoid undue influence of the insurance on the ranking of technologies, we have assumed that the BEIS value for CCGT is the same for all technologies. However, we recognise that this may undervalue the risk of new technologies.

- <u>High and low costs</u>. Again, we have taken the spread for unabated CCGTs and applied this to the other technologies. Given that the model preferentially selects low cost options, there is a risk that a technology with more uncertain costs is preferentially selected by the model if we give a wider cost range because the lowest cost in the range is lower than for a technology with more certain costs. For this reason, we have not changed the cost range between technologies.

- <u>Efficiency variation with time</u>. All these technologies are GT-based, so we have applied the same variation of efficiency with time as for the unabated CCGT. We do not expect significant degradation of capture performance with time.

- <u>Construction periods.</u> We have not changed these. Experience from the ROAD project was that the longest lead-time component in a capture plant (the CO2 compressor) has a led time comparable or slightly shorter than that of an advanced gas turbine. Therefore, the addition of carbon capture should not lengthen the overall construction program. Transport and storage construction times are comparatively short. The FOAK plant may have a long development time before the investment decision, but that depends on the subsidy regime and planning obstacles which are difficult to predict. Also, given the model works with perfect knowledge, it is not clear if this makes any difference to the result.

- Availability. We have taken the early availability of the FOAK plants from the results of an internal analysis of breakdown availability for the ROAD plant. This used two different approaches – one being a bottom-up prediction of possible failures by experts, and the other being comparison of early availability of other new technologies (FGD and F-class gas turbines). The average of the different approaches was a breakdown availability of only 72% in year 1, ramping up to 95% in year 6 and beyond. The available information on Boundary Dam and Petra Nova give no reason to change this analysis. For NOAK we have assumed that the novel (CCS) components have a 95% availability from year 1, and adjusted downwards the conventional CCGT availability profile accordingly.

- CAPEX construction cost profile. This is unchanged.

- Location of Planned Sites. The selected sites are based on existing power stations that can be added to, and that are known to have good access to gas and to potential CO_2 storage sites. The CO_2 storage sites are the more restrictive, and are either in the North Sea off the east coast of England (Norfolk, Lincolnshire and Yorkshire) or in the Irish Sea (off Merseyside and Lancashire). The best access to both is on the east coast, hence 3 of the five sites are located there. However, there is sufficient CO_2 storage in the Irish Sea to allow multiple units on Merseyside. Finally, one site is proposed in the Thames Estuary (Grain / Tilbury / Kingsnorth). This is because, for a large power plant, the benefit in lower grid connection costs of being located close to the major centre of electricity demand that is London, is considerable, and may outweigh the additional CO_2 pipeline costs required to transport the CO_2 to storage sites off Norfolk. For the sites involving hydrogen storage, an additional factor comes into play, which is the proximity to suitable geology for hydrogen storage. This matches CO_2 storage only in East Cheshire and near the east coast of Yorkshire / Humberside. For this reason, proposed sites in Merseyside have been moved further east and the Thames Estuary site is dropped from the list.

- Ramp rates from hot and cold start. These are based on Uniper's experience of typical behaviour for existing CCGTs. It is possible that new CCGTs could ramp up faster on starting.

  How quickly a CCGT can reach its maximum output depends on how long it has been off. If it has been off for a long time then the plant's output must be increased gradually to avoid the stress of thermal expansion damaging the plant and increasing maintenance costs. If the plant has run recently then the equipment is still warm and it can be started faster. We define a hot start as occurring within 48 hours of the last shutdown.

  We assume in our numbers that hour 0 is defined as the point at which the CCGT synchronises and starts to feed power into the grid. Notice to deviate from zero (NDZ) would need to be given before this time to prepare the plant to start. However, our understand is that the DDM is a deterministic (no uncertainty) scheduling model, in which case we would not expect the NDZ to change the scheduling of the plant.

7 REFERENCES

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