AGL Energy Limited
ABN: 74 115 061 375
Level 22, 101 Miller St
North Sydney NSW 2060
Locked Bag 1837
St Leonards NSW 2065
T: 02 9921 2999
F: 02 9921 2552
www.agl.com.au

A few words.

Mr Gary Henry
Queensland Competition Authority
Level 19, 12 Creek Street
Brisbane NSW 4000

8 May 2012

Regulated Retail Electricity Prices 2012-13 (March 2012) - Supplementary Information

Dear Gary,

As discussed at our meeting on Friday 4 May 2012, the market-based approaches used by the QCA to set the energy purchase costs (EPC) in the 2012-13 Draft Determination make no allowance for the exposure of a 'representative retailer' to the cost of Power Purchase Agreements (PPAs) or other longer term, structured hedging arrangements. AGL Energy Ltd (AGL) considers it imperative that the QCA reconsider its calculation of the EPC component of retail tariffs so as to reflect a retailers 'actual cost of supply' for a small customer load in Queensland – thereby including structured transactions as part of its energy costs, as would be necessary to satisfy the requirement of Section 90(5) of the Electricity Act 1994.

In principle, AGL believes that the most appropriate approach for setting the EPC, as part of a regulated retail electricity tariff, is to calculate the long run marginal cost (LRMC) of generation and a market-based cost for the regulated load and use the higher of the two costs. The QCA has dismissed any use of an 'LRMC-as-floor' approach for 2012-13 prices, and instead relied solely on market-based approaches. By excluding any consideration of LRMC in the EPC, this approach ignores the cost of long-term hedging arrangements entered into by retailers which, in turn, underwrite the development of electricity generation in Queensland. The QCA has expressed concern that because the cost of longer-term supply agreements is not publicly available then they can't be considered in the regulated price.

In light of this requirement of the QCA, AGL has given further consideration as to how the QCA might incorporate a cost-based approach into the 2012-13 EPC to reflect a 'representative retailer's' exposure to longer-term hedging costs (i.e. PPAs) calculated using publicly available data. The Attachment sets out two methodologies for valuing PPA's in the current market, which cover base, intermediate and peak load arrangements. AGL presents two methodologies to calculate the cost of a PPA for various technologies based on current market conditions.

Using these PPA prices (and with ACIL Tasman considering and analysing PPA outage risks using their own published data on outages rates) along-side the hedging approach described in the Draft Determination, the QCA would be able to recalculate the wholesale energy cost for the 2012-13 Energex and Ergon NSLP tariffs incorporating long-dated instruments.

AGL has contended that the regulated price should basically reflect the long run cost of generation (i.e. PPA) as a floor with a market price as a cap. However, since such an approach has been rejected by the QCA for 2012-13, an assumption is required as to the composition of a retailer's portfolio of PPAs vs shorter-dated market instruments.

The approach adopted by ACIL Tasman as to the construction of a short-dated hedge portfolio assumes a certain layering of hedges at specific timeframes prior to the determination year in question. Whether this modelled approach to short-dated hedge contract accumultation reflects the actual approach adopted by various retailers is of course uncertain at best – but provided its use is not intended to reflect all hedge contracts accumulated, AGL considers that it represents a pragmatic compromise under the circumstances.

As to how PPAs might be accumulated is perhaps more difficult to define, particularly given that most PPAs have been written in recent years. However, AGL notes that even though retailers hedge their load prior to the period in question, it is appropriate to calculate PPA prices based on current fuel and plant costs, to reflect and indeed, to enable forward decisions by retailers to facilitate new plant entry as, and when, required, rather than presuming no further PPA activity is envisaged as this would run counter to the underlying reason for writing PPAs in the first place. This would therefore reflect industry practice, that writing PPAs for the purposes of funding new generation projects, is crucially contingent upon the power project developer demonstrating to Project Banks that the price obtained through the PPA will ensure that the developer can meet their debt and equity commitments. As such, any PPA would closely reflect the current project fuel and technology costs.

Finally, AGL noted in its submission to the Draft Determination that the majority of the QLD peak-load market (including peak swaps and caps) appears to be covered by non-futures contracts (i.e primarily PPAs and physical generation) and that only 51% of the base load appears to be covered by futures contracts.[1] However, given the short timeframe available to the QCA to recalculate the EPC for the Final Determination, at this late stage the QCA might consider using a simple 50:50 split, which if nothing else would not deviate from the historical QCA approach (albeit noting our views in relation to the fact that PPAs should be effectively setting the floor).

If you have any further questions or queries with this information please do not hesitate to contact me or Elizabeth Molyneux (03 8633 6207).

Yours sincerely,

[redacted]

Paul Simshauser
Chief Economist & Group Head of Corporate Affairs
AGL Energy Ltd

[1] AGL Energy Ltd, Draft Determination – Regulated retail Electricity Prices 2012-13, AGL submission to the Queensland Competition Authority (7 May 2012). Figure 4. QLD Peak Generation Capacity vs. QCA Cap Volume highlights available capacity in QLD for peak load market. Figure 3. Energex Base Demand vs. d-cypha Trade + TFS 'open interest' shows level of base demand hedged with QLD futures in the Draft Determination.

Attachment

Introduction

We were advised by the QCA on 4 May 2012 that PPAs have thus far been excluded from the 2012-13 Wholesale Energy Cost (WEC) calculation because:

1. No PPA contracts or data exist in the public domain (which is entirely correct, PPAs are the subject of strict confidentiality clauses and are therefore unable to be disclosed in the public domain); and

2. The QCA cannot determine how to model a PPA, using publicly available data as the inputs.

If we understood the QCA's comments correctly, ACIL Tasman was also unable to advise the QCA on how to model a Power Purchase Agreement using relevant inputs. AGL made it clear on 4 May 2012 that we find it hard to believe that ACIL Tasman is not able to producw modelled estimates of reference PPAs using publicly available data (particularly since ACIL Tasman publish all of the inputs required, as we highlight below).

We set out below how a PPA structure and price can be modelled using two different approaches. (AGL could offer a 3rd, more detailed approach involving the use of a Project Finance Model, however such an approach involving more detailed data would seem unhelpful at this point given the limited time available).

We would hasten to add that ACIL Tasman's existing publicly available plant financial modelling approach and methodology is perfectly suitable for the purpose of deriving PPA prices and structures. We therefore believe that the additional approach outlined below (and our alternate, Project Finance Model Approach) are quite redundant given ACIL Tasman's in-house capability.

And finally, as we noted on 4 May 2012 to the QCA, the task of modelling PPA's pales into absolute insignificance by comparison to the complex task of modelling future pool prices in one of the world's most volatile commodity markets. Thus there is no reason why modelled PPAs might be considered anywhere near as difficult a problem as modelling highly uncertain future spot prices.

What PPAs are Designed to Achieve

The structure and pricing of any PPA for a given technology needs to meet the collective objectives of the three principal parties to a power project:

- Project Sponsor/Developer: who is seeking a financial return on their equity invested, which as ACIL Tasman (2011) highlights is c.16.5% (see Table 53, page B-20). All things being equal, a project developer will seek the highest PPA price achievable but this will be tempered by Project Banks and quite clearly, by the PPA counterparty.

- Project Banks: amongst many variables, are solving for a secure, long-dated, project income stream to ensure solvency of the plant and security of their investment (i.e. debt facilities). This relies quite crucially on the price level, PPA tenor and credit quality of the PPA counterparty (i.e. energy retailer). While it may not be obvious, Project Banks are acutely focused on the pricing level and structure of any PPA to manage their own downside risks. That is, the overall project (and the PPA) should have a cost structure which resembles the general market consensus on the overall Long Run Marginal Cost of Supply of that particular technology (presuming the technology choice has been selected in the first instance). This is critically important to Project Banks in the event of PPA counterparty failure. If the 'right' project technology had a cost structure that was higher than market consensus of the Long Run Marginal Cost of Supply for that technology, and the PPA Counterparty failed (for any reason), Project Banks would be left with power station and associated debt facility exposures susceptible to asset write-downs and debt facility losses. In other words, Project Banks actively use Long Run Marginal Cost of Supply benchmarks to gauge the efficacy of any under-written PPAs, and forms a part of their due diligence prior to providing Project Debt facilities. This is not contentious, it simply reflects good banking practice.

- Energy Retailer: who is seeking a long-dated hedge contract and is seeking to minimise their cost of supply over the commodity cycle. Estimates of Long Run Marginal Cost are an important input into the decision making process, and will represent a critical benchmark used in the internal approval process by Executive Management and Board Directors prior to PPA sign-off. As an aside, such estimates or benchmarks are most frequently produced by independent advisory firms (such as ACIL Tasman and their competitors).

For the purposes of raising finance, and given the gearing levels cited by ACIL Tasman (2011, see Table 53 at Page B-20) for their reference plants, it should be obvious that a Project Financing is envisaged by ACIL Tasman, as such, debt levels deviate from typical businesses than rely on corporate debt facilities (as distinct from project debt facilities). For a power project developer seeking to raise Project Debt, it is essential that they hold a suitable PPA for banking purposes. Banks no longer entertain project finance in the absence of PPA underwriting due to the acute risks facing purely merchant plants. For a more detailed explaination of why this is the case, see Simshauser (2010).

The proximate structure of a template Power Purchase Agreement can be quickly calculated. While PPAs come in many forms, the most conventional form involves (1) a stream of fixed payments (e.g. usually monthly) which are designed to cover all costs other than those costs that vary with output over the short run, and (2) variable payments designed to cover fuel and VOM charges.

Bonus/penalty arrangements are frequently added which provide incentives to the plant operator to meet certain reliability criteria. However, these can be assumed away by the QCA given the limited time involved (although clearly such costs should be accounted for if time was not a constraint).

In order to produce a suitable set of values for a Power Purchase Agreement for a given technology (e.g. Combined Cycle Gas Turbine or Open Cycle Gas Turbine), Project Developers/Sponsors, Project Banks and the PPA counterparty (i.e. scale-efficient Energy Retailer) will generally rely on a detailed Project Finance Model (PF Model) which is used in the first instance for banking purposes, and specifically, for raising project debt. Such models discount future cash flows to equity on a post-tax basis, using a suitable equity return and suitable debt sizing parameters. We note that ACIL Tasman provide relevant equity return parameters in Table 53 of their most recent report to AEMC (see ACIL Tasman, Table 53, page B-20). A suitable methodology for PF Modelling including debt sizing parameters used by Project Banks can be found in the published, peer-reviewed academic works of Simshauser (2009), Simshauser and Nelson (2012), or for a thorough and detailed explanation of line-by-line modelling concepts, see Nelson (2011). However, as we noted earlier, modelling of this detailed nature would prove unhelpful given the acute time constraints faced by the QCA.

Fortunately, as with most highly detailed modelling exercises, less granular modelling will inevitably obtain sufficiently reliable results for the purposes of estimating PPA costs. This can include discounting un-geared cash flows before or after taxation, using relevant estimations of the weighted average cost of capital. Again, we note that ACIL Tasman (2011) provide all the relevant inputs to produce relevant estimates of the weighted average cost of capital, either before or after tax, geared or ungeared.

Methodology 1 - Producing PPA estimates using existing ACIL Tasman Modelling Results

ACIL Tasman provide data that is suitable to estimate PPA Fixed Payments for a Combined Cycle Gas Turbine (CCGT) and an Open Cycle Gas Turbine (OCGT) in their most recent report to AEMC (See ACIL Tasman, 2011, Table 6, page 20) while data suitable to provide estimates of Variable Payments under a PPA are accounted for in the same report (See ACIL Tasman, 2011, Table 6, page 20). While we are uncertain as to which modelling methodology has been used, the numbers are within the 'ball-park' estimates from our alternate modelling result in Methodology 2 (described later), which uses a Levelised Cost of Electricity approach.

Fixed Payments

Using the ACIL Tasman (2011) Report, their reference CCGT has a $174/kW annual fixed capital, operating and maintenance costs in 2011/12 dollars (see Table 6, page 20). Thus by increasing these by 2.5% to account for inflation and dividing by 8760 hours in each year, the approximate Fixed Payment Stream of a CCGT expressed in $/MWh can be defined as follows:

- $174 x 1.025 / 8.760 = $20.35/MWh, where the implied ACF = 100%. For example, for a 700MW CCGT these would be paid as Monthly Fixed Payments of 700MW x 8760/12 x $20.35/MWh = $10,398,850.

For a reference OCGT, $112/kW has been cited as the annual fixed capital, operating and maintenance costs in 2011/12 dollars (Table 6, page 20). Thus by increasing these by 2.5% to account for inflation and dividing by 8760 hours in each year, the approximate Fixed Payment Stream of a OCGT expressed in $/MWh can be defined as follows:

- $112 x 1.025 / 8.760 = $13.10/MWh, where the implied ACF = 100%. For example, for a 450MW OCGT these would be paid as Monthly Fixed Payments of 450MW x 8760/12 x $13.10/MWh = $4,303,350.

Variable Payments

ACIL Tasman provide suitable variables which can be used as inputs to calculating PPA Variable Payment estimates for CCGTs and OCGTs. Variable Payments under PPAs are calculated quite easily, as follows:

- Fuel Cost ($/GJ) x Power Station Heat Rate (GJ/MWh) + VOM ($/MWh). These are paid according to MWh produced, within a credible operating range.

ACIL Tasman provide publicly available inputs for such modelling. ACIL Tasman (2011, see Tables 8-9 on pages 21-22) list suitable gas prices at $5.97/GJ for a CCGT plant and 7.45/GJ for a OCGT plant in 2011/12 dollars. ACIL Tasman do not include estimates in their AEMC 2011 Report for Heat Rates, however earlier reports by ACIL Tasman (see for example ACIL Tasman 2011a, Report to the QCA) include estimates for heat rates (HHV) which translate to 7258kJ/kWh for CCGT plant (49.6% thermal efficiency) and 10843kJ/kWh for OCGT plant (33.2% thermal efficiency). ACIL Tasman (2011, see Table 56, page B-21) set out VOM charges at $1.08/MWh for CCGT plant and $7.69/MWh for OCGT plant in 2010 dollars. Using these inputs and the equation above, the Variable Payments under a PPA can be defined as follows:

For CCGT Plant:

- $5.97/GJ*1.025 x 7.258 + $1.08*1.025^2 = $45.55/MWh for any credible reasonable ACF range, say 62.5%-77.5%

For OCGT Plant:

- $7.45*1.025 x 10.843 + 7.69*1.025^2 = $90.88/MWh.

Methodology 2 - LCOE Modelling

The Levelised Cost of Electricity (LCOE) approach is another method for estimating the entry cost of a power station and therefore provides an adequate method to estimate the suitable price of a PPA. LCOE can be thought of as the energy price/cost at which a power project breaks even, expressed in $/MWh, prior to restructuring this headline result into a typical PPA format. This latter restructuring involves a very basic set of calculations.

The LCOE approach requires calculating the present value of plant costs, and dividing these by the present value of the wholly or partially inflation-adjusted energy produced over the project life, adjusted for auxiliary loads and transmission losses to arrive at a suitable energy price/cost estimate relevant to modelling the construct of a PPA. The LCOE approach is widely used by many institutions (see Department of Resources, Energy and Tourism (2011), and Institute for Energy Research (2011)) and is widely used in academic literature (for example, see Simshauser, 2011). All of the data required to fullfill a LCOE calculation can be sourced from published ACIL Tasman Reports.

To begin with, the first exogenously set variable for producing plant costs relevant to the price under which a PPA would be referenced is the overnight capital cost of plant (i.e. the aggregate capitalized costs of a new power station). This essentially comprises the main power island[2] and the balance of plant construction contracts, site acquisition, planning and permitting costs, pre-development costs, electricity grid connection, gas pipeline or fuel connection costs, project development fees, project management fees, aggregate commissioning costs (including fuel consumed if applicable) and project contingencies.[3]

The overnight capital cost of plant for each plant type 'j' (Capexj) can be given by:

$$Capex_j = [k_j \times 1000 \times us_j] \qquad (1)$$

Where:

- k_j is the Greenfield overnight capital cost associated with generating plant technology *'j'* and is expressed in $/kW and can be found in ACIL Tasman (2011, see Table 5, page 20, expressed in real 2011/12 dollars);
- us_j is the installed capacity of the *'j-th'* plant and is expressed in MW.

ACIL Tasman (2011) clearly sets out capital costs for the relevant technologies.

$Capex_j$ can be further allocated to account for multi-period construction costs as follows:

$$Capex_j(t) = \left(Capex_j \times CPI(t) \times \upsilon O_j(t)\right) \qquad (2)$$

$Capex_j$ was defined in (1), $CPI(t)$ denotes the inflation based escalation in power station capital costs and is generally set a 2.5% for each future year which is the midpoint of the RBA's stated inflation range, and $\upsilon O_j(t)$ depicts how the sunk capital costs associated with the construction of technology *j* are incurred over the investment horizon. How this capital expenditure is allocated across the investment horizon depends critically upon the last variable $\upsilon O_j(t)$ in (2). For example, with a Combined Cycle Gas Turbine (CCGT) plant, the

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[2] The Power Island is defined as the core components of a generation plant (i.e. boiler, turbine, generator) whereas the Balance of Plant comprises auxillary equipment (e.g. feed-heating, fuel processing, cooling systems and so on). In some cases the Power Island and Balance of Plant contracts are combined to form an Engineering, Procurement and Construction or EPC Wrap.

[3] In some cases, interest costs capitalised (IDC) during construction are also included. However, in this analysis IDC is excluded and instead captured by the discounting of cash flows over the construction period. If no construction period is included in the discounting process, some allowance for IDC should be included in the Overnight Capital Cost.

capital is sunk over two successive years at the rate of 40% and 60%, respectively, as ACIL Tasman note (see ACIL Tasman 2011, Table 54 at page B-20).

For thermal technologies, Fuel Costs FC_j are a crucial component of the overall cost structure. Fuel costs are driven by two key variables, the thermal efficiency of the plant given by its Heat Rate (HR_j) and the unit cost of raw fuel (UFC_j). Fuel Costs can be expressed as:

$$FC_j(t) = \left(\frac{(HR_j \times UFC_j)}{1000}\right) \times \left(us_j \times ACF_j \times 8760\right) \times CPI(t) \qquad (3)$$

where $FC_{j}(t)$ is the fuel cost of generating plant '*j*' for which reference costs for UFC_j can be found in ACIL Tasman (2011, see Table 8 at Page 21 for CCGT gas prices and Table 9 at Page 22 for OCGT gas prices).

HR_j is the heat rate of each generator expressed in kJ/kWh and UFC_j is the constant raw unit fuel cost for each generator in $/GJ as noted above, and when divided by 1000, produces the unit cost of fuel expressed in $/MWh. Heat Rates for CCGT plant are generally about 7000kJ/kWh (HHV) and about 11500kJ/kWh (HHV) for OCGT plant. ACIL Tasman do not include estimates in their 2011 Report to the AEMC, however as we noted earlier, other reports by ACIL Tasman (for example ACIL Tasman 2011a, Report to the QCA) include estimates for heat rates (HHV) of 7258kJ/kWh for CCGT plant and 10843kJ/kWh for OCGT plant.

The term us_j is installed capacity as defined above, ACF_j is the Annual Capacity Factor of plant '*j*' and 8760 is the number of hours in each year and when combined produces energy generated (MWh) per annum.

Each power project *j* faces two Operations & Maintenance (*O&M*) cost streams during operating periods; Fixed Operations and Maintenance costs (*FOM*) and Variable Operations and Maintenance costs (*VOM*) which can be expressed as follows:

$$O\&M_j(t) = \left(us_j \times FOM_j \times CPI(t)\right) + \left(VOM_j \times us_j \times ACF_j \times 8760 \times CPI(t)\right) \qquad (4)$$

For most plant, the mix of operations and maintenance costs tends to be dominated by fixed costs. Reference costs for FOM_j can be found in ACIL Tasman (2011, see Table 55 on Page B-20) while VOM_j can also be found in ACIL Tasman (2011, see Table 56 on Page B-21).

Given these parameters, the levelised cost of any power project using technology *j* can be represented by:

$$PS_j = \left[\frac{PV\left(\sum_{i=1}^{I} Capex_j + FC_j(t) + O\&M_j(t) + \left(CW_j \times Capex_j \times CPI(t)\right)\right)}{PV\left(\left(us_j \times ACF_j \times 8760\right) \times \gamma CPI(t)\right)}\right] / \left(1 - x_j\right) \qquad (5)$$

In (5), the cost and quantity streams are discounted at the relevant weighted average cost of capital on a pre-tax basis, which can be calculated from ACIL Tasman data (ACIL Tasman, 2011, see Table 53 at Page B-20). The cost stream in (5) is represented by the initial investment capital $\sum_{i=1}^{I} Capex_j$ and incurred in accordance with (2), plant fuel costs $FC_{j}(t)$ are incurred in accordance with (3) and plant O&M costs ($O\&M_j$) are incurred in accordance with (4). In addition, we would typically model ongoing structural modifications to the plant, otherwise known as capital works (CW_j), and we usually set this at a certain (and small) percentage of initial capital $Capex_j$ and escalate at the full rate of inflation $CPI(t)$. We note however that ACIL Tasman do not account for such costs (beyond VOM costs) and so we would not propose to conflict with ACIL Tasman's existing approach given time constraints.

The production stream arising from the plant given by plant capacity (us_j), Annual Capacity Factor (ACF_j) and the hours in each year, was outlined earlier. Unit volumes are then escalated at the envisaged terminal revenue escalation rate $\gamma CPI(t)$ in which γ is set at some level at or below 100% (i.e. some firms opt for γ =85%, thereby representing a discount to the headline inflation rate). This is intended to reflect the price at which a PPA is likely to be struck (excluding Fuel Costs, FC). The discounted cost and quantity streams are then divided by the net output ratio of the technology $(1-x_j)$. The variable x_j represents the auxillary load of technology *'j'* and ACIL Tasman defines these (see ACIL Tasman's, 2011a Report to the QCA, Table 29 at Page 58 for suitable auxillary losses for existing CCGT and OCGT plant). Additionally, transmission losses will need to be accounted for in relation to variable charges, the statistics for which are publicly available from AEMO.

Converting LCOE Estimates to a Power Purchase Agreement

The Fixed Payments involved in a PPA can be estimated as follows:

$$FP_j = PS_j - \left(FC_j + \left(VOM_j \times us_j \times ACF_j \times 8760 \times CPI(t)\right)\right) / \left(1 - x_j\right)$$

Where FP_j is Fixed Payments for generating plant type 'j' expressed in $/MWh (and therefore need to be annualised into a Payment Stream given total plant capacity and hours in each year), PS_j is total plant cost expressed in $/MWh as noted earlier, FC_j is unit fuel cost as noted earlier, VOM_j is variable O&M costs as noted earlier, and the term $(1-x_j)$ is intended to represent auxillary losses.

By definition, the PPA variable payments are simply the difference between total costs and fixed costs, which will need to be adjusted for both auxillary and transmission losses.

By definition, the PPA variable payments are simply the difference between total costs and fixed costs:

- For CCGT plant, Fixed Payment FP_j = $22.18/MWh (which should then be converted into a monthly payment stream based on time and plant capacity) and $44.46/MWh for variable payments

- For OCGT plant, FP_j = $13.27/MWh (which again should be converted into a monthly payment stream based on time and plant capacity) and variable payments = $91.40/MWh

Above all, these estimates from the LCOE approach line up closely with the ACIL Tasman estimates of $20.35/MWh plus $45.55/MWh for CCGT plant, and $13.10/MWh and $90.88/MWh for OCGT plant.

The differences between the ACIL Tasman results and our results would be attributed to differing approaches to the treatment of pre- or post tax cash flows, and other differences in model designs, useful lives and so on.

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