CS Energy submission: Structure of Participant Fees in AEMO's Electricity markets

Summary and key points

CS Energy thanks the Australian Energy Market Operator (AEMO) for consulting on the structure of Participant Fees. We hope you find this response helpful in determining an efficient fee structure for the NEM.

In this submission we provide comment on the structure of fees, referencing previous AEMO determinations and the Rules requirements. It is our view that a new structure of fees would better satisfy the National Electricity Objective (NEO) and Rule 2.11.1. In particular we note that AEMO received economic advice that in the absence of being able to implement a tariff based on marginal cost (due to marginal cost being less than actual cost) it is sensible to employ a Multi-Part tariff to balance the allocative and dynamic inefficiencies (of recovering AEMO's actual costs, required under the Rules). After a review of the documentation, we agree a Multi-Part tariff should be used for both generators and Market Customers. For this reason this submission recommends the structure of fees be changed.

In a general sense, at least a proportion (say 50%) of Market Customer costs should be charged on a $/per customer connection point basis. This should comply with: 2.11.1(3) 'involvement with AEMO' as if a retailer grew in customer numbers its contribution would increase; and 2.11.1(4), 'not unreasonably discriminate' because this removes the cross subsidy from larger to smaller end customers.

We agree Rules requirement 2.11.1(3) 'involvement with AEMO' necessitates generators paying fees to AEMO for NEM Operations. However, rather than 100% fixed fee, at least a proportion (say 50%) of Generator and MNSP costs should be charged on a $/MWh basis, or should be reallocated to Market Customers. To do so would be consistent with a Multi-Part tariff and we believe the improvements in dynamic efficiency would satisfy the NEO and outweigh the requirement of 2.11.1(3).

Retaining the allocation of costs of the National Transmission Planner (NTP) function to Market Customers is sensible. Participants most affected by this service don't yet exist, as these are new investors, not existing 'sunk' investments. In addition, we see no Rules requirement for the allocation of costs to generators given they are not in any way involved in the function which is Rule clause 2.11.1(3) (unlike their involvement in NEM Operations).

In the consultation AEMO suggests the Full Retail Contestability operations costs be charged on a $/connection point basis. We shall explain we only agree to the extent that a proportion of costs should be allocated on a $/connection point basis, as this is consistent with our overall recommendation that costs be charged to Participants using a Multi-Part tariff.

CS Energy can see no reason for staging any of our recommendations and consider any changes should be enduring and only subject to revision if there are significant changes in the Rule 2.11.1; costs; operations; or type of Participant.

What is the preferred length of time over which the structure of Participant fees for electricity markets should apply?

CS Energy has no objection to AEMO determining an enduring structure on the basis that it satisfies the NEO and the other Rules requirements. Should there be any significant changes in circumstance, such as a redrafting of the Rules, different costs being incurred or the introduction of new types of Participant then this may trigger a new determination to be made by AEMO.

What are your comments on the current NEM fee structure?

The last fees Determination in 2010-11 drew heavily on recommendations from Allen Consulting from the 2006 determination.

Rules requirements and previous work

Allen Consulting considered different charging approaches AEMO could adopt and then compared them to the following requirements under the Rules 2.11.1:

In determining Participant fees, AEMO must have regard to the **National Electricity Objective**.

The structure of Participant fees must, to the extent practicable, be consistent with the following principles:

(1) the structure of Participant fees should be ***simple***;

(2) Participant fees should ***recover the budgeted revenue*** requirements for AEMO

(3) the components of Participant fees charged to each Registered Participant should be ***reflective of the extent*** to which the budgeted revenue requirements for AEMO ***involve*** that Registered Participant;

(4) Participant fees should not ***unreasonably discriminate*** against a category or categories of Registered Participants;

The charging approaches were:

1. Marginal Cost;
2. Average Cost;
3. Fully distributed cost (accounting based allocation of costs to customers);
4. Ramsey (the levying of cost dependent on price elasticity of demand); and
5. Multi-part (fixed fee and variable fee).

The report struggled to identify marginal cost for AEMO, given the report assumed, possibly incorrectly, that AEMO produced more than one unit of output. It assumed marginal costing would be the most efficient structure, because the price would reflect the opportunity cost to society of providing the extra unit; however the report also assumed the identification of AEMO's output into units for marginal costing purposes would be impossible.

By making the assumption that AEMO's marginal cost would be very low, because of a high proportion of fixed costs, Allen assumed marginal costing would not comply with the Rules 2.11.1 because fees would be insufficient to recover the budgeted revenue of AEMO (which is required under the Rules). Once marginal costing was ruled out by Allen Consulting, the report focused on the least worst of the other options in satisfying 2.11.1.

Average Costing was considered to be allocatively inefficient; Ramsey pricing too complex; Fully Distributed Cost too difficult to achieve (although with some elements of merit) and therefore the Multi-Part fees could be used to moderate some of the problems of each of the other pricing methods.

Allen Consulting concluded that Multi-Part fees would be most economically efficient given the constraints of the Rules and the National Electricity Objective. CS Energy agrees with this conclusion as it balances the allocative and dynamic inefficiencies of the two elements of the Multi-Part tariff.

The Allen work also adopted a number of premises, which we consider were largely unjustified in the report to AEMO. These premises, which we shall explain below, resulted in their recommended tariff structure for both generators and Market Customers varying from their original conclusion of a Multi-Part tariff being most efficient.

Existing fees - Generators

Following on from a conclusion that generators needed to pay fees due to their involvement with AEMO as required under 2.11.1(3), (which we agree with), it was premised that generators should not be able to recover fees (which would occur if they were charged on a variable $/MWh basis). The reason given for this was that it would put pressure on AEMO's costs and not distort the end market for electricity.

The reflective of involvement was balanced between fixed fees based on capacity (MW) and historic production (MWh), in order to not unreasonably discriminate between generator participants (2.11.1(4)).

The advice suggested that if generators faced a variable element in a Multi-Part tariff, charged on a current dispatch $/MWh basis, then this would be economically pointless, as it would be more efficient to levy the variable fee on Market Customers closer to the end consumer. Unfortunately this went against the conclusion to use a Multi-Part tariff in the first instance to be balanced between fixed and variable fees (based on current generation) to balance dynamic and allocative inefficiencies caused by the tariff.

We conclude that AEMO's current 100% effectively fixed fee cannot be considered, by definition, to be a Multi-Part tariff. It is dynamically inefficient and does not satisfy the NEO.

Existing fees - Market Customers

Allen's concluded that Multi-Part fees could not be applied to Market Customers, in the form a fixed fee ($/Participant). This was largely premised on the potential for it to increase economies of scale in electricity retailing, which would retard competition (which would not satisfy the NEO or comply with 'not unreasonably discriminate between participants' 2.11.1(4)) and would not reflect involvement with AEMO (required under 2.11.1(3)).

A second premise was that variable $/MWh fees are reflective of involvement, (whereas a fixed fee was not), with this therefore ignoring the potential for economies of scale to be passed on to particular Participants (or their large end user customers). This ignored the potential for cross subsidies to be introduced between different customers in the payment for certain allocated costs (especially for retailers, such as retail contestability), which one could easily assume vary on the basis number of connection points rather than electricity consumption. Instead of a fixed fee being $/Participant the fixed fees could have been per connection point. It was unnecessary to assume fixed fee being $/Participant: in any case the advice had recognised that fixed fees, in this case for generators, could be adjusted by MW or MWh from the previous year, so there is equally an argument that fixed fees could structured by $/connection point.

In summary Allen Consulting recommended Multi-Part tariffs as being the most economically efficient but then found, for reasons we shall explain can be overcome, it was not possible to apply Multi-Part fees to Generators and Market Customers.

One assumption which appeared unreliable was that the unit output of AEMO was a MWh. The average cost of AEMO was assumed to be $budget / total electricity exchanged. There is no real basis to assume this for AEMO. Generators have MWh output and have marginal and average cost, but not AEMO who operates a monopoly service for market operations, clearing and settlement.

It is worth considering that AEMO produces one unit, therefore marginal cost is equal to average cost. As long as consumers are funding the budgetary requirements for AEMO the community faces a price equal to the opportunity cost of using or not one extra unit of AEMO. The Rules wouldn't allow it even if it was possible to charge the 'community' the marginal cost of AEMO. Given 'agents' for the community have to pay AEMO fees, rather than the community as a whole, this leads, given the reasoning in the Allen report, to some kind of Multi-Part fee (part fixed, part variable) for Participants.

In considering the application of Multi-Part tariffs Allen Consulting appeared to unnecessarily constrain themselves to a $/MWh variable fee, a $/MW fixed fee for generators and a fixed $/Participant fee for Market Customers. These constraints appeared unnecessary and ignored the potential for charging on a per customer connection point, which should allow the implementation of Multi-Part tariffs, which appropriately meet the requirements of 2.11.1 and satisfy the NEO.

What are your comments on the current method of charging Generators and MNSPs fees?

The overarching reason to allocate any costs to generators appears to the 'involvement with AEMO' 2.11.1(3). This reason is sound. This could be done by $/MWh or $/MW, although the latter results in generators not recovering their costs and reduces dynamic efficiency.

It is difficult to understand the premise that fixed fees should be levied on generators so they can't recover costs in the NEM. Generators have struggled to recover costs and earn an adequate return in the NEM since its inception due the very high levels of competition. Allen suggests that average costing $/MWh is allocatively inefficient yet $/MW is dynamically inefficient; therefore it is best to trade off the two. As we have mentioned, given the advice, AEMO generator tariffs should not be 100% fixed as they are today.

Because of this, it would be sensible to reduce the fixed fee, at least by a proportion and allocate costs on a $/MWh variable basis. This is consistent with a Multi-Part tariff, which was Allen's recommendation to AEMO, which we support.

We note the Allen report effectively concluded a $/MWh would be economically pointless as they fees would be passed on in higher wholesale prices (and so should be levied on Market Customers instead), but this ignores the requirement under 2.11.1(3) to do so. It also misunderstands the NEM where generators, at certain times, do face prices below their avoidable costs.

Whether or not fees are reallocated to Market Customers, we consider there to be a clear case to reduce the fixed component on generator fees consistent with Allen Consulting recommendations that this would reduce the dynamic inefficiencies this created. The question is by how much and this can be answered by balancing the competing objectives of the NEO and the other elements of 2.11.1.

Is there a more appropriate method to charge Generators and MNSPs?

The current fee structure for generators, being 100% fixed, is not dynamically efficient and therefore does not satisfy the NEO. It would be sensible to improve the tariff's performance by amending it to a Multi-Part tariff that aims to balance the dynamic and allocative inefficiencies of fixed and variable tariffs. A starting point would be to a 50:50 (fixed / variable) Multi-Part tariff.

AEMO could amend the tariff structure to a Multi-Part tariff by reducing the proportion that is fixed, noting the dynamic inefficiencies these charges cause; and the remaining allocated costs to generators could be charged on an average cost basis $/MWh (based on current generation).

If charging on a $/MWh basis is considered economically pointless, the proportion could be reallocated to Market Customers in the General Unallocated fees. This would depend on AEMO's view as to the necessity to comply with 2.11.1(3), specifically the 'reflective of involvement' element. It is CS Energy's view that the NEO would be better served by reducing the fixed component of generator fees (to improve dynamic efficiency) even if it meant these costs need to be reallocated to Market Customers.

What are your comments on the current method of charging Market Customers fees based on actual energy consumed?

We consider Market Customer tariffs are inappropriate for larger energy users who don't benefit from FRC, Planning and see no economies of scale because the tariff is $/MWh, not per connection point (bar the new Energy Consumers Australia tariff for 2015-16). The $/MWh fee for Market Customers could be considered to not satisfy 2.11.1(4) given it unreasonably discriminates against Participants representing customers that are larger consumers, which do not benefit from the costs AEMO is incurring.

Is there a more appropriate method to charge Market Customers?

There are clear options to more efficiently allocate costs to Market Customers. This is already done with the 2015-16 fees, where ‘Energy Consumer Australia’ costs are charged on a $/per customer point basis. These concepts may also apply to the ‘FRC Operations’ and ‘Allocated Customer’ costs which AEMO has identified should be placed on Market Customers.

Allocating on a $/customer connection point basis may not lend itself to the ‘General Unallocated’ amounts which may be more suitable for $/MWh rates, although this would ignore any economies of scale of larger end users have in determining their ‘involvement with AEMO’ element of 2.11.1(3) and would ignore the requirement for the tariff to not unduly discriminate against certain Participants 2.11.1(4), which they do by creating a cross subsidy between larger and smaller end customers which are often reflected by different types of Participant in the NEM.

Overall, the allocation of costs on $/per customer point basis would also not distort competition, as if a retailer grew in customer numbers its contribution would increase. It would prevent the cross-subsidy between large customers to small customers that exists today.

As mentioned earlier there are clear options to more efficiently charge costs to Market Customers where at least a proportion of costs for ‘FRC Operations’, ‘Allocated Customer’ and possibly ‘General Unallocated’ could be charged on a $/per customer connection point basis.

For example, should there be a fixed component of fees as well as a variable consumption based fee?

We have mentioned allocating on a $/per customer point basis may not lend itself to the ‘General Unallocated’ amounts which may be more suitable for $/MWh rates, although this would ignore any economies of scale of end users in determining ‘involvement with AEMO’ 2.11.1(3) and the requirement to not ‘unduly discriminate against certain Participants’ 2.11.1(4), which occurs by creating a cross subsidy between larger and smaller end customers reflected by different types of Participant in the NEM.

Because of these reasons there is a case that at least a proportion, if not all ‘General Unallocated’ costs should be charged on a $/customer connection point basis rather than the $/MWh approach today.

Attached is further analysis demonstrating that the cost increase per NMI per year is insignificant should a proportion of fees be under a fixed tariff.

If a Multi-Part tariff is adopted with 50% $/NMI and 50% $/MWh, the increase is estimated at around $2.19 per NMI per year. Even with a 100% fixed cost $NMI, the increase per NMI per year is estimated at around $4.38.

What are your comments on the current approach on the fee structure for the NTP function?

Retaining the allocation of costs of the National Transmission Planner (NTP) function to Market Customers is sensible. Participants most affected by this service don't yet exist, as these are new investors, not existing 'sunk' investments.

In addition, we see no Rules requirement for the allocation of costs to generators given they are not in any way involved in (required under 2.11.1(3)) the function (unlike NEM operations).

Is there a more appropriate method to charge fees for the NTP function?

We consider our arguments made in regards to charges for Market Customers should apply.

In particular we consider it sensible that larger consumers not be exposed to NTP costs because it is arguable whether they are involved or benefit in any way of the function. These larger users have sunk investments and are unlikely to respond to any activities from the NTP function.

Given there may be linkages between the NTP and NEM functions, should the NTP function potentially be consolidated into the NEM function with one fee charged?

For the reasons above, no.

What are your comments on the current fee approach for the electricity FRC function?

We consider there are particular arguments that need to be considered in regards to charges the FRC function. Our previous arguments made in regards to charges for Market Customers for NEM function (allocated and unallocated) suggested there needed to be a rebalancing between fixed ($/customer connection point) and variable charges ($/MWh consumption) to a Multi-Part tariff.

With regards to FRC function, we note the fees cover 'operations' and no longer 'establishment'. Given FRC operations are related to the transfer of customers by connection point, it is arguable that charging 100% of the AEMO budget on the basis of $/customer connection point would be: more reflective of involvement 2.11.1(3); not discriminate 2.11.1(4) and economically efficient (satisfy the NEO).

However to charge 100% of the FRC budget on the basis of $/customer connection point would not be consistent with our general recommendation for Market Customer tariff to change to a Multi-Part tariff. It may also not satisfy clause 2.11.1 (1) which requires the tariff be simple, because the FRC tariff would differ from the other Market Customer tariffs.

Is recovering electricity FRC costs on a connection point basis more appropriate?

For the reasons above, we agree but only to the extent that a proportion of costs should be allocated on a $/connection point basis, as this is consistent with our overall recommendation that costs be charged to Participants using a Multi-Part tariff.

AEMO welcomes comments on the concept of having a staged implementation if material changes are proposed to the fee structure and also the types of changes that may warrant a staged implementation.

We consider it unnecessary to have staged implementation for a new structure of fees. In recent years AEMO has, as a result of changes to the Rules, changed the recovery of network support and control ancillary services and system restart ancillary services. These changes have resulted in changes to settlement amounts that Participants have managed effectively.

In any case in:

- typical retail contracts for commercial customers fees are passed through to consumers;
- regulatory determinations fees have been included by the regulator (QCA); and
- those jurisdictions where there is no price regulation, retailers are fully able to adjust their tariffs if they are given sufficient notice.

AEMO fees are a small proportion of the overall tariff and any change will be immaterial to other potential changes in costs (such as network, environmental subsidy and wholesale energy costs).

For these reasons CS Energy can see no reason for staged implementation of a new fees structure.

What are your comments on the current registration fee structure and the proposal to determine and set the actual amount of the registration fees for each application type via the annual AEMO budget and fee setting process?

We have not considered this matter.

What are your comments on how to charge NEM PCF fees to Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers?

CS Energy does not understand why generators and MNSPs should have to pay the premium to insure themselves from errors by AEMO. We assume this may be because of the reflective of involvement test 2.11.1(3). In a general sense, our earlier comments regarding charges for generators and MNSPs apply.

What are your comments on charging for incremental services fees where a specific service is performed?

We have not considered this matter.

We welcome your comments on any other issues relating to the structure of Participant fees in AEMO's electricity markets.

The following table presents some options regarding the suggestions we have made in this response to the consultation paper, specifically for Market Customers.

Given we have recommended a $/customer connection point tariff or proportion thereof, the table shows Option 1 which has 100% of AEMO's Market Customer budgeted revenues for 2015-16 charged on a $/NMI basis. This results in an annual increase for a 5MWh customer of $4.38. Option 2 only allocated 50% of AEMO's Market Customer budgeted revenues for 2015-16 on a $/NMI basis and therefore the increase is only $2.19 per annum.

In this consultation we have stated that the 100% fixed tariff for generators is dynamically inefficient and that it would be efficient to either charge this on a $/MWh basis or reallocate the cost to Market Customers. In Option 3 we have reallocated only 50% to Market Customers, on the basis that a there remains 50% of allocated generator costs charged on a fixed basis (consistent with a multi-part tariff). Otherwise Option 3 is the same as Option 2. This option results in an increase of $2.95 per annum for a customer consuming 5MWh per annum.

	2015-16	Option 1	Option 2	Option 3
Industrial (GWh)	46,995	100% $/NMI	50% $/NMI:$/MWh	50% $/NMI:$/MWh, plus 50% allocated generator costs
Residential Commercial (GWh)	128,992	Removes cross subsidy between larger and small users	Rebalances tariff to multi-part	Rebalance Customer tariff to multi-part and avoids charging variable part to generators (whist reducing the dynamic inefficiencies of the existing generator tariff)
NMIs	8,850,000			
AEMO budget				
General unallocated	$20,053,000	$20,053,000	$20,053,000	$20,053,000
Allocated	$25,267,000	$25,267,000	$25,267,000	$25,267,000
FRC ops	$6,474,000	$6,474,000	$6,474,000	$6,474,000
NTP	$3,658	$3,658	$3,658	$3,658
Generator	$21,524,000			$10,762,000
Total Customer		$51,797,658	$51,797,658	$62,559,658
Fee $/MWh	$0.29		$0.15	$0.18
Annual cost at 5MWh	$1.47		$0.74	$0.89
Fee / NMI / year		$5.85	$2.93	$3.53
Total	$1.47	$5.85	$3.66	$4.42
Increase/ NMI/ year		$4.38	$2.19	$2.95