VICTORIAN RENEWABLE ENERGY AUCTION SCHEME

Consultation paper response

Edify Energy Pty Ltd

Table of Contents

1 Scheme structure 2
2 Payment structure 5
3 Contracting elements 8
4 Scheme administration and cost recovery 11
5 Auction evaluation principles 12
6 Conclusion 15

1 SCHEME STRUCTURE

How can the Department ensure that a pipeline of projects will be ready to meet the Government's targets for 2020 and 2025 while maintaining appropriate flexibility for Government to adjust the scheme where required?

Policy and mechanism clarity, and lead-time are the key elements that will provide the confidence for development activity to be initiated and result in (good) projects being brought into reality. Considering there is a relatively limited window to deliver an estimated 1,800MW of additional renewable energy capacity in time for a 2020 commissioning date, it is in the scheme's interest to set an aggregate 2020 capacity target as soon as possible. The timelines are already tight to have meaningful capacity operational by 2020.

At this point, it is also critical that the Department provides a very clear and firm auction roll out plan spelling out the MW of capacity to be auctioned and the technology split of that capacity for each calendar year to 2020. Uncertainty as to that roll out plan will stifle development and increase the risk that there will not be a pipeline of projects ready to meet the Government's 2020 and 2025 targets. Clarity on the specific details of the auction mechanism and eligibility criteria should also be announced as soon as possible. There should be a commitment to stand by any announced incremental auction timeline, mechanism and eligibility criteria so that development activity can confidently target timing milestones around known auction dates. Allowing a possibility for significant change will introduce an element of uncertainty into the scheme and compromise the development signal to meet the 2020 target.

The separation of 2020 and 2025 targets permits a flexibility breakpoint. The period immediately following the 2020 delivery would provide an appropriate time to assess the scheme's effectiveness and make amendments accordingly.

In relation to the 2020 targets, the Department (following the Victorian Government LGC auction) will have a view as to the state of readiness of many projects. They are the 'low hanging fruit' or present the 'quick wins' for Government to get some momentum in the process and to take steps in the very near term to rapidly bridge the 1,800MW gap to the 2020 new generation target.

How much notice should be provided to industry of upcoming auctions?

As a general rule, Edify Energy proposes robust eligibility criteria as a pre-requisite for participation in auctions. Bidding into the auctions should not be costless. In addition, the greater the forward clarity on auction timing and pre-requisites, the more confidently projects will be able to progress development activity and be in a position to participate.

It is expected that initial auctions will largely consist of incumbent projects that are already at an advanced stage of development. For new large-scale solar projects, there is a minimum 12-month lead time between project origination and achieving the three key milestones of land agreement in place, development approval and an invitation to connect.

In practice, a clear auction timeline should consist of windows of no more than a few months during which time an auction will take place. For a given auction, a period of 1 to 2 months (say 6 weeks) advanced notice should be given between an auction announcement and the auction to allow the compilation of documents to meet clear eligibility criteria and determine a bid.

Should capacity be auctioned in consistent capacity tranches (e.g. 200MW etc)?

Edify Energy does not hold a strong view on this. In general, our preference is for 'front loaded' auctions to reduce the risk of non-delivery of the targets, both in 2020 and 2025. Capacity tranches should be weighed up against allowing enough lead-time to the primary targets of 2020 and 2025 (i.e. not leaving too much too late) and the execution risk that any supply bottlenecks may pose from a single very large tranche.

At what frequency should auctions be held?

There are a number of considerations that should be made when setting auction frequency:

- There should be enough time between auctions to allow projects that were ineligible for one to progress through development activity in time for a subsequent auction;
- Equally too much time between auctions may unnecessarily preclude high quality projects that were close to, but just missed a key eligibility criteria deadline; and
- The fewer auctions held to reach a 2020 / 2025 target, the more competitive tension will exist in each auction.

Edify Energy considers auctions spaced every 9 months to appropriately balance these considerations. 6 monthly auctions may well be too short and time frame and 12 months too long.

What proportion of scheme generation should be dedicated to solar projects?

In our opinion, large-scale solar will, even in Victoria, prove to be the technology that provides the lowest cost generation. For the Government to benefit from this it needs to actively promote solar in the short-term to enable supply chains and construction efficiencies to develop in Victoria.

The current proposal for 20% is appropriate, but should represent a minimum. Diversification of the renewable technology mix provides benefits to the network and the market and, while the generation profile of large-scale solar is variable, this variability is relatively predictable as evidenced by greater certainty between forecast and actual production and the ratio between P90 and P50, compared to competing technologies. This 20% of the total capacity to be auctioned by 2025 should be targeted by the earlier 2020 milestone to achieve the full benefit of learning and improve the competitive tension of auctions held in the 2020 to 2025 period.

Solar and wind should not be auctioned separately. Rather, all auctions should be technology agnostic (i.e. solar and wind compete against each other in the same auction), but have a minimum capacity threshold for solar, that on aggregate represents the targeted ambitions suggested above. Technology agnostic auctions will result in more efficient outcomes in the event the competitiveness of solar markedly improves over the target period, while still maintaining a minimum level of solar capacity is deployed. Such an approach also allows co-located solar / wind projects to participate.

Should the proportion of solar be different pre and post 2020 to allow a solar pipeline to develop and technology costs to come down?

Yes, for the reasons noted above. Reduction in solar costs worldwide can be linked to the volume deployed in individual markets and not just time, with local learning providing much of the cost reduction scope. For example, the balance of system is a key cost driver for large-scale solar that does not have the same global commoditised cost reduction pathway as the modules, inverters and to a lesser extent frames. Equally, reductions in the cost of capital as local investors become more familiar with the risk attributes (primarily construction and volume / resource) are a significant driver of project economics. In order to realise these cost reductions, it is important to deploy volume in the local market as rapidly as possible.

Are there any other matters the State should consider when setting the scheme's technology split?

Subject to some comments in section 5 below, we think the State has its priorities for the auctions appropriately set.

As indicated above, auctions should be technology agnostic with minimum solar levels (to 2020) to permit the competitiveness of solar and wind to play out.

What is the best way to treat LGCs under the scheme to enable successful proponents to secure project finance, ensure scheme costs are minimised and ensure adequate market interest from industry to participate in the auctions is attracted?

Edify Energy prefers the approach outlined whereby LGCs are included within the auction process to be resold by Government in a bundled power and certificates arrangement. This is the conventional approach taken in the commercial offtaker market and the best way to ensure the revenue certainty required to attract low cost sources of capital to projects.

What are stakeholders thoughts about complementarity/additionality if the Federal RET were extended/expanded?

Edify Energy agrees that taking a complementary approach to 2020 is appropriate. Thereafter, additionality is important (in the absence of expansion of the RET) to prevent a structural oversupply of certificates in the market and potential for price collapse. Note that expansion and extension are different in this regard, with an extension of time not removing the price risk of surplus certificates.

We think that the Departments proposals in this regard are appropriate.

2 PAYMENT STRUCTURE

Do stakeholders agree with the proposed CfD payment structure approach?

Yes, with some caveats.

CfDs are a well-understood mechanism that have been successfully employed in both local (e.g. ACT) and international (e.g. the UK) markets. These derivative structures provide the benefit of revenue certainty, while ensuring the complete participation in and efficient functioning of wholesale markets.

A contract structure currently commonly employed by commercial offtakers in the market is the ISDA 2002 Master Agreement coupled with the 2006 Australian Electricity and 2013 Australian Environmental Addenda. This structure is a derivative swap arrangement between the buyer and seller, which effectively replicates a CfD structure.

Edify Energy considers that consistency between what is currently found in the market and any proposed structures is important for investor familiarity and also to ensure that growth in the renewable sector as catalysed by this Government-led scheme translates well into further opportunities with commercial offtakers meeting mandatory LRET obligations.

Importantly, projects' value-for-money should be assessed on the top-up to the strike price required, not the strike price bid itself. This approach better recognises:

- That electricity is a commodity with a value that differs according to the time-of-day value; and
- The top-up amount is the true economic cost to Government, not the value of the strike price. For instance, a project with a higher strike price, but generating in high-price periods of the day may constitute a lower economic cost to Government than a project with a low strike price generating during low price periods.

With a view to begetting the lowest cost of capital into the best projects (and therefore the lowest strike prices), we believe that 20 year:

1. One-way CfDs (like the QLD Solar 120 program), even in nominal terms; or
2. Two-way CfDs in real terms,

will produce the best 'value for money' outcome for the State.

If a CfD payment structure is used, on what basis should a NEM reference price be set? (e.g. monthly average, half hourly NEM price)?

Edify Energy has a strong preference for setting the reference price as the half-hourly Victorian Regional Reference Node price. There are a few reasons for this:

- As correctly pointed out, the CfD contract is designed to achieve certainty and stability of revenue. Using monthly settlement for the CfD contract against the half-hourly settlement achieved by trading power in the NEM introduces a basis risk that erodes some of this benefit of revenue certainty and stability. For instance, should the captured price of the project be less than the monthly average price, the contract will have a degree of missing-money for the project, and vice-versa for Government;

- The ISDA structure mentioned above that is currently employed by commercial offtakers is settled against the half-hourly price. Considering there is already familiarity in the market with the principles of half-hourly settlement, investors will look kindly to an equivalent structure, particularly when deriving bid prices. This logic can be equally applied to projects' improved preparedness for commercial sector opportunities; and
- In order to correctly assess projects on a top-up basis, the time-of-day attributes that half-hourly settlement provides is necessary.

What would be the impact of adding a floor price to cap the total payment applicable in any one period?

With a floor price of zero, projects will still rationally bid into the wholesale market to a level equal to:

$$minimum\ bid = -(CfD\ stri\quad price - SRMC)$$

As the SRMC of renewable assets is very small an approximation to this is simply negative the CfD strike price.

In forming auction bids, projects will therefore need to take a view of two things:

- The frequency of negative price events; and
- The magnitude (i.e. how negative) of these negative price events, with the greater the decrease below zero, the less revenue received up to a zero revenue limit at negative the CfD strike price.

Although ideally revenue uncertainty around negative price events is not a risk a project would look to take on, it is a risk that could be priced.

A floor price higher than zero should not be considered.

Do stakeholders agree that payments should be made under the scheme based on energy delivered as defined above? Are there other ways that stakeholders consider are possible to provide locational signals to projects to ensure they are appropriately sighted on the network?

Payments should be referenced to the Victorian Regional Reference Node, such that projects are taking on MLF / DLF risk and locational signals become one of the decision criteria at the point of project origination. This is the standard approach accepted by most projects entering into commercial offtake agreements.

Do stakeholders consider that any alternative payment structures could be employed for the scheme, such as a fixed payment approach? If so, what are the relative advantages and disadvantages of these options?

Edify Energy does not consider taking non-standard approaches will add value to the scheme outcomes. It will likely only serve to complicate a process that has been successful in other jurisdictions and will also represent a departure from what is found in the commercial sector. Efficiency (based on market standard practices) will reduce costs for the State and improve the outcomes.

Do stakeholders agree that a fixed payment approach would be less likely to address the barriers faced by project proponents in relation to attaining project finance, resulting in lower value for money bids?

Yes. It would also increase execution risk and potentially compromise the ability for staged capacity targets to be met. Simultaneously relying on revenues from the commercial sector and Government presents an execution risk should the terms or credibility of the commercial sector agreement change post Government contract award.

3 CONTRACTING ELEMENTS

Are the above contract elements broadly appropriate?

In the event that the LRET scheme is altered or repealed, there should be no change to the contract (i.e. Government assumes this risk).

Within the contract range of 10 to 20 years, is there an ideal duration, particularly with the aim of minimising project financing costs?

As a minimum, the contract tenor should be until the end of the LRET period (30 December 2030) to insulate projects against structural risks in the price of LGCs. Beyond that, the longer the contract tenor, the lower the overall cost of capital of the project is likely to be achieved, considering both the type of equity investor and the terms on debt. This will translate into value to the Government by way of lower bid prices.

We strongly recommend 20 year contracts (with one-way CfDs).

What would be an appropriate project delay threshold for contract termination clauses?

Sunset commissioning dates should be minimally set around the time required to order and receive the longest lead-time item. In the case of large-scale solar this will typically be the transformer. A lead-time of 12 months is appropriate in this case.

We prefer termination clauses that do not have an arbitrary date, rather they look at the cause of the delay and impose a best endeavours remediation plan on the generator. That said, most delays in a large-scale solar plant should be able to be remedied / corrected in 12 months.

Would quarterly payments have a significant impact on financing costs compared to monthly payments?

Monthly settlements would be preferred and are not considered to represent an overly onerous administrative, monitoring or transactional burden provided systems are well arranged. Settling against the final AEMO statements (as opposed to preliminary statements) would reduce the need for resettlements as well as provide an independent monitor / calculation agent.

What are the implications of a two-way CfD?

A one-way CfD is our strongly preferred structure. We have seen first-hand how it leads to a lower cost of capital. Once the market price is above the reference price, there is no cost to the State. Further by offering some of that 'upside' to the generator, a lower strike price can be bid.

Nevertheless, a two-way CfD structure is appropriate as it is a well-understood mechanism with precedence both at a Government level and in the commercial sector.

What do stakeholders think about the generation requirements being considered? Where maximum and minimum generation volumes are contained in scheme contracts how should these be set?

No maximum or minimum generation limits should be set. This is for a number of reasons:

- The projects at all times have a commercial incentive to maximise generation and achieve greater revenues. This is ensured through considered upfront design, use of a quality EPC contractor and components, and a properly planned and resourced O&M program consisting of both preventative and corrective maintenance;
- A pre-condition to participation in the auction should be an independent yield assessment provided by a competent and qualified technical advisor. This should serve as a mitigant against the volume risk (both positive and negative) to Government. Government should also appoint a technical advisor to review project technical details, EPC contracts and O&M contracts as key eligibility criteria to ensure that project quality is paramount from day one and maintained; and
- Introducing a minimum performance requirement with some sort penalty (e.g. mark-to-market liquidated damages) regime is a misappropriation of risk. In the unforeseen event that the project generates far below expectation, the capacity for this individual project SPV to absorb the cost of this shortfall is likely to be far less than the Government across its portfolio of many projects under contract. This risk ultimately translates into a project bankability concern or premium in the bid price and a loss of value for Government.

If a minimum performance requirement is put in place, there are a number of circumstances which should be exempt from counting against this level. These circumstances broadly coincide with events that are outside of the project's control and include:

- Instructions issued by AEMO (network curtailment or otherwise) that limit the output of the plant;
- Force majeure. If for instance an unforeseen event incapacitates the plant, this should immediately revoke any minimum performance requirement;
- The requirement should be structured such that it is immune to changes to MLF / DLF so projects are not overly exposed to a risk that other projects connect in close proximity; and
- Where a floor price of zero is in place and the project takes a decision to curtail its own generation due to negative price events of low enough level for generation to be uneconomic.

Moreover, if a minimum performance requirement is in place, a cure regime should be set up such that projects can make up for lost generation in a subsequent 12-month period (say) or bank any excess generation above P50 against a future minimum performance requirement breach.

Are there any other contract elements that should be considered?

The contract strike price should be annually indexed to CPI (All Groups). This permits a better alignment between revenues and the underlying fixed costs of maintaining the assets. Moreover, the long-term yielding type of investors that are likely to be attracted to a long-term contract with a sovereign counterparty will have a preference for indexed revenues.

In the absence of indexation to CPI a structure, then the one-way CfD structure should be employed (if not already) as the one-way nature of the contract permits generator access to inflation over time through inflationary rises in the wholesale electricity price.

Two other elements that would assist with enabling more renewable energy deployment and generation are:

- Streamlining the grid connection process (not making an application costless) by looking at the characteristics of a utility scale renewable energy power plant, compared to a conventional power plant. We are prepared to produce all necessary reports for a grid connection process, but do not want to be producing reports / grid studies at a stage in the process where they are not of value to the Network Service Provider; and
- Enabling virtual net metering and reduced network charges for renewable energy generators selling directly to end users. This will facilitate (a) the opening up of competition in the retail market and (b) the acceleration of corporate buyers into the market. It will also prevent the ‘death spiral’ for networks and the push for consumers to go ‘off grid’.

Are any of the elements likely to lead to perverse outcomes?

Edify Energy does not anticipate any elements will lead to perverse outcomes.

4 Scheme administration and cost recovery

Edify Energy does not hold strong views on the mechanism used to recover the scheme's costs. However, in order to achieve maximum value for Government, it is important that whatever structure the cost recovery mechanism assumes, the credit rating of the CfD contract is consistent with Government's credit rating.

5 AUCTION EVALUATION PRINCIPLES

What do stakeholders think of the proposed evaluation criteria set out above?

Edify Energy are proponents for stringent pre-conditions to be met to be eligible to submit a bid. Only the best, most credible, construction ready projects should be entitled to bid. Stringent eligibility criteria will significantly reduce the execution risk of participating projects, ensuring that auction outcomes are a true reflection of the ultimate capacity deployed. These pre-conditions should minimally include:

- A bankable land agreement is in place;
- Development approval has been granted with all pre-commencement of construction conditions discharged (or alternatively, at least advanced progress and clear line of sight to fulfilling all pre-commencement of construction conditions);
- Evidence that an invitation to connect from the relevant network service provider has been offered or is in progress and supported by the appropriate network service provider in writing;
- Preferred contractors (EPC and O&M) have been nominated with transparent quotes and bankable heads of terms, if not full form contracts;
- A credible procurement and construction timeline is in place, with key risks identified and mitigated;
- The source of equity is known;
- Where debt is to be provided, indicative debt terms are known; and
- A requirement for projects to post a bid-bond of a sufficiently high level to dissuade non-credible bids and failed auctions. This is particularly important for pay-as-clear auctions.

As outlined earlier, the value-for-money assessment should be made against the expected top-up required by Government and not the level of the strike price. This approach is a more accurate reflection of the economic cost and value to Government of entering into the contract as it takes into consideration the time-of-day value of the electricity generated by the project, not just the volume.

In order for this assessment to reasonably occur Government will need to take a view of future electricity prices on a relatively granular basis (say hourly). This view could be provided by one of a number of independent market price projection providers. Projects would also need to submit a forecast P50 generation profile to the same level of granularity, that could be subject to an independent technical advisor assessment.

Do stakeholders have views on how evaluation criteria might be weighted?

Execution risk and value for money should form the primary evaluation criteria. The first of these should be linked to the proposed timely construction and operation criteria.

Edify Energy views economic development benefits to Victoria as more of an outcome than an evaluation criterion. This is because, for large-scale solar, what is good and cost-effective from a project perspective will typically be good from a Victorian economic development benefits perspective. This is particularly true of local job creation, content and supply chain development for balance of system components (the high value components such as modules, inverters and frames will invariably be procured from international suppliers). Therefore, although economic development benefits should form a separate evaluation criterion, its weighting should be relatively small.

Costs required to augment networks to make an individual connection should be reflected at a project level as opposed to sitting with the Network Service Provider and passed on as costs to consumers. Equally, benefits that accrue to the network on account of a connection should be reflected in embedded benefits to the generator (such as avoided TUoS or network support payments) that improve the project's economics. Therefore, these factors will ultimately impact the competitiveness of the project bid, so should not form an evaluation criterion in and of itself. Connections into unstable parts of the network will present a volume risk to Government, which should be accounted for when assessing projects (in addition to the other volume risk attributes outlined below). It should however be noted that generally large-scale solar enhances grid (voltage) stability, which is largely underappreciated in the current market. We have been on an education journey in that regard.

The approach outlined in the consultation document of favouring projects with higher capacity factors to make a greater contribution to targets would unfairly discriminate solar, which will typically have lower capacity factors than that of wind. An alternative to proposing MW-based capacity targets is to propose MWh-based generation targets, in much the same way as the LRET. This would insulate against this capacity factor assessment distortion as it is ultimately generation volumes (in a technology-agnostic way) that is the important target for Government. In order to effectively implement a generation-based target, volume risk should be included as an evaluation criterion. This should be based on an independent yield assessment that takes particular note of:

- The P50 generation forecast for the individual project;
- The record between forecast and observed output on a technology basis, where a greater difference represents a volume risk in advance of project execution; and
- The spread between forecast P50 and P90 yield estimates, where a greater difference represents a volume risk during operation.

Community engagement is another key area of project development and another example where typically what is good for the project is also good for the community. Therefore, although it is correct to include community engagement as a separate evaluation criterion, its weighting should be relatively small as poor community engagement will typically manifest itself in execution risk (especially where the planning approval has been obtained and the scope of the project is well known within the local community). An inability to secure development approval, discharge pre-commencement of construction conditions or sustained objection to the project proceeding highlight poor community engagement.

Are there other evaluation criteria/principles that the Government should consider to ensure the scheme meets its objectives?

Edify Energy would prefer pay-as-clear auctions as they lead to more efficient auction outcomes due to improved cost-discovery attributes and reduced incentives to include any premiums in bid prices. Pay-as-clear auctions better and correctly reward cost-efficient projects for their competitiveness.

As outlined above, a volume risk evaluation criterion should be included, particularly in the event that generation-based targets are set in place of capacity-based targets.

Are the costs associated with developing a proposal to bid into the scheme based on addressing the above criteria effectively likely to be prohibitive?

No. None of the evaluation criteria suggested represent steps that a project developer wouldn't have to undertake and carefully in order to successfully execute a project in the absence of a Government-led scheme. Rather a greater cost would be failed auction outcomes leading to a lack of confidence in the scheme if projects that represent high execution risk are awarded a contract and then unable to deliver. Although an unsuccessful outcome for a project will necessarily incur high development costs put at risk, the scheme is still providing opportunities for successful project development that may not otherwise exist.

What would be appropriate minimum project sizes (both in general and for large-scale solar)?

Placing limits (upper and lower) on project sizes should generally be avoided as it can constrain the opportunity to optimise projects, each of which will have individual determining characteristics. Just as we are advocating technology agnostic auctions (after an initial minimum for solar), we also believe that projects of any size should compete within the aggregate auction limit. The smallest large-scale solar plant in the ARENA shortlist is about 12MW AC, which may well represent an appropriate minimum size bearing in mind the administrative cost to Government of assessing the eligibility of projects.

Would there be benefit in asking proponents to submit expressions of interest to participate in the auctions to ensure only more advanced projects proceed to the full evaluation round and that costs are minimised for project proponents where possible?

As outlined above, Edify Energy are proponents of stringent eligibility criteria to be met as a pre-condition to participating in auctions. If Government views that the best way to ensure this is through a two-step EOI and evaluation process, then this is acceptable. Depending on the timing and frequency of auctions this may be a challenge to administratively manage however.

Given the recent Government LGC auction, the Department would be well aware of the most advanced / construction ready projects in Victoria. A two-stage process for the initial auction would appear inefficient in the circumstances.

6 CONCLUSION

Edify Energy applauds the Victorian Government for taking the initiative to propose strong 2020 and 2025 renewable energy targets. We are confident that if implemented correctly, this policy will have the desired effect of sending a strong signal to the renewable energy sector to develop projects in Victoria, and in doing so meet the Government's objective of creating jobs, stimulating economic development and reducing greenhouse gas emissions.

In addressing these consultation questions, the key areas that we have identified in order to implement an effective policy mechanism can be summarised as follows:

- Clarity on and commitment to the aggregate 2020 and 2025 targets, coupled with a clear auction timeline to 2020. The first auction should occur in very short order following the recent preparation of bids for the Victorian LGC tender;
- Technology agnostic auctions with minimum levels of large-scale solar, corresponding to the overall 20% objective;
- Front-loading this minimum solar target so that 20% of the total 2025 target is met by large-scale solar by 2020. This enables the acceleration of the learning curve and cost-reduction trajectory, which has a high dependency on local deployment, such that the competitive tension between wind and solar in the post 2020 period is greater;
- Generation-based targets (in place of capacity based targets) to remove the distorting effect that large differences in capacity factor between technologies may introduce. These generation-based targets should be accompanied by a volume risk assessment at the project eligibility stage;
- 20 year bundled one-way CfD products, similar to that proposed for the QLD Solar 120 program. The low cost of capital that such contracts unlock will be reflected in high value bids to Government;
- Reference prices based on the Victorian Regional Reference node and to half-hourly granularity to remove the basis risk associated with differences between contract and market settlements;
- Value-for-money considered against the top-up required of Government to the strike price and not the level of the strike price itself. This is a fairer reflection of the economic cost to Government as it accounts for the time-of-day value of electricity generated; and
- Stringent pre-conditions for auction eligibility, with a focus on project execution risk. This is crucial to ensuring successful auction outcomes and maintaining long-term confidence in the mechanism.

We look forward to participating in the auction processes in the very near future and adding to the renewable energy generation base in Victoria.

Please do not hesitate to contact us if any aspect of this submission requires amplification or clarification.
