RWE Supply & Trading Submission: National Energy Guarantee, Draft Design Consultation: March 2018

1 Summary and Overview

RWE Supply & Trading (RWEST) very much welcomes the opportunity to contribute to the consultation on the design of the National Energy Guarantee (NEG). RWEST is one of Europe's largest traders of power, gas, emissions and related global commodities. We act as a significant provider of liquidity and market maker across Europe's interconnected power, gas and emissions wholesale markets. RWEST is part of the RWE Group which is a leading pan European energy company with over 40 GW of installed capacity in Germany, the UK and the Netherlands. RWEST entered the Australian wholesale market in 2013 and is an active participant on ASX. This submission draws on our experiences in the Australian wholesale market coupled with our knowledge and experience of power and emissions market design and trading in Europe and North America.

RWEST has serious concerns about the proposed design for the NEG. The proposals threaten to fundamentally undermine the efficiency and integrity of the current electricity market and the associated financial hedging market. Obligations which require evidence of direct bilateral contracting between individual generators and retailers for bespoke characteristics fundamentally undermine the fungibility and liquidity of the spot and wholesale markets. The proposals as they stand also face several practical difficulties that will be difficult, unduly costly or impossible to overcome. Far from underwriting future investment in sustainable and secure resources, the proposals will lead to the inefficient operation and dispatch of generation and demand-side resources, sub-optimal investment, reduced retail competition and greater scope for the exercise of market power.

The aims of the NEG can, however, be delivered while retaining the current benefits of an efficient spot market for physical electricity and a deep and liquid wholesale market for risk hedging. This can be done by separating the emissions and reliability requirements of electricity from the physical delivery and pricing of fungible MWh and the financial hedging of those deliveries. RWEST would therefore propose a design featuring the following key elements:

- The **real-time spot market for physical electricity** would continue to price actual deliveries of physical electricity from all production sources and to all retailers and large consumers.
- The **financial hedging market** would continue to provide the opportunity for market participants to hedge the spot market price risk associated with their deliveries of physical electricity.
- An **emissions requirement** requiring retailers to meet an emissions intensity target by contracting with different generation resources with standardised "Emissions Requirement Contracts" which either:
    - refers solely to the emissions component of each MWh, i.e., be structured as a contract for a volume of "Emissions Intensity Certificates"; or
    - specifies the volume of MWh purchased, but with a floating price equal to the real-time spot price plus/minus any fixed premium for the emissions component.

- A separate, **centrally-procured reliability requirement** which would purchase MW capacity from generators in the form of reliability options. Reliability options would be purchased with a four-year lead time, e.g., in 2020 for delivery in 2024 with the option for an additional top-up procurement year-ahead if required (i.e. in 2023 for 2024). The procurement costs would be reimbursed by retailers in accordance with their contribution to total peak load. The volume of options sold by generators would be scaled explicitly (or implicitly) to the ability to dispatch that capacity to provide “firm” capacity.

This framework will deliver the emissions and reliability guarantees while allowing physical MWh to remain fungible in the spot market. This retains fungible pricing, production and dispatch of the plain energy component of each MWh which underwrites competition and market efficiency. The fungibility of delivered MWh is also essential to the efficient functioning of a liquid wholesale financial market for hedging.

RWEST would also recommend that the review is extended to the gas market. A transparent and liquid physical and financial gas market would significantly increase the scope for contracting and investment in the power sector by allowing generators to better manage the spread between gas and power prices. It would also provide signals for investment in gas assets as well as power assets. These forward gas markets would build on the short-term physical markets around the Wallumbilla hub that have become increasingly liquid.

Sections 2 and 3 below address the questions raised in the consultation on the emissions and reliability requirements respectively in more details and explain the reasoning behind the proposed approach summarised here.

Although not subject to the current consultation this framework could also be readily adapted to incorporate a day-ahead market. We offer some thoughts on how a day-ahead market could be incorporated into this framework in section 4 below.

2 Emissions Requirement

2.1 Summary: Resource-specific contracts will be required for emissions requirement

RWEST has serious concerns about the practicability and efficiency of the proposed approach to the emissions requirement. While possible to attribute the emissions under a power purchase agreement (PPA) with a specific resource, it will be difficult, inefficient or impossible to attribute emissions to contracts which do not reference a specific generation source or to attribute deemed emissions to financial and other hedging contracts. This would be further complicated by the interaction of the emissions requirement with the Renewable Energy Target (RET); retailers would effectively be trying to meet two separately identified, but overlapping, targets via the same contract pool. We have therefore concluded that a retailer-based emissions requirement <u>can only</u> be practically delivered with contracts that reference individual generation sources.

The separate contracting of individual generating resources, however, also removes the fungibility of each MWh in the spot and contract markets. This will undermine the efficiency of the physical market as plants respond to the incentives provided under the contract rather than efficient spot market price signals. The result will be inefficient maintenance, availability, scheduling and dispatch decisions.

A lack of fungibility in the physical market also threatens to destroy liquidity in the financial hedging market. (Indeed, market liquidity has already fallen in response to the consultation on these proposals.) Reduced liquidity will further undermine competition by removing efficient forward market signals for investment, maintenance and unit commitment and, longer term, making it harder for investors and new entrants to enter the generation and retail markets. An illiquid forward hedging market also increases the scope for generators to exert market power in the spot and associated contract markets to the detriment of electricity consumers.

Delivering the emissions requirement therefore requires the decoupling of procurement to meet the emissions requirement from the pricing and hedging of the underlying MWh energy component. RWEST would therefore propose that the emissions requirement is fulfilled via the development of standardised "Emissions Requirement Contracts (ERCs)" which achieves this decoupling in one of two ways

- The ERCs would refer solely to the emissions component of each MWh purchased from the individual resources and could and would be separately procured to the associated MWh; or
- The ERCs would specify the volume of MWh purchased from each resource, but with a floating price equal to the real-time spot price plus/minus any fixed premium for the emissions component.

The standardised ERCs would be available for all generation sources not covered by existing PPAs. Resources covered by those PPAs or resources owned by individual retailers could have emissions directly attributed according to the generation source. Alternatively, existing PPAs could be revised to incorporate these requirements while respecting the other commercial terms of those agreements. It would also make sense to merge the emissions requirement with the RET to ensure efficient emissions abatement across the board rather than with specific sub-targets for individual technologies.

The result of either approach is that each and every MWh remains fungible and, at the margin, responsive to efficient spot market price signals. This crucially retains the incentive and ability of market participants to participate in liquid, fungible forward markets to hedge spot market price and volume exposures.

The following sections explain these conclusions further and address the specific questions raised in the consultation.

2.2 Applying the emissions requirement

The volume purchased on the wholesale market may not be the appropriate basis for the emissions requirement. These volumes may be net of generation that is either onsite or embedded in local distribution systems. This could result in significant and costly distortion to the market by providing inefficient incentives to invest in relatively highly emitting distributed resources. Gross measures of generation and supply/consumption would therefore be preferable.

In respect of the process for calculating a retailer's requirement, we have serious reservations about the tiered approach to attributing emissions to contracts which do not reference individual generation sources and/or the application of default factors for "uncontracted emissions". RWEST would therefore propose a system whereby contracts for emissions intensity are specific to individual generating plants and cover all plants but are decoupled from the delivery and hedging of the MWh energy in the spot and forward markets.

2.3 Contracting and emissions

2.3.1 Contracts that specify a generation source

It is possible to attribute emissions to specific generation sources and to have plant-specific contracts relating to those emissions to fulfil the emissions requirement. However, bundling the emissions intensity element with the production of the underlying power within a "Power Purchase Agreement" PPA paradigm will be inefficient and unworkable. As we outline in the following sections, bundled contracts covering several generation sources will not work and the only way in which the emissions requirement could work is if contracts are plant specific. As a result, the PPA paradigm is likely to have to apply to all generation sources to meet the emissions requirement. However, having all plant contracted individually under PPA style arrangements will lead to significant market inefficiency. Plants will respond to the terms of the contract and not spot market signals in making their maintenance, availability, unit commitment and output decisions. This is likely to lead to errors in the availability and scheduling of plant and lead to plant not generating when efficient to do so and, as noted in respect of the RET contracts, generating to meet the contract even when it would more efficient not to generate.

The potential for this inefficiency is illustrated further by the question referring to contracts for a portfolio of plants, e.g., the use of gas plant to "firm up" zero emissions plant. The only way to guarantee a fixed "blended" emissions figure under such a contract would be to ensure that the gas plant runs in a fixed ratio to the renewable output. This would clearly ignore market signals on whether gas, or indeed that specific gas plant, should actually be running at specific times. From an efficiency perspective, therefore, the emissions requirement would require specific individual sources to be identified and contracted separately.

It is precisely these inefficiencies that underwrite the need for fungible spot and hedging markets. As noted above, a move to contracting for individual resources will, destroy forward market liquidity, undermine competition and increase the scope for generators to exercise market power. It is for this reason that we propose that procurement against the emissions requirement is decoupled from energy procurement via forward and spot markets.

2.3.2 Contracts that specify emissions per MWh but not a generation source

The consultation envisages pooling together several "generators with similar emissions in a region to create a more standardised contract that is more fungible and easier to trade". We see several practical difficulties associated with this concept.

- **Lower emissions generators have no incentive to enter the contract.** All else being equal, we would expect generators with lower emissions intensity to command a premium for their output. Lower emissions generators will therefore want to market their emissions intensity directly rather than via a portfolio contract. Any portfolio contract is therefore likely to unravel.
- **It will be difficult, if not impossible, to reconcile actual emissions to contracted output.** The actual output of individual plants and the offtakes of individual retailers will differ over the course of the day and during the year. Less efficient plants are likely to have lower load factors and to be relatively more polluting. To correctly attribute the emissions to individual retailers accurately would therefore require the calculation of emissions intensity for every settlement period. This is neither necessary nor practical.
- **Retailers with beneficial profiles have no incentive to enter a portfolio contract either.** Retailers with profiles weighted toward consumption at times of lower emissions intensity will want to mirror that in their contracting rather than contract with a portfolio with higher emissions intensity.
- **Inefficient maintenance, scheduling, dispatch and consumption.** Even if some way could be found to overcome the difficulties above, the "stapling" of an average emissions profile to a range of different resources is likely to lead to mispricing of the output from the portfolio which would lead to inefficient dispatch and consumption. This pooling of resources would remove the (very beneficial) incentive for retailers, large customers and storage operators to shift their load efficiently to periods of lower emissions intensity (i.e., to consume or to charge storage when the wind blows and the sun shines).
- **Reduced competition and reinforcement of market power.** Any attempt to coordinate generators into a contracting portfolio is likely to significantly reduce competition and reinforce market power. Indeed any such agreement arguably falls foul of competition rules

by restricting, distorting and preventing competition via a contract that explicitly applies a standard “non-competing” emissions profile to differentiated resources.

In summary, physical contracts based on a portfolio of resources are highly unlikely to provide a stable basis for contracting. Even if it could be made to work, it would either be hugely complex to implement in practice and likely to come at a significant cost in terms of market inefficiency and reduced competition.

2.3.3 Contracts that specify neither emissions per MWh nor a generation source and unhedged load

At best, applying a deemed emissions intensity to contracts that specify neither emissions per MWh nor a generation source present the same problems as applying an average emissions intensity across a pool of resources. However, deeming emissions intensity for financial hedges presents several further, insurmountable challenges.

The most fundamental problem is the mismatches between physical and financial hedging requirements and an apparent misconception that power is either physically contracted or financially contracted and that the combination of the two will tally with actual physical production. The reality is significantly more complex:

- Generation resources might be both physically contracted and financially hedged. For example a plant might have a PPA in which the energy price is indexed to spot market prices.
- Retailers may sell on indexed contracts, flexible tariffs or fixed rates which will affect whether and how they choose to hedge those risks.
- Physical spot deliveries may remain unhedged with financial swap power contracts and/or be over-hedged. This happens clearly for unforeseen production/consumption in the spot market.
- Fossil generators might choose to hedge with a gas-power spread swap rather than outright power swaps.
- Generators and retailers may choose to hedge their volume and price risks with financial options rather than financial swaps linked directly to their expected offtakes.
- In any liquid market, the financial market will “churn” a multiple of the underlying physical volumes.

All of this presents an insurmountable challenge in terms of deciding which contract the deemed emissions intensity might be “stapled” to. Would a retailer selling back a swap that was no longer needed qualify? If not, how could we distinguish this contract from a “genuine” first order sale by a generator? The consequence is that there will never be any ability for a one-to-one link between a financial contract and a physical MWh, before you even get to the question of the emissions intensity of that MWh.

Even if this were possible (and it’s not), deemed emissions intensity would not work in practice for stapling nor for unhedged load. The deemed emissions intensity would be based on the average intensity of uncontracted physical resources. Any resource with below average intensity would then have an incentive to contract directly rather than via the “deemed” portfolio. This would in turn increase the average intensity of the deemed portfolio still further prompting more resources to opt out

Even if these problems were surmountable, this attempted bifurcation between different types of contracting would be inefficient, distort competition and seriously disrupt market liquidity.

2.4 Flexible Compliance Options

The scheme we have outlined significantly increases the flexibility of retailers to comply. Decoupling of the Emissions Requirements Contracts (ERCs) from the pricing and delivery of the underlying power would permit secondary trading between retailers to meet their annual commitments. This would cover all mismatches between expected and actual running regimes for individual contracted resources. The remaining mismatch would represent the residual mismatch across the market between total emissions and the target with allowed emissions increasing with total consumption and vice versa. This significantly mitigates the uncertainty as to individual retailers’ requirements. While total emissions may be hard to forecast given year-to-year variation in load, relative emissions per MWh will be significantly more stable and forecastable from a known plant portfolio and as market participants observe relative fuel prices, availability and dispatch during the course of the year.

There will inevitably be some residual variation in total emissions resulting from good or bad years for wind, water and luminosity etc. Limited banking of overachievement can help to deal with this variation. However, we would question whether further flexible compliance options and deferred compliance were necessary or desirable at all for the following reasons:

- Compliance timetables could be used to permit some borrowing from future years. For example, the requirement to comply with Year X may take place several months into Year X+1. This could allow Emissions Requirement Contracts from generation in those months to be used against the compliance obligation for Year X.
- A hard obligation provides positive dynamic incentives for market participants to respond by shifting load to lower intensity resources during the course of the year.
- Moral hazard; insuring market participants against the late arrival of new, cleaner generation sources is in itself likely to delay the delivery of those new sources.
- The scope to use offsets would provide another efficient and flexible means of securing compliance.
- Deferral should face appropriate discount rates to ensure that retailers do not get a competitive advantage from deferral.
- A mechanism would also be required to collateralise deferred compliance to ensure that retailers did not benefit from the avoidance of their deferred obligations in the event of bankruptcy.

In respect of offsets, any limits on their use by each retailer should be framed as a percentage of their emissions requirement rather than an absolute limit per retailer. The latter, as envisaged in the consultation document, would undoubtedly promote the dilution of the limit by breaking into smaller retailers.

We appreciate that the scheme is intended to target emissions intensity to avoid uncertainty in the tightness of the constraint in response to natural fluctuations of demand from year to year. Ultimately, however, the constraint is imposed to reduce total emissions in the sector and the economy. Given that decarbonisation in other sectors is likely to increase electricity demand overall, we would expect the framing and evolution of the intensity targets to ensure that total emissions fall over time. Ideally, there would be some advance certainty over this process via transparent targets for absolute emissions reductions together with a defined feedback loop or reconciliation between annual emissions intensity targets and the absolute trajectory.

2.5 Reporting and Compliance

The proposed approach to compliance and reporting seems workable but incredibly complex and unduly expensive. A compliance registry will be essential to verify the emission intensity of the generation sources, to ensure that all emissions sources are accounted for and, crucially, that there is no double counting or surrender of specific sources.

We would note, however, that the proposed approach seems unnecessarily complex given the need to monitor a potentially large number of contracts to track entitlements to satisfy the requirement. This will be hugely costly for industry and consumers will end up bearing the costs. This process could be significantly streamlined by moving to a certificate-based system which attributed emissions intensity certificates to each generator according to their output and allowed the surrender of verified certificates against retailers' obligations. This would largely remove the need to register and reconcile the volumes in the Emissions Requirement Contracts against production and compliance volumes. As noted above this approach would also allow the emissions requirement and the RET to be merged into a single target which will reduce administration costs and increase the efficiency of abatement by targeting a single emissions reduction goal.

3 Reliability Requirement

3.1 Summary: centralised procurement of reliability options will work better than a reliability requirement on retailers

RWEST has fundamental doubts about the practicality of a reliability requirement placed on retailers. Specifically, we do not think an approach based on signalling a future need to retailers coupled with an expectation of action will be sufficient for the retailers to procure the required capacity. There are several reasons why a requirement on retailers to contract to meet the requirement is likely to prove unworkable:

- **Retailers' future peak demands are uncertain.** In a competitive retail market, retailers have no visibility or certainty over their future peak load in two to three years' time which creates a fundamental mismatch between the aims of the reliability requirement and an obligation based on retailers' (unknown) future customer profiles. A new entrant retailer may be very successful in five years' time, but not have to ability to fund any reliability gap in the meantime. Similarly, others may be required to fill any gap against a shrinking future customer base. It is therefore difficult to impose any requirement on future demand which is both fair and which does not distort retail competition.
- **Security, credit and collateralisation.** Retailers have no security over their future customer portfolios, they have few if any tangible assets to underwrite a commitment to back future capacity build. Any contracts that are signed are therefore likely to require collateralisation which is likely to prove prohibitively expensive for a long-horizon, multi-year capacity contract where the liquidated damage of non-performance is the value of lost load.
- **Retailers have strong incentives to under procure.** An uncertain future and the high cost of credit support, provide strong incentives for retailers to under procure against their likely future requirements.
- **The backstop of a "provider of last resort" removes any incentive to procure.** Not only are retailers unlikely to procure capacity voluntarily, they don't need to. Any failure to procure will be covered by centralised procurement and retailers will bear the costs. Rather than be on the hook for capacity they might not need, retailers get to pay just for the capacity that they use. Far from being a "backstop", centralised procurement will become the default option to meet the requirement.

If it is deemed necessary to underwrite future reliability, RWEST would therefore recommend a reliability requirement backed by the centralised procurement of capacity with retailers meeting the costs according to their annual peak consumption. The requirement could be met via the annual procurement of "reliability options" at a forward horizon of 4 years together with an annual "top up" procurement for the following year if required. The reliability options would be bespoke instruments for the purpose of meeting the reliability requirement. The following sections outlines the reasoning underlying these proposals in addressing the questions raised in the consultation.

3.2 Triggering the requirement

RWEST would propose that any reliability requirement should be introduced as an ongoing obligation from the outset rather than incorporating various stages and triggers for the reasons outlined below. The horizon of the obligation should not foreclose new build of any type of capacity, which would suggest an initial time horizon of around 4 years (roughly sufficient to build a new CCGT). This would see an obligation imposed in current Year for Year+4, e.g., a requirement in 2020 to procure capacity for 2024. Uncertainty about capacity developments in the interim period could be handled by incremental requirements in the interim, e.g., in 2023 for 2024. This would allow incremental procurement in the event that an unforeseen shortfall emerged (i.e., it would allow plant closures to be deferred and/or more expensive demand-side or small-scale capacity to be bought on line).

As noted above, we don't think that a decentralised obligation on retailers will work. The fact that retailers will not contract for future capacity does not, in itself, mean that a reliability obligation is necessarily required. Appropriate scarcity pricing – as practised in the NEM – can be sufficient to ensure that sufficient capacity is brought forward by generators in response to the prospect of future price spikes. There is no guarantee of when and to what extent the gap is closed if capacity is left solely to market, but market participants will have their own views on the likely level and duration of any future scarcity to fund their investment. The consultation acknowledges the ability of the market to fulfil this function with the concept of notification of a reliability gap, a period during which the gap might be closed voluntarily and a "trigger" for the reliability requirement.

A reliability requirement, however, largely erodes the market's ability to deliver investment even if it is intended as only a backstop measure. Rather than have market participants judge how likely scarcity is and invest in resources to offset that scarcity, there is a known threshold – the reliability standard – at which a retail obligation will kick in and, if that obligation is not delivered, central procurement will take place instead. This can remove much of the incentive for decentralised investment. Those with a more bullish view of scarcity, who might otherwise have built "early" in the prospect of scarcity rents are now assured that any gap will be closed in a timely and orderly fashion. They will now only invest against the central forecast and the obligated reliability standard. They may also prefer to wait to sell their capacity to a credit-worthy central counterparty than to sell it to a retailer or bear the investment risk on their balance sheet. In effect, the promise to intervene if the market does not deliver becomes the cause of the market's failure to deliver.

A decision to rely ultimately on a reliability requirement rather than the market is not a "conditional" decision, but an absolute one, and the requirement should be triggered from the outset. This is not necessarily a problem: if the market largely delivers the reliability standard, the cost of meeting the requirement should be minimal. Similarly, if the market was falling short of delivering the standard the requirement should kick in sooner rather than later in any case. An absolute, rather than a conditional, reliability requirement therefore also has the benefit of reducing the uncertainty and complication of precisely when and how we move between "market", "warning period", "intervention" and back again.

3.3 Qualifying instruments

The proposed approach of certifying the physical backing of existing financial hedging contracts is wholly unsuitable to meeting the reliability requirement. We are effectively comparing apples and oranges in several crucial respects:

- **Product.** Hedging instruments are used to manage future financial exposure on energy production (MWh) whereas the reliability requirement is targeting peak capacity (MW).
- **Tenor.** Financial hedging is typically dealing with a horizon of up to 2-3 years at the most, whereas we're looking for a reliability requirement that could get triggered at a horizon of 3 to 10 years.
- **Mismatches between financial and physical hedging and risk exposures.** As noted in respect of the emissions requirement, there are many reasons why financial hedge positions may or may not match the underlying physical volumes and any attempt to staple one to the other either won't work or will result in significant distortion to the wholesale contract market.

This is not to say that financial instruments cannot be used to meet a reliability or capacity requirement. Indeed 'reliability options" have been used to meet reliability requirements in New England and Colombia. The reliability requirements are delivered by buying call options with relatively high strike prices for the delivery of MW of capacity at peak times. Generators receive an upfront option payment in return for forgoing some of the benefits of very high prices at peak. Reliability Options provide strong incentives for generators to remain available at times of scarcity because they face a price exposure above the strike price up to the value of lost load if they're not available. Reliability options would therefore fit particularly well alongside the NEM given its strong focus in the spot market on scarcity pricing up to the value of lost load.

Reliability options can be designed with varying degrees of linkage to the underlying physical generation assets. For example:

- **Physically-backed reliability options** would be procured from all generators according to their ability to contribute firm capacity at system peak. This would require generator (and interconnector) capacity to be de-rated in line with expected unavailability due to unforeseen outage, wind availability, luminescence, interconnector switching direction etc. Different resources would accordingly have different derating factors; dispatchable thermal, hydro and biomass plant would therefore face relatively low derating factors when compared to interconnectors and intermittent renewable resources.
- **Implicitly-backed purely financial reliability options** would be procured up to the reliability requirement. Generators could sell directly, but other credit-worthy intermediaries would also be able to sell and take the financial exposure. Sellers would effectively determine their own view on the firmness of their capacity and de-rate their sales against physical installed capacity accordingly. Those selling purely financially would also still ultimately need physical backing for their financial position, as the only way to hedge the short exposure to scarcity pricing at peak would be to acquire title to generation at those times.

Crucially, reliability option schemes have to date involved the bespoke introduction of these instruments solely for the purpose of meeting the capacity requirement rather than attempting to piggy back on the use of other hedging instruments serving other purposes. The schemes have also involved centralised procurement of these options up to the reliability requirement with the costs subsequently recharged to retailers.

Decentralised models can be conceived with an obligation to buy reliability options up to a retailer's peak load. However, for the reasons outlined below, decentralised reliability requirements present significant practical difficulties in allocating and securing the requirement placed on retailers. We would therefore recommend the central procurement of the reliability requirement in the form of reliability options.

3.4 Allocating the requirement

There are significant difficulties in allocating a future requirement with a horizon of 3 to 10 years to competing retailer providers. As noted above, **i**n a competitive retail market, retailers have no visibility or certainty over their future peak load in two to three years' time, have few assets to back such long-horizon contracts and have strong incentives to underestimate their requirements. While an individual retailer's requirements could be assessed independently, in practice, it will be difficult or impossible to arrive at an objective and acceptable benchmark for applying the obligation to contract for future reliable capacity over such horizons Any projection from historic values for 3 or 4 years hence will face an understandable challenge from incumbents who are losing customers and future projections will be seen as having very little basis and presenting a significant barrier to new entrants. The high cost of credit support would also act as a significant barrier to entry for new retailers, could reinforce a need for vertical integration and/or restrict electricity retailer to companies with very strong balance sheets. This would further restrict retail competition unduly.

Reliability mechanisms tend to be based on centralised forecasting and procurement for precisely these reasons. Those decentralised options that have been adopted have also necessarily adopted a significantly shorter horizon with obligations and payments based on more readily observable and secure current metrics. For example, the French capacity mechanism is based around a rolling annual obligation to surrender capacity tickets. Pool-based capacity mechanisms in Spain and the former pools in the UK and Ireland also effectively charged a dynamic capacity price to retailers based on their current load.

Given the apparent desire in Australia to address the reliability gap across a future horizon of 3-10 years, we would therefore recommend a centralised procurement of reliability options to meet the reliability requirement. The annual costs of meeting this requirement would then be charged to retailers and large customers according to their peak load during the year. This option also has the advantage of allowing those large customers who can and do respond to high prices to avoid contributing to the need for – and therefore bearing the cost of - peak requirements.

The requirement should be expressed as a total requirement based on AEMO forecasts. The above difficulties mean that it will be difficult to verify the degree to which a retailer is contributing to the total and hence the responsibility to contribute to an increment.

3.5 Procurer of last resort

For the reasons outlined above, RWEST would recommend the centralised procurement of reliability options. This would obviate the need for a procurer of last resort.

Having a procurer of last resort within a decentralised mechanism would likely result in a shift to centralised procurement in any case. Given the difficulty in verifying a retailer's future load and their incentives to understate that load, there is likely to be significant under-procurement by retailers and a significant and increasing role for the procurer of last resort in any case. It would significantly increase certainty and reduce costs to jump straight to central procurement.

3.6 Penalties

We share the view that any penalties should be based on the efficient costs of the shortfall rather than "exacting penalties" to ensure compliance. We would note, however, that the fair, efficient cost for failing to meet the reliability requirement would be the cost of procuring replacement capacity in advance or the value of lost load at the time of system scarcity. These would automatically be delivered by the centralised procurement of reliability options. Retailers would be required to meet the cost of the (centrally) procured capacity for their peak load. Any incremental, unforeseen peak load or shortfalls (e.g., from large consumers who fail to reduce demand or generation shortages) would then face a spot price up to the value of lost load for their failure to buy or deliver sufficient capacity.

4 Options for a day ahead market

RWEST's proposed approach to retaining the integrity of the spot and forward hedging markets would also be consistent with the introduction of a day-ahead market. Day-ahead markets can be useful to help optimise generation unit commitment and to ensure sufficient operating reserve is available on the following day. In a market framework based on real-time spot pricing together with financial hedging in the forward markets, the day-ahead market could be introduced in one of two-ways:

- **A daily futures market** would allow market participants to fine tune their volumes day-ahead to match their expected dispatch on the day. This would provide a bridge between longer period futures and the daily spot market, facilitate the re-optimisation of scheduling and dispatch and allow changes to unit commitment to be underwritten financially.
- **A physical day-ahead market (e.g., a day-ahead auction)** would schedule deliveries and offtakes for the following day and allow the procurement of operating reserves. The real-time spot market would then price net deviations from the day-ahead commitments. Financial contracts could continue to be written against the real-time spot prices and/or against prices concluded at the day-ahead stage.