WA Independent Power Association Inc.

'An independent voice for a competitive power industry'

RESPONSES TO DISCUSSION PAPER: ELECTRICITY MARKET REVIEW

General Discussion

Electricity markets are inherently complex. The nature of the product sold makes them so. But the fact that electricity supply is also considered an 'essential service' which, until relatively recently, was almost exclusively supplied by governments, creates additional complexity when structuring a marketplace for the trading of electricity.

While the mechanisms in the market may be complex, the objective of the market should be clear. An electricity market should seek to achieve similar objectives to any simple marketplace, a place (physical or theoretical) where consumer demand is met by supply – such as a Sunday farmers market. Suppliers have an opportunity to sell their product to consumers. Similar products will compete on price. If one supplier has a better cost structure than another, they will generally be more profitable. Suppliers are incentivised to differentiate their product to gain an advantage over others. This benefits consumers as their choice of goods or services increases. Consumers will generally be worse off if there are only one or two large suppliers rather than an array of more diverse ones.

Participants in the market take risks. Suppliers wishing to sell goods at a farmer's market understand that unsold produce may go to waste at a cost to them. Better demand forecasting and understanding demand dynamics will minimise this risk (e.g. a cold rainy day may keep customers away). Suppliers should not expect to be rewarded for supplying excess product than is required. This blunts the risk signals that keep supplier operations efficient.

The operators of a marketplace have their own objectives. This is where complexity starts to creep in. If an operator wants to ensure a product is always available in order to keep customers interested in his marketplace, then he must either reward suppliers for maintaining excess product; or penalise them for running out. Either way, we have now introduced parameters to the operation of a marketplace that produce sub-optimal efficiency outcomes.

Markets rarely 'don't work'. Goods and services will be traded in poorly designed markets – they just won't be traded effectively or efficiently. The complexities added to markets are typically to meet the objectives of the operator. In the case of an electricity market, this is the Government. So when designing how a market should operate, it is important to understand what these objectives are, and build mechanisms that achieve them with the least disruption to efficiency and effectiveness.

The WEM has been 'working' now for eight years. Electricity is traded and its objectives have been met. However, it is evident that these objectives are being achieved in a sub-optimal manner. One of the key reasons for this is that while the objectives appear clearly stated (in the Market Rules), the structure of the market is not equipped to meet them effectively. In order to challenge the status quo, the first thing that needs to be reviewed is this structure. While it is a necessarily slow process in making major structural changes, it is of vital importance that such changes are clearly articulated along with a well-defined pathway for realising them. Without clarity of future structure, reforms are little better than a shot-in-the-dark attempt to create a better outcome than is already being achieved.

Chapter 3.1 High Cost Energy

In developing competitive electricity markets how important is the structural separation of Synergy into several generators and retailers?

Competition should be sought at both the wholesale and retail sections of the market. It may be argued that there has been competition at the wholesale level, but this is not strictly true. While there has been competition for investment in new capacity, it has predominantly been underpinned by long-term bilateral contracts (or capacity payments), meaning competition for supply was a one-off process which may have been impacted by any number of factors prevalent at the time but since rendered redundant. As has been pointed out in the Discussion Paper, the absence of a gross pool has seen little actual competition in the wholesale supply of electricity, with only small volumes of competitively priced energy being traded in the short-term markets.

It is widely acknowledged that retail competition is limited. While there are other factors impacting retail competition (such as FRC), any structural changes to promote competition in the wholesale market should seek to do likewise in the retail segment.

To promote competition at the wholesale level, there should be a greater number of options for retailers to trade with suppliers. The current scenario, where Synergy holds over 50% of installed generation but also has contractual control over a large portion of the remainder, means that retailers looking for wholesale supply have limited options. Indeed, the recent re-merger of Verve and Synergy required the introduction of 'standard products' in order to mitigate this monopoly supply situation. It would appear that competition for wholesale supply would be better served if the concentration of Synergy's control of generation was lessened. This could be achieved in a number of ways. Synergy could be split into competing gentailers, each with a suitable suite of generation assets and/or contracts. Each gentailer will compete with each other and would also compete to provide other retailers with wholesale supply. Synergy could also be split into individual retailers and generators to achieve the same end – though experience elsewhere suggests a level of vertical integration is desirable for risk mitigation. Another option would be to sell Synergy's generation assets to existing and new participants. This could create more wholesale competition, but would leave a dominant retailer. While this might work under a 'single buyer' retail model, such a model would entrench the underwriting of generation by government.

Whatever option is considered, there should be some key outcomes that are achieved:

- No single retailer should control the majority of generation;
- The existing Synergy generation fleet should end its portfolio bid in status; and
- The Synergy generation fleet should be rationalised with uneconomic plant retired or sold.

The WA IPA recommends the splitting of Synergy into two or more separate gentailers, each with a suite of generation assets and/or contracts suitable for its load. Excess generation should be retired or sold.

Should the retail electricity market be opened to FRC and should all retailers also be able to retail gas?

Not opening the retail market to FRC will lead to a sub-optimal outcome. The bigger and more diverse the market a retailer has access to, the more scope they have to construct an efficient business. If a retailer chooses to only service larger customers, it can construct its business model accordingly. But the point of competition in the retail market is to offer more price and service offerings for the benefit of all consumers. As the rate of change in the sector increases (energy efficiency; distributed power; time-of-use charging etc.) enabling innovation in retail will drive important changes to the traditional service model.

The same concept holds for the supply of gas. While the wholesale gas market is another story entirely, we cannot accurately predict the way in which competition will change the nature of gas supply in the future – so the broader the opportunity to participate, the better.

<u>Chapter 3.2 The Capacity Mechanism</u>

Could alternative capacity mechanisms work within the current industry structure?

The capacity mechanism is exactly that… a 'mechanism'. It is designed to achieve a number of outcomes – and therein lies its biggest weakness. It aims to kill too many birds with the same stone. This often occurs when mechanisms are 'designed' to mimic complex market dynamics in order to incentivise a number of desired outcomes. A recent example of this was the 2009 expanded MRET scheme legislation, where small scale renewable installations were included into the existing scheme. A single legislative mechanism was used to incentivise two quite distinct forms of renewable capacity with very different characteristics (rooftop solar and hot water versus utility scale power generation). The market fundamentals for each were very different and the legislative arrangement delivered unintended consequences. These consequences were addressed with further regulatory improvements, splitting the MRET into the current LRET and SRES.

The *underlying rationale* of the capacity mechanism is to ensure that there is enough available capacity in the market to meet the stringent 1-in-10 year peak plus reserve margin. In other words, to ensure enough capacity is built so that the lights don't go out. But a simple read of the Market Rules will quickly demonstrate that the capacity mechanism is pervasive throughout, influencing many other, shorter term aspects of the market. The capacity mechanism attempts to incentivise behaviour in too many ways and is defined and applied in a very broad sense leading to unintended consequences.

For example, a fundamental tenet of the capacity mechanism is that all capacity credits are the same. This must be the case so as not to discriminate against a MW of available capacity. And while the capacity mechanism is used to entice new capacity into the market years in advance, it is also configured to penalise unavailable capacity in real time. The long term role is aimed at encouraging liquid peakers (by definition) – an inexpensive form of capacity but an expensive form of energy. The real time role of the capacity mechanism however applies to all capacity, and leads to the perverse incentive where some generators increase their balancing market bids to incorporate a risk-adjustment for tripping and needing to refund their capacity payments.

Can alternative capacity mechanisms work? The short answer is: Yes. The trick is designing one that will achieve better outcomes without leading to more perverse consequences. Much work

has been done in recent years to improve the current capacity mechanism. However a flaw in a lot of this work is the confines in which any reform options were limited to.

The WA IPA believes there are relatively modest changes that can be made to the existing capacity mechanism which will deliver better outcomes at low cost. We would also encourage further work looking at more substantial changes to the capacity mechanism – even moving to a proper capacity market over time rather than an administered price mechanism. The goal would be to create a mechanism that is more resilient to decreases in demand as well as potential demand growth from block loads.

Could the capacity mechanism be carried out one year ahead rather than two years to minimise forecasting error?

There are a number of options for rolling capacity accreditation aimed at reducing forecast error. Little attention is given to an existing market mechanism – the Supplementary Reserve Capacity mechanism, which already provides options for shorter term capacity procurement in times of shortfall. While not ideal (in that SRC seems an open-ended liability, which is inconsistent with most other more tightly regulated aspects of the market), it should be feasible to construct a more fluid approach to certifying capacity in advance which makes use of both longer dated and shorter term capacity certification.

Are there other ways to provide the market with sufficient reserve at lower cost?

There are many ways to procure capacity in a market, some of which bear little semblance to the current capacity mechanism. While extensive work could be done on developing new methodologies, the IPA believes that making targeted improvements to the current mechanisms is a viable option.

A fundamental problem of the current mechanism has simply been that the price for capacity has not reflected demand. Other capacity markets have steep price curves which drop off quickly when sufficient capacity to meet forecast load plus a reserve margin are met. Steepening the price curve in the WEM is an obvious way to address the cost of excess capacity. In the short term, this is a preferred method, because it addresses an immediate problem, but it allows time to consider other ways of allocating capacity which move closer towards a proper market mechanism. Other alternatives are listed below, but are not exhaustive.

One option for reform of the current capacity mechanism is the institution of capacity auctions. Capacity providers would bid for capacity, with the cheapest forms of capacity being accredited up to the Reserve Capacity Requirement. This would see the Reserve Capacity Price equate to the clearing price set by the market rather than set by a formula determined by a centrally planned administrative body, with consumers the beneficiaries of the resulting efficiencies. Appropriate monitoring and mitigation mechanisms would have to be designed to ensure market power was not exercised by dominant participants.

Another way to simplify and reduce costs would be to only apply capacity credits to that portion of capacity that requires them – or a 'capacity-lite' methodology. Rather than credit all generation in the market, capacity-lite might only be set (by the IMO or appropriate forecasting body), to meet any projected shortfall of peaking energy. In other words, Market Customers would only be liable for their share of a nominated 'capacity buffer' to meet the one-in-ten-year peak plus reserve

margin. Preferably, Market Customers would be free to purchase (certified) capacity at market prices. Customers should make rational decisions on what type of capacity to purchase to meet their demand portfolios. Certified capacity capable of providing a peak summer hedge (gas peaker or perhaps solar with storage) may be preferable for a portion of the requirement, but so too would cheaper capacity for meeting the very rare peak loads – such as liquid peakers or demand management.

An alternative approach, or more likely an additional safeguard to the above, would be to adopt a Reserve Trader mechanism, managed by the appropriate operating entity (likely the IMO). It should be noted again that a similar mechanism already exists in the form of Supplementary Reserve Capacity. This could be expanded to provide the operating entity some clear guidelines around the form and quantity of capacity and the term it was able to contract for, if it was apparent that Market Customers were not contracting enough. And rather than being a last-minute mechanism (as SRC is in its current form), it would be more integrated with a rolling capacity procurement cycle.

The IPA believes that it would be imprudent to rush into a new mechanism for providing capacity without clearly understanding the implications for existing market participants, as well as the implications for future investment. The reforms to the capacity market to date that have been put in place have been done through a consultative mechanism that brings with it the support of market participants and investors. While the consultative mechanisms can be improved, particularly from a governance perspective (and moving to the NEM could address this), it is important that any reforms to the capacity mechanism are done carefully and with the involvement of industry.

Chapter 3.3 The Network

Would it be more efficient, and cheaper for new entrants, to move to an access code based on constrained connection for all parties connected, similar to that applying in the NEM?

The current arrangement where Western Power operates an unconstrained access regime in name, but manages multiple constraints on an ad-hoc basis in reality, is both inefficient and unsustainable. While the cost comparison of Western Power's network is surprisingly favourable to other jurisdictions, this likely represents recent high expenditure in those jurisdictions that has not occurred to date, but urgently needs to, in the SWIS. In order to mitigate the impending higher capital expenditure, the unconstrained model should be jettisoned.

Transitioning to a robust constrained connection model will be challenging – given the contractual nature of existing network access agreements. It represents an opportunity however to remove the advantage of incumbency and the impediments to retiring inefficient plant.

Whether the SWIS adopts the same model as the NEM is open for discussion. In a future where the SWIS adopts the Rules of the NEM, this might make sense. If the SWIS were to retain its distinct form or market, other network models may be appropriate. A key deficiency in the SWIS is the lack of appropriate pricing signals for locating new-entrant generation. Where prices may diverge significantly between NEM regions, price variation in the SWIS is limited to transmission loss factors. In a capacity and energy market, capacity pricing (or allocation) might be a better signal for location of new generation. Generation (or demand reduction) in areas of higher load (and high generation inflows) may be rewarded with a capacity uplift over those areas of high

generation and low demand (and high generation outflow). This would inherently ascribe any value to new generation (or demand management) gained by deferring network augmentation, which is not included in the current capacity pricing structure. Such a proposal would likely require the unification of the capacity forecasting function with the network planning function.

A higher WACC would encourage network investment but could lead to an increase in network tariffs. Is this is a necessary trade-off to achieve a reliable network?

The WACC is among the most important of a suite of regulatory mechanisms aimed at incentivising the monopoly owner of an asset – which cannot be duplicated economically, to operate those assets as a prudent operator would in a competitive environment (i.e. as if they could be duplicated economically). This requires the asset operator to structure itself efficiently; provide a level of customer service that would enable them to remain competitive; and to take an appropriate amount of risk in order for them to compete with other prudent operators. The rate of return should be reflective of this.

There is no magic formula for applying just the right set of incentives to make a monopoly service provider act in a perfectly competitive manner (especially so when the service provider is government owned). This has been evidenced in all jurisdictions around the world in myriad different industries. The main differentiator in this case will be what the government's plans are for the future of the network operator. If it plans to privatise, then the regulatory oversight should be modified to this end. If it plans to retain ownership, then a different type of oversight might be warranted. While no single model of regulation is perfect, there would be a good case to study international best practice when making a determination on this given the very large potential benefit of even small improvements.

<u>Chapter 3.4 Fuel</u>

Fuel is a fundamental consideration of all energy markets. The IPA recommends that the Energy Market Review considers fuel more broadly than a choice between coal and natural gas. Conventional fuels play an important role in the WEM today, but the EMR would do well to weigh the impacts of further technology improvements (especially renewable generation and storage) or the potential introduction of a future carbon price.

Technology and carbon pricing issues become prominent when planning energy policy for the medium term, requiring prudent risk assessment. For example, while the IMO projects no need to build new capacity in the SWIS, the rapid cost decline of solar PV and the likely emergence of storage technologies could displace more expensive incumbents or may preclude otherwise necessary network refurbishment. Another example is to invest in augmenting WA's rail capability to supply coal to Collie's power stations, to find a few years later that a new carbon price strands the investment by making coal power uneconomic.

Do you consider that domestic prices will reach netback levels or some level below this?

No comment

Will there be sufficient gas reserves for future electricity generation needs?

No comment.

How can the transparency and liquidity of the local gas market be improved?

In order to assist competition in the electricity market, there should be consideration of moving towards a sport market in gas. In itself this won't necessarily immediately improve competition upstream, but it would give more avenues to trade and access gas for power generation and encourage gas suppliers with smaller reserves into the domestic market.

How can new domestic gas supplies best be encouraged by downstream markets?

No comment.

Do you consider coal resources sufficient for future needs?

There are significant untapped coal resources in the Collie basin and certainly enough to meet the future requirements of existing assets.

Other sectors of the mining industry have recently undertaken significant cost-cutting exercises. Is there similar need in the coal industry for greater efficiencies?

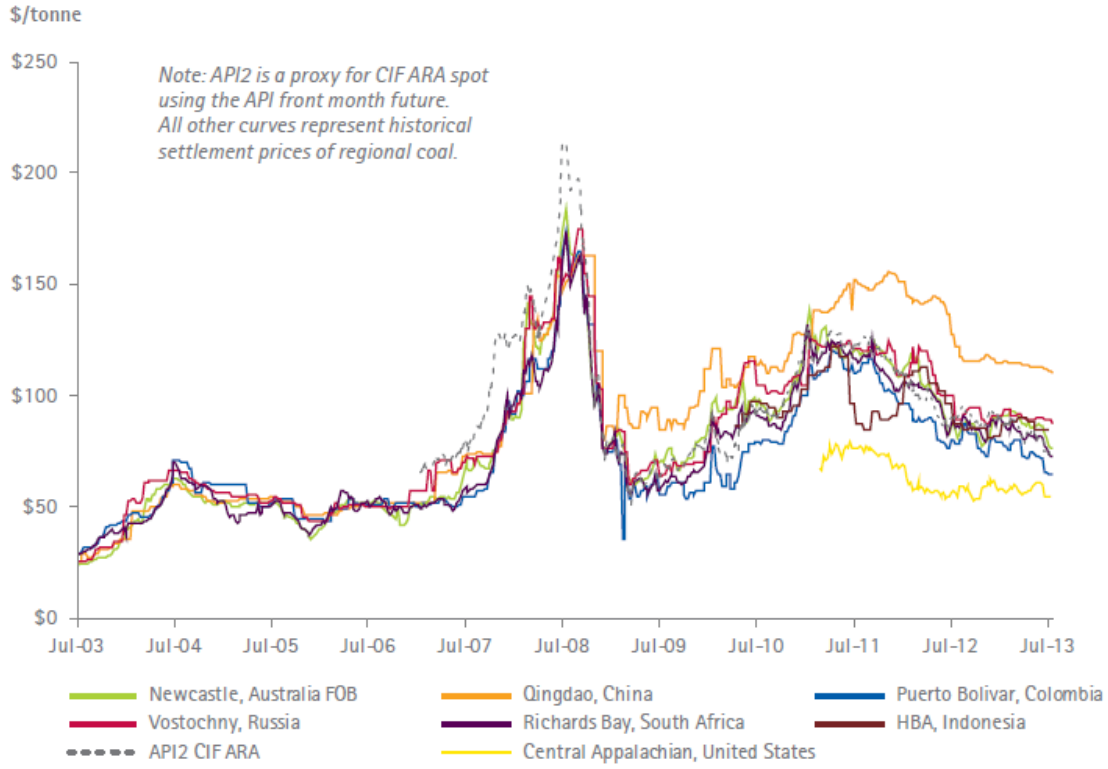
Up until a decade ago, coal mining in Collie occurred in a fairly stable environment. The advent of successive mining booms in WA changed this. As with virtually all sectors in the state, input and labour costs rose. Productivity did not follow. This, coupled with the declining grades and higher overburden has led to mining costs that are higher than the average cost of product sold.

Around 2006, the seaborne price of thermal coal was low, as it had been for many years. At the same time, domestic gas supply in Western Australia was at historically low prices, providing direct competition with coal for electricity generation. This was around the time that long-term supply contracts for Collie coal were entered. In other words, low prices have been locked in for lengthy durations whereas input costs have risen. While the productivity of Collie mining operations are likely to be low compared to other similar jurisdictions (due to a lack of competition and an entrenched duopoly), it is fair to suggest that the price of coal is not representative of either the cost of extraction or its economic value as a fuel for generation. This is not good news for the SWIS as the logical response will be a rise on coal supply price.

While coal supply prices may rise in the short to medium term, there is little prospect of exported coal setting a sensible price cap. The high cost of the infrastructure required to transport coal internationally to a suitable port and then on to Collie (where the coal generation infrastructure is) will be very high. And given Collie coal is well suited to electricity generation and not well suited to export, it is likely to remain captive to local electricity generation and other domestic uses.

So while cost cutting and greater mining efficiency will be welcome, there is unlikely to be a reduction in the price of coal for power generation in the near term.

Historical Spot (FOB) Coal Price



Source: Accenture

Chapter 3.5 The Future

What industry changes need to be made to reduce subsidies?

Clearly, the TEC cross-subsidy from SWIS network users to regional consumers should be removed immediately and funded as a CSO.

As for the TAP, there are a number of issues requiring a necessity to cross-subsidise Synergy. The first, although by no means the greatest, is likely to be the cost structure of Synergy. Without commenting directly on the internal management processes of Synergy and/or Verve over recent years, it is generally accepted that incumbent government owned corporations are over-staffed; overly bureaucratic and generally inefficient when compared to their privately owned peers. Whatever structural reform of Synergy is contemplated, attention should be given to employing efficient structures in the resultant entities.

Implicit inefficiencies within Synergy will exist in the operation of the aging generation fleet. Relative to its modern, private competitors, high staffing and maintenance costs and poor generating efficiencies will likely be systemic. At the very least, the 'portfolio' nature of the Synergy generation fleet must be dismantled. Accounts should be maintained for Individual generation facilities to work out which are profitable and which are not. No private operator would contemplate otherwise.

Given the volume of generation that entered the market over the last decade (and mostly contracted by Synergy); and the failure of much of the forecast demand growth to materialise,

there is a strong likelihood that Synergy has substantial take-or-pay obligations above their demand requirements. If so, this would make it difficult for Synergy to recover its wholesale energy commitments even if retail tariffs were set at cost reflective levels. While easy to admonish in hindsight, it should be remembered that in 2006, Supplementary Reserve Capacity was called to cover a potential capacity shortfall. And most of the following five years were characterised by a commodity and mining boom in the state. Even so, if there is a supply-demand imbalance, steps should be taken to address this. Contractual agreements with private investors will be unlikely to be altered in favour of Synergy – and doing so against the will of private generators will create significant legal and sovereign risk implications. Given the newer private generators are likely to be more cost effective than aging Synergy plant, it would appear to be sensible to retire inefficient plant to reduce the supply-demand imbalance.

Another significant cost to the market, above what could be considered efficient, it that of excess capacity. While the argument has been made that the Excess Capacity Adjustment (ECA) factor contained within the current capacity mechanism leads only to a wealth transfer between participants rather than an inefficient cost on consumers, this is not the case. If it were true that 85% of the MRCP (or the RCP) represented the marginal cost of the last MW required in the market, then this would mean that excess capacity would indeed merely be a wealth transfer. But given that more capacity than is required is able to enter the market (even after the ECA factor reduces the RCP), then this suggests that the RCP was set too high in the first place, meaning that consumers have paid too much for the capacity in the market. Clearly, if the WEM is to maintain its current fundamental design, changes must be made to the Reserve Capacity Mechanism to reflect this perverse outcome. Some discussion on this is included in responses to questions from Chapter 3.2 above. However the WA IPA acknowledges the complexity of this issue and would encourage further dialogue with the Review Committee on methods to achieve this change.

<u>Chapter 4.2 Competition</u>

Do you see the structural separation of Synergy as important for achieving a competitive market?

See responses to questions from Chapter 3.1.

Do you see regulating Synergy to mitigate its market power as a superior or inferior option to structural separation into two or three sets of assets?

Regulation to mitigate market power is always an inferior option to competition itself (as discussed in response to Chapter 3.3 on Network regulation). Human nature is not something that responds well to regulation. If you were able to control, through rules and regulations, the impulses of an individual (or a group of individuals) to not be as successful as they might be if they were to benefit from (if not outright abuse) their monopoly power – then those individuals are probably ill equipped to run a successful business. Nothing drives innovation on price and service like an even, competitive playing field.

Is the level of market concentration a matter of concern for existing and potential investors? Is it a factor in choosing to invest or not invest in the WEM?

The level of market concentration is a concern for investors, existing and potential alike. Monopoly power manifests in many forms – not necessarily just competition for market share. Supply contracts negotiated with a monopolist are highly risk weighted against the supplier – given there is little option to not agreeing to terms. And it is not just the level of market concentration *per se* that is the issue, but the implications of this on the mechanics of doing business in the sector. A very large participant (especially a government owned incumbent) has many more tools at its disposal than most typical private investors. Synergy (and before it, Verve), would have twice the project development team than the rest of the private generators combined. They would have twice the regulatory team and hence much greater ability to understand and influence the rules. They have standing relationships with top service providers – legal, technical, advisory and so on. They have funds[1] to spend in areas that private investors cannot often justify, such as membership of technical and industry forums; executive staff training and development; attending conferences and other industry development benefits. Even the Market Rules have been written to accommodate the large incumbent(s). And the benefit of incumbency should not be underestimated. Access to legacy contracts (fuel suppliers and customers); access to generation sites; access to the transmission network are some of the benefits held by incumbents that make them, difficult to compete against. Add to this an implicit access to the Government's balance sheet and, if the business is unprofitable, to taxpayer subsidies, and you have an organisation with a lower risk threshold than private organisations. Nothing sharpens risk appetite than having your own money on the line.

However, the single biggest matter of concern for investors is the relationship, real or perceived, that the government owned incumbent has with the government itself. The Synergy Board has a level of contact with, and implicitly influence on, the Government that is well beyond the scope of private investors.

<u>Chapter 4.3 FRC</u>

In moving to a market that can accommodate FRC, how should the TAP and TEC be handled?

As discussed earlier, it seems sensible and non-controversial to remove the TEC from network users in the SWIS to a CSO payment out of consolidated revenue. This should be a quick and easy reform to administer.

Rather than waiting for cost reflective pricing before moving to FRC, the TAP should be levied on a per-customer basis in a manner where all retailers have access to the customers and the associated TAP. Perhaps a trade-off between waiting for cost reflectivity and introducing FRC would be to periodically auction off tranches of non-contestable customers to retailers. Those able to supply customers (at the defined tariff) at the lowest cost to the TAP would win the customers. This should only be a short-term measure as it offers little to customers by way of price or service innovation.

[1] Noting that these benefits are funded through significant taxpayer subsidy.

What factors need to be considered in the repeal of the Gas Market Moratorium?

Access to wholesale gas supply is a different situation to wholesale electricity. The ability of a retailer to contract for electricity efficiently does not necessarily mean they can do the same for gas. The IPA supports development of a gas spot market to encourage transparency and competition.

Should the TEC continue to be funded from SWIS distribution tariffs, or instead be funded from consolidated revenue?

Consolidated revenue.

Chapter 4.3 Network Investment

Should the network operator be subject to competition in the provision of metering and other services?

Yes. There is little rationale for preventing competition in this area.

Should the WEM adopt the NEM access regime?

The NEM access regime is certainly an option for the WEM. However more analysis would be required to test whether this regime is well suited to the WEM, especially if the WEM were to maintain its capacity and energy market rather than join the NEM.

Chapter 4.4 Fuel Costs

Would there be material benefit in establishing a gas supply hub in Western Australia? How should it be implemented?

No comment.

Chapter 5.2 Option 1 – Amend Current Market

Would one or more IMO auctions for capacity, in which only capacity to meet the Reserve Capacity Requirement was acquired, produce more competitive prices for capacity?

Yes it would. Whether it would produce an appropriate mix of capacity is another question. If the IMO were to act as a reserve trader (in the instances where extra capacity is required), then a suitable auction process, governed by criteria around quantity, term and type of capacity to be contracted, should lead to market reflective prices.

Are there alternative methods for lowering capacity acquisition costs that should be considered?

Some observations on the capacity mechanism and suggestions are offered in Chapter 3.2.

What benefits could be realised by requiring Synergy to bid on a facility-by-facility or unit-by-unit basis?

The immediate benefit would be an understanding of the true cost of supply from individual facilities, leading to only the lowest cost facilities being bid.

A longer term benefit would be to identify inefficient and unprofitable plant for retirement or sale.

Would co-optimisation of ancillary services and energy markets be beneficial? Would it assist participants in offering more capacity to either or both markets?

Ancillary services are levied on consumers of those services after their provision. Real time transparent estimates of the cost of ancillary services would benefit the market (generators could rebid in the balancing market to adjust output as they do in the NEM) without imposing the complexity of full co-optimisation that the NEM deploys.

Would a transparent and liquid contract market be of benefit to generators and retailers?

No comment.

Are the current rule change assessment arrangements appropriate? Do you think it would be better to have the rule change process undertaken by a body other than the market operator?

While the WEM is not a large market and hence cannot sustain the multiple regulatory bodies required for truly independent rule making and enforcement, the current structure vests too much authority in too few and is naturally subject to influence. The market operator should have the best working knowledge of the Rules and how they apply in practice. This is the most appropriate location for the rule change administrative process to sit. It is also a natural location for rule enforcement – at least that part of enforcement relating to identification and investigation of breaches.

Decision making on rule changes could be made within a separate body, consisting representation of the market operator as well as industry and regulatory/ statutory representatives (e.g. ERA). Decisions on breaches and enforcement of penalties should also sit outside of the market operator and within an appropriate statutory body.

Additionally, existing and well-functioning institutions exist in the NEM that could be utilised to manage the rule change and assessment process in the WEM. Please see our comments relating to Chapter 5.3 Option 2.

Are there any systemic problems affecting System Management's performance? Is there a case for changing its structural or governance arrangements?

While there are legacy reasons for it, there appears little sense in System Management remaining part of the network operator. For example, would this be appropriate if the network operator was privatised? System Management's function is now inextricably linked to that of the market operator. The system manager has as much regard for the operation of (often privately owned) generating facilities as much as it does the network itself. Additionally it is difficult for System

Management to be truly independent when its personnel are largely recruited from, and share the culture and values of, the network operator.

While the relationship between System Management and the IMO seems to work at present, there could be a case made that it would be more effective if they were part of the same operating entity. Taking System Management out of Western Power would circumvent any issues for a future potential privatisation of the network operator. It might also allow a rethink of the network planning function – and how this might be more tightly integrated with the capacity planning function, with perhaps the adoption of capacity locational signals within a constrained network.

Chapter 5.3 Option 2 – Move to NEM

Questions in this section are quite specific and targeted at the actual process of transitioning to the NEM. There is little discussion on the merits of joining the NEM.

While most of the discussion on the NEM looks at replicating the energy-only design, this should not necessarily be the case. Just as some east coast states handled joining the NEM without physical interconnectors via derogation (both Queensland and Tasmania were not initially connected to the NEM), so too could the SWIS. The SWIS derogations may make quite significant departures from the current NEM design – even retaining some form of capacity mechanism. But there could be merit in utilising market institutions and a rules structure that have been well functioning for over 15 years. It is likely the NEM itself will undergo market reform in the coming decade, with growing calls for its own form of capacity mechanism, as electricity supply undergoes the paradigm shift of falling demand, energy efficiency, rooftop solar and other renewables and, inevitably, battery storage. It would make sense to consider aligning the SWIS with the NEM now, albeit loosely, so that both major electricity markets evolve in a similar fashion rather than potentially diverging further over time.

Should facilitated contracting be a design feature of a NEM gross pool in the SWIS?

No comment.

What do you consider the most important matters to be managed in a transition to the NEM?

No comment.

Are there any matters that you would see as the subject of Western Australian derogations to the National Rules?

No comment.

How long would it take to transition to a NEM gross pool for the SWIS?

No comment.