Demand Response Implementation

A Report to the Energy Market Authority of Singapore from Cybele Capital Limited
Cybele Capital Limited

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1. Executive Summary

1.1 Regulatory Objective and Outcomes

The purpose of this study is to review how to design a demand response programme that can bring about savings to consumers, taking into consideration the existing design of the National Electricity Market of Singapore (NEMS).

Savings to consumers are to be achieved through:

- the expansion of market participants and increase in competition, which in turn puts downward pressure on prices, and
- the direct financial benefits from reducing demand when financially expedient to do so.

1.2 Current Market Arrangements

Globally electricity market designs and regulation have not promoted innovations for demand side responses in practice, although some designs would claim to encourage demand side participation. However, advances in technology are increasing the potential for innovative pricing structures and generation alternatives to allow consumers to better respond to prices in near real time.

Allowing customers to participate in the electricity market can play a vital role in increasing market efficiency and reducing price volatility. Allowing customers to react to wholesale market pricing signals, or more specifically, allowing a “demand response” in the electricity market can promote efficient long-run investment, help mitigate any competition or antitrust issues, reduce spikes in prices, lower price volatility and reduce consumer energy costs.

In markets like the Australian National Electricity Market (NEM) and the New Zealand Electricity Market (NZEM), the development of fixed price fixed volume (FFPV) based hedging instruments has been an increasing feature which provides a mechanism for financially viable demand response. These products have developed organically in these markets in response to consumer needs and in some cases, generator contracting preferences.

The apparent absence of these products in Singapore is a material problem for the development of an organic (i.e. purely market based) demand response solution in Singapore, as well as a major reason for seeking active (i.e. the use of additional incentives) solution(s) to facilitate demand response programme.

1.3 Problem Definition

Our proposed problem definition is that there is currently little opportunity for consumers to effectively sell back their load, independently of their retailers. Due to the current market condition, there is little evidence of demand response activity in the Singaporean market context.

A number of meetings with end users and also with generation companies (gencos) have identified broadly the generic Time-of-use (TOU) product offerings with the exception of a high sulphur fuel oil (HSFO) linked product.

1.4 Issues

Consumers’ risk aversion and inflexibility to electricity consumption are often listed as barriers to demand side participation. Despite this, there is clear consistent evidence globally over many years indicating that some consumers have some flexibility and do respond to changes in electricity prices.

An important success factor in the development of an effective demand response programme is the reduction of barriers (perceived or real) to wholesale market information, and the relevance of that information to individual circumstances. In many markets the benefits of demand response are seldom realised because the market design did not allow wholesale price signals to reach consumers, nor did it allow consumers to express their willingness-to-pay for services in a manner that could be communicated to the wholesale market (e.g. by offering to reduce load in return for a financial payment tied to the wholesale price).

Any demand response design needs to be assessed for its gaming risks to ensure the sustainability of the solution. The maintenance of simplicity and symmetry (with generators) in any scheme is in our view a strong primary defence against gaming. The risk of gaming increases with the degree to which bespoke rules are established for demand response providers (beyond short term stimulus) - as observed in other markets, this have proven to be less sustainable. The development of a demand response programme which does not incentivise gaming (i.e. prohibits gaming) is vital.

In addition, the almost complete absence of effective and competitive fixed price fixed volume (FFPV) hedging arrangements in the NEMS, after a decade of development almost certainly introduces the need for some form of market stimulation to incentivise the demand side participation in the wholesale market.

1.5 Development Options

A number of development options have been considered in the development of a preferred solution for demand response in the Singaporean context.
The following analysis concentrates only on the market based mechanisms.

1.5.1 Contracts for Differences: Market Based and Passive

The overwhelming preference of stakeholders was for some form of passive market based solution for the provision of a demand response signal. Our conclusion in the medium to long term mirrors this preference. However the lack of market infrastructure (i.e. competitive contract for difference (CID) markets for consumers) means that the ability for this option to meet the objectives of EMA in the short term is almost entirely compromised. The development of a liquid futures market will provide the opportunity for CID based instruments to be utilised in the years to come.

1.5.2 Dynamic Demand Response: Market Based and Active

The use of dynamic demand response programmes which provide incentives dislocated from actual economic benefits for consumers to undertake demand response actions and without a defined market reform development path have proven internationally unsustainable. It is for this reason that this approach is not favoured in Singapore and that a considered and integrated approach to the introduction of demand response is recommended.

The development of a mechanism, which can in the short term provide a sufficiently strong incentive for consumers to reflect on their own internal costs of electricity abatement, their own contracting mechanisms and the alternatives, while also being given a financial incentive for direct action is in the short term important to overcome consumer inertia.

1.6 Preferred Option

The preferred solution detailed in this section of this document has been developed after careful assessment of the Energy Market Authority's (EMA) objectives, the capacity of the Singaporean market to sustain a demand response solution (both for the short term and long term) and the ability of existing infrastructure and rules to support such a development.

The development path is proposed in two stages, the first being the development of a dynamic demand response programme with an expected life span of at least three years, and the second being delivered through the use of passive instruments when adequate market features or conditions are developed. Figure 1.2 illustrates the stages of development.

This approach is preferred as the secondary trading mechanisms within the wider Singaporean power market (for example the competitive offering of FPFV hedging instruments) are not available. This primary stage of development is to be continued until such time as a degree of primary liquidity is achieved in the hedge market. The length of time that this pro-competitive intervention (i.e. Stage One) is largely dependent on the time taken by market participants to provide the conditions necessary for the demand side to participate effectively in the energy market through competitively priced and traded FPFV (or CID) contracts. The delivery of primary liquidity to satisfy the EMA in the development of a sustainable futures market would be at the bottom end of the ‘necessary conditions’ required to see a transition to Stage Two of this progressive development model.

1.7 Core Elements of Design

The core elements of the design of the proposed approach are described in this sub section. The core design elements are supported by a cost benefit analysis, regulatory changes and more detailed product descriptions that are detailed in the following sections of this document.

The core elements of Stage 1 design incorporates demand side bidding coupled with a payment mechanism based on contributed consumer benefits within a robust regulatory framework. These core elements (demand side bidding, funding regime and the associated regulatory risk management framework) are described sequentially in the following sections.

1.7.1 Demand Side Bidding

The introduction of a demand side bidding mechanism is the single largest recommended change to market operation as a result of this analysis. Demand side bidding should be introduced to achieve the following:

- Provide consumers and aggregators with a transparent baseline and pricing mechanism for their participation in the wholesale market – particularly as they will form part of the price setting process.
- Provide vital demand elasticity information to both Energy Market Company (EMC) and Power System Operator (PSO) to maintain the good order and stability of the market end grid.

It is a working and important assumption of this analysis that consumers offering demand response are doing so at prices higher than the average marginal generator in the NEMS. The introduction of demand side bidding should also include the following features:

- Demand side bids should be introduced on largely the same basis as are currently used for generator offers.
- Ramp up and ramp down rates are to be provided in the same way generation assets currently provide respective ramping information. Ramp (up and down) rates would be required to cater for loads that cannot achieve instantaneous reduction. Loads would have to specify ramp down rates which enables full curtailment in compliance with dispatch instruction within a reasonable period from the start of the dispatch period. Due to the characteristic of some demand response load, a ramp rate is necessary for these participants expected in the scheme. The symmetry with generators is also important.
Demand side bids will be subject to a price floor equal to $300/MWh, this is to prevent possible gaming of the demand side bids (see Section 6.5.4).

Demand side bids are to contain load volumes for both the pre and post dispatch, to enable compliance to be evaluated if bids are dispatched.

Demand side bidding is to be supported by metering requirements similar to that of the Interruptible Load (IL) scheme.

For bona fide reasons referred to the MSCP, additionality tests will be applied to all demand side bids to assess whether on the balance of probabilities the offered reduction was additional to business as usual.

As with generator’s bona fide claims for non-performance, the demand response aggregator would have the option to appeal to the Market Surveillance and Compliance Panel (MSCP) for any bona fide reasons and these should be made public.

An additionality test will be applied to all demand side bids so that responding loads can be referred to the MSCP to assess whether on the balance of probabilities the offered reduction was additional to business as usual.

All load groups that comprise an aggregated demand side-bidding block, or a specific consumer site if not part of an aggregation, are to be identified (by individual meter number) in advance of any demand side bids being made and accepted into Market Clearing Engine (MCE).

Demand side bids will be submitted on a zonal basis with the potential for fixed adjustment factors to harmonise them into the MCE, with potential IL bids in the same zone.

The preferred approach proposed is to treat the demand response based bid in the same way that a generator would be treated in the generator stack. A notional nodal price adjustment from Uniformed Singapore Energy Price (USEP) may be required to be made given that all generator offers are dispatched on a nodal, and not zonal basis. This approach to dispatch effectively places consumers in the position where they can have a material impact on prices, subject to performance.

It is proposed that the MCE is run twice where demand side bids are present within the stack and where they are not. Any positive variance (i.e. prices have been reduced due to the inclusion of demand side bids) will form the basis for the computation of any proportional sharing of consumer benefits. As proportional sharing of benefits will be done on a volumetric basis for each of the participants that have made a contribution to the reduction which is naturally ex post, this may require at least two runs of the MCE to identify individual contributions to reductions in market prices.

1.7.2 Funding, Benefits and Detriments

The use of the increase in the consumer surpluses, if and when consumer action has generated an observable benefit, should in part be used to incentivise demand side participation.

**Figure 1.3: Sharing of Consumer Benefits**

Figure 1.3 provides an illustration of the contestable load that would share a proportion (in our view collectively of no more than 33%) of consumer benefits from the reduction in prices (from p to p’). The area in the graphic subject to payout is therefore the yellow shaded box.
In our view, a third of the consumer benefit could be paid to demand response parties (again that have generated a benefit) with the introduction of a cap at the current market price cap of $4,500/MWh. The cap is introduced due to the following reason:

- Generators are unable to receive more than the energy price cap (90% of Value of Lost Load (VoLL) for offered generation, which essentially is the same product as demand response from the markets’ perspective.

In the event that the consumer has not performed to their bids and is without a bona fide reason for their non-performance then a penalty of no more than 33% of the generator detriment should be imposed (again providing symmetry with generator treatment). The 33% limit when combined with other conditions and the price cap constraint provide a comprehensive set of limits and boundaries to maximum payments to demand response providers. Extreme care should be taken when extrapolating potential payments to demand response providers to ensure all constraints and boundary conditions are included.

The proposed approach does provide the opportunity for parties that undertake CFD hedging to receive an additional benefit as they participate actively under the demand response scheme and also passively under the CFD payment mechanism.

The fact that vested consumers face prices related to long run marginal costs of new generation and not the spot price has lead us to consider that funding of this programme should be aligned to the parties which benefit from the reduction of prices and market volatility – all market participants buying on behalf of all non vested consumers. A reduction in both prices and volatility, through active demand side participation in the price formation process should in the medium to longer run feed back into non vested consumer prices. Under this approach, market participants buying on behalf of non vested load can then choose to pass through any perceived costs or not, as ultimately the benefit is accruing to them in the short run.

1.8 Risk Management

As with all approaches of this type it is necessary to establish a strong and robust management and measurement system around the programme to ensure sustainability of the scheme from both a commercial and a regulatory perspective.

1.8.1 Annual Review

EMA should undertake periodic reviews of demand response uptake and performance in the NEMS. It should however provide the certainty that the proposed scheme will be operative for at least three years with the expectation that market developments will make demand response an enduring feature of the NEMS.

1.8.2 Volume Cap

The introduction for the first three years of stage ,1 of a volume cap for the maximum capacity that can be bid into the market from the demand side has been set at 200 MW. This is to ensure that issues of system stability can be measured and managed during the initial phases of demand side market participation.

1.8.3 Price Cap

We strongly believe that a price cap should be applied alongside the proportional sharing of contestable consumer benefits (up to 33%). The introduction of an effective price cap, where the total benefit when divided by total load reduced, must not exceed the energy price cap is strongly recommended.

Between the price cap and the sharing rate (33%) the maximum possible pay out under the scheme is severely constrained.

1.8.4 Gaming

The proposed approach has incorporated a number of anti-gaming mechanisms, including:

- The introduction of a price floor ($300/MWh) to protect the market against parties that offer their normal load fluctuations at prices below the marginal price to ensure dispatch and a potential share of consumer surplus. The use of a floor price is an important mechanism to ensure the additionality of any load being offered into the demand response programme.

- The offering of both load levels at or below the demand bid provides the strong discipline for participants to deliver the offered volumes. Failure to deliver, without a bona fide reason, will deliver a penalty that would have a material adverse impact.

- Participants that provide demand side bids will be required to register their assets in the market. A condition of their licence is that the maximum demand reduction is explicitly detailed and referenced against assets and connection arrangements for each site.

- As with generator's bona fide claims for non-performance, the demand response aggregator would have the option to appeal to the Market Surveillance and Compliance Panel (MSCP) for any bona fide reasons and these should be made public. An additionality test will be applied to all demand side bids so that responding loads can be referred to the MSCP to assess whether on the balance of probabilities the offered reduction was additional to business as usual.
2. Background

2.1 Regulatory Objective and Outcomes

The purpose of this study is to review how to design a demand response programme that can bring about savings to consumers, taking into consideration the existing design of the National Electricity Market of Singapore (NEMS).

Savings to consumers are to be achieved through:

- the expansion of market participants and increase in competition, which in turn puts downward pressure on prices, and
- the direct financial benefits from reducing demand when financially expedient to do so.

This document will assess the ability of demand response programmes against this consumer-orientated set of objectives.

2.2 A Common Definition of Demand Response

The definition of a workable, highly simplified model of demand response is provided in this section of the report.

2.2.1 Demand Response Defined

We have chosen to use the Federal Energy Regulatory Commission’s (FERC)\(^3\) definition of demand response, as we believe it to be broad enough to cover the range of initiatives being considered in this paper.

Demand Response is the change in electric usage by consumers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

2.2.2 Demand Response Categories

Demand response under this definition can be categorised into four groups:

- **Active Demand Response**: includes direct demand control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, critical-peak pricing and ancillary services market programs.
- **Passive Demand Response**: includes time-of-use rates and real-time (spot) pricing and energy efficiency programmes.
- **Market Based Demand Response**: includes programmes where economic benefit is derived through the spot, reserve or ancillary services markets.
- **Non-Market Based Demand Response**: includes programmes which are not dependent on energy market outcomes, but rely on the benefits of reduced consumption against contracted rates or through direct or indirect incentives or penalties that are not directly related to spot, reserve or ancillary market price outcomes.

Figure 2.1 provides an illustration of the approach and the various demand response schemes that fit within the various categories and sub-categories.

**Figure 2.1a: Matrix of Demand Response Categories**

**Figure 2.1b: Matrix of Demand Response Examples**
2.2.3 Highly Simplified Model of Demand Response

For the benefit of a reader with little previous understanding of demand response and its application, the following simplified model is presented. This is not the proposed design, but a highly simplified model to ensure the concepts and issues raised in this paper can be done so in the right context.

The following chart illustrates a simplified electricity market where a single consumer is supplied electricity (quantity \( q \) at price \( p \)) in Figure 2.2. This starting example is labeled the ‘baseline’ case as it reflects the normal operating regime for the consumer.

**Figure 2.2: Simplified Market with One Consumer – Baseline Case**

![Diagram showing a simplified electricity market with one consumer.](image)

If it was economically rational, for the single consumer in this example, to reduce its consumption by a certain quantity, then this activity would be a form of active demand response. Figure 2.3 illustrates this action as a move in the demand curve from \( D \) to \( D' \) with the consumer realising the benefit in the area \( p \) to \( p' \) and \( q \) to \( q' \).

**Figure 2.3: Simplified Market with One Consumer – Demand Response Case**

![Diagram showing a simplified electricity market with one consumer under demand response.](image)
2.3 Rationale for Demand Response

Globally electricity market designs and regulation have not promoted innovations for demand side responses in practice (although some designs would claim to encourage demand side participation). However, advances in technology\(^4\) are increasing the potential for innovative pricing structures and generation alternatives to allow customers to better respond to prices.

Allowing customers to participate in the electricity market can play a vital role in increasing market efficiency and reducing price volatility. Allowing customers to react to wholesale market pricing signals, or more specifically, allowing a "demand response" in the electricity marketplace can promote efficient long-run investment, help mitigate any competition or antitrust issues, reduce spikes in prices, lower price volatility and reduce customer energy costs.

Currently vertically integrated utilities or gen-tailers have provided the vast majority of retail customers with electricity using single rate electricity products (e.g. FPVV contracts). Most customers pay a single price (or a range of prices based on time of consumption) per month for electricity independent of varying generation costs or energy scarcity.

The progressive deregulation of electricity markets has brought with it large fluctuations in wholesale electricity prices as scarcity signals are seen on the wholesale market. These prices generally reflect the scarcity of the electricity at a given point in time and are typically based on the marginal costs of the last unit of required generation, and the relative demand inelasticity to changes in price levels. Currently, only generators have the incentive to respond to the price signals in the marketplace. Generation of electricity increases with higher prices and decreases with lower prices – as one would expect.

As a result of technological and regulatory barriers\(^5\) the majority of electricity pricing plans globally do not allow end users to see and react to the actual market value of their electricity consumption/conservation. Since end-users do not face the real-time market price in making their consumption decisions, there is little demand reaction to changes in real time wholesale electricity prices. This lack of demand side response results in inefficient market outcomes. End-users (implicitly) make consumption decisions by comparing their marginal valuation of consumption with the marginal cost of consumption – if the marginal cost is not reflective of the true supply cost of electricity, there can be situations where inefficient consumption decisions are made.

2.3.1 Singaporean Consumer Product Development

In markets like the Australian NEM and the NZEM, the development of FPFV based hedging instruments has been an increasing feature which provides a mechanism for financially viable demand response. These products have developed organically in these markets in response to consumer needs and in some cases generator contracting preferences.

The apparent absence of these products in Singapore\(^6\) is a material problem for the development of an organic (i.e. pure market based) demand response solution in Singapore, as well as a major reason for seeking active solution(s) (i.e. the use of additional incentives) to make demand more responsive.

2.4 Non-Market Based Solutions

As previously mentioned, non-market based demand response solutions are not covered in this report in great detail\(^7\).

The following subsections provide background detail on these approaches.

2.4.1 Network Company Demand Response

Critical Peak Pricing (CPP) is a form of retail Time-Of-Use (TOU) pricing that relies on very high critical peak prices, as opposed to the ordinary peak prices in TOU rates. CPP is an overlay on either TOU or flat pricing and uses real-time prices at times of extreme system peak. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market. Unlike TOU blocks, which are typically in place for 6–10 hours over the year or the season, the days in which critical peaks occur are not designated in the tariff, but dispatched on relatively short notice as needed, for a limited number of days during the year.

The use of CPP mechanisms has generally been deployed in markets suffering from relatively weak transmission (or distribution) systems as a rationing mechanism. The relative strength of the Singaporean transmission grid and distribution systems provides few benefits to introducing CPP in Singapore.

2.4.2 Energy Efficiency & Energy Conservation

Energy Efficiency and Energy Conservation are not covered in our assessment of demand response due to the lack of an inherent short-term ‘response’ element – being applied constantly and not in response to high system demand or electricity prices. Again, we follow the FERC’s definition of both energy efficiency and energy conservation:

- Energy efficiency lowers energy use while providing the same level of service.
- Energy conservation reduces unnecessary energy use.

Both energy efficiency and conservation provide environmental protection and utility bill savings. Energy efficiency measures can permanently reduce peak demand by reducing overall consumption.

The development of effective energy efficiency and energy conservation programmes is in our view initiated by having very strong insight into the consumption of electricity within residential and small commercial premises. This insight is provided most usefully in the form of actual data monitoring and regular consumer surveys. Current United States practice provides a very useful example of what can be done to best target energy efficiency and conservation gains.
2.5 Current NEMS Features

The current structure of the NEMS has elements, which are conducive to the development of demand response initiatives and other features, which may not be conducive to demand response implementation.

2.5.1 Value of Lost Load (VoLL) & Price Caps

The NEMS' current VoLL prescription provides a top-down Gross Domestic Product (GDP) based assessment of the effective costs that most consumers are willing to pay to avoid electricity deprival. This highly-aggregated top-down approach lacks some of the detail from the bottom-up approach which provides details with respect to customer damage.

To develop the customer damage model, the total damage cost, which comprises several types of ‘damage’, needs to be calculated. For example, for contestable industrial and business customers, the damage cost for each customer comprises the following:

- Cost of loss of profit opportunity;
- Cost of loss of raw material;
- Cost of salary or work payment;
- Cost of damaged equipment; and
- Cost of re-starting and industrial or work process.

These damage costs may vary with interruption duration. Data collected from customer surveys is used to create damage functions for certain classes or “sectors” of customers. These surveys give information about the perceived interruption costs for each specific customer separately, and may contain information about the effect of the duration of the interruption, the time of occurrence, the amount of interrupted power or energy, etc.

The raw data from the customer surveys has to be processed and transformed to create customer damage functions (CDF), which can also be used as projections for consumers who have not been surveyed. All raw damage functions are then grouped according to customer classifications.

The lack of this material makes it difficult to make an assessment of a Singaporean CDF.

Figure 2.4: Commercial and Industrial Customer Damage Functions (SGD)

<table>
<thead>
<tr>
<th>Market &amp; Sector</th>
<th>Year</th>
<th>Mean</th>
<th>Median</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid West, USA: Manufacturing</td>
<td>2006</td>
<td>$160.00/kWh</td>
<td>$51.25/kWh</td>
</tr>
<tr>
<td>New Zealand: Large Consumers</td>
<td>2012</td>
<td>$65.00/kWh</td>
<td>n/a</td>
</tr>
<tr>
<td>New Zealand: Large Consumers</td>
<td>2004</td>
<td>$80.00/kWh</td>
<td>n/a</td>
</tr>
<tr>
<td>Australia: Commercial</td>
<td>2007</td>
<td>$62.50/kWh</td>
<td>n/a</td>
</tr>
<tr>
<td>Ontario - Canada: All Consumers</td>
<td>2004</td>
<td>$28.25/kWh</td>
<td>n/a</td>
</tr>
<tr>
<td>UK: Unknown</td>
<td>2007</td>
<td>$25.00/kWh</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Figure 2.5: Customer Damage Functions (CDF) by Industry Type

The large concentration of manufacturing businesses in Singapore introduces further upward pressure on the CDF and the bottom-up assessments of VoLL. Figure 2.5 provides relative CDF functions for different business types.
The duration of the outage affects customers differently. For instance, surveys of the value of CDF in the United States (Lawrence Berkeley National Laboratory 2001) seemed to suggest that:

- Residential customers’ customer damage tends to increase disproportionately with outage duration, such that a single 8-hour outage is more costly than the sum of eight 1-hour outages; and
- The opposite tends to be the case for commercial and industrial customers where the incremental value of consumer damage tends to decrease relative to outage duration.

In our view, from the point of evaluating a demand response programme, the current Singaporean price cap (currently set at 90% of a $5,000/MWh VoLL) is reasonably expected to be below CDF levels. Therefore, it is unlikely that demand response will be achieved organically when relying solely on the economic benefits from energy prices (i.e. savings from energy).

2.5.2 Metering Standards

The Singapore standards for metering established in the Metering Code\(^\text{10}\) lays down the licensing and performance requirements of meter asset owners and associated metering service providers.

The current standards and industry arrangements reflect legacy arrangements in Singapore, with the Market Support Services Licensee (MSSL) providing metering services for consumers.

We have reviewed the required metering for the implementation of demand response in Singapore. The acceptable metering asset should provide for robust meter readings that is similar to that deployed for the revenue metering of IL.

2.5.3 Load Curtailment

There is some evidence to date of economically motivated demand response from contestable consumers in the energy market in the NEMS. For example, the current demand response trial being conducted by CPvT Energy Asia Pte. Ltd has provided examples of demand response. The novelty of the programme and the fact that it is government sponsored\(^\text{11}\) are potential reasons for action that evidently appear to be contrary to quantitative assessments of consumer propensity to reduce consumption in other jurisdictions.

Notwithstanding the above, there are examples of economically motivated demand response from contestable consumers in the ancillary market – specifically through the IL Scheme where load participates in the reserve market.

This scheme enables the consumers to voluntarily choose to have their electricity supply interrupted in exchange for a reserve availability payment, thereby competing with the generating plants directly in the reserve market. Depending on the types of reserves the consumers intend to participate in, these ILs should either be disconnect automatically once the system frequency reaches a preset threshold setting or are manually disconnected by the IL provider when instructed. To ensure inadvertent non-performance of ILs does not compromise power system security, PSO estimates the safe quantum of ILs that can be scheduled as reserve. This quantum is currently reviewed annually\(^\text{12}\).

The opportunities for parties that have loads that can be curtailed in Singapore fall into two broad categories, specifically:

- Supplements: Consumers that have a small proportion of their processes or assets that can be curtailed (e.g. lighting, cooling and non essential services) for short periods of time. Examples include buildings and shopping centres. This type of demand response is likely to deliver a lower volume of demand response – >100 kW per site.
- Substitute: Consumers that have processes or assets that have storage capacity (e.g. thermal inertia in district cooling projects or pump storage in water utilities) or sites that are able to substitute grid connected power with onsite generation (e.g. Standby Diesel Generators). This type of demand response is likely to deliver a higher volume of demand response ->1 MWs per site.

2.5.4 Demand Bids

The MCE clears the market by matching generation offers to forecasted demand at the least cost. Unlike some other gross pool energy only markets (e.g. New Zealand and Australia), the NEMS does not include a bidding process from loads or retailers.

Centralised, bid-based markets can promote efficiency in energy markets by creating the opportunity to select from a larger pool of participants in order to meet demand at least cost. In principle, there is also an opportunity to select from a large customer pool in order to allocate scarce supplies to buyers that most value electricity service, and to elect not to serve certain customers when the cost to serve them exceeds their willingness to pay.

While the formulation of the MCE includes demand side bids, it is unclear whether this formulation has been carried into the software itself.
2.5.5 Demand Response in the Energy Market

While demand resources usually have some role in ancillary services markets, the potential is really of a second-order effect compared to the impact demand response can have in energy markets. However, the take up of demand response in ancillary service markets is often significantly higher than the response in the associated energy market. This take up is particularly true when Capacity Markets are included in this definition of ancillary markets. This mismatch between the potential benefit and the take up is also instructive in thinking about how the incentives need to be structured to encourage demand response. For example, in New Zealand significant amounts of load started to participate in the Instantaneous Reserve (IR) market with annual average prices of around NZD4/MWh. The IR market, while volatile, pays out to dispatched reserve providers in all periods, regardless of whether a load reduction is activated or not.

This number seems to be significantly lower than the international experience, suggesting the need for energy market demand response. The implication is that the frequency and consistency of the benefits to the response provider is a significant factor in the take up of demand response.

There may also be an element, somewhat irrationally, that the receipt of revenue is valued more highly than the equivalent avoidance of cost.

Demand response in energy markets may have indirect benefits in ancillary services markets during times of tight supply when demand response allows generation capacity to shift from energy markets to ancillary services especially since the MCE co-optimises for energy and reserves—as this provides the EMC the ability to dispatch the least cost solution across the two products. This means that any load bidding in for energy and reserves cannot be dispatched for both products in the same dispatch period.

2.5.6 Market Security & Stability Arrangements

The market has a number of embedded security measures to both protect the wider electrical system and the market from disruption. The development of demand response products may have an impact on these arrangements as demand reductions may have occurred that are being relied upon for other purposes. Examples where these market and system security elements would impact on a demand responsive load include the following:

- Any market design will need to ensure security arrangements are not compromised by the introduction of demand response products and market enhancements. In particular, the offering of demand response load on an AUFLS block can be potentially addressed during demand response load registration stage.
- The offering of IL while also offering energy reductions.

Any market design will need to ensure security arrangements are not compromised by the introduction of demand response products and market enhancements. In particular, the offering of demand response load on an Automatic Under Frequency Load Shedding (AUFLS) block can be potentially addressed during demand response load registration stage.

The issue of system stability is also relevant for the consideration of a demand response programme. In deciding a limit of participation for demand response it is best to select a limit that recognises the potential effect of a large amount of load reduction on system frequency. While it is likely that most of the demand response loads would have staggered and/or delayed start times, there is a chance that it could all start at the same time. The PSO has verified that up to 200MW (including both IL and demand response) could be dispatched without impacting system security. This limit will be reviewed when EMA observes that the load offered for both IL and demand response is approaching the limit.

2.6 Futures Market Development

EMA has both announced and commenced a project to assess the viability of an electricity futures trading market for Singapore. This project has the following stated objectives, which will have a potential impact on the development of demand response initiatives.

Specifically, EMA seeks the development of a fair, efficient and effective forward market for electricity in Singapore so that existing, emerging and prospective participants can both have transparency in wholesale pricing (not to be confused with the spot or dispatch market) while also being able to access (for transactions) that same market.

The further development of new electricity retailers, the emergence of consumer product innovation, and the greater use of traded risk management instruments are the primary regulatory outcomes sought by the EMA.

The development of a futures market is fully expected to lead to the development of consumer centric pricing arrangements including FPFV or CfD pricing arrangements. This greater transparency and product availability is expected to provide greater choice for consumers and therefore greater incentives to examine current electricity purchasing decisions, energy efficiency and demand response opportunities.

2.7 Desired Features

From a development perspective we understand that the EMA has a preference, for options that can be implemented, are ambivalent to customer contracting arrangements, and provide an opportunity to increase demand side participation in the wholesale electricity market more generally.
3. International Experience

The international experience of active demand response schemes is largely concentrated in United States based jurisdictions with more passive (i.e. financial contracts and VoLL) approaches being applied in other developed markets.

The following table provides a brief summary of the various non-United States based markets, and their similarities and differences with Singapore. These elements are not considered on a market-by-market basis due to their similarity and are dealt with collectively in Section 3.1 of this paper.

Figure 3.1: International Summary Table outside of the United States

<table>
<thead>
<tr>
<th></th>
<th>Singapore</th>
<th>NZ</th>
<th>Nordpool</th>
<th>UK</th>
<th>Australia (NEM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical Size</td>
<td>42 TWh</td>
<td>43 TWh</td>
<td>400 TWh</td>
<td>390 TWh</td>
<td>205 TWh</td>
</tr>
<tr>
<td>Pool Type</td>
<td>Gross</td>
<td>Gross</td>
<td>Net</td>
<td>Net</td>
<td>Gross</td>
</tr>
<tr>
<td>Vertical Integration</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Pricing Basis</td>
<td>Ex Ante</td>
<td>Ex Post</td>
<td>Ex Ante</td>
<td>Ex Ante</td>
<td>Ex Post</td>
</tr>
<tr>
<td>Dominant Fuel</td>
<td>Thermal</td>
<td>Hydro</td>
<td>Hydro</td>
<td>Thermal</td>
<td>Thermal</td>
</tr>
<tr>
<td>Demand Side Bidding</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Ancillary Market Demand Response Initiatives</td>
<td>Yes, IL</td>
<td>Yes, IL</td>
<td>Yes, IL</td>
<td>Yes, IL</td>
<td>Yes, IL</td>
</tr>
</tbody>
</table>

3.1 Passive Demand Exchange Markets

A number of the markets, which have a similar market design to the NEMS, have considered mechanisms to improve the penetration of demand side participants in recent years. Most of these investigations relate to providing certainty in ex post markets (which is not an issue in the ex ante NEMS) to those consumers utilising passive forms of demand response.

Therefore, we do not consider the experience of these markets at a high level to be relevant for the consideration of demand response market design in Singapore. Notwithstanding this, many of the component developments relevant for a demand response programme in Singapore have been incorporated in our analysis.

In both the Australian and New Zealand markets, there is very little active demand response outside of the ancillary markets, with the exception of producers of low value and highly energy intensive industries undertaking passive demand response when economically viable to do so.

3.2 United States based Active Demand Exchange Markets

In contrast to the experience outside of the United States, markets in the United States, under the leadership of FERC (and in many cases due to less developed wholesale markets) developed very active demand response markets.

3.2.1 Historical Context

The development of demand response programmes increased markedly in the 1980s and early 1990s. This increase was driven by a combination of directive from the Public Utility Regulatory Policies Act (1978) to examine time-based rate standards, and by state and federal regulatory and policy focus on demand-side management and integrated resource planning.
Regulatory support and technical advances in controls, communications, and metering also led to a marked increase in load management, particularly direct load control programs and interruptible/curtailable service tariffs.

3.2.2 Wide Variety of Schemes

The United States environment is littered with almost every conceivable combination of demand response programme including the following:

- Direct load control
- Interruptible/curtailable rates
- Demand bidding/buyback programmes
- Emergency demand response programmes
- Capacity market programmes
- Ancillary-service market programmes

The environmental scan provided in this section has concentrated on the delivery of both demand bidding/buyback and emergency demand response programmes.

3.2.3 Federal Intervention

In the mid 2010, industry concerns over the implementation of demand response systems prompted the US FERC to develop a range of new mechanisms. These federal requirements are detailed in FERC’s Order 745. The Order states that when demand response assets are able to provide a balance of supply and demand as an alternative to generation, and dispatching demand response is at the lowest cost, then demand response will be compensated at the locational marginal price (LMP).

Demand response resources will be compensated at full LMP when they are used to balance supply and demand, and when the LMP is above a threshold point as determined by the Net Benefits Test. The Net Benefits Test will be executed monthly to determine the threshold point where the benefits of deploying DR resources outweigh the costs. RTOs (Regional Transmission Organisations) have been required to explain why existing Measurement and Verification (M&V) protocols are sufficient or propose revisions; and this has led some to legally contest the process. RTOs are also required to undertake a study to determine the viability of integrating a dynamic version of the Net Benefits Test into the dispatch software on a real-time basis.

These changes are likely to have significant implications on legacy demand response schemes, and also provided many signals on how a demand response programme should be considered within the NEMS.

3.2.4 Demand bidding/buyback

Demand bidding/buyback programmes have been designed to encourage large consumers to provide load reductions at a price at which they are willing to curtail, or to identify how much load they would be willing to curtail at explicit prices. These programmes provide any opportunity for the demand side to participate in the price setting process in the wholesale market. These programmes have been both mandated / initiated by independent system operators and also on a utility basis (but only generally when the utility is also a monopoly).

This approach follows much the same path as would be followed by a generator when offers are dispatched. When consumer bids present a lower cost market price solution than generator offers, consumer load would be dispatched accordingly.

In the United States, these programmes are attractive to many customers because they allow the customer to stay on fixed rates, but receive higher payments for their load reductions when wholesale prices are sufficiently high to economically justify curtailment.

Examples of a couple of programmes that incorporate demand bids directly into the market solver and associated scheduling and dispatch process are introduced below:

- The New York ISO’s Day-Ahead Demand Response Program (DADRDP) sees consumers typically bidding a price at which they would be willing to curtail their load and the level of curtailment in MW on a day-ahead basis. If these bids are selected for operation during the security-constrained dispatch process, then customers must execute the curtailment the next day. If they do not reduce their load, they are subject to a penalty.

- An alternative to this arrangement is used in by the New England ISO under their Real-Time Price Response Program, where the customer acts as price-taker. Participants in this program reduce consumption when notified, and they receive the market-clearing price as payment.

Interestingly it seems that the ISOs have identified demand-bidding programs as transitional programs that will be supplanted by more dynamic retail pricing and metering schemes. The stated goal of the PJM Economic Program is to “provide a program offering that will help in the transition to an eventual permanent market structure whereby customers do not require subsidies to participate but where customers see and react to market signals or where customers enter into contracts with intermediaries who see and react to market signals on their behalf.”

There are also examples of retailer (effectively monopoly utility companies) operating their own schemes. (e.g. Con Edison’s Day Ahead Demand Reduction Program) which are designed to aggregate customers for participation in ISO demand-bidding programs. Several utilities operate these programs to meet their own resource needs. This is not materially different from New Zealand retailer Mercury Energy’s “Beat your Bill” product.

The issue of revenue adequacy has been an issue in the United States based programmes. A 2002 National Association of Regulatory Utility Commissioners (NARUC) report examined this controversy and concluded that there was no consensus on the issue and additional effort would be needed to examine the issue.
### 3.2.5 Emergency demand response programmes

Emergency demand response programs provide incentive payments to customers for reducing their loads during reliability-triggered events, but curtailment is voluntary. Customers can choose to forgo the payment and not curtail when notified. If customers do not curtail consumption, they are not penalised. The level of payment is typically specified beforehand.

The voluntary nature of emergency demand response programs does have implications for its use in grid operation and planning. Since there is no contractual obligation to curtail, system operators cannot accurately forecast how much load curtailment will occur when the program is activated. Consequently, participants in these programs do not receive capacity payments.

### 3.2.6 Consumer Benefit Sharing

Minnesota encourages investment in cost-effective demand response programmes by allowing consumers to share the net savings that their programs generated for customers, provided they achieve a certain percentage of a pre-agreed minimum target of peak load reduction.

**Shared Savings - Minnesota**

Minnesota encourages investment in cost-effective DR (demand response) and EE (energy efficiency) by allowing utilities to share in the net savings that their programs create for customers, provided they achieve a certain percentage of their target. Each utility in the state is required to show that their demand side expenditures (with minimum spending levels as a function of energy sales) result in net ratepayer benefits. Net ratepayer benefits are calculated as utility program costs netted against avoided supply-side costs, according to a standard avoided cost calculation. A portion of net customer benefits, with the exact amount dependent on savings achieved relative to targets, is then given to the utility as an incentive. If savings of 90 percent or less of the goal are achieved, the utility receives no incentive. The percentage of net benefits paid to the utility increases as savings levels increase. The utility’s incentive is capped at 30 percent of its spending requirement and achieving the maximum requires hitting 150 percent of the savings goal.

This shared savings mechanism combines the target with incentive mechanism and is designed to ensure that a utility’s program is cost-effective. If programs are not cost-effective, then there are no net benefits and no incentives are paid. No significant incentive is provided unless a utility meets or exceeds its savings target at the minimum spending requirements. As the cost-effectiveness increases, net benefits and incentives increase accordingly.

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This shared savings mechanism achieves the target using an incentive mechanism and is designed to ensure that a utility’s program is cost-effective. If programs are not cost-effective, then there are no net benefits and no incentives are paid. No significant incentive is provided unless a utility meets or exceeds its savings target at the minimum spending requirements. As the cost-effectiveness increases, net benefits and incentives increase accordingly.
4. Challenges, Issues and Factors

Many articles, especially in the United States, described the barriers to the implementation of demand response programme. This section details the many issues, challenges and factors that will need to be successfully resolved to deliver a demand response implementation in a Singaporean context.

Each of these issues is detailed in the following sections and can be summarised in the following categories:

- Consumer Issues
- Measurement Issues
- Regulatory Issues

Each of these issues are interrelated as illustrated by the graphic in Figure 4.1, and all combined to test the economic rationality of demand response given a particular consumer circumstances.

4.1 Consumer Issues

The engagement and over-engagement of consumers are addressed in this section of the paper.

4.1.1 Consumer Preferences

Consumers’ risk aversion and inflexibility to electricity consumption are often listed as barriers to demand participation. Despite this, there is clear consistent evidence globally over many years indicating that some consumers have some flexibility and do respond to changes in electricity prices.

An important success factor in the development of an effective demand response programme is the reduction of barriers (perceived or real) to wholesale market information, and the relevance of that information to individual circumstances. In many markets the benefits of demand response were seldom realised because the market design did not allow wholesale price signals to reach consumers, nor did it allow consumers to express their willingness-to-pay for services in a manner that could be communicated to the wholesale market (e.g. by offering to reduce load in return for a financial payment tied to the wholesale price).

A degree of spot exposed load is a very useful starting point for the development of a more active, and therefore responsive market. For example Braithwaite & Faruqui estimated that if California had 50% of its large industrial load and 25% of its large commercial customer load on real-time pricing, a typical wholesale price spike in the range of $750/MWh would produce a load reduction of 2.5%, which would in turn cause a reduction in wholesale prices of 24%.

The current practice in Singapore of short-term (~12 month) electricity contracts with very few consumers exposed to the pool price would suggest that consumers are not in tune with wholesale electricity prices, pricing and market conditions. This low degree of market visibility is a barrier to development; ironically the barriers to greater consumer engagement may lie with retailers and not with consumers.

The real time nature of the electricity market and lead times required, especially in manufacturing industries, to respond to changes in energy availability have traditionally been considered against demand side participation.

4.1.2 Gaming

The simplified example of demand response provided in section 2.2.3 introduced a number of variables, most of which are independent of the consumer making the demand response action. The price prior to and after demand response can be calculated independently, and the actual load the consumer used during the period can be independently metered. However, the electricity load expectations of the consumer prior to the decision to reduce demand cannot be independently assessed. This therefore introduces the risk that this baseline level of consumption could be gamed to maximize consumer benefit as opposed to maximizing system benefits.

Any demand response design therefore needs to be assessed for its gaming risks to ensure the sustainability of the solution. The maintenance of simplicity and symmetry (with generators) in the scheme are in our view the primary defences against gaming. The risks of gaming increases with the degree to which bespoke rules are established for demand response providers (beyond short term stimulus), as has been observed in other markets.

4.1.3 Measurement Issues

Both baseline and physical measurement of energy related issues are introduced as issues in this section of the paper. The measurement of demand response activity is central to the development of a credible demand response programme.

The traditional method of establishing a baseline measure to assess performance is a common challenge in global demand response implementations. We have observed, even in the Singaporean context, the use of simple average consumption of previous periods (daily, weekly, monthly, same period last year) as a methodology for demand response measurement or baseline.
The following stylized examples illustrate the point of why baseline selection is difficult to manage with explicit rules.

**Figure 4.2a: Apparent Performance below Baseline**

The above case (Figure 4.2a) would be a good example of demand response on the basis of a baseline set upon data from the previous weekday as illustrated in Figure 4.2b. With the green point reflecting a signal to reduce and the yellow point to resume normal operations.

**Figure 4.2b: Apparent Performance below Baseline**

If however the plant is scheduled for maintenance every 12 working days, which reduce consumption (but on a timescale not easily calibrated for market rules – but easily measured in plant running hours) as depicted in a fortnightly chart in Figure 4.2c (please note the different timescale). Then, the providence of the baseline becomes questionable. Furthermore, it becomes more problematic when plant operations are changed to take advantage of static rules.

**Figure 4.2c: Apparent Performance below Baseline**
4.1.4 Metering

Until recent times technological issues have been material barriers to the adoption of demand response in all but the largest industrial sites. Metering and communication advances in the past decade have made the needed technology both more available and more affordable\(^{24}\). This technology is required to be of a sufficient standard to meter consumption at five minute intervals.

Singapore’s development of a smart grid would be expected to deliver the infrastructure to consumers in at least the High Tension consumer category.

As detailed in Section 2 of this report, we believe that the available metering assets are of sufficient quality (essentially replicating the metering assets deployed for IL participation) to support demand response participation.

The general absence of uniform technology standards adds a new uncertainty, worsens the impact of uncertainty about regulatory commitment, and discourages investment in the needed technology. In many jurisdictions, there remains uncertainty over the basic issues of who owns the meter and who pays for the meter and its installation. Likewise, uncertainty about regulatory commitment to cost recovery discourages investment in the needed technology. These issues in the New Zealand context saw meters being physically replaced by some competing retailers when a customer switched retailer—this needs to be addressed in market regulation.

As detailed in Section 2.5.2 of this report, The minimum acceptable metering asset should provide for meter readings that is similar to that of IL.

4.1.5 Baseline Issues

The issue presented by the selection of a baseline quantity from which demand response is assessed was discussed in the above section on gaming (see section 4.1.2) and in the measurement section (see section 4.2). The problems in accurately quantifying the amount of load response offered by retail customers can be a barrier to the implementation of demand response programs. The basic problem is that only energy consumption can be measured. Energy reduction must be inferred by comparing actual consumption against some baseline representing expected consumption if load response had not occurred. The establishment of baseline setting is one, which seeks to confirm a ‘additionality problem’. The use of simplistic baselines can only be justified if we have sufficient confidence in our ability to predict behaviour within the classes of activities included in a demand response program. In our considered view there is, not surprisingly, no predictive capacity held by market oversight authorities including EMA (including the PSO) or EMC that can avoid issues of potential gaming.

Competitive electricity markets provide a solution to the baseline problem. If retail electricity evolves like those of other commodities and financial arrangements, then the typical competitive retail service will consist of a spot contract overlay with a forward contract (i.e. CfD) for expected needs, with balancing occurring at spot market prices. The forward contract in essence becomes the all-important baseline. In competition, the size and shape of the forward contract will be determined solely by the customer’s hedging needs.

For other markets the development of a bidding mechanism which has a design that provides incentives for demand response and penalties for non-performance is vital.

Many of the United States based demand response providers identify a small number of baseline design elements that should be incorporated within any demand response system design\(^{25}\):

**Accuracy**

Customers should receive credit for no more and no less than the curtailment they actually provide, so a baseline method should use available data to create an accurate estimate of what load would have been in the absence of a demand response event.

**Simplicity**

The baseline should be simple enough for all stakeholders to understand, calculate, and implement, including end-use customers. In addition, it should be possible to determine the baseline in advance of or during demand response events, so that it can be used to monitor curtailment performance in real time.

**Integrity**

A baseline method should not include attributes that encourage or allow customers to distort their baseline through irregular consumption nor allow them to game the system.

Balancing these traits is not simple. In some cases, a baseline resistant to manipulation can be so complex such that it becomes unworkable by program stakeholders. On the other hand, the simpler approaches could allow market participants to exploit the baseline in their favour. Therefore, baselines should be evaluated to ensure they provide for all three attributes of accuracy, simplicity, and integrity.

4.1.6 Not Energy Efficiency / Energy Conservation

The bidding of demand response load into the market must be done on an additional basis - i.e. is additional to business as usual during periods of high demand (read prices)). The reduction of demand during normal market conditions is energy efficiency and/or conservation and is therefore out of scope for demand response.

The concept of additionality is therefore vital for the consideration of demand response in the Singaporean context.

The use of price floors either delivered either by static (a set limit adjusted periodically) or a dynamic (at a predetermined percentile level in the offer stack) limit are an effective method to avoid the risk that non additional volumes are offered into the market at prices that are highly likely to clear (i.e. be dispatched). A demand response provide should never be confident that they will be dispatched to avoid the case where business as usual loads are offered into the market at low prices.
4.2 Regulatory Issues

Regulatory efforts to protect consumers from price volatility need to be considered in the design of demand response initiatives. Examples of the protection include non-market based standard offer service and price caps, some of which are relevant in a Singaporean context and are detailed in the following subsections.

4.2.1 VoLL & Price Caps

As introduced in Section 2.5.1, previous assessment by the EMC indicated that the current VoLL might be insufficient to justify the organic development of demand response. Refer Page 10 of RCP paper EMC/RCP/60/2012/CP38

Given that the VoLL is unlikely to be reviewed in the near term, this barrier will more likely need to be overcome in the near term through a regulatory stimulus for a compliant and successful demand response to be implemented.

4.2.2 Other Regulatory Considerations

There are also a number of additional regulatory issues that will need to be addressed in any implementation of demand response in Singapore, these include:

- Metering code changes;
- Mechanisms to stop activity and arrangements counter-productive to the development of demand response in Singapore, e.g. restrictions or limitations on demand response participation in retail contracts;
- Market bid arrangements; and
- Change to the MCE used by EMC.

4.3 Stakeholder Positions

Obtaining stakeholder input has been a core element of this project. The contributions from various stakeholders have been incorporated and are detailed in the following paragraphs.

4.3.1 Industrial, Commercial & Non Contestable Consumers

The ability to respond in the energy as well as the reserve market (via IL Scheme) was seen as a benefit by the aggregators that currently provide services to consumers that participate in the IL market currently. The size of consumer groups was not tested explicitly but by general consensus, contestable consumers who have High Tension (Large) connections could be easily incorporated without material issues.

4.3.2 Generation / Retailers

Just as aggregators positioned the enabling of demand response as a positive development, generators see any development of demand response markets beyond passive measures as an unwarranted market intervention.

The introduction of a degree of symmetry in the treatment of demand response parties was generally supported, but within the context of a generally, although not exclusively negative, reaction from generator / retailers.

4.3.3 Draft Report Specific Comments

The following table details the comments, observations and positions from stakeholders received after the circulation of the first draft of this report.

<table>
<thead>
<tr>
<th>Serial</th>
<th>Stakeholder Observation</th>
<th>Paper Reference</th>
<th>Commentary</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>The development of a demand response market in Singapore has been designed with a degree of inherent bias to facilitate demand response entry.</td>
<td>1.4, 7.1</td>
<td>The initial design has incorporated features to stimulate demand response. This effort is required due to a lack of suitable risk management instruments in the wider market.</td>
</tr>
<tr>
<td>2</td>
<td>The cost benefit analysis is weak.</td>
<td>7.0</td>
<td>We have attempted to refine and improve the detail in the cost benefit analysis and would welcome the opportunity to gather more detailed data from market participants (including information on CfD pricing models, marketing materials and transaction logs) to complete this work.</td>
</tr>
<tr>
<td>3</td>
<td>Payments only if there are tangible net benefits</td>
<td>5.4, 4</td>
<td>We agree that payments should only be made on the basis of demonstrable benefits. The design of payments on the basis of when demand response has resulted in the increase in consumer surplus should provide considerable comfort that payments are only made when economic benefit to the system is positive.</td>
</tr>
<tr>
<td>Serial</td>
<td>Stakeholder Observation</td>
<td>Paper Reference</td>
<td>Commentary</td>
</tr>
<tr>
<td>--------</td>
<td>-----------------------------------------------------------------------------------------</td>
<td>-----------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>4</td>
<td>Stakeholder comments have not been reflected in the paper.</td>
<td>4.3.3</td>
<td>To the best of our knowledge, stakeholder comments throughout the engagement process have been addressed in the report. This section of the report provides further feedback to the views of relevant stakeholders we have engaged for this project. If there are specific issues previously raised by stakeholders but have not been addressed in the draft report or final report, Cybele will be happy to respond.</td>
</tr>
<tr>
<td>5</td>
<td>Consumers on fixed price / indexed arrangements and the associated hedging instruments of retailers are unable to adjust to costs coming from any demand response programme.</td>
<td>5.6.1</td>
<td>While in the near term this is true, we fully expect that reductions in overall price levels and associated volatility will over time filter through into lower contract prices. It is intended that average prices will be reduced by the demand response programme, which are intended to be ultimately reflected in both hedging and tariff based products. It is recognised that the development of demand response in Singapore will introduce some small transitional challenges for participants as consumers hopefully become more reactive to changes in prices.</td>
</tr>
<tr>
<td>6</td>
<td>The potential beneficiaries of the demand response scheme are only spot exposed consumers.</td>
<td>5.6.1</td>
<td>See Item 5</td>
</tr>
<tr>
<td>7</td>
<td>Non Vested Loads should have the option to either fund or not fund the demand response scheme.</td>
<td>n/a</td>
<td>We believe non vested load based consumers will be the ultimate beneficiaries of these reforms. As such, the cost of demand response being borne by the market participants buying on behalf of this group of load is appropriate.</td>
</tr>
<tr>
<td>8</td>
<td>Retailers cannot benefit from this service.</td>
<td>n/a</td>
<td>Retailers can benefit as they can become demand response aggregators under this proposed design.</td>
</tr>
<tr>
<td>9</td>
<td>These arrangement interferes with Retailer property rights.</td>
<td>6.4.2</td>
<td>This is not our intention and we have designed the cost recovery model to provide an effective cost pass through for retailers who can choose to absorb or pass through the cost of demand response.</td>
</tr>
<tr>
<td>10</td>
<td>The changes are the best practices of a free economy.</td>
<td>n/a</td>
<td>All regulators reserve the right to make changes to rules, codes and introduce regulatory mechanism to facilitate the move towards a liberalised and competitive market, taking into account the existing design and characteristics of the electricity market.</td>
</tr>
<tr>
<td>11</td>
<td>The current position of the market should be verified with a survey of consumers about the performance of their retailers.</td>
<td>n/a</td>
<td>We agree such benchmark surveys have been used in other electricity markets (including New Zealand) to good effect. However, this is outside the scope of this study.</td>
</tr>
<tr>
<td>Serial</td>
<td>Stakeholder Observation</td>
<td>Paper Reference</td>
<td>Commentary</td>
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</tr>
<tr>
<td>12</td>
<td>The calculated benefit is enormous as a $4,000 drop in prices for a unvested load of 3,500 for a single hour would be $4.62m</td>
<td>8.3</td>
<td>No, this calculation is not correct. There are two additional constraints detailed in the report, which require any effective reduction to be capped at the $4,500/MWh price cap AND the maximum volume of combined demand response and interruptible load that can be dispatched is capped at 200 MW.</td>
</tr>
<tr>
<td>13</td>
<td>Retailers are able to keep pace with consumer demands.</td>
<td>2.3</td>
<td>The design of the demand response programme is intended to encourage innovation beyond relatively simple time-of-use, indexed and discount based tariffs. Extreme caution should be exercised when assuming greater knowledge of consumer preferences or assuming that silence is indicative of comfort.</td>
</tr>
<tr>
<td>14</td>
<td>Offshore experience in demand response has seen considerable gaming and other undesired outcomes for consumers.</td>
<td>3.0, 4.1.2</td>
<td>We have designed the demand response programme to avoid the pit falls experience in other schemes. The use of a self-nominated baseline for example provides a very high hurdle for compliance. In addition stringent levels of penalties for non-compliance have been put in place to prevent / deter potential gaming.</td>
</tr>
<tr>
<td>15</td>
<td>The introduction of demand side bidding mechanism will have fundamental implications for the market clearing process and the robustness of price signals</td>
<td>8</td>
<td>We agree that there are implications for the clearing and settlement. But also note that the desire to utilise more FPFV instruments in an ex-ante market also have considerable risks for market clearing process and the robustness of price signals. Overall, our assessment is that the benefits of implementing demand side bidding mechanism outweighs the costs.</td>
</tr>
</tbody>
</table>
| 16     | Some consumers are presented with hybrid fixed price fixed volume contracts with load variations to be based upon the pool price. This product is not popular. | 2.3             | Without the benefit of being able to see the contract type it is difficult to comment on individual structures. The relevant tests are:   
  - to what extent are the instruments explained and properly presented (web based product simulations, descriptions and examples are common in other markets).  
  - to confirm that the consumer owns the property right around load if their consumption falls to zero.  
  - to what extent the benefits and costs are presented.  
  - what tools and other products/services are offered to support consumers with FPFV hedges. |
<p>| 17     | We have a number of pool exposed customers.                                              | n/a             | We would very much like to gather further insight on volumes and values of these contracts to better assess the cost benefits of the demand response programme as presented. |
| 18     | The level of VoLL should be addressed.                                                   | n/a             | This outside of the terms of reference for this work programme.                                                                                                                                               |
| 19     | The key thesis of CCL's assessment is that individual benefits of a “passive DR” model accruing to a DR provider are insufficient. |                 | Our view is that they are initially insufficient due to the barriers detailed in the paper. A sustainable passive demand response programme is entirely achievable subject to the availability of FPFV instruments and associated infrastructure. |
| 20     | Pool exposed loads are the only beneficiaries of the demand response scheme.              | 5.6.1           | No, other contestable consumers will ultimately benefit from lower average spot prices and lower levels of market volatility in the medium to longer run.                                         |
| 21     | The HEUC mechanism for recovering costs is too complicated.                              | 8.0             | We appreciate there are differing views on this issue, see comment 22.                                                                                                                                     |
| 22     | The HEUC mechanism for recovering costs is the right mechanism to use to enable pass throughs of costs. | 8.0             | We appreciate there are differing views on this issue, see comment 21.                                                                                                                                     |</p>
<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>23</td>
<td>The basis for the dispatched 200 MW limit is not well detailed.</td>
<td>2.5.6</td>
<td>The 200 MW limit is based on advice from the PSO.</td>
</tr>
<tr>
<td>24</td>
<td>The Price Floor is not required, or should be at a much lower level than that proposed.</td>
<td>4.1.6</td>
<td>The Price Floor is a vitally important anti-gaming mechanism to ensure that the probability of being dispatched for demand response is uncertain for period to period. We are open to alternative mechanisms that can address the gaming issue to achieve the same outcome.</td>
</tr>
<tr>
<td>25</td>
<td>The period for Stage 1 of the Demand Response programme is too short at around three years, it should be set at ten years.</td>
<td>7.1</td>
<td>Stage 1 of the Demand Response programme proposed in this paper is intended to enable parties to transition to a CfD based programme. Loads that require the extension of Stage 1 to up to 10 years (assuming a liquid hedge market) are likely to be uneconomic demand response resources.</td>
</tr>
<tr>
<td>26</td>
<td>Detail on the Licensing regime is not provided in the Draft Report</td>
<td>8.2.1</td>
<td>An example of the licence is provided in the EMA Consultation. It is based upon the IL licensing regime but is a separate class of licence for demand response.</td>
</tr>
<tr>
<td>27</td>
<td>The Baseline mechanism is not dynamic within the gate closure period.</td>
<td>5.4.1</td>
<td>This is a key feature of the approach. The fact that demand response as designed impacts on energy prices therefore necessitates a higher standard of performance than has been the case in the past for the demand side. Changes to demand response within the gate closure period, for bona fide reasons, can avoid the penalty detailed in this policy.</td>
</tr>
<tr>
<td>28</td>
<td>IL and demand response should be able to be offered (bid) for the same load.</td>
<td>8.2.3</td>
<td>Agree, but naturally can only be dispatched for one (the lowest cost option).</td>
</tr>
<tr>
<td>29</td>
<td>Dispatched demand response loads should access the clearing price if dispatched, irrespective of whether consumer benefits have been increased.</td>
<td>6.2</td>
<td>Agree only if the load is on a CfD/FFPV contract and in the passive DR model. Payment only when there is an increase in consumer surplus ensures that the system</td>
</tr>
<tr>
<td>30</td>
<td>Demand response is a resource of last resort</td>
<td>4.1.6</td>
<td>Agree entirely.</td>
</tr>
<tr>
<td>31</td>
<td>The transfer of funds from non vested consumers to demand response providers is essentially a subsidy.</td>
<td>n/a</td>
<td>There will be a payout to demand response providers only if there is evidence of additional consumer surplus generated as a result. The surplus sharing mechanism also ensures that the majority of the benefits accrue to consumers.</td>
</tr>
</tbody>
</table>
| 32     | The proposal to base the subsidy on 33% of a theoretical value appears arbitrary and does not appear to be related to any estimate of the strength of incentive necessary to incentivise consumers to provide demand response. | 6.4.3 | Our approach has been to utilise a range of constraints so the 33% cannot be looked at in isolation, it must be considered in the context of the other constraints in the design, specifically:  
- Application of the $4,500 energy price cap.  
- Look-back feature to ensure consumer surplus is generated by demand side action.  
- Rules on the sharing of any surplus when multiple parties have contributed to the reduction in costs.  
- Penalties for non compliance.  
- Floor Price of $300/MWh  
- and of course the 33% Share of Generated Consumer Surplus itself. |
<table>
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<th>Commentary</th>
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</table>
| 33     | Based on the argument at there are indirect benefits to the non vested consumer on fixed price retail contracts, the cost of demand response should be extended to vested customers because they may benefit from demand response when the EMA's goal to achieve full retail contestability is achieved.                                                                 | n/a             | We believe that it would be more difficult for consumer loads who are covered under the vesting contracts to achieve the benefits of demand response, even in the long run.  
Furthermore as the pricing basis for vested contracts is based upon an EMA regulated price and therefore the connection to market prices is more abstracted.                                                                                                                                                                                                                                                                                                                                                       |
| 34     | It would be desirable for the levy only to be applied to retailer contracts signed after the EMA's final decision to implement the demand response scheme, and that all contracts signed prior to that point are exempt.                                                                                                                     | 6.4.2           | The cost recovery model has been designed to provide an effective cost pass through for retailers who can choose to recover the cost of demand response regardless of when the retail contracts are signed.  
Additionally we have responded to feedback from Retailers and have avoided establishing a new line item on bills so that existing contracts need not be reviewed.                                                                                                                                                                                                                                                                                                                                                       |
| 35     | It is important to be clear how this 200MW would be allocated to the various demand side participants. Economic rationing could be used as a way of identifying those participants that require the least incentive to provide demand response (and IL) and this could reduce the overall subsidy required to stimulate demand response.                                                                 | n/a             | Based on the bids submitted for demand response and IL, the MCE will co-optimise to maximise total system benefits to generate the dispatch schedule.  
Our preference is to avoid any merit order non price (through the MCE) based dispatch method for either generation or load.                                                                                                                                                                                                                                                                                                                                                                                                                       |
| 36     | There should be a full analysis of how the scheme would impact the treatment of embedded generators (and similar facilities) to ensure a level playing field between the various types of market participants is maintained.                                                                                                              | n/a             | The proposed design of the demand response programme should not interfere with the treatment of embedded generators in the electricity market.  
The DR scheme allows parties with embedded generation assets to freely reconsider their market arrangements.                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| 37     | With the incorporation of demand-side bids into the market, it will be important to ensure that the PSO's load forecast is as accurate as possible.                                                                                                                                                                               | n/a             | Yes, the PSO will continue to ensure the accuracy of load forecast with incorporation of the demand side bids.  
Communication between the PSO and EMC on the volume of demand response has been identified as being important to avoid any potential under or over forecasting of demand as a result of demand response activity.                                                                                                                                                                                                                                                                                                                                                   |
<p>| 38     | The penalty collected from non-compliant demand response providers should be paid to the gencos as they are the market participant group that suffers the detriment associated with demand response providers' non-compliance.                                                                                                                 | n/a             | The return of penalties to all consumers is the same as per current market arrangement. This is no different from the case where penalties collected from a non-compliant genco is not returned to other gencos suffering the detriment, but to the consumer base.                                                                                                                                                                                                                                                                                                                                                       |
| 39     | Consumers who offer load curtailment should be licenced by EMA to facilitate regulatory oversight by EMA                                                                                                                                                                               | 8.2.1           | Yes we agree and it is proposed that providers of load curtailment, including single site participants, multi-site participants and retailers would need to be licensed by the EMA through a new licence category called Wholesaler (Demand Side Participation).                                                                                                                                                                                                                                                                                                                                                     |</p>
<table>
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<tbody>
<tr>
<td>40</td>
<td>The current dispatch process requires gencos to achieve their target by the end of the dispatch period. It is unclear whether demand response would have the same requirement and how suitable the MCE’s assumption of linear ramp rate is for modelling demand response</td>
<td>6.4.1, 8.2.5, 8.4.3</td>
<td>The requirement for demand response parties to comply with a whole of period dispatch is a feature of our proposed design and does differ from gencos treatment to address potential gaming issues. The use of limited ramp rates, as are currently utilised by gencos, has been included in the design to reflect the realities of plant operation.</td>
</tr>
<tr>
<td>41</td>
<td>Further details on the proposed licensing regime for demand response aggregators will be required.</td>
<td>n/a</td>
<td>Details on the licensing regime for the demand response programme are reflected in EMA’s consultation paper</td>
</tr>
<tr>
<td>42</td>
<td>It is not clear which baseline approach Cybele is recommending and how it is established on a day to day basis.</td>
<td>4.1.5, 5.4.2</td>
<td>The design of a dynamic baseline is a core element of the design. The baseline is set through the bidding process where consumers participating in demand response are required to make their own assessment of the price at which they wish to curtail demand.</td>
</tr>
<tr>
<td>43</td>
<td>Loads which are dispatched by the MCE and respond must be paid the clearing price for the dispatched period regardless of whether a reduction to the marginal price has been determined. This is to incentivise participation in the demand response scheme.</td>
<td>6.4.2</td>
<td>This payment approach can be achieved in addition to the DR payment mechanism described in this paper if the party has a CfD/PPFV based hedging arrangement.</td>
</tr>
<tr>
<td>44</td>
<td>It is necessary for the demand response aggregator to be able to bid for into both the reserve market and energy market simultaneously for load.</td>
<td>8.2.3</td>
<td>The scheme is designed in such a way which will allow demand response aggregators to be able to bid for both the energy and reserve market. Details can be found in the EMA’s consultation paper.</td>
</tr>
<tr>
<td>45</td>
<td>To ensure a robust mechanism, adequate controls needs to be in place to ensure that the base volume of consumption that a customer declares is an accurate level of consumption.</td>
<td>6.5.4, 8.2.5</td>
<td>The proposed demand side bidding mechanism and price floor seeks to provide adequate controls against potential gaming.</td>
</tr>
<tr>
<td>46</td>
<td>What level of penalties would a participating consumer who is not scheduled to reduce load but does so be subjected to? Strong penalties should be put in place that heavily penalise any errant customer.</td>
<td>6.4.1, Figure 6.5c, 8.4.5</td>
<td>Strong penalties are detailed in the core design - set at least at automatic penalty scheme levels.</td>
</tr>
<tr>
<td>47</td>
<td>There is a need to better understand the process by which assets have to registered in the market.</td>
<td>n/a</td>
<td>Details on this can be found in EMA’s consultation paper.</td>
</tr>
<tr>
<td>48</td>
<td>Metering requirements for demand response should be in 5 minutes interval</td>
<td>8.2.5</td>
<td>We recommend the movement to 5 minute compliance monitoring and metering. We appreciate that the PSO recommended a higher standard of metering / compliance for power system reasons.</td>
</tr>
<tr>
<td>49</td>
<td>Penalties for non-compliant is too high and should be revised.</td>
<td>6.4.1</td>
<td>The level of penalties are put in place to address potential gaming issues. In addition, there is a provision to appeal to the MSCP on bona fide reasons for non-compliance for penalties to be reduced or waived.</td>
</tr>
<tr>
<td>Serial</td>
<td>Stakeholder Observation</td>
<td>Paper Reference</td>
<td>Commentary</td>
</tr>
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</tr>
<tr>
<td>50</td>
<td>It is unclear how this aggregation for demand response will work.</td>
<td>5.4.6</td>
<td>More detail is also provided in the EMA Consultation Paper.</td>
</tr>
<tr>
<td>51</td>
<td>The market design should allow customers and market participants to cumulate the incentives from the various markets, in order for customers and market participants to accelerate the recovery of their upfront investment.</td>
<td>8.2.3</td>
<td>The design of the demand response programme allows participations in both the energy and reserve market to be co-optimised and provides for additional benefits if consumers move to CfD based instruments.</td>
</tr>
<tr>
<td>52</td>
<td>There can be a significant improvement in the functioning of the market if Singapore Power be given a role in providing the infrastructure to support demand response participation and function as a neutral manager to ensure that dispatch of demand response does not comprise the grid.</td>
<td>n/a</td>
<td>Singapore Power, EMC and PSO all have roles to play in the management of elements of the Singaporean electricity market which can achieve the same outcome inferred by the question.</td>
</tr>
<tr>
<td>53</td>
<td>We do not support the concurrent roll-out of both demand side bidding and futures market. Sufficient gestation time would be preferred for stakeholders to fully digest the implementation and implications of each. The need for a demand response scheme might also dampened by the futures market, and vice versa.</td>
<td>n/a</td>
<td>We see the development of a futures market and a demand response market as highly co-dependent. We have recommended to the EMA that both programmes are introduced together to ensure the inter-relationships between the two programmes are able to be identified. We see the DR programme creating demand for products that are derived from the futures market. In our view this type of implementation is always best done concurrently to ensure parties are aware of relationships and interdependences between programmes and avoid any suggestion of a hidden regulatory agenda.</td>
</tr>
<tr>
<td>54</td>
<td>There is no need to meter the dispatchable load from the non-dispatchable load separately.</td>
<td>8.2.5</td>
<td>The proposed design of the programme does not require the dispatchable load and non-dispatchable load to be metered separately.</td>
</tr>
<tr>
<td>55</td>
<td>The report contains many statements and opinions which are not balanced in the context of the Singapore market and is biased to favour the providers of demand response.</td>
<td>n/a</td>
<td>We are please to respond to specific observations and references.</td>
</tr>
<tr>
<td>56</td>
<td>None of the facts nor concerns on the level of hedging and price indexed products by the retailers on the behalf of the customers which are same as the characteristics as the vesting contract load have been documented or presented in the report.</td>
<td>n/a</td>
<td>We believe that it would be more difficult for consumer loads who are covered under the vesting contracts to achieve the benefits of demand response, even in the long run. This is different from retailer offered products which are commercially priced (i.e. non regulated).</td>
</tr>
<tr>
<td>57</td>
<td>There is no mention on the potential direct beneficiary from the demand response service, which should essentially be only the contestable consumers settling their electricity usage on pool prices.</td>
<td>Various</td>
<td>We believe that the all contestable consumers whose load is not covered under the vesting contracts will benefit from the demand response programme. Please refer to this paper and the EMA Consultation Paper.</td>
</tr>
<tr>
<td>58</td>
<td>There is no reasons provided as to why the demand response service is made mandatory by the Regulator on the retailers who cannot benefit from this service.</td>
<td>6.4.2</td>
<td>We have designed the cost recovery model to provide an effective cost pass through for retailers who can choose to absorb or pass through the cost of demand response. Retailers can benefit as they can become demand response aggregators under this proposed design.</td>
</tr>
<tr>
<td>Serial</td>
<td>Stakeholder Observation</td>
<td>Paper Reference</td>
<td>Commentary</td>
</tr>
<tr>
<td>--------</td>
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</tr>
<tr>
<td>59</td>
<td>It is necessary for the Regulator to engage the services of other reputable and suitably qualified consultants with in-depth or intimate knowledge of the local electricity market to provide a check and balance for these recommendations and verify their suitability and relevance for Singapore before spending a substantial budget to implement the demand response service as it stands.</td>
<td>n/a</td>
<td>This is naturally a question better posed to the EMA than ourselves. We note that other suitably qualified consultants including respected academics (e.g. Prof Frank Wolak of Stanford University) have been involved in this workstream.</td>
</tr>
<tr>
<td>60</td>
<td>There is a need to ensure that the appeal process to MSCP is not too costly.</td>
<td>6.4.1</td>
<td>We note this and have highlighted the concern in this paper for the attention of EMC.</td>
</tr>
<tr>
<td>61</td>
<td>Please clarify the following statement “There may also be an element, somewhat irrationally, that the receipt of revenue is valued more highly that the equivalent avoidance of cost.”</td>
<td>2.5.5</td>
<td>This is almost a statement of behavioural economics; making the point that consumers generally consider smaller yet predictable income in contrast to larger yet unpredictable income.</td>
</tr>
<tr>
<td>62</td>
<td>How many contestable consumers are there with the MSSL?</td>
<td>n/a</td>
<td>The figures are published in EMA’s website.</td>
</tr>
<tr>
<td>63</td>
<td>It is unclear from the report which benefits (behavioural change vs a tool to be used in operating the system) are of the highest priority to the EMA, and therefore the basis on which a recommendation maybe be provided.</td>
<td>n/a</td>
<td>Through demand response programme, we hope to incentivise behavioural change that would benefit the electricity consumers in Singapore.</td>
</tr>
<tr>
<td>64</td>
<td>While the role of aggregators are not explicitly discussed in the report, it is important that the market arrangements that are proposed take aggregation into account.</td>
<td>5.4.6</td>
<td>The design of the demand response programme will allow aggregation of load. As with many commercial arrangements, such considerations and determinations within the rules, are best left to those commercial interests to determine.</td>
</tr>
<tr>
<td>65</td>
<td>If the customer’s load is lower than expected, why would they face a penalty? This does not seem appropriate and could lead to artificially high consumption and gaming.</td>
<td>5.4.5</td>
<td>A load reduction below the offered volume without a valid dispatch instruction, when load has been offered, is a clear example of gaming. Penalties are designed to avoid potential gaming.</td>
</tr>
<tr>
<td>66</td>
<td>Why is dynamic demand response not sustainable? There is high risk for aggregators if the payments move from consumer surplus to settlement of market contracts.</td>
<td>3.2.3</td>
<td>International experience has shown that over the long run incentive schemes like that proposed in Stage 1 are not sustainable in the long run. Our long term preference is for a programme that enhances and builds liquidity in the hedge markets and not outside of them. However we recognise that in the near term demand needs to be stimulated.</td>
</tr>
</tbody>
</table>
5. Market Based Solutions

The prospective options development of an effective mechanism for demand to respond to wholesale market conditions to improve electric grid reliability and manage electricity costs are detailed in this section.

5.1 Framework of Development Options

As initially introduced in Section 2.2 (see Figure 2.1) we have developed a matrix to reflect a wide variety of options which could be introduced in to the Singaporean electricity market environment and incorporated within the broad set of market options called Demand Response.

Our consideration of market based options is considered in this section, with a focus on practical and sustainable solutions.

5.1.1 Property Rights

The consideration of a mechanism where a party is financially rewarded for an action presupposes that the party has the right to financially benefit from the action. The ownership of the property rights around load needs to be established or explicitly determined in any scheme design. Where the decision to respond (through a reduction of demand) to an event is dislocated from the benefits of doing so, the incentives to respond must be weak. Therefore it is important that decision making capability and accrued benefits are aligned to a single party in any programme design.

For clarity, we define property rights in this context as:

A property right is the exclusive authority to determine how a resource is used. All economic goods have a property rights attribute. This attribute has four broad components:

1. the right to use electricity
2. the right to earn income from the use of electricity
3. the right to transfer the use of electricity to others
4. the right to enforcement of property rights.

In an electricity context, when considering a consumer on a fixed price variable volume (FPVV) contract, the property right of the load is owned by the supplier (retailer) of the load and not the consumer. The nature of a FPVV contract is that the customer has bought electricity at a price premium and the supplier has taken both the customer’s volume and price risk. A supplier would then consider anything extraneous to the customer’s normal energy preferences that modifies (and particularly if it exacerbates) the customer’s price and/or volume risk to be a change in the nature of the contract.

This contrasts with a fixed price fixed volume (FPFV or CfD) arrangement. The following table (Figure 5.1) details these differences, using the definition of property rights provided in the sections above.

<table>
<thead>
<tr>
<th></th>
<th>FPVV</th>
<th>FPFV / CfD</th>
</tr>
</thead>
<tbody>
<tr>
<td>The right to use electricity</td>
<td>Yes</td>
<td>Yes\textsuperscript{27}</td>
</tr>
<tr>
<td>The right to earn income from the use of electricity</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>The right to transfer the use of electricity to others</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>the right to enforcement of property rights</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

The design of any demand response scheme must provide clear ownership of the load that is to be part of any scheme, as the economic benefits of any load reduction will also have value to other parties.

5.1.2 Symmetry

The ability of a demand response provider to impact market price, in much the same way that generators can through their market offers, brings with it considerable responsibility. Demand response providers therefore need to be considered as inverse generators with very similar performance and compliance obligations.
5.1.3 Gaming

Related to the confirmation of property rights are the issues relating to the potential gaming of any rules designed to deliver property rights when financially beneficial to do so. The strong alignment of property rights with scheme design is strongly recommended coupled with the development of material penalties for non-compliance to established rules, to reduce any gaming risks.

A simple method of determining additionality is recommended to reduce gaming risks.

5.1.4 Incentives

The incentives for demand response need to be sufficient to compensate parties for curtailment of their activities that are dependent on electricity. Electricity is generally considered to have one of the lowest short run price elasticities of demand, in that as prices rise demand is largely unaffected. The price consumers are willing to pay to avoid system disruption is referred to as the value of lost load (VoLL), almost by definition this value needs to be reached or exceeded to provide incentives for behavioural changes (including demand response) to the status quo.

In the Singaporean context, VoLL is established through a top-down (or rule-of-thumb) approach rule-of-thumb estimate of VoLL is derived by dividing the country’s gross domestic product (GDP) by its total energy consumed, which – in some way - proxies the costs of lost production due to power supply interruption. An alternative approach to that used in Singapore for the identification of VoLL is to use a bottom-up consumer survey of actual customer preferences. For Singapore this approach would have the benefit of identifying the levels at which consumers (across different industries and enterprise sizes) would be prepared to respond to market price events.

Section 5 of this paper provides details on the VoLL regimes and levels in other comparable energy markets. This analysis work shows in other markets that where consumer surveys are employed they identify considerably higher levels of VoLL than supply side options (i.e. peaking generation).

Therefore it will be important that once a demand response programme is implemented, that VoLL levels are not suppressed as a blunt consumer protection, but to be determined preferably through a bottom-up survey of consumers who would be expected to participate in any scheme.

5.1.5 Funding

The method of funding any demand response programme is also of considerable importance. The funding of demand response initiatives could be either from the wholesale prices (in the case of the passive mechanisms) or through side payments - effectively uplift payments.

The potential for generator retailers to fund demand response programmes, given that in many cases they are the beneficiaries of lower energy demand from their customers when prices are elevated should also be considered. We see some obvious benefits to such an approach but do not favour the approach given that the property rights of the generator / retailer are being compromised in the first instance and a further requirement to fund the benefits that accrue would seem inequitable.

5.1.6 System Security and Assurance

A requirement for a credible and sustainable demand response programme is that demand response providers are treated in a similar way (naturally adjusting for size) as generators.

Our working assumptions are that the PSO would impose a number of requirements on the demand response provider, including:

- Real time indications and measures;
- A system for communication with the system operator; and
- Tests of control systems.

The exact details of these requirements would be a matter for the PSO to consider.

The PSO's system security obligations may limit the ability for some potential demand response providers to offer volumes into the scheme due to its standards around system security – this is likely to be an issue for the participants that access the scheme through an aggregator.

5.1.7 Sustainable and Realistic

The design of any scheme needs to be capable of practical implementation and delivery on the stated objectives of the EMA as it seeks to introduce greater demand side participation into the NEMS.

A strong preference for market based solutions is supported. To the extent that conditions should, but currently do not exist, then transitional mechanisms should be considered to bridge any gap. This provides strong incentives for all stakeholders to establish the conditions required for a market based solution to flourish and therefore wind back any transitional mechanisms.

5.2 Passive Commercial Models

5.2.1 Contracts for Differences

The Contracts for Differences (CfD) approach is the primary passive mechanism discussed in this document. It is recognised that there are other financial instruments that can be used (including futures and options based arrangements) but these structures have essentially the same characteristics as CfDs and therefore any detailed analysis of alternatives would be repetitive.
As introduced in the previous section, the inherent property rights associated with a CFID product enables an easy commercial decision to be made in respect of price and volume tradeoffs. The graphics in Figure 5.2 illustrate the operation of passive demand response when used with a CFID instrument in contrast to a FPV contract in the current market environment.

Figure 5.2a: Electricity Delivered via FPVV

![Base Case](image1)

- Contracted Price $200/MWh
- Fixed Price Variable Volume (FPVV)
- Spot Price $220/MWh
- Cost of Energy for 1 Hour Period = 10 MW x 1 Hour x $200 MWh = $2,000.00

1 Hours Load

The case in Figure 5.2a illustrates electricity being delivered through a traditional FPVV tariff based supply contract. A decision to reduce load and conserve energy in this case, does not have a commercial basis under existing system design, as the benefits from any reduction on load are not captured by the consumer. Figure 5.2b illustrates the situation where prices move to the energy cap price at $4,500/MWh for a single hour.

The reduction in load in the example in 5.2b from 10MW to 1MW clearly reduced system loadings, but only presented a saving equivalent to the load reduction at the contract price for the consumer. Conservation of this type therefore could happened at any time as it is dislocated from the events of the spot market, at least in terms of financial risk.

In our view, the savings from contracted prices are insufficient to generate a demand response from any customer.

Figure 5.2b: Electricity Delivered via FPVV with Demand Response

![Base Case](image2)

- Contracted Price = $200/MWh
- Fixed Price Variable Volume (FPVV)
- Load reduced from 10 MW to 1 MW
- Spot Price $4,500/MWh
- Cost of Energy for 1 Hour Period = 1 MW x 1 Hour x $200 MWh = $200
- A saving of $1,800

1 Hours Load

In contrast, the use of a CFID arrangement provides a strong, albeit passive, signal for consumers to react to prices higher than their forgone profits and unavoidable variable costs. Figure 5.2c provides an example of a customer that has both a spot contract for the supply of physical energy and a CFID between the prices from the spot contract and a pre agreed contracted rate (in this case $200/MWh).

The incentives can be much stronger for demand response with an ex-ante market where the responder can be more certain of the forecast settlements for their demand response.
In fact the main benefit of dispatchable demand is that it ensures that the demand response is included in the market clearing calculation.

Figure 5.2c: Electricity Delivered via CFD/PPSV with Demand Response

In the above example, the consumer has received the benefit of the spot price (when at market price cap) and payment has been made under the normal settlement arrangements of the transaction.

5.2.2 Changes to Existing Arrangements

The infrastructure for the use of over the counter (OTC) derivative transactions like CfDs is currently available within the NEMS market design. The ability to procure contracts of this type from incumbent retailers has not been tested but seems to be limited given the limited amount of financial trading being conducted between generator / retailers and through feedback from meetings with consumers who have not indicated this type of contract being used.

The Singaporean market has ex ante pricing, which has the benefit of providing certainty for participants in their pricing of risk and reward. The passive demand response approach introduce the issue that the total cost/value of any demand reductions are socialised across the entire market. The following table summarises the changes required, or not required, to implement the CfD based passive approach described above.

Figure 5.3: Table of Market Changes Required for Passive Demand Response

<table>
<thead>
<tr>
<th>Element / Market Rule Change</th>
<th>Passive Demand Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre DR and Post DR Solve under MCE to set Prices</td>
<td>No</td>
</tr>
<tr>
<td>Uplift Payments for Load</td>
<td>No</td>
</tr>
<tr>
<td>Ex Ante Audit prior to Participation</td>
<td>No</td>
</tr>
<tr>
<td>Introduction of Demand Side Bidding</td>
<td>No</td>
</tr>
<tr>
<td>Implications for Ex Ante Pricing</td>
<td>Yes</td>
</tr>
<tr>
<td>Impact on IL Scheme</td>
<td>No</td>
</tr>
</tbody>
</table>
5.2.3 IL and UFLS

As responding to high prices using a CfD and participating in IL are both voluntary, customers will be able to provide both and choose the most valuable use of their demand response. There is a theoretical risk that a concentration of passive demand response in a UFLS region could undermine the availability of UFLS. However, this is a prevailing problem with UFLS and changing load patterns, which is not made worse through the increased use of CfD products.

5.3 Active Commercial Models

Unlike the CfD approach where it is the primary mechanism for consideration, there are a number of active models in use globally (with a strong concentration of implementations in the United States) from which we have derived a small number of potential models that could be implemented in the Singaporean market. A more detailed consideration of the other approaches and why they have not been described in this section is provided in Section 6 of this paper.

5.4 Dynamic Demand Response

5.4.1 Initial Design Elements

The design of a demand response approach for very large customers has been described as Dynamic Demand Response (DDR). The approach has the following core design elements.

1. The compliance regime for dispatch and offering demand reductions is largely symmetrical with an equivalent sized generator; specifically be:
   a. able to receive and acknowledge dispatch instructions; and
   b. capable of complying with dispatch instructions; and
   c. able to provide metering information; and
   d. (potentially) “ring fenced” from non-dispatchable load.

2. A calculation of deadweight losses and/or consumer benefits is made from payments which are made to the demand response consumer based upon a baseline level of consumption; and

3. Load reductions are to be measurable and additional.

Each of these elements is described in more detail in the following paragraphs.

The concept of reciprocity (or symmetry) with generators is an important design feature to ensure competition between loads (consumers) and generation. This can benefit all consumers by promoting efficiency and stability in electricity markets. Allowing customers to react to pricing signals (i.e. ‘demand response’) in the electricity marketplace can promote efficient long-run investment, help mitigate short-run market power by generators, reduce electricity price spikes, lower price volatility and ultimately reduce consumers’ costs.

Figure 5.4: Table of Market Changes Required for Active Demand Response

<table>
<thead>
<tr>
<th>Element / Market Rule Change</th>
<th>Active Demand Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre DR and Post DR Solve under MCE to set Prices</td>
<td>Yes</td>
</tr>
<tr>
<td>Uplift Payments for Load</td>
<td>Yes</td>
</tr>
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</tr>
<tr>
<td>Introduction of Demand Side Bidding</td>
<td>Yes</td>
</tr>
<tr>
<td>Implications for Ex Ante Pricing</td>
<td>Yes</td>
</tr>
<tr>
<td>Impact on Interruptable Load</td>
<td>Yes</td>
</tr>
</tbody>
</table>

5.4.2 Demand Side Bids

Bids from demand response participants would consist of a series of prices and associated quantities forming a sloping demand curve to include in the MCE. Bids would only be required to be submitted when reductions are dispatchable. They would not be required to bid for all periods. The bids would therefore set the baseline for reduction, as they would be required to provide absolute (rather than relative) starting and ending points.
Potentially the model could be substantially modified to allow nodal demand side bidding or more simply modified to treat demand reductions as if they are generation increases (which is not best modeling practice). At this stage, we think zonal biddings is the most robust methodology that is relatively simple to implement, and is more straightforward for demand side bidders, but are likely to be delivered on a zonal basis.

The following graph (Figure 5.5) provides an example of how this approach could be applied across a series of trading periods.

There is a theoretical risk that a concentration of passive demand response in a UFLS region could undermine the availability of UFLS. However, this is a prevailing problem with UFLS and changing load patterns, which is not made worse through the increased use of CfD products.

**Figure 5.5a: Example of Demand Side Bidding**

In this example a customer has a 20 MW load, and has the ability to either supplement or curtail consumption.

**Figure 5.5b: Example of Demand Side Bidding**

In this example, a customer has a 20 MW load, and has the ability to either supplement or curtail consumption.

The ability to submit demand side bids to reduce consumption in a nominated time period is to be made operative under Section 6 of the Market Rules. The rules will largely mirror the operation of generators within the NEMS.

**Figure 5.5c: Example of Demand Side Bidding**

In this example (Figure 5.5c), the consumer offers 10 MW of load reduction through demand side bids.

The bids are set at $1,000/MWh (and may sit alongside IL offers for the same volume, but only one can be dispatched).

The demand side bid was put into the market in time period 5 (TP5 in red).
The following figure in 5.5 introduces a price element, and also truncates the time periods to the periods of activity.

Figure 5.5d: Example of Demand Side Bidding

![Diagram of Demand Side Bidding](image)

In this example (Figure 5.5d), as the market clearing price is above the offer price of the 10MW load will be dispatched.

Dispatch of demand response is to follow in the same way as a generator is dispatched.

Load reduction (green Line) gradient reflects ramp (down and up) rates.

When demand response is dispatched over a long period of time previous period performance (i.e. dispatch performance) must be taken into consideration for performance.

5.4.3 Payment Regime – Deadweight Loss

The following simple forward demand supply graphs isolate a small system efficiency (a form of deadweight loss) that arises from allowing efficient demand response from a pre-determined baseline position.

Figure 5.6a: Demand and Supply Curves – Pre Demand Response

![Diagram of Demand and Supply Curves](image)

In this example (Figure 5.6a), the end-user has no incentive or ability to respond to the wholesale price, and consumes at q (the optimal point given their marginal cost of electricity, which may be a FPV contract price). The market clears at price p.

Allowing consumers to efficiently respond to wholesale price, given its marginal valuation of consumption (Figure 5.6b) sees the market clear at p’ and q’, creating an efficiency gain (the blue shaded area). This efficiency gain arises as the end-user is no longer consuming system resources (generation) where costs exceed the end users’ marginal valuation.
Naturally the benefits to the demand response provider will be where prices are being materially reduced from price cap levels, and not from the near market clearing prices depicted in Figure 5.6.

Assuming there is a single provider in Figure 5.6, payments to the demand response provider would be the sum of \((p - p') \times (q - q')\) – represented by the shaded blue box in Figure 5.6b. However, if the generator is a marginal, the dead weight loss will be of a more complex shape.

The calculation of this would be done by doing two runs on the MCE.

5.4.4 Payment Regime – Consumer Benefits

An extension of the regime described in section 5.4.3 is presented in Figure 5.7, where the benefit is extended beyond the deadweight loss to include a proportional share of the consumer benefits (the blue shaded area) - the sum of \((p - p') \times (q - q')\). The proportional nature of the sharing is illustrated in Figure 5.7.

Figure 5.6b: Demand and Supply Curves – Post Demand Response

Figure 5.7: Demand and Supply Curves – Post Demand Response – Consumer Benefit
5.4.5 Penalty Regime

The penalty regime would be designed to provide a material disincentive to gaming. To deliver a degree of symmetry to the benefits from the scheme the design includes a generator detriment payment in the event of willful non-compliance.

Figure 5.8 illustrates how a willful non-compliant demand response participant would have to pay a proportion of the generator detriment (the red shaded area). A penalty would apply to both a situation where the generator was dispatched but did not comply with dispatch instructions or a situation where the demand response participant reduced load even if they were not dispatched.

Willful non-compliance would include situations where non bona fide reasons for non-performance were observed irrespective of whether material benefit accrued to the demand response participant. EMA would reserve its right to investigate potential breaches of these rules relating to demand response participants and take action if anti-competitive activity was found to exist. Where no symmetrical penalty exists for generators, strong consideration should be given for the introduction of such a penalty.

Where there has been non-compliance but there has been no generator detriment then a penalty equal to the automatic penalty scheme should be applied.

Figure 5.8: Generator Detriment

5.4.6 Aggregated Demand Response

The ability for smaller consumers to be aggregated into a demand aggregation group is something that should be supported under the development of an active demand response programme. In a prior section we have identified that for reasons related to security of supply, these aggregated consumers may not be able to be collectively dispatched for demand response if security is being (or likely to be) compromised.

In all other respects the provision of demand response services will need to be on the same basis as has been detailed in section 5.4 of this paper.
5.5 Incentivising CfD Take Up

The basis of any of the models we have considered in this section is to have an incentive structure that encourages any demand responsive consumer (i.e. curtailable load) to reveal its true willingness to pay for electricity consumption; and where economically rational to do so to reduce demand. The CfD based mechanism has the benefits of being sustainable in the longer term but does suffer from a significant challenge to overcome consumer inertia to migrate from passive electricity supply arrangements to those that require more dynamism.

The migration to a long term sustainable demand response programme is likely to require some incentive based arrangement in the short to medium term.

We have considered in detail a number of different mechanisms, including arrangements to incentivise CfD based contracts. This section details how incentive structures can be introduced to promote the use of CfD contracts for demand response.

5.5.1 Retailers offering CfD Contracts

The widespread and consistent offering of CfD contracts to consumers is an important requirement for consumers to have confidence that this type of risk management approach is itself sustainable.

Our investigations have not identified widespread consistent offering of CfDs to consumers by retailers which therefore would suggest that an intervention of some type would need to encourage their constant and consistent offering. Intervention by the regulator in requiring retailers to provide consumers with bespoke contracts through tender, auction or other methods would be required. In our view, such regulatory intervention is not sustainable in the long-run for demand response implementation.

From a practical perspective this would require bespoke contracts to be introduced to match and offset existing FPVV arrangements and would a considerable and complex administrative undertaking.

5.5.2 Unwinding FPVV and other Consumer Contracts

The more challenging requirement of this approach is to develop a mechanism that reverses the effect of fixed price variable volume (FPVV) and other contract (e.g. fuel pass through contracts) arrangements to enable the CfD to incentivise the consumer to respond to prices. Introducing the CfD in addition to a legacy FPVV arrangement effectively provides a purely speculative instrument on price – providing no curtailment signal.

Therefore, there is a requirement to reverse the impact of a FPVV contract through the use of a variable volume variable price (VVVP) contract where the volume is based on a consumer actual load and the price is set against the same price series as the CfD being introduced. The variance (margin) between the spot price and the FPVV contract strike price will need to be funded. This funding gap (in green) is illustrated in the following stylised graphic alongside the potential performance of a CfD contract.

The unwinding of fuel oil based pass through contracts, depending on the basis for price setting oil, could be achieved in a similar form – albeit at probably higher cost.

Figure 5.9: FPVV Unwinding
5.5.3 Commentary
The use of incentives to encourage CfD take up is a valid option for the development of a sustainable demand response capability in Singapore. The issues above however show that this approach is not costless and has the added risk that payments are made to consumers (for the common FPVV contract) constantly over time irrespective of performance in delivering demand response. This introduces the risk that the incentive is taken by the consumer and the behaviour is not observed. The complications of funding and having an entity being able to offer the VVVP contract have not been fully assessed at this stage.

5.6 Commentary & Consideration
Following on from the introductions in Section 2 of this document. Where demand response activity reduces the marginal price – funding from the market (as opposed to a direct levy or from retailer) can be extracted from two sources – specifically the consumer surplus and potentially also through the contract mechanism.

Figure 5.10: Demand Response Categories

5.6.1 Short Term Spot Prices impacting on Long Term Contract Prices
There is a feedback loop between sustained short term spot prices (both the level and the apparent level of volatility) and longer term contract prices.

Generally, the relationship between wholesale and retail in the long run is unsurprising. Wholesale prices are an indication of short run marginal cost, which must be recovered. Given the tenure of a retail customer, in any market retail tariffs must surely only reflect an “expectation” of future wholesale prices (and other contract prices) - plus risk premium. The introduction of the DR scheme should have the effect of increasing downward pressure on prices as more competition is observed at the top of the supply stack and therefore also reducing market volatility.

The expectation of greater competition and lower volatility should therefore put pressure on prices in the near term. This is especially true in markets with more stable SRMC characteristics (gas, coal) which will probably have a better medium-term connectedness (i.e., Singapore).

This loop has been documented in part in the PhD dissertation of Cybele Capital Limited staff member Dr. Stephen J Batstone in “An Equilibrium Model of an Imperfect Electricity Market” Stephen R J Batstone, Department of Management University of Canterbury.’

Chapter 13 of this important work provides considerable technical detail on the nexus between short term and long term prices.

We note the work of Professor Wolak of Stanford University detailed in the EMA Consultation Paper.
5.6.2 Commentary

The discussion above highlights the various components of consumer wealth increase when demand response occurs. Each of these offer opportunities for a modest re-distribution from the parties to whom this naturally accrues, to the demand response providers as an incentive to respond.

Extracting any of these surpluses in order to make a payment to demand responders is fraught with complexity, but we make the following observations:

1. The “deadweight loss” component, as discussed, is a reversal of what is a consumer (and societal) net dis-benefit or negative externality under the no-response scenario. In our view, the responder has no clear property right over the total or any sub-component, which should accrue to the responder. In most cases, the deadweight loss component will be quite small and insufficient to change the incentives for response.

2. The “producer/retailer surplus” is a genuine wealth gain to retailers, but we think it would be difficult to justify extracting a component of this as a payment to demand responders, as the retailers do have a clear property right over the (dominant) FPVV load; and for responders on CfDs, this payment will accrue to them directly.

3. The increase in “consumer surplus” is more justifiable as the property rights are less clear.

Arguably, all payments are a form of market “distortion”, as they increase the payoffs to demand response providers above the level that would naturally occur. This puts demand response in an advantageous position relative to peaking generation.

Notwithstanding the above, these payments are desirable in the short-medium term in order to incentivise demand response. In all likelihood, there will come a time when the market has scaled up demand response and achieved the necessary scale economies, behaviour changes, and even moved more towards the FPFV contractual arrangements which more directly (and correctly) reward demand response. At that point in time, EMA should choose to scale back or remove the payments, thus achieving the pro-competitive benefits of DR.

To that end, we recommend using a proportion of the consumer surplus component as such:

- It is easy to calculate;
- It is effectively a wealth transfer between consumers, and does not require challenging the property rights of retailers;
- While it is arguable that the deadweight loss area should be included, the magnitude of this area (relative to the consumer surplus) almost makes this moot, given the approximate nature of the proportional/scaling variable.
6. Preferred Solution

6.1 Introduction

The preferred solution detailed in this section of this document has been developed after careful assessment of the EMA’s objectives, the capacity of the Singaporean market to sustain a demand response solution (both currently and into the future) and the ability of existing infrastructure and rules to support such a development.

6.2 Staged Development

The development path is proposed in two stages, the first being the development of a dynamic demand response programme with an expected life span of at least three years, and the second being delivered through the use of passive instruments. Figure 6.1 illustrates the stages of development.

Figure 6.1: Development Approach

This approach is preferred as the secondary trading mechanisms within the wider Singaporean power market (for example the competitive offering of FPFV hedging instruments) are not available. This primary stage of development is to be continued until a certain degree of primary liquidity is achieved in the futures market. The time period for Stage One is largely dependent on the time taken by market participants to provide the conditions necessary for the demand side to effectively participate in the energy market through competitively priced and traded FPFV (or CfD) contracts. The delivery of primary liquidity to satisfy the EMA in the development of a sustainable futures market would be at the bottom end of the ‘necessary conditions’ required to see a transition to Stage Two of this progressive development model.

The second stage of the development approach effectively sees the funding of demand reduction move from an appropriation of a share of the consumer surplus to being funded by the market through the settlement of market contracts – see Appendix A for an example of how the CfD mechanism functions.

The following graphic (Figure 6.2) illustrates the different funding approaches for the development of demand response initiatives under both Stage 1 and Stage 2.

Figure 6.2: Development Funding Approaches
6.3 At a Cross Road….

6.3.1 Introduction

The consideration of two approaches to transition to a predominantly CfD based demand response approach have been considered in our analysis. These approaches consider either an incentive to move consumers to purchase CfD based contracts (Model 1) or a more direct incentive based upon outcomes to have consumers consider their options in providing demand response (Model 2).

6.3.2 Incentivising CfD based hedging (Model 1)

A potentially useful approach that has been suggested to Cybele Capital has been the direct movement to CfD based hedging products. This approach has the benefit of not requiring a transition phase as the transitional arrangements are wound back / turned off. However, it does have the detriments associated with climbing the experience curve of an unfamiliar product (seemingly for both consumers and gencos) and the cost of incentivising retailers to offer such new products would be paid irrespective of performance. In our view, retailers would have to incentivised to offer these CfD based products given that such products are unlikely to evolve organically based on current market dynamics.

The following stylized graphic seeks to illustrate the costs and benefits of the approach.

Figure 6.3: Incentivising CfD Uptake – Payout Diagram

6.3.3 Look Back Payments based upon Performance and Benefits (Model 2)

The alternative methodology to transition to a CfD based mechanism is based upon a look back (perfect hindsight model) where payments to demand responding consumers are only made when activity satisfies a range of predetermined conditions, specifically:

- The reduction in load occurred as offered.
- The reduction led to an observable and quantifiable reduction in the energy price and therefore increased consumer benefits.
- The reduction was additional to normal operations for the load.

The above conditions introduce a least regrets method for consumers being paid for dispatched reductions in consumer loads. The following stylized graphic seeks to illustrate the costs and benefits of the approach.

Figure 6.4: Look Back Payments – Payout Diagram
6.3.4 Conclusions

In essence the decision between these two approaches comes down to what is believed to be the state of the market. If CfD based instruments are seen to be easily offered at small premiums (or even discounts) to knowledgeable consumers that are prepared to make an investment in understanding the ability for their consumption to react to price signals then the CfD incentive approach is the logical solution. If however one’s view is that the offering of CfD’s will take a significant effort from both consumers and the gencos alike and that incentive payments should only be made for actual effort which result in real consumer benefit, then the look back based arrangement is assessed to be a more appropriate and viable approach.

Our assessment is that the CfD incentive approach can only achieve the objectives set by the EMA against a backdrop of an actively traded futures market – something that currently does not exist. Given the phased development and incubation cycle for a futures market development the only viable approach for a transition mechanism is the use of a look back mechanism until primary futures liquidity is achieved on the futures market.

6.4 Core Elements of Design

The core elements of the design of the proposed approach are described in this sub section. The core design elements are supported by a cost benefit analysis, regulatory changes and more detailed product descriptions that are detailed in the following sections of this document.

The core elements of the design of the proposed approach are described in this sub section. The core design elements are supported by a cost benefit analysis, regulatory changes and more detailed product descriptions that are detailed in the following sections of this document.

6.4.1 Demand Side Bidding

The introduction of a demand side bidding mechanism is the single largest recommended change to market operation as a result of this analysis. Demand side bidding should be introduced to achieve the following:

- Provide consumers offering load curtailment as part of a demand response programme and aggregators with a transparent baseline and pricing mechanism for their participation in the wholesale market – particularly as they will form part of the price setting process.
- Provide vital demand elasticity information to both EMC and PSO to maintain the good order and stability of the market.

It is a working and important assumption of this analysis that consumers offering demand response are doing so at prices higher than the average marginal generator in the NEMS. The introduction of demand side bidding should also include the following features:

- Demand side bids should be introduced on largely the same basis as are currently used for generator offers.
- Ramp up and ramp down rates are to be provided in the same way generation assets currently provide respective ramping information. Ramp (up and down) rates would be required to cater for loads that cannot achieve instantaneous reduction. Loads would have to specify ramp down rates which enables full curtailment in compliance with dispatch instruction within a reasonable period from the start of the dispatch period. Due to the characteristic of some demand response load, a ramp rate is necessary for these participants expected in the scheme. The symmetry with generators is also important.
- Demand side bids will contain load volumes for both the pre and post dispatch, to enable compliance to be evaluated if bids are dispatched.
- Demand side bidding is to be supported by metering communications requirements similar to that of the Interruptible Load (IL) scheme.
- For bona fide reasons referred to the MSCP, additionality tests will be applied to all demand side bids to assess whether on the balance of probabilities the offered reduction was additional to business as usual.
- Where there is an energy deficient and demand response has been dispatched without any increase in consumer benefits, then the price for the calculation of demand response payments will be the positive difference between the VoLL ($5,000/MWh) and the energy market price cap ($4,500/MWh).
- As with generator’s bona fide claims for non-performance, the demand response aggregator would have the option to appeal to the Market Surveillance and Compliance Panel (MSCP) for any bona fide reasons and these should be made public.
- An additionality test will be applied to all demand side bids so that responding loads can be referred to the MSCP to assess whether on the balance of probabilities the offered reduction was additional to business as usual.
- All load groups that comprise an aggregated demand side-bidding block, or a specific consumer site if not part of an aggregation, are to be identified by individual meter number in advance of any demand side bids being made and accepted into Market Clearing Engine (MCE).
- Demand side bids will be submitted on a zonal basis with the potential for fixed adjustment factors to harmonise them into the MCE, with potential IL bids in the same zone.

It is recommended that the demand side bidding approach as detailed in Section 5 be implemented, with the following additional extensions.
Figure 6.5a: Demand Side Bidding – Case 1: Performance with dispatch instruction

Following on from the example in Figure 5.5d, Figure 6.5a shows that when the market clearing price (red line) is above the offer price of the 10 MW offered (blue line) from periods 8 to 11, the bid will be dispatched.

Dispatch of demand response to be followed in the same way as a generator is dispatched.

The load reduction (green line) gradient reflects ramp down and subsequent ramp up rates during the dispatch periods.

Payment is made on the per metered volumes.

A 10 MW reduction for 2 hours (4 time periods) is achieved in this example (shaded light green area above the green line).

Figure 6.5b: Demand Side Bidding – Case 2: Non-Performance with dispatch instruction

A failure to undertake any demand response activity when dispatched would see a strong penalty payment made. This approach is a vital anti-gaming feature. The example in Figure 6.5b is an example of non-compliance with a dispatch instruction between periods 8 to 11 when spot price is higher than the offer price. As shown by the green line, there was no load reduction and load will be subject to penalty payment.

Figure 6.5c: Demand Side Bidding – Case 3: Non-Performance with no dispatch instruction

Figure 6.5c shows that where demand response is not dispatched (as prices are lower than demand side bid with the red line below the blue line) and a consumer responds (reduction in load shown by the green line and red shaded area) as if it had been dispatched, a penalty will be imposed. Similar to Case 2 above, this approach also is a vital anti-gaming feature.
As has been previously introduced, the approach proposed in this section is to treat the demand response based bid in the same way that a generator would be treated in the generator stack. A notional nodal price adjustment from USEP may be required to be made given that all generator offers are dispatched on a nodal, and not zonal basis. This approach to dispatch effectively places consumers in the position where they can have a material impact on prices, subject to performance.

It is proposed that the MCE to be run twice where demand side bids are present within the stack MarketPriceDSB, and where they are not MarketPriceGBO. Any positive variance (i.e. prices have been reduced due to the inclusion of demand side bids) between MarketPriceDSB and MarketPriceGBO will form the basis for the computation of any proportional sharing of consumer benefits. As proportional sharing of benefits will be done on a volumetric basis for each of the participants that have made a contribution to the reduction which is naturally ex post, this may require at least two runs of the MCE to identify individual contributions to reductions in market prices.

6.4.2 Funding, Benefits and Detriments

The use of the increase in the consumer surpluses, if and when consumer action has generated an observable benefit, should in part be used to incentivise demand side participation. Figure 6.6 provides an illustration of the contestable load that would share a proportion (in our view collectively of no more than 33%) of consumer benefits from the reduction in prices (from \( p \) to \( p' \)). The area in the graphic subject to payout is therefore the yellow shaded box.

**Figure 6.6: Sharing of Consumer Benefits**

In our view, a third of the consumer benefit could be paid to demand response parties (again that have generated a benefit) with the introduction of a cap at the current energy price cap of $4,500/MWh. The introduction of this cap is done due to the following reason:

Generators are unable to receive more than the energy price cap (90% of VoLL) for offered generation, which essentially is the same product as demand response from the markets’ perspective.

In the event that the consumer has not performed to their bids then a penalty of no more than 33% of the generator detriment should be imposed (again providing symmetry with generator treatment). The 33% limit when combined with other conditions and the price cap constraint provide a comprehensive set of limits and boundaries to maximum payments to demand response providers. Extreme care should be taken when extrapolating potential payments to demand response providers to ensure all constraints and boundary conditions are included.

As with generator’s bona fide claims for non-performance, the demand response aggregator would have the option to appeal to the Market Surveillance and Compliance Panel (MSCP) for any bona fide reasons and these should be made public. An additionality test will be applied to all demand side bids so that responding loads can be referred to the MSCP to assess whether on the balance of probabilities the offered reduction was additional to business as usual.

The proposed approach does provide the opportunity for parties that undertake CFD hedging to receive an additional benefit as they participate actively under the demand response scheme and also passively under the CFD payment mechanism. This would see both the yellow and the green boxes in Figure 6.4 paid to the CFD based demand response participant. There is no effective method of isolating these consumers and also remaining largely indifferent to the contract type being used by the consumer.
The fact that vested consumers face prices related to long run marginal costs of new generation and not the spot price has lead us to consider that funding of this programme should be aligned to the parties which benefit from the reduction of prices and market volatility – all market participants buying on behalf of all non vested consumers. A reduction in both prices and volatility, through active demand side participation in the price formation process should in the medium to longer run feed back into non vested consumer prices. Under this approach, market participants buying on behalf of non vested load can then choose to pass through any perceived costs or not, as ultimately the benefit is accruing to them in the short run.

We propose that the charge be effectively levied on all market participants buying on behalf of all contestable load through the Hourly Energy Uplift Charge (HEUC), which also includes net energy settlement credit due to differences between nodal prices and USEP as well as transmission losses. The actual recovery mechanism would be via a HEUC charge on all consumers with a rebate for contestable loads so that these loads are not impacted and therefore indifferent to the outcomes of the demand response scheme. The payment of penalties be returned to all load under the current market rules. Under this approach market participants buying on behalf of non vested load can then choose to pass through any perceived costs or not, as ultimately the benefit is accruing to them in the short run.

The following graphic illustrates the payment approach.

**Figure 6.7: Sharing of Consumer Benefits**

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### 6.4.3 Constraint Design

Our approach has been to utilise a range of constraints to both provide a value bounded incentive. Therefore no one element of the design should be looked at in isolation, it must be considered in the context of the other constraints in the design, specifically:

- Application of the $4,500 energy price cap.
- Look-back feature to ensure consumer surplus is generated by demand side action.
- Rules on the sharing of any surplus when multiple parties have contributed to the reduction in costs.
- Penalties for non compliance.
- Floor Price of $300/MWh
- and the 33% Share of Generated Consumer Surplus.

We have conducted simulations to assess the interaction of each of these constraints. Our assessment was that the $4,500 energy price cap constraint was able to exclude very high payments where demand response had operated at the top end of the demand curve, it didn’t however bind when reductions, prices and quantities of reduction where lower. The additional restriction of payments to 33% was recommended as an additional constraint on top of the energy price cap after assessing the impact of sharing rates of 8 - 10%, 25%, 50% and 100%. The 33% was selected after qualitatively assessing the impact of all of these constraints on historical price data and also ensuring that it provided a sufficiently strong potential incentive for consumers to critically examine their electricity price risk management practices. Figure 6.8 illustrates the concept behind the use of constraints.

**Figure 6.8: Stylised example of use of Constraints**
6.5 Risk Management

As with all approaches of this type it is necessary to establish a strong and robust management and measurement system around the programme to ensure scheme sustainability both from a commercial and a regulatory perspective.

6.5.1 Annual Review

EMA should undertake annual reviews of demand response uptake and performance in the NEMS. It should however provide the certainty that the proposed scheme will be operative for at least three years with the expectation that market developments will make demand response an enduring feature of the NEMS.

6.5.2 Volume Cap

The introduction for the first three years of Stage 1 of a volume cap for the maximum capacity of demand response and IL that can be dispatched by the MCE is capped at 200 MW. This is to ensure that issues of system stability can be measured and managed during the initial phases of demand side market participation.

6.5.3 Price Cap

As we have previously articulated the belief that a price cap should be applied alongside the proportional sharing of contestable consumer benefits (up to 33%). The introduction of an effective price cap, where the total benefit when divided by total load reduced, must not exceed the market VoLL price is strongly recommended.

Between the price cap and the sharing rate (33%) the maximum possible pay out under the scheme is severely constrained.

The prospect of increasing the proportion of sharing and exposing only spot exposed consumers has been discounted as it would make FPFV contracts progressively (as consumers progressively attempted to avoid the costs of the sharing mechanism) unattractive – something that conflicts with the objectives of this proposed programme.

6.5.4 Gaming

The proposed approach has incorporated a number of anti gaming mechanisms, including:

- The introduction of a price floor ($300/MWh) to protect the market against parties that offer their normal load fluctuations at prices below the marginal price to ensure dispatch and a potential share of consumer surplus. The use of a floor price is an important mechanism to ensure the additionality of any load being offered into the demand response programme.
- The offering of both load levels at or below the demand bid provides the strong discipline for participants to deliver the offered volumes. Failure to deliver, without a bona fide reason, will deliver a penalty that would have a material adverse impact.
- Participants that provide demand side bids will be required to register their assets in the market. A condition of their licence is that the maximum demand reduction is explicitly detailed and referenced against assets and connection arrangements for each site.
- The introduction of powers for the MSCP to investigate and invoke penalties where any demand side bid fails to meet an additionality test where on the balance of probabilities the load reduction would have been offered in the market anyway.

6.5.5 Active Disincentives

The practice of providing retail contracts to consumers that explicitly and/or effectively preclude the use of demand response instruments or energy efficiency initiatives from third parties should be prohibited. We recommend to the EMA to review the Retailers’ Code of Conduct to ensure the above.

6.5 Transition Path

The development of a transition path from the proposed approach to a more sustainable market driven solution should be a priority for EMA. The proposed design has the benefit of being a least regrets approach in that it only makes a payment to consumers if all conditions have been satisfied, specifically:

1. The party (or parties) are registered as being participants in the demand response programme; and
2. A load reduction has occurred utilising rules broadly the same as those for generators; and
3. The marginal price of electricity has been reduced as a direct result of the offering and dispatch of a consumers demand response.

Only once these conditions have been met does a recovery from non-vested consumer loads under the HEUC mechanism occur. This mechanism has the benefit of providing an additional incentive (over and above the passive CfD mechanism for demand response and is only paid on success (hence least regrets). Other incentive approaches will have higher transaction costs (for example to provide incentives for the take up of CfD based contracts) as while they also potentially incentivise demand response they require the payment of subsidies (e.g. to encourage of the offering of CfDs) but are not tied to actual demand response outcomes. In the first instance we are behaviourally seeking consumers to both see the incentive and react to it.
7. Cost Benefit Analysis

7.1 Introduction

This cost benefit analysis seeks to identify the costs and prospective benefits from the introduction of the suite of elements detailed in Section 6 of this report.

It must be noted that the benefits that are projected to ensue from Stage 1 developments are illustrative. The stimulation of the demand side of the market by the regulator is warranted given the lack of organic development of products and or services required to support the demand side of the market. The dynamic efficiency gains from the stimulation should outweigh any associated costs, given the relative small cost of implementation.

This paper has assessed high level implementation costs, therefore this cost benefit analysis should be seen as a high level assessment of costs.

7.1.1 Economic Analysis

The development of a demand response programme is designed to reduce on short term consumer inertia to consider their options for demand side participation. The behaviour of the programme is intended to alter, to improve the performance of the electricity market, through more efficient signals and responses from consumers.

In the following sub-sections, we identify the main types of costs and benefits for the development of a dynamic demand response programme in Singapore, and describe how we quantify and value these costs and benefits. This modelling inevitably involves some simplification of market features and elements and as a result the size of any benefits will be scaled back to more than compensate for any simplifications in input data. This inherent conservatism is a benefit of this approach, as it does not seek to infer a level of precision that cannot be realistically achieved.

Although, in the first instance, the lower volatility of the spot market represents simply a transfer from peaking generators to participating consumers, it would ultimately provide real efficiency benefits to the economy through reducing the costs of producing the goods and services supplied to consumers.

For the benefit of completeness the three components of economic efficiency are:

a. allocative efficiency – the price and quantity of electricity or other goods and services supplied;

b. productive efficiency – the cost of supplying electricity or other goods and services; and

c. dynamic efficiency – investment and innovation to pursue reduction over time in the cost of supplying electricity or other goods and services.

7.2 Sources of Economic Benefit

The benefits to the system as a whole from the Proposed Design would take the form of:

• The security benefits from the PSO being able to exert additional control over a greater proportion of system assets;

• Greater efficiency from being able to bring an electricity user’s price responsive demand on or off in merit order even over time;

• Greater efficiency from more efficient price signals due to the use of richer information in the price determination process.; and

• Reduced spot market volatility during periods of high prices.

7.3 Sources of Economic Cost

The costs to the system would be:

• The additional operational costs faced by participating dispatching consumers, including the value of the lost freedom to use electricity to meet business needs, the cost of metering and communications systems, and the costs of testing, compliance monitoring, reporting and subsequent MSCP follow up.\(^{34}\)

• The costs of changing the EMC’s scheduling and settlement systems, PSO’s dispatch systems, including the need for near real-time monitoring and the recording of dispatchable load to implement the proposed demand response programme.

7.4 Assessed Economic Costs

Our assessment of the costs of implementing the proposed design are dependent on the costs associated with enabling the MCE system to accept and then dispatch demand side bids. The calculation of resulting increases in consumer benefits and its allocation to dispatched loads will effectively be the costs of an additional model run of the MCE.

The following table details our assumptions around the costs of the preferred solution.
Using a conservative approach, the total net present value of costs, under a moderate (average of high and low) cost scenario, for an implementation over three years is just over $680,000\(^\text{25}\). The cost of the Demand Side Bidding and Forecasting project in New Zealand had a budget of around $600,000 - which seems consistent with the values detailed in this document.

7.5 Net Benefits

Net Benefits

A barrier approach has been used to assess the net benefits from the introduction of the preferred market design for a period of three years. The barrier method simply seeks to reduce benefits to within a single dollar (i.e. benefits are $1 greater than costs) on a net present value basis. A 10% discount rate was used for this analysis.

A key feature of the preferred approach is to only socialise benefits to consumers that they themselves generate in, the case of an demand response that results in an increase in consumer benefits. We have therefore only sought to assess the net benefits from this approach.

7.5.1 Productive Efficiency Gains

Using the barrier based (i.e. tipping point) approach, for the benefits to exceed the costs the demand response programme would have to deliver a two one-and-a-half hour (3 hours or 6 time periods) events (out of 8,760 hours in an entire year) where load contributes to an average $100 reduction in prices only. This scenario seems conservative (i.e. highly achievable).

7.5.2 Dynamic Efficiency Gains

A more robust approach to the hedging of market risk is expected to improve investment as well as operating decisions from consumers as they, where appropriate, make plant investment decisions to reduce energy costs – through the use of these assets and contracts to participate in the demand response market.

Electricity demand is expected to grow on average by around 3-4\% per annum, with peak demand growth expected to increase even faster. Investment over the next ten years is expected to meet demand growth and maintain existing security margins. The more effective (as opposed to efficient) use of consumer assets has the potential to reduce the impact of rises in peak demand over this period.

The benefits premise on the uptake of the demand response programme, but our preliminary assessment is that the net benefit is above zero. Including these dynamic efficiency gains would naturally increase the net benefits and lower the tipping point of a three hour event with an average $100 reduction in prices described on 7.5.1.

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### Figure 7.1: CBA Cost Matrix (Work in Progress)

<table>
<thead>
<tr>
<th>Type</th>
<th>Frequency</th>
<th>Low Case</th>
<th>High Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implementation Costs</td>
<td>Initial</td>
<td>$300,000</td>
<td>$900,000</td>
</tr>
<tr>
<td>Operating Costs for EMC &amp; EMA</td>
<td>Ongoing</td>
<td>$40,000</td>
<td>$120,000</td>
</tr>
</tbody>
</table>

Using a conservative approach, the total net present value of costs, under a moderate (average of high and low) cost scenario, for an implementation over three years is just over $680,000\(^\text{25}\). The cost of the Demand Side Bidding and Forecasting project in New Zealand had a budget of around $600,000 - which seems consistent with the values detailed in this document.
8. Implementation

8.1 Introduction

The implementation of a the preferred solution as outlined in section 6 of this report has been divided into two distinct phases, specifically the implementation of a demand side bidding regime in Singapore and also the development of a payment mechanism to give effect to the payments also outlined in Section 6.

8.1.1 Demand Side Bidding

The development of a demand side bidding regime is a necessary development for the Singapore national electricity market in the near term irrespective as to whether an associate payments mechanism is also implemented. For long run market efficiency, it will be increasingly important to encourage and facilitate demand side bidding and incorporate demand response into the markets ex-ante pricing arrangements. Without demand side bidding, consumers can reduce loads in response to spot prices, and potentially benefit from difference payments under CfD arrangements, but their action will not form part of one price discovery process in the NEMS.

8.1.2 Payment Mechanism

The further extension of the demand side bidding implementation to make demand response performance assessments and associated payments is detailed in the Payment Mechanism section of this paper. This mechanism is intended to encourage the behavioural changes for increased demand exposure to spot prices with risk managed through financial derivatives.

8.2 Demand Side Bidding

8.2.1 Licensing and Registration

The licensing of Demand Response Aggregators (DRA), including single site participants, multi site aggregators and retailers, would be introduced through a new licence category – the Wholesale (Demand Side Participation) Licence with the EMA. This category would enable parties to bid volumes into the energy market. The licence would also stipulate the specific market obligations and rights of the licensee in respect of demand response. In addition to the Wholesale (Demand Side Participation) Licence, the DRA would also be required to register as a Market Participant with EMC.

The registration of individual demand side bidding facilities or sites is to be approved by the PSO. Individual facilities will be required to have the demonstrable capability of providing a minimum of 0.1 MW of demand reduction and be vetted by the PSO. Individual meter asset numbers will be recorded as part of the registration process.

The registration of facilities can be done on a ‘Block’ basis where the facility is also registered within an IL zone. A facility can only belong to one Block, but can either be bid into the market as a single facility or as part of the Block. The decision on how the facility is to be offered (either as a single facility or as part of a Block) is made at the time the bid is made (65 minutes before real time) and not retrospectively.

The bidding of demand from consumers will be subject to an upper dispatch limit of 200 MW in aggregate, which will also include dispatched IL. The volume limit is likely to be also constrained by limits within each IL Zone as will be specified by the PSO at the time of any asset registration.

As more than the 200 MW of demand can be registered (but not dispatched) the PSO will have the obligation to provide the MW capacity of registered demand side participants in each of the existing IL Zones.

Where more than 200 MW of demand is bid into the market, the EMC will the dispatch the least cost demand and interruptible load, as determined by the MCE, up to this 200 MW limit. Where greater volume than the 200 MW limit is offered at the same price then a ‘tie break’ will need to be applied, as detailed below in order of importance:

1. Generator Offers will take precedence over Demand Bids.
2. The Demand Bids placed into the market earliest will take precedence – a First in Last Out (FILO) basis.
3. Bids which can be scaled down will have precedence.
4. Pro rata scaling of bids - reduce all bids by a common scale factor until all bids are within the limit.

Demand bids will be subject to the same tranche restrictions as generators but with no obligation to bid (see section 8.2.2).

8.2.2 Bidding

Demand bidding is optional in every period. The default standing bid for a DRA block is no bid.

Each demand response bid is a bid to provide a reduction in energy consumption to the relevant real-time market by a DRA block in a demand response zone in a dispatch period.
When a DRA does submit a bid for a DRA block it will state:

- the identity of the DRA block that the demand response is for;
- the dispatch period that the demand response bid is for;
- between 2 to 10 price-quantity pairs. These shall be stated in increasing order of price (a single price-quantity pair is effectively no bid) - see Figure 8.1;
- when a DR bid is made, the quantity with the lowest price in the price-quantity pair will be the minimum consumption the wholesale market participant (demand response) registered facility intends to consume without demand response (i.e. the self nominated baseline);
- the quantity in every other price-quantity pair will be the minimum reduction of consumption at that price and each tranche bid must be for a minimum of 0.1 MW;

**Figure: 8.1 Market Systems / Sources**

- the demand response ramp-up rate and the demand response ramp-down rate, which respectively imply the allowable increase and decrease in the output of the wholesale market participant (demand response) registered facility during the dispatch period.

Gate closure for a DRA block bid is 65 minutes before the trading period as per the current market rules. All demand bids must comply with the Market Rules. There will be five minutes notice of dispatch.

The price in each price-quantity pair of an energy offer shall as per current rules for demand and generation:

- be expressed in $/MWh to two decimal places;
- for the lowest price price-quantity pair not exceed 10 x VOLL;
- for the other price-quantity pairs not exceed VOLL; and
- not be less than the lower price limit of $300/MWh.

The quantity in each price-quantity pair of an energy offer shall be expressed in MW to one decimal place and shall not be less than 0.1 MW.

**8.2.3 Market Clearing**

The MCE is generally formulated to accept demand side bids. The modifications to the MCE itself are relatively minor to accept DRA block bids.

Existing IL providers should be able to bid for demand response and DRA should also be able to offer reserve if they also met IL requirements (including metering). This requires IL offers and DRA bids to be co-optimised. Co-optimising IL and DRA may not be as simple as using existing generator energy/reserve co-optimisation methods but still should be relatively minor modification to the MCE.

**8.2.4 Market Systems / Sources**

The introduction of information systems and services to support the development of demand side bidding is also recognised. The following table details some of the data and system requirements to support demand bids.

**Figure: 8.2 Market Systems / Sources**

<table>
<thead>
<tr>
<th>Serial</th>
<th>Market / Information Source</th>
<th>Responsible Party</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Register of Demand Assets</td>
<td>PSO</td>
</tr>
<tr>
<td>2</td>
<td>Licence Registration</td>
<td>EMA</td>
</tr>
<tr>
<td>3</td>
<td>Demand Curve from Bids</td>
<td>EMC</td>
</tr>
<tr>
<td>4</td>
<td>Performance Reporting of MCE</td>
<td>EMC</td>
</tr>
<tr>
<td>5</td>
<td>Forecasting feedback process</td>
<td>EMC/PSO</td>
</tr>
</tbody>
</table>
8.2.5 Metering

Metering is critical to monitoring compliance. As much as possible, to keep the costs of DRA provision down, the intention is to use existing revenue metering for compliance. Figure 8.3a to 8.3c provide a graphical illustration of the performance of a demand response bid initially with a simple ramp rate requirement alone, and then followed by examples of how demand response could be assessed without short interval (e.g. 5 minute metering).

Figure: 8.3a: Demand Bid Compliance with Ramps

Figure: 8.3b: Demand Bid Compliance with Ramps measured with Revenue Meters

Figure: 8.3c: Demand Bid Compliance with Ramps measured with Revenue Meters – Alternative Case
For larger numbers of smaller aggregated DR providers, revenue metering should be sufficient. In theory each facility could delay response and meet the compliance requirements by responding to a proportionally greater degree. In practice this not likely to be a viable cost effective way for small providers to provide the DR and is unlikely to be done by a large number of small facilities at the same time.

As loads get larger their exact dispatch compliance becomes more of an issue for system security. At a certain point (still to be determined by the PSO) the larger loads will require metering similar to IL metering whereupon a dispatch signal input triggers the meter to record periodic (at least one minute) snapshots of DR load. Such recording would start before dispatch and continue for the 30 minute period. IL metering would qualify if it could also use a dispatch signal to trigger the recording function.

8.2.6 Compliance Testing

The requirement to undertake compliance testing will be conducted by the PSO to ensure that the DRA facility or aggregated demand response (hereafter a ‘Block’) was at or above its bid volume if it was in its standing tranche, or at or below the level in any subsequent dispatched tranche.

A failure to comply with bids as described in the previous section would be considered non-compliance.

8.3 Payment Mechanism

8.3.1 Payment Calculation

A key element of the demand response solution developed by Cybele Capital Limited for the EMA is the introduction of a payment method during a period of transition to a CfD based demand response regime.

The calculation of net benefits would be done in the following sequence.

**Figure: 8.4 Payment Calculation Sequence**

<table>
<thead>
<tr>
<th>Serial</th>
<th>Activity</th>
<th>Responsible Party</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Undertake 2 Runs of MCE (with and without stepped demand curve) to see if there is any difference in USEP when volumes other than Standing Bids have been bid into the market.</td>
<td>EMC</td>
</tr>
<tr>
<td>2</td>
<td>If there has been a difference in USEP generated, EMC to advise EMA of Demand Response Payment Mechanism is operative.</td>
<td>EMC/EMA</td>
</tr>
<tr>
<td>3</td>
<td>Forecast Demand provided to EMC</td>
<td>PSO</td>
</tr>
<tr>
<td>4</td>
<td>Vested Volumes for each time period provided to EMC</td>
<td>MSSL</td>
</tr>
<tr>
<td>5</td>
<td>Payment Quantity Calculation (Total Forecasted Load - Notional Vested Volume * 0.33 - capped at VoLL) made by EMC.</td>
<td>EMC</td>
</tr>
<tr>
<td>6</td>
<td>Allocation of Payments to DRA’s compliant with 8.2. based on dispatch volumes/quantities.</td>
<td>EMC</td>
</tr>
<tr>
<td>7</td>
<td>Receipt of actual metered Contestable volumes after day 6 in line with current settlement cycle. See Chapter 7 of Market Rules.</td>
<td>MSSL</td>
</tr>
<tr>
<td>8</td>
<td>Allocation of Costs to Contestable consumers from metered volumes through HEUC mechanism.</td>
<td>EMC</td>
</tr>
</tbody>
</table>

8.3.2 Performance / Penalties

In order to avoid the gaming risks inherent in paying for something that is not or would not be otherwise provided - it is critical to have relatively severe penalties for non-compliance with measurable baselines.

For demand response there are two parts to this compliance:

1. Not reducing the quantity bid against a baseline when not dispatched, and
2. Reducing quantity against a baseline when dispatched.

If there is no good reason for either of these situations, i.e. a reasonably unforeseeable situation where the reduction or non-reduction occurs beyond the DR provider's control, then the assumption must be that the DR provider was trying to affect price by using normal load fluctuations under business as usual conditions.
In this case, where successful gaming would lead to a lower USEP, then generators suffer a detriment through an inefficient reduction in generation revenue. In this case the penalties are based on paying a share of the generator detriment (the countervailing pressure to receiving the share of consumer surplus).

In this case the non-compliant DRA is penalised by paying 33% of the producer detriment, i.e. the change in price with and without the non-compliant bid times the bid volume times 33%. Like the consumer surplus payment the effective price for the penalty will be capped at VoLL.

This method will not necessarily yield a penalty under all circumstances (i.e. the non-compliance will not necessarily affect price) but repeated non-compliance would be grounds to remove a DRA’s licence. And, for the avoidance of doubt, at a minimum any non-compliant DRA block receives no payments.

Partial performance cannot be accepted. Otherwise, the incentives are to bid amounts to maximise price effect while only intending to meet a portion of the quantity bid.

It is suggested that the scheme undergoes a ‘honeymoon period’ for six months from the operational start of the scheme. Penalties would not be applied automatically but may be applied under the additionality provisions (see section 8.3.4) if the DRA is deemed to have wilfully non-complied. After the honeymoon period then penalties would be automatically applied and the burden is on the DRA to demonstrate bona fide reasons for non-compliance.

When a DRA facility of group is set up then any reasonable testing required for licencing and registration will be exempt penalties if non-compliance occurs for the purpose of testing; similar to the flexibility given for generator commissioning.

8.3.3 Payment Mechanism

The use of the HEUC is recommended to recover payments to DRA’s for load reductions where an increase in consumer benefits has been observed. The HUEC mechanism would be used in the manner described in Figure 8.5.

Penalties are recovered using the same method but will be a returned to the non vested consumer as a HEUC payment.

Figure: 8.5 Payment Mechanism

8.3.4 Other Matters

The introduction of the ability for the MSCP to examine cases where on the balance of probabilities there was no additional action taken by a DRA (i.e. the actions where business as usual) then it will have the ability to retrospectively recover any payments made to the DRA in the period concerned and impose a penalty.
8.4 Technical Detail

The following table details the technical detail and conditions relating to the following types of demand response categories:

- Single site >= 10MW or any DR site that also provides IL
- Single DRA aggregate >= 10MW
- Single DRA aggregate < 10MW

Figure: 8.6 Element Table

<table>
<thead>
<tr>
<th>Type (by IL zone)</th>
<th>Single site &gt;= 10MW or any DR site that also provides IL</th>
<th>Single DRA aggregate &gt;= 10MW</th>
<th>Single DRA aggregate &lt; 10MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum size of potential load reduction</td>
<td>10MW</td>
<td>0.1MW</td>
<td>0.1MW</td>
</tr>
<tr>
<td>Licencing</td>
<td>Needs to be licenced as, or by, a DRA approved by EMA and EMC</td>
<td>DRA needs licence approved by EMA and EMC</td>
<td>DRA needs licence approved by EMA and EMC</td>
</tr>
<tr>
<td>Registration</td>
<td>PSO registration for site</td>
<td>PSO registration by site</td>
<td>PSO notification by site</td>
</tr>
<tr>
<td>Connection</td>
<td>Must have valid and current connection agreement</td>
<td>Must have valid and current connection agreement</td>
<td>Must have valid and current connection agreement</td>
</tr>
<tr>
<td>Bidding and Dispatch Block Registration</td>
<td>Can be registered in a Block of sites in the same IL zone</td>
<td>Can be registered in a Block of sites in the same IL zone</td>
<td>Can be registered in a Block of sites in the same IL zone</td>
</tr>
<tr>
<td>Nodal Bids</td>
<td>At load node</td>
<td>At suitable zone node</td>
<td>At suitable zone node</td>
</tr>
<tr>
<td>Dispatch instructions</td>
<td>SCADA interfaced communications – 1 second polling (may be through DRA)</td>
<td>SCADA interfaced communications – 1 second polling through DRA</td>
<td>SCADA interfaced communications – 1 second polling through DRA</td>
</tr>
<tr>
<td>Data Acquisition communication requirements to PSO</td>
<td>SCADA type communications – 1 second polling (may be through DRA)</td>
<td>SCADA type communications – 5 minute polling</td>
<td>No communications</td>
</tr>
<tr>
<td>Class A &lt; 5 min ramping</td>
<td>Ramping performance as per class or based on volume weighted average of each class in the registered Block</td>
<td>Ramping performance based on volume weighted average of each class in the registered Block</td>
<td>Ramping performance based on volume weighted average of each class in the registered Block</td>
</tr>
<tr>
<td>Class B &lt; 10 min ramping</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class C &lt; 15 min ramping</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Performance monitoring</td>
<td>Event recording – when DR is bid at 1 sec samples over the period that DR is bid</td>
<td>5 minute energy reading</td>
<td>30 minute energy reading</td>
</tr>
<tr>
<td>Metering</td>
<td>Separate revenue metering + 1 sec power samples + event recording</td>
<td>Ordinary revenue metering per site or DRA's own solution</td>
<td>Ordinary revenue metering per site</td>
</tr>
<tr>
<td>Settlement volumes</td>
<td>As per bid validated by ordinary revenue metering</td>
<td>As per bid validated by ordinary revenue metering</td>
<td>As per bid validated by ordinary revenue metering</td>
</tr>
<tr>
<td>Ramping performance</td>
<td>Monitored by PSO and verified by event recorder file</td>
<td>Monitored by PSO and verified by 5 min energy reading</td>
<td>Verified by 30 min energy reading</td>
</tr>
<tr>
<td>Metering files</td>
<td>Revenue metering data provided by MSSL aggregated by DRA, by IL load zone, by Block</td>
<td>Revenue metering data provided by MSSL aggregated by DRA, by IL load zone, by Block</td>
<td>Revenue metering data provided by MSSL aggregated by DRA, by IL load zone, by Block</td>
</tr>
</tbody>
</table>
8.4.1 Type

There are three types of demand response that can be provided that have varying technical requirements. A single site of greater than or equal to 10MW must have performance requirements similar to a small generator for which it is substantially similar to for the purposes of price discovery. 10MW is also the threshold for PSO performance requirements for generators.

Similarly once a DRA has a total aggregated demand response of 10MW or greater (regardless of how the sites are registered in Blocks) then some extra performance requirements fall on the DRA but based on lower performance requirements for each site.

Under 10MW then neither a single site nor a DRA has any extra requirements above those to licence, register and facilitate bidding, dispatch and settlement.

8.4.2 Connection

There will be no changes to connections arrangements. DRA parties must still meet, and demonstrate they meet, the connection requirements of the SP Grid and associated distribution assets.

8.4.3 Bidding & Dispatch Blocks

DRAs may have as many Blocks as they wish for bidding and dispatch providing they meet the following criteria:

- Every site in a block dispatch group must be in the same IL zone
- Every site in the Block dispatch zone is considered in assessing Block compliance and settlement (every site's installation must be registered with the Block)
- Every site must be registered by ramp rate class and the bid ramp rate for the Block is the load weighted average ramp rate of each site
- The Block must meet or exceed the ramp rate of the Block but performance is considered in aggregate

For the avoidance of doubt the Blocks do not affect the types for technical requirements. The technical types are based on the total of sites for each DRA in each IL load zone.

8.4.4 Nodal Bids

Larger nodes will need to be bid at their nodal location. For the aggregation of smaller loads either a single or group of nodes will be selected by EMC to bid at. The choice of these zone nodes for DRA bidding is balancing the risk of a node being at the fringes of the pricing network where reconfiguration of the network can have unexpected price effects and having nodes with sufficient load capacity for the demand bids. And, of course, keeping the modelled network flows approximately correct is also important.

8.4.5 Dispatch Instructions

Any DRA must have a suitable connection with the PSO to receive dispatch instructions. The control arrangements from the DRA to their DR providers are the responsibility of the DRA but all Blocks must meet their minimum ramp rate requirements.

8.4.6 Dispatch Instructions

Any DR site of greater than 10MW, any DR provider that is also an IL provider and any DR providers who total more than 10MW with one aggregator in an IL zone must provide some form of data to the PSO's SCADA system.

A site of greater than 10MW or a provider who also provides IL must have 1 sec polling power measurement provided to the PSO. They must also have event recording whereby a record of the power output from the site by 1 second intervals can be provided over any period when DR is bid.

Smaller loads, but who still exceed 10MW of total load (regardless of Block allocations) for a single DRA in aggregate, may use their energy metering to provide instantaneous power readings (aggregated by the DRA) every 5 minutes where

\[ P_n = (E_n - E_{n-1}) \times 5 \]

Where the deemed instantaneous power output at a site \( P_n \) in the nth 5 minute interval during the current trading period is given by the function above, and \( E_n \) is the instantaneous energy reading at the same 5 minute point.

This method should allow that smaller DR loads can use IES meters, for DR performance monitoring, when they are rolled out. However, the provision of suitable metering is entirely the responsibility of the DRA.

8.4.7 Class

The three classes of DR are proposed to allow as many DR providers as practical while recognising that slower demand response has impacts on system frequency regulation. Therefore, while three classes of participant are allowed the payments mechanism will adjust DRA payments based on the speed of DR.
The three classes are shown in the table below:

**Figure: 8.7 Element Table**

<table>
<thead>
<tr>
<th>Response/ Ramp rate</th>
<th>Class A</th>
<th>Class B</th>
<th>Class C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt; 5min</td>
<td>Between 5 min and 10 min</td>
<td>Between 10 min and 15 min</td>
</tr>
<tr>
<td>Payments</td>
<td>Payment based on 100% of dispatched load curtailment</td>
<td>Payment based on 75% of dispatched load curtailment</td>
<td>Payment based on 50% of dispatched load curtailment</td>
</tr>
</tbody>
</table>

Notwithstanding the provision for different classes of DR the proposal attempts to still allow for DRAs to aggregate Blocks with some flexibility to make their own trade-offs between compliance, payment and portfolio flexibility. However, this approach does create quite a lot of extra complexity. Most of this complexity can be addressed by system changes but the registration options for a DRA are complex. A DRA can reduce this complexity by choosing Blocks of similar classes.

When a Block is registered with the EMC then each site and its class will also need to be registered as part of the Block registration. Once a Block has been registered then the following fixed factors for that Block’s dispatch and payment can be derived. These factors are fixed by Block and can only be changed by re-registering

\[
\begin{align*}
    k_1 &= \frac{\sum R_A}{\sum R_{all}} \\
    k_2 &= \frac{\sum R_B}{\sum R_{all}} \\
    k_3 &= \frac{\sum R_C}{\sum R_{all}}
\end{align*}
\]

Where \(R_A\) is any DR registered in the Block of any Class, \(R_B\) is any DR registered in the Block as Class A, \(R_C\) is any DR registered in the Block as Class B and \(R_{all}\) is any DR registered in the Block as Class C; all in MWs.

The payment factors for the Block (in accordance with the table above) are also fixed in proportion to the registration of the Block.

Payment to a Block would be then the full payment (33% of increase in consumer surplus) \(\times PF\) or $4,500/MWh, whichever is the lower.

### 8.4.8 Performance Monitoring

Any DR site of greater than 10MW, any DR provider that is also an IL provider and any DR providers who total more than 10MW with one aggregator in an IL zone will be monitored by the PSO. However, the PSO will monitor their compliance within any Block they are registered to.

There are two modes for monitoring performance.

1. The Block is dispatched to full load (and must consume), or
2. The Block is dispatched to reduced load (and must reduce).

If the Block is dispatched then performance is met if

\[
D_Q \leq P_R
\]

Where \(D_Q\) is the dispatched quantity and \(P_R\) is the instantaneous power output of the Block during the trading period.

If the Block is dispatched to reduced load then performance is met if

\[
\begin{align*}
P_0 &= D - \Delta D \\
P_5 &= P_0 + k_1 \cdot \Delta D \\
P_{10} &= P_{10} + k_2 \cdot \Delta D \\
P_{15} &= D
\end{align*}
\]

Where \(P_0, P_5\) and \(P_{10}\) is the instantaneous power consumption of the Block at the start of the trading period, 5 minutes into the trading period and 10 minutes into the trading period respectively. \(P_{15}\) is the instantaneous power consumption of the Block from 15 minutes on in the trading period.

\(D\) is the dispatched volume for the Block and \(\Delta D\) is the algebraic change in dispatch from the previous dispatch instruction (i.e. + = ramp up and - = ramp down). The power levels are maximum levels at each time period for ramping down and minimums for ramping up.
The three classes are shown in the table below:

**Figure: 8.7a Element Table**

<table>
<thead>
<tr>
<th>Response/Ramp rate</th>
<th>Class A</th>
<th>Class B</th>
<th>Class C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt; 5 min</td>
<td>Between 5 min and 10 min</td>
<td>Between 10 min and 15 min</td>
</tr>
<tr>
<td>Payments</td>
<td>Payment based on 100% of dispatched load curtailment</td>
<td>Payment based on 75% of dispatched load curtailment</td>
<td>Payment based on 50% of dispatched load curtailment</td>
</tr>
</tbody>
</table>

Notwithstanding the provision for different classes of DR the proposal attempts to still allow for DRAs to aggregate Blocks with some flexibility to make their own trade-offs between compliance, payment and portfolio flexibility. However, this approach does create quite a lot of extra complexity. Most of this complexity can be addressed by system changes but the registration options for a DRA are complex. A DRA can reduce this complexity by choosing Blocks of similar classes.

When a Block is registered with the EMC then each site and its class will also need to be registered as part of the Block registration. Once a Block has been registered then the following fixed factors for that Block’s dispatch and payment can be derived. These factors are fixed by Block and can only be changed by re-registering the Block.

Where \( R_A \) is any DR registered in the Block of any Class, \( R_B \) is any DR registered in the Block as Class A, \( R_C \) is any DR registered in the Block as Class B and \( R_C \) is any DR registered in the Block as Class C; all in MWs.

The payment factors for the Block (in accordance with the table above) are also fixed in proportion to the registration of the Block.

\[
PF = (100.k_1 + 75.k_2 + 50.k_3)\%
\]

Payment to a Block would be then the full payment (33% of increase in consumer surplus) x PF or $4,500/MWh, whichever is the lower.

8.4.8 Performance Monitoring

Any DR site of greater than 10MW, any DR provider that is also an IL provider and any DR providers who total more than 10MW with one aggregator in an IL zone will be monitored by the PSO. However, the PSO will monitor their compliance within any Block they are registered to.

There are two modes for monitoring performance.

1. The Block is dispatched to full load (and must consume), or
2. The Block is dispatched to reduced load (and must reduce).

If the Block is dispatched then performance is met if:

\[
D = D_0
\]

If the Block is dispatched to reduced load then performance is met if

\[
P_{15} > P_{10} > P_5 > P_0
\]

Where \( D_0 \) is the dispatched quantity and \( P_0 \) is the instantaneous power output of the Block during the trading period.

If the Block is dispatched to reduced load then performance is met if

\[
P_{15} > P_{10} > P_5 > P_0
\]

Where \( P_0, P_5 \) and \( P_{10} \) is the instantaneous power consumption of the Block at the start of the trading period, 5 minutes into the trading period and 10 minutes into the trading period respectively. \( P_{15} \) is the instantaneous power consumption of the Block from 15 minutes on in the trading period.

\( D \) is the dispatched volume for the Block and \( \Delta D \) is the change in dispatch from the previous dispatch instruction.
8.4.9 Performance Monitoring

DR should be settled on a pay as bid basis. However a further compliance check is proposed at settlement, which is also the only compliance check for DRAs whose total aggregate load in a zone is less than 10MW.

At settlement then for a Block that was dispatched at full load then

\[ E_M \geq \frac{D}{2} \]

Where \( E_M \) is the revenue metered energy for the trading period of dispatch and \( D \) is the dispatched volume.

Where the Block is dispatched for reduced load then

\[ E_M \leq \frac{P_0}{12} + \frac{P_1}{12} + \frac{P_{10}}{12} + \frac{P_{12}}{4} \]

Based on the instantaneous power performance requirements, where connection rules/requirements agreements are fully adhered to.

8.4.10 Other Issues

Distribution losses are not expected to be an issue in this assessment.

In the event that non IES meters are deployed then a metering performance regime will be required.
As an example of this trend in Singapore - The Intelligent Energy System (IES) Pilot programme has the objective of encouraging the development of applications that are enabled by a smart grid such as dynamic pricing plans and advanced energy management systems, which could help consumers to better manage their energy consumption and lower their energy costs.

Ironically, the HSFO linked product appears to be offered more widely as compared to to oil refineries and oil companies – which adds further weight to the concern that products offered by the gencos are more about managing generation risk than that of their consumers. Notwithstanding this there are some companies that purport, and their websites support this position (albeit with generalities rather than specifics), that they offer tailored products to reflect consumer risk preferences. We have not found any evidence of event basic derivative products being offered like those openly marketed by New Zealand retailer Mercury Energy at http://www.mercury.co.nz/For-your-Business/Pricing-options/Hedge.aspx.

Refer to www.ferc.gov

The introduction of real time (or at least half hourly) metering assets in recent years and the use of web-based tools to observe and manage consumption are two notable examples.

The development of smart grid technologies (e.g. smart metering assets) have reduced the technological barriers to the implementation of active demand response programmes – however in many global jurisdictions these smart grid elements are at best the exception and at worst a rarity or non existent. The regulatory barriers reflect the fact that much of the global energy industry still does not use deregulated markets for delivery of energy to consumers.

We have tried to identify consumers that use this type of product through both direct interviews with consumer and also literature and web based research. We found no evidence of the routine pricing of CfD based mechanisms or any examples of Generators / Retailers attempting to groom the market or educate consumers as to their use and availability.

The scope of work required by EMA in the terms of reference of this project does not include the consideration of non-market based solutions.

Also called the Value of Unserved Energy (USE).


Refer to the Metering Code, Energy Market Authority, January 2012

This was given as a reason for demand response in our meeting in June 2012 with CPvT Energy Asia Pte. Ltd

Refer to http://www.ema.gov.sg/page/8/id:31/

The US markets have seen demand response offerings being a considerable proportion of offered capacity in capacity auctions. Within the PJM market, the first capacity auction held under the Reliability Pricing Mechanism in 2007 saw almost half of the 270 MW offers from demand response providers.


Both the Australian NEM and the NZEM have addressed these issues in the past decade (Australia in 2004/05 and New Zealand in 2011/12). Refer to http://www.ret.gov.au/Documents/mca_/documents/UserParticipationAugust0420041126105900.pdf.


Refer to http://www.scoop.co.nz/stories/BU0305/S00070/mercury-energy-first-out-of-the-blocks.htm,


For example see Laurits R. Christensen Associates, Inc., 31 August 2002, Encouraging Demand Participation in Texas’ Power Markets, for Market Oversight Division of the Public Utility Commission of Texas.
The first hint of trouble came in December 2009, when PJM revealed in a load management performance report that customers who bid demand response (DR) resources into the RPM capacity market for the 2009/2010 delivery year had actually over-performed—they had backed off 18 percent more capacity (1,299 MW) than promised. Trouble, that is, because when PJM’s independent market monitor began to parse the data, that surplus started looking more like a shortage. Led by its president, Joseph Bowring, the IMM Monitoring Analytics LLC had found that by taking advantage of a loophole in PJM rules, certain aggregators of retail customers (known in PJM as curtailment service providers, or CSPs) had figured out clever ways to assemble portfolios of demand-side resources so as to earn twice the credit for capacity relief that PJM ordinarily accorded to DR offers. (Public Utilities Fortnightly, October 2011, p.18)

For example, Auckland City New Zealand has seen the deployment of GPRS and Radio Mesh Metering Networks which can be configured to deliver demand response products

Given the relatively integrated transmission grid and distribution network environment and the fact many of the potential grid and transmission issues were also raised by other stakeholders we have not summarised their transmission / distribution comments in this section.

Recognising that a FPFV / CID arrangement may not include a physical delivery contract.

In our view, we expect the demand response to participate in the energy market during peak periods when peaking plants are dispatched. Given the new capacity that is entering the Singapore market in 2013, we expect base-load plants to be combined cycle gas turbines (CCGT), which marginal cost is not expected to be more than $300/MWh under normal market conditions, and that is proposed to be used for the setting of a price floor.

In the short term spot prices will have no impact, over time elevated (or suppressed) spot prices would be expected to be reflected in contracting prices.
Annex A: CfD Example

The following example provides an example of the execution and settlement of a contract for difference (CfD) arrangement.

**Traditional Tariffs: Fixed Price Variable Volume Contract (FPVV)**

Most traditional tariff based sales arrangements for electricity combines the physical delivery of electricity and fixed prices for the sale of the delivered electricity. Figure A.1 gives a graphic illustration of this traditional approach. This approach is often referred to as a fixed price variable volume (FPVV) arrangement.

**Figure A.1: FPVV Tariff Consumption**

Table A.2 provides a tabular view of the cash costs for each time period for the consumer (Columns 6 and 8). The spot rate has no impact on this commercial arrangement therefore there are no spot costs (Column 7) in this example.

**Figure A.2: FPVV Tariff Consumption Table**
In the above FPVV example, the total cost of energy was $18,555 for fifteen time periods in the example. This example contrasts with the CfD (or FFVV contract) arrangement described for the same consumer described below.

Financial Arrangements: Contract for Differences (CFD)

Figure A.3 gives a graphical illustration of this financial contract based approach. This example in terms of loads is identical to the scenario depicted in Figure A.1, albeit the contract rate is different. The red line in Figure A.3 depicts the volume of hedging in this example (at 13MW base load).

Figure A.3: CFD Consumption

Table A.4 provides a tabular view of the cash costs for each time period for the consumer (Columns 6, 7 and 8). The spot rate is a direct pass through (probably with a small fixed margin) from a traditional electricity retailer or SP Services. The total cost of energy for the consumer in this example is reflected in Column 8, which is the sum of columns 6 and 7.

Figure A.4: CFD Contract Consumption Table

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time Period</td>
<td>Average MW</td>
<td>Load (MWh)</td>
<td>Contract Rate ($/MWh)</td>
<td>Spot Rate ($/MWh)</td>
<td>Contract Cost/Benefit @13 MW ($</td>
<td>Spot Cost ($)</td>
<td>Total Cost ($)</td>
</tr>
<tr>
<td>1</td>
<td>10</td>
<td>5</td>
<td>$214</td>
<td>$175</td>
<td>$253</td>
<td>$875</td>
<td>$1,128</td>
</tr>
<tr>
<td>2</td>
<td>12</td>
<td>6</td>
<td>$214</td>
<td>$200</td>
<td>$91</td>
<td>$1,200</td>
<td>$1,291</td>
</tr>
<tr>
<td>3</td>
<td>13</td>
<td>6.5</td>
<td>$214</td>
<td>$225</td>
<td>$71</td>
<td>$1,463</td>
<td>$1,391</td>
</tr>
<tr>
<td>4</td>
<td>15</td>
<td>7.5</td>
<td>$214</td>
<td>$278</td>
<td>$416</td>
<td>$2,085</td>
<td>$1,669</td>
</tr>
<tr>
<td>5</td>
<td>15</td>
<td>7.5</td>
<td>$214</td>
<td>$4,500</td>
<td>$27,859</td>
<td>$33,750</td>
<td>$5,891</td>
</tr>
<tr>
<td>6</td>
<td>13</td>
<td>6.5</td>
<td>$214</td>
<td>$4,500</td>
<td>$27,859</td>
<td>$29,250</td>
<td>$1,391</td>
</tr>
<tr>
<td>7</td>
<td>13</td>
<td>6.5</td>
<td>$214</td>
<td>$596</td>
<td>$2,483</td>
<td>$3,874</td>
<td>$1,391</td>
</tr>
<tr>
<td>8</td>
<td>11</td>
<td>5.5</td>
<td>$214</td>
<td>$210</td>
<td>$26</td>
<td>$1,155</td>
<td>$1,181</td>
</tr>
<tr>
<td>9</td>
<td>10.5</td>
<td>5.25</td>
<td>$214</td>
<td>$195</td>
<td>$123</td>
<td>$1,024</td>
<td>$1,147</td>
</tr>
<tr>
<td>10</td>
<td>10</td>
<td>5</td>
<td>$214</td>
<td>$175</td>
<td>$253</td>
<td>$875</td>
<td>$1,128</td>
</tr>
<tr>
<td>11</td>
<td>10</td>
<td>5</td>
<td>$214</td>
<td>$198</td>
<td>$104</td>
<td>$990</td>
<td>$1,094</td>
</tr>
<tr>
<td>12</td>
<td>9.5</td>
<td>4.75</td>
<td>$214</td>
<td>$197</td>
<td>$110</td>
<td>$936</td>
<td>$1,046</td>
</tr>
<tr>
<td>13</td>
<td>9.5</td>
<td>4.75</td>
<td>$214</td>
<td>$201</td>
<td>$84</td>
<td>$955</td>
<td>$1,039</td>
</tr>
<tr>
<td>14</td>
<td>9.5</td>
<td>4.75</td>
<td>$214</td>
<td>$203</td>
<td>$71</td>
<td>$964</td>
<td>$1,036</td>
</tr>
<tr>
<td>15</td>
<td>11</td>
<td>5.5</td>
<td>$214</td>
<td>$196</td>
<td>$117</td>
<td>$1,078</td>
<td>$1,195</td>
</tr>
<tr>
<td>Totals</td>
<td>86</td>
<td></td>
<td></td>
<td>$57,456</td>
<td>$80,474</td>
<td>$23,018</td>
<td></td>
</tr>
</tbody>
</table>
In the above CfD example, the total cost of energy was $23,018 for fifteen time periods. The consumer being under-hedged during time period 5 (their consumption average 15MW during that half hour period but their hedge volume was only for 13 MW) was the material driver of variances between the FPVW and CfD examples. It is this type of situation that provides the incentives for passive demand response using CfD contracts.

The following table (Figure A.5) illustrates the financial benefit of demand response actions during high price events, where the consumer reduces their consumption by half in time periods 5 and 6. Changes from Figure A.4 are highlighted in yellow in the table below.

**Figure A.5: CfD Contract Consumption Table – with Demand Response**

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Average MW</th>
<th>Load (MWh)</th>
<th>Contract Rate ($/MWh)</th>
<th>Spot Rate ($/MWh)</th>
<th>Contract Cost/Benefit @13 MW ($)</th>
<th>Spot Cost ($)</th>
<th>Total Cost/Benefit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>5</td>
<td>$214</td>
<td>$175</td>
<td>$253</td>
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<td>12</td>
<td>6</td>
<td>$214</td>
<td>$200</td>
<td>$91</td>
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<td>$1,291</td>
</tr>
<tr>
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<td>13</td>
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<td>$214</td>
<td>$225</td>
<td>$71</td>
<td>$1,463</td>
<td>$1,391</td>
</tr>
<tr>
<td>4</td>
<td>15</td>
<td>7.5</td>
<td>$214</td>
<td>$278</td>
<td>$416</td>
<td>$2,085</td>
<td>$1,669</td>
</tr>
<tr>
<td>5</td>
<td>15</td>
<td>3.75</td>
<td>$214</td>
<td>$4,500</td>
<td>$27,859</td>
<td>$16,875</td>
<td>$10,984</td>
</tr>
<tr>
<td>6</td>
<td>13</td>
<td>3.25</td>
<td>$214</td>
<td>$4,500</td>
<td>$27,859</td>
<td>$14,625</td>
<td>$13,234</td>
</tr>
<tr>
<td>7</td>
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<td>6.5</td>
<td>$214</td>
<td>$596</td>
<td>$2,483</td>
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<td>$1,391</td>
</tr>
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</table>

This example shows that the net cost of energy for fifteen time periods is a negative value (i.e. consumer in turn receives a payment for their consumption of 79 MWh).
## Annex 2: Parties Interviewed During Analysis

We appreciate the generous assistance provided by the following organisations during the course of our study:

<table>
<thead>
<tr>
<th>Party</th>
<th>Organisation Type</th>
<th>Meeting Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GMR Energy</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Keppel Merlimau Cogen / Keppel Electric</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Power Seraya / Seraya Energy</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Sembcorp Energy / Sembcorp Energy Supply</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Senoko Energy / Senoko Energy Supply</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Tuas Power Generation / Tuas Power Supply</td>
<td>Generator / Retailer</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Tuaspring</td>
<td>Generator</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Diamond Energy Ltd</td>
<td>Retailer / IL Provider</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Energy Market Company</td>
<td>Market operator</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Entelios</td>
<td>Demand Aggregator</td>
<td>Telephone Conversations</td>
</tr>
<tr>
<td>KiwiPower</td>
<td>Demand Aggregator</td>
<td>Telephone Conversations</td>
</tr>
<tr>
<td>Panasonic</td>
<td>Equipment Provider</td>
<td>One-on-one session</td>
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<tr>
<td>SP Services</td>
<td>Market Support Services Licensee</td>
<td>Industry meeting / One-on-one session</td>
</tr>
<tr>
<td>Shell Eastern Petroleum Ltd</td>
<td>Consumer / Embedded Generator</td>
<td>One-on-one session</td>
</tr>
<tr>
<td>Ministry of Trade and Industry (MTI)</td>
<td>Government agency / Regulator</td>
<td>Inter-agency meeting / One-on-one session</td>
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<tr>
<td>Enernoc</td>
<td>Demand Side Aggregator</td>
<td>One-on-one session in New Zealand</td>
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<tr>
<td>New Zealand Electricity Authority</td>
<td>Foreign Government agency / Regulator</td>
<td>One-on-one session in New Zealand</td>
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<tr>
<td>Mitsui</td>
<td>Demand Aggregator / Equipment Provider</td>
<td>One-on-one session</td>
</tr>
</tbody>
</table>