Response to Post 2025 market design issues paper.

A review of the issues facing large-scale despatchable generation investments within the NEM, an alternative approach and a survey of global experience with nuclear energy investments.

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This submission was prepared by representatives from DUNE (Down Under Nuclear Energy Pty Ltd) and NECG (Nuclear Economics Consulting Group) to provide the ESB (Energy Security Board) with recommendations for the post-2025 NEM market structure.

This submission is intended for the ESB and shall be treated as confidential. Written permission shall be sought from DUNE prior to wider circulation of this document.

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Executive Summary

Societies across the world are trying to deal with the problem of providing inexpensive and reliable energy while at the same time reducing emissions and other ecological impacts to our planet. There is an increasingly strong view that this cannot be done without nuclear energy and consequently there is renewed interest and debate in Australia at state and federal levels to assess, once again, the desirability of nuclear energy.

Regardless of the desirability of nuclear energy for its environmental and economic benefits, including affordable and reliable supply of power, it has proven to be difficult to realise these benefits within liberalised electricity markets. Such markets fail to value the multitude of social goods and desirable characteristics that nuclear technology delivers and do not provide the long-term revenue certainty needed for long-lived nuclear power projects. The same issue faces other technologies that are expensive to deploy and have long operating lives.

However, there are opportunities to learn from the experience of other advanced economies who have, with varying success, managed to provide or are working towards market structures that explicitly price or implicitly assign value to the qualities that 21st century citizens demand from their electricity supply;

1. Affordability
2. Reliability
3. Stewardship – both ecological and economic

There is no question that a domestic nuclear energy industry will require the vocal support of governments to make the case for nuclear technology to voters. However, government will also need to work with the market operator and the private sector to overcome some of the unique investment challenges that nuclear energy deployments face. We offer a suggested market framework that can accommodate all technologies, including nuclear.

There is a strong case for Australia to consider small modular reactors (SMRs) operating within the NEM as this class of reactors have characteristics that reduce project risks, reduce development time, increase system flexibility and provide ample grounds for innovative business models, financing techniques, and applications not available to traditional reactors. They are also more suited for smaller markets such as Australia.

Some offerings of an SMR deployment are external to the electricity market, including industrial heat and desalination, providing nuclear project developers with diverse means of realising the value of these investments.

SMR success will need an alliance among industry, public, and the government. Industry must provide viable technologies and deployment structures, the public must understand the need for nuclear power under a clean growth strategy for an advanced economy, and government must employ the necessary tools to promote this new technology, given market and regulatory constraints.

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Introduction

DUNE and NECG understand that nuclear energy is not currently permitted under Australian law. However, three ongoing government inquiries (federal, NSW and Vic) at least warrant consideration of how this energy source could operate within a future, optimised NEM structure so as not to unfairly disadvantage nuclear investment should it be legalised in the future.

DUNE and NECG understand that it is a simple thing for business to demand a market structure that provides a level playing field and which fairly values the three fundamental imperatives of energy to a modern economy; affordability, reliability, stewardship. We also appreciate that it is much harder to deliver a structure that assigns value to social goods such as clean air, lower ecological footprint, reliability, resilience and diversity – our country has tried this once before with the *Emissions Trading Scheme*.

In the context of trying to encourage private investment in new generation within the NEM, the investment case and the economic case are steadily diverging – and the investment case is winning. Private investment is nearly exclusively allocated to intermittent energy infrastructure which can externalise the costs of intermittency whilst enjoying substantial subsidies and preferential market access. Our reading of the ESB position paper indicates that this investment incentive structure is fully understood at a policy level.

This failure of the market structure to maximise social benefits across multiple essential characteristics is made worse by our nation's current ban on an entire class of technology that has a demonstrated track record in many other countries of maximising both measurable and intangible benefits to the public.

This submission is broken into two parts. The first part, prepared by DUNE, is focused on the NEM structure as it is, as it could be and nuclear energy in the Australian context. The second part, drawing on the expertise of NECG, examines the experience of other electricity markets where nuclear energy forms part of the energy mix. Broadly, this submission seeks to

- Outline the aspects of the current market structure that undermine the investment case for anything other than intermittent renewable energy;
- Propose a rough outline of a market/planned hybrid approach that balances competing objectives and should provide adequate investment signals;
- Provide the ESB with relevant information regarding a potential nuclear energy project within the NEM;
- Briefly describe alternative global approaches to electricity markets;
- Survey international experience with electricity markets that include nuclear energy as part of the diverse energy mix; and
- Conclude with considerations for the ESB that, if incorporated, could provide fertile ground for a future nuclear energy investment within the NEM.

The document will not repeat the economic and environmental case for developing nuclear power within Australia. Both DUNE and NECG have made extensive contributions to the recent *Inquiry into the Prerequisites for Nuclear Energy in Australia* which we invite the ESB to consider. (See https://www.aph.gov.au/Parliamentary_Business/Committees/House/Environment_and_Energy/Nuclearenergy/Submissions) Submissions 159 (DUNE) and 144 (NECG).

Part 1.

The Electricity Market – The Shape of the Challenge

Given the rapid escalation of energy prices within the NEM and the uncertainty associated with future prices, would the current market structure allow a private developer to profitably build and operate a merchant nuclear power station? Perhaps – but no investor would be prepared to take the risk given the scale of the capital outlay, revenue uncertainty, long project development time, and high regulatory requirements on nuclear power plants.

Anti-nuclear advocates have taken to justifying the continued ban on nuclear energy from a market perspective, arguing that renewable energy is now cheaper than all other forms whilst demanding that government retain the generous direct and indirect subsidies that renewable energy investments enjoy. They conveniently ignore the observed realities across the world – expansion of renewable energy past a certain market penetration level rapidly drives up end-user electricity prices, increases system costs and grid management issues, and may increase total system carbon emissions, whilst past investments in nuclear energy assets have resulted in cleaner electricity systems and some of the lowest end-user energy prices in the world today.

Sober analysis of these renewable advocate claims, and the claims of nuclear or other generation technology advocates, reveal that the noisy arguments over technology selection are obscuring a more fundamental and important consideration (the shape of the problem);

> *In the electricity sector, can a market structure be designed to provide long range investment signals and feedback loops that cover the full range of attributes our society expects of its energy whilst ensuring timely and adequate investment for future energy needs?*

OR

> *Have the limits of markets already been found in the electricity sector? Weighing the likely needs of future generations, is long-range planning and government control of capacity expansion decisions necessary to ensure cheap, reliable and ecologically sound energy for decades into the future?*

These remain open questions; on the available evidence, only ideologues at either end of the economic spectrum would confidently declare the superiority of one approach over the other. The optimal solution probably lies somewhere between a fully liberalised market and a fully planned, state owned utility.

However, the evidence for the efficiency of markets in other sectors is overwhelming, so we are obliged to thoroughly consider market reform.

What characteristics would an electricity market framework need to maximise public good? And how might this hypothetical market framework provide adequate incentive for future developers of energy infrastructure, nuclear or otherwise? We begin with a brief description of some shortcomings of the current market structure.

Shortcomings of the NEM: A Summary

Markets work efficiently when they are designed to provide a noise-free feedback signal that reflects full total system costs for participants; that is, participants assume the market risk of their own decisions and reap the rewards of good judgement (or suffer the consequences of bad judgement). Several factors have combined to destroy negative feedback for investors in intermittent renewable energy or prevent affirmative signals to prospective investors in other energy technologies.

Subsidies

The first of these is the extensive subsidies which exist outside of the market at both the state and federal levels and which have largely insulated renewable energy developers from market feedback and from responsibility for system costs due to backup generation and other system operator action to address intermittent operation. Large-scale Generation Certificates (LGCs) and preferential market access provide incentives for renewable investment with little or no downside risk. Where the opportunity to do so exists, investors can be counted on only to develop projects that receive a handsome return on investment (ROI) with little or no market risk. Any subsidy insulates against or distorts market feedback by insulating investors against the realities of the market – policy makers must find another method of implementing environmentally-minded energy policy.

Simplistic Market Structure

The second factor is the simplistic nature of an energy-only market which results in low resolution and distortive market feedback. The multiple parameters that useful energy investments should seek to maximise, have been reduced to a single tradeable commodity within a single market (ignoring the Frequency Control Ancillary Services (FCAS) market). The result of this oversimplification is a market structure that provides no investment signals for the other attributes that we demand of our electricity markets in an advanced economy. Figure 2 demonstrates that these imperatives, in combination with environmental stewardship, have multiple sub-parameters that may be in competition. Policy makers need to find another way to send investment signals to technology that can provide essential qualities that may be in short supply, including despatchability, flexibility, resiliency, fuel and technology diversity, price stability and ecological soundness.

Externalisation of Shortcomings

The price-merit order of despatch within an energy-only market structure has, until recently, obscured the violation of a fundamental market principle that market proponents should compete, not predate one another. There are total system costs due to intermittency that are not born by investors in intermittent generation assets but are instead transferred to the owners of other market assets that are not technically or economically optimised to bear these costs in the long-term but are capable of operating flexibly to backstop the market (and network) in the short-term. The ability to externalise costs[1] is another way that market feedback can be ignored by some investors at the expense of others and provides ample incentive for them to keep doing more of the same. Policy makers must find a

[1] Externalised costs are not limited to network costs associated with intermittent assets but also include emissions (carbon or otherwise) and end-of-life waste disposal amongst others.

way to ensure that investors in a particular technology internalise the full costs of their selection or are at least not paid for qualities they do not provide. Not all MWs are created equal.

Deployment and Investment Timeline

In Australia, the electricity market was liberalised when the NEM effectively had one type of technology; coal. This meant the elasticity of supply[2] for all market participants was effectively the same and the broad considerations for investment, including operating life and operating characteristics, were also similarly matched. Over 20 years later, new technologies have mushroomed with much greater supply elasticity and very different operating characteristics.

The current NEM structure provides short-range investment signals and short-range supply/demand outlook which obviously favours small, fast-to-deploy assets with short operating lives and fast payback periods. If policy makers wish to attract large, despatchable generation investment to the NEM, there will need to be long-range investment signals and long-range supply planning for assets that may take up to 10 yrs to develop (even if actual construction time is shorter) and have an operating life in excess of 60 yrs.

Fast-to-deploy technology presents both an opportunity and a risk in a liberalised market. Investors and market purists will always favour flexibility and without incentives to invest large amounts of capital for very long periods, investors will always opt for smaller capital outlays with faster payback times (maximising public good does not have a bearing upon a discounted cashflow analysis). In addition to benefiting the investor, it is undeniable that there are some market benefits to this flexibility such as market responsiveness to cover energy shortfalls/oversupply not predicted by long range demand forecasts.

However, this same flexibility comes with some risks and costs. First, in markets with high penetrations of renewable energy (and the accompanying, necessary simple cycle gas turbine generation), global experience has shown that the deployment costs of this technology have scant relationship to the average cost of energy as experienced by customers. Instead, the actual cost of energy is primarily a function of

i) *energy costs in adjacent markets* (from which energy is purchased or sold on a price-taker basis, i.e. Denmark);

or

ii) *gas costs*.

The NEM has no adjacent, high reliability market from which to purchase or sell energy to balance the system and it can be expected that by investors continuing to favour more flexibly deployed renewable energy, energy prices will increasingly move in lockstep with gas prices and eventually, with the cost of deploying and operating utility scale storage (see figure below).

[2] Supply elasticity in this context should be considered as a combination of development time and increment size. Renewable energy and gas fired generation can be deployed far more quickly and in much smaller increments than either coal or nuclear energy.

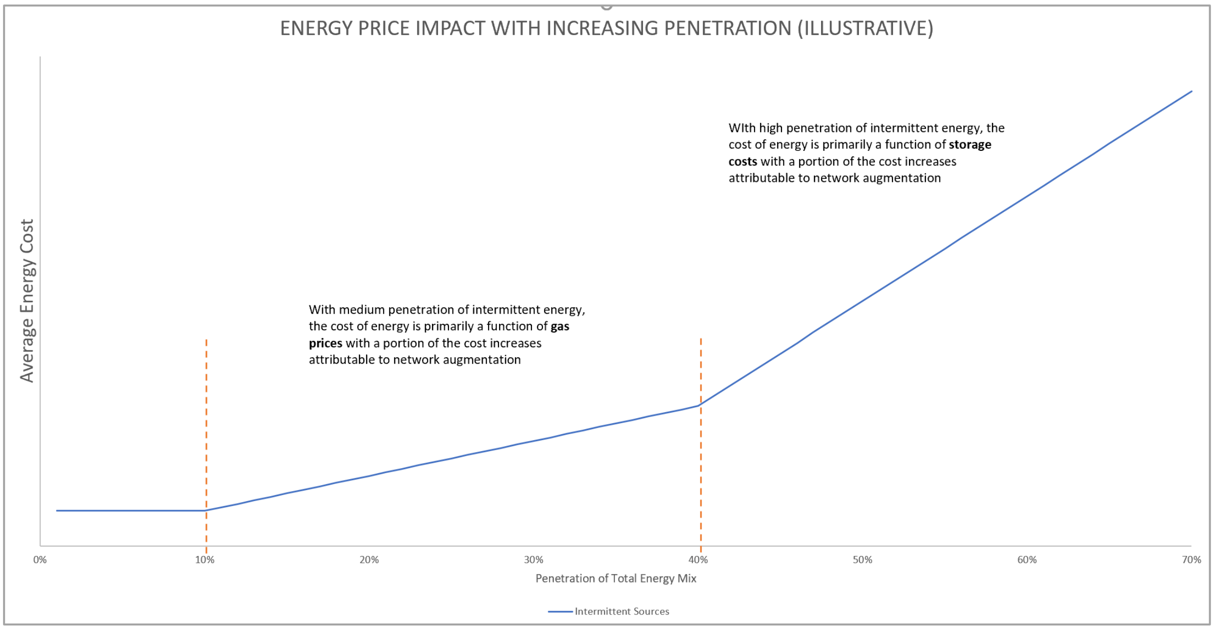

Figure 1. Synthesis of observed and predicted average energy prices with increasing penetration of renewable energy.

In countries with cheap, plentiful gas, the short-term impact on energy prices is negligible although there is an oft forgotten opportunity cost of consuming a finite resource for its least-value economic application[3]. In Eastern Australia, our export industry ensures that we are coupled to international LNG markets and bringing new, economical gas to the domestic market in sufficient quantities will be a challenge.

Lack of System Diversity

There is also a risk that our national skills base is hollowed out and that we may find it very difficult to re-orient our future energy mix in response to as-yet-unseen market or ecological forces. It is a fundamental rule of optimisation that optionality (separate from flexibility) should be maintained, but and we may lose that optionality after an extended period where investors are permitted to exclusively deploy the technology that suits (which may not achieve the desired fuel or generation technology diversity at a system level).

An Alternative Approach

In the process of understanding what would be required to justify a nuclear energy investment within the NEM, DUNE has conceived a market structure that we believe would provide maximum policy and economic flexibility for governments and energy users whilst also providing the high resolution and timely investment signals for various technology and fuel types. It remains a rough outline and, for brevity, is only summarised here.

Figure 2 below provides the framework by which the structure was conceived. Whilst this structure requires further development and evolution, this framework may be useful for assessing the merits of alternative approaches.

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[3] Natural gas is an essential feedstock for hundreds of essential products like plastics, fertilisers, explosives, liquid fuels etc. and we should be making some attempt to preserve this precious commodity for future generations. To burn it for its calorific value when alternatives exist seems wasteful and short-sighted.

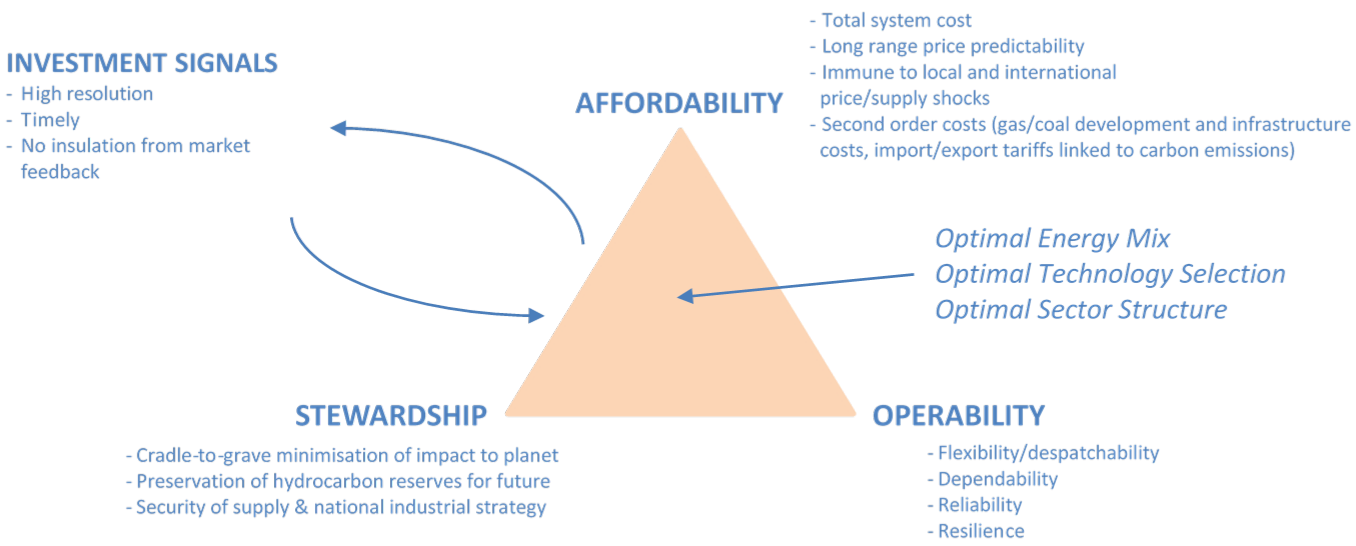


Figure 2. Market Structure Assessment Framework

The Australian Energy Market Operator (AEMO) must be able to operate a market structure with parameters that can be regularly adjusted to adapt to changing policy settings, economic conditions and technological development. With this flexibility built into the design, future governments should not need to change the market structure or offer out-of-market subsidies to implement policy, - adjusting the parameters within the existing structure will be sufficient (after extensive consultation with AEMO!). By making incremental changes in the parameters, government can ensure an orderly transition to a different energy mix whilst minimising the risks of over-reliance on a specific technology.

At a minimum, the attributes of generation technology within the system must compliment the nature of the load to be serviced; baseload & variable load. To do this, DUNE proposes <u>three separate reverse auction markets across different, but overlapping classes of energy generation</u>. Each market will have several available contract durations which reflect the time-range required for <u>investment signals that are appropriate to the development timelines of the technology classes required by the market</u>. A solar/storage investor does not need 20 years notice to deploy its assets whilst a nuclear project developer needs at least 10 years – the investment signals for the various classes of technology require different notice periods.

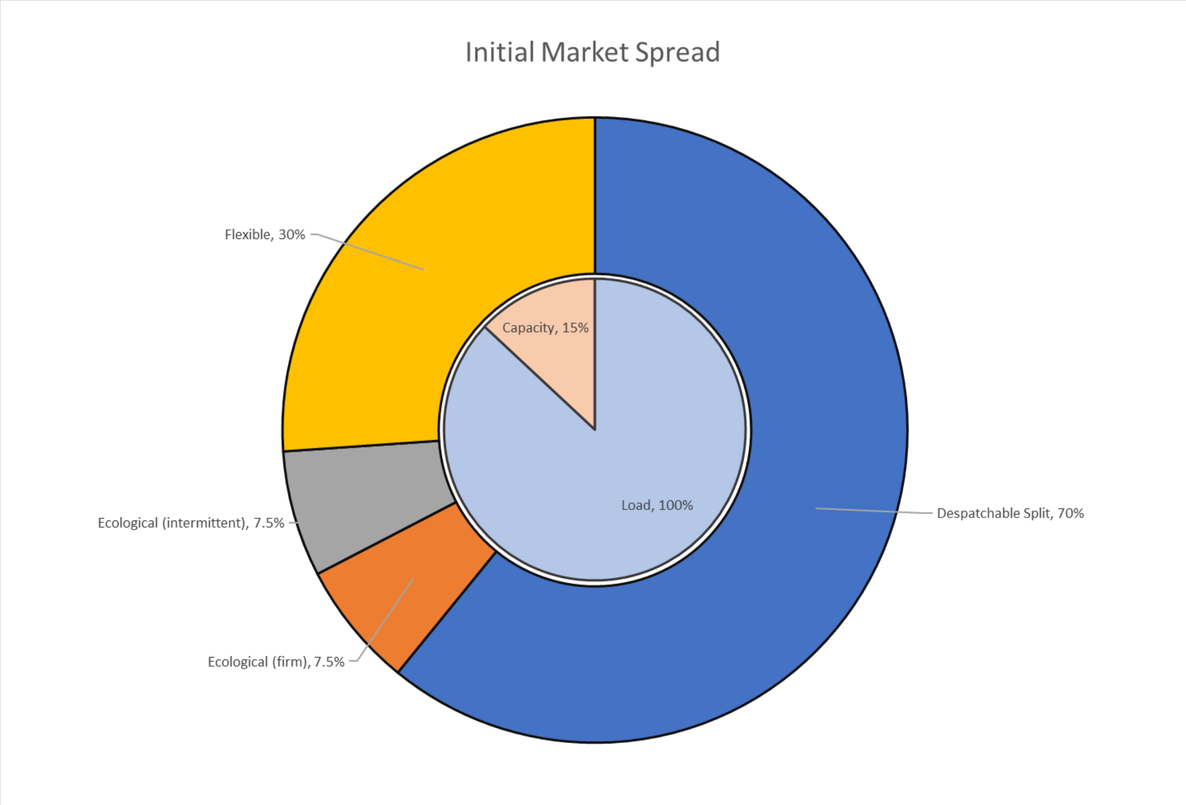


Figure 3. Starting spread across the despatchable, ecological and flexible markets. The split can be incrementally adjusted to achieve policy goals including reduced carbon emissions, reduced energy price volatility etc.

The first of the three reverse auction markets is the **despatchable** (i.e. baseload) market and it has the following rules and structure;

- Participation in this market is primarily limited to coal, gas, nuclear with a small amount of the market allocated to "firmed" renewables (physically firmed, use of financial instruments is not permitted).
- The despatchable market auctions should be for a mix of 5yr, 10yr, 20yr and 40yr durations with expectations that longer contracting periods will attract lower margins on energy prices but provide the investment certainty needed for major capital investment.
- To trial new technologies that claim to be fully despatchable (i.e. solar thermal), AEMO could allocate a small portion of the despatchable market (say 5%) to this technology class for a 10 or 20yr contract period so that investment occurs and performance data is generated before allowing the technology class to bid into the open despatchable market.
- Conversely, AEMO would exclude fossil fuel assets from 20yr or 40yr tranches which would discourage new investment in these technologies but allow the economic value of existing infrastructure to be maximised or provide justification for modest life extension capex.
- Contracted market participants are expected to produce a steady power output with high availability guarantees. This allows thermal generators to be operated in manner that maximises their economic value.
- Planned downtime (maintenance or core refuelling) must be advised in advance and the market participants must procure the backup supply from the annual **flexible** market reverse auction. AEMO will use its contracted **flexible** capacity to meet generation shortfalls caused by unplanned outages and on-charge the costs to the unavailable contracted generator.
- Bids for future volumes by yet-to-be-built generators must be accompanied by a credible project development plan including financing arrangements contingent on contracting a portion of future output prior to project development.

- Market participants are expected to publicly declare the 'end of useful life' year of each of their assets and bids will not be accepted to supply energy from an asset after this date without credible relicensing/refurbishment plans except within the 1yr tranche auction.

The second of the three reverse auction markets is the **ecological** market and participation is limited to solar, wind, hydro, nuclear, coal or gas with CCS and storage which utilises these energy sources.

- The ecological market should be evenly split in to **intermittent** and **'firmed'** sub-markets. 'Firmed' participants would be nuclear, hydro or intermittent technology coupled to onsite storage capacity (for which minimum capacity and technical requirements should be defined by AEMO in advance).
- Government policy could steadily increase the ecological market split overtime in a controlled, predictable way (say +1%/yr) to demonstrate commitment to international emissions treaties.
- These auction contract periods should be for 1yr, 5yr and 10yr durations.
- As new technology within the ecological market demonstrates capacity to be considered for the **despatchable** market, it can make offerings to both markets and AEMO can adjust the ecological-despatchable split accordingly[4].
- Contracted market participants are expected to produce a minimum quantity of energy per month for the contracted period (seasonally adjusted) and excess energy above this minimum will attract a reduced rate (nominally approximate to the bid price minus that year's average standby capacity price). This will increase the investment incentive for deploying storage to effectively monetise this excess production by moving it in to the 'firm' ecological submarket.
- This market is not intended to provide adequate investment signals for new nuclear or hydro assets but can supplement the investors revenue if a portion of new plant output is contracted into the ecological market.

The final of the three reverse auction markets is the **flexible** market and it is broken into an **energy** and a **capacity** component.

- Contracted participants are required to provide an hourly <u>standby price</u> and an hourly <u>energy price</u> so that AEMO can contract the cheapest average flexible generation.
- The standby price should include the costs of regular <u>proof of capacity testing</u> (fortnightly or monthly) where the asset is not normally operated (OCGT or distillate fuelled reciprocating engines).
- The size of this market should always be **at least twice as large by nameplate** than the size of the intermittent portion of the **ecological** market. That is, if the ecological market is 25% of the total fleet generating capacity, and if 10% is intermittent renewable energy, then the name plate capacity of the **flexible** market must not be less than 20%. This figure can be adjusted as more experience is gained with different market spreads.
- Despatch of flexible generation is on price-order-of-merit basis based on energy price component of annual reverse auction bids.
- Flexible generation can include non-contracted spare capacity from generation assets that sell the majority of their energy within the **despatchable** market. As well as being used to match demand and supply throughout the day and provide back-up to the intermittent portion of the ecological market, AEMO will also use this market to contract reserve capacity for unplanned outages in the despatchable fleet.
- Demand response market offerings can bid into the flexible market with a standby and negawatts price.

[4] An intermittent + storage deployment doesn't qualify for entry in the despatchable market without at least 3 years operating data within the ecological market. AEMO can then assess if this specific generator qualifies as despatchable which would give it the right to contract into both markets.

- Despatchable market participants will be required to source generation from the annual flexible auction for planned outages including maintenance or re-fuelling.
- These auction contract periods should be for 1yr, 3yr and 5yr periods. Merit order of despatch applies to flexible generation as AEMO needs to convert capacity to generation to balance intermittent supply or load swings.

As regards to the spread across these three markets, DUNE proposes that the daily energy load cycle (normalised across the previous calendar year) is the most logical starting point. Using the seasonal maximum demand figures for 2018 and split by the seasonal average load profile, this would indicate that roughly 70% generation share be allocated to the despatchable market, 15% to ecological and 30% to flexible to give a total capacity of 115%. These are suggested starting points only and it is expected they will change overtime and based on the operating experience of AEMO.

One benefit of this market structure to investors, is that different market niches or multiple market offerings are open to a generation asset reflecting the attributes of the technology. For example, whilst coal fired power stations (without CCS) could not enter the **ecological** market, they can diversify across the **despatchable** and flexible markets. Also, a market participant who is considering a new investment has flexibility about the scale and the length of the committed forward contracts entered in to which provides flexibility to meet minimum financing requirements whilst providing the option to keep some capacity uncontracted for future short-term tranches if the market participant believes the demand/supply dynamic will lead to higher future prices.

This proposed structure allows investors a great deal of flexibility to balance their risk profile as needed but avoids the scenario that allows investors to deploy capital with above average returns that are risk free. Much business commentary with regards to energy policy demands "certainty"; this is entirely reasonable. However, a closer examination reveals that this too often code for "guaranteed returns". Guaranteed returns can only be acceptable when those returns are modest. To preserve the risk-return nexus that is necessary for effective markets, above average investment returns must require that investors take some risk. An example from a prospective nuclear energy developer may be useful.

DUNE is considering bidding into the 20yr and 40yr tranches within the despatchable (baseload) reverse auction market to underwrite a planned investment in the NEM. One bidding scenario involves contracting to sell 100% of the energy the asset will produce in the 40yr tranche. This is an ultra-conservative approach as it virtually guarantees the revenue needed to fully cover capital and financing costs, operating costs and infrastructure-style ROI for equity investors in advance of DUNE taking any project risk. Accordingly, AEMO starts the 40yr auction with a modest contract price compared to what is available in the 10yr tranche auctions. Some of the equity investors are demanding higher returns and so DUNE considers contracting to supply 50% of energy under the 40yr tranche, 25% under the 20yr tranche and 25% under the 10yr tranche. DUNE can make a higher margin on energy sold in the 10yr market but takes the risk that energy sales after this initial 10yrs are in a well-supplied market where prices are low leading to lower sale price or uncontracted capacity.

However, this type of market structure requires disciplined long-range planning and a forward contracting approach outlined in figure 4 should be considered.

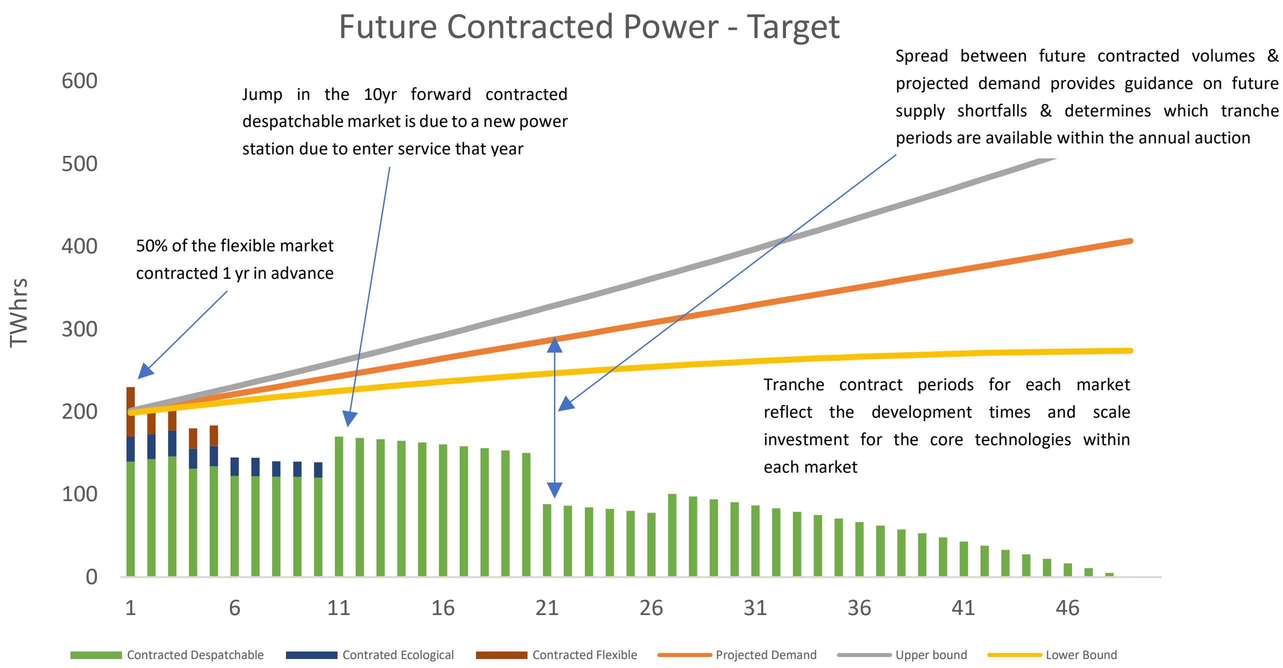


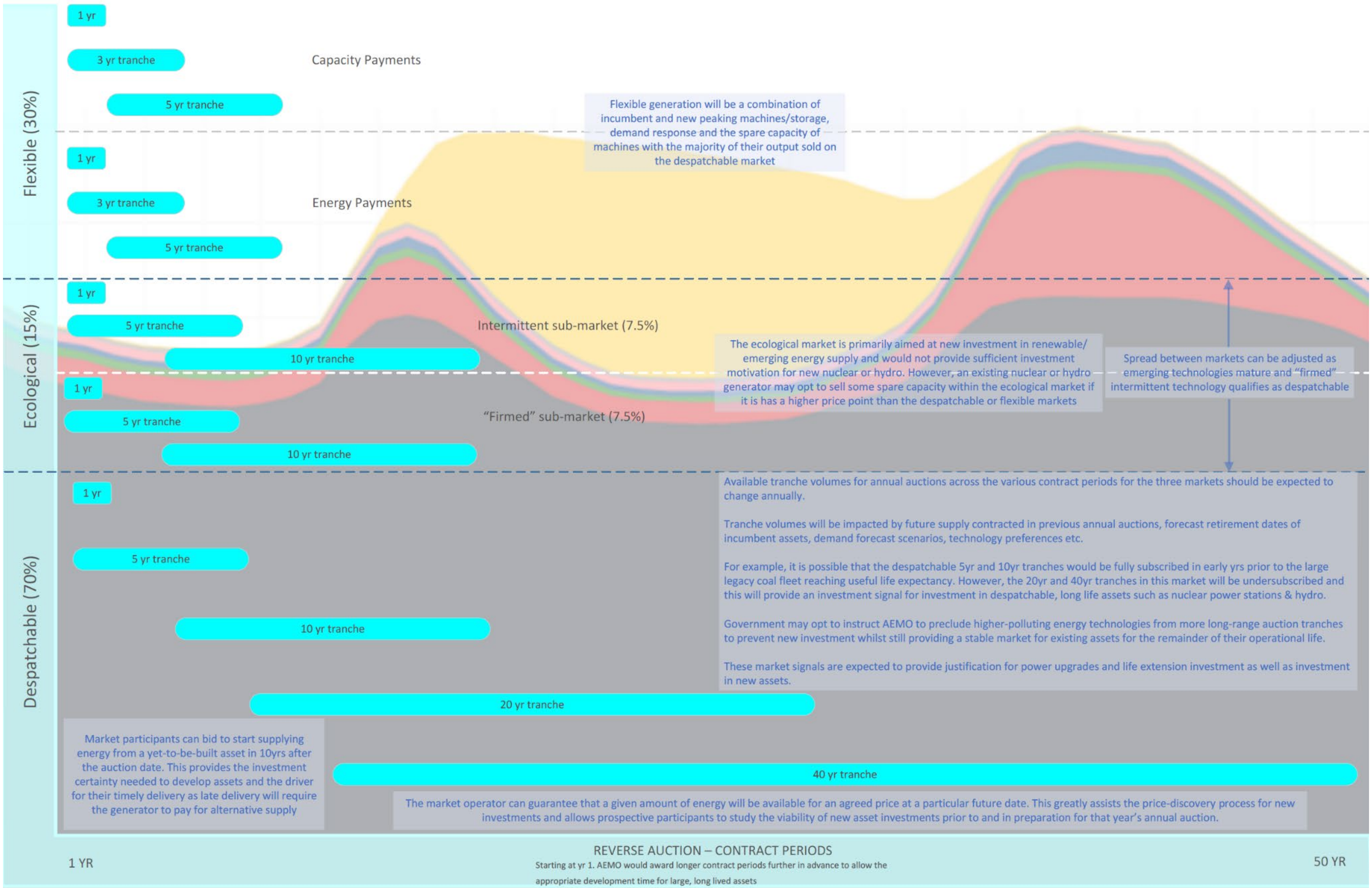
Figure 4. Target profile for future contracted power. Each year, AEMO would schedule auctions for the appropriate tranche and generation type to achieve best fit to this curve.

Another benefit for investors and energy users alike is the smoothing effect that forward sales over various tranche lengths will have on average energy prices in any given year. If price hikes in international LNG markets transfer to higher domestic gas prices, this will directly impact a portion of the NEM generating fleet. If gas prices soar for 6-12 months due to international conflict before returning to normal levels, the price impact to NEM electricity customers will be heavily dampened by not only the diversity of energy sources but also by the variance of contracting periods used to aggregate that year's energy supply. If the gas price hike is structural due to dwindling reserves etc. then the impact to energy prices would not be a sudden jump, but a long, slow ramp which would provide long-range market signals for new investment in alternative technologies before NEM energy prices reached unacceptable levels.

Note: DUNE has conceived of this market structure as a way for AEMO to contract adequate future energy requirements which provides opportunity to all technology classes, allowing each technology class to play to its strengths and provide the market with the full range of characteristics that are demanded by 21st century advanced economies. This brief summary only covers the high-level considerations for the proposed structure and some of the benefits – DUNE would be happy to provide more information and work with the ESB to further develop this concept.

Proposed NEM Market Framework

(developed using the VISION 2050 framework)



Nuclear Energy for Australia: The Investment Case

With an overriding principle of ecological and economic stewardship, DUNE was formed to begin early development on a future nuclear energy investment within the NEM. Our research and analysis justify strong support for a place for nuclear energy within the NEM because of the ecological and economic benefits. Importantly, our research indicates that there is an attractive investment case to be made for a nuclear energy deployment if the NEM market structure can be updated to allow the full range of power generating technologies to play to their strengths.

Our detailed cashflow modelling, using a traditional project finance structure[5] required that assumptions were made with regards to revenue. Whilst these revenue assumptions are adequate during the early phases of concept development, they are not acceptable when attempting to secure finance prior to an investment decision – revenue certainty is demanded by investors, regardless of the opportunity presented by a shortage of despatchable supply within the NEM.

DUNE's cashflow modelling revealed risks that other developers of nuclear energy know only too well. Forgetting the legal prohibition and the current lack of a predictable licensing and regulatory framework, the challenges with our planned nuclear energy investment can be divided into **project development** and **operating** challenges. Based on the findings of the sensitivity analysis, we have broken these down further in order of criticality.

Project Development challenges – project finance, development timeframe, development cost, unknown regulatory risks (including cost, schedule, and non-completion).

It is anticipated that government support will be required to develop Australia's first nuclear energy project. This may include arrangements to provide revenue certainty which are needed to make an investment decision, even though these will not apply until commercial operation begins. We anticipate that the use of loan guarantees, which can contain financing costs during development, will keep government financial investment modest. These government loan guarantees are only required whilst the facility is under construction and they will be exchanged for a standard operating debt and/or equity facility when commercial sale of power commences. We believe that government support could be successful in helping DUNE manage risk and cost escalation during project development but that this assistance should be confined to off-market measures.

Operating challenges – Revenue uncertainty

In a fully reformed market, such as the concept discussed in the previous section, revenue certainty should be exclusively achieved through market mechanisms; <u>administrative off-market measures during the operational/trading phase of a power project are highly inadvisable as they are not time-limited or moderated through market forces.</u> They also leave the government of the day exposed to legitimate claims by other market proponents or technology spruikers for similar support.

[5] We note that the traditional non-recourse Project Finance approach has not been done for nuclear power projects.

However, the existing NEM structure cannot provide the revenue certainty needed for nuclear power development, so 'bolt-on' revenue mechanisms must be integrated within the existing structure or come from off-market policies such as zero-carbon credits etc.

Cashflow Modelling

With input from the chosen technology provider, DUNE ran multiple scenarios including for revenue cases of $65, $75 and $85/MWhr. Whilst the investment case relies heavily on financing arrangements and project CAPEX (for which we also ran various scenarios), a disciplined deployment of NuScale SMR technology within Australia can be a viable investment at $65 and an attractive investment at $75/MWhr (average price).

This assumes that DUNE is able to run at 85% capacity or better; an assumption that is not supported by the recent experience of thermal generators within the NEM.

If the NEM is to attract new investment in large scale despatchable generation facilities that also address climate change concerns, as it must if the priority is to arrest electricity price increases, the market structure will need to be re-configured to;

1. Guarantee these generation investments can sell a large portion of their future for long periods (at least 20 yrs); and
2. Guarantee a certain price for this contracted future power

Conclusions

1. By insulating certain technologies from market feedback and failing to signal that investment is required to alternative technologies with different characteristics, the current NEM structure is unable to attract new investment in large-scale emission-free despatchable power generation.
2. By not tailoring markets for the diverse range of characteristics that are implicitly valued in advanced economies, the gradual withdrawal of these valuable characteristics, including despatchability and flexibility, is manifested in higher average power prices.
3. Government policy should be implemented by carefully changing parameters within a market structure (i.e. market splits or reverse auction starting bid prices). Off-market support for specific technologies is highly inadvisable using the operating phase. Any support for specific technologies should be during their deployment phase only and so time limited.
4. If these reforms can be realised, nuclear energy can play a vital role in stabilising and then reducing power prices whilst lowering emissions.
5. Absent large-scale, emissions-free, baseload generation platforms such as nuclear power, Australia will fall far short of its goals for lowering emissions.

Part 2

Electricity Industry Approach

World nuclear power is seen in two competing industry models – the traditional regulated / government utility model and the reformed/restructured model with a competitive electricity market. These two models are based on different economic principles.

Traditional Model

The traditional model has vertically integrated monopolies subject to economic regulation or government ownership. These regulated and government utilities plan and build a portfolio of generation units, along with supporting transmission and other supporting infrastructure, to meet projected customer demand with the objective of minimizing the long-term total cost of the electricity system.

The generation planning process and investment decision-making in the traditional model can allow governments and/or utility economic regulators to consider all relevant generating technology attributes, including long-run cost levels, volatility of costs, environmental impact, power density, controllability, reliability, and diversity (i.e., these include economic issues and public good issues).

The long-term revenue certainty implicit in the traditional model supports investment in capital-intensive generation projects, including nuclear power. The average cost approach allows these capital-intensive generation projects to provide low-marginal-cost baseload electricity that lowers total system generation costs.

Liberalized Electricity Market Model

The liberalized electricity market model usually includes a de-integrated / restructured / privatized electricity industry with generators that compete in the liberalized electricity market.

This approach uses short-term electricity spot markets to manage system dispatch with the objective of minimizing the short-term system marginal price in each trading period. This is similar to the merit order dispatch activity of regulated and government utilities.

Unlike the traditional model, this liberalized electricity market model relies, absent some intervention (i.e., as discussed in the county lessons below), on private investment in new generation assets.

The liberalized electricity market model assumes a portfolio of generation assets with non-zero short-run marginal cost (e.g., a portfolio of fossil-fuelled power plants). When a significant part of the *actual* generation mix has short-run marginal costs of zero (i.e., zero-carbon generation including nuclear power and renewables), electricity markets may not work. Recent negative price episodes in Europe, the U.S., and Australia are a symptom of this issue.

Nuclear power is the only non-combustion generation technology that can provide large amounts of reliable baseload capacity that is emissions-free (noting that opportunities for new large hydro power project are limited and that hydro can be negatively influenced by drought/climatic conditions).

Finding a way for nuclear power to work in liberalized electricity markets is a challenge for the electricity industry and the nuclear power industry, especially when liberalized electricity markets have outcomes influenced by out-of-market subsidies for renewable generation (i.e., wind and solar).

Capacity Investment in Electricity Markets

In liberalized electricity markets, short-term electricity market spot prices (and expectations of future spot prices) are expected, *in theory*, to provide economic signals for new generation investments.

In practice, this may not be working well, because:

- It is difficult to forecast long-term electricity spot prices;
- Electricity spot market prices may be distorted, or even negative, due to out-of-market payments and preferential dispatch of renewable generators; and
- Electricity market spot prices may not fully reflect actual system marginal costs due to ancillary services, reserves, and other system/market operator activities.

Ironically, an efficient electricity market (i.e., short-run spot prices are minimized in each trading period), may lead to high and volatile long-term total system costs because of the mix of market-based generation investments. There is concern that reliance on market-based generation investment may result in dirtier, riskier, and more expensive electricity in the long term.

New generation investments in liberalized electricity markets are made by private investors that seek to maximize profits and to minimize commercial risk, not to minimize long-run total system costs. The financial evaluation of private generation investments is based on discounted future cash flow analyses. Major infrastructure investors will generally have investment preferences that favour shorter construction periods and shorter recovery time frames, both of which result in higher discounted net cash flow.

Project cash flows more than about 30 years in the future have little or no value today (as financial models discount cash flows beyond the 30-year period to approximately zero). This is incompatible with nuclear power projects that may have a 10-year development period followed by a 60-year (or longer) operating life. Private investors see little or no value in the later decades of the nuclear power plant operating life; at a macroeconomic level, the benefits in later years (i.e., after the first 30 years of operation) have tremendous value to the grid, with significant positive impact on household disposable income and industrial competitiveness.

Intervention in Electricity Markets

Global experience suggests that nuclear power is not compatible with liberalized electricity markets. Nuclear power assets are valuable long-term infrastructure investments that may not be developed by the market despite the large net public goods provided (i.e., market failure[6]).

Nuclear power is feasible in liberalized electricity markets only with some form of intervention. Out-of-market intervention may include a range of mechanisms[7], including:

- Capacity markets outside the electricity spot market that provide additional revenue;
- Reliability requirements imposed on Load Serving Entities that drive bilateral contracts outside the electricity market;
- Mandates imposed on Load Serving Entities to include a specific level (or greater) of specified capacity and/or energy (e.g., U.S. renewable mandates and proposed Clean Energy Mandates that would include nuclear power);
- Power Purchase Agreements (PPAs) or hedge agreements imposed on Load Serving Entities or spread over all power sales by the market operator (e.g., like the UK CfD for Hinkley Point C);
- Tax credits provided to nuclear power projects (i.e., similar to U.S. production tax credits for wind projects and investment tax credits for solar projects);
- Government ownership (like Ontario's government-owned Darlington nuclear power plant) or Government lending to nuclear projects (e.g., like the U.S. nuclear loan guarantees); and
- Regulated asset treatment of nuclear power plants that operate in the electricity market (e.g., like the nuclear power plants in Virginia and California[8]).

There is a role for out-of-market incentives, but the case for these incentives must be made to the general public. This case is that nuclear power is providing public goods and benefits to the electricity system and national economy that would not otherwise be satisfied if nuclear were not developed by the market.

Nuclear power plant investments are comparable to long-term infrastructure investments such as roads, water/sewer systems, and electricity transmission networks that are usually made by governments or regulated utilities to obtain long-term public goods from these assets that are fundamental to the needs of modern industrial society.

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6 See NECG Commentary #21 (https://nuclear-economics.com/21-market-failure/)

7 A comprehensive set of actions to help avoid market failure related to nuclear power is presented in the American Nuclear Society Toolkit (http://nuclearconnect.org/wp-content/uploads/2016/02/ANS-NIS-Toolkit-V2.pdf) . While some of these tools are unique to the U.S., there are multiple ideas that could be applied in other countries including Australia.

8 These two states have a unique mix of regulated utility assets and participation in formal bid-based electricity markets.

An example of a publicly demonstrated need, which prompted government financing tools and incentives to drive project development, is the Thames Tideway Tunnel project in the UK (noting, too, the use of a Regulated Asset Base approach).

Overseas Experience

The discussion in this section responds to the ESB Issues paper Section 3.2 and Section 5 (i.e., last bullet point).

The ESB notes that this project "will comprehensively review the experience of relevant overseas markets to understand what worked and what did not."

We provide a general discussion of overseas experience with electricity markets and nuclear power as context for a discussion of lessons from countries with nuclear power and electricity markets that follows.

Some high-level conclusions supported by the discussion that follows:

- All existing operational nuclear power plants, and most of the nuclear power plants under construction in the world, were sanctioned under a traditional electricity market structure (i.e., not in liberalized electricity markets);
- It will be difficult for nuclear power plants to succeed in liberalized markets without intervention in these markets;
- Investors in nuclear power plants (and any capital-intensive power generation project) need long-term revenue certainty (both tenor and pricing) to justify investments;
- A wide range of out-of-market mechanisms are now used to support nuclear power in electricity markets while maintaining an electricity market to manage short-term system dispatch; and
- Out-of-market mechanisms for nuclear power can be justified by the public goods (clean, reliable, dispatchable power) provided; this is like the justification for various renewable subsidies. In the context of an industrialized economy, these public goods become fundamental to the social contract between the government and its people (noting other similar activities like clean water, roads, and national defense).

Context

It is important to understand that there is little experience with nuclear power in liberalized electricity markets. We provide some context that explains how the traditional electricity industry approach works for nuclear power, but liberalized electricity markets (i.e., without intervention) do not.

This section provides some background on electricity industry approaches, on electricity industry capacity investment and investors, and on how intervention helps nuclear power in liberalized electricity markets.

Overseas Experience – Lessons

We provide a brief discussion of lessons from the overseas experience in a few countries with nuclear power and electricity markets.

Ontario

Ontario's approach shows that it is possible to have an electricity market and nuclear power, with a stable and reliable electricity system and very low carbon emissions.

Ontario has an electricity market but does not rely on market-based generation entry. Instead, Ontario relies on administrative resource planning, government ownership of generation, and supply contracting[9] to determine the development of generation resources.[10]

Ontario entered into long-term contracts to support the refurbishment of the Bruce nuclear power plant units to extend the operating life of these units to 60 years or longer.

The long-term Bruce Power Refurbishment Agreement includes provisions that implement public-private risk sharing and decision-making with respect to future capital investment projects (refurbishment of each Bruce reactor), a long-term power purchase arrangement, and a compensation scheme to provide incentives for real-time flexible operation of the Bruce Power nuclear units.

The Refurbishment Agreement provides long-term revenue certainty to support Bruce Power's significant investment in a major life extension effort.

The government-owned Ontario Power Generation company is undertaking a similar refurbishment of the Darlington reactors that will result in a major life extension.

Lessons from Ontario:

- A long-term government contract with a nuclear power plant (i.e., as at Bruce Power) can provide a mechanism for nuclear power plant major investment; for profitable operation in the electricity market; and to achieve government objectives for the power generation sector;

- The Bruce Power arrangements include unique features that allow Bruce Power to offer (and provide) more than half of its generating capacity into the market in fast-response load-following mode[11] (i.e., overcomes the fundamental mis-match between zero-short-run-marginal-cost nuclear power and the loss of revenue from flexible operation); and

- Government ownership and regulation of a nuclear power plant (i.e., as at Darlington) can provide a mechanism for nuclear power plant major investment; for continued cost-based

[9] A recent report on Ontario electricity contracts is at http://www.ieso.ca/-/media/Files/IESO/Document-Library/contracted-electricity-supply/Progress-Report-Contracted-Supply-Q1-2019.pdf?la=en

[10] See http://www.ieso.ca/Learn/Ontario-Power-System/Electricity-Market-of-Tomorrow

[11] See NECG Commentary #12 on nuclear flexibility (https://nuclear-economics.com/12-nuclear-flexibility/)

operation in the electricity market; and to achieve government objectives for the power generation sector.

Great Britain

Great Britain has one of the earliest electricity markets, but also has a strong commitment to nuclear power.

British Energy, the national nuclear generating company, was privatized in 1996, well after non-nuclear generating assets were privatized. British Energy ran into financial difficulties operating in the electricity market, and British Energy was restructured and effectively re-nationalized by 2005.

Around 2010, the UK Government concluded that the UK electricity market would not incentivize new nuclear power investment that was needed to meet policy objectives. The Government embarked on a series of reforms and initiatives that included the Electricity Market Reform (EMR) programme, passed into law in 2013.

The EMR programme included multiple incentives for nuclear power, including Contract for Difference (CfD) arrangements and a Capacity Market. EMR was the basis for the incentive package supporting the Hinkley Point C nuclear power project.

The incentive package for Hinkley Point C (initially developed by EDF, a foreign, state-owned entity) led to an investment decision and the start of construction, with a high CfD price, investment and support from the Chinese government nuclear company CGN (absent which EDF would not have been able to continue), and with a commitment by the British Government to support a larger role, including a dedicated site, for Chinese reactor technology. Two other nuclear power projects, Horizon and NuGeneration, were expected to follow Hinkley Point C, but both were terminated after significant development investment and extensive negotiations with the British Government.

Great Britain needs more new nuclear power plants to meet policy objectives and is considering new approaches, including creation of a new regulated nuclear company, to achieve this.

Lessons from Great Britain:

- Electricity markets alone will not provide financial incentives for new nuclear power plant investments;
- Incentives outside the market will be required to provide incentives for new nuclear power plant investments;
- The type and level of these out-of-market incentives is important,[12] including consideration of the participants involved (contrasting the two state owned entities that are the owners of

[12] See NECG Submission in UK Parliament Inquiry on Financing Infrastructure (https://nuclear-economics.com/2019-04-02-necg-submission-to-uk-inquiry-financing-energy-infrastructure/)

Hinkley Point C, which is proceeding, as opposed to the present failures of both Horizon and NuGen, which were backed by corporate entities); and

- A regulated asset approach, now being considered in Great Britain for new nuclear investments that would operate in the electricity market, may be a better approach than the EMR incentive package.

U.S.

About half of the U.S. nuclear fleet operates as merchant nuclear generators participating in one of several electricity markets (i.e., the others are regulated or government-owned). The merchant nuclear plants have difficulty covering cash generating costs in the short-term electricity markets, even while regulated and government-owned nuclear plants in the same market conditions (e.g., low natural gas prices) lower total system costs for utility owners.[13]

Out-of-market approaches have been implemented to keep merchant nuclear plants from early retirement in several U.S. states, including New York, Illinois, Connecticut, New Jersey, and Ohio. These states provide additional revenue, with most providing Zero Emission Credits ("ZEC") or ZEC payments linked to the value of zero-carbon nuclear electricity, to supplement revenue from electricity spot market sales and capacity markets.

Multiple new nuclear power plant projects in states with liberalized electricity markets have been granted construction licenses, but all these projects have been deferred or cancelled.

The only U.S. nuclear power plant under construction is in the state of Georgia, a state with a traditional electricity approach. This project (Vogtle) is supported by a loan guarantees from the federal government (i.e. part of the Energy Policy Act of 2005, which also provided tax credits and regulatory standby support), showing the need for government support, even in a country with a long history of nuclear power, the largest and most experienced nuclear safety regulator, and the largest nuclear power plant fleet in operation in the world.

Lessons from the U.S.:

- Nuclear power plant value and profitability in states with liberalized electricity markets is low and uncertain;

- A modest ZEC payment was enough to prevent multiple existing merchant nuclear power plants from retiring early in multiple states;

- States that declined to put out-of-market mechanisms in place to support merchant nuclear power plants had nuclear power plants retire early and permanently; and

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[13] See Economic and Market Challenges facing the U.S. Nuclear Commercial Fleet (https://nuclear-economics.com/wp-content/uploads/2017/10/2017-09-Market-Challenges-for-Nuclear-Fleet-ESSAI-Study.pdf)

- Multiple new nuclear power plant projects are deferred or canceled in states with liberalized electricity markets, despite having approved construction licenses.

Japan

Japan is considering approaches to keep nuclear power plants financially viable after implementing electricity market reforms, in order to ensure long-term electricity supply and stable customer electricity rates.

Japan is restarting its fleet of nuclear power plants and undertaking electricity industry reform and restructuring. Japan examined global experience with nuclear power in restructured and reformed electricity industries to develop multiple market design features and out-of-market activities aimed at maintaining the long-term economic value of nuclear power.[14]

The Japanese electricity reform process is proceeding in a careful manner. There are several features of the Japanese electricity reform that help ensure nuclear power plant financial viability, including;

- A baseload power market
- Regional capacity markets
- A zero-carbon electricity market, and
- CfD contracts for nuclear power plants.

Lesson from Japan:

- METI has taken a careful approach to electricity industry reform and its impact on nuclear power profitability;
- The Japanese electricity industry generally expects that METI will take action to help nuclear power remain financially viable if electricity reforms present problems; and
- It is possible to implement electricity industry reform without creating financial problems for existing or new nuclear power plants.

Finland

Finland is in the Nord Pool electricity market. The Finnish electricity sector has a unique approach to new power plant investment based on the Mankala approach.[15] The Mankala approach involves a group of power-using companies that cooperate to invest in, build, own, and operate power plants, principally for the purpose of obtaining electricity on an "at cost" basis (and locking in such a position over a long term to support their business needs, as high-end users of electricity).

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14 See NECG Commentary #26 (https://nuclear-economics.com/26-japan-nuclear-power-and-electricity-reform/)

15 See WNA Nuclear Power In Finland page (https://www.world-nuclear.org/information-library/country-profiles/countries-a-f/finland.aspx)

A member of a Mankala power entity agrees to share the investment cost, the cost of operation, and other aspects. In return, the member gets a share of the power plant output. This cost-based power is a physical hedge of the member's exposure to Nord Pool electricity market prices.

Mankala companies are similar to U.S. Generation and Transmission Cooperatives, with Mankala company members including large manufacturing and forest products companies.

Existing nuclear power plants in Finland are owned by a Mankala company (i.e., TVO) and new nuclear power plants are under construction and in development by Mankala companies (i.e., TVO and Fennovoima).

Lesson from Finland:

- The Finnish Mankala concept, similar to the U.S. G&T Cooperative approach, offers a business model for nuclear power projects in a liberalized electricity market that might be used in other countries;

- Mankala company members get benefits that are similar to electricity market hedging agreements in the Australian electricity market.

Germany

The German electricity market and national policy offers a unique set of lessons. Germany put in place the Energiewende strategy that, among other things, involved the closure of existing nuclear power plants and a focus on renewable generation.

The German electricity market has seen generally low wholesale market prices, although with a higher level of volatility. German electricity generators face financial issues and Germany is considering more fundamental market structure changes in order to provide financial incentives for capacity resources needed to preserve grid reliability.

The shift away from nuclear power has led to a reliance on natural gas generation and even on new coal-fired power plants to maintain system reliability.

Other outcomes in Germany include a failure to meet carbon emission targets (and even rising carbon emissions) and some of the highest electricity prices for end users in the industrialized world.

Lessons from Germany:

- A shift from nuclear to renewable generation may lead to lower system reliability, more volatile wholesale market prices, and higher carbon emissions;

- Germany's renewable generation levels are high, with the cost of renewables falling mostly on electricity end users and with de-stabilizing impact on wholesale market prices; and

- The wholesale electricity market delivers insufficient revenue for many existing and new power plants, leading to plans to modify the wholesale market to increase revenue for capacity.

Countries without electricity markets

There is a century of successful experience with the traditional electricity industry model. All operating nuclear power plants were built under the traditional model as a result of past investments made by government and regulated utilities.

Almost all nuclear power plants under construction today are in systems using the traditional model, including countries with government-owned electric utilities such as China, India, Korea, and the UAE.

A government or regulated utility can take a different approach to considering nuclear power that considers the long-term impact on total system cost instead of discounted cash flow. These entities can also include an explicit or implicit value for public goods (e.g., system reliability, lower system risk, energy diversity, energy security, clean air, lower land use, etc.) provided by a nuclear power project.

In planned economies, the government owns and controls the electricity industry and the nuclear power industry. Some of these countries are building nuclear power plants as a part of national energy and nuclear industry strategies. These countries have state-owned utilities buying nuclear power plants from national nuclear industrial companies that also compete in the world market. These national nuclear power companies are examples of state capitalism,[16] where government-owned and government-controlled companies compete in global markets against private companies.

Conclusions

1. The general and country lessons above show that there are a range of out-of-market incentive mechanisms for nuclear power that do not require moving back to the traditional electricity industry model.

2. A country must appreciate the value that nuclear power brings to successfully "go nuclear." Many of these values do not fit classic financial modeling techniques; yet, they are important for national planners to capture for the good of the country. Furthermore, to "go nuclear", a country must "make the case" to all key stakeholders (including the public) of the benefits and utility of nuclear power.

3. For a variety of reasons, including regulatory burdens which competitors in its asset class do not suffer, nuclear power is a unique asset with a special set of challenges. In regulated markets, these challenges can be addressed, given the long-term, holistic view taken by regulated utilities and/or by national planning authorities. However, in deregulated markets – especially those that then favor certain forms of generation over others – nuclear power plants are not well-suited, which then disfavors both initial investment and long-term operation (absent out-of-market techniques to support such projects).

[16] As discussed in "The End of the Free Market" by Ian Bremmer.

4. Several techniques have been demonstrated to be effective in supporting nuclear power plants in liberalized markets; however, such techniques require policy support at the highest levels.

5. In an industrialized society, intermittent generation is not cost-effective once it hits certain levels of market penetration, given technological limitations now (and for the foreseeable future)[17]. If a country wishes to prioritize emissions-free generation in effort to hit climate goals, then the only baseload options are nuclear and hydro, with the latter having a considerable number of limitations.

6. If a country only views nuclear power under an Independent Power Producer lens, focusing only on costs and economics at the project level, nuclear power may be viewed as either uncompetitive or simply "too difficult". Nevertheless, if larger societal goals are to be achieved (energy security, energy diversity, market reliability and price stability, emissions-free generation – attributes that are not reflected in electricity market prices or in a project-level financial analyses), then nuclear power must be a significant part of the country's energy portfolio and those key intangibles must be properly valued in other ways (than financial modeling). With such an imperative, the necessary policy tools become easier to justify.

7. Often, the most challenging period for a nuclear power project is the development and construction period. During this relatively short time, financing sources are limited. It is in this period that government support is most needed. However, if a robust economic profile is created around the project (long-term, credit-worthy offtake and a price point that provides a reasonable economic return), refinancing options exist where debt can be restructured, and equity positions refashioned. Thus, even in an extreme case where the government must provide debt and/or equity financing during development and construction, such a position can be refinanced after commercial operation, which then limits the commitment of government resources to a finite and relatively short period (which, nevertheless, is critical to capturing both the intangible and long-term benefits of nuclear power).

8. Further, it is important to recognize that the challenges noted in this submission have focused on the historical situation for nuclear power plants - a story based on large reactors. With the development of small modular reactors (SMRs), new financing structures can be created (multiple-ownership models; phased development and financing / project scaling; and internal financing[18]) that can further support the deployment of SMRs. While these new approaches have not been the focus of this submission, we would be happy to discuss this with you further. For the purpose of this submission, we simply note the new opportunities (for project development and for financing), while also acknowledging that the deployment of any new technology (in this case, SMRs) is not without some elements of first-of-a-kind risk, which should be considered and addressed through government policy tools that would create a suitable platform for the promotion of this technology (including addressing regulatory uncertainty). As we have noted in this submission, nuclear power does not

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[17] For example, see https://www.forbes.com/sites/brianmurray1/2019/06/17/the-paradox-of-declining-renewable-costs-and-rising-electricity-prices/#3d8ea03861d5

[18] Internal financing would involve a fleet structure, where the first SMRs in the fleet or first modules in an assembly would be financed externally, then, as these first units enter commercial operation, the revenues from operation can be used to support the financing of additional SMRs or modules.

develop absent significant support. For large reactors, the support required is more significant and the applications of the technology are more limited, whereas SMRs can create more tailored solutions to development challenges and for a wider variety of applications (on-grid, off-grid, mining, desalination, industrial heat, hydrogen production, etc.).

Authors

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James has practiced engineering and project management in the power and oil and gas sectors throughout Australia for 15 yrs including working for some of the world's biggest companies on the design, construction, start-up and operation of some of Australia's biggest and most complex energy projects.

He founded DUNE in 2018 after extensively studying the difficulties within, and prospective options for the NEM. James also has extensive small business experience in the solar energy industry.

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Mr. Kee provides strategic and economic advice to companies and governments on nuclear power and electricity industry issues. He has testified as an expert witness in US and international legal and arbitration cases.

The International Atomic Energy Agency (IAEA), the International Framework for Nuclear Energy Cooperation (IFNEC), and the U.S. Civil Nuclear Trade Advisory Committee (CINTAC) have recognized Mr. Kee as a nuclear power industry expert.

Prior to starting NECG, Mr. Kee held senior consulting positions at NERA Economic Consulting, CRA International, PA Consulting Group, Putnam, Hayes & Bartlett, and McKinsey & Company. He was a merchant power plant developer and a nuclear power plant engineer (qualified as chief engineering officer on Nimitz-class nuclear aircraft carriers) before becoming a consultant.

Mr. Kee was the Managing Director of the Putnam, Hayes & Bartlett (PHB) Australian office in the late 1990s. In this role he served as Economic Advisor to the governments of South Australia and Queensland on issues related to the electricity market and electricity industry restructuring / privatization; advised multiple companies and other Australian government entities on electricity industry issues; and made multiple presentations on electricity industry and electricity market topics.

Mr. Kee's articles on nuclear power and the electricity industry appear in World Nuclear News, Wall Street Journal Europe, Nuclear Engineering International, ANS Nuclear News, Nuclear Power International, Bulletin of the Atomic Scientists, The Electricity Journal, Public Utilities Fortnightly, Energy Law Journal, Atlantic Council EnergySource, Power Economics, and other publications.

Mr. Kee holds an MBA from Harvard University and a BS in Systems Engineering (Distinction; Trident Scholar; Colt's Award) from the US Naval Academy.

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Paul's practice focuses on multiple aspects of the nuclear industry – from commercial and policy matters, including international regulatory and treaty frameworks and issues regarding nuclear liability, to strategies for developing and financing nuclear power programs and the identification and mitigation of associated risks – representing developers/owners, lenders, investors, technology providers, and contractors on nuclear projects internationally. He is recognized as an expert in the development and financing of nuclear power programs by the International Atomic Energy Agency (IAEA), the OECD's Nuclear Energy Agency (NEA), the International Framework for Nuclear Energy Cooperation (IFNEC), and the U.S. Government.

He has served as a designated expert, chairman, and author at several special meetings and for multiple working groups of the IAEA, primarily involving the development, financing, and structuring of nuclear power projects. He has worked with the IAEA in several key areas, including a revision of the IAEA's Handbook on Nuclear Law and as lead author for an IAEA report, entitled, "Alternative Contracting and Ownership Practices for Nuclear Power Plants."

Paul is a five-time appointee to the U.S. Secretary of Commerce's Civilian Nuclear Trade Advisory Committee (CINTAC), and he previously chaired its Finance subcommittee twice. CINTAC is a nuclear advisory board for matters relating to the export and competitiveness of U.S. nuclear technology and services. Paul has also worked with the US Departments of Commerce, State, and Energy on matters relating to the development of nuclear power programs and the financing of nuclear power projects, as well as matters concerning nuclear cooperation agreements. He has been heavily involved with the U.S. Nuclear Energy Institute and the U.S. Nuclear Industry Council on issues relating to the development and financing of nuclear power projects, to include work on issues relating to small modular reactors and advanced nuclear reactors. Paul has been invited twice by the U.S. Nuclear Regulatory Commission to make presentations before the NRC on issues related to the development and financing of nuclear power projects.

In addition, Paul served as the U.S. Government's sole representative on an NEA working group called "Financing of Nuclear Power Plants," acting as chairman for the working group. Paul also chaired the IAEA working group titled "Issues to Improve the Prospects of Financing Nuclear Power Projects." Paul has also worked with the Nuclear Energy Institute, the U.S. State Department, the US Mission to the OECD, and the Export-Import Bank of the United States on revisions to the OECD's Guidelines for the financing of nuclear power projects by Export Credit Agencies.

For multiple years, Paul has served as a faculty member for the "Training Course on Nuclear Power Infrastructure Programs and Related Projects in Emerging Nuclear States," held on behalf of the U.S. State Department and the IAEA at the Argonne National Laboratory and attended by representatives of over 20 foreign governments. Paul has served as the lead instructor for the segments on financing and the bidding / evaluation process for nuclear power projects. In addition, in 2014-2015 and 2017-2019, Paul served as the lead organizer and a faculty member for the "Interregional Training Course on Legal and Financial Issues for a Decision in Countries Introducing or Expanding Nuclear Power," held on behalf of the U.S. State Department and the IAEA at the Argonne National Laboratory. Paul also teaches financing, contracting, and project development for Texas A&M University's Nuclear Power Institute, as part of the its international training programs.

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