Below the Waterline: What's Driving the Hidden Half of Energy Costs

Submission to AEMC Consultation ERC0406 (Treatment of jurisdictional policies and system costs in the ISP)

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Executive Summary

Australia's energy transition cannot be judged by generation costs alone. Transmission and Distribution (T&D) now account for the majority of consumer electricity bills (roughly 45–60% according to AER and ACCC data). Yet the Integrated System Plan (ISP) continues to focus on ideal generation and transmission build-outs, whilst ignoring distribution costs and the escalating cost of maintaining system security. This misalignment risks locking in higher long-term costs for consumers.

Reform must begin by addressing the structural bias of the Regulatory Asset Base (RAB) model, which rewards TNSPs for capital expenditure and disincentivises innovative, market-based procurement of essential system services. These bias drives investment into synchronous condensers (syncons) — expensive, single-purpose assets — rather than flexible solutions like grid-forming (GFM) batteries or clutched open-cycle gas turbines (GTs) that can provide multiple services simultaneously.

Batteries have already proven that markets can outperform regulation. The FCAS markets incentivised private investment, expanded supply, and reduced costs — outcomes that central planning alone could not achieve. A similar market construct should now be applied to **system strength and inertia**, which do not require real-time settlement but could be efficiently procured through annual tenders.

AEMO's latest System Strength and Inertia Report shows that **system strength** — not inertia — is the binding constraint across the NEM. However, the current regulatory approach continues to favour syncons as the default response. Comparative analysis shows that, per unit of service delivered (fault level, inertia, flexibility, black start capability), GFM batteries and clutched GTs can outperform syncons on both cost and delivery time when given access to stacked revenue streams.

Asking AEMO to report on whole-of-system cost while leaving transmission and distribution network service providers (TNSPs and DNSPs) under the same regulated-asset framework fundamentally limits the usefulness of that reporting. The cost imbalance is structural, not analytical. AEMO can model scenarios, but it cannot correct for a regulatory regime that rewards capital growth in the RAB rather than least-cost service outcomes. Until network services are exposed to market-based or competitive procurement mechanisms, any whole-of-system cost analysis will be describing symptoms rather than solving the disease: the entrenched regulatory capture that drives ever-larger network capex, isolates non-network solutions, and pushes costs onto consumers regardless of efficiency.

Transitioning to a market-based approach for these services would reduce total cost to consumers by enabling competition and value stacking in Network Services; shorten lead times by allowing merchant and hybrid delivery models; and align Australia with international best practice, such as the UK's Stability Pathfinder.

This submission urges the AEMC to ensure that future iterations of the ISP not only recognise these cost drivers but actively implement **structural reforms** to open network services to competition. Rather than relying on the RAB model and regulated monopoly investment, the AEMC should enable competitive, performance-based procurement of essential network services—allowing markets to determine the most efficient and lowest whole of system costs for consumers.

Whole-of-System Costs

AEMO's Integrated System Plan (ISP) should serve as a whole-of-system planning tool rather than a narrow generation expansion plan. In recent years, network infrastructure costs – transmission and distribution (T&D) – have become the dominant drivers of rising electricity bills, outpacing generation costs. Notably, around *40–50% of a typical electricity bill now goes to "poles and wires" costs*, and the massive new transmission projects to connect renewables are directly passed through to consumers. This underscores that planning focused solely on generation capex is no longer fit-for-purpose.

Indeed, the proponent of ERC0406 highlights that the ISP's current approach omits critical cost categories and fails to reconcile conflicting investment signals. For instance, while the ISP identifies new gas generation as essential emergency backup to maintain reliability through the coal exit, TNSPs are instead investing billions in synchronous condensers — assets that provide no dispatchable energy and cannot contribute to reliability during supply shortfalls. This misalignment reflects a deeper structural flaw: the ISP points to multiple system needs, while the regulatory framework incentivises TNSPs to build only a subset. To ensure true least-cost outcomes, the ISP must explicitly integrate system strength procurement with broader reliability planning, ensuring investment dollars flow to assets that can serve multiple roles — including inertia, fault current, and firm capacity — rather than single-function hardware justified by regulatory expedience.

Encouragingly, AEMO is moving in this direction. In preparation for the 2026 ISP, AEMO's Draft 2025 Network Options Report incorporated sharp increases in transmission costs (25–55% higher for new lines compared to estimates in the 2024 ISP) and began modelling distribution network investment to support high DER uptake. These updates reveal that the cost of delivering renewable energy to load centers is significantly higher than previously anticipated, largely due to transmission complexities and community acceptance challenges. Planning must therefore be holistic: generation, transmission, and distribution investment are interdependent, and optimizing one without the others risks higher overall costs. We support rule changes that would require the ISP to include a broad assessment of "whole-of-system" costs (e.g. distribution upgrades, firming, recycling/decommissioning, system strength and inertia). This will ensure consumers and policymakers have transparency on the *total system cost* of different policy scenarios and can avoid choices that minimize one category of expenditure at the expense of far greater costs elsewhere.

In summary, controlling electricity prices throughout the transition will depend on addressing the structural issues driving up network costs. **A whole-of-system cost approach in the ISP is a critical first step — but it will only be effective if accompanied by structural reforms that open networks to competition and performance-based procurement.** Without reform, even the most comprehensive cost modelling will remain constrained by a regulatory framework that rewards capex growth over service efficiency. Embedding market mechanisms and contestability into how network services are delivered will allow the ISP's whole-of-system cost perspective to translate into real consumer savings, ensuring that investments are chosen for value, not simply because they can be added to a NSP's Regulatory Asset Base (RAB).

RAB Incentives and Capex Bias in Network Investments

Current regulatory settings inadvertently reward Transmission Network Service Providers (TNSPs) for capex-heavy solutions and discourage more flexible, service-based alternatives. Under the Regulatory Asset Base (RAB) model, TNSPs earn a regulated return on capital investments – meaning their profits increase when they build new infrastructure. In contrast, operational expenditures or contract payments for non-network services typically cannot be added to the RAB. As a result, when faced with a system need (such as a system strength shortfall), TNSPs have a clear financial bias to propose building a capital asset (e.g. a synchronous condenser) over procuring an equivalent service (e.g. contracting a battery or generator for system support). The RAB model thus creates a capex bias, prioritizing capital-intensive network solutions even if more cost-effective solutions exist outside the traditional network ownership framework.

This incentive issue is evident in how system strength shortfalls are being addressed. Following the AEMC's 2021 system strength framework, TNSPs across the NEM initiated Regulatory Investment Tests for Transmission (RIT-Ts) that predominantly feature new synchronous condensers (syncons) as the preferred solution. According to industry analysis, TNSPs in NSW, Queensland and Victoria have flagged installation of over 30 new syncons by 2035, at an estimated capital cost exceeding $4.7 billion. These are large, utility-scale machines being added to the RAB – the epitome of a capex-heavy approach. By contrast, few if any TNSP proposals have primarily relied on contracting with independent providers of system strength (such as grid-forming batteries or reconfigured generators), even when those alternatives might provide the required service at lower total cost. The incentive to favour solutions that expand the TNSP's asset base is powerful.

Crucially, under current rules **only the capital component of a solution contributes to the TNSP's RAB** – not the total cost or the net market benefit. As Powerlink Queensland explained in its recent system strength RIT-T: *"Only the prudent and efficient capital costs of the network components of the preferred option will factor into the Regulatory Asset Base (RAB)… it is not the total capital costs (across network and non-network solutions), nor the estimated net economic benefits, that factor into the RAB"*. In practice, this means if a portfolio includes a mix of a network asset and a contracted service, the TNSP's future earnings derive solely from the asset portion. The disincentive to pursue non-network solutions is clear – even if a third-party service contract is cheaper for consumers, the TNSP has less financial motivation to adopt it, and may even face regulatory hurdles in doing so.

Moreover, historical ring-fencing arrangements have limited TNSPs from owning or controlling "generation" assets, such as batteries or clutched generators. While the new system strength framework does allow TNSPs to procure services, the cultural and economic preference for in-house asset solutions remains. Simply put, **TNSPs are not yet fully incentivised or accustomed to acting as purchasers of services** rather than builders of plant.

To correct this bias, regulatory reform is needed. The AEMC should consider measures to **neutralize the preference for capex**. E.g. allowing an equitable rate-of-return or financial reward for successfully procuring non-network solutions that meet system needs at lower cost. TNSPs could be encouraged or mandated to run open tenders for services (with robust evaluation to ensure reliability standards are met), before defaulting to building a regulated asset. If the **regulatory toolkit rewarded innovation and efficiency over asset expansion**, we would likely see more creative, hybrid solutions: for instance, contracting a share of system strength from merchant batteries or retrofitted generators, in combination with fewer new syncons. This approach aligns with the

National Electricity Objective by promoting efficient investment in electricity services for the long-term benefit of consumers.

In summary, the RAB-driven incentive structure is skewing outcomes toward capital-intensive investments when more flexible alternatives exist. **We urge the Commission to calibrate the framework such that TNSPs are made indifferent (or even positively inclined) to choosing the solution that minimizes total system costs for consumers, rather than the one that maximizes their regulated asset base.**

Market-Based Delivery of Essential Services: FCAS and Grid-Forming Batteries

The rapid rise of **batteries** in Australia's Frequency Control Ancillary Services (FCAS) markets provides a compelling case study in how **well-designed markets can outpace regulation in delivering essential system services**. Prior to 2017, FCAS (frequency regulation and contingency reserves) was largely the domain of ageing thermal generators, and costs had been climbing due to tight supply. The introduction of large-scale battery projects – beginning with the 100 MW Hornsdale Power Reserve in South Australia – dramatically transformed this landscape, to the clear benefit of consumers.

Hornsdale Power Reserve (HPR) demonstrated that battery storage could provide fast and precise frequency control more efficiently than traditional plants. Within its first year of operation, HPR captured a major share of South Australia's FCAS market and drove prices down precipitously. By 2019, the Hornsdale battery alone had *reduced SA's grid FCAS costs by an estimated $116 million, nearly eliminating local FCAS constraints (91% cost reduction, from ~$470/MWh to ~$40/MWh)*. In its first two years, the 100 MW battery delivered an aggregate saving of around $150 million for South Australian consumers by providing contingency and regulation services at lower cost. **These extraordinary savings were achieved not by regulatory mandate, but by market-driven investment – the battery owner monetized high FCAS prices, and competition swiftly eroded what had been a costly service shortage**.

The FCAS market evolution over the last five years highlights several important dynamics:

- **Speed of Deployment:** When a clear price signal emerged (e.g. extreme FCAS prices after network events), battery proponents were able to deploy assets in a matter of months. Hornsdale was built in under 100 days. Additional merchant batteries soon followed across the NEM to provide FCAS and arbitrage energy prices. This responsiveness far exceeds the typical multi-year lead time of regulated network investments.
- **Investment Scaling and Falling Costs:** Initial projects like Hornsdale were partially subsidized but quickly proved the technology. Now, battery costs have fallen and multiple projects are proceeding on commercial terms, each larger than the last. The entry of new battery capacity has expanded FCAS supply and *significantly lowered market clearing prices*, to the point that quarterly FCAS costs in the NEM have trended down despite growing variability. AEMO reported as early as Q4 2017 that the entry of just two new participants (Hornsdale and a demand response provider) cut FCAS costs by $13 million quarter-on-quarter. Today, dozens of batteries are registered for FCAS, creating a competitive, liquid market.
- **Innovation in Services:** Because the FCAS markets are technology-neutral and performance-based, they incentivised new capabilities. For instance, fast response (Contingency FCAS within 6 seconds, and the

newer Fast Frequency Response requirements) naturally favour inverter-based technologies. Grid-forming battery inverters can now even provide inertial response – in 2022 HPR became the first big battery to provide an estimated 2,000 MW·s of synthetic inertia to the grid, a service traditionally supplied by synchronous inertia of large generators.

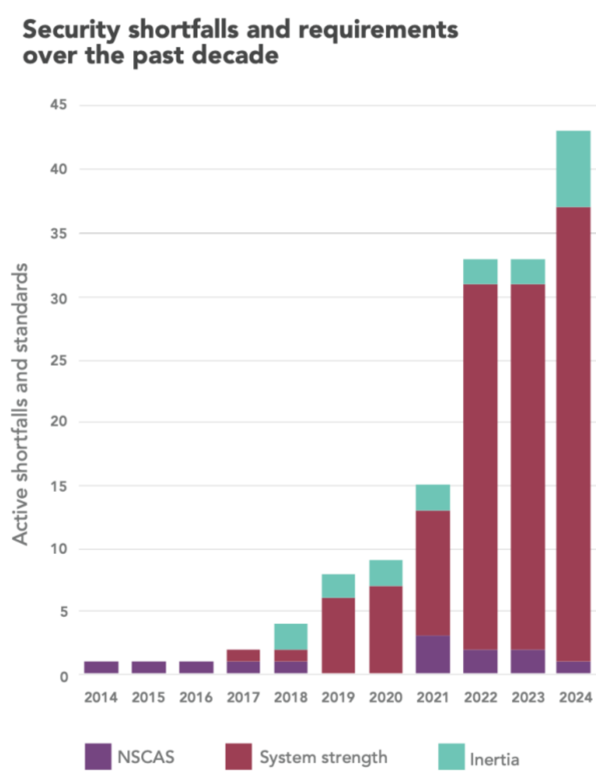
The FCAS example shows that if markets are designed to value a service, innovators will find a way to deliver it, often faster and cheaper than anticipated. The lesson for system strength (and other essential system services) is that **competitive markets or procurement mechanisms can deliver timely outcomes**. Had we relied solely on TNSPs or regulated processes to procure fast frequency control capability, it is doubtful we would have seen 100 MW of new response commissioned within one summer as happened with Hornsdale. Instead, merchant participation harnessed private capital and risk-taking to solve a system need quickly. Regulation then followed up by updating frameworks (e.g. creating new Fast Frequency Response market ancillary service arrangements) to integrate these innovations.

We encourage the AEMC to wherever feasible, use market-based mechanisms to procure system services such as FCAS, inertia, system strength and black start capability to reduce overall costs through competition. Even if some services require initial interim procurement by TNSPs, those procurements should be structured to mimic market tender principles – open to all technologies and providers, with clear performance requirements – so that the most efficient providers win. The experience with FCAS and batteries shows that market-driven solutions not only *work*, but often *outperform traditional solutions in speed, cost, and innovation*.

System Strength as the Urgent Bottleneck in System Security

Of the various system security challenges in the transition (voltage control, inertia, system strength, frequency response, etc.), **system strength has emerged as the most urgent and constraining issue** for the NEM – even more pressing than inertia in the near term.

According to AEMO's **2024 System Strength, Inertia and NSCAS Reports**, new system strength gaps are projected to rise in coming years unless prompt action is taken. System strength relates to the ability of the power system to maintain stable voltage waveforms under disturbance, and it is essential for connecting large amounts of inverter-based without risking instability. AEMO's 2024 assessment highlights that *"new system strength shortfalls may emerge if investment or other responses are not forthcoming,"* and notes that while inertia shortfalls are also possible, a new inertia standard/obligation will commence in 2027 to help address that.



Recent real-world experience bears out the primacy of system strength as a bottleneck:

- **Connection Constraints:** Weak grid conditions (low fault levels) in areas like north-west Victoria, south-west New South Wales, and parts of Queensland have already forced AEMO to impose constraints on renewable generators and to declare system strength gaps. Without adequate system strength, new renewable projects face delays or expensive mandates (such as installing their own on-site syncons). This directly threatens Australia's renewable rollout pace.
- **Operational Risks:** South Australia famously declared a system strength shortfall in 2017–2018, which was temporarily managed by directing online gas units and later solved by installing four high-inertia syncons. Other regions are following suit – for example, Queensland and Victoria have system strength shortfall projections aligning with major coal retirements around 2025–2030. System strength has become a binding operational constraint requiring immediate mitigation (e.g. contracting existing generators for short-term fault current support).

By solving system strength cost-effectively, we also unlock progress on emissions targets (since more renewables can connect) and alleviate related challenges such as inertia and voltage control — as many technologies that provide system strength also deliver these services as by-products.

Network Service Providers (NSPs) understand this interplay, yet the current regulatory framework encourages them to treat it as a capital opportunity rather than a system optimisation challenge. Instead of leveraging competitive or modular solutions, many NSPs are expanding their Regulatory Asset Base through the rollout of large, single-purpose synchronous condensers — expensive assets justified by regulation rather than efficiency with all costs flowing on to consumers.

The AEMC must ensure that system strength procurement frameworks facilitate fast, competitive deployment of flexible technologies, because inefficiency or delay here will ripple through the entire transition — raising costs, slowing renewable integration, and undermining the ISP's intent to determine the least-cost for consumers.

Comparing Solutions for System Strength

To address system strength shortfalls, there are three main technical solutions being considered and deployed in the NEM: **synchronous condensers (syncons)**, **grid-forming battery energy storage systems (GFM BESS)**, and **clutched gas turbines (GTs)** (i.e. synchronous generators that can be coupled/decoupled from a turbine). We provide a detailed comparison of these options below, considering quantitative and qualitative aspects such as fault level contribution, inertia provision, energy capability, cost, lead time, black start capability, and commercial considerations. Our analysis underscores the advantages of solutions that can **"stack" multiple services** and be procured competitively, thereby minimizing whole-of-system costs.

Attribute	Synchronous Condensers (SynCons)	Grid-Forming BESS	Clutched Gas Turbines (GTs)
Fault Level Contribution	High: Provides strong short-circuit current (fault level) because it's an electromechanical device. A syncon can typically supply a fault current several times its rated current, which directly strengthens the grid. This makes it effective at improving transient stability and supporting protection systems.	Moderate: Inverters can be programmed to provide fault current, but they are usually limited to ~1–2 per unit of their rating for brief periods. This is lower than a comparably sized syncon or generator. While advanced grid-forming inverters can improve fault levels somewhat, they cannot yet match the fault current of a large spinning machine. (They may, however, help ride through faults by rapid control.)	High: When the generator is spinning (even if the turbine is not driving it), it behaves like a synchronous machine, contributing substantial fault current. A clutched GT in condenser mode will have fault level contribution similar to a generator of equal size – often ~3–5 times rated current. Thus, it can supply both system strength and inertia akin to a syncon.
Inertia (Frequency Support)	Physical inertia: The large rotating mass of a syncon provides stored kinetic energy. If the grid frequency dips, the syncon naturally slows slightly, releasing energy to support frequency. This response is *immediate* and autonomous. For example, SA's 4 new syncons each have a flywheel to boost inertia – collectively providing 4,400 MW·s inertia in SA . Syncons provide inertia 24/7 as long as they're online (they typically run continuously).	Synthetic/Virtual inertia: A GFM BESS can detect frequency changes and inject power rapidly (far faster than typical governor response). Effectively, it can emulate the behaviour of inertia through control algorithms – responding within milliseconds to counter frequency deviations. However, it is limited by its power rating and the energy stored in the battery. The "inertial" response might last only a number of seconds unless sustained by real power from the battery. In practice, these provide excellent fast frequency response (FFR) and can arrest frequency drops quickly, but unlike a heavy machine, they don't have a massive spinning reserve – they rely on battery energy.	Physical inertia: The generator rotor of a GT set provides true inertia whenever it's synced to the grid. In condenser mode (turbine offline, generator spinning), it gives inertia without fuel consumption. In generator mode (turbine firing), it gives inertia *and* power. A 200 MVA generator, for instance, might have an inertia constant H ~5–6 seconds, equating to around 1,000–1,500 MW·s of inertia contribution (depending on design). Thus, a few such units can supply a substantial inertial floor. Clutched GTs are particularly useful at low demand periods – the units can be spun for inertia without generating, avoiding minimum generation issues yet maintaining security.
Energy and Capacity	No energy delivery: A syncon does not provide active power to the grid (aside from very small adjustments to inject/absorb reactive power or to cover losses). It cannot supply electricity to meet load. Its role is purely "electrical flywheel" and voltage support. (It *consumes* a small amount of power to keep spinning – e.g. a 50 MVAR syncon might draw a few hundred kW to a couple MW in losses.)	Energy storage resource: This is a key advantage – the BESS can charge and discharge. A grid-forming battery can provide not only stability services but also time-shift energy and supply capacity during peaks. Many large BESS have 1–4 hours of storage. They can, for example, reduce peak demand on networks (deferring upgrades) and participate in energy markets for arbitrage. Their ability to provide energy means any inertia they provide can be replenished (by recharging) and they can also help reboot a system by energizing islands (acting as a virtual generator during black start). The flip side: their energy is finite, so they are limited in duration for supplying high power. But for frequency containment, the required burst is typically seconds to minutes – easily achievable.	Fully capable generator: A clutched GT can operate as a normal generator when needed, offering potentially hundreds of MW of capacity to meet demand. For example, the two rapid response gas plants awarded inertia contracts in the UK (Drax's Millbrook and Progress Power stations) can not only provide inertia but also supply energy during tight periods. Fuel-based generation can run as long as needed (subject to fuel supply), which complements renewables by providing firm backup. In syncon mode, the GT's turbine is idle, so no fuel is burned – it's just providing standby inertia and voltage support. This dual-mode capability means the asset serves double duty: reliability capacity and stability service.

Black Start Capability	None (by itself): A synchronous condenser cannot black start the grid because it has no prime mover or energy source. In fact, a syncon itself typically requires station service power to start up (motoring up to speed). It can *assist* in black start once running, by energizing the voltage and providing reactive support, but it's not a source of generation.	Possible (with sufficient battery and controls): Grid-forming batteries are theoretically capable of black start. They can establish a reference voltage and start energizing a dead network, then pick up loads – effectively doing what a traditional generator does during system restoration. In South Australia, there have been successful tests where the big battery helped restart an islanded grid in combination with wind farms. AEMO has reported the addition of batteries (and even rooftop PV emergency control) is part of SA's black start strategy. The limitation is the battery's energy – it might only sustain the grid until other generation comes online.	Yes: Most gas turbine plants can be outfitted for black start (many have a diesel generator or battery to crank the turbine). In practice, clutched GTs could be excellent black start units. Gas turbines are often preferred black start sources due to fast start and high power output. Having them in the fleet (even primarily for inertia services) maintains robust black start options – something purely-electronic solutions might struggle with at very large scale.
Operational Flexibility & Duration	Always on (must run): Syncons are typically run continuously or at least whenever the system is at risk of low strength. They don't have "dispatchable" levels – they either provide their full inertia/fault capability when online or nothing when offline. They can, however, be switched off during high inertia conditions to save losses. In practice, their operating cost is low, so they're kept in service. They can provide reactive power indefinitely and inertia indefinitely. There is no duration limit – they are spinning mass. Thus, they are great for steady, always-available grid support, but inflexible in that they can't ramp up/down a service level (other than providing dynamic reactive support as needed).	Highly flexible, limited duration: BESS can be turned on and off (inverter pulses) in fractions of a second. They can provide full services one moment and zero the next, following dispatch or autonomous settings. They are the most *controllable* of the three. However, they have a duration constraint – typically after a few hours of discharge, the battery is depleted. For inertia/FFR, this is usually not an issue, as those events are short. But if asked to provide, say, 100 MW of contingency reserve continuously for 8 hours, most batteries would run out. They excel at fast, short-duration tasks and rapid cycling. Over a day, they can provide multiple cycles of support as long as they recharge. Their flexibility is hugely valuable (e.g., they can seamlessly switch from charging to discharging to absorb disturbances).	Flexible in mode, slower in operation: Clutched GTs can switch between modes, but not instantaneously. To go from syncon-mode to generating-mode, the turbine must be started and synchronized – this could take several minutes to tens of minutes depending on the technology (some aero-derivative GTs start very quickly). Once generating, they can ramp output typically within their design limits (many can ramp 10–20 MW per minute or faster in newer units). They can also be shut down and left spun as syncons (some designs allow dropping the fuel and immediately clutching out to syncon mode to coast down under grid power). So, while not as nimble as a battery, a clutched GT is reasonably flexible for an engine. Duration in generation mode is as long as fuel lasts (which can be effectively infinite with pipeline gas or long with stored liquid fuel).
Capital Cost	High capital, low operating cost: Syncons are capital-intensive network assets. Each unit (often 100–250 MVA) can cost on the order of tens of millions of dollars, with recent projects indicating unit costs in the range of $50–$100+ million depending on size and complexity (flywheel, etc.). The planned 32 new syncons across the NEM represent roughly **$4.7 billion in capital expenditure** to 2035. Operating costs are relatively low	High capital, multi-purpose value: Large-scale batteries are capital-intensive, but their costs have been dropping. Today's capital cost for a 100 MW battery might range from $100–$150 million (depending on MWh duration and chemistry). While still substantial, batteries are already competitive on a services-per-dollar basis because they can generate multiple revenue streams (energy arbitrage, FCAS, possibly capacity payments, and now system strength	Moderate-to-high capital (if new), low capital (if retrofitting existing): This option can be very cost-effective if there are existing gas turbines that can be utilized. Adding a clutch and necessary control systems might cost only a few million dollars per unit (e.g., roughly $2–6 million depending on size). That is a *tiny fraction* of building a new syncon of similar capacity. For instance, a 200 MW generator with a clutch ($3m) provides inertia

	(mainly maintenance and electricity for losses). But the upfront cost is sunk and recovered via regulated charges on consumers. There is no market competition once approved; consumers pay the allowed return regardless of actual usage. While syncons have long lifespans and relatively low operating costs, this upfront cost is significant and falls directly onto consumers via TNSP regulated revenue. **There is minimal offsetting revenue since syncons do not earn market income.**	services). Importantly, the **net cost to consumers can be lower if the BESS can stack revenue**. From the consumer perspective, if they contract with a battery for system security, they might pay an annual fee significantly lower than the amortized cost of a new network asset, because the battery expects to earn the rest from market revenues. The incremental cost to enable grid-forming capability in a battery is relatively small – mainly additional control systems and maybe slightly more robust inverter hardware. A recent study estimated the extra costs for GFM functionality in existing batteries could be in the low single-digit millions or less (for software, some hardware, and testing). So if the battery is being built anyway, making it grid-forming is cost-effective.	similar to a new 100 MVA syncon (~$40m). If a new gas turbine plant is needed, then you incur its cost (which can be ~$800–$1000/kW for an OCGT: so $160–200m for 200 MW). The key advantage lies in **value stacking**. By earning revenue from system strength and inertia services while operating in clutch (syncon) mode — and from energy and capacity markets when generating — the operator can spread fixed costs across multiple income streams. **The consumer benefits because the total system cost per service is lower** than that of a single-purpose syncon that earns only a regulated return. Furthermore**, AEMO's ISP already identifies gas generation as a critical backup for seasonal shortfalls in wind and solar production**. These assets will be required for reliability regardless of how many syncons are installed. Clutched GTs therefore represent **a rational, multi-purpose investment**: assets that we will need for reliability anyway, configured to also deliver system strength and inertia when idle.
Deployment Lead Time and Practicality	Building and commissioning syncons is a multi-year process. It involves manufacturing large rotating machines (a specialized global supply chain), civil construction, and careful grid integration testing. A major concern is the **supply chain bottleneck**: with dozens of units needed by 2030, global manufacturers may face constraints. One analysis noted that Australia's requirement of ~19 syncons over 2 years around 2029–30 would **strain global production capacity and risk schedule delays or price premiums**. Thus, while syncons are proven technology, the sheer volume needed and slow delivery pose timing risks.	Battery projects have among the shortest lead times of any infrastructure. A large BESS can typically be built within 12–18 months from investment decision, or even faster for smaller projects. The components (battery modules, inverters) are mass-manufactured commodities with expanding global supply due to the electric vehicle boom. Australia has already seen batteries built in record time (100 days for Hornsdale's initial phase). **Modularity** allows staging capacity in blocks, and multiple providers (Tesla, Fluence, etc.) offer relatively turnkey solutions. Overall, GFM BESS can be deployed quickly enough to meet even near-term shortfalls, provided regulatory arrangements for contracting are in place. They also have a smaller physical footprint and more siting flexibility.	The lead time depends on whether existing assets can be utilized. If an operational generator can be upgraded with a clutch, it might be feasible within 1–2 years including engineering and outages. A new-build GT would likely take ~2–3 years for permitting, construction, and commissioning. Thus, clutched GTs are **not as fast as batteries** but could come online sooner than a large transmission project or new coal replacement. One practical consideration is **fuel and emissions**: deploying new gas units in the current policy environment may face social license hurdles, although for emergency and security support their role can be justified.
Commercial	Syncons procured by TNSPs are	GFM batteries open up a much more	Clutched GT solutions could also be

Model and Flexibility	**regulated assets** – their costs (capex and allowed return) go directly into network tariffs. There is no market for "syncon services" per se; they are effectively a **monopoly network service**. This means consumers bear the full cost, and there is no competition driving that cost down (apart from competitive procurement during construction contracting). Syncons also have no inherent revenue streams to offset their cost. Once built, they operate in the background, and market participants cannot readily replicate or replace their function. In short, the syncon model is a **traditional regulated investment** approach.	**flexible commercial model**. A TNSP or planner can procure system strength as a **service via contract** from a battery proponent, as AEMO Victorian Planning is currently doing. The contract might pay for availability and performance (fault level contribution, etc.), but the battery remains a **merchant asset in the energy market** as well. This allows the battery operator to earn energy and FCAS revenue on top of the contract, reducing the level of payment needed from the TNSP/consumers. **Competition can be introduced by having multiple developers bid for the contract, driving innovation in technical design and cost efficiency**. The TNSP avoids owning generation directly (preserving ring-fencing) yet secures the required service. Additionally, batteries can be relocated or repurposed if needs change, offering asset flexibility that a fixed syncon lacks. Overall, **competitive procurement of battery-based system strength services** promises lower whole-of-system costs by unlocking private co-investment and multi-service monetization.	delivered via **competitive contracts**. The real barrier is not technical but economic — the current market structure makes new gas peakers unviable if they can only recover costs through energy market participation. Enabling them to compete in system strength and inertia markets would make them financially viable while reducing the total cost borne by consumers compared to regulated network alternatives. For example, an independent power producer with a new or existing gas peaker could enter an arrangement with the TNSP: in return for an availability payment (or cost recovery mechanism), the generator would operate in synchronous condenser mode at certain times or provide a guaranteed fault level when needed for system strength. The generator still participates in the energy market when it runs for electricity production, earning market revenue.

Each solution has its strengths, but on balance, **the grid-forming battery approach offers the greatest flexibility and potential for stacking value**, while **clutched gas turbines offer valuable multi-service capabilities as well (especially if leveraging existing units)**. Synchronous condensers, although robust in providing fault current and inertia, are a single-purpose, single-use asset. They will remain important – a certain amount of synchronous fault current source is likely needed in any scenario – but an over-reliance on syncons would come at a high direct cost to consumers with less adaptability.

By contrast, **GFM batteries can provide system strength, fast frequency response, capacity support, and other services all in one resource**, and do so with a business model that can offset costs through market revenues. The Victorian analysis quantified this benefit: incorporating battery solutions avoided roughly three-quarters of a billion dollars in otherwise necessary network investment. Similarly, clutched generators can contribute to reliability (keeping lights on during peak demand or after outages) while also meeting system strength needs – a form of **capital efficiency** that pure network devices cannot achieve.

What other jurisdictions have done

The UK has progressively moved away from a **capex-only, RAB-driven** paradigm by (i) changing how networks are remunerated and (ii) introducing **contestability for network-adjacent services**.

1) Remunerating outcomes, not just assets (RIIO/TOTEX).

Ofgem's RIIO price-control framework ("Revenue = Incentives + Innovation + Outputs") regulates networks on **TOTEX** (total expenditure) rather than loading returns only onto capital spend. This reduces the capex bias and pays companies to deliver specified outputs (reliability, connections, customer service, environment) efficiently, with upside/downside incentives for performance — not just asset growth. In short: networks are rewarded for **least-cost delivery** of outcomes, whether the solution is capex or opex (including contracted non-network services).

2) Making parts of the "network" competitive (OFTO, interconnectors).

For offshore wind grid connections, the UK created **Offshore Transmission Owners (OFTOs)** selected via competitive tenders run by Ofgem. Developers build or specify the assets; long-term ownership and operation are competitively awarded, bringing in third-party capital on regulated terms discovered through a tender, not via an incumbent's RAB roll-in. The regime has matured into multi-billion-pound tender rounds that explicitly **attract new investors** and lower consumer cost through competition. For cross-border links, Ofgem uses a **cap-and-floor** model (revenue band with upside sharing and downside protection), again separating investment from a pure RAB allowance and disciplining costs through a bespoke regime.

3) Procuring stability as a service (not just building machines).

Rather than defaulting to regulated synchronous plant, the UK system operator (now National Energy System Operator, NESO) has run **Stability Pathfinder** tenders to buy inertia, short-circuit level and voltage support from a mix of technologies — synchronous condensers, retrofitted generators, and increasingly **grid-forming batteries** — via multi-year contracts. The first phases have been delivered and further tenders are planned, with work under way toward an enduring **stability market**. This approach **prices the service** and lets technology compete, instead of socialising single-purpose assets into the RAB.

Takeaways for Australia.

- Move from asset-based returns to **output/TOTEX incentives** so networks are indifferent between building, contracting, or enabling third parties when that's cheaper.
- Introduce **contestability** for suitable network functions (offshore/onshore connections, stability, potentially REZ-related assets) to bring in new capital at competitive terms, as per OFTO/cap-and-floor precedents.
- Procure **system strength/inertia as services** via multi-year tenders (Pathfinder-style), creating a pipeline where **GFM BESS and clutched GTs** can compete with syncons, lowering whole-of-system cost and shortening lead times.

The UK model isn't perfect, but it shows a practical way to **de-emphasise RAB expansion**, embed competition where feasible, and buy **capability** rather than just assets — exactly what's needed if the ISP is to deliver **lowest whole-of-system cost** to consumers.

Conclusion and Recommendations

In light of the above analysis, we recommend that the AEMC, AEMO, and network service providers pivot towards a framework that explicitly pursues the **lowest whole-of-system cost to consumers**. Achieving this requires moving beyond the Regulatory Asset Base (RAB) model toward a **hybrid-cost framework** that enables **value stacking across energy and network services**. By allowing assets such as grid-forming batteries and clutched gas turbines to recover costs through both market participation and system service provision, the overall cost of stability and reliability can be reduced. This approach replaces the incentive to maximise regulated capital expenditure with one that rewards efficiency, flexibility, and performance — ensuring that every dollar consumers pay delivers multiple system benefits rather than a single, siloed outcome.

The key policy implications and actions we urge are:

- **Embed Whole-of-System Cost Analysis in Planning:** Amend the ISP requirements to include all material costs that the transition will impose on consumers – transmission, distribution, DER enablement, FCAS, system strength and inertia. The goal should be an optimal development path that truly minimizes total costs (not just one segment of costs). This will likely favour solutions that reduce the need for expensive new network build, such as strategically located storage and generation closer to load. It will also illuminate the trade-offs of jurisdictional policies in a transparent way, aiding better decisions.
- **Align TNSP Incentives with Least-Cost Outcomes:** Evolve the regulatory framework so that TNSPs are no longer **incentivised to build expensive capital-intensive projects** that increase their RAB but rather paid for delivering service outcomes. The focus must shift from **"build and own" to "procure and enable"** – with TNSPs as facilitators of the best solutions the market can offer.
- **Accelerate Competitive Procurement for System Strength:** We applaud initiatives like AEMO Victoria's competitive tenders for system strength services. These should become the norm. The AEMC could formalize guidance that when a system strength shortfall is identified, the SSSP (System Strength Service Provider) should first seek market responses (contracts with existing generators, new battery projects, etc.) and only build syncons as a last resort. This open solicitation process, with clear specification of the needed fault level and availability, will reveal the true least-cost mix of solutions. It also encourages **new entrants and technologies** to participate, as demonstrated by the FCAS market experience. This approach should be extended to an open tender for provision of system strength at each system strength node each year.
- **Leverage Capability Stacking:** Regulatory arrangements should recognize and **value the stacking of multiple services** from one asset. For instance, if a battery provides system strength under a network contract, it should not be prevented from earning market revenue in energy/FCAS markets – rather, its contract can be structured to share those benefits (reducing the net cost to consumers). Similarly, if a generator provides a guaranteed system strength service, that should be compatible with its energy

market offers. The goal is to maximize the utilization of each asset for multiple purposes, thus spreading costs. This reduces the need for one-service assets and leads to a more **efficient asset base overall**.

- **Ensure Sufficient Synchronous "Core" Strength:** While we champion batteries and hybrid solutions, we also acknowledge that a base level of synchronous machines (be it syncons or generating units) is likely needed for fault current and system robustness. The planning process should determine that minimum synchronous requirement and make sure it is met – but beyond that, **incremental needs should be opened to alternatives**. For example, if studies show you need X MVA of true fault current at a node (which only syncons/rotating machines can supply), install that, but if you need additional support for hosting capacity, let batteries fill the rest. This **hybrid approach** will ensure security is maintained while avoiding over-investment in one type of asset.
- **Monitor and Update Standards:** Finally, we encourage ongoing review of standards (like the system strength standard and inertia metrics) as technology capabilities change. If, for instance, grid-forming inverters prove they can indeed provide "protection grade" fault current in the future, the frameworks should adapt to count that. The regulatory environment should be **dynamic and innovation-friendly**, not locking in outdated assumptions. Close collaboration between AEMO, AEMC, and industry will be needed to keep technical requirements in step with what modern power electronics can achieve.

In conclusion, we strongly support the direction of **ERC0406** in seeking more holistic planning and cost treatment. By adopting a whole-of-system lens and embracing competitive, flexible solutions for system strength, the energy market reforms can deliver a more secure transition at lower cost. The experience with FCAS markets and the comparative analysis of solutions indicate that Australia can meet its system security needs in a way that harnesses new technology and private investment, rather than relying solely on traditional network expansion. This will ultimately benefit consumers through more affordable and reliable energy. We appreciate the Commission's consideration of these views and would welcome further engagement or clarification on any of the points raised.

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