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Senate Economics Legislation Committee

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Comments on Domestic Gas Reservation legislation

Australian Energy Producers supports a well-designed, prospective gas reservation scheme linked to new supply. These design elements are essential to strengthening competition, encouraging long-term investment and contracting, and ensuring reliable and affordable gas for Australian industries and households.

The legislation as currently drafted falls well short of what is needed to provide long-term certainty and positive incentives for all market participants. Like the price caps and Gas Market Code before it, the proposed reservation scheme is driven by short-term price outcomes at the expense of an enduring, sustainable policy framework. Domestic-focused gas producers, LNG exporters, state governments, investors and trading partners have all raised serious concerns about the current design. Without significant changes, the scheme risks undermining the investment and competition needed to deliver reliable, affordable gas where and when it is needed.

The Australian Government's own impact analysis confirms industry's material concerns. The analysis finds that the net impact is a transfer of value from gas producers to domestic users through downward pressure on domestic gas prices; that some higher-cost gas production may become uneconomic; that production, investment and LNG exports could be lower relative to the status quo; and that the regulatory burden rises to $134 million over 10 years (compared with $59 million under the status quo). Further, the impact analysis reports that some international stakeholders may perceive the scheme as increasing regulatory uncertainty, particularly during transition. Stakeholders also raised concerns about unintended consequences and whether the proposed settings would achieve the objectives in practice.[1]

The impact analysis does not quantify the scheme's net impact on national income or employment. Guidance from the Office of Impact Analysis requires formal cost-benefit analysis that accounts for economy-wide effects for proposals of this scale. The guidance clarifies that "impacts should be quantified for each time period over the life of the proposed regulation" and that the analysis "should present the best estimates of expected costs and benefits, along with a description of the major uncertainties and how they were taken into account".[2] However, while the impact analysis finds that the proposed scheme is "expected to improve supply security and put downward pressure on domestic gas prices", it does not reconcile this finding with the prospect of lower gas production and investment, and higher regulatory costs. Nor does the analysis explain or assess how a policy that undermines one of Australia's largest export industries could deliver net national benefits.

[1] Australian Government, *Domestic Gas Reservation Bill 2026: Explanatory Memorandum*, Attachment A.
[2] Office of Impact Analysis, *Cost-benefit analysis*, May 2023, pp. 2, 4.

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Domestic gas prices are materially below prices received for Australian LNG exports. Analysis by EnergyQuest shows that, over the 12 months to June 2026, the average published realised east-coast domestic price was $10.07/GJ, 36% lower than the average published realised LNG price. The Australian Competition and Consumer Commission has found that existing contracts between retailers and commercial and industrial users are predominantly fixed-price, so they are not affected by changes in global energy prices.[3] These data refute the framing of the policy problem by the impact analysis as encompassing "continued exposure to international price volatility".[4]

Australian gas markets are well supplied until at least the end of the decade. The Australian Energy Market Operator has continued to push forecast shortfalls further into the future, reflecting increased supply capability and moderating demand.[5] Domestic-focused producers supply approximately two-thirds of the east-coast market and play a key role in meeting east coast demand efficiently – especially for winter peak-day deliverability in southern states. Queensland LNG producers have unlocked gas that would otherwise not have been economic solely for domestic use.[6] The core policy problem is regulatory uncertainty and insufficient incentives for additional investment and production – not high prices or an imminent shortage of molecules.

The Domestic Gas Reservation Bill contains some positive refinements to the exposure draft. The bill no longer requires infrastructure-adjustment requests to be included in the export licence application, or licence holders to be "actively taking steps" to improve their ability to make domestic supply obligation volumes. The bill also permits the forward banking of credits and extinguishes unused credits after 3 regulated periods. Further, the Minister for Resources must now consult state and territory governments that have existing reservation arrangements before setting a varied domestic supply obligation percentage, and merits review has been extended to additional decisions, including demand calibration, extended-period determinations and the variation or revocation of adjustment determinations.

Notwithstanding some improvements, there remain critical flaws that must be addressed for the reservation scheme to work. These include: a forced-sale requirement, default demand buffer, uncapped accrual of deferred quantities, uncertainty regarding the national scheme's interaction with state arrangements, a narrow and time-limited infrastructure adjustment, excessive ministerial discretion, uncertainty regarding the setting of baselines to determine additional gas, and a blunt and disproportionate compliance regime. Left unaddressed, these shortcomings risk displacing domestic-focused producers, reducing competition and diversity of supply, discouraging investment in future gas supply, undermining Australia's reputation as a reliable trade and investment partner, and inducing the very supply shortfalls and higher prices that the scheme is intended to avoid.

Australian Energy Producers proposes the amendments set out in the table below to improve the scheme's operation and strengthen its durability. AEP urges the government to continue consulting with industry on the bills, subordinate instruments and changes to the Gas Market Code. Industry also encourages the Commonwealth to work with states to expedite new supply, through faster and more certain approvals, clearer offshore consultation requirements, support for exploration, timely native title decisions and stable, internationally competitive tax settings.

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[3] EnergyQuest, *Australian gas prices vs Australian LNG prices*, report prepared for Australian Energy Producers, September 2026.
[4] Australian Government, *Domestic Gas Reservation Bill 2026: Explanatory Memorandum*, Attachment A, p. A2.
[5] Australian Energy Market Operator, *2026 Gas Statement of Opportunities*, 26 March 2026;
[6] See Kroll Economics, *An Assessment of East Coast Gas Adequacy and Policy Design*, 10 June 2026, pp. 4, 88; Department of Climate Change, Energy, the Environment and Water and Department of Industry, Science and Resources, *Gas Market Review Report*, 22 December 2025, pp. 7, 37f.

Summary of proposed amendments

1. **Replace the effective forced-sale requirement with a genuine-offer obligation (s20 of the Domestic Gas Reservation Bill and s57A of the Gas Market Code).** Allow domestic supply obligation (DSO) gas that has been genuinely offered to domestic users at competitive prices and on commercial terms, but not needed by the market, to be exported.
2. **Calibrate domestic supply obligations to deliver a balanced market without oversupply (ss24 and 25 of bill).** The percentage buffer should be removed. The goal should be a balanced market that preserves investment signals for future gas supply, and ensures the upstream gas industry remains competitive with a diversity of suppliers.
3. **Prevent deferred supply obligations and banked surplus supply from creating future oversupply or distorting the market (ss21, 24 and 25).** Require the Australian Energy Regulator to account for deferred obligations and banked surplus supply across the market when calibrating future DSOs. Provide symmetrical treatment so that, after 3 years, both unused banked surplus supply (as now provided in s21(6)-(7)) and unresolved deferred obligations expire, with deferred obligations treated as deemed supply where the gas has been genuinely offered on competitive commercial terms but not purchased.
4. **Ensure Western Australia's existing reservation framework is not undermined or overridden by the national scheme (ss8, 9, 23 and 26).** Clearly recognise the state domestic gas policy as the primary and ongoing policy in Western Australia, including for new and expanded projects, and avoid unnecessary duplication of Commonwealth and state regulation and compliance. Where the Western Australian market domestic supply obligation is set at zero, the Gas Market Code and the Australian Energy Regulator's jurisdiction should not apply.
5. **Recognise genuine and ongoing infrastructure constraints (ss26 and 27).** Grant DSO adjustments for any year where physical, capacity or other material infrastructure constraints prevent domestic supply, without requiring LNG exporters to overcome those constraints unilaterally or undertake uneconomic investment. Remove the condition that constraints must have existed before commencement and the 31 December 2027 cut-off, so that adjustments can be sought whenever a material constraint arises or becomes relevant.
6. **Narrow and clarify ministerial discretion (ss23, 24(6), 26-30, 103).** Bind the Minister for Resources and Minister for Energy to the same statutory criteria, keep the Industry Minister's role consultative only, fix timeframes from s31 advice (deemed approval; no prejudice if applied on time), require published reasons, permit extended DSO regulated periods for all exporters (including in subsequent periods), ensure determinations relating to a DSO adjustment or an extended period remain unchanged, and allow merits reviews that can substitute decisions.
7. **Provide certainty on production baselines and additional gas (ss9 and 18 of the Domestic Gas Reservation Bill; Gas Market Code ss57F-57P).** Ensure new and expanded supply is recognised as additional gas where the producer demonstrates that investment or development activity has caused it, regardless of the baseline outcome. Baselines should operate only as a secondary administrative measure, must not retrospectively reclassify gas already recognised as additional, and should be published, consulted on and finalised before commencement.
8. **Establish a proportionate, graduated and risk-based compliance regime (ss14, 16, 29, 55, 85, 99, 101)**. Distinguish deliberate or repeated non-compliance from inadvertent or technical breaches, limit executive and licence penalties and cancellations to serious misconduct, provide reasonable rectification and transitional protections, and recognise voluntary compliance efforts.

Table 1: Amendments proposed by Australian Energy Producers to domestic gas reservation legislation

Provision	Adverse unintended consequences	Proposed amendments	How this solves the problem
1. Forced sale with limited flexibility **Minimum total quantity for DSO** (s17 of Domestic Gas Reservation Bill): For each market, the exporter must supply gas (DSO supplies, which can include deemed supplies under s19) equal to 20% of the energy in its LNG exports from that market (or the varied percentage for that market), minus any adjustment quantities determined by the minister (s26). **Two compliance pathways** (s16(1)): Either supply 100% of the minimum total quantity, or use the flexible route in s20. The latter requires DSO supplies of at least 90% and meeting the **flexibility requirements** for the remainder (s57A of Gas Market Code, as inserted by schedule 2, part 1, item 5 of consequential amendments bill; s20(2) of main bill). An exporter must demonstrate one of the following: a. Pursued "best endeavours" to sell uncontracted regulated gas, by: i. issuing expressions of interest on "domestically competitive terms" (and advertise through any facilitated markets); ii. negotiating in good faith; and iii. not refusing reasonable offers. Or, b. A buyer not exercising a call option. Or, c. Non-supply of contracted gas owing to unforeseeable circumstances outside the exporter's control.	The bill contains an effective forced-sale obligation with no reciprocal commerciality test. It does not take account of the cost of production, transport and delivery, market conditions, project economics or need for reasonable return. Also, the bill does not oblige buyers to engage constructively in procurement processes. Requiring supply, rather than a genuine offer on competitive terms, would force licence holders to push gas into the market regardless of demand. In a balanced or oversupplied market this would suppress prices, displace domestic-focused producers, and compel exporters to choose between uneconomic options. The Australian Government's own impact analysis acknowledges that the scheme's net effect is to shift value from gas producers to domestic gas users through downward pressure on domestic prices, that downward price pressure may render some higher-cost production uneconomic with consequent reductions in production and investment compared with the status quo, and that LNG export volumes may be lower than under the status quo. It also notes that international stakeholders may see the scheme as adding regulatory uncertainty during the transition (pp. A3-A4, A6).	Amend s20 of the Domestic Gas Reservation Bill and s57A of the Gas Market Code so that: a. any/all DSO volumes that are diligently marketed and genuinely offered on competitive commercial terms, but not taken up by domestic users, should be allowed to be exported efficiently and without pre-approval (noting proposed treatment of accruals proposed in item 3 below). b. the Australian Energy Regulator is required to develop guidelines (in consultation with stakeholders) setting out its compliance approach.	Ensures gas that is genuinely and competitively offered to domestic users in good faith – but not required – can reach export markets rather than being sold at the expense of domestic-only producers or acquitted via uneconomic means. This approach is consistent with the flexible, practicable model that has underpinned Western Australia's successful domestic gas policy.

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2. Calibration of domestic supply obligations to demand Under ss24 and 25 of the bill (and the methods the AER determines under ss57B and 57C of the Gas Market Code), the AER will: • Forecast aggregate domestic demand for each market (effectively east coast/NT and WA) for the regulatory period (year beginning 1 Jan 2028 and each following year). • Subtract forecast supply from non-licence holders from forecast aggregate demand. • Add a percentage buffer of aggregate domestic demand to that figure to calculate the "targeted aggregate supply" for each regulated period. • The default percentage buffer is 10% of forecast aggregate domestic demand (s24(3)(a)(ii) and (5)), but the minister may determine a lower percentage by legislative instrument (s24(6)). • Determine each exporter's demand-calibrated quantity using that target and the exporter's forecast share of total covered exports (s25(5)-(6)). This takes effect only if it is lower than the exporter's minimum total quantity (s25(4)), and does not apply where a DSO adjustment or extended period determination is in force for the exporter (s25(3)).	A default percentage buffer risks: • inducing an unsustainable and damaging oversupply • artificially pushing prices below the marginal cost of new supply • crowding out domestic-focused producers • reducing competition and diversity of supply • weakening incentives for the additional investment and production that the scheme is intended to support, and which is essential to competitive prices in the long run. The percentage buffer exacerbates the adverse effects of the forced-sale obligation. The impact analysis observes that stakeholders "raised concerns about unintended consequences and whether the proposed settings would achieve the objectives in practice" (p. A6f). With east-coast domestic demand of approx. 500 PJ a year, a 10% buffer equates to approx. 50 PJ – double the maximum capacity of the Iona gas storage facility and comparable to annual industrial gas demand in Victoria.	Amend the Domestic Gas Reservation Bill to: a. remove the percentage buffer (s24(3)(a)(ii), (5) and (6)) so that domestic supply obligations are calibrated to deliver a balanced market without oversupply b. recognise that a downward calibration of an individual licence holder's obligations should not result in an increase to other licence holders' obligations.	Removing a percentage buffer would: • reduce the risk of the domestic gas reservation scheme inducing an unsustainable structural oversupply • better align reserved volumes with genuine demand • preserve the price signals needed to sustain investment and supply by both exporters and domestic-focused producers • be more conducive to competition and competitive prices in the long run. • recognise that AEMO already takes a conservative approach in forecasting demand and supply conditions.

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3. Deferral (accrual) of domestic supply obligations and banking of surplus supply The bill allows exporters to defer up to 10% of their annual DSO (ss20 and 21(2)). Deferred quantities must be fully offset within the following 3 regulated periods (s21). The bill also permits banking of oversupply as a credit quantity that must be applied to offset deferred quantities (s21(4)-(5)). The bill caps retained credits at 10% of the minimum total quantity for the year in which it was earned (s21(6)), and unused credits expire 3 years after they accrued (s21(7)). Deferred quantities have no equivalent overall accumulation cap beyond the annual 10% limit and the three-year offset requirement. A deferred quantity that is not fully offset in time becomes a debt quantity, which is added to the licence holder's minimum total quantity for the following regulated period (ss21(8) and 33(1), (3) item 3), and non-compliance with s21 is also a contravention of s16(1) – attracting a civil penalty.	The deferral (accrual) of borrowed volumes may see material obligations at the end of the compliance period, without a clear means of achieving compliance. The forced offsetting of liabilities within 3 years – irrespective of market need or storage capacity – would discourage investment and long-term contracting, and further damage domestic-focused producers. This is at odds with a key objective of the domestic gas reservation scheme: To promote a return to long-term contracting.	Amend ss21, 24, 25 and 33 of the Domestic Gas Reservation Bill so that: a. The Australian Energy Regulator is required to take into account the accumulated deferred supply obligations and banked surplus supply across the market when determining the demand calibration; and b. Unused credit quantities and unresolved deferred quantities are treated symmetrically, so that both automatically expire 3 years after they accrue – rather than an unresolved deferred quantity becoming a debt quantity under s33(3), table item 3. Where gas has been genuinely offered on competitive commercial terms but not purchased within that time, the unresolved deferred quantity should instead be treated as "deemed supply" under s19. Credit quantities already expire after 3 regulated periods under s21(7), and that outcome should be retained.	Requiring the AER to account for the accumulated deferred supply obligations and banked surplus supply when calibrating future demand ensures that unresolved volumes are reflected in future DSOs. Managing deferred supply obligations and banked surplus supply with a predictable roll-off after 3 years prevents the compounding of accruals to unsustainable and unworkable levels, consistent with the bill not requiring the accrual of DSO variations. It also provides a clear and achievable path to compliance in every scenario.
4. Clarifying interaction of national scheme with Western Australia and other jurisdictions while reducing regulatory duplication The Domestic Gas Reservation Bill effectively recognises that the Western Australian market is separate from the eastern market, by allowing DSOs to be set based on individual markets (domestic gas markets being defined by	The impact analysis reported that stakeholders are concerned that the national gas reservation scheme "would increase compliance and reporting burden, particularly if obligations overlap with existing frameworks (for example, Western Australia) while noting any reduction in complexity will depend on effective streamlining and clear design" (p. A7). Clarity is still required in relation to:	Amend sections 8, 9, 23 and 26 of the Domestic Gas Reservation Bill to clarify that the intent of the Act is to: a. Not override, duplicate or replace existing reservation arrangements that apply to domestic gas markets, including future updates and extensions. b. Ensure that recognition of existing domestic gas reservation arrangements	These proposed changes: • preserve Western Australia's domestic gas policy • provide the certainty required for state-based investment decisions • ensure existing agreements entered into between producers and the state government, which give effect to the WA domestic gas policy, are protected

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reference to physically interconnected pipeline networks: ss9 and 12; the bill does not refer to Western Australia by name). Under ss26(1)(b) and 26(4) of the bill, exporters may request that the minister determine an adjustment quantity, reducing their obligations, to recognise "existing domestic gas reservation arrangements" – but only arrangements in force on or before 22 December 2025 (s9), and only if applied for by a separate application made before 31 December 2027 and determined on or before that date (s26(4)), subject only to the narrow pathway in s26(5) where a market's DSO percentage moves from 0% to above 0%. The minister must also be satisfied that demand and supply conditions in the market make the adjustment appropriate (s27(3)). The minister can effectively lower the WA obligation, and in doing so may have regard to any existing state or territory reservation arrangement (e.g., WA's domestic gas policy) that applies to participants in the market (s23(4)(a)). Any such decision for the first year of the scheme would need to be made by 30 June 2027 (s23(3)(f)). Before doing so, the minister must now consult the relevant state or territory government on the effect of its reservation arrangement on supply in the market (s23(3)(d)), but the state or territory government has no veto.	• The exercise of significant ministerial discretion in relation to the treatment of WA exporters and the mechanism for determining adjustment quantities. • Uncertainty regarding the definition of existing domestic gas reservation "arrangements" (s9) and the potential for including new projects or extensions. • If and how the Gas Market Code will be extended to Western Australia. • The demand-calibration method and reliance on the WA Gas Statement of Opportunities (see s57B(2)(a)(ii) of the Gas Market Code, as inserted by the Consequential Amendments Bill) – noting that the WA statement is not designed for this purpose and there is no requirement in the bill that the AER must consult the WA State Government on potential market imbalances. The new requirement in s23(3)(d) to consult state and territory governments applies only to the minister's decision on a varied DSO percentage. Section 68(g) only permits, and does not require, consultation with state entities. Further, there is no recognition of Australian Market Supply Conditions attached to certain Queensland tenements.	includes future changes and extensions, short of the complete repeal of those arrangements. c. Ensure that agreements entered into between governments and producers, which implement an existing reservation arrangement, are considered part of an existing arrangement d. Ensure that new and expanded projects that would ordinarily be captured under the WA domestic gas policy will be regulated in the same way under that policy as existing projects. e. not to extend the Gas Market Code or the jurisdiction of the AER to Western Australia, when the minister sets a DSO for the WA market at zero (s23(6)). Further, the bill should ensure that: f. the Commonwealth consults *and gives due regard* to the views and preferences of state/territory governments in assessing supply and demand, evaluating potential imbalances and making determinations relating to demand calibration. g. compliance and reporting requirements are minimised, including where such obligations would ordinarily be regulated under the WA domestic gas policy and when a domestic supply obligation for the WA market is set to zero.	• remove doubt that the Gas Market Code or the jurisdiction of the Australian Energy Regulator will not apply to Western Australia • ensure that the assessments and advice of the Australian Energy Regulator demand calibration method in Western Australia is fit-for-purpose, properly informed and endorsed by the WA Government • avoid inconsistent or duplicative regulation between the WA domestic gas policy and the national scheme.
5. Recognising infrastructure constraints, including NT-based LNG exporters who are not part of the east-coast gas	The requirement that the constraints existed immediately before the commencement of s27 means no relief is available for infrastructure	Amend s27(4)(a) to remove the requirement that infrastructure constraints must have existed immediately before the commencement	Recognises genuine physical limits without compelling uneconomic capital expenditure. Allows the scheme to respond to constraints

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market owing to technical constraints in gas supply Section 26(1)(c) of the Domestic Gas Reservation Bill allows the minister to determine an adjustment quantity where infrastructure constraints limit a licence holder's ability to make domestic supply obligation (DSO) supplies. Further, under s27(4), the minister may only make an adjustment where satisfied that the infrastructure constraints existed immediately before the commencement of s27 (s27(4)(a)) and that their effect is that it would be uneconomic for the licence holder to make DSO supplies in the market during the regulated period or extended period (s27(4)(b)). The bill removes the exposure draft's requirement that the licence holder be "actively taking steps to improve its ability to make DSO supplies". There is also a timing restriction on seeking an infrastructure adjustment. Under s26(4), the minister can only make a DSO adjustment determination if the licence holder has applied for such a determination before 31 December 2027 and the determination is made on or before that date – subject only to the narrow exception in s26(5), where a percentage moves from 0% to above 0%. The s27(4) limits continue to apply under that exception.	constraints that arise, or become relevant to an exporter's ability to meet its DSO, after commencement. The exporter must also satisfy the minister that the effect of the constraints is that making DSO supplies would be uneconomic (s27(4)(b)), rather than the test being whether genuine physical, capacity or other material constraints prevent domestic supply. Section 26(4) effectively requires an exporter to anticipate and apply for an infrastructure adjustment before 31 December 2027, rather than simply applying when an infrastructure constraint subsequently arises. The bill no longer requires the request to be made in the initial export licence application, but the cut-off date remains. Further, the current exemption framework only applies where an export facility lacks a physical connection to a network of interconnected pipelines supplying a domestic gas market (ss47(2)(c) and 48(1)(b)). This approach fails to recognise circumstances where a physical connection exists but practical barriers render domestic gas supply unfeasible. These barriers include insufficient pipeline capacity, incompatible operating pressures or gas specifications, or other infrastructure limitations, which either cannot be resolved technically or physically, or cannot be resolved without the LNG exporter (or a third party that the LNG exporter doesn't control) having to incur unreasonable levels of costs, which other LNG exporters are not required to incur.	of s27, so that an infrastructure adjustment can be made for material constraints whenever they arise. Amend s26(4) so that a licence holder is not required to apply for an infrastructure adjustment before 31 December 2027 (and to have it determined by that date: s26(4)(a) and (d)). Instead, the bill should allow a licence holder to apply for an infrastructure adjustment at any time when an infrastructure constraint arises or becomes relevant to its ability to meet the DSO. Amend s27(4) so that an adjustment can be made to recognise genuine physical, capacity or other material infrastructure constraints, without requiring the licence holder to overcome them unilaterally or undertake uneconomic investment. Exemption provisions should expressly recognise material infrastructure constraints as a valid basis for exemption and that infrastructure constraints may pre-exist or may arise in the future. Facilities should not be required to satisfy domestic supply obligations where they are unable to do so because of demonstrable infrastructure limitations. Such exemptions should remain available unless and until the relevant constraints have been resolved.	that emerge after licences are granted. Gives due regard to the material technical constraints that prevent LNG exporters in Darwin from gaining access to east-coast gas markets.

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	The existence of a physical connection alone should not be treated as evidence that a facility is capable of supplying the domestic market. The current drafting risks imposing obligations on facilities that they cannot comply with owing to factors beyond their control.		
6. Narrowing and clarifying ministerial discretion The bill gives the minister wide discretion – circumscribed only by broad criteria and "reasonableness" tests – over the decisions that set an exporter's domestic supply obligation and export rights: • a varied DSO percentage for a domestic market, of at least 0% and less than 20% (s23(1)-(2)). • a demand calibration percentage that is less than 10% and greater than or equal to 0% that the minister considers to be reasonable (s24(6)) • DSO adjustment quantities for existing contracts, existing reservation arrangements and infrastructure constraints (s26) • extended period determinations (s28) • variation or revocation of a s26 or s28 determination if information was false, misleading or incomplete, or if the circumstances that underpinned specified findings have "materially changed" (s30). In each case, the Energy Minister must also be satisfied that the decision should be made, and	The framework relies heavily on ministerial discretion in areas that are fundamental to commercial certainty and long-term investment. Decisions affecting domestic supply and export rights involve multiple ministers and are not subject to clear, objective or time-bound criteria. An investor could not confidently quantify the regulatory risk on the bill as introduced. Discretion of this breadth is likely to be priced as a risk premium, whichever way it is exercised. The Minister for Resources is subject to some statutory criteria (for example, ss27(1)-(4) and 28(5)(d)), but the Energy Minister need only be "satisfied" that a decision should be made (ss23(3)(b), 24(7)(a), 26(4)(e) and (5)(f), 28(5)(e) and 30(2)(a)) and the Industry Minister need only be consulted, with no equivalent criteria or timeframes for either. Decisions are also exposed to missed cut-off dates: If a determination has not been made by 30 June (s23(3)(f)) or by 31 December 2027 (ss26(4)(d) and 28(5)(h)), the Minister can no longer make it and the exporter bears the consequence through no fault of its own. Timing is also open-ended in places. A variation or revocation of a varied DSO percentage need not be made by 30 June and takes effect from	Where ministerial discretion remains necessary, the legislation should: a. Bind ministerial decisions to prescribed criteria. For DSO settings, demand calibration and other significant regulatory determinations, the legislation should i. specify clear and objective criteria that must be satisfied ii. require decisions to be reasonable and proportionate iii. require decision-making ministers to take specified matters into account, rather than leaving some ministers effectively unfettered. These criteria should apply to decisions Under: s23 (varied DSO percentage); s24(6) (market buffer percentage); s26 (DSO adjustment determination), s28 (extended period determination) and s30 (variation or revocation of those determinations). b. Clarify the role of ministers. The Energy Minister's current role – being "satisfied that the decision should be made" – without the same statutory criteria as the primary decision-maker – should not	These proposed changes would: • give exporters and investors predictable, enforceable timeframes for the decisions that set their domestic supply obligation and export rights, so that reservation decisions cannot be stalled by inter-departmental or intergovernmental processes • protect exporters from losing an adjustment or determination because a statutory cut-off passes while the minister has yet to decide • apply consistent, objective criteria to every decision-maker, including the Energy Minister, rather than leaving some decisions effectively unfettered • improve transparency and accountability through published reasons for all determinations, and give exporters recourse to merits review where a determination directly affects their obligations.

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the Industry Minister consulted. Some decisions have fixed cut-off dates, but have no decision-making timeframe. While export licences must run for 20 to 50 regulated periods (s47(4)), the minister may suspend or cancel an export licence if the minister believes on reasonable grounds that the licence holder has failed to comply with its Part 3 obligations, failed to pay any required levies, provided false or misleading information, or contravened a civil penalty provision (s55).	the start of the next regulated period (s23(7)), and an adjustment quantity in a determination made for an extended period, and the extended period itself, can be varied without a timing limit (s30(3)-(4)). Merits review is now available for the AER's demand calibration decisions (s25(1)), adjustment determinations (s26(1)), decisions to make extended period determinations (s28(1)) and decisions to vary or revoke determinations (s30(1)) (s103(1)), but not for decisions under s23 (varied DSO percentage) or s24 (target aggregate supply, including the percentage determined under s24(6)). Further, decisions should not be capable of being delayed through interdepartmental or intergovernmental processes. There is a risk that existing approval delays could effectively be replicated within the reservation framework. Section 28(1)(b) allows the minister to vary or revoke a DSO adjustment determination or extended period determination whenever the minister reasonably believes that circumstances have "materially changed" since the determination was made. Such broad and retrospective discretion would create an untenable degree of uncertainty for significant and long-lived capital investments.	operate as an unstructured veto. Any approval or veto power should either: i. operate as a formal concurrence mechanism; or ii. be subject to the same prescribed criteria as the primary decision. The Industry Minister should remain a consultation-only party and should not become a third decision-maker. c. Fix timeframes and the consequences of delay. The bill should: i. impose a defined decision-making timeframe (for example, 28 days from receipt of the regulator's advice under s31) for decisions under s23 (varied DSO percentage), s24(6) (market buffer percentage), s26 (DSO adjustment determination), s28 (extended period determination) and s30 (variation or revocation of determinations) ii. provide that a decision on an application (including an application for an adjustment under s26) that is not made within that timeframe is taken to be an approval; iii. provide that a missed statutory cut-off does not prejudice a licence holder that applied in time (e.g., by allowing the decision to be made after the cut-off date); d. Require published reasons. A statement of reasons should be published for every such decision. Sections 24(11), 25(8),	

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		26(7), 28(8) and 30(8) already require this for the regulator's and the minister's determinations under those sections; ss23 and 24(6) do not. e. Amend s28 to clarify that: i. The minister may make an extended period determination for a licence holder in any subsequent regulated period following commencement of the scheme (s28(5)(h) and (i) currently require such a determination to be made by 31 December 2027, other than where a market's DSO percentage moves from 0% to above 0%). ii. once a determination relating to a DSO adjustment or an extended period has been made, it should remain unchanged for the duration of the export licence. h. Expand and strengthen merits review. Merits review should cover licence-specific decisions that materially affect export operations, compliance obligations and commercial interests, and other significant determinations affecting domestic supply obligations and export rights (including decisions under ss23 and 24, which are not reviewable under s103(1)). Reviews should be effective, including giving power for the Administrative Review Tribunal to substitute a decision, rather than only affirm or remit as currently required by s103(5).	

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		i. Permit a licence term shorter than 20 years when requested by an applicant (s47(4) requires an expiry day no earlier than the 20th regulated period).	
7. Setting of domestic production baselines to determine "additional gas" A DSO volume must be the licence holder's "own gas" or "additional gas" (s18 of the Domestic Gas Reservation Bill). "Additional gas" is defined in s9 by reference to the Gas Market Code made under s53WA of the Competition and Consumer Act 2010 or by a legislative instrument made by the Energy Minister under that section (s53WA(6)-(7), inserted by Schedule 1 of the Consequential Amendments Bill). Under the amended Gas Market Code, gas produced above an AER-determined gas production baseline is additional gas (ss57F and 57K), and the AER may also approve other quantities as additional gas (s57L), on application by any gas market participant (s57L(1)). Neither the bill nor the code prescribes how a baseline is calculated. The AER must determine baselines in accordance with an instrument it makes under s57F(9)-(10) of the code, which must specify the circumstances in which a baseline of zero may be determined (baselines may also be varied on application: s57G). If a licence holder acquires domestic gas that is not additional gas (other than under an existing contract) and uses it to produce exported LNG,	A baseline that is set too high, or that is changed retrospectively, would mean less produced gas qualifies as "additional gas" and could therefore reduce the volume of incremental domestic gas that exporters can purchase to satisfy their DSO. This in turn could weaken the demand signal for incremental domestic production and, depending on how the baseline is set and updated, adversely affect investment incentives.	Amend sections ss9 and 18 of the Domestic Gas Reservation Bill and ss 57F-57P of the Gas Market Code, so that any production baseline operates only as a secondary administrative measure that must not override direct evidence of additionality. Specifically: • Gas must qualify as additional where the producer demonstrates that identified investment, development activity or a commercial arrangement has caused (or will cause) gas to be developed, produced and supplied to the domestic market that would not reasonably have been supplied in the absence of that activity, regardless of the baseline outcome. • Later baseline determinations or variations must not absorb or reclassify gas that has previously been recognised as additional. • Production attributable to new drilling, field development, workovers, recompletions, compression, debottlenecking or other investment in existing fields must be capable of qualifying as additional where it would not otherwise have been supplied to the domestic market. • The baseline methodology must be published, consistently applied, developed through formal consultation with producers, and finalised before the	Getting the setting of production baselines right is crucial to domestic-focused producers, who supply approximately two-thirds of the east-coast market and play a key role in meeting east coast demand efficiently – especially for winter peak-day deliverability in southern states. An onerous or rigid test for "additional supply" will undermine the investment case for domestic-focused producers and act as a handbrake on new domestic supply. It would strip offtake from producers who have no export alternative, and freeze the capital needed to maintain production in existing domestic fields. That outcome would be the opposite of the objectives in section 3 of the bill: lower natural gas prices for Australian businesses and consumers. Requiring the regulator to undertake a robust, deliberative and thorough process for setting baselines, informed by close consultation with industry, would: • give producers and investors certainty, before significant investment decisions are made, that genuinely new supply will count as additional gas • ensure the baseline and additionality method – which the bill and the Gas Market Code leave to an AER instrument – is developed with industry input and

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the purchase does not reduce its DSO; instead, its DSO increases by the volume acquired (s22). Section 69 of the Bill allows the AER to make guidelines (and s57P of the code allows it to make guidelines for additional gas approvals).		scheme commences (and sufficiently early to inform investment decisions).	published, so that it cannot be set or updated in ways that undermine investment • preserve the demand signal for incremental domestic production.
8. Penalties and licence cancellation Sections 14, 16, 29 and 101 of the bill, enforced under s85, establish a substantial civil penalty regime. As Mallesons explains: "For core obligations – including exporting without a licence, failing to meet the DSO and anti-avoidance, the maximum penalty for a body corporate is the greatest of 50,000 penalty units ($18.2 million), three times the benefit derived or detriment avoided, or 10% of annual turnover, capped at 2.5 million penalty units ($910 million)." Executive officer liability under s99 applies only where the officer knew, or was reckless as to whether, the contravention would occur and failed to take all reasonable steps to prevent it, but it extends beyond the core obligations to compliance plan, reporting and notification obligations (ss37(2), 40(4) and 44(5)); the maximum is 10,000 penalty units for contraventions of ss14(1), 16(1), 29(2), 43(1), 48(5) and 101(1) and lower amounts for the other listed provisions.	The maximum penalties are exceptionally high, particularly given: • DSO compliance depends on forecasts, complex calculations and methods yet to be settled through subordinate instruments • the bill does not expressly distinguish between deliberate avoidance of a DSO obligation and a breach arising from a good-faith or technically driven shortfall. The impact analysis estimates the regulatory burden of the scheme at $134 million over 10 years (p. A3) and records that stakeholders "raised concerns about unintended consequences and whether the proposed settings would achieve the objectives in practice."	Amend the bill to ensure that the penalty regime: a. distinguishes deliberate and systemic non-compliance from inadvertent or minor breaches b. ensures penalties are proportionate to the severity of the breach, reserving the highest turnover-based penalties for deliberate avoidance and unlicenced export conduct c. confines executive officer liability to the most serious contraventions and not extend to administrative, reporting and information-provision obligations. d. limits the use of licence suspension and cancellation powers to serious, deliberate or repeated misconduct and requiring objective statutory criteria, proportionality assessments and consideration of factors outside a licence holder's control e. allows reasonable time for licence-holders to rectify any inadvertent or unavoidable breaches f. recognises timely and voluntary engagement with the regulator to maintain compliance and seek assurance g. contains transitional protections during the initial implementation period, including an	A proportionate, graduated and risk-based compliance regime would better support the scheme's objectives, while: • recognising good-faith efforts • avoiding punitive penalties for outcomes that were unforeseeable, unintentional or beyond the control of exporters. The proposed amendments address the bill's failure to distinguish between technical, inadvertent and deliberate conduct within any given contravention. As written, a licence holder facing a good-faith calibration-driven shortfall is exposed to the same maximum penalty, the same personal liability for executives, and the same suspension or cancellation risk, as one engaged in deliberate avoidance. Tying regulatory actions and penalties to objective criteria – seriousness, intent, repetition and causes within the licence holder's control, would reflect standard regulatory design principles and provide certainty to entities acting in good faith.

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		educative compliance approach, limits on licence suspension and cancellation, and mechanisms to address liabilities arising from forecasting or calibration errors rather than licence holder conduct.	