Santos

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Australian Competition and Consumer Commission
Review of upstream competition and the timeliness of supply

Email to: gas.inquiry@accc.gov.au and [redacted]

Dear Warren

Submission on ACCC review of upstream competition and the timeliness of supply

Thank you for the opportunity to provide a submission in response to the ACCC's review of upstream competition and the timeliness of supply issues paper.

Santos provides this response as our perspective on the factors which affect upstream competition and timeliness of supply. In this submission Santos will:

1. Provide our perspective on the assumptions underpinning the review
2. Provide our perspective on the structural and behaviour factors outlined in the issues paper

Santos is of the view that additional government regulation would have a negative effect on perceived competition and timeliness issues relating to upstream gas supply development. Further government intervention would threaten the hundreds of millions of dollars per year we are investing in drilling more wells and bringing on more domestic gas supply in the Cooper Basin. It would also threaten the ~A$1 billion Santos and our GLNG partners are investing year on year drilling more wells and developing more gas fields in the Surat and Bowen Basins. Our French, Korean and Malaysian investors in this joint venture are already cautious about investing in new supply following the introduction of the ADGSM which they regard as having raised sovereign risk in Australia.

Further, it has been government intervention that has slowed down the bringing on of new supply from projects Santos has been willing to invest in, in both NSW and the NT. Our Narrabri Gas Project has been delayed for the best part of a decade because of moratoriums and inquiries into the environmental safety of the industry, lengthy approval processes and judicial challenges to those approvals, despite Santos investing more than A$1.5 billion so far. Similarly in the NT, moratoriums and inquiries have delayed exploration and development of the highly prospective McArthur Basin for more than half a decade. Around 14 independent, scientific inquiries into hydraulic fracturing, water and environmental safety of the industry have universally concluded that gas extraction can be done in a safe and sustainable way without harm to water resources or the environment, yet regulation continues to increase in a way that is increasing both the difficulty and cost of developing more gas supplies for both the domestic and export markets without adding to environmental protection.

Santos and the east coast gas market

In 2021, Santos is forecast to supply approximately 65PJ to the east coast domestic gas market, which is the equivalent of 11 per cent of demand. Over 70 per cent of Santos' total Australian gas production (including west coast production) is supplied to the domestic market. In addition, Santos has committed that 100 per cent of Narrabri gas would go into the east coast domestic market, potentially supplying up to half of NSW natural gas demand. This provides important energy security and feedstock security for businesses which rely on gas in a state that currently imports upwards of 95 per cent of its gas supply from other states and territories, and is considering importing gas from overseas. Santos had budgeted expenditure of A$215 million this year and next to advance Narrabri, however, this was necessarily delayed because of a lengthy judicial review of the 2020 Narrabri Gas Project approval decision and the lack of certainty this created.

Despite the volatile environment of 2020 when the coronavirus pandemic led to record low commodity prices and a dramatic reduction in worldwide oil and gas development, Santos was one of few operators on the east coast to continue with its drilling commitments.

The issue is supply

Geoscience Australia's 2021 Australian Energy Commodity Resources report outlined that Australia's currently identified gas resources are sufficient to supply domestic demand and Australian LNG exports for over 40 years.[1] And yet, there is a scarcity of gas projects in the development pipeline.

There is only one sustainable, long-term solution to east coast gas – more supply, providing more competition that will put downward pressure on prices. Santos believes the best way to bring more gas to market is to remove bans or restrictions on gas developments, such as in Victoria and New South Wales, foster a supportive policy environment, implement faster and clearer planning and approval processes to provide oil and gas companies with certainty and enable them to bring gas to market more quickly.

If sufficient indigenous gas supply is not available and eastern Australia becomes reliant on imported LNG (e.g. the Port Kembla regas project), Australia's domestic gas market will be directly exposed to international LNG prices. Today the North Asian LNG spot price is equivalent to ~A$45/GJ due to strong European and Asian demand for gas and an underinvestment in supply during COVID-19. This would impact east coast gas prices driving up domestic energy bills and potentially leading to some industrial gas users shutting down as their operations became uncommercial. To avoid such a situation Australia needs timely investment in new indigenous gas supply. It is worth noting that despite the current LNG netback price at Wallumbilla, domestic gas prices on the STTM are well below LNG netback pricing, whereas LNG imports would be priced well above the LNG netback price.

In addition to the COVID-19 downturn, oil and gas companies have come under increasing pressure from debt and equity capital markets to address Environment, Social and Governance (ESG) issues, in particular climate change and carbon emissions. Access to capital markets to fund upstream oil and gas investments is an increasing risk and could lead to higher costs of capital, lower levels of investment in new gas supply and industry consolidation to provide the scale to self-fund investment from free cash flows. Further, investment in reducing emissions means there will be less capital available for upstream oil and gas exploration and development.

These trends present a risk to future Australian indigenous gas supply. Whilst renewable energy, such as solar and wind can provide lower emissions electricity, it does not address the 80% of final energy consumption which is currently met by fuels. Creating cleaner fuels, such as decarbonised natural gas, through carbon capture and storage and nature-based emission offsets, is key to reducing emissions and providing energy security for Australian customers. Natural gas, combined with CCS, is also the lowest-cost pathway to a hydrogen economy.

Review assumptions

Upstream competition

ACCC assertion: Competition is not effective
In the issues paper, the ACCC asserts there are sufficient indicators that upstream competition is not effective, without providing evidence beyond referencing observations which infer pricing decisions, and a survey of C&I users.

Santos does not agree with this characterisation of gas market competition, particularly over the past 18 months. Contract prices have been softening for some time, as evidenced by the ACCC's Gas Inquiry interim reports:

- The July 2020 interim report outlined that prices offered over late 2019 to early 2020 were in the $8-11/GJ range, down from the $9-12/GJ range reported in the January 2020 report.

[1] https://www.ga.gov.au/digital-publication/aecr2021

- The January 2021 interim report outlined that prices offered for 2021 supply by both producers and retailers (under GSAs) declined noticeably from $8-14/GJ over the second half of 2019 to $6-8/GJ by mid-2020.
- The latest interim report in July 2021, said that “while a tightening supply-demand balance could be expected to place upward pressure on prices, we observed prices in offers for supply in 2022 remained relatively low up to February 2021”.

ACCC assertion: Prices should be below netback

The issues paper outlined that in the ACCC’s opinion:

> *If the east coast gas market had sufficient supply and effective competition, we would expect domestic gas prices to sit somewhere between the costs of domestic production and the LNG netback price.*

Santos queries whether this is an accurate metric to assess sufficient supply and effective competition. The price of gas is primarily determined by a producer’s cost of supply, particularly for those producers without oil or liquids production to subsidise gas production and/or without exposure to the LNG market, which brings the economic benefits of scale and access to higher prices. Further, the gas reserves and resources developed for the export market are typically committed to long term sales and purchase agreements and cannot be diverted into the domestic market. Gas supply developed for the domestic market (e.g. Narrabri) is evaluated on its own economic merits and requires a market price which incentivises investment (e.g. a price which delivers an appropriate return on invested capital).

As explained in Santos’ LNG netback submission in earlier this year, cost of supply varies from field to field:

- Santos observed that pricing at the Wallumbilla hub tends to stabilise around A$6/GJ, with the lowest-cost LNG producers (who have the advantage of high quality resources combined with scale) withdrawing volumes at a price of around A$5.15/GJ, indicating the marginal cost of supply (ex-field) in the region is around A$6/GJ.
- In the Cooper Basin in South Australia and southwest Queensland, the estimated cost of new Cooper supply ex-field is in the A$5-7/GJ range. This includes the benefit of liquids credits, without which the cost of gas supply ex-field would be more than A$9/GJ. Pipeline transport costs to southern markets from Queensland and South Australia could result in an additional cost of ~A$2-4/GJ.
- In the Beetaloo Basin in the Northern Territory the estimated cost of supply ex-field is currently in the A$4-5/GJ range with pipeline transport to Darwin estimated at A$1-2/GJ and to east coast markets A$5-9/GJ reflecting the large distance to markets and the high cost of pipeline transportation (requiring new infrastructure investment).
- In New South Wales, the Narrabri project (which will be committed 100% to the domestic gas market) had an estimated cost of supply ex-field in 2019 was in the A$6-7/GJ range with pipeline transport to the Sydney hub estimated at A$1-2/GJ.

The LNG netback price in September 2021 was A$14.85/GJ. The price in September 2020 was A$3.14/GJ as a result of the global pandemic and a slump in demand. The price in September 2019 was A$4.78/GJ. Given the price volatility in the market in recent years, it’s difficult to see how the ACCC’s assertion that sufficient supply and effective competition would mean domestic prices sit between cost of production and LNG netback price.

As we said in our LNG netback submission: “The ACCC LNG Netback Price Series has relevance only to domestic spot prices and short-term contract prices of one to two years, but it is just one factor influencing price. For Santos, forward term LNG prices are not relevant at all to long-term domestic gas contract offers which are predominantly influenced by the cost and risk of supply (drilling new wells, new field development, processing and pipeline infrastructure costs). Other influences include the cost of terms and conditions that customers might require.”

ACCC assertion: Supplier’s lack of reference to competitors’ pricing evidences ineffective competition

An absence of reference to competitor pricing does not necessarily evidence a lack of competition. Gas prices paid by users ultimately reflect the producers’ cost of supply and transport to users as well as opportunity costs. The high capital cost and long lead times for investment mean that most gas developments require long-term contracts to underpin the investment decision. These investments are not made on the back of spot pricing. The absence of consideration of competitors' pricing does not evidence a lack of competition, but rather a sophisticated and measured pricing analysis based on the actual costs of the business. Further, Santos has five core assets where it can choose to deploy capital. Capital allocation takes into account the investment returns and investment certainty associated with these assets and their investment opportunities.

Market concentration

The upstream market is 'relatively concentrated'

The issues paper describes a perceived relative concentration in the upstream market, noting that the top five suppliers accounted for 86% of 2P reserves and 89% of production in 2020.

Taking into account the capital intensity, risk and financial backing needed to develop projects, it is unsurprising that there are a limited number of companies in a position to make those investments and manage the risks involved in bringing gas to market. Queensland's coal seam gas resources would never have been developed without the scale of LNG contracts that underpinned Surat Basin development by the three LNG projects. Smaller companies that have entered the market following the development of these resources for LNG have benefited from access to the infrastructure expansion created by the LNG players. They have been able to cost-effectively develop their resources predominantly for the domestic market through access to higher priced, contracted LNG markets for a proportion of their gas with these LNG contracts key to their ability to access finance and reduce development risk. Senex has publicly acknowledged this was a factor in enabling development of its Roma North project.

Santos contends that the figures and graphs (table 2.1 and chart 2.2) used in the report do not accurately reflect holdings of reserves and production. The figures lump some companies and their joint ventures together (i.e. Santos and GLNG, in which Santos has a 30% interest) but not others (i.e. Origin and APLNG, in which Origin has historically held a 37.5% interest; QCLNG/QGC, which has complex commercial arrangements that see Shell holding substantial equity or other relevant interests and Arrow, in which Shell holds a 50% interest). The figures do not accurately reflect the true nature of joint venture agreements and their decision-making processes, ignore other important commercial arrangements and do not accurately reflect who has control of reserves and resources.

When JV participants are properly considered as separate entities, established technical measures to assess market concentration such as the Herfindahl-Hirschman Index (HHI) reflect the market is unconcentrated for both 2P reserves (HHI = 940) and production (HHI = 1088). A HHI of below 1,500 indicates an unconcentrated market.

The issues paper also references the fact that not many producers had uncontracted gas available for sale in 2020, however, most projects require production to be underwritten with supply contracts. Further, this would suggest that there is not a competition issue, but a physical supply issue and/or a lack of willingness by customers to enter the long-term contracts necessary to underpin supply investments. In fact, the east coast market experienced a buyers' strike in late 2020 and early 2021 following the announcement by the federal government of a code of conduct requirement for gas sales negotiations and negotiation of a new Heads of Agreement under the ADGSM with the Gladstone LNG producers, citing an imbalance of power between buyers and sellers, and implying that domestic gas prices were too high. Gas buyers believed these two measures would lower gas prices and Santos' experience was that some were unwilling to enter contracts as a result.

ACCC assertion: True concentration is likely to be more intense due to JV partnerships

The paper also appears to reference Santos' joint venture arrangements, indicating that the true degree of market concentration is understated by the figures presented as it does not account for the control that some producers have over supply through JV arrangements.

Joint venture arrangements are a legitimate business structure allowing the diversification of risk and the spread of financial resources across a portfolio of upstream opportunities. The Santos GLNG JV has its own decision-making processes which are separate from Santos Direct. To assert Santos has control over GLNG assets is not correct.

Santos is the operator of the upstream fields of the GLNG project, however, the remainder of the GLNG project is operated by GLNG Operations Pty Ltd (GLNG OPL), an incorporated entity in which Santos is a

30% shareholder. GLNG OPL has an independent CEO who is responsible for, among other things, producing the GLNG budgets, the purchasing and sale of third-party gas and management of the LNG offtake agreements. The GLNG Project has an 'operating committee' where all project participants are represented, and this is the decision-making forum. Santos has a 30% vote in relation to operating committee decisions. Most commercial decisions have a 90%+ vote threshold and Santos is therefore not in a position to control the pace of development of the upstream assets or the supply of gas to or by, the GLNG Project. Santos has often supported and promoted new supply investment that has not passed the GLNG voting thresholds. In part, the perception of sovereign risk by GLNG's foreign investors following the introduction of the ADGSM has led to an abundance of caution by them in making new investments in Australia.

<u>ACCC assertion: Diversity criteria in tender processes increases competition</u>
The ACCC notes in the paper that certain jurisdictions (such as Queensland) have introduced a diversity requirement for acreage. This is noted as a 'positive development' with the potential to increase competition between producers over the medium to longer term.

Santos queries this assumption, as it has not been proven that the diversity criteria improve competition in the market. Senex's Atlas block remains the only producing tenure of all the areas awarded with the diversity and efficiency criteria in Queensland. Further, when comparing the diversity in the 2C resources holdings compared to 2P reserves, and as the ACCC states – it is unlikely that small junior producers will be able to make the transition from holding 2C resources to producing and selling gas in the future.

The diversity and efficiency criteria do not guarantee that the companies awarded the permits will remain on title and ultimately develop the acreage. Once awarded all or part of the permits could potentially be divested either formally or through other commercial arrangements. There has been some evidence of this occurring in Queensland. For example, APLNG and Armour won a bid (90:10) for acreage in the Surat Basin in March 2020 (ATP 2046). The PL was later transferred to 100 per cent APLNG ownership in October 2020 (PL 1084).

Rather than considering the diversity of the producer, it would be more appropriate to consider operator capability. Diversity alone will not necessarily result in increased competition. To support competition, operators should be required to demonstrate financial capacity and development capability. Awarding acreage to companies without these capabilities, who then sell down into joint ventures for development, is a significantly longer path to development than simply awarding acreage to a proven operator, or a JV which includes a proven operator.

As another example, ATP 2031 was awarded in August 2018 to Central Petroleum who farmed out a 50 per cent interest to Incitec Pivot, a major Queensland gas user which consistently complains about gas cost and supply availability. Exploration results from four wells drilled in 2019 confirmed that this is a highly prospective CSG block resulting in a 2C resource booking of 270PJ.[2] The block is approximately 100km from the Wallumbilla hub. Production was initially planned to begin well ahead of the December 2022 end date to Incitec's supply agreement with APLNG. However, production has been delayed several times. The most recent update is that Central is targeting 2025 for first gas.[3] Nonetheless, IPL continues to raise concerns about the cost of gas and supply availability in the east coast market, culminating in a market release on 8 November 2021 saying it was closing its Gibson Island Plant at the end of 2022 citing inability to secure economic gas supply.

Santos notes the recent announcement by Fortescue Future Industries and IPL to conduct a feasibility study to investigate converting IPL's Gibson Island plant into a green hydrogen/green ammonia plant. While there is currently no market price for hydrogen in Australia as there is for gas, the Clean Energy Finance Corporation recently published a report forecasting the cost of hydrogen production to be equivalent to $22.70/GJ in 2025, a price much higher than the price of natural gas.

Timeliness of supply

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[2] https://centralpetroleum.com.au/our-business/our-licence-areas/surat-basin/project-range/
[3] https://centralpetroleum.com.au/our-business/our-licence-areas/surat-basin/project-range/

The issues paper outlines the ACCC's concern that some producers may not be bringing gas to market in a timely or efficient manner. Many of the questions and content in the paper appear to assume that producers are deliberately not bringing supply to market quickly enough.

ACCC assertion: Some producers make strategic decisions to 'bank' or 'warehouse' gas or to try and maintain or raise prices by withholding supply.

There is a difference between warehousing gas to maximise value for the holder of the resource and staging feedstock gas to support an investment decision in relation to a resource development. Each of the differing factors which make projects unique, such as composition, size, location and geography can affect the decision as to when to bring gas to market. Santos continually appraises and schedules development plans in line with long-term contracts. This matches supply with contractual demand.

The process of exploring a prospective resource and maturing through contingent resource to reserves and producing asset is lengthy and includes spending large amounts of capital up front, with considerable risk. Developing resources involves:

- Exploration to discover the resource,
- Evaluation of the results prior to converting to the contingent resources,
- Additional appraisal and evaluation to convert to reserves and,
- Additional development spend before bringing into production.

Each step requires costly technical and commercial evaluation to ensure the resource can move to the next stage. Further, each stage carries the risk that an investment decision will not be economic. The data below (updated since our LNG netback pricing submission) demonstrates the ongoing investment required to continue to develop and produce onshore resources:

- The Santos GLNG joint venture drilled over 700 wells and invested around A$2 billion in gas field developments over the past two years.
- The joint venture has also made final investment decisions for new investment in 2021 of around A$800 million in further drilling and gas field developments in Queensland.
- In the Cooper Basin in South Australia and southwest Queensland, Santos is investing A$590 million drilling new wells in 2021 to maintain and grow supply.
- In the Beetaloo Basin in the Northern Territory we are spending A$105 million on exploration which we hope will open up a vast new gas supply source.
- In New South Wales, around A$100 million will be invested in the Narrabri Gas Project over the next two years.

In the Productivity Commission review of resource sector regulation in 2020, the costs of project delays were highlighted:

> *Project delays are costly because the delay of a net revenue stream leads to net revenue forgone. The Commission has previously estimated that a one-year delay for a gas project could cost in the order of 10 per cent of its net present value…. Given the size of most resources projects, delay costs can dwarf the direct costs.*

Producers have no incentive to delay production because deferral of gas production has a negative impact on project economics. Bringing forward the earliest commercial development of a resource means reducing the capex costs relative to the expected revenues of the development. As such, there is a significant financial driver to develop at the earliest opportunity.

We acknowledge there are cases where this has not occurred and other non-financial drivers may be a factor. For example, Arrow Energy holds the largest undeveloped reserves on the east coast. Arrow's Surat Basin Project (a 50:50 joint venture with Royal Dutch Shell and PetroChina) originally covered an area of approximately 6,100 km^2 with a total of 6,500 planned production wells. In 2010, Arrow intended for the gas to be developed through their own LNG export project in Gladstone, but this was abandoned. It was a further ten years until Arrow approved the first stage of the project based on gas flowing through the Shell-operated QGC facilities for both the domestic and export markets.

ACCC implication: Governments should more actively employ 'use it or lose it' controls on tenure.

The issues paper questions whether governments should employ a more proactive approach to specifying timeframes for activities and enforcing compliance. The ACCC states that such approaches in Queensland resulted in production in “a much shorter period of time than would have otherwise been the case”.

Permits and work programs across all jurisdictions are already governed by statutory timeframes. Santos contends that commercially viable gas fields will be developed because they are commercial, not because of a prescriptive provision in the tenure conditions.

Senex’s Atlas block is often referred to as evidence of the success of Queensland’s shorter permit terms and conditioning. However, the Atlas block was unique in that the acreage was essentially development-ready, in close proximity to existing acreage, and was released as a production lease, not exploration acreage. The quick development timeframes reflect commercial reality, not compliance. In addition, Senex has been open about the fact long-term contracts from GLNG, an exporter, enabled its Queensland business. GLNG was the only customer who agreed to take the gas from Senex’s original Queensland acreage in Roma through a 15-year gas supply agreement. Senex’s CEO has publicly acknowledged that without that agreement, Senex may never have developed that resource.[4]

Further, consideration of government management of tenures has been undertaken relatively recently. In 2018, the COAG Energy Council Upstream Petroleum Resources Working Group engaged a consultancy to review the petroleum licensing regulations (specifically retention leases) across Australian jurisdictions. The review found that “there appears to be no evidence that gas is being withheld (or warehoused) from development production”.[5]

The review also noted the essential role that retention leases play in Australia as limited infrastructure and infrastructure capacity (such as pipelines and conditioning plants) means that for a discovery to be commercially viable, it is likely that some resources will not be commercial until foundation infrastructure is in place. This contrasts with comparative overseas jurisdictions (like the US and Norway) where significant long-standing production, processing and pipeline infrastructure means that development of discoveries is readily expedited through brownfields expansions at a much lower capital cost.

ACCC assertion: It is difficult to negotiate access to third party infrastructure

The issues paper talks about the challenges smaller producers face in terms of infrastructure, and that it can be difficult to negotiate access to other producers’ infrastructure even where there is spare capacity. Moomba production facility is noted as an exception. The paper specifically asks whether the owners of upstream infrastructure with spare capacity should be required to provide third party access on reasonable terms.

Santos supports the concept of third party access to infrastructure on commercial terms. As referenced in the ACCC’s paper, Santos does provide third party access in the Cooper Basin. This is consistent with our Vision 2025, which includes optimising infrastructure and running it strategically as a midstream business.

While Santos is providing access to infrastructure, currently there are not a large number of customers taking up this opportunity. Santos is providing access to the Moomba production facility for Santos operated JVs (~90% throughput) and Beach operated JVs (~10% throughput). Future third party opportunities are being discussed with other companies although these are not large volumes and are relatively immature.

Infrastructure owners are motivated to agree to third party access to their facilities. Processing third party product generates new revenue that reduces the overall cost of supply. Lowering the cost of supply is the primary focus of all oil and gas producers, to ensure they remain competitive in often unpredictable price environments. Further, increased third party access is typical of what we see in other mature markets (such as in the Gulf of Mexico).

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[4] https://www.senexenergy.com.au/wp-content/uploads/2021/03/ADGO-speech-Stable-policy-matters-Senex-Energy-MD-Ian-Davies.pdf

[5] https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/publications/documents/Noetic%20Group%20report_Review%20of%20Petroleum%20Licencing%20Regulations.pdf

Negotiating third party access to infrastructure is achievable, but there are unique challenges, including the availability of upstream infrastructure capacity (e.g. satellite compression and pipelines). There needs to be sufficient capacity in pipelines and processing facilities so that existing users do not lose access which could increase the risk of them not being able to meet supply commitments. Mitigating this risk may mean that the upstream infrastructure owner cannot provide third parties a firm service. Without a firm service, a producer will struggle to commit to a gas sale agreement.

Providing third party access to upstream infrastructure is achievable (as demonstrated in Cooper Basin). Infrastructure owners should already be incentivised to allow third party access although any barriers to third party access may need further discussion with market participants.

Factors

Structural factors

When setting out the scope of the review, the issues paper indicated seven factors which the ACCC thought may affect the degree of upstream competition and/or timeliness of supply. The second of those factors was:

> *The geological, land access, environmental, regulatory, commercial and infrastructure related barriers that producers can face when undertaking exploration activities and when moving from the exploration phase to production.*

This broad point captures most of the barriers producers face in getting projects off the ground. The remaining areas with development potential are becoming increasingly more difficult, technically challenging, costly, riskier, and only marginally economic. This is coupled with the cost and time delays resulting from increasing layers of approvals and regulation which is often not adding proportionately to safety or environment protection or other factors which purport to underly the increased requirements.

Key barriers faced by producers in developing projects are access to capital, government process and market intervention (or threat thereof) and infrastructure availability. These factors can and do affect decisions about when to develop new sources of supply and can delay projects significantly.

<u>Access to capital</u>
There are a number of ways in which access to capital can be a barrier for producers. Resources projects are capital intensive and carry significant risk.

Capital constraints are a live issue for producers of all sizes, along with increasing difficulty in securing debt funding. New developments need sufficient 1P or 2P reserves to underpin long term contracts for project FID at prices that meet required hurdle rates for the risk taken. Access to capital and managing risk are key reasons why upstream assets are typically developed through a joint venture structure.

Increasing ESG pressure is tightening access to capital with banks increasingly under pressure from their own investors to not fund projects in the fossil fuel sector. Lenders and insurers are progressively implementing policies which constrain capital resources for projects. In addition, pressure from equity investors to reduce emissions and establish credible pathways to net-zero emission means less capital is available for upstream developments as more capital flows into carbon reduction projects (like Santos' A$255 million Moomba CCS project) and new technologies. These factors are expected to increasingly impact competition as producing companies need to secure capital or fund projects from their own balance sheet. This is also likely to limit the ability for smaller players to enter the market with scale to self-fund investments becoming increasingly important.

<u>Government intervention</u>
The gas industry has been subject to several federal and state government initiatives and policies which have intervened in the market and affected investment over the last 5 years, including:

- Since February 2017, the Queensland Government has released land for gas development on the condition that gas produced on the tenure be supplied and used in Australia to help meet domestic gas demand.

- Since 2017 the Queensland Government has been considering, but has never finalised a Pristine Rivers policy that could restrict gas exploration and production in the Cooper Basin in southwest Queensland.
- In July 2017, the federal government introduced the Australian Domestic Gas Security Mechanism, which can be triggered each year to limit LNG exports. This led to the Prime Minister and LNG exporters signing a Heads of Agreement which has been updated twice since 2017 and requires LNG exporters to offer uncontracted gas to the domestic market before exporting, and have regard the ACCC's LNG netback price when offering gas domestically.
- In 2017, the Victorian government imposed a moratorium on onshore conventional gas production until 20 June 2021.
- In 2020, the Victorian Government enshrined a ban on unconventional gas extraction in the state's constitution, which includes hydraulic fracturing and coal seam gas exploration.
- In 2021, the Minister for Energy and Emissions Reduction asked producers and consumers to agree on a Code of Conduct for gas sales, citing a power imbalance between buyers and sellers.
- In July 2021, the NSW Government released the Future of Gas Statement, which effectively took back exploration acreage, including areas where contingent resources existed. In addition, the Statement effectively limits any new gas projects in NSW to the Narrabri Gas Project.

These policies applied to gas which was/is being produced and has damaged Australia's reputation as a safe place to invest.

As Santos stated in our LNG netback submission, unless producers can be certain that government intervention will not undermine their business cases, which assume the ability to recover their cost of supply and provide an appropriate return on their investment, new gas supply sources to maintain long-term reliability of supply and add competition to the east coast gas market will not be developed. This outcome would only lead to higher domestic gas prices as the east coast gas market relies on continuous investment in drilling new wells and without the right price signal, that investment would inevitably cease.

<u>Inefficient and ineffective approval processes</u>
Over recent years Santos has observed a significant increase in the level of detail and approvals required to progress tenures to grant which can impact on cost and timeliness of supply. This causes uncertainty in the planning process required to support timeliness of development.

Narrabri example
Santos has been exploring New South Wales for natural gas resources since 2008. Since 2011, Santos has spent more than $1.5 billion acquiring, exploration and appraising gas assets in the Narrabri region. Explorers in NSW have experienced significant delays and uncertainty over this time, and since 2011, the area in New South Wales licensed for exploration and appraisal has reduced from approximately 60% of the State to less than ~1.5%, and the number of operators has reduced from 14 to two (with AGL announcing that it is shutting down its operations in Camden in 2023).

Following extensive independent review, and extensive State and Federal approval processes, which were completed in late 2020, it was a further year until an appeal against the State approval was determined in Santos' favour, with additional appeals still possible.

The release of the NSW Future of Gas Statement in August 2021 reduced Santos' tenure by 77 per cent and committed the State to not releasing new areas for gas exploration in NSW. The NSW Government has said it "*will only support limited gas production projects in NSW, specifically, the Narrabri Gas Project and its potential extensions*". While this announcement provides some certainty for the Narrabri Gas project tenure, it limits access to new gas supply sources, consigning the State's businesses and manufacturers to reliance on higher-priced gas imports from other states or overseas.

The continuing increase in the number and extent of approval conditions is noticeable as governments appear to respond to pressure from activist groups rather than a science-based need for increased regulation. Although many governments state their approach is for 'outcome based' approvals and conditioning, the approvals themselves do not reflect this approach.

Infrastructure
Pipeline development is a major impediment to new supply. The lack of transport solutions for new basins (e.g. NSW and NT) to access markets and existing infrastructure is a significant barrier to expanding the supply of additional gas to the market, given the size of Australia and concentration of markets. Most identified undeveloped gas supply basins are located a long distance from demand centres and existing infrastructure. Unlocking these developments will require major upfront investment in new surface facilities, especially pipeline and processing.

Projects are often required (by pipeline transmission companies) to fully underwrite the capacity of new pipelines via long term contracts, carrying the supply risk. In the event of supply shortfall, the pipeline capacity becomes an onerous contract. Forced short term capacity markets, unless incremental revenue flows back to the original underwriting customers, still leaves the onerous contract with the original project proponents, thus discouraging upstream developers taking the risk to underwrite new pipelines. In addition, short term capacity does not underpin new developments.

One or more parties at FID need to have the confidence in the volume of basin recoverable reserves as well as there being a market commitment for these volumes of production over the long term. This is the key challenge for developing these large, but distant identified resources. The lack of a transport solution also discourages further exploration and appraisal, even after initial discoveries within a basin are made. How to motivate pipeline companies to build investment cases to bring forward these major surface facilities is worth further investigation.

As per previous Santos submissions to the ACCC gas inquiry, the costs of sales gas transport still remain a significant barrier to commercialisation. In the case of the Beetaloo sub-basin for example, it's possible that the cost of transport to the east coast market would exceed the cost of supply ex-field. As Australia's resources are generally distant from concentrated coastal markets and with a small population and therefore relatively small market overall, infrastructure to transport gas is a significant issue unique to Australia.

One of the reasons transport costs are increasingly an issue is that manufacturing is no longer co-located with gas production. There is a fundamental disconnect between where many large manufacturers are located and where gas is being produced. Manufacturing is largely located in the southern states of Victoria and NSW, having been established when cheap gas was a by-product of oil production in the Gippsland and Cooper Basins. This is no longer the case. In addition, much of the new gas supply on the Australian east coast is dry gas, and therefore the domestic price must cover the full cost of production, as there are no liquids to improve the margins. This issue is worth consideration when thinking about how governments could incentivise location of large-scale manufacturing initiatives or indeed when manufacturers consider efficiencies in their own businesses.

Behavioural factors

Joint ventures
The issues paper poses specific questions about joint venture arrangements and suggests the potential need for increased regulation. The ACCC is interested in whether greater scrutiny of JV arrangements, particularly by larger producers, may be required under the Competition and Consumer Act 2010 (CCA).

As the ACCC acknowledges in the issues paper, JVs are necessary for projects because of the significant risks involved in developing assets in the oil and gas sector. JVs are used by many upstream parties to diversify risk and spread financial resources across a portfolio of upstream opportunities. This is an important means by which exploration companies can attract new funding to a prospective block without needing to completely sell out of their interest. This is particularly so for smaller companies or very large greenfield developments.

However, the trade-off is that JV parties will have different views of subsurface risk appetite, funding ability and marketing opportunities for their own share of gas. This will be a natural outcome of bringing together competitors to jointly develop any asset. The process for decision making and resolution of misalignment is keenly negotiated at the inception of JVs. These governance rules can't be separated from the wider transaction, which typically involve consideration to buy into the asset, the split of working interests and future funding commitments.

Further regulation to address the perceived 'shortcomings' of JV arrangements would introduce more risk into projects and have potential to adversely affect investment decisions in precisely the way the ACCC is seeking to avoid.

Mergers and acquisitions
The issues paper also asks about the impact of mergers and acquisitions on competition and timeliness of supply. The paper outlines that some C&I users have suggested that changes to section 50 of the CCA may be required, and that some smaller producers think that the ACCC should, as a condition of a merger of acquisition, be able to impose supply conditions to ensure that an acquisition does not affect the timing of developments.

While the issues paper raises various concerns (including from C&I users who are not party to these transactions and who are unwilling to take the risk of upstream investment themselves), there is no evidence of an impact on competition or timeliness of supply.

Against the backdrop of the ever-increasing cost and timeframe for securing approvals and the increasing difficulty in raising funds for the exploration, development and production of gas, consolidation transactions, such as mergers, are likely to become more common as scale becomes more important to enable self-funding of upstream investments. The need for balance sheet strength to be able to self-fund oil and gas development, rather than rely on access to debt and equity capital markets, is expected to drive further consolidation in the Australian oil and gas sector. M&A is a critical part of asset development and may assist smaller players who prove up a project but lack the capacity to proceed with development.

An example of the effectiveness of acquisitions is the Mahalo Gas Project. Comet Ridge acquired APLNG's stake in the project in August this year.[6] Santos provided JV partner Comet Ridge with a loan package to fund the upfront consideration in exchange for an option of increased equity in the project. The acquisition unlocks the Mahalo Gas Project providing a pathway to project development. In this case, the acquisition resulted in a larger company (Santos) enabling a smaller company (Comet Ridge) to access capital and bring gas to market.

ACCC approvals could be a potential barrier to transactions which could prevent assets changing hands to parties with capacity and desire to develop, and which could contribute to companies holding acreage that they do not intend to develop or lack capacity to develop. The issues paper implies that large companies often warehouse permits and prevent smaller companies from developing in shorter timeframes whereas there is some evidence to the contrary.

Marketing
The ACCC asks two sets of questions on marketing arrangements (including joint and separate marketing) and exclusivity provisions in GSAs, respectively. This includes questions about what aspects adversely impact upstream competition and timeliness of supply, and whether current laws are sufficient to respond to those issues. Santos is of the view that further regulation is not required to increase either competition or timeliness and would not achieve that outcome.

Santos contends that authorisation from the ACCC for exclusivity provisions between producers should not be required. Offering exclusivity to a buyer under a GSA is often traded in return for the buyer providing confidence that it will purchase minimum volumes of gas produced by the seller over an extended period at the agreed contract price. These arrangements can sometimes provide the necessary confidence required by the gas seller to undertake the upfront investment in developing resources.

Exclusivity means that the buyer also has confidence that it can expect to receive gas produced from that development over the life of the agreement. Mutual confidence in the commercial terms for the sale of gas produced from these fields over an agreement life can be required for both parties to secure funding or

[6] https://company-announcements.afr.com/asx/sto/58a4d391-f3ed-11eb-881f-96d72bf112ea.pdf

make follow-on long term sale commitments. Without this mutual undertaking, the attractiveness of buyers entering into a one-sided long term volume commitment will be reduced.

This can help smaller producers secure the GSAs they require to underwrite certain areas of their discovered resource which can result in incremental gas being made available to the domestic market. Examples include the agreements the GLNG joint venture has in place with Senex and Meridian.

Conclusion

The sustainable, long-term solution to east coast gas is more supply, providing more competition that will put downward pressure on prices. A supportive investment and regulatory environment that properly ensures the safety of people and the environment is necessary to provide community confidence in the industry. In this environment, new upstream supply investments will be developed to meet the market when it is commercial to do so.

Santos would be pleased to provide further information or answer any questions you may have. Please contact Tracey Winters at [redacted] or Emma Hansen at [redacted]