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Will a contract make the difference? Government policy and new coal power stations

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Executive Summary

The Finkel Review recommended a Clean Energy Target (CET) and other measures to underpin new investment in electricity generation. Some policy makers have suggested that whether or not Australia adopts a CET, additional policies are needed to incentivise new coal fired power stations. One such concept is a 'contract for difference' (CFD), under which government provides a price guarantee and other terms to qualifying projects, potentially awarded through a competitive reverse auction process.

This paper explores the necessary provisions of a CFD for a new "High Efficiency Low Emissions" (HELE) coal generator producing steam at ultrasupercritical pressure and temperature. These provisions include (**chapter 2**):

- 30 year term.
- A guaranteed price for all power sold, plausibly $80 per megawatt hour, or potentially lower if more aggressive estimates commissioned by the Minerals Council are achievable.
- Freedom to rely on price guarantee revenue, rather than wholesale market revenue, as much as necessary to ensure very high capacity factor.
- Absolute guarantee against carbon cost or constraint during the life of the contract.
- Compensation and cost-sharing provisions to address political, community and legal risks.

Investors may not find it credible that a contract with these generous provisions will be offered and honoured given long lead times to deliver a project, Australian political cycles, and the controversy attaching to such a project.

Recent competing cost estimates for new-build Australian coal generation are explored (**chapter 3**). The lowest cost recent estimates rely on extreme and highly specific assumptions and are unlikely to be achievable. The highest cost recent estimates incorporate market and carbon risks which are real but could be shifted through a CFD. The central estimates of the Australian Power Generation Technology Report seem to be the most credible for a project shielded from market and carbon risk. A competitive process could reveal the price at which investors consider a plant viable.

The potential costs to government of CFDs for several power technologies are compared (**chapter 4**), using three illustrative scenarios for energy policy, climate policy and energy market trends. A coal contract for difference looks significantly more expensive than one for baseload gas, and much more so than variable wind and solar technologies. The costs of 'firming' wind and solar are difficult to credibly estimate at this point, but would have to be substantial to make a coal CFD less risky for government.

The wider effects of a coal CFD (**chapter 5**) on affordability, security, reliability and emissions are ambiguous, given the likelihood that a project would compete with and accelerate the closure of existing old coal plants, and the underpinning assumption for lower cost coal estimates that a new plant is a brownfield replacement for an existing plant. Even a limited CFD would create a privileged competitor and could produce both a chilling effect on private investment and a self-fulfilling expectation of further CFDs, expanding government's role and financial responsibility in electricity.

On balance, a coal CFD that would attract investors does not seem to offer sufficient benefits to outweigh its costs and risks to government and the economy (**chapter 6**). The full Finkel Review reform recommendations plausibly provide the opportunity for flexible new coal technologies to compete with the full range of other technologies, including flexible-operation upgrades to existing coal generators, to support the affordable, reliable and clean energy system that Australians demand.

1. Introduction

The recently released Finkel Review of energy security has been welcomed by most observers as a blueprint for reform to deliver a more affordable, reliable and clean National Electricity Market. But while the Review's recommendations are wide-ranging, one recommendation in particular has dominated nearly all discussion: a 'Clean Energy Target' (CET), which would provide incentives for new low-emissions electricity generation of any technology. There are three broad viewpoints:

- A CET is a workable, investable, reasonably efficient approach to get new generation into the electricity system and reduce emissions – though there are important arguments to be had about crucial design decisions, like the ambition of the targets or the treatment of trade exposed industry;
- A CET is a poor substitute for other policies, like an Emissions Intensity Scheme or an Emissions Trading Scheme, that may have lower economic costs, sharper incentives for emitters or energy users, or be more investable;
- A CET may be workable for new renewable or gas investment, but provides inadequate incentives for new coal generation; a complementary policy is needed to support new coal generation through long term contracts.

Ai Group's blog has previously started to explore how a CET might work.[1] This working paper focusses on the approach suggested in the third viewpoint above: what would a contract policy to bring in new coal fired generators look like? What would be its costs to government and its wider effects? Should Australia adopt such a policy?

There is a threshold question of whether we need an additional specific policy to ensure new coal generation. The Finkel Review recommends a technology-neutral approach that focusses on the outcomes we want from the power system – on price, reliability and emissions. The wholesale power market would reward energy supply at the times and places it is most valuable; the CET would provide an additional revenue stream to new generation that is lower-emissions; and the Generator Reliability Obligation (GRO) would provide incentives for sources of reliability and flexibility needed by the grid, paid for by new variable generators. Coal should be able to prosper under such a system if it offers a more valuable mix of those outcomes than competing technologies, particularly since it neither old nor new generators would incur a carbon penalty. There are also different views on how well new coal generators would perform in contributing to price, system reliability and emissions.[2]

These merits will be considered in chapters 3 and 4. However, there is a well established model, used in Australia and overseas, for governments and market operators to bring in new generators through a 'contract for difference' (CFD). These contracts typically run for 15 years or more, and guarantee that a generator will receive an agreed price for the power they produce – the so-called 'strike price'. The government does not buy the power itself; the project sells into the wholesale electricity market like any other generator. But if the wholesale price in the market is below the strike price, the government tops up the generator's revenue to ensure they earn the strike price. In some versions, the project agrees to refund the government when market prices wind up above the strike price.

The strike price calculations usually take account of any other revenue a project may get from incentive

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[1] http://blog.aigroup.com.au/what-will-new-energy-policies-actually-do/.
[2] See, eg, http://blog.aigroup.com.au/should-we-be-looking-at-new-coal-fired-power-stations/, and http://www.minerals.org.au/file_upload/files/publications/Latrobe_Valley_Securing_energy_and_jobs_and_Australias_export_advantage_June_2017.pdf.

schemes like Renewable Energy Targets. And the contracts for difference are typically awarded through a reverse auction where bidders compete to offer the lowest strike price to secure a contract.

The chart below illustrates how a basic CFD works. Government makes top up payments (the yellow area) when the market price is below the strike price, and the generator pays back (the blue area) any market revenue above the strike price.

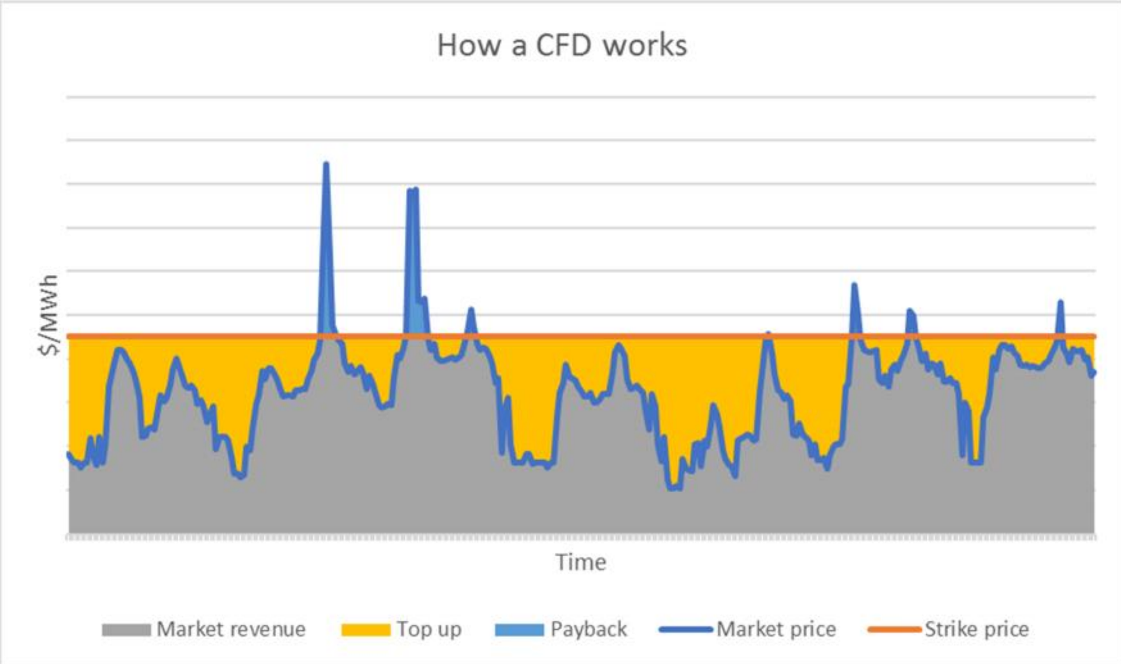

Figure 1 - illustrative simple contract for difference

CFDs and similar long-term contract schemes have been used in the United Kingdom, Mexico, Chile and more. Here in Australia, the ACT has already run one to meet its renewables targets, and NSW, Queensland and Victoria plan CFD auctions to contribute to their own goals.

Like any other policy approach, CFDs have costs and benefits.

On the positive side, CFDs have demonstrated the ability to deliver large numbers of low-priced power projects. The competitive process encourages bidders to submit the lowest prices at which they believe they can make a reasonable return. The contract reduces the risks a project must bear – they don't have to worry about where wholesale electricity prices may go, only about demand and their own project delivery and cost control. This lower risk can enable projects to attract cheaper finance and bid a lower strike price.

On the negative side, CFDs do not reduce risk overall, but transfer it to government, which may have significant financial obligations depending on how markets for power and carbon evolve. Signing CFDs also represents a major intervention in the power market: the requirements that government defines for generation (including amount, location, dispatchability, emissions) mean that government is centrally planning the electricity system. In some power markets the market operator or government already plays a central role in planning. But Australia's National Electricity Market (NEM) has been market-led rather than centrally planned for the last two decades. Government intervention needs to manage two risks: central planning may not do a good job, leading to higher overall energy system costs despite cheap individual projects; and intervention through CFDs may scare off non-CFD investment and lead ultimately to government finance or guarantees for all new generation.

2. Elements of a contract for difference

What would a CFD for a new coal generator look like? Currently there no specific and detailed proposals. But rough parameters can be established by considering the challenges a new coal generator faces.

PRICE RISK

Price risk is substantial. An electricity generator will want to be confident that the average price it can sell power for is consistent with recovering its total costs. But electricity markets in Australia and worldwide are going through an enormous transition with changing technology and consumer behaviour. The total costs of renewable energy and other technologies are coming down rapidly, raising the possibility that long term prices may fall below the costs of a generator built now. On the other hand, the additional costs to integrate variable renewable power into a reliable grid are real, and could be significant. Under an approach like the Finkel GRO recommendation, new variable renewable projects would bear the cost of their own integration, perhaps levelling the playing field with a coal fired generator. The outcome is highly uncertain, and the relevance of a CFD, which guarantees a fixed price per megawatt hour of output, is obvious.

The strike price needed to ensure a generator earns a long term financial return would depend on the cost of building and financing a new coal fired power plant. A new plant would likely be 'ultrasupercritical', operating at high temperature and pressure to increase efficiency and reduce emissions. The Australian Power Generation Technology (APGT) report, prepared in 2015 by experts from CSIRO, the coal and coal power industries and others, estimated the costs of Australian new builds for a variety of technologies.[3] They put the levelised cost of energy (LCOE) of an ultrasupercritical plant using black or brown coal at around $80 per megawatt hour.

On the other hand, the Minerals Council of Australia recently gave a low-detail cost estimate for a new Latrobe Valley brown coal plant at $55-$65/MWh,[4] based on estimated costs of a proposed German plant. The MCA has also commissioned reports from consultants GHD[5] and Solstice Development Services[6] that it argues show a new Hunter Valley black coal plant would cost $40-$78/MWh.[7] The basis for the more detailed black coal estimates is explored in detail below; different assumptions about coal prices account for much of the difference. However, a competitive CFD process would reveal the price real investors actually consider viable.

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[3] CO2CRC, *Australian Power Generation Technology* (November 2015) http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf.
[4] MCA, above n2.
[5] GHD, *Solstice Development Services – HELE Power Station Cost and Efficiency Report* (June 2017) http://www.minerals.org.au/file_upload/files/reports/HELE_Plant_Cost_and_Efficiency_Report_FINAL.pdf.
[6] Solstice Development Services, *Prospects for a HELE USC Coal-fired Power Station* (June 2017) http://www.minerals.org.au/file_upload/files/reports/HELE_PS_Prospects_-_Desktop_Study_FINAL.pdf.
[7] http://www.minerals.org.au/file_upload/files/publications/HELE_The_affordable_energy_solution.pdf.

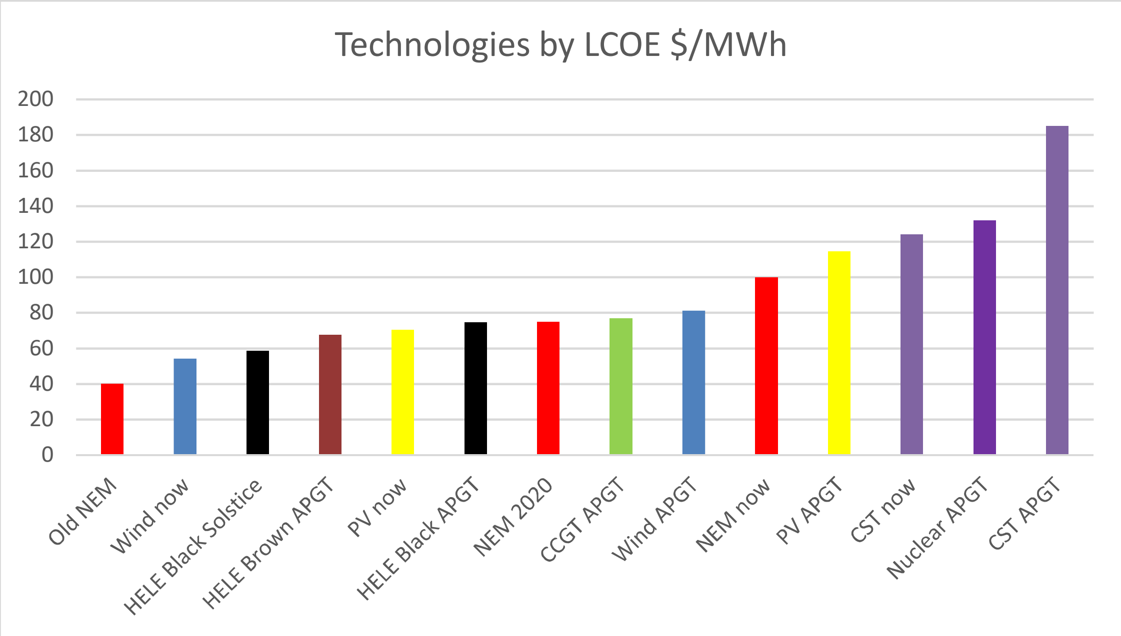

Figure 2 –Levelised Cost of Energy (LCOE) estimates for selected technologies, combined with historical, current and futures prices in the National Electricity Market. Estimates are from the Australian Power Generation Technology report (APGT); the Solstice coal power report; and recent actual projects contracted in Australia ("now"). PV is large scale solar photovoltaic; HELE is ultrasupercritical coal; CCGT is baseload gas; CST is concentrating solar thermal. System integration and carbon costs not included.

VOLUME RISK

Volume risk is also important. Electricity generators generally have a mix of fixed costs to be available at all (construction and finance, general maintenance) and variable costs when they choose to supply (fuel costs, extra maintenance from wear and tear). The levelised cost estimates above assume that generators generate as much as they can in order to spread their fixed costs across higher volumes and offer lower overall prices. A coal or baseload gas generator is physically capable of sending out the equivalent of its full capacity 80% or 90% of the time (allowing for maintenance downtime, accidents and other interruptions). Wind and solar are variable resources with much lower 'capacity factors', though lower capital costs and zero variable costs help their overall pricing. For any generator, however, sitting idle when they could be generating means they will need a higher price when they do generate, or risk failing to recover their investment.

The emerging energy market presents a big risk that new generators will not be able to generate as often as they would like. Distributed rooftop solar is taking an ever bigger chunk out of the daytime electricity market, and growing energy storage may spread this to other times of the day; Bloomberg New Energy Finance projects that even without new policy, by 2040 45% of Australian electricity demand will be met 'behind the meter' rather than in the wholesale electricity market.[8] Some significant industrial energy users have closed and more may follow, reducing the amount of steady demand – and the growing practicality and value of demand response may limit demand and prices during what are currently the most profitable peak demand periods. Large scale wind and solar

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[8] Ben Potter, 'Cheap wind, solar will make Australia a magnet – Bloomberg' *The Australian Financial Review* (Melbourne), 15 June 2017, http://www.afr.com/news/cheap-wind-solar-will-make-australia-a-magnet--bloomberg-20170615-gwrwat.

generation is growing and with zero variable costs these plants are happy to bid zero in the wholesale electricity market (or even below zero, with backup revenue from the RET or a possible CET) to ensure they dispatch. The market also includes existing brown- and black coal-fired generators with sunk capital, low-to-moderate operating costs and physical inflexibility: ramping up and down is slow and wearing, and they are willing to accept negative wholesale prices for short periods to ensure they keep dispatching.

The average capacity factor of thermal generators in the NEM in 2016 was running at around 65%, with black coal generators mostly lower and brown coal generators mostly higher (reflecting lower running costs and less ability to vary output, rather than higher reliability). The amount of 'base load' – the always-there demand that an always-on 'baseload generator' requires – is likely to shrink further and there will be plenty of competition from existing baseload and new renewables to service that load. A new coal fired power plant thus faces the strong likelihood of generating much less frequently than would be financially ideal for them. New coal plants can be designed to be capable of rapid and regular ramping up and down, and could potentially adapt to a more variable market – but they would have to recover significantly higher prices when they did generate.

A CFD can protect against this volume risk. If a generator is guaranteed a strike price regardless of the market price, they can ensure they always dispatch when they want to by always offering their power to the wholesale market at a very low price – potentially the market floor price of -$1,000 / MWh. In the NEM the wholesale price a generator receives is set every half hour based not on their own bid, but on the price of the marginal bidder in the cheapest stack of bids the market operator can assemble to meet demand. Much of the time the marginal bidder will be a gas generator with short run costs comparable to or above the long run costs of a new coal generator. The rest of the time a coal generator could accept a low or negative wholesale price because it could depend on the CFD to make good any gap between wholesale price and strike price.

This would have a couple of consequences. Firstly, a new coal generator with a CFD could potentially suppress wholesale electricity prices somewhat, as it would crowd out other bidders unable to bid such low prices. However, the source of the price suppression would be the contractual guarantee, rather than any features of the technology. Secondly, the CFD generator would take substantial volumes of demand away from existing coal fired generators, who would also be impacted by any wholesale price suppression. It is plausible that a new coal CFD would accelerate the closure of existing coal generators.

CARBON RISK

Carbon risk is a major issue. The Federal Government has committed through the Paris Agreement to reduce national emissions by 26-28% below 2005 levels by 2030. The overarching goals of the Paris Agreement include to limit global climate change to well below 2 degrees Celsius above preindustrial levels, and to bring global sources and sinks of greenhouse gas emissions into balance in the second half of this century – net zero emissions, in other words. The Governments of NSW, Queensland, SA, Tasmania and Victoria have committed to net zero emissions for their states by 2050. More commitments are likely, as are policies from all levels of government to achieve these goals. The Finkel Review's proposed CET is intended to be the primary national climate policy instrument for the electricity sector, but if it is not agreed or is implemented differently there could easily be other proposals, including a return to some form of carbon pricing.

Ultrasupercritical coal plants have also been described as 'High Efficiency Low Emissions' (HELE), but they still have fairly substantial carbon dioxide emissions. The Finkel Review published the comparison table below, largely derived from work by the CSIRO:

Generation type	Estimated operating emissions as generated (kg CO2-e/MWh)
Subcritical brown coal	1,140
Supercritical brown coal	960
Subcritical black coal	940
Supercritical black coal (HELE)	860
Ultra-supercritical brown coal	845
Ultra-supercritical black coal (HELE)	700
Open cycle gas turbine (OCGT)	620
Combined cycle gas turbine (CCGT)	370
Wind	0
Hydro	0
Solar PV	0
Average NEM grid emissions intensity	820

Figure 3 - emissions intensity of selected generation technologies[9]

It is possible that further efficiencies or coal drying could bring new coal emissions down slightly further. Carbon Capture and Storage (CCS) is also a physically viable and available technology that could bring emissions down by up to ~90%. However, CCS is a significant additional expense for coal power, requiring substantial extra capital investment and incurring higher operating and fuel costs to run the capture and storage processes. The CO2CRC, a research organisation dedicated to CCS, recently estimated that retrofitting CCS to an existing coal power station would increase the levelised cost of that plant's output by a further $100/MWh.[10] For an all-new plant built with CCS from the beginning, APGT (*Figure 2*) suggests total costs around $170-$180/MWh.

So a new coal plant will carry either high emissions or a substantial additional investment in CCS. Australia's current national emissions policies, including the Safeguard Mechanism, impose no burden or limit on any individual generator unless the electricity sector as a whole exceeds its historical emissions peak. This seems unlikely ever to happen. However, a new coal generator investment is very heavily exposed to costs under any future national or state climate policy.

What could those costs look like? Under the Finkel CET proposal a new non-CCS coal generator would not face any direct penalty or burden, ever: they would simply miss out on (or at best scrape a small fraction of) the incentives paid to new low-emissions generators; and they would likely face lower wholesale prices and volumes given the additional generation being brought on by the CET.

However, if a CET is not implemented, or is thought inadequate, different policies are very likely given the increasingly strong commitment of governments and the community to emissions reduction and the significant role of electricity in the overall challenge. These policies could include:

- A large program of CFDs for renewables and other low-emissions technologies, which would suppress prices and volumes for other generators similar to a CET;
- a form of carbon pricing, such as an emissions trading scheme or carbon tax which directly penalises all emissions;

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[9] Independent Review into the Future Security of the National Electricity Market, *Blueprint for the Future* (June 2017) 203.
[10] CO2CRC, *Retrofitting CCS to coal: enhancing Australia's energy security* (March 2017) http://www.co2crc.com.au/wp-content/uploads/2017/03/Retrofit_ccs_report_web.pdf.

- an emissions intensity scheme, which requires high-emitting plants to pay low-emitting plants for the right to operate; or
- emissions regulations which might force a plant to close before its engineering life is complete.

The levels that such prices or burdens might reach are hard to predict. They depend on the overall level of national emissions reduction ambition; the share of effort towards that goal that is required from the electricity sector; the (rapidly changing) underlying cost of low- and zero-emissions technologies on both the supply and demand sides; and more. In recent work for the Climate Change Authority, consultants Jacobs adopted the carbon price path depicted in *Figure 4*, derived from the most recent report of the Intergovernmental Panel on Climate Change on global prices consistent with a two-thirds chance of limiting warming to 2 degrees.[11] Prices rise from \$69/t in 2020 to \$277/t in 2050, which would add \$53/MWh to \$214/MWh to the operating costs of an ultrasupercritical black coal generator.

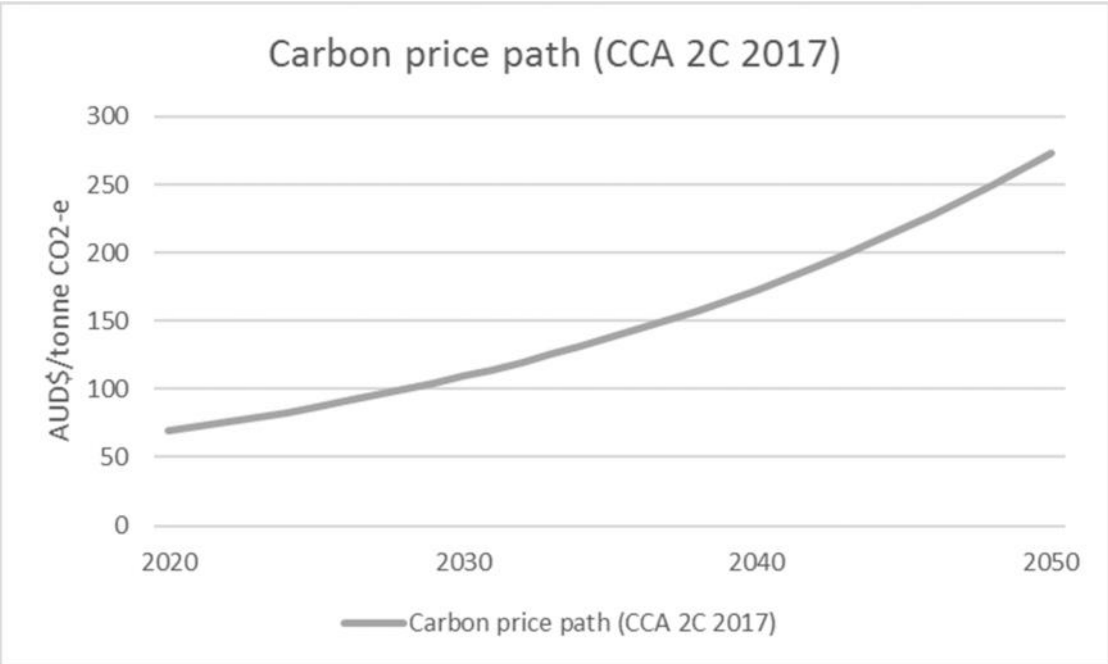

Figure 4 - carbon price pathway developed for 2017 Jacobs report to the Climate Change Authority

Given that Australia was recently roiled by dispute over whether the Gillard Government's carbon price, which started at \$23 a tonne, was too high or not, the price path above looks incredibly aggressive. It could also be argued that the falling cost of non-emitting alternatives will make such high prices unnecessary. On the other hand, achieving the 2C goal is an immense challenge that should not be underestimated; and even if a zero emissions electricity system can be delivered at much lower cost than previously thought, a wide range of other energy and non-energy emissions are likely to be costly to avoid. The Paris Agreement also nods towards an even more challenging 1.5C goal. For their part, Jacobs considered a lower carbon price path consistent with a weaker 3C goal globally, which still

[11] Jacobs, *Modelling illustrative electricity sector emissions reduction policies* (February 2017) http://climatechangeauthority.gov.au/sites/prod.climatechangeauthority.gov.au/files/files/170217%20Jacobs%20Final%20Report%28revised%29.pdf p48.

started at $30/t in 2020 and hit $196/t in 2050.

The key point here is not whether the Jacobs carbon price curves are accurate, but that the carbon risk for a power plant with significant emissions is substantial and potentially enormous. That risk is a major concern for potential investors in a new Australian coal fired power plant, as these costs could render a plant unprofitable or shut it down well before it has returned their investment. Investors are aware of various forms of carbon pricing and constraint in many major economies, and are increasingly building carbon risk and shadow or explicit carbon price expectations into their reporting and decisions.

To attract investors a CFD would have to transfer the carbon risk to government through an absolute guarantee against any future carbon constraint being borne by the project. This could be done by:

- specifying in the calculation of the strike price that government will top up the plant's revenue to cancel out any carbon price or penalty imposed by any level of government; and
- providing a guarantee of compensation if new climate policy by any level of government forces early closure of the plant. The level of compensation would likely need to be the net present value of expected earnings under the remaining term of the contract at the time of closure. This could also involve an option for the government to make such a buyout at any time (for instance if it decides that its future carbon costs are too high).

The government signing such a CFD would be accepting significant financial risks, including for the actions of other governments. It could try to spread these risks by involving other levels of government in the contract, though this would increase the complexity of negotiation and administration.

POLITICAL AND COMMUNITY RISK

Political and community risk is substantial for many major projects, as seen with recent and ongoing disputes over the East-West Link, the Adani Carmichael Coal Mine, and various coal seam gas and wind farm projects held up by community protest, private legal action, or blockage by government. A new coal fired power station is likely to attract significant controversy and face ongoing risks throughout its planning, permitting, construction and operation. Typically a CFD leaves project delivery risk with the project proponent, as they are best placed to manage it. However, the elevated risks for a coal CFD project might require additional provisions to attract investors. These might include government guarantees of legal costs, or compensation if the project is blocked or must be abandoned. Compensation could reflect costs incurred to date, the net present value of expected future project earnings, or anything in between.

CONTRACT DURATION

Contract duration is the final major aspect of a CFD to be determined. Longer terms mean lower risk to developers, allowing them to access cheaper finance and offer cheaper projects. Shorter terms mean lower risk to government. The Hinkley Point C nuclear power project in the UK has a 35 year CFD. Renewables CFDs have often involved terms of 15 to 20 years. Projects may expect to keep making some money as merchant generators after their contracts end, for as long as their engineering life allows. Some renewables projects have managed to bid lower CFD strike prices by leaving some of their cost unrecovered in the contract period, hoping to recover them in the merchant period. This involves some risk, since it is possible that wholesale power prices will be very low in the future – particularly if the market is saturated with zero-marginal-cost renewable generation or future generators derive much of their revenue outside the wholesale market.

A bankable coal project would need to ensure it recovers all its capital costs in the contract period. Plausible climate policy and market conditions may make it difficult for a coal power station to survive in the open market once out of contract. The coal generator levelised cost estimates discussed above are based on a 30 year operating life. Shorter periods mean increasingly high levelised costs, since the project must spread its costs across fewer units of energy sold. The chart below illustrates the effect for an ultrasupercritical brown coal power station, assuming a $4,000/kW capital cost and a 10% discount rate (consistent with APGT).

Figure 5 - Levelised costs for a brown coal generator, recalculated for operating lives between 5 and 40 years

Any bidders for a coal CFD are thus likely to seek the longest contract they can get, which will enable them to bid lower strike prices and be more competitive in a selection process. A contract length of 30 years seems likely, and less than 20 years seems highly unlikely. However, a government that was keen to limit its risks or to reconcile a coal CFD with long term climate ambitions might set a shorter contract and mandate closure at the end of that period, accepting a higher price as a result.

Summary of necessary CFD parameters

- 30 year term.
- Price guarantee of $80 per MWh (if ADGSM estimates are right) or $40-$78 per MWh (if Minerals Council estimates are right).
- Freedom to rely on price guarantee revenue, rather than wholesale market revenue, as much as necessary to ensure very high capacity factor.
- Absolute guarantee against carbon cost or constraint during the life of the contract.
- Compensation and cost-sharing provisions to address political, community and legal risks.

CFD CREDIBILITY

There is at least one further element a contract would need to offer: credibility. With sufficiently generous terms it would seem evident that some investor will be willing to put a project forward. To do so, however, that investor – and their own financiers – must believe that the generous contract will be honoured. This is open to question. While government contracts have generally been regarded as sacrosanct, in practice many incoming governments have found grounds to extricate themselves from arrangements they did not support. Victoria's East West Link project broke new ground in the rejection by a new government of a contract through which their predecessor sought to bind them. The very substantial compensation bill that resulted in that case should give future governments pause before either rejecting or signing similarly controversial contracts.

A coal CFD would be highly controversial, and the more generous its core terms, carbon guarantee and compensation provisions, the more fire it may attract. With combined feasibility and construction period of 6 years (Solstice estimate) or more, on top of however long it takes to devise and run a process for awarding a contract, the project is likely to extend across at least two federal elections and two elections in the relevant State. Each level of government will have a potential veto over the project.

We therefore need to allow for the possibility that even the terms outlined above may be insufficient to attract private investment in a new coal power station. The expressed lack of interest in new coal by existing electricity market participants, and in high-emitting projects by some Australian financial institutions, is sobering.

3. Digging into levelised cost estimates

The different estimates of new coal LCOE from APGT and Solstice/GHD for the Minerals Council, canvassed above, deserve closer analysis, as they heavily affect the overall costs and risks of a CFD. How are the estimates produced, and why are they different?

A levelised cost calculation is most heavily shaped by assumptions around capital costs; operating costs including fuel costs; capacity factor; carbon intensity and any carbon price; and the discount rate applied. This last element may be obscure to many people, but it hugely shapes the results. The discount rate is used to reduce the current value of future costs and benefits. This reflects the time value of money – for instance, the return that investors expect. Higher discount rates, reflecting a requirement for higher financial returns, lead to higher levelised costs for capital-intensive generators, since the high capital expenditure from the early years is only lightly affected by the discount rate while decades of future revenue are heavily affected.

The treatment of each factor in the two assessments is outlined below.

DISCOUNT RATES

APGT uses a 7.4% discount rate for all technologies (post tax, in current dollars). Solstice use a somewhat lower rate, 6.6%, reflecting cheaper assumed costs for debt. If all other elements were the same, this lower discount rate would reduce Solstice's LCOE estimates by around 2.5%.

The Solstice report also states that all its estimates imply 'underwriting' of the projects considered by a long term agreement (such as a CFD) to purchase their full output and guarantee against carbon costs. Neither APGT nor Solstice use different rates for different technologies; Solstice states that this allows "a like-for-like comparison of underlying power generation costs, unfettered by arbitrary risk premiums intended to reflect current-day regulatory uncertainty or other assumed investment risk differentials."

Solstice's statement is a response to efforts like those of the Finkel Review or Bloomberg New Energy Finance (BNEF) to estimate the additional risk premium that market-driven investors would require, based on all the price, volumes, carbon, community, legal and political risks considered above, to finance a new coal plant. The specific premia developed by Finkel and BNEF can be argued over, but the basic concept is sound and both the APGT and Solstice cost estimates should be regarded as relevant only to a fully underwritten project, and far below the cost of a purely market-driven coal project.

CAPACITY FACTOR

APGT assumes an 85% capacity factor for new pulverised coal plants. Solstice use even higher capacity factors – 87% in their high-cost case and 90% in their low-cost case. If all other elements were the same, the highest capacity factor would reduce Solstice's LCOE estimates by around 2.6%.

Neither LCOE estimate allows for the lower capacity factors being achieved by actual baseload generators in Australian and overseas markets. Nor do they account for the growing share of rooftop and large scale solar, which is likely to consume much of the daytime power market and make high capacity factors difficult to achieve on a market basis. Solstice's assumption of a long term underpinning agreement would be necessary to guarantee such high factors.

Figure 6 below illustrates the relationship between levelised costs and capacity factor for black and brown coal and baseload gas fired generators.

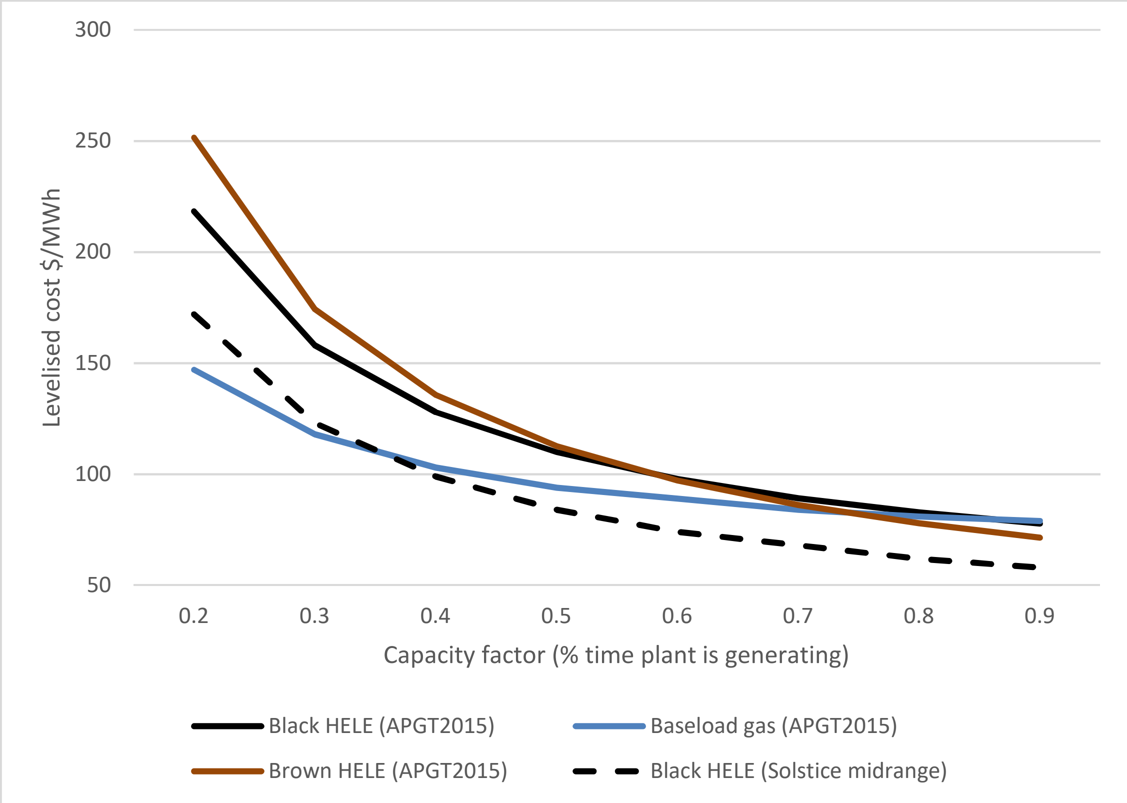

Figure 6 - Levelised costs increase as capacity factor declines

CAPITAL COSTS

APGT uses models which estimate the capital costs of new build power plants on the United States' Gulf Coast, then adapts these to Australian conditions based on a study of regional comparisons for labour costs and productivity and materials costs. For an ultrasupercritical black coal power plant, APGT derives an all-in capital cost estimate of $3,100 per kilowatt of capacity.

Solstice produces much lower numbers. For their low cost case they start with a GHD-produced estimate of $2,845 per kilowatt, and for their high cost case they allow for a 15% higher estimate of $3,300 per kilowatt. For both cases they then make three further cost reduction assumptions:

1. The power station is constructed entirely using capital equipment imported from China, assumed to be available at a 14% discount;
2. The power station is a 'brownfield' project, built on the site of an existing black coal power station that closes. The project is assumed to be able to reuse existing common infrastructure, existing equipment for coal handling and stockpiles, and existing ancillary equipment like black start generators. It is unclear whether these reused assets are assumed to last for the life of the new plant. Reused assets are calculated to reduce capital costs by about 7%;
3. The power station is assumed to be able to use the existing water storage and entitlements of the existing power station it replaces, and can therefore be 'wet-cooled'. 'Dry-cooled' power stations (assumed in APGT) are modestly more expensive to build and run, but less vulnerable to water limitations. Many thermal power stations had to constrain their output during the Millennium Drought due to lack of water availability, despite their existing water storage and entitlements. Future changes in water availability due to climate change are widely expected. The wet-cooling assumption reduces capital costs by about 4%.

The total effect of all these assumptions is a Solstice low-case total capital cost of $2,523 per kilowatt of capacity, and a high-case of 3,046 per kilowatt of capacity. If all other elements were the same, the low case capital assumption would reduce Solstice's LCOE estimate by around 7.5%.

OPERATING COSTS

There are three broad elements to operating cost: fixed operation and maintenance (O&M) costs to maintain the station in working condition; variable O&M costs that depend on how much the station is used; and fuel costs that depend on efficiency and fuel prices.

APGT calculates fixed O&M of $45,000 per megawatt of capacity, variable O&M costs of $2.50 per megawatt-hour generated, plant efficiency of 41%, and a fuel price for black coal of $2 to $4 per gigajoule.

Solstice uses different figures for their low cost and high cost cases. At the low cost end they assume the same fixed O&M cost as APGT; lower variable costs of $1.60 per MWh; a higher plant efficiency of 42.3%; and a lower fuel price of $1.32 per GJ. Compared to APGT their high case includes a higher fixed O&M cost of $87,000 per MW capacity, a higher $4/MWh variable O&M cost, a marginally lower 40.7% efficiency, and a fuel cost of $4/GJ – the high end of APGT's range.

Of these differences, by far the most significant is the fuel cost assumption. If all other elements were the same, the low case fuel cost assumption would reduce Solstice's LCOE estimate by around 31.9% from APGT's top end and 23% from its mid-range. The remainder of the differing assumptions reduce Solstice's estimate by about 1.6% from APGT.

Is the lower fuel cost reasonable? Very low fuel prices are associated with 'captive' mines that can only serve a power station, not the export market, and are generally owned by the same entity as the power station they serve. However, the spread of coal rail networks and changes in the structure of the electricity industry mean that more coal is potentially exportable and integrated mines and power stations are less common. The Newcastle FOB price for thermal coal has ranged in the last ten years between a low of $2.56/GJ in April 2016, and a high of $7.18/GJ in July 2008; the average price has been $3.77/GJ. As of June 2017 it was $4.06. Depending on mine and power plant locations, power usage may involve lower rail costs than export, though the NSW and Queensland coal rail networks have greatly increased their efficiency to support export competitiveness.

All in all, a higher fuel price seems more plausible in the absence of further government intervention. State governments can potentially guarantee a lower fuel price through restrictive licensing or directly developing a mine themselves and contracting the coal at below-market rates. Such intervention would not be cost-free, given foregone export and tax revenue, and should be fully accounted for if considered.

CARBON

APGT assumes an emissions intensity for ultrasupercritical black coal plants of 773 kg carbon dioxide equivalent (CO2-e) per MWh sent out. APGT included no carbon price in their base case, but did sensitivities for a low price of $30/t , a mid price of $70/t and a high price of $130/t. These prices were simply derived as the gaps between the cheapest fossil technology in APGT's analysis, supercritical black coal, and wind, solar and coal with carbon capture and storage.

Solstice include no carbon price in their analysis of an ultrasupercritical black coal plant. They do include a modest carbon price of $25/t in their analysis of the costs of carbon capture and storage technologies. They state that they have borrowed this price from AEMO's 2016 National Electricity Forecasting Report (NEFR), which incorporates an assumption that emissions abatement costs add 2.5% per annum to retail electricity prices from 2020 to 2030. However, this borrowed assumption does not seem to be coherent. The AEMO assumption is fairly arbitrary and not part of a detailed plan to achieve the current national 2030 targets. It is explicitly premised on the absence of any direct carbon cost on electricity generators. And the relevance of the chosen carbon price to the carbon capture and storage costings is questionable, since it is far too low to make investors prefer coal with CCS to coal without CCS on Solstice's cost estimates.

The lack of a value on emissions is a substantial gap in the base costings from APGT and Solstice (remedied in APGT by the inclusion of sensitivities). Emissions valuations are highly contestible, but price paths worth considering include those consistent with the current 28% 2030 target and with longer term net zero ambitions, such as the Jacobs price paths discussed in Chapter 2.

TOTAL COMPARISON

The Solstice low-end estimate explicitly only applies to a black coal power station built on the site of an existing station, reusing its facilities and equipment where possible, relying on an existing and continuing water resource, built with all possible components imported from China, guaranteed coal at far below export prices, and backed by a long-term offtake agreement that guarantees against any carbon cost.

Each of these elements is highly arguable, and the highly specific combination of circumstances involved may not be easily achieved in practice. In particular, the most relevant potential brownfield site for a black coal plant is at Liddell in NSW, where the current ageing 2 gigawatt power station is scheduled to retire in 2022. Liddell's current mine is close to the coal rail network, and it is not obvious that a new plant would be able to secure coal at prices far below export. If it cannot, the low end of the Solstice cost estimates is far out of reach.

On balance, the APGT and high-end Solstice estimates of $75-78/MWh seem much more plausible than the low-end Solstice estimate, as long as the project has a guaranteed offtake for all its power and is shielded from any carbon cost. Incorporating carbon costs, a likely lower capacity factor, and higher finance risk premiums related to these factors makes sense for a market-driven cost estimate. This would produce much higher estimated costs: around 85% higher, or $140/MWh, with an average $30 carbon price, 60% capacity factor, and 14.9% discount rate.

4. Assessing the costs of a CFD

Putting together all the factors canvassed above, what might be the cost to government of a CFD for a new coal fired power station, and how might this compare to other options – such as a CFD for gas, wind or solar generation? These are complex questions and require assumptions about many factors:

- The levelised costs of different generation technologies;
- The characteristics of a CFD;
- The pathway of future market electricity prices, which determines how much project revenue a government may need to top up;
- The pathway of future carbon prices, which determines the value of any carbon guarantee a government provides;
- The impact of any other climate and energy policies which may provide revenue or cost to projects, or affect the path of electricity prices.

There are no definitively right assumptions and these matters are best considered through scenarios and ranges.

With that said, the following section analyses the potential costs to government of CFDs for four technologies in three broadly indicative scenarios.

SCENARIO ASSUMPTIONS

The technologies considered are:

- Brown coal High Efficiency Low Emissions (HELE) ultrasupercritical – LCOE of $82/MWh drawn from APGT's central estimate, without any carbon, risk or capacity issues. The Minerals Council's recent $55-65 estimate has not yet been fleshed out in detail or adapted to Australian conditions.
- Black coal HELE ultrasupercritical – two LCOEs are used, including the APGT central estimate of $80/MWh (without any carbon, risk or capacity issues), and the midrange of the Solstice estimates ($59/MWh). The latter still involves challengingly low and specific assumptions, but is more plausible than Solstice's low end.
- Combined cycle gas generation ('baseload gas') – LCOE of $78/MWh drawn from APGT's central estimate, assuming fuel prices of around $8/GJ (roughly export parity, but well below the extreme prices currently being experienced in Eastern Australia).
- Onshore wind – LCOE of $61 averaged from several recently concluded projects in Eastern Australia. No 'firming' costs to integrate variable generation with the needs of the grid are included (but see below for more discussion).
- Large-scale solar – LCOE of $70 based on multiple projects and generally available quotes in Eastern Australia. Firming costs as for wind.

All technologies are considered on the basis of the need to generate an equal total volume of electricity over their lifetime to a 2000MW coal plant – a Liddell replacement – taking account of the lower capacity factors of wind and solar, and assuming that the CFD allows all technologies to generate as much as they are physically capable of.

The scenarios considered below are:

Scenario A

No new climate policy for the electricity sector. Wholesale electricity prices evolve in line with the 'business as usual' case in the Jacobs modelling for the Finkel Review. The Commonwealth and States bear the costs of emissions reduction; these are estimated using the very aggressive CCA 2 degrees price path depicted in *Figure 4* above.

Scenario B

Clean Energy Target 26%. A CET is introduced consistent with the scenario modelled for the Finkel Review, issuing certificates to new generators below a threshold of 600kg CO2 per MWh, with targets calculated to deliver the electricity sector's equal share of a national 26-28% 2030 target and to achieve net zero emissions around 2070. Wholesale electricity and certificate prices evolve as per Jacobs' CET scenario modelling. Electricity emissions are fully addressed through the CET and high-emitting generators never face any carbon cost.

Scenario C

Clean Energy Target 2 degrees. A CET is introduced consistent with the aggressive Low Emissions Target modelled by Jacobs for the CCA, issuing certificates to new generators below a threshold of 600kg CO2 per MWh, with targets calculated to deliver electricity emissions reductions consistent with a global effort to keep temperature increases below 2 degrees. Wholesale electricity and certificate prices evolve as per Jacobs' CCA modelling. Electricity emissions are fully addressed through the CET and high-emitting generators never face any carbon cost.

For all scenarios, the contracts for difference offered include 30 year terms and other provisions as set out above, and are taken up by projects which commence operations in 2020 and run to 2049. The analysis does not attempt to present the potential costs of any provisions around legal challenges or early termination.

The analysis presents the net present value in 2020 of a CFD, discounting future costs and benefits at 7% per annum including inflation.

RESULTS BY SCENARIO

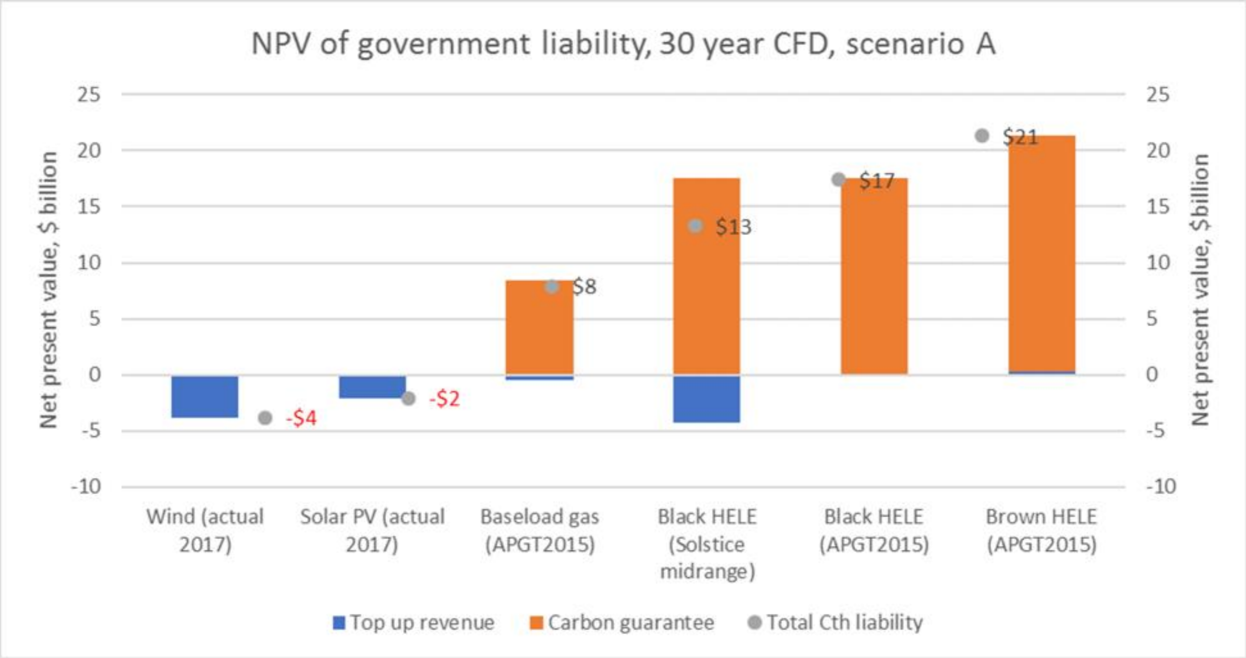

Figure 7 - CFD NPV with no new electricity sector policy and 2 degree scenario carbon value

Under scenario A, the high wholesale electricity prices assumed (consistent with a lack of policy resolution and continuing shortfall in electricity sector investment) mean that all CFDs are cost-neutral or cost-negative with respect to government's price top-up obligation. That is, the strike price is at or below the achieved wholesale market price and government either makes no payments or receives significant refunds. On this basis, black HELE (on the Solstice midrange cost estimate, if actually achievable) and onshore wind would be the cheapest options, at a benefit of $4.2 billion and $3.8 billion respectively in net present value terms.

However, consideration of carbon risk radically changes the assessment. Ascribing a high value to carbon emissions over the years to 2049 would leave the net benefit of a wind or solar CFD unchanged, but turn a black coal HELE CFD to a net cost of up to $13.3 billion (for the Solstice midrange cost estimate) and up to $17.4 billion (for the APGT base estimate) in net present value terms. The impact is so large that even with lower future carbon price assumptions, renewables CFDs appear substantially cheaper. A baseload gas CFD would be the cheapest dispatchable generation technology if any significant value is placed on emissions.

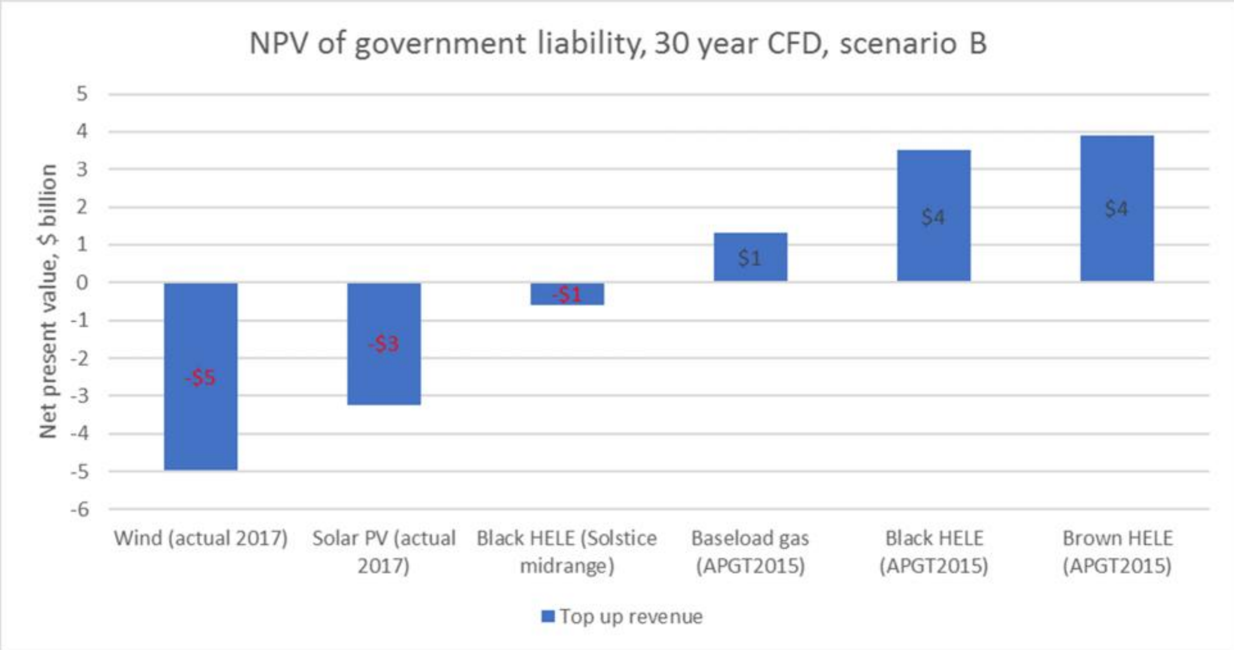

Figure 8 - CFD NPV with Finkel 26-28% Clean Energy Target

In Scenario B, wholesale electricity prices are considerably lower thanks to reduced uncertainty, increased generation investment and the price-suppressing effects of the Clean Energy Target. Wind, solar and gas also benefit from CET certificate revenue. Wind and solar CFDs would be substantially cost-negative for government at -$5 billion and -$3.2 billion respectively. A black HELE CFD would be slightly cost-negative (-$0.6 billion) if the Solstice midrange costs were achievable, or a substantial net cost ($3.5 billion) if APGT and the Solstice high end estimate are correct. A baseload gas CFD would be carry a modest net cost of $1.3 billion.

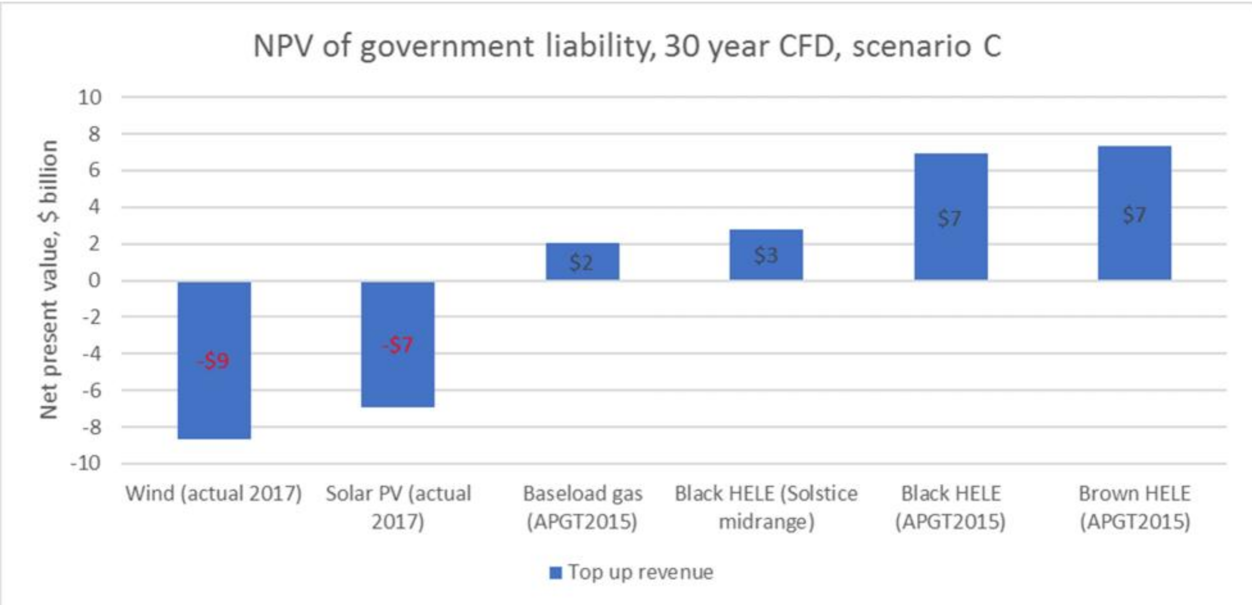

Figure 9 - CFD NPV with 2 degree scenario Clean Energy Target

Scenario C is similar to Scenario B but with even lower wholesale electricity prices and higher CET certificate revenue. Wind and solar CFDs are substantially cost-negative at -$8.7 billion and -$6.9 billion respectively, while baseload gas overtakes even the Solstice midrange estimate for black HELE, at net costs of $2 billion and $2.8 billion respectively.

Note that none of the above results attempts to assess the net costs and benefits of the policy scenarios themselves. They are solely an assessment of how CFDs for assorted technologies would stack up within the context of each scenario.

FIRMING COSTS

It is important to note that wind and solar generation do not necessarily offer the same services to the grid as gas and coal generation. Fast frequency control and synthetic inertia can potentially be provided by suitably equipped renewable generators at modest cost. However, achieving greater 'dispatchability' for renewable generators – the ability to supply power on demand, rather than just when the wind happens to blow or the sun happens to shine – is a bigger challenge. There are many potential options to integrate variable generators into a reliable grid, including but not limited to:

- backup generation from flexible gas, hydro or modern coal plants;
- energy storage including pumped hydro and batteries;
- demand response from loads that are able to reduce or switch off when rewarded for doing so; and
- geographic and technological variety in renewables to reduce the expected range of variation in output.

The Finkel Review's recommended Generator Reliability Obligation would require new generators to acquire sufficient services to firm as much of their output as expected market conditions required. But whoever decides on the appropriate mix of firming services, and whoever pays the associated costs, the costs are real. It seems obvious that they should be incorporated into estimates of the cost of new generation.

It may be obvious, but it is certainly not easy. How much firming is actually needed? This depends not just on the expected availability of a particular generator but on the state of the market. Both are evolving. Capacity factors for wind farms are increasing significantly with improved technology, and cheaper sun-tracking is lifting large scale solar average output too. The shares of dispatchable and variable generation in different parts of the National Electricity Market are changing rapidly, and so is the amount of always-there base load. The costs of firming technologies are moving very fast, with gas currently on the way up and batteries rapidly coming down. The technology and economics are in place to make large volumes of cheap demand response available, but in the National Electricity Market we are at an early stage of implementing the policies and developing the market experience to realise this. Western Australia's electricity markets have long had substantial amounts of demand response, and the NEM demand response program recently launched by the Australian Renewable Energy Agency and the Australian Energy Market Operator has attracted very strong interest.

It is plausible that the costs of adequately firming renewables might move nonlinearly or in step changes as the overall penetration of variable renewables increases. At higher penetrations wholesale prices will tend to be deeply suppressed at sunny and windy times, and the cheaper sources of flexibility to shift energy to higher value times and demand to lower value times may be exhausted. Which technologies offer the cheapest (or alternately, most valuable) incremental addition to the system will thus depend on the state of the system as well as on technology and policy.

With all these moving parts, it is difficult to rely on any single estimate of the cost of firming. The

Solstice report previously discussed attempts to consider wind and solar on the basis of including sufficient lithium-ion battery storage capacity in each project to supply its full output for two to three days. This seems grossly overconservative even at the individual project level, given the availability of much cheaper options than Li-ion for long-duration dispatchability. It is even more excessive considered at the system level, where managing total expected system variability is unlikely to require three days redundant backup to every variable element.

Recent work by Andrew Blakers and others at the Australian National University provides an alternative perspective on firming costs.[12] This work models the costs of balancing the National Electricity Market if it is reliant on 100% renewable energy. The main technology used for firming in the exercise is Pumped Hydro Energy Storage, connected to the grid with new High Voltage Direct Current transmission lines. The estimated range of costs for the Levelised Cost of Balancing the system is an additional $25-30 per MWH system wide. The authors suggest this is an upper range estimate, which could be reduced by more reliance on demand management, improving batteries, or firming from legacy coal and gas generators.

Given the difficulty of specifying firming costs, one way to bring them in to the consideration of a CFD is to ask how large firming costs would need to be before they erased the apparent cost advantage of renewable technologies over coal technologies. *Figure 10* below attempts this for each of the scenarios considered above, based on the cost gaps between renewable-fossil pairings involving wind, solar, two estimates of black HELE, and brown HELE.

Again, note that these are *not* estimates of the actual cost of firming wind and solar, which will depend on the extent of firming needed, the breadth of firming options available, and the evolving cost of those options. Actual firming costs could imaginably be below or above the 'limits' calculated below.

The 'limits' are also not estimates of the maximum marginal cost of delivering a dispatchable megawatt hour. They take the firming-exclusive NPV gap between each technology pair, and spread that gap across all lifetime generation for the renewable technology. That translates to a maximum firming spend for each MWh of lifetime output.

In Scenario A, the high value placed on carbon means that firming costs could be very high before a coal CFD became cheaper than a renewable one – between $80 and $120/MWh depending on the technology pair. Less ambitious carbon valuations would produce a smaller gap.

In Scenario B, the lack of any carbon penalty and the modest incentive for low emissions generation mean that firming costs would have to be significantly lower for renewables CFDs to be cheaper for government than coal ones. Wind would be more expensive if it had to pay more than $22/MWh for firming, supposing the Solstice midrange black coal estimate were achievable, or $43-45/MWh if the APGT coal costings are correct. Solar would have a somewhat lower tolerance for firming costs.

In Scenario C, the higher incentive for low emissions generation in a CET with 2 degree ambition produces firming cost limits that are in between the other two scenarios: $55-82/MWh for wind, $46-73/MWh for solar.

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[12] Dr Matthew Stocks, Prof Andrew Blakers and Mr Bin Lu, *Pumped Hydro Energy Storage to support a 50-100% renewable electricity grid* (January 2017) http://energy.anu.edu.au/files/Senate%20submission%20-%20ANU%20pumped%20hydro%20energy%20storage%20030217.pdf.

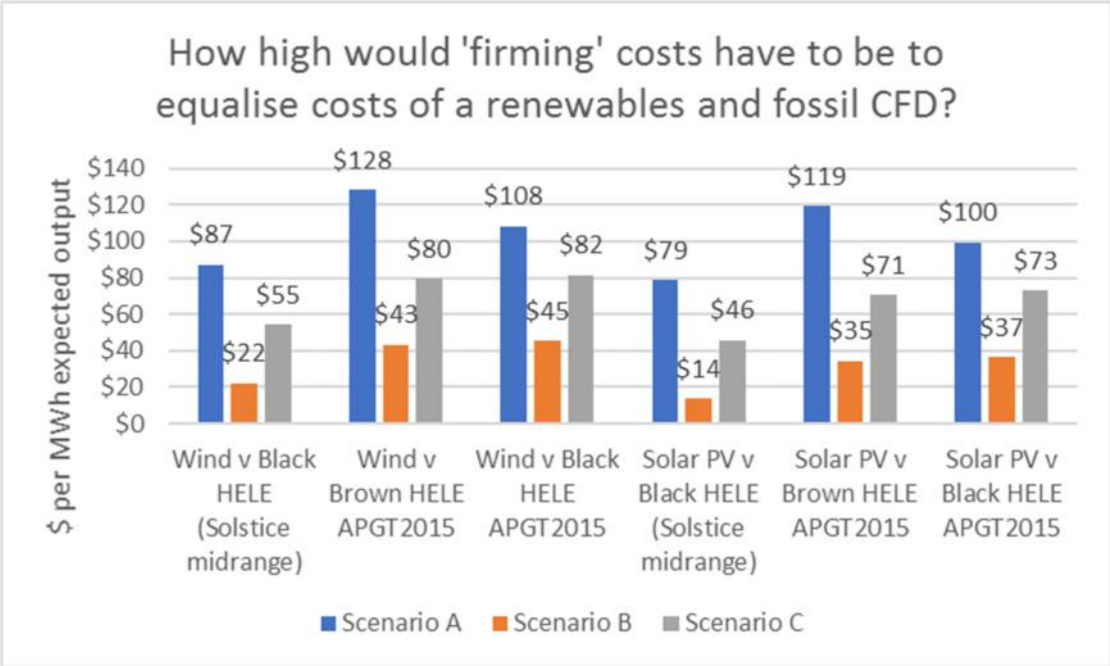

Figure 10 - Firming cost limits for assorted renewable technologies

These crossover cost estimates are not directly comparable to the ANU firming cost estimates considered above. The latter cover system wide costs, rather than the incremental firming costs associated with an individual variable generator, and they are based on a 100% renewables scenario that is much more aggressive than our scenario B. Nevertheless, overall these estimates suggest there is significant financial scope for variable renewables to add firming services while remaining competitive. This is even more so if we consider a more realistic dynamic scenario, rather than the fixed wholesale, carbon and CET certificate price paths assumed above. In a dynamic CET scenario, for instance, certificate demand would reflect the overall electricity sector intensity goal, and certificate prices would reflect the full costs – including Generator Reliability Obligation costs – of the most competitive low-emissions generation technologies available at scale. Subject to scheme design, certificate prices would rise as high as necessary to bring on sufficient low-emissions energy to meet the sector goal.

5. Assessing the wider impacts of a CFD

Based on the calculations above, a CFD for a new coal plant would expose government to substantially higher financial risks than a CFD for baseload gas or variable renewables. These costs are highly variable based on a range of future policy, market and technological variables, meaning that point estimates should be treated with great caution and policy makers need to think in terms of risk and ranges. Nonetheless, the costs look potentially significant.

Governments incur many significant financial costs when they judge it worthwhile. What would a coal CFD deliver in return for its costs? Implications for the wider energy system are important. The provisions of the CFD will shape what a coal CFD can deliver, as will the logical consequences of certain costing assumptions. The so-called energy trilemma provides three headings to consider: impacts on affordability, security and reliability, and emissions.

AFFORDABILITY

A coal CFD would affect energy affordability in a few ways. The contract would encourage the generator to make very low bids in the wholesale market at all times, which could *ceteribus paribus* shift the merit order of generation in the Australian Energy Market Operator's bid stack, lowering wholesale prices. This effect would not be from lower underlying generation costs, but from the availability of non-market revenue to offset costs not recovered in the energy market. This is similar to the wholesale price suppression effect associated with the Renewable Energy Target.

As with the RET, the wider and longer term consequences limit this effect. Suppressed wholesale prices reduce the returns to other generators. While Renewable Energy Certificates and possible Clean Energy Certificates would increase in value if wholesale prices fell, generators without access to such revenue sources – particularly existing coal- and gas-fired plants – would suffer. Price suppression and loss of sales volumes from a coal CFD would likely accelerate the closure of the most marginal existing coal plants, particularly black coal. These old generators are pursuing exactly the same market and business model as a new coal generator would: meeting always-there electricity demand, which is likely to continue to shrink as distributed energy resources proliferate. Any closures would tighten the market and put upward pressure on prices. The size and direction of any net effect would depend on the amount of capacity forced into the market. The location of any new capacity could also be significant, upsetting key assumptions on which previous investments were made – like the network constraints or marginal loss factors than apply in a given area.

It is also possible for the existence of a CFD project to reduce wider investment in electricity generation. The CFD creates a competitor with effectively privileged access to the market, reducing the volumes and prices available to other existing and new participants. If further CFDs are offered or thought to be available, investors would be foolish to put their money into the electricity system without a CFD of their own to reduce their risk. A CFD might be pitched as a one-off, in the hope that it would not worry investors or distort their decisions. But it is very plausible that a significant CFD chills investment and creates an expectation that more CFDs will be offered. Faced with weak private investment in a system that needs new capacity, government might feel forced to meet that expectation, or directly invest in electricity assets itself. This 'you break it, you bought it' scenario could amount to a costly expansion of government's financial responsibilities and a lurch towards central planning.

The low Solstice costings for new coal considered above are also predicated on the closure of an existing plant and its replacement with a brownfield project. If such costings are accepted this closure reduces the extent to which the new plant could produce net downward pressure on electricity prices.

The costs of the CFD itself also need to be considered. While in theory government could pay these through some mix of unrelated tax increases or spending cuts, experience suggests that any net costs to government are likely to be passed through to energy users. The Commonwealth and most States already recover or avoid the costs of various energy policies through a levy or obligation on electricity retailers or network businesses. In some circumstances, the costs passed through to energy users can be outweighed by the wholesale price suppression effect. This has been a key issue in arguments over the current RET.

SECURITY AND RELIABILITY

A coal CFD would provide a substantial source of inertia and synchronous generation for the electricity system, both of which are (in the right places and at the right times) helpful for maintaining the physical stability of the grid. It would also provide a large volume of potentially dispatchable generation, particularly as modern coal plants can be designed to operate more flexibly with much higher ramp rates than older plants.

However, these benefits are limited by CFD provisions and costing assumptions. Again, if lower project costs are assumed on the basis of a brownfield project, at best a coal CFD continues existing inertia and synchronous generation levels rather than being a net addition to them. If a coal CFD accelerates the retirement of other synchronous generators with inertia it may not even maintain existing levels of security. Security outcomes will depend on conditions in the specific parts of the grid where capacity or inertia is added or subtracted.

Furthermore costing assumptions like those from Solstice and APGT assume that a coal plant is run at a very high capacity factor of 85-90%. As discussed a CFD can assure this by subsidising low bids when necessary. But whatever its physical flexibility, a plant whose financial model depends on running at full output all the time will not be able to offer dispatchable capacity to the grid. If demand increases or other sources of supply experience problems, a CFD-supported coal generator will not be in a position to respond.

EMISSIONS

Estimates of the emissions intensity of a new ultrasupercritical black coal plant differ. *Figure 3* above sets out Finkel Review figures for several technologies, including HELE black coal at 700kg CO2/MWh. On the other hand, the Solstice paper for the Minerals Council estimates an intensity of 776kg/MWh. The Liddell power station, the likeliest medium-term candidate for brownfield replacement, emits more than 900kg/MWh.[13] The current grid average is 820kg; baseload gas can achieve 373kg; hydro, wind and solar achieve 0kg.

On this basis many contradictory arguments can be made. Replacing Liddell with black HELE might be said to:

- reduce emissions by 14-22% (comparing the new plant to the old plant),
- reduce emissions by 5-15% (comparing the new plant to the current grid average)
- increase emissions by 87-100% (taking baseload gas as the benchmark for new build)
- increase emissions by an infinite percentage (taking zero emissions generation as the benchmark for new build).

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[13] ACIL Allen Consulting, *Emission Factors Assumptions Update Final Report* (May 2016), 8.

A coal CFD would certainly involve large absolute emissions of 366 million tonnes CO_2 over a 30 year period in which, as previously discussed, Australia may target net zero emissions. The waters are muddied further by the likelihood that a coal CFD will take market share away from existing coal plants and the possibility that this will accelerate their closure. There is also the fact that under possible designs for energy and climate policy that involve a sectoral emissions cap or standard, a single plant does not impact net national emissions. For instance, under a Clean Energy Target expressed as an emissions intensity standard for electricity retailers' portfolio, buying some energy from a high-emissions plant simply means that the share of energy purchased from very low-emissions plant must increase. Under such designs, forcing in a particular plant can change the generation mix but not the emissions outcome.

Overall, it seems reasonable to judge that a coal CFD could achieve a moderate near-term reduction in emissions, but create a long tail of continuing substantial emissions. This could be managed within a coherent national emissions policy, with the costs borne by other emitters or the public.

WHAT ABOUT RENEWABLES CFDS?

On the numbers presented earlier, CFDs for renewables or gas may look more attractive than coal CFDs. However, several of the concerns presented above out coal CFDs apply in principle to a contract for any technology. Renewables CFDs would also create privileged market participants, also risk discouraging investment by those without a contract, also draw government further into a central planning role.

The first wave of CFDs proposed by NSW, Queensland and Victoria are within the RET, meaning that the projects are likely to meet their strike price through market and RET revenue with little or no call on the contracts. There may be little cost and little change to investor expectations already shaped by the RET. This would reduce, but not eliminate, the concerns above. Further and more ambitious use of CFDs for any technology does carry risk.

On the other hand, if the wholesale electricity market remains doubtful as a driver of new investment, and if other reforms do not eventuate, the risks of technology-neutral CFDs would need to be balanced against the risks of a lack of investment of any sort.

SUMMARY

On balance, the impacts of a coal CFD on affordability, security, reliability and emissions look ambiguous and do not provide a large and clear benefit to offset the financial costs and risks to government.[14]

The circumstances assumed in some costings for new coal plants will heavily affect the wider impacts that are possible, as summarised in the table overleaf.

[14] Employment is another issue, beyond energy affordability, reliability and emissions, that may be significant, but has not been addressed in this paper. Further work would be useful to compare the overall employment impacts of different technologies and policy scenarios. For instance, new coal fired power stations may be more automated than old plants, which could be especially sensitive in a brownfield replacement scenario.

Costing	Circumstance	Affordability impact	Security and reliability impact	Emissions impact
Low costing (Solstice)	Brownfield plant with guaranteed revenue and carbon shielding	May not improve as it replaces existing low-price plant	Small increase as it replaces existing dispatchable plant but may be more robust and flexible	Modest reduction from replaced plant emissions in near/medium term; high lifetime emissions
Medium costing (APGT)	Greenfield plant with guaranteed revenue and carbon shielding	Additional subsidised supply may suppress wholesale prices (unless it accelerates closure of existing dispatchable plants), though cost of subsidy must be recovered too	Adds inertia and dispatchable power (unless it accelerates closure of existing dispatchable plants)	Increases emissions in all timescales (unless it accelerates closure of existing dispatchable plants)
High costing (BNEF)	Plant with market revenue and carbon policy exposure	Requires, but does not cause, sustained high wholesale prices	Adds inertia and dispatchable power	Increases emissions in all timescales

6. Conclusion: do we need a contract for difference?

This paper suggests that a coal CFD is not a good idea. A CFD approach for any technology needs caution, since government would be taking on a central planning role that it may be neither fully committed to nor ready to execute competently. CFDs for any technology risk undermining new non-CFD investment. The terms of a coal CFD in particular would have to be generous to manage the major risks such a project faces, but such generosity may make it less likely that the resulting contract will credibly be honoured. The financial risks taken on by government would be substantial, and the additional benefit for affordability, security, reliability and emissions is ambiguous.

That does not necessarily mean that Australia will not or should not see any new coal fired power stations built.

The CFD parameters considered in this report have been assessed on the basis of what would be necessary to absolutely ensure a new coal fired power station is built. But it may be possible to put together a CFD that carries less risk for government. For instance, government could participate in a hybrid public-private CFD where private backers – energy retailers or energy users – would have to be found to guarantee the project for its first decade, while government would guarantee longer-term risks over the following two decades. The requirement for significant private backing could also serve as a test for the viability of a project. Alternately, government could specify other conditions for a CFD, such as a maximum strike price consistent with lower estimates of new coal costs, or a more limited carbon guarantee. Another option would be to run a genuinely technology-neutral CFD procurement process. These and other changes would limit public risk, though they would also reduce the likelihood that the process results in a new coal power station being built.

It is also quite possible that a differently configured and conceived coal plant could prosper without a CFD, by adapting itself to the Finkel Review's proposed reforms. A Clean Energy Target with a sufficiently high emissions threshold for certificate issuance could provide some recognition to the most efficient new coal plants, while the Generator Reliability Obligation would mean not just additional cost for variable renewables, but an opportunity for coal and other dispatchable technologies to offer low-cost firming services. If new ultrasupercritical coal plants can achieve the cost and engineering efficiencies and high physical flexibility canvassed in the Solstice report, they could be conceived and operated not as always-on high capacity factor generators pursuing a shrinking base load, but as low capacity factor generators servicing a growing market for flexibility.

There would be plenty of competition for that role from gas generators, demand response, pumped hydro, batteries, and potentially solar thermal or nuclear power. And there could also be competition from existing coal plants.

Recent work commissioned by respected German think tank Agora Energiewende argues that existing coal plants can be upgraded to be much more flexible, at substantially lower cost than building all-new flexible coal plants (estimated at €100-500 per kW upgraded capacity, versus €1200 and up per kW new capacity). [15] Upgrades can extend the technical life of a plant by 10-15 years despite increased wear and tear from flexible operation, and profitability is higher despite increased operation and maintenance

[15] Agora Energiewende, *Flexibility in thermal power plants* (June 2017) 15 https://www.agora-energiewende.de/fileadmin/Projekte/2017/Flexibility_in_thermal_plants/115_flexibility-report-WEB.pdf.

costs. However, in the Australian context such upgrades are unlikely to be considered by the owners of existing assets unless there is a durable bipartisan agreement on climate policy.

In short, neither new coal nor any other technology is guaranteed to succeed. But the specific mix of technologies in our evolving energy system is much less important to energy users than the outcomes achieved on affordability, reliability and emissions. Technology neutral and outcomes-focussed energy policy will help ensure we do not confuse means with ends.