The Australian Industry Group
Level 2, 441 St Kilda Road
Melbourne VIC 3004
PO Box 7622
Melbourne VIC 3004
Australia
ABN 76 369 958 788

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Mr Scott Hamilton
Executive Director – Renewable Energy
Department of Environment Land Water and Planning
renewable.energy@delwp.vic.gov.au

AI GROUP SUBMISSION ON THE VICTORIAN RENEWABLE ENERGY AUCTION SCHEME

Ai Group welcomes the chance to provide input on the Victorian Government's proposed Renewable Energy Auction Scheme (the Scheme). This policy constitutes a major shift both in the National Electricity Market (NEM) and the Victorian Government's relationship to that market. As we understand it, the scheme will operate in two phases:

- In Phase One, the Government will sign contracts for difference (CfD) for 1,500 megawatts (MW) of new renewable generation capacity with the winners of a series of reverse auctions. This capacity is intended to commence operations by 2020 and will not be additional to the Commonwealth Renewable Energy Target (RET).
- In Phase Two, the Government will sign contracts for further new renewable generation capacity of up to 3,900 MW after further reverse auction processes. This capacity is intended to commence operations between 2021 and 2025 and will be in addition to the Commonwealth RET.

The intention is that Victoria will increase the renewable share of electricity generation from 14% today to 25% in 2020, and 40% in 2025.

The current consultation process is very truncated for such a significant scheme, and we note the lack of available information on potential impacts. We understand that the Government hopes to pass any necessary legislation in the first half of 2017 and commence the first reverse auction in mid 2017. A desire for swift action is understandable in relation to Phase One, given the risk that the Commonwealth RET will not be met in 2020 and the limited time available for construction. However, Phase Two involves substantially larger change and presents greater risks to energy costs and grid stability. Much more work, consultation and information is needed, and the Government needs to take full advantage of the time available.

Before addressing the specifics of the proposed Scheme, Ai Group must emphasise our strong preference for nationally coherent energy and climate policy. Australia has a national electricity market and national commitments under the Paris Agreement on climate change. While Commonwealth policy in this space has been highly contested and unstable, the prospect of a patchwork of State policies and targets – however well intended – raises profound concern.

It was not long ago when the interaction of poorly coordinated State feed-in tariffs and Federal rebate and crediting policies led to a costly and disruptive surge in costs. The larger ambitions now pursued by Victoria and other States come with commensurately larger risks that the net effect of national and State policies will be more costly, less equitable and less effective than a nationally coordinated approach. The fragmentation of energy and climate policy across different levels of government and different geographic regions greatly increases the risk of high costs, unintended consequences and market instability. We strongly urge Victoria to work with other States and the Commonwealth to ensure the best possible energy and climate policy outcomes for Victoria and the nation.

The remainder of this submission will address three sets of issues: renewables integration and systemic transition; the scope and pass through of scheme costs; and the design of the auction and contract elements.

Integration issues

The single biggest concern that industry has with the scheme is only tangentially discussed in the consultation paper: the need to ensure stable and affordable energy supply during a major transition in the electricity sector. Increasing renewable generation to 40% and injecting up to 5,400 MW of new capacity into the market are enormous changes with far reaching potential consequences.

Given weak electricity demand projections and the strong existing oversupply of generation capacity, substantial new capacity is likely to induce the early retirement of existing generators. These will sell lower volumes of energy and may face lower wholesale prices at times, particularly in the middle of the day when solar generation is at its peak. If closure is rapid and disorderly it would unsettle the wholesale market and pose an especially difficult transitions for supply chains, communities and workers. In the absence of additional policy interventions, black coal-fired power stations in NSW are likelier to close than brown coal-fired power stations in Victoria, reducing the emissions cuts that may be expected from the scheme and complicating the Government's targets. The new generation capacity will be variable and intermittent, capable of being throttled back when necessary but not ramped up.

This all suggests that Victoria will face similar challenges to those that have affected South Australia recently. SA has a long history of volatile prices and many factors have contributed to the lift in wholesale price futures over the past year and the extreme wholesale price event in July: constraints on the SA-Victoria interconnector, gas price and supply issues, inflexible demand, and limited competition. The growth in variable renewables has so far left South Australia more exposed to these factors, however: renewables have helped drive some baseload out of the market, reducing competition and increasing dependency on the interconnector and on gas as the marginal generator. The lack of demand flexibility and energy storage increases the potential for wild price swings when supply falls short. Without further action SA faces the likelihood of more frequent spot price surges and a consequent substantial lift in retail electricity contract prices.

Victoria is larger and better connected than SA, with more substantial supply competition. But it is similar in its exposure to gas market problems and its lack of demand flexibility and storage. The Australian Energy Market Operator (AEMO) warned in its recent 2016 Electricity Statement of Opportunities that in the absence of corrective steps the scale of generation closures it expected in response to Australia's existing 2030 emissions reduction targets would cause Victoria and other states to breach the capacity buffers that have been established to guarantee reliable supply. The Government is quite properly interested in the billions of dollars of investment and thousands of jobs associated with growing renewables. But hundreds of billions of dollars of investment and millions of jobs across the State depend on secure and affordable energy supply. The former cannot come at the cost of the latter.

Victoria's targets, and particularly the rapid ramp from 2021 towards 40% renewables, therefore raise significant questions about managing the transition without serious consequences across the energy market. There is little doubt that renewables can be integrated into a successful energy system, and that they will play a large and even dominant role in Victorian energy supply over time. But the integration challenges are real and will require careful planning and multiple reforms within Victoria and across the energy market.

Those reforms include:

- Demand side flexibility. The Demand Response Mechanism proposed by the Australian Energy Market Commission's *Power of Choice* review in 2012 could incentivise enough demand reduction to sharply reduce price surges due to extreme events or swings in renewable generation, but progress through COAG has stalled. Meanwhile Victoria is failing to capitalize on its smart meter rollout through time of use network pricing and other dynamic price options; the current opt-in approach minimizes the risk that consumers are caught out by prices they don't understand, but also ensures very slow progress in providing incentives to most energy users to respond to system constraints.

- Gas supply security. Gas will play a crucial role in backing up renewables and setting wholesale electricity prices for some time to come. The eastern domestic gas market faces tight supply and rising prices as a result of the growth in Liquefied Natural Gas exports, even as oil-linked overseas gas prices are low. A market reform agenda to increase competition and transparency is taking shape and making progress, but the market also needs new suppliers and sources of supply. All supply growth is likely to come from unconventional onshore sources, but Victoria seems set to continue a moratorium on onshore gas exploration and production. While demand efficiency can play a role in rebalancing the market, Victoria will need to do its part on the supply side to ensure sufficient gas is able to be produced to provide secure and affordable supply.

- Storage. Energy storage, particularly through batteries, is likely to play a central role in balancing future energy systems with high or total renewables penetration. Battery costs and performance are now improving rapidly, and other storage options may be practical as well – including pumped hydro systems and molten salt storage. However, the technical standards, market rules and policy incentives that would facilitate and encourage uptake of storage are absent or embryonic. While the proposed renewables scheme might support generation projects with integrated storage, it appears that pure storage projects would be ineligible.

More broadly, substantial analysis and planning is needed in relation to the market-wide implications of Victoria's transition to 40% renewables. The consultation paper and stakeholder discussions indicate several small steps to assist integration issues through the design of the auctions and contracts, including some regard to stability in project selection and the choice of revenue metrics that encourage proponents to follow electricity market demand. However, there is no evidence of a systematic approach to the overall issue of transition. This is far too large and multifaceted to be dealt with solely through design of the auction scheme. We strongly urge the Victorian Government to consult more extensively on transitional challenges and responses, to lay out a detailed approach, and to aggressively pursue the reforms referred to above.

A final aspect of the integration issue is that the Government's auction scheme will effectively design a substantial chunk of Victoria's energy system for the next two to three decades. It is vital that the scheme be administered with that context in mind, and not just with a narrow focus on successful auctions and achieving the lowest strike price possible. The scheme administrator should define the kinds of capacity it requires with reference to wider systemic needs, and should work closely with AEMO, COAG energy officials, and energy market stakeholders to do so. Relevant features to inform bidders of may include needs for storage; ability to contribute to frequency control, inertia or system restart services; correlation with demand; and non-correlation with other sources of supply.

Costs and pass through

The Government's proposed Contracts for Difference (CfD) would set a strike price for each contracted renewables project; if project revenue is below the strike price, the State will make up the difference, while (under the preferred option) if project revenue is above the strike price the proponent will refund the difference to the State. Any costs to the State will be recovered from energy users via transmission or distribution network charges. This raises several issues: the size of potential costs, the symmetry of payments, the basis and mechanism for passing through costs, and the need for and mechanics of exemptions.

The ***potential cost*** of the Scheme is difficult to estimate. We understand that the Government has commissioned modelling and we urge that this work be released to inform debate. In the absence of this information we estimate the costs as follows:

- Phase One may come at zero direct cost to energy users, since it is not additional to the Commonwealth RET and so projects will have revenue from both the wholesale electricity market and the Large-scale Generation Certificate (LGC) market. Current electricity and LGC futures prices for 2017-20 are around $50 and $85 per megawatt hour (MWh) respectively. Wind and solar project costs have been falling and seem very likely to fall within the $135/MWh envelope implied by these futures. Thus while the revenue certainty offered by Victorian contracts may plausibly induce projects to be built, significant payouts to developers may not be required in practice. Indeed, there could be significant payments flowing the other way, if project revenue turns out to exceed the contracted strike price. The biggest risk to this outlook would be if the relatively poor opportunities for solar generation in Victoria, combined with the proposed minimum 20% solar share of the Scheme, led to exceptionally high project costs.

- Phase Two costs are deeply uncertain and could range from nothing to as much as $20/MWh – comparable to the former carbon tax. The incremental cost of the scheme depends on:

    - future wholesale electricity price movements. low prices would increase the revenue gap which Victoria must cover, and could result from continued weak demand and growing supply from renewables; high prices would reduce direct scheme costs, and could result from a recovery in demand (potentially associated with electric vehicles) or substantial generation retirements;

    - future Commonwealth energy and climate policy. The absence of revenue from the existing Commonwealth RET for post-2020 Victorian Scheme projects leaves a large gap for the State to cover. An expansion of the Commonwealth RET or introduction of a carbon pricing scheme could significantly increase the expected revenue of renewables projects and narrow or eliminate the gap.

    - Future renewables technology and construction costs. While relatively recent Australian projections put the cost of generic new wind and large solar PV projects at around $100/MWh and $140/MWh respectively, these are already out of date and further improvements are likely. Internationally, wind projects are being contracted for the equivalent of $60/MWh and solar for as little as

$40/MWh. Whether these costs are reproducible in Australia, and how fast costs may further decline, is unknown.

All of these Phase Two variables are deeply uncertain. In the worst case for Scheme costs that we have considered to date, where wholesale prices are further depressed to around $35/MWh, projected high technology costs apply and there is no further Commonwealth policy, the cost of contracting for 3,900 MW in Phase Two would be just under $900 million per year in 2025. That would add around $20/MWh to electricity costs if passed through evenly to a Victorian demand base of around 45 terawatt hours. On the other hand, scheme costs could be very low if wholesale prices are high, Commonwealth policy is significant and technology costs turn out to be low. While consumer-friendly outcomes are possible, uncertainty itself has a serious cost.

Turning from the quantum to the ***distribution of costs***, the proposed approach of spreading costs to energy users via network charges raises complex questions. There is great potential for administrative complexity, forecast risk and damaging uncertainty.

The Scheme is likely to require project proponents to pay the Government if project revenue exceeds the contracted strike price. There is reason to believe that many projects contracted in Phase One may be in this position and that refunds may therefore be collectively significant. We strongly urge the Government to accept the principle that both the costs and any financial benefits of the Scheme should be spread to energy users. Therefore any net revenue in excess of scheme costs in a given year should be applied for the benefit of consumers through one of two mechanisms:

- Retained in an independently administered fund for the sole and automatic purpose of reducing future net scheme costs that would otherwise flow to electricity users; or
- Refunded to energy users as soon as practical via the network service provider(s) chosen to administer payments.

Experience with other programs shows that estimation of scheme costs carries significant forecast risk, and may lead to consumers being substantially overcharged at times. The Government itself is best placed to bear this risk and should take it on by creating a structure along the following lines:

- A public agency manages payments to and from project proponents, drawing on the State's account in the first instance.
- At the end of each year of operation – defined with regard to the National Greenhouse and Energy Reporting cycle for ease of interaction between schemes – the net total of scheme costs is reported by the public agency and divided up among the responsible network businesses in line with their share of the market in the past year.
- Networks charge customers on the basis of actual scheme costs in arrears.

This approach would not provide full certainty to energy users, who would still need to speculate and extrapolate from recent and current-year data to estimate their future costs. But it would greatly limit uncertainty for networks, who otherwise might overestimate scheme costs to avoid the risk of under-recovery. The impacts on the State budget should be minor and transient, since only the timing of costs would change.

Passthrough to individual energy users should be based on their energy consumption from the grid, not total energy consumption. The latter would greatly disadvantage businesses and individuals who self-generate through cogeneration or through renewables including biomass and solar.

The potential for the Scheme to impose significant costs in Phase Two raises a serious potential concern for Victoria's ***trade exposed industries***. Energy costs are a significant input for many businesses, particularly in manufacturing, and those that export or compete with imports often face slim margins and intense competition. Relatively low energy costs have historically been a source of competitive advantage for Australia, and for Victoria in particular. This competitive advantage has already been significantly eroded in recent times with increasing gas prices. Further compromising that competitiveness through significant increases in the cost of electricity would be deeply counterproductive in Victoria's efforts to maintain a vibrant and diverse economy.

The consultation paper proposes exempting Emissions Intensive Trade Exposed (EITE) businesses from Scheme costs. This is strongly preferable to no exemption, but does raise some important issues to resolve about the scope of exemption, its administration and its costs.

EITE is a well defined and familiar category established under Commonwealth legislation and regulations. It is used for exemptions from the Commonwealth RET and the NSW Energy Savings Scheme, and Ai Group has urged it as an option for use in administering an opt-in system under the Victorian Energy Efficiency Target (VEET). However, it is an imperfect category. It targets emissions intensity rather than just energy intensity; the intensity thresholds are somewhat arbitrary and exclude many activities with significant trade pressure, including food processing, foundries, wool scourers and others; and trade exposure has generally increased since the reference periods used to establish EITE status.

An alternative would be to base an exemption on the 100 terajoule energy threshold already used under the VEET to determine site-based exemptions. This covers many facilities that are trade exposed but not part of the Commonwealth EITE category. On the other hand, some facilities are not trade exposed at all and some EITE sites fall below the 100TJ threshold.

As we recommended for the VEET, the best approach is to exempt sites in both categories. In either case, the Commonwealth Clean Energy Regulator holds the data needed to determine who is exempt, and has a Memorandum of Understanding with Victoria. Neither network businesses nor energy retailers have access to this data, and therefore the Government will need either to maintain a publicly accessible list of exempt sites, to which network or retail businesses can refer, or – preferably – administer the exemption arrangements itself.

Government administration of the exemption would avoid the need for network businesses to attempt to estimate future demand from exempt sites. The Government could take two approaches to the costs of exemption to minimise complexity and impacts on energy users:

- Direct responsible network businesses to recover the full net cost of the Scheme from all customers, and provide a separate direct annual refund itself to exempt sites based on NGER data;

- Reduce the recoverable costs of the Scheme to reflect the exempt sites' consumption, and direct responsible network businesses to not pass remaining costs on to exempt sites.

The first option would minimise administrative complexity for responsible network businesses, though it could tie up significant sums for trade exposed businesses paying higher prices while awaiting refunds. Either approach would have a small net impact on the State Budget, but would also prevent the exemption from impacting unexempted energy users.

Other auction and contract design issues

We have further input on some of the additional questions raised in or inspired by the consultation paper and stakeholder discussions.

How can the Department ensure that a pipeline of projects will be ready to meet the Government's targets for 2020 and 2025 while maintaining appropriate flexibility for Government to adjust the scheme where required?

The main flexibility the Government will need is the ability to vary the size of future auction rounds up or down depending on progress towards targets; the ability to vary the characteristics of generation sought (region, expected generation profile, storage integration) based on transparently defined network stability requirements; and the ability to evolve the terms for future contracts to reflect updated developments, particularly with respect to Commonwealth policy. Signaling these as possibilities while providing an indicative schedule of future auctions and holding rigorously to the terms of contracts once signed should be sufficient to foster a project pipeline.

To maintain flexibility the Government should ensure that any legislation to facilitate the scheme does not include the targets, whether in the form of percentages, energy volume or generation capacity. The CfD structure already limits project proponent risks; locking in any version of the targets limits State flexibility without providing further confidence to proponents.

What proportion of scheme generation should be dedicated to solar projects?

While diversity of supply and building experience with large scale solar construction and operation are worthwhile objectives, we are doubtful that setting a hard minimum percentage of solar is worthwhile – or that the indicated 20% minimum is the right number. Solar costs are declining precipitously and there is every chance that solar will make up a high proportion of future renewable generation anyway. If solar does not prosper under the Victorian Scheme it will most likely be because Victoria's solar resource is less promising than its wind resource. If so, diversity of supply can come from other States where solar conditions are more favourable, and from storage and other local options if they are competitive. We do not support a sub-target for solar. The prospect of multiple auctions stretching over several years should give solar a substantial chance to compete.

Are there any other matters the State should consider when setting the scheme's technology split?

As argued above, storage and demand management are critical to price and supply stability in the largely renewable energy system the Government is targeting. While other reforms are best placed to drive these, as an alternative the Government could consider opening up the Scheme to contract for these technologies too.

What is the best way to treat LGCs under the scheme to enable successful proponents to secure project finance, ensure scheme costs are minimised and ensure adequate market interest from industry to participate in the auctions is attracted?

Leaving project proponents in possession of any LGCs from projects contracted pre-2020 seems the best approach. It seems likely that the de-risking nature of the CfD combined with revenue assessment against spot prices would make proponents much more likely to sell their LGCs on the spot market rather than sign offtake agreements. However, the reduced willingness of retailers to sign such agreements is one of the reasons why CfD is being considered. Government sale of the LGCs would seem significantly more likely to distort the market.

Judging LGC revenue by reference to individual proponents' offtake contracts might be an alternative to referencing spot prices, and could make it easier for proponents to put together packages that pass the Government's bankability requirement. However, it is also possible that such agreements could be underpriced to maximize revenue from CfD payments. Unless this can be avoided without intrusive verification, it is probably best to stick to spot prices.

What are stakeholders thoughts about complementarity/additionality if the Federal RET were extended/expanded?

This question highlights again the concerns we raised above about the complexity and scope for higher costs and unintended consequences involved in the layering of multiple State and Commonwealth policies for energy and climate.

While Commonwealth energy and climate policy is unstable and deeply unpredictable, there is a substantial chance that an expanded RET and/or a form of carbon pricing is introduced within the life of this Scheme (which could run to 2045 assuming contracts of up to 20 years). There could be two approaches to this.

- Do not make provision for new policy, but instead assume and assist the Commonwealth to ensure that any new policies take the Victorian contracts into account. For instance, if the Commonwealth introduced an extended RET it could provide that Victorian Phase Two projects were ineligible for support under the new Federal policy. This would contain national costs but leave Victoria bearing a larger share of them.

- Alternatively, all contracts could include catch-all provisions to the effect that any revenue from Commonwealth policies beyond the existing RET would be counted towards meeting the project strike price.

The latter may be preferable, since experience shows the dangers of assuming that another level of government will account properly for another level's policies.

Do stakeholders agree with the proposed CfD payment structure approach?

The basic CfD approach has been widely used overseas, as well as its successful but small-scale use in the ACT, and there is no reason to think that it cannot deliver the narrow but important goal of getting the targeted capacity financed and built.

If a CfD payment structure is used, on what basis should a NEM reference price be set? (e.g. monthly average, half hourly NEM price)?

Similar to the considerations about LGC price metrics above, the Government could choose to refer to specific power purchase agreements for projects that have managed to sign one. However this would raise similar issues about potential underpricing, and may be irrelevant given the unwillingness of many energy players to sign such agreements.

The use of monthly price averages to create incentives for project operators to locate and manage their projects to maximize half hourly revenue, and so follow energy market needs, is sensible.

What would be the impact of adding a floor price to cap the total payment applicable in any one period?

We support the concept of using a floor price on the energy revenue metric to moderate the incentive for projects to put energy into an oversupplied market. However since once a wind or solar project is built the marginal price of generating is zero, and since trends toward future oversupply may be hard to spot, proponents may generate anyway and may only be dissuaded from bidding where a clear point of supply congestion has emerged.

Do stakeholders agree that payments should be made under the scheme based on energy delivered as defined above? Are there other ways that stakeholders consider are possible to provide locational signals to projects to ensure they are appropriately sighted on the network?

Payment by energy delivered is sensible and will help ensure that strike price bids reflect the full costs of a given location. The need for clear management of renewables integration is so great, however, that it needs more than just modest signals within the value for money metric in the auctions. Instead the public agency that administers the auctions should consider needs across the NEM, in consultation with AEMO and others as necessary, and when appropriate it should communicate geographical or capability requirements that will serve either as qualifications for auction entry or as selection criteria for success.

Do stakeholders consider that any alternative payment structures could be employed for the scheme, such as a fixed payment approach? If so, what are the relative advantages and disadvantages of these options?

We do not support a fixed payments approach, which appears likely to increase risks for project proponents and inflate total costs to the State.

Are the above contract elements broadly appropriate?

The counterparty in contracts should be the public agency tasked with scheme administration, not a network business. The proposed elements are otherwise appropriate.

Within the contract range of 10 to 20 years, is there an ideal duration, particularly with the aim of minimising project financing costs?

20 year contracts are common overseas and will tend to minimise the project risk and hence lead to better financing and lower strike prices. While there is considerable uncertainty over future renewables technology costs and wholesale market prices, the unambiguous saving through lower strike prices is very likely to make the longer contract term worthwhile. This is particularly so for the Phase One capacity, which must be built anyway under the Commonwealth RET and should be made as inexpensive as possible.

What are the implications of a two-way CfD?

A CfD already contains the risks of project proponents. A one-way CfD would turn a contained risk into a one-way bet with the prospect of windfall gains encouraging excessive risk and placing it on the State. A two-way CfD limits the potential gains of proponents to reasonable levels and balances the risks to the State and electricity users. As argued above, the potential savings through two-way CfD should flow to users just as the costs do.

What do stakeholders think about the generation requirements being considered? Where maximum and minimum generation volumes are contained in scheme contracts how should these be set?

Maximum and minimum volumes are appropriate and should be set by reference to the expected capacity factor of the project, with an additional range to account for resource variability. A maximum could discourage proponents from potential future capital upgrades to increase the capacity factor of their projects. In such cases a contract variation could potentially be negotiated, lifting the ceiling but lowering the strike price in order to spread the value of the improvement to both parties.

Are there any other contract elements that should be considered?

As argued above, contracts should include catchall terms to the effect that additional revenue from any new Commonwealth policies, including an extended RET or carbon pricing schemes or similar, will be counted towards the strike price assessment.

What are the relative advantages and disadvantages of the different scheme administration and cost recovery options listed above?

Consistent with our argument above, the auction process and wider planning associated with it should be undertaken by a public agency, not a network business. The administration of an exemption for trade exposed sites should also be either entirely administered by government or based on information from government. Cost recovery via network charges is more practical than via retailers, but it is unclear why the Department prefers to use distribution businesses for this purpose rather than the single transmission business. The latter would appear to minimise overall administrative costs. Whoever is required to administer cost recovery, their own reasonable administrative costs should be recoverable.

What do stakeholders think of the proposed evaluation criteria set out above?

The multiple criteria reflect many legitimate values, but there is a substantial risk that they result in an opaque, unpredictable and seemingly arbitrary auction process. The value for money criterion is very important, but given network integration concerns it cannot be the sole concern. The answer may be to turn some criteria into minimum eligibility requirements, rather than evaluative criteria. For instance, economic development could be addressed through a requirement for an Australian industry participation plan or similar. Wholesale market participation, timely construction and community engagement can all be addressed through eligibility requirements and contract terms.

Contribution towards Victoria's targets should not be a criterion at all. The value for money criterion already gives proponents a strong incentive to maximize capacity factor, subject to impact on transmission and other costs. If projects that offer good value for money but low capacity factors do succeed in sufficient volumes to threaten the renewable percentage targets, future auction volumes could always be adjusted over time to compensate.

Interaction with network stability may be appropriate as a more evaluative criterion. Projects that offer integrated storage or other grid advantages should be preferred. However network stability should also be pursued through the framing of the auctions themselves – how much is sought, where and with what generation profile could be specified to a high degree based on network needs. In any case, the Government should make clear in the leadup to each auction the factors that assessment will have regard to.

Conclusion

We and our members would value further consultation on the approach to the initial phase of the Scheme, and even more so on the second phase. For any questions relating to this submission, the best contact at Ai Group is

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Yours sincerely,

Tim Piper
Head - Victoria