Centre for Energy and
Environmental Markets

CSIRO Future Grid – Cluster Project 4

Robust Energy Policy Frameworks for Investment in the Future Grid

Draft Milestone Report 5

by

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CEEM Milestone Report

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1 Introduction

1.1 CSIRO Cluster Project Background

The broad objectives of this CSIRO Cluster project are:

- The development and application of an interdisciplinary policy assessment framework to better understand and assess existing and proposed policy options for driving appropriate investment in the electricity industry given its unique technical (e.g. system security), economic (e.g. network investment) and wider social (e.g. affordability imperatives) characteristics. A key focus is on the interactions between these policies.
- Development of a high level (ie. focused on broader policy relevant perspectives rather than just detailed technical and economic modelling) quantitative policy analysis tool for exploring the potential impact of different policies on the most economic future electricity generation portfolios.
- Application of this policy assessment framework and quantitative policy analysis tool to develop high level insights on coherent and comprehensive climate and energy policy frameworks to drive appropriate investment in the future grid. A particular focus is on maximising the synergies and minimising possible conflicts between multiple policy instruments such as might be seen with renewable energy targets and network investment drivers.

1.2 Scope of this analysis

This analysis is the fifth deliverable Milestone analysis for the CSIRO Future Grid project from the University of New South Wales. It is intended to cover the following topics:

- Finalised extensions to quantitative modelling tool
- Preliminary findings for policy design frameworks

2 Extensions to quantitative modelling tool

2.1 Price and revenue modelling

Extensions to the quantitative modelling tool

The recent focus for extensions to the quantitative modelling tool has been on replicating market pricing and revenue outcomes in the electricity market, with a particular focus on scenarios with high renewable generation.

Background

Given falling solar and wind energy technology costs and growing concerns over climate change and energy security, future electricity industries seem likely to feature a growing proportion of highly variable renewable generation. For restructured electricity industries with competitive market arrangements, the high capital yet low operating costs (short run marginal cost or SRMC) of these technologies poses some interesting challenges. In particular, growing penetrations of low SRMC renewable generation in energy only wholesale markets are likely to reduce spot electricity prices and hence market returns to all generators. The risk of insufficient revenue to recover both fixed and variable operation costs is one of the major concerns for generators. Concerns around revenue sufficiency are also shared by many policy makers and market regulators given that this might lead to resource adequacy challenges by promoting early retirement and deferred entry to the market [1, 2].

The Australian NEM provides an interesting case study for analysis of high renewable scenarios, including their revenue implications. Previous studies have explored the technical feasibility and economics of high renewable scenarios in the NEM, including scenarios of 100% renewable energy [3, 4]. These studies, however, have not considered directly revenue implications. Meanwhile, some observers have raised questions about the feasibility of the NEM's energy-only market design in high renewable scenarios, including claims that a system composed of a majority of low SRMC generation may not deliver appropriate commercial incentives for assured resource adequacy [5].

Approach

The quantitative modelling tool was extended to calculate market prices and generator revenues on an SRMC basis (assuming a competitive market). The model was then applied to explore these issues within a possible future Australian NEM with high wind and PV penetrations. In particular, the study provides a quantitative analysis of spot market prices and generator revenue sufficiency within such an industry, with a view to assessing the viability of the present energy-only market and its mechanisms to ensure resource adequacy and hence long-term reliability.

Scenarios considered

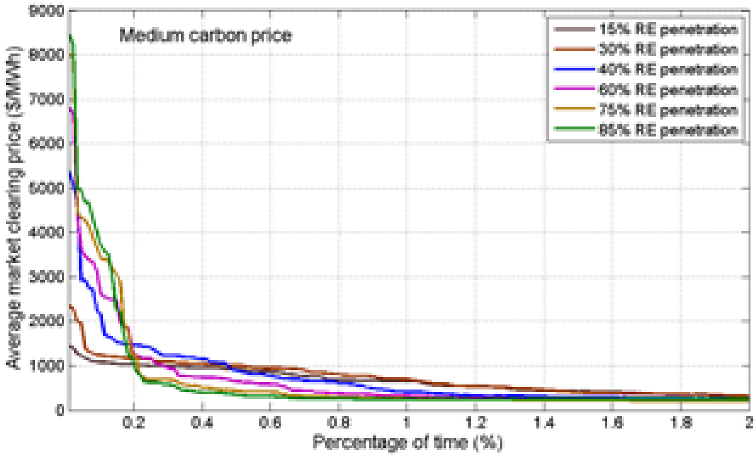
One of the significant strengths of the quantitative modelling tool is that it explores hundreds of different generating portfolios, under thousands of possible combinations of conditions of future carbon prices, fuel prices and demands.

For this case study, six different renewable scenarios for the NEM in 2030 were considered: 15%, 30%, 40%, 60%, 75% and 85% penetrations, by energy. Each of these generating portfolios was modelled with different proportions of the other technologies included (coal, CCGT, and OCGT). These scenarios are therefore most similar to the CSIRO Future Grid scenarios "Renewables Thrive" and "Set and Forget", although a much wider range of scenarios was considered than these two alone.

Results and Discussion

As the amount renewables increases, the annual average price was found to reduce due to the low operating costs of wind and PV generation. However, the magnitude of price spikes is found to be greater with high renewables. The average price duration curve for each renewable percentage is illustrated in Figure 1.

Figure 1 - Average market price duration curve for the top two percent of periods



The reduction in spot prices results in reduced revenue and profit of generators and potentially leads to insufficient revenue. The revenue impacts on large-scale PV are very severe at high renewable penetrations. Changes in market mechanisms (such as a higher market price cap) are likely to be required to ensure long-term resource adequacy and revenue sufficiency in an energy only market.

Future work will aim to explore the magnitude of the MPC that may be required to support a high renewable market.

Collaboration

This work has been accepted for presentation as a conference paper at the 38th IAEE (International Association for Energy Economics) International Conference, to be held in Antalya, Turkey on 25-27 May 2015. The conference paper outlining full details of the work is included as an attachment to this report:

- P. Vithayasrichareon, J. Riesz, I. MacGill, "***Market Pricing and Revenue Outcomes in an Electricity Market with High Renewables – An Australian Case Study***", IAEE International Conference, Antalya 2015.

2.2 Gas generation modelling

Background

While there is growing agreement on the need to decarbonize the global electricity industry there is far less consensus on the most appropriate generation technologies to achieve this. For many countries, the most immediate options would seem to be increased gas-fired generation or renewables. A key question, then, is how gas and renewables might complement, or perhaps compete with, each other towards a low carbon electricity industry future.

This case study compares different possible future generation portfolios including varying quantities of gas-fired and renewable generation. Comparisons were conducted on the basis of expected costs, cost risk and greenhouse gas emissions.

Approach

The Monte-Carlo based generation portfolio modelling tool was applied to take into account the effects of highly uncertain future gas prices, carbon pricing policy and electricity demand.

Input assumptions were based upon widely accepted Australian government estimates of future technology costs, electricity demand, fuel costs, and carbon prices, including and their associated uncertainties. Geographically dispersed hourly wind and photovoltaic generation profiles based on historical weather patterns over a year were used to account for aggregate renewable generation variability, and its correlation with demand.

Scenarios considered

Outcomes were modelled for 396 possible generating portfolios in 2030 and 66 possible generating portfolios in 2050, each with 10,000 simulations of possible fuel prices, carbon prices and electricity demands.

As for the previous case study, six different renewable scenarios for the NEM in 2030 were considered: 15%, 30%, 40%, 60%, 75% and 85% penetrations, by energy. Each of these generating portfolios was modelled with different proportions of the other technologies included (coal, CCGT, and OCGT). These scenarios are therefore most similar to the CSIRO Future Grid scenarios “Renewables Thrive” and “Set and Forget”, although a much wider range of scenarios was considered than these two alone.

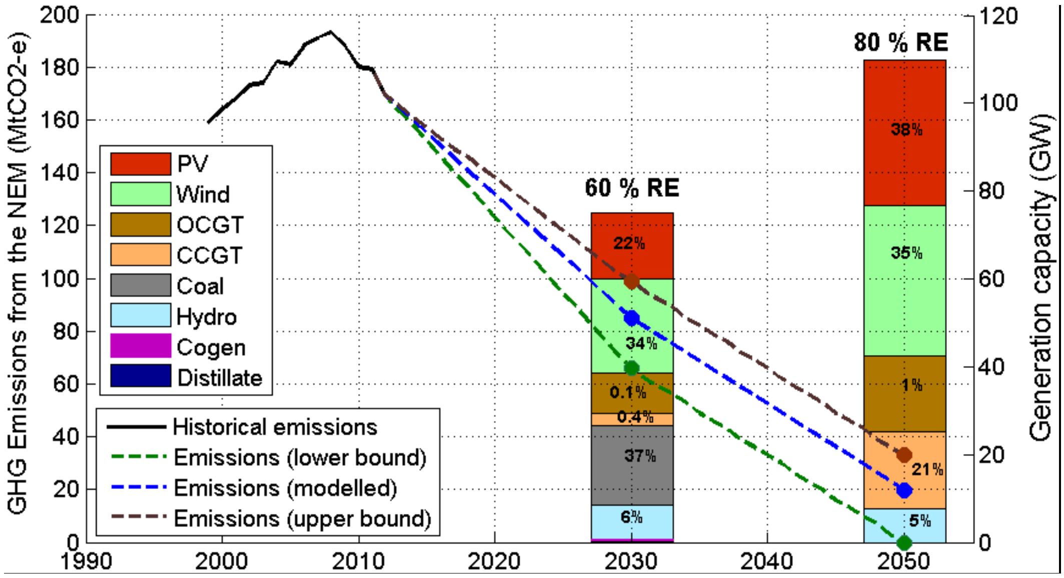
Results

Results indicate suggest that portfolios sourcing significant quantities of energy from gas-fired generation in 2030 and 2050 are likely to be significantly higher cost and significantly higher risk than the other alternatives considered. High gas portfolios also do not achieve the greenhouse gas (GHG) emissions reductions levels that appear required to avoid dangerous global warming. For example, portfolios that source 95% of energy from gas-fired generation in 2050 experience expected generation costs that are $65/MWh (40%) higher than portfolios that source only 20% of energy from gas-fired generation. These high gas portfolios also exhibit a cost risk (standard deviation in cost) that is three times higher. The lowest cost portfolios in 2050 source less than 20% of energy from gas with the remaining energy sourced from renewables.

Even in the absence of a carbon price, the lowest cost portfolio in 2050 sources only 30% of energy from gas-fired generation, with the remaining 70% of energy being sourced from renewable technologies. Approximately half of the installed gas-fired capacity in this portfolio is peaking OCGT plant, providing firm capacity without significant quantities of energy. This suggests that investment in gas-fired plant is likely high cost and high risk, even in the absence of any expectation of a carbon price.

Results suggest the optimal strategy for minimising costs, minimising cost risk and reducing GHG emission levels in future electricity markets industries may well involve minimising energy sourced from gas, and increasing renewable generation. In the Australian context, for example, it seems appropriate to target renewable energy penetrations approaching towards levels around 60% of energy by 2030 and 80-100% by 2050, as illustrated in Figure 2. In the lowest cost and lowest risk portfolios, firm capacity is provided primarily by the transition of existing coal-fired plant into a peaking role, and later by further investment in peaking open cycle gas turbine plant. These results are found to be robust to a wide range of assumptions around future carbon prices.

Figure 2 - GHG emissions trajectories for the Australian NEM in the proportions of national targets recommended for Australia by the Climate Change Authority (upper and lower bounds), with lowest cost portfolios that meet the targets in 2030 and 2050. Percentages indicate the % of energy supplied by each technology.



Collaboration

This work has been accepted for the journal *Applied Energy*; the complete submitted manuscript is provided as an attachment to this report:

- J. Riesz, P. Vithayasrichareon, I. MacGill, "***Assessing "Gas Transition" pathways to low carbon 1 electricity – An Australian case study***", accepted for Applied Energy, 2015.

This work has significant cross-over and relevance to the modelling and work being conducted by the P2 and P3 groups on gas markets and gas network optimisation.

2.3 Impact of Operational Constraints on Portfolio Planning with Renewables

Extensions to the quantitative modelling tool

The quantitative modelling tool was examined for applicability of modelling high renewable systems, by considering the impacts of operational constraints in the modelled scenarios in a time sequential PLEXOS tool.

Background

Increasing variable renewable generation penetrations will cause increased cycling operation for conventional generating plants. Not all of these plants are necessarily well suited to such operation. Traditional long-term generation planning frameworks often neglect these operational characteristics and therefore do not reflect the operational constraints and costs associated with cycling of generating plants.

This case study examines the impact of short-term operational characteristics on generation portfolios obtained under a long-term portfolio planning modelling. These include start-up costs, minimum generation levels, ramp rate limits and synchronous generation requirements.

Approach

The quantitative modelling tool was used to develop a series of least cost generating portfolios of interest, at different levels of renewable generation. However, since this tool does not apply a time sequential approach, it could not be used to assess many important operational characteristics. To understand the influence of these operational constraints (such as ramp rate limitations, minimum operation levels, and start-up costs) a detailed generation dispatch model in PLEXOS was applied. The PLEXOS model was used to assess the potential impact of short-term operational constraints and costs on future high renewable generation portfolios obtained from the long-term portfolio planning framework.

This modelling was important to understand the degree to which operational constraints may limit the applicability of the quantitative modelling tool to high renewable systems.

Scenarios considered

As for the previous case studies, six different renewable scenarios for the NEM in 2030 were considered: 15%, 30%, 40%, 60%, 75% and 85% penetrations, by energy. Each of these generating portfolios was modelled with different proportions of the other technologies included (coal, CCGT, and OCGT). These scenarios are therefore most similar to the CSIRO Future Grid scenarios "Renewables Thrive" and "Set and Forget", although a much wider range of scenarios was considered than these two alone.

Results

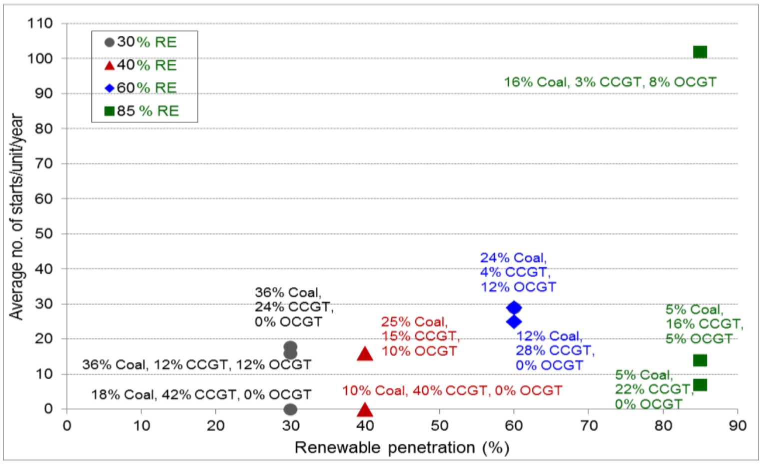
Results from the case study with different levels of renewable penetrations in 2030 suggest that the inclusion of start-up costs, minimum generation and ramp rate constraints do not have a significant cost impact on generation portfolios obtained using a long-term portfolio planning framework that does not include these factors. While there are shifts in the amount of generation dispatched, ultimately the total annual cost does not change by more than 2%, even under very high (85%) renewable penetration.

These results suggest that the technical and cost impacts associated with the operational constraints modelled are moderate even at high renewable penetrations. This indicates that the results obtained from the quantitative modelling tool (which do not take these more detailed operational constraints into account) are likely to remain relatively accurate, even at very high renewable penetration levels.

The synchronous generation requirements were found to result in significant increases in generation costs, particularly at high renewable penetrations and carbon prices. However, the synchronous generation requirements have been included in the quantitative model (since this constraint does not rely upon time sequential modelling). This therefore indicates that the quantitative model adequately captures the most important operational constraints.

Generally, coal and gas plants are found to experience more frequent cycling operation (ramp up/down and starts/stops) with higher renewable penetration levels. However, the number of unit start-ups appears technically feasible except for some portfolios with high renewables and a high share of coal capacity, where coal units face up to 100 starts per year, as illustrated in Figure 3. This suggests that coal plants may need to increase their flexibility to withstand increased cycling in low-carbon and high renewable futures, if a high proportion of coal plant is to remain in the market in the future.

Figure 3 - Average number of coal starts per unit per year in a range of portfolios for different renewable penetrations. Percentages indicate the proportion of installed capacity that is coal, CCGT and OCGT.



The impacts of the operational constraints modelled depend particularly on the level of carbon price and the mix of generation technologies within the portfolio.

Collaboration

This work has been accepted for presentation at the IEEE Power and Energy Society (PES) General Meeting, to be held in Denver in July 2015. This opportunity for presentation of the work in an important international context should lead to insights on how to improve and extend the analysis conducted. The full conference paper accepted for presentation is included as an attachment to this report:

- P. Vithayasrichareon, T. Lozanov, J. Riesz, and I. MacGill, "***Impact of Operational Constraints on Generation Portfolio Planning with Renewables***", IEEE PES General Meeting, Denver, 2015.

This work would seem to have particular relevance for the P1 group, since many of the impacts of high renewables systems could relate to dynamic, short term effects.

2.4 Impacts of Electric Vehicles and Solar PV on Portfolio Investment

Extensions to the quantitative modelling tool
The quantitative modelling tool was extended to include the impacts of electric vehicles and photovoltaics in combination.

Background
This case study examined the potential impacts of EVs and PV deployment on the future overall industry costs, associated cost uncertainties and CO2 emissions of different generation portfolios. The quantitative modelling tool was used to assess the expected overall industry cost, associated cost uncertainty and CO_2 emissions of future generation portfolios where EVs and PV generation have both achieved major deployment. Potential synergies between PV generation and managed EV charging were assessed.

The Australian National Electricity Market (NEM) was used as a case study under uncertain future fuel and carbon prices, electricity demand and plant capital costs.

Approach
The Monte-Carlo based portfolio modelling tool was used to assess the expected overall industry cost, associated cost uncertainty and CO_2 emissions of future generation portfolios where EVs and PV generation have both achieved major deployment.

Scenarios considered
Two EV charging scenarios were considered:

- ***Unmanaged charging*** which commences immediately as the EVs arrive at suitable charging infrastructure and
- ***Managed charging*** where EV charging loads are managed so that they better align with PV output.

These scenarios are likely to have broad similarities with the CSIRO Future Grid scenarios "Rise of the Prosumer", "Set and Forget", and "Renewables Thrive".

Results
Results show that there are potentially valuable synergies between PV generation and EV charging demand in minimizing future electricity industry costs, cost uncertainties and emissions, particularly when EV charging loads can be managed. The value of PV generation and managed EV charging is greater for higher EV fleet size and moderate carbon prices.

EV charging management to better align EV charging demand with PV output is found to be valuable as a means to maximise benefits and minimize costs associated with high EV and PV penetrations in future electricity industries. Although EV charging is found to increase overall costs and emissions for the electricity industry, such increases can be reduced through PV generation, particularly when EV charging is managed to align with PV output. With such EV charging management, the system can accommodate higher EV uptake without significant additional conventional generation capacity since EV charging demand can be satisfied by daytime PV output. In addition, the capacity factors of conventional generators that were operating at part load can be improved as a result of daytime EV charging. By contrast, unmanaged EV charging demand is highest during evening peak demand periods, resulting in higher system peak demand. This leads to higher industry costs and emissions due to the considerable amount of additional capacity required and increased output from conventional plants. The value of PV in the presence of managed daytime EV charging becomes more apparent as EV fleet size increases.

These results also highlight the important role of carbon pricing in improving the economic merit of PV, and subsequently the value of EV uptake in the presence of managed daytime charging. Without a carbon price, adding more PV is likely to increase overall industry costs due to its high capital cost, despite significantly reducing CO2 emissions and cost uncertainty. With moderate carbon prices starting from around $50/tCO2 however, increasing PV penetration results in cost reductions, particularly for larger EV fleet sizes. As the carbon price increases, the share of coal in the optimal portfolios is also reduced as a result of its high carbon costs.

While the EV modelling indicates that sufficient load flexibility exists to significantly align EV charging with PV output, examining the issues associated with such an arrangement (including direct control and tariff measures) represent an area of future work. Note that while the use of LDC techniques has many advantages in generation planning, the chronology of demand, solar generation, and EV charging load is only partially captured. As such, the simulation tool used in this study is best suited to assess long run societal investment costs and risks under high uncertainty, rather than problems requiring detailed operational modelling. Addressing these limitations represents another possible area for future work.

Collaboration

This paper has been accepted for *IEEE Transactions for Sustainable Energy*:

- P. Vithayasrichareon, G. Mills, I. MacGill, "***Impact of Electric Vehicles and Solar PV on Future Generation Portfolio Investment***", accepted for *IEEE Transactions for Sustainable Energy*, 2015.

The full paper is included as an attachment to this report.

3 Policy Design Frameworks

This Milestone Analysis focuses on four case studies relevant to policy design frameworks:

- An analysis of international transmission development frameworks, undertaken in collaboration with a CIGRE working group.
- An analysis of capacity market design, undertaken in collaboration with colleagues based in Europe.
- A case study of the potential impact of electric vehicles on future grids, undertaken in collaboration with Beyond Zero Emissions. This analysis aims to quantify a viable upper limit for the potential uptake of electric vehicles, and determine the impact of this upon electricity grids.
- A direct response to the Energy White Paper, detailing insights around policy design frameworks relevant for this specific policy development process.

These are outlined in the following sections.

3.1 International review of transmission frameworks

Background

Large transmission infrastructure investments are needed in many power markets in coming years for various reasons such as cross-border market integration, increase of demand, integration of new generation, or security of supply improvement. In this context, the achievement of efficient power systems, from operational and planning perspectives, requires effective coordination, both horizontally (coordinating investment between neighbouring grids) and vertically (coordinating generation and transmission investments). This case study involves a review of international frameworks for transmission development, with a view to understanding those designs that are likely to be more efficient.

Approach

This case study presents an extensive review of market and regulatory frameworks for transmission and generation investment coordination from about 15 areas or countries, distributed over all continents.

These frameworks are not only surveyed on a local basis but include also broader regional and transnational arrangements. A questionnaire was prepared by Cigré WG C 5-18 and sent to all Cigré members in SC C5. Analyzing the responses, the paper discusses different organisations for transmission planning and investments, generation connection policy and network tariffs.

The paper also discusses the current reform process in transmission investment coordination in different countries or regions. Specifically, as concerns horizontal coordination we discuss the European Infrastructure Regulation and FERC Order 1000. Regarding vertical coordination, the paper compares OFTO (Offshore Transmission Regime) in Great Britain and HVDC offshore wind connection in Germany, and presents OFA (Optional Firm Access) in Australian NEM.

Results

Many players are found to be involved in the process of transmission development, including network owners and operators, generators, States (government / parliament) and regulatory authorities. Various organisational models are currently implemented worldwide, ranging from Vertically Integrated Utility to unbundling of electric utilities.

Concerning networks in unbundled systems, several organisations are possible: basically in the TSO model the transmission system operator is the owner of the network, whereas in the ISO/TO model there is possible combination of independent system operator and network owners. Finally, the inclusion of third party / merchant operators is more or less developed depending on local regulation.

According to the local context, the role of these players and the mechanisms implemented strongly varies across areas. Mechanisms range from regulation to market-price signals, from regulatory approval of investments to competitive tenders, and can be facilitated by approaches such as central planning, locational price or network tariff signals, cross-border compensation mechanisms and special regimes for connection of offshore RES generation.

Collaboration

CEEM contributed to this collaborative work with an international working group within CIGRE. Through this group, CEEM contributed to the development of a conference paper that will be presented at the CIGRE Symposium to be held in Lund, Sweden, in May 2015:

- F. Regairaz, M.R. Hesamzadeh, A. Di Caprio, A. Balkwill, F-P. Hansen, J. Riesz, "***Market price signals and regulated frameworks for coordination of transmission investments***", CIGRE Symposium, Lund, Sweden, 2015.

This paper is provided as an attachment to this report.

3.2 Capacity Market Design

Background

Resource adequacy in electricity markets refers to the mechanisms that manage the capacity of installed generating technology, and the adequacy of that generation to meet anticipated demand. Electricity markets around the world are currently facing new pressures that exacerbate challenges around market mechanisms for maintaining resource adequacy. Plateauing or reducing demand in many nations is combined with policies intended to drive investment in renewable and other clean technologies, many of which have highly variable availability (such as wind and solar photovoltaics). Both of these factors are likely to create a more challenging investment environment, with less certainty around the future market revenues that drive investment in new generation.

For this reason, many jurisdictions are considering moving towards more explicit capacity remuneration mechanisms to increase investment certainty (including France, Germany, Great Britain, Italy and others). These mechanisms are intended to operate alongside markets trading wholesale energy. This makes it an important time to provide improved frameworks for making decisions about the design of capacity markets. Furthermore, in the European context, the emergence of a multitude of different market designs within individual countries in an interconnected electricity market raises questions with regards to the possibility of cross-border participation, market integrity and compliance with EU trade and state aid regulations.

Approach

The process for making key design choices was analysed in markets where a fundamental change in market design is being or has been considered. A two-tiered classification framework was developed, aiming to capture key design choices and provide a starting foundation for considering capacity market design questions. This framework was applied to a number of capacity markets in operation or under consideration in Europe, namely France, Germany (where different design options are discussed at the time of writing), Italy and the United Kingdom. Besides discussing the respective design choices made or under consideration, special attention was given to issues such as cross-border participation of generators situated in neighbouring countries (both EU and non-EU).

Results

Three key design choices were identified as being fundamental in defining the distinguishing features of various capacity market designs. These were defined as "first tier" design choices. Other design choices will also be significant in determining how the mechanism operates, but do not differentiate between common models; these were classified as "second tier" design choices.

Collaboration

This design framework was initially developed in collaboration with an International CIGRE working group. It has since been used as a foundation for a workshop on the Swiss market design, held at Zurich University in February 2015 by CEEM colleagues and collaborators. This work has also been accepted as a conference paper, for presentation at the 38th IAEE International Conference to be held in Antalya, Turkey, in May 2015:

- J. Riesz, G. Thorpe, Regina Betz, Johanna Cludius, "***A framework for designing and categorising Capacity Markets – Insights from an Application to Europe***", Accepted for presentation at the 38th IAEE International Conference, Antalya, Turkey, May 2015.

This paper is provided as an attachment to this report.

3.3 Insights into policy design frameworks in response to the Energy White Paper Process

Background

The Energy White Paper process provides a valuable case study for analysing the policy design frameworks being implemented at present. CEEM has been actively participating in this process, providing responses to Government intended to guide improved outcomes.

Key insights

Energy policy has a vital societal role and will invariably require ongoing efforts given changing priorities and other drivers. Proper integration of policies is also essential – within the inevitably large number of policy measures and instruments that will be required to drive appropriate development of the energy sector, and also the broader policy context of related areas including climate change, transport and regional development policy.

Unfortunately, the Green Paper did not provide clear guidance on how such integration will be achieved. It will require prioritisation of objectives and detailed analysis of the potential interactions – synergistic and adverse – that may occur between policies. Such analysis should also focus on policy framework robustness so that essential objectives are achieved regardless of the potential failure of particular, novel and hence unproven, policy measures.

Another area requiring integration is that of policy coherence and consistency over time. The Green Paper has emerged within the context of a decade long series of efforts to respond to emerging economic development, energy security and climate change concerns. This includes two previous Energy White Papers in the past decade. However, the Green Paper made very little effort to integrate the learnings of these efforts, or explain why changes to them are required.

The previous energy white paper process was particularly drawn out but did, in 2012, deliver a comprehensive energy policy framework. The International Energy Agency commended the work in its 2012 review of Australian energy policy noting that: "The IEA welcomes the publication of the Draft EWP and commends the open, inclusive manner of its preparation."

While some elements remain in the Green Paper, others do not; notably the prioritisation of clean energy transformation in the earlier document. The reasons for this have not been made clear in the current paper. The risk, of course, is that we continue to see policy making undertaken without a clear understanding of where and why some previous policy plans and efforts are no longer considered appropriate. Without such understandings, our ability to develop effective, efficient, equitable and robust energy policy is severely hampered.

Contributions

The response to the recent Energy Green Paper, submitted in November 2014, is included as an attachment to this report. CEEM was invited to participate in a forum held at the Australian National University following the release of the White Paper. A/Prof. MacGill's presentation focussed on three key points:

- The White paper failed to reconcile its market oriented framework – notably "*Investment decisions on future generation assets, including choice of technology, are best made by industry, given its insights into market needs. The Australian Government will seek to maintain stable and predictable policy settings across the range of areas that affect such investment decisions, while taking a technology-neutral approach.*" – with the scale and speed of change required to address our national and international energy challenges, and effective risk management and allocation. In particular, investor certainty in an uncertain world doesn't manage risk but just reallocates it onto public. Also, there are the market inefficiencies associated with unpriced environmental and social market 'externalities.
- There is a welcome focus on the customer – notably "*…development of market frameworks to encourage innovative products & services that give consumers more choice in managing bills & support greater competition*"; also "*Regulation should generally encourage competition & consumer choice, not stifle it*" However, there is insufficient attention to the reality that incumbents will generally prefer less competition, while there are limits to the interest, motivation, knowledge and capabilities of many energy consumers. They will, therefore, require protection and facilitation to support meaningful engagement. Also, current measures of competition are inadequate; in particular, does 'churn' and market offer 'spreads' reflect competition or the absence of it? Shared choices are important too; including for example, questions of renewable energy policy and further electricity industry privatization.
- The focus on improving energy productivity was also welcome, but requires greater coherence with market reform. In particular, the White Paper acknowledges that "*Artificially low domestic prices do not encourage gas users to use gas more efficiently or encourage innovation in the use of alternative fuels and processes.*" Which is also undoubtably true but also surely applies to electricity which is currently seeing artificially low domestic prices given unpriced externalities including but not limited to greenhouse gas emissions. Furthermore, energy productivity requires clearer definition – in particular, is it to be considered the economic value derived through energy use compared against energy costs, or energy consumption?

In conclusion, CEEM analysis suggests that the Energy White Paper is largely a 'to do' list of government priorities rather than a vision and long-term planning framework for Australia's energy future. There are opportunities to focus more on longer-term planning including detaching the process from the political cycle, undertaking broader and ongoing stakeholder engagement, exploring a wider range of scenarios including robustness testing, and leveraging ICT advances to support an ongoing dialogue as new inputs emerge (eg. NESA), circumstances change and policies are implemented.

3.4 Potential impact of Electric Vehicles on Future Grids

Background

This case study aims to explore potential uptake of electric vehicle technologies, including personal vehicles and buses, and therefore quantify the maximum impact that this may have upon electricity grids in future. The aim was to develop an upper limit scenario for comparison with business as usual, to allow quantification of the potential challenges that may arise with a rapid shift to electric vehicles, should this occur in the near future.

There are a number of electric vehicle technologies in use today requiring various degrees of support and augmentation from petrol engines. These include:

- Battery electric vehicles (BEVs or simply EVs for the purpose of this analysis), which are fuelled solely by electricity from a rechargeable battery
- Hybrids, which use a petrol engine and a battery system;
- Plug in hybrids, which top-up the battery with mains power; and
- Petrol-electrics, which can operate like a battery EV, but with a petrol generator on stand-by to extend the vehicle range)

This analysis focuses upon a shift to battery electric vehicles, since this technology is solely reliant upon electricity for fuel, and will therefore have the maximum potential impact upon the electricity grid.

Approach

A spreadsheet model was developed to project the number of private vehicles and buses that may be required from 2015 to 2035, and calculate the costs and electrical load associated with a transition to 100% electric vehicles by 2025.

Scenarios considered

Two scenarios were considered:

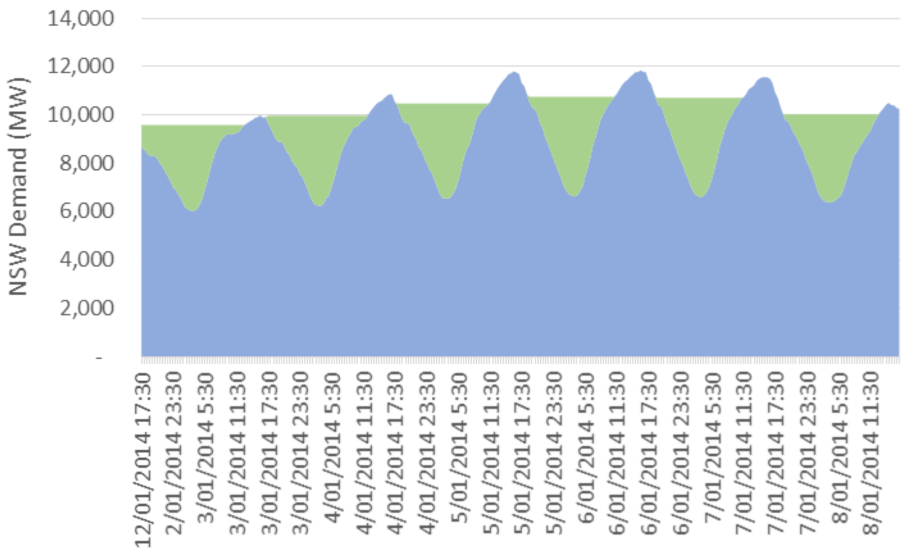
- A "business as usual" scenario which continues the use of internal combustion engine (ICE) vehicles
- A rapid transition scenario, which assumes a shift to 100% electric vehicles by 2025.

Results

The scenario modelled in this analysis would require an increase in electrical generation of 43 TWh per annum by 2025, and 45 TWh by 2035, to supply sufficient EVs and electric buses to replace the entire Australian fleet. This would be an increase of 18% from the present total Australian electricity generation of approximately 255 TWh per annum [1].

It is likely that this amount of additional electrical load can be accommodated by the present electricity system with minimal augmentation of the transmission system and generation system. Figure 4 illustrates the amount of additional electrical load from EVs and electric buses for New South Wales and the ACT, superimposed on a week of typical high electrical demand in January 2014. Assuming that charging can be managed through mechanisms such as time of use tariffs or direct load control by the system operator, the additional charging load can be accommodated entirely during off-peak periods (a "trough-filling" approach). This means that minimal further transmission infrastructure and generating infrastructure would be required to accommodate this additional load. Furthermore, the addition of this electrical load would serve to improve network utilisation, reducing network tariffs for customers. Similar results were found for other regions.

Figure 4 – Illustration of increased electrical load in New South Wales due to EVs and electric buses in 2035



This analysis emphasises the finding of previous studies that implementation of managed charging is very important for minimising electricity grid impacts. Significant uptake of Level 2 charging in homes could necessitate significant upgrades to electricity distribution grids, if the charging of EVs is not managed in any way. However, implementing time of use incentives such as those already offered for home water heating may be able to largely ameliorate this effect, and as indicated above may serve to improve electricity network utilisation [2]. Distribution network impacts requires further analysis, and will need to be assessed on a local area basis.

Collaboration

This work has been developed in collaboration with a transport consultancy (MRCagney), and the non-profit organisation Beyond Zero Emissions. A draft of the work summarising modelling outcomes is provided as an attachment to this report.

4 Conclusion

We look forward to receiving feedback from the CSIRO and the Industry Reference Group on this analysis, and guidance on future work under the Future Grid Project.