March 2014

Issue 16

2014 RET Review and its Impact on the National Electricity Market

Introduction

Amidst declining electricity demand, strong participation from households and businesses in energy efficiency and distributed energy sources such as solar PV, solar hot water heaters, and small-scale wind, the National Electricity Market (NEM) is undergoing an unprecedented transformation.

The Large-scale Renewable Energy Target (LRET), as the principal policy to promote large-scale renewable energy forms such as wind, large-scale, solar PV and solar thermal, hydro and geothermal, has been the crucial factor driving investment decisions in utility-scale renewable energy projects in Australia.

In particular, wind farms have proliferated in the NEM, with some 3,100 MW of installed capacity entering the market to date. Together with hydro capacity, large-scale renewable generation makes up over 23% of total generation capacity in the NEM.

In view of the current discussion on the future of the RET within the Coalition Government and among political parties, the forthcoming RET review could have a profound impact on Australia's renewable energy industry.

Given the likelihood of a reduced LRET, the industry is anxiously searching for answers such as:

- *"What will the NEM look like under a reduced LRET going forward?"*
- *"What are the implications for investments in large-scale renewable projects in the NEM under a lower target or abolition of the LRET?"*
- *"Could large-scale renewable energy projects stand on their own feet in absence of LRET?"*
- *"How will energy companies in the NEM adjust their business strategies as a result of this change?"*

IES Advisory Services (IES Advisory) has undertaken electricity market modelling to assess some of the impacts that changes to LRET may have on the NEM under different policy settings, with a particular focus on what might occur if the LRET is revised down to 20% of electricity demand or scrapped entirely from 2015.

We provide some analysis into the NEM's generation mix, wholesale electricity prices and LGC prices and endeavour to answer these questions.

Scenarios on 2014 RET review

Based on the current discussion around the 2014 RET review, we have considered three different scenarios:

1. LRET maintains the current 41,000 GWh target by 2020;
2. LRET is revised down to 20% of electricity demand by 2020 (estimated to be around 26,400 GWh); and
3. RET is scrapped from January 2015.

Scenario 1 is the base case where existing policy remains unchanged, including the assumption that carbon prices will continue in their currently legislated form. In contrast, scenario 2 (referred to as the "20% LRET scenario") and scenario 3 (referred to as the "0 RET scenario") have zero carbon prices to illustrate the impact on the NEM of potential LRET and carbon price changes between 2015 through to 2024.

To emphasize the effect of LRET changes we have modelled three scenarios with the following assumptions remaining unchanged:

- Electricity demand based on the medium planning scenario published by AEMO in November 2013;
- Technology costs; and
- Fuel costs, including coal and gas prices.

Table 1 summarises the main assumptions made in our NEM market simulations.

Table 1 Key electricity market simulation assumptions (2015 to 2030)

Inputs	Scenario 1	Scenario 2	Scenario 3
LRET	41,000 GWh by 2020	26,400 GWh by 2020	scrapped from 2015
SRES	Maintain as current	Maintain as current	scrapped from 2015
Carbon Prices	Treasury core scenario	0 from 1 July 2014	0 from 1 July 2014
Fuel costs	Sourced from IES Advisory	same as Scenario 1	same as Scenario 1
Technology costs	Sourced from IES Advisory	same as Scenario 1	same as Scenario 1
Demand forecasts	AEMO Nov 2013 and 2013 NEFR Planning scenario forecasts	same as Scenario 1	Scenario 1 demand forecasts + 50% solar rooftop PV forecasts

Source: IES Advisory, AEMO

For scenario 3, 50% of solar rooftop PV forecasts is added to the demand forecasts to demonstrate the impact of the scrapping of the RET, including SRES and LRET.

It has also been quoted that the LRET would be cut down to 10% of electricity demand (estimated to be less than 10,000 GWh). The impact of this on the prospective large-scale renewable investments will be similar to that of the 0 RET scenario as the current LGC-eligible generation already exceeds 12,000 GWh.

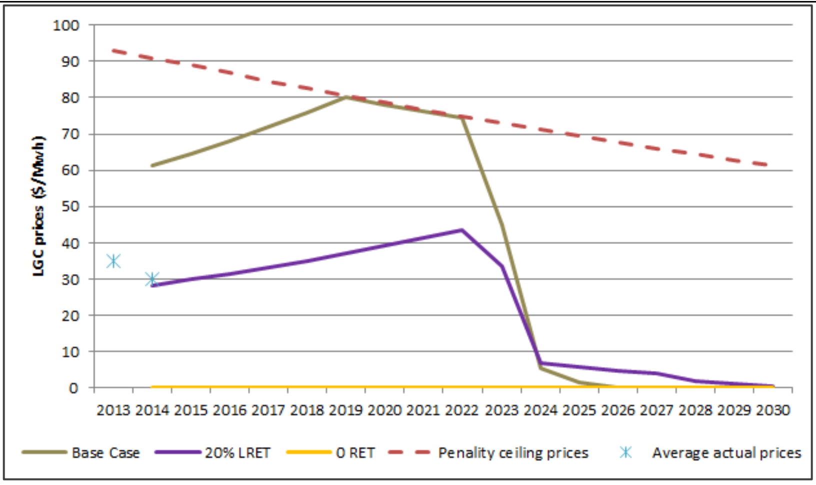
LGC Prices and Our Price Projections

Uncertainties around the 2014 RET review and carbon prices have been reflected in LGC prices in the last few months. Prices have dropped from $35 per certificate in July 2013 to around $30 per certificate in January 2014, sitting well below the forecast price of $61 if the LRET retains its 41,000 GWh target and the current legislated carbon policy continues (base case), and on par with the forecast price of $29 if the LRET reduces to 20% of electricity demand and the carbon tax is successfully repealed by 30 June 2014 (20% LRET scenario).

LGC forward prices, estimated by various broking firms, match rather closely with the price trajectory of the 20% LRET scenario, signalling that the market is taking the view that a revision of the LRET to 20% of electricity demand will be the most likely outcome from the 2014 RET review.

Figure 1 illustrates the forecast LGC prices under three different scenarios.

Figure 1 LGC price projection – 2013 to 2030



Source: IES Advisory

LGC prices have also been suppressed by the excessive number of banked LGCs since the split of LRET and SRES in 2011, of over 20 million at present.

Drawing down 4 million banked LGCs per annum, LGC prices under the base case will reach the penalty price (above $70) in 2019 and stay at the penalty prices until 2023 when the LRET of 41,000 GWh target is finally met.

Under the 20% LRET scenario, LGC prices are 55% lower than those prices under the base case till 2024, which will negatively impact the profitability and investment decisions of large-scale renewable projects.

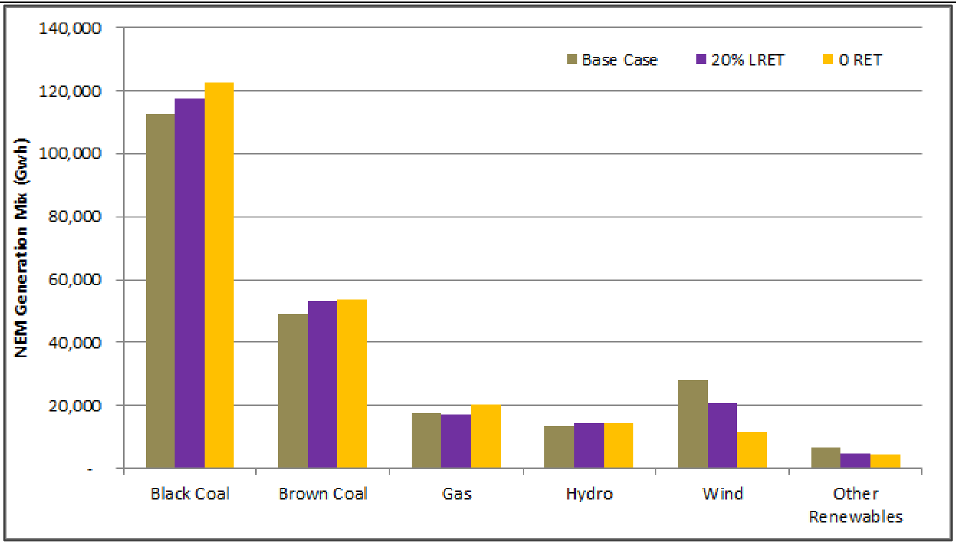
We anticipate LGC prices being likely to remain close to $30 per MWh till the completion of the 2014 RET review.

What the NEM will look like under a reduced RET

NEM Generation Mix in 2020

Figure 2 illustrates the NEM generation mix by fuel type in 2020 under three scenarios.

Figure 2 Comparison of NEM generation mix by fuel type in 2020



Source: IES Advisory

The effect of the reduction on LRET requirements is evident as wind and other renewable (excluding hydro) generation decrease significantly. Under the 0 RET scenario, wind and other renewable generation decrease by more than 50% compared to the base case.

Under zero carbon prices and lower LGC prices, coal-fired power plants will move up in the generation merit order (more likely to be dispatched). Black coal and brown coal generation is

9% higher under the 0 RET scenario and 5.6% higher under the 20% LRET scenario compared to the base case scenario.

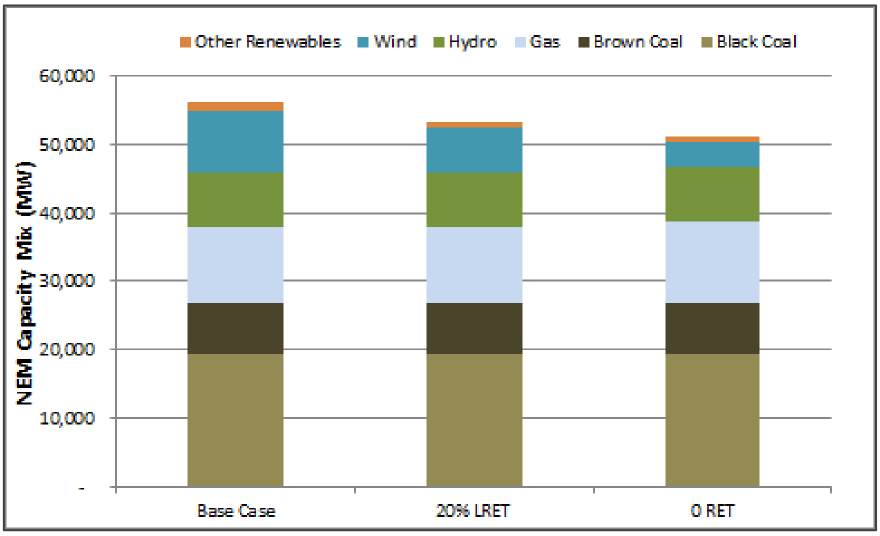
Gas-fired generation (GPG) is estimated to be 16% higher under the 0 RET scenario than the base case despite high gas prices envisaged in the domestic market[i]. This is because few renewable projects will be commercially viable and be developed in absence of LGC prices and carbon prices.

As modelling results do not take into consideration of the scarcity or unavailability of gas fuel for power generation, tight supply of electricity is likely when high demand events occur, such as heat waves. The detailed analysis of gas prices on the NEM can be found in IES Advisory's recent work for the Department of Industry[i].

Generation Capacity Mix in 2020

Figure 3 illustrates the generation capacity mix by fuel type in 2020 under three scenarios.

Figure 3 Forecast generation capacity mix across NEM regions in 2020



Source: IES Advisory

Given the moderate growth in demand forecast till 2020, new generation capacity in brown coal, black coal and gas will not increase due to their high Levelised Cost of Energy (LCOE) and Short Run Marginal Cost (SRMC) compared to renewable generation. Hydro capacity has saturated in Australia and will remain flat in the next 10 years without significant technological advancement. The majority of new generation capacity is expected to come from renewables to meet the demand growth in the NEM, including wind, solar, biomass.

Under a reduced LRET, investments in electricity generation will fall dramatically. Around 5,080 MW less capacity will be built under the 0 RET scenario and 2,940 MW under the 20% LRET scenario, particularly wind generation.

Due to the long approval and development time of new generation capacity, in the event of the economy picking up better than expected, a relatively low level of generation capacity investments could restrain economic growth and lower the level of services to consumers.

Potential under-investment in generation capacity in the NEM can create many challenges to network operators with increased network constraints and higher frequency of blackouts, and to independent retailers, industrials and consumers, inducing wholesale price volatility, difficulties in hedging and risk management, and weaker market competition.

Wind and Other Renewables

Among all categories of renewable generation, wind has the most growth potential due to its technological maturity, low investment costs per MWh and its abundant resources.

Due to the unfavourable economics under a reduced LRET and zero carbon prices, only 3,400 MW is projected to be built under the 20% LRET scenario by 2020 and a meagre 600 MW under the 0 RET scenario.

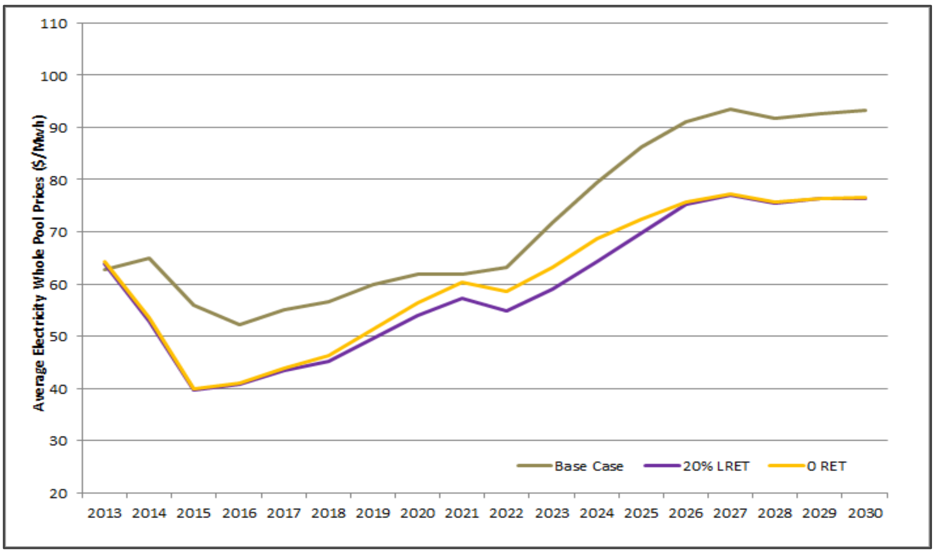
Around 223 MW of large-scale solar PV or thermal solar developments was modelled in this study. However, at LCOE of over $150/MWh these projects would not be economically viable without substantial government subsidies in place, even under the base case scenario.

Bio-mass is another form of low cost renewable generation, comparable to wind. However, its growth potential is limited due to the availability on feedstock.

Wholesale Electricity Prices

Figure 4 shows projected average NEM Wholesale pool electricity prices (excluding Tasmania) from 2014 to 2030 under three scenarios.

Figure 4 Projected average wholesale electricity pool prices – 2014 to 2030



Source: IES Advisory

Electricity prices under the base case are on average $13 per MWh higher than under the 20% LRET scenario, due to the combined effect of carbon prices and LRET as currently legislated.

Notably, electricity prices under the 0 RET scenario are above prices under the 20% LRET scenario as less renewable generation will push up the generation-weighted SRMC of the NEM and therefore increase pool prices. This will at least partially counteract cost savings effected from scrapping the RET.

From the above analysis, a halt to the LRET may not clearly outweigh the benefits of a well-set long term large-scale renewable energy target, nor will it result in the lowest electricity prices due to restrained investments in generation capacity.

Apart from secondary gains in creating employment and gaining strategic advantages in new technologies, a healthy level of LRET will also

- sustain and encourage long term investments in the NEM;
- benefit businesses, industries and consumers in the long run;
- help to balance the market power and facilitate market competition; and
- reduce carbon emissions in the NEM.

Wind Project Economics

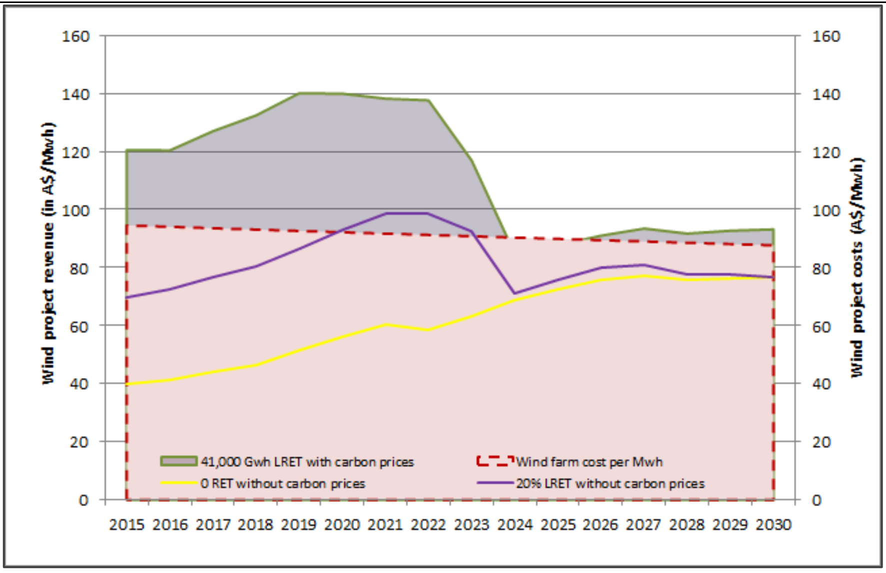
The economics of renewable energy projects will be significantly impacted by the changes in the LRET and carbon prices. IES Advisory has focused on wind projects and estimated the internal rate of return (IRR) for prospective wind projects under the three scenarios.

Wind project revenue and costs

The revenue steam for wind projects consists of LGC revenues and electricity sales revenues, either through the electricity wholesale market or a power purchase agreement (PPA). Carbon prices, which makes up of roughly 30% of wholesale prices at present, indirectly improve wind project economics through elevated electricity prices.

Figure 5 shows the wind project costs and wind project revenue for a prospective wind farm commissioned in 2015 under three scenarios.

Figure 5 Revenue and Cost of wind projects in the NEM



Source: IES Advisory

Wind project revenue is the highest under the current legislated RET and carbon prices (base case), rising significantly with the increasing electricity prices and LGC prices till 2023. This is well above the average wind project LCOE of $95 per MWh.

After the LRET of 41,000 GWh is reached, project revenue will drop significantly as LGC prices reduce to zero by 2024. Assuming the LCOE of $95 per MWh, a 34% capacity factor and project life of 25 years, the project Internal Rate of Return (IRR) is estimated to be around 7%.

Under the 20% LRET scenario, the wind project revenue will reduce by 40% due to lower LGC prices under a 20% LRET target and lower electricity prices under zero carbon prices, which is mostly below the assumed LCOE of wind projects.

In the absence of the RET and carbon prices, wind project revenue will be well below its LCOE cost as it will completely rely on revenues from electricity sales, although its potential revenue is expected to rise with the increase in electricity prices over time.

The loss in LGC revenue would reduce the project IRR from 7% in the base case to 3% under the 20% RET scenario and reduce even further under the 0 RET scenario.

Wind project economics vary considerably depending on wind resources, wind sites, network accessibility and connection, development costs and operational efficiency. We have not considered network effects and assumed an average LCOE of $95 per MWh based on a 34% capacity factor in this study.

Overall, the analysis suggests that wind projects are unlikely to be economic in a merchant market, obtaining an IRR of below 3% under a 20% LRET target or lower and without the support of carbon prices.

To sustain organic growth achieving a project IRR of above 7% under the 0 RET scenario, the LCOE will need to be below $70 per MWh, even with a high capacity factor at 41%.

In addition, wind project development will be further impeded by:

- more stringent environmental and development regulations in some states;
- rising costs of grid connection and access;
- a weakening Australian dollar; and
- higher borrowing costs.

Shifting company strategy under reduced LRET

Owing to difficulties in debt-financing for independent wind developers and uncertainties around securing a PPA, more than 70% of wind farms developed since 2010 were gen-tailer owned.

At present, at PPA prices of below $90 per MWh offered by gen-tailers, it is challenging for independent wind developers to develop economically viable wind projects, even with the support of the LRET.

Under a reduced LRET, worsening economics will put on hold or trigger the cancellation of many planned projects. Wind project development will reduce by 2,280 MW under the 20% LRET scenario and by 5,100 MW under the 0 RET scenario, resulting in the loss of investment opportunity of $4.5 billion and over $10 billion respectively.

Operating in an increasingly vertically-integrated National Electricity Market, independent wind developers are likely to be further squeezed in their operating margins. Selection of best wind sites, the ability to acquire favourable financing, strategic partnership to minimize the risk of wind intermittency and effective deployment of new technologies, such as battery or wind following technology will be paramount to the continued success of independent wind developers.

A revision on LRET will also instigate a shift in company strategy for utilities and gen-tailers such as AGL, Original Energy and Energy Australia who are mandated to purchase LGCs under the current LRET scheme. The recent acquisition of Loy Yang A and Macquarie Generation by AGL has clearly signalled a big step back from a green energy strategy by companies as well as a bearish view on the future of LRET.

NEM Outlook under a reduced LRET

The development of large-scale renewable projects since 2001 has been primarily driven by the Renewable Energy Target, firstly set at 9,500 GWh known as MRET, and then revised to 45,000 GWh by 2020 in 2009 (including LRET of 41,000 GWh).

The imminent RET review and the repeal of carbon tax in 2014 will reshape the landscape of the NEM going forward, particularly:

- The share of coal generation will likely increase by 6-9% due to rising gas prices, the removal of carbon prices and decreased LGC prices, which will create some challenges for Australia to fulfil its 5% emissions reduction target under the Kyoto Protocol.
- Over 2,900 MW of planned wind projects and other form of large renewable projects are likely to be scrapped due to weak project economics and difficulty in obtaining debt financing.
- Loss of generation investments can mount to $10 billion if the RET is scrapped and the carbon price fully repealed.

- In the event of the rapid economic expansion combined with a low level of generation capacity investment, shortage of supply and high pool prices may occur with greater frequency during peak demand events, such as heat waves and network constraints.
- Higher volatility in electricity prices can be experienced when there will be more opportunities for generators to exercise their market power.
- Consolidation in electricity retailers is likely when market risks rise for poorly-hedged retailers and more firms pursue vertical integration strategies.
- Innovations in technology, financing and operations will be critical for independent wind developers to compete with fossil fuel generations under a reduced LRET scenario.
- Gen-tailers will rebalance their generation portfolio to step away from renewable energy projects to pursue lower-cost fossil fuel options, largely coal.

Contacts

IES Advisory Services

Emi Gui
Phone: +61 2 8622 2221
eGui@iesys.com

Philip Travill
Phone: +61 3 9614 6200
pTravill@iesys.com

Disclaimer

Please note that the articles that appear in Insider are generally written by individuals at IES, and that the views expressed are the views of the individual authors and do not necessarily represent the views of IES or of other individuals at IES.

The objective of this article is to provide some insights on the outlook of the NEM under different policy settings based on the market modelling and simulation done by IES Advisory, and does not aim to guide or influence decision making of the Government, businesses and individuals.

References

[i] *Study on the Australian Domestic Gas Market – IES* for the Department of Industry, December 2013. http://www.innovation.gov.au/Energy/EnergyMarkets/Pages/GasMarketDevelopment.aspx

About IES Advisory Services

IES Advisory Services (IES Advisory) is a team of energy professionals with a focus on market modelling, analytics and energy trading experience which is highly applicable in today's energy markets with recent projects for the Department of Industry (extensive domestic gas market study), Clean Energy Regulator (small-scale technology certificate forecasts) and energy companies in Australia and Asia. IES Advisory brings together a wealth of experience spanning the NEM, SWIS, Australian gas markets and emerging markets to deliver clients innovative solutions backed by rigorous research and analysis.

Our expertise is drawn from the following backgrounds:

- Mergers and acquisitions, due diligence, strategy, contract reviews and negotiations;
- Physical spot and forward trading of electricity, gas and portfolio optimisation and management;
- Wholesale risk management solutions including financial and physical options;
- Detailed market modelling, transmission studies and cost benefit analyses;
- Innovative price risk management solutions for end-use customers;
- Policy impacts and market frameworks for governments and regulators; and
- Market development and reviews for overseas markets and organisations.

We are focused on providing solutions that make sense and that satisfy each client's unique requirements. For further information, please visit http://www.iesys.com/ies/advisory/Home.aspx or contact us directly at (02) 9436 2555.

Some of IES advisory's key consultants include:

Hugh Bannister (Chief Executive Officer) - is the founder of IES and CEO of IES Advisory Services. He has over 25 years' experience in providing advice to government, industry and regulatory bodies on electricity markets and macro energy policy in Australia and the countries of ASEAN, including development and implementation of energy policy, electricity market design and the process of industry reform. He also has expertise in mathematical modelling of complex technical problems, including the pricing and dispatch algorithms used in electricity markets.

Stuart Thorncraft (Managing Consultant) - is a Managing Consultant responsible for IES's Asia Advisory practice with a particular focus on Singapore, Philippines, Vietnam, South Korea and Myanmar. He provides technical and regulatory advice to governments, market operators, energy companies and financial institutions on issues including energy policy, regulations, electricity market design and implementation, power system operations, demand response and demand-side management, energy system modelling, market studies and valuation of energy sector assets.

Emi Gui (Senior Consultant) – has extensive experience across the energy value chain in demand forecasting, generation, transmission, distribution and regulation in both Australian and European markets. Having worked for AEMO, Essent Energy Trading and IHS Emerging Energy Research, her areas of expertise include energy forecasting, econometric modelling, energy policy impact analysis, renewable energy, carbon, energy efficiency, demand-side management, along with energy trading and portfolio optimisation. Emi has a Master of Engineering in Pattern Recognition and Neural Networks with Nanyang Technological University and an MBA with Melbourne Business School.

Prayank Katiyar (Senior Consultant) – has experience across the Australian power and gas markets having worked in different analyst, trading, consulting and advisory roles for organisations based in Sydney and Melbourne. Prior to joining IES Advisory, Prayank lead the Reputex consultancy and was part of energy trading teams where he worked on optimising generator gross margin for Origin Energy and reviewed and advised on hedging strategies for Westpac. Prayank has Bachelors of Mechanical Engineering, Masters of Information Technology and Masters of Business Administration.

Patrick Wang (Senior Consultant) – has well-regarded experience across the power and gas markets highly applicable in a trading environment focused on detailed analytics and modelling. His background covers proprietary and asset-backed electricity trading, risk management and financial modelling with a background in applied finance and actuarial studies.

Philip Travill (Modeller and Market Analyst) – brings to the team expert modelling knowledge of the NEM and east coast gas markets. He has a detailed understanding of simulating electricity markets, power system security constraint equation modelling and calibration of game theoretic modelling tools to reflect market dynamics. Philip holds a Bachelor of Science, majoring in Applied Mathematics from Melbourne University.

IES Advisory at the Argus Australian Gas and Energy Markets 2014 (Mar 20, 2014)

IES Advisory will be presenting our domestic gas market study (commissioned by the Department of Industry) at the Argus Australian Gas and Energy Markets 2014 (20 March at the Establishment Hotel, Sydney). The presentation covers all the current issues and concerns around supply and demand and price levels relative to the international netback price. Please drop by if you have the chance.

The third annual Argus Australian Gas and Energy Markets conference examines the impact of these changing forces, as east coast power generators and industrial firms go head to head for gas supplies with fast-growing emerging economies like China. This conference brings together international speakers to discuss how changes in the Asian gas market place will affect Australia’s role in the global race for LNG. It aims to answer the following key questions from the perspective of the international LNG industry and the east coast domestic gas market:

What does international LNG demand mean for Australian east coast domestic gas pricing and power generation economics? And how will Australia's high-cost LNG industry withstand the threat of US exports at Henry Hub-linked pricing, as well as new supplies from east Africa and Russia? For further information please visit: http://www.argusmedia.com/Events/Argus-Events/Asia/AGEM/Home