EESA
Electric Energy Society of Australia

National Bulletin

Bulletin 7 | 2021

President's Article

Author: Jeff Allen, National President of the Electric Energy Society of Australia
Date: July 2021

This month my article is all about EESA and some of our activities in the last 12 months.
Firstly – our Executive Officer – Penelope Lyons – returned to her role on Monday 5th July after approximately 8 months of maternity leave. Welcome back Penelope!
Thanks to Heidi, Candice, and Vanessa (all from 2em) who provided great support to EESA during this period.

Secondly – a summary of the key results for the 2020/21 financial year.
As National President, each year I prepare an annual report which is published on our website (in August or September) and is presented at our Annual General meeting in November. This report also goes to Engineers Australia. In summary, 2020/21 was another year of change for the electric energy industry, for EESA, and for our members.

Key activities included a National Council election in late Oct/early Nov 2020 for some positions for the new "2021" EESA National Council that commenced its term in late November 2020. The "2020" and "2021" National Councils met 14 times in 20/21 – all via Zoom. At each of the monthly meetings, the National Council reviewed our finances and progress with key elements of our business plan as well as reviewing the success of our monthly events and progress with membership growth. A big thank you to all the members of the National Council for their contributions.

The EESA remains healthy financially with approximately $600,000 in assets as of 30th June 2021.
The following are the preliminary figures for 2020/21.

EESA Finances	2020/2021	2019/2020
Annual revenue	$128,845	$225,300.10
Annual expenses	$146,429	$205,101.77
Annual Profit/Loss	-$17,584	$20,198.33
Total Assets	$599,245	$616,136.52

Jeff Allen
EESA National President

Note that the 19/20 year included the income and expenses of the face-to-face EECON 2019 (in Sydney) whereas our virtual EECON 2020 was a much less expensive event. Also, some income and expenses associated with EECON 2021 (to be held in Perth in November as a hybrid event) are also included in the above figures.

Affiliations

Also note that the annual expenses in 20/21 included $32,500 for the new EESA website. This was necessary because the current website's platform (Adobe Business Catalyst) was not going to be supported from March 2021. Following a review of offers from 7 different potential suppliers, the EESA Website Working Group recommended to the National Council in August 2020 that TMD Online's NetRanger system should be used to replace the existing EESA website. Following a demonstration, the National Council agreed to the recommendation and entered into a contract with TMD Online. The new website went live in March 2021. Thanks to all the members of the Website Working Group for a great result.

Our membership base has continued to grow. Membership numbers were 1012 in July 2020 and 1265 in June 2021 (although the final June 21 figure is dependent on membership renewals). We continued to have great support from our many corporate members across Australia. A total of 54 events were offered to EESA members across Australia from July 2020 until June 2021 thanks to the efforts of our volunteers from all the chapter committees across Australia. This included EECON 2020 which was a virtual event held over 2 days and attended by 259 people. We also promoted events from other organizations that EESA members were able to attend. The continuation of national webinars (including the live streaming of most state-based seminars) resulted in more members from across Australia being able to access CPD. The new website also allows members to easily access recordings of these webinars at any time.

Thirdly – an update on the possible closure of the Lane Cove Testing Station.
The announcement in late March of the closure of the Lane Cove Testing Station was of great concern to the electricity supply industry. This well-known facility is owned and operated by PLUS ES – an independent affiliate of the consortium that owns Ausgrid. The Australian electrical equipment manufacturing industry (the main customers of the facility) indicated the importance of this facility continuing due to the Lane Cove High Current Test Facility being a unique specialist high current electrical testing station, and this capability being a critical function for the 'type testing' of new electrical equipment designs. This testing is often mandated by Australian and New Zealand design standards and in some instances by Government Regulation. The testing is also a key component of R&D for the development of new electrical equipment utilised within Australia and for export.

EESA has worked with Engineers Australia and representatives of the Australian Industry Group to communicate the importance of this facility to affected electric energy industry participants and government representatives to ensure everyone fully understands the implications of the closure of this facility.

In my view, the closure of Lane Cove Testing Station would have a significant impact on the development of new Australian electrical equipment products for the "electricity system of the future".

I understand that confidential discussions are ongoing regarding a suitable short-term and long-term solution, and this includes discussions with the Federal and State Governments for their support in keeping this facility operating.
And fourthly – EESA's National Bulletin and our "Editorial Policy."

As you know, our monthly Bulletin covers many topics. We endeavour to have content that covers a varied cross section of published articles that are relevant to all our members, and feel it is particularly important that members are aware of what is out there in the public domain - even though these views/opinions may not necessarily resonate with theirs. We also publish different items that present different viewpoints of the same topic. We normally publish all items without comment.

Please note that the Bulletin content is pulled together by two very experienced EESA members who volunteer their time each month to create a Bulletin that covers the many issues that are being discussed in the media in the constantly changing electric energy area. These volunteers fully understand that the views in the article may not at times fully reflect the majority view.
We are constantly seeking interesting and relevant articles for the Bulletin, particularly from members and I would encourage you to submit an article explaining your views on these articles or any others if you desire.

Robust debate on various issues that are being discussed in the media can only enhance the quality of the bulletin content and its value to members.

Thanks for being a member of EESA.

Jeff Allen – EESA National President – July 2021

Contents

AUSTRALIAN ARTICLES

CALLIDE REPAIRS DELAYED

Author: Mark Ludlow
Date: 9 July 2021
Source: Energy Council of Australia (reprinted from Australian Financial Review)

The delayed return of the Callide coalfired power station to full operation until December next year will put pressure on other generation assets and push up electricity prices, according to energy experts.

After CS Energy confirmed it cannot get a replacement turbine installed in the Central Queensland power station for another 18 months, some energy insiders have started to ask whether the 420-megawatt unit – which will cost hundreds of millions of dollars to replace – will ever be fixed.

The C4 unit at Callide power station exploded in May, causing a state-wide blackout of more than 500,000 homes and businesses. The cause is still being investigated.

Energy Edgemanaging director Josh Stabler said the loss of the Callide power station, along with the Yallourn plant in Victoria, had put more pressure on other generation assets, especially gas, as Queensland diverted gas normally sent to Victoria to cover the domestic shortfall in production.

A popular 1896 textbook featured a radiograph of a woman's foot inside a boot.

Mark Ludlow "There is lot of interconnectedness between each state and generally an energy constraint somewhere becomes an energy constraint everywhere," said Mr Stabler.

"Callide C is an energy producer and if that asset is going to remain offline, it's going to mean that so many others are going to have to change their behaviour to manage that.

"The speculation now is, will they even fix it [Callide C4] at all? It has to be an option on the table."

Global Roam managing director Paul McArdle said the longer than expected outage of the Callide C4 unit would inevitably push power prices up – with wholesale prices jumping 60 per cent in May – and ensure a rough next 18 months for CS Energy and its joint venture partner InterGen.

"With the unit not there for JuneJuly-August 2022 – and also one unit at Liddell gone and so on – then there is less existing capacity around. But this needs to be balanced by what is coming that is dispatchable," Mr McArdle said.

"The only things new that are dispatchable that will be there in time are batteries, so then you get into wondering whether they will be charged or not, and how those who charge them will operate them."

State-owned CS Energy has been gradually bringing back its three other units at Callide power station in Central Queensland since the explosion and fire at C4, which "tripped" electricity assets across the state.

Two units are back in operation and C3 is to be brought back online on July 15.

CS Energy said the delayed return of C4 – which had been scheduled for June next year but has now been pushed out to December 2022 – had not been a surprise, given the long lead time for Toshiba to build a new turbine and then ship it to Australia.

It was not related to insurers wanting to wait for the outcome of the Brady review into the incident. A CS Energy spokeswoman said the insurance claim was progressing.

Queensland Energy Minister Mick de Brenni, a shareholding minister in CS Energy, rejected the speculation the C4 unit replacement could be abandoned. "With two units already back online and a third – C3 – forecast to return to service next week, Callide power station is expected to be generating up to 1120 megawatts of reliable, firmed energy into the National Electricity Market," he said.

"My expectation remains that CS Energy and InterGen Australia work closely with their respective insurers on the potential cost and timeline for the replacement of the C4 unit."

GE TURBINE SELECTED FOR HYDROGEN, GAS FIRED TALLAWARRA

Author: Rod Walton
Date: 16 June 2021
Source: Power Engineering

Photo courtesy EnergyAustralia

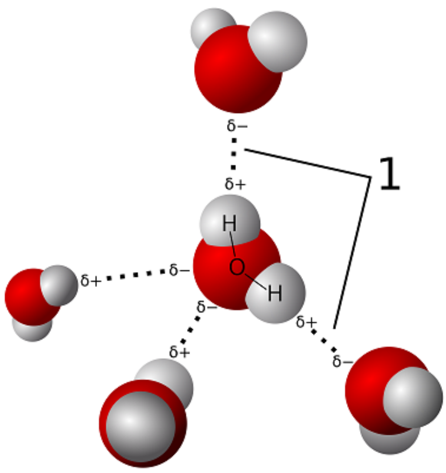
EnergyAustralia has ordered one of GE's 9F.05 gas-fired turbines to power the nation's first gas-hydrogen dual-fuel power plant.

The GE turbine will be installed at the Tallawarra B Power Station in New South Wales, Australia. The plant is intended to reduce emissions and replace capacity being lost when the 1.560-MW Liddell coal-fired plant in closed by 2023.

"Our new open-cycle, hydrogen and gas capable turbine will provide firm capacity on a continuous basis and paves the way for additional cleaner energy sources to enter the system," said Catherine Tanna, Managing Director of EnergyAustralia. "We are leading the sector by building the first net zero carbon emissions hydrogen and gas capable power plant in New South Wales."

While many questions remain about the relative roles of electricity and chemical energy carriers in a decarbonized economy, two things seem clear: (1) use of fossil fuels as energy sources and carriers will decrease, although probably not to zero, and (2) use of "manufactured" chemical energy carriers, such as hydrogen that is produced using renewable power, will grow. These will be used to both move energy from sources to user, as well as to store energy.

There are three key issues around hydrogen as an energy carrier: (1) generation of hydrogen, (2) logistics, handling, and movement of hydrogen, such as via pipelines, and (3) utilization of hydrogen by a variety of "energy conversion device" – i.e., devices that generate electricity (e.g., fuel cells or gas turbine power plants), or are used to heat water or building spaces.



The primary focus of this article is to address issue (3) –to identify the opportunities and challenges associated with utilizing hydrogen in energy conversion devices. For example, a key opportunity for hydrogen is to store it and then burn it in gas turbines during times of peak demand. This has the benefits of re-purposing existing technology (gas-fired plants and natural gas infrastructure) for combustion-based energy storage with no carbon emissions. Here we address the following questions:

Is hydrogen viable as a fuel? Can hydrogen be used in retrofitted devices or new systems?
If so, what are the constraints or issues that must be understood by policymakers, users, and the public?
Can Hydrogen be used in Energy Conversion Devices?
The answer to this question is emphatically yes. There is no fundamental reason why hydrogen cannot be combusted in gas turbines, heaters, boilers, or other energy applications such as generating electricity. It can be used in a blend with natural gas, or as pure hydrogen.

In fact, today hydrogen is used as a dominant fuel source for a number of power generating plants, such as the Fusina hydrogen power station in Italy (100% hydrogen), a petrochemical plant in Daesan, South Korea (95% hydrogen), a steel mill in Wuhan, China (60% hydrogen), and several planned facilities converting to 100% hydrogen such as the Magnum plant in Vattenfall, Netherlands, and the Intermountain Power Agency plant in Utah. It has been flown in specially designed aircraft by Martin, Tupelov, Boeing, and Skyleader, and airframers have pledged future hydrogen aircraft such as the Airbus ZEROe.

What are the Constraints Associated with Utilizing Hydrogen in Existing Systems?
While hydrogen combustion offers a promising energy storage and conversion pathway, it is not a "drop-in" fuel for much of today's natural gas fired energy conversion devices. In other words, alterations are needed in the fuel handling systems, valves and piping, and combustor hardware. These alterations are needed to address several issues of concern to stakeholders, including pollutant emissions, operability, and cost. These issues are highly interdependent.

We will address pollutant emissions first. In addition to concerns around CO2 emissions associated with climate change concerns, combustion can generate other pollutants, even zero-CO2 fuels like hydrogen. Pollutants most commonly associated with fossil fuel combustion are particulates (e.g., soot), carbon monoxide, and NOx.

Hydrogen combustion emits no particulate or carbon monoxide emissions, since it contains no carbon atoms – another major benefit of it as a fuel. However, hydrogen combustion can generate nitrogen oxides (NOx) emissions. In essence, NOx is generated when air is heated to high temperatures and the N2 and O2 in air start to react with each other. NOx is a regulated criteria pollutant because of its potential to cause adverse respiratory health effects and because it contributes to acid rain.

In situations where NOx emissions are not a concern, many options are available to use hydrogen and hydrogen blends, including the ability to use legacy combustor hardware for a range of hydrogen and natural gas blending levels. In other words, the key challenges associated with using hydrogen are in low NOx combustion systems. So called "diffusion combustors" are an older technology that leads to high levels of NOx pollutants. These systems require water or steam injection to comply with the NOx regulations in modern air permits, which may be unattractive due to the cost and complexity of the water management systems. These systems need large volumes of clean, de-mineralized water, which introduces additional environmental considerations. In many places, such as the desert, water injection systems are not practical. Nevertheless, diffusion combustors have good fuel flexibility. Many of these systems operate today on fuels with very high hydrogen content, fuels that are naturally produced as biproducts of industrial processes in steel mills and petrochemical plants. Many of these diffusion combustors are 100% hydrogen capable (see specific site examples above) but their deployment is limited to locations and economies where water/steam injection is viable for NOx control.

So called "lean, premixed combustors" are inherently low NOx systems, and can produce compliant emissions without any water or steam injection because they avoid the high temperature regions that produce NOx. This is illustrated in Figure 1, which shows the differences of lean premixed combustors relative to non-premixed combustors. Therefore, lean-premixed systems dominate new electric power plant installations and are the predominant technology in the power generating fleet. However, legacy systems do not have the operational flexibility or fuel flexibility of diffusion combustors.

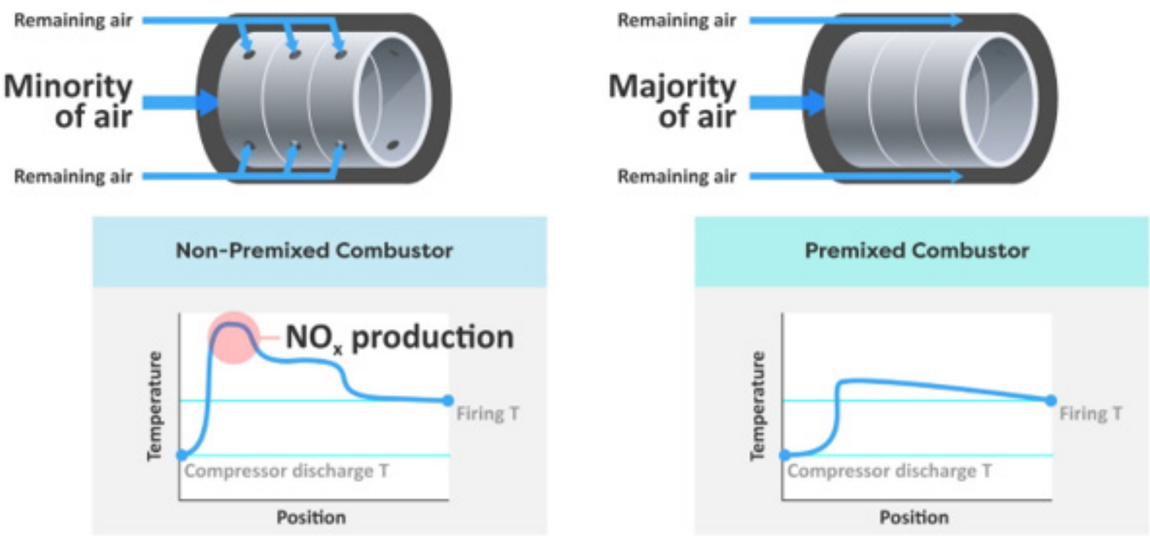


Figure 1. Comparison of non-premixed vs lean-premixed combustors

Given these points, we'll next dig into the details a little further on both operability and emissions in lean, premixed combustors, and what the concerns are and where the issues arise. Operability refers to the ability to operate the plant reliably without having it shut itself down, damage itself, or have unacceptable performance. Hydrogen affects operability in several ways.

Flashback – this is the most severe concern around high H2 levels in systems designed for natural gas, as the flame can propagate upstream and catastrophically damage hardware. Hydrogen's flame speed is an order of magnitude higher than that of natural gas. Therefore, flashback is the dominant issue for modern lean premixed combustors on hydrogen fuel.
Blowoff – If you've ever tried to light a match outside when its windy, you'll know what this is. Similarly, combustors have flow velocities that can exceed 100 MPH and so preventing the flame from flying downstream and out of the system is a major challenge. Because hydrogen propagates so fast, blowoff challenges are alleviated with hydrogen. However, this issue is compounded for fuel flexible combustors, which must avoid blow out with slower burning natural gas fuel and simultaneously avoid flashback with high hydrogen fuel. For these reasons, the highest hydrogen capability marketed for any frame engine with lean premixed combustion is 50% hydrogen by volume, and much lower for most systems.
Combustion Instabilities- Modern low NOx systems are prone to a variety of damaging oscillations and a great deal of effort is spent on modern systems to develop designs that avoid these issues at the operating conditions of interest. What this design must look like, however, changes with fuel composition or ambient temperature. Thus, in cases where the fuel composition can vary widely, it becomes impossible to develop a static design that is stable over all conditions and for all potential fuels. This has the practical impact of restricting certain operating regimes from operation, depending upon fuel composition. For example, a plant may not be able to operate at peak power for certain fuel composition ranges.
Finally, lets dig a little further into NOx emissions. First, we should correct some common errors that are out there. Since NOx emissions increase exponentially with temperature, and because hydrogen can burn hotter, its sometimes said that hydrogen combustion will produce more NOx. However, this point needs to be contextualized as to whether the combustor design is a diffusion flame combustion or lean, premixed combustor. It is true for diffusion flame combustors, which are inherently high NOx devices. It is not necessarily true for premixed, low NOx systems. This is because NOx emissions are a function of temperature in these systems and many energy systems run at a fixed temperature or power settings. To restate – premixed hydrogen powered systems can be designed for near-zero NOx emissions.

Next, it's important to understand the connection between efficiency of the engine and its NOx emissions. An approximate rule of thumb is that higher efficiency machines run at higher temperatures and, therefore, emit higher NOx emissions. For reference, current EPA regulations on NOx for gas turbines is 30 ppm, while in certain areas such as in California with air quality problems, they can be as low as 3 ppm. The highest thermal efficiency devices on the planet, combined cycle gas turbines, are now designed to operate with NO emissions between 2-25 ppm. When operating with various H2 blends, since they are designed to operate at a fixed temperature, hydrogen addition need not adversely impact NOx emissions for premixed, low NOx designs.

However, H2 also has additional effects on NOx emissions in low NOx, premixed systems associated with subtle differences in the way it burns which causes it to generate trace increases of NO. For big, high efficiency engines, these effects are very small. However, for smaller engines, such as microturbine that might emit 1-3 ppm, the effect could be noticeable – for example, a 1 ppm emission level could become 2 ppm.

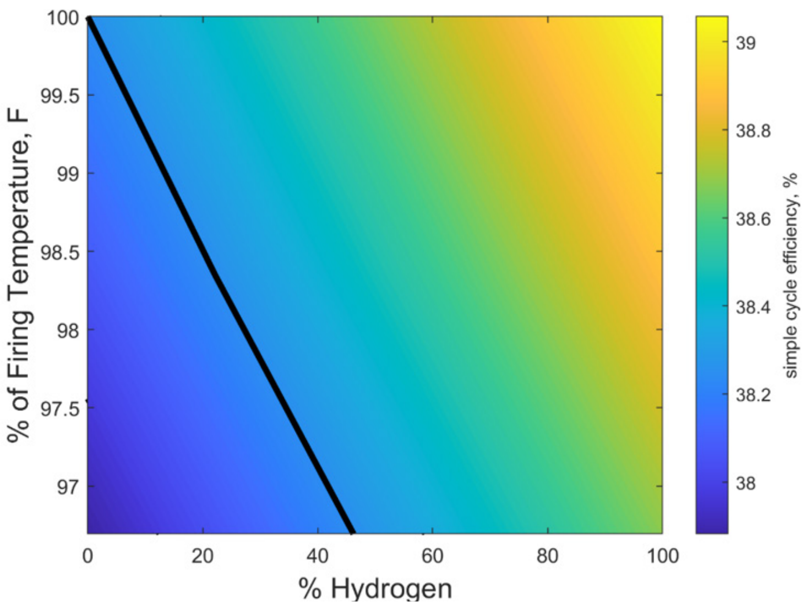


Figure 2. Simple cycle efficiency as a function of the fuel's hydrogen content and the firing temperature. Calculation is based on an F class turbine with methane/hydrogen fuel mixture. For reference, full firing temperature on 100% methane fuel provides an approximate efficiency of 38.3%. That value is indicated as a black iso-line.

To summarize, for lean, premixed combustion systems, increasing hydrogen levels can cause small absolute increases in NO levels, which could be large absolute changes (e.g., in the above example it doubled NOx emissions from 1 to 2 ppm). However, for larger, high efficiency machines hydrogen effects can be minimal.

A final point – heat transfer coefficients of combustion products fueled with hydrogen are higher than natural gas. Because the peak temperature in a gas turbine is controlled by heat transfer to the rotating turbine, this could necessitate a reduction in turbine inlet temperature as hydrogen levels increase. While high hydrogen fuels can actually benefit cycle efficiency, this can be counteracted by the efficiency reduction from a reduction of the turbine inlet temperature. **Figure 2 illustrates this tradeoff.**

Key Future Needs

To summarize, this paper has shown, first, that hydrogen is certainly an acceptable, very clean fuel. Second, it has shown that it can be used at low levels in existing fielded systems, and some low NOx gas turbines exist in the field today that can operate with H2 levels of up to 50% , cofired with natural gas. Furthermore, systems have been developed to operate with pure hydrogen. The key development challenge for the future is low NOx, fuel flexible systems, that can be readily operated with a range of fuel compositions, ranging from pure H2 to pure natural gas. **Figure 3** below summarizes the hydrogen readiness, R&D needs, and NOx compliance of these various technologies. All of these will enable the combustion technology of the future – low NOx, wide operability range, fuel flexible combustion systems capable of operating up to 100% hydrogen.

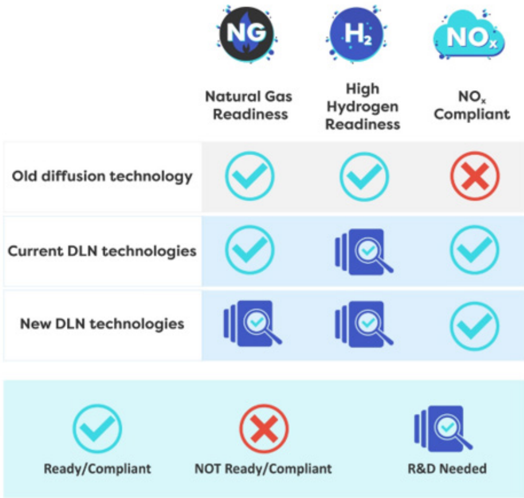


Figure 3. Hydrogen readiness and R&D needs for various combustor

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Bobby Noble is gas turbine programs manager at EPRI and a Fellow of American Society of Mechanical Engineers. He is a key global leader in hydrogen combustion development and test experience, and has authored a number of EPRI reports on hydrogen utilization case studies

CELEBRATING NAIDOC WEEK- RUBY HEARD, ELECTRICAL

Author: Matilda Brown
Date: 5 July 2021
Source: Create Digital Magazine, Engineers Australia

Ruby Heard has Jaru ancestors from the Kimberley, Western Australia.

After starting as a building services engineer with Arup in Melbourne, Heard now runs her own consultancy, Alinga Energy Consulting, which specialises in engineering feasibility and design for renewable energy and micro grids. One of her current projects involves energy feasibility studies for six remote Indigenous communities in Wester Australia. To capture the learnings, she is documenting her findings about sustainable energy solutions for remote communities in a PhD with the University of Melbourne.

"Aboriginal people believe if the land is sick, we are sick, and if we are sick, the land is sick because we are completely linked. So it's not just about Healing Country; it also has to be about healing people. Aboriginal people are still suffering through so much generational trauma.

My recent experience is that some engineers believe that engineering is just about the technology, and the social, economic, environmental stuff is not engineering. That's how we harmed Country in the first place: by not considering the environmental, cultural and the social aspects. So, let's make sure engineers are now part of the solution.

My role now is to look at sustainable, responsible design and to encourage other engineers to do the same, because if we're not considering who we are designing for, then what is our purpose? It's all about the end user and the environment.

The projects I'm doing in WA are very close to my own Country. This is my first opportunity to go to Country where my mob is from and have a beneficial impact on that community, so it's really exciting for me.

I'll be making a few trips this year to understand the actual challenges. We often don't do that, because it is a more costly, time consuming way of doing things, but it's the right way to do things, and it's the only way we're going to get really appropriate solutions."

IPART SLASHES ROOFTOP SOLAR FEED-IN TARIFF

Author: Michael Mazengarb
Date: 2 July 2021
Source: One Step Off The Grid

New South Wales households could be about to see a significant cut to the tariffs paid for their excess solar power exported to the grid, with the key regulator slashing the benchmark tariff rate about a quarter.

The NSW Independent Pricing and Regulatory Tribunal (IPART) has published its final determination for 2021-22 benchmark feed-in-tariff for solar exports at between 4.6 and 5.5 cents per kilowatt-hour.

It's a significant cut, with the feed-in-tariff benchmark falling by around 25 per cent, compared to the level set for the 2020-21 year. IPART said that the reduction was justified as wholesale electricity prices – and therefore the value of solar exports – had fallen over the last year.

While the feed-in-tariff benchmark set by IPART is not binding on electricity retailers, it provides an indication of what households may expect to receive from their retailer for the excess solar they send back to the grid.

Many electricity retailers set their solar feed-in-tariffs in line with the benchmark issued by IPART, while some retailers offer a premium above the benchmark amount in an effort to attract customers.

It will likely see New South Wales households paid less for excess solar power fed back into the grid, with many electricity retailers likely to readjust their feed-in-tariffs in line with the lower amount set by IPART.

In its final report, IPART suggested that increasing uptake of rooftop solar had been at least partially responsible for the need to cut the benchmark tariff, as increasing supplies of solar power had been working to push wholesale electricity prices lower.

But IPART said that the lower feed-in-tariff benchmark should be counterbalanced by lower retail electricity prices paid for electricity purchased from the grid.

"This is due to lower forecast wholesale electricity prices. Increasing solar penetration has resulted in these lower prices because it has reduced demand for electricity from the National Electricity Market," IPART said.

"As more customers export their excess electricity and increase the supply of solar generated electricity available, electricity prices are likely to continue to fall during the day."

"This means that the value of solar exports is likely to remain low in the longer term. However, customers will continue to make savings on their bills by using the electricity they generate – the key benefit of having solar panels," IPART added.

The tribunal also said that retailers could consider offering time-based tariffs to customers to reward those who are able to export power during periods, such as households with battery storage.

IPART indicated that excess solar power exported during peak periods, such as between 5 pm and 6 pm, could be worth as much as 14 cents per kWh.

IS MINIMUM DEMAND CAUSING A MAJOR HEADACHE?

Author: Graham Pearson
Date: 24 June 2021
Source: Energy Council of Australia

Last week the Australian Energy Market Operator (AEMO) released the **2021 Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO).** The WEM ESOO provides a practical function for setting the Reserve Capacity Requirement (RCR) but it also offers an interesting insight into the future of the WEM and some of its potential challenges.

The ESOO presents a confident picture of generation meeting demand over the forecast period, in part aided by the dampening impacts of the COVID-19 pandemic and the growth of rooftop solar PV. The flipside is that the ESOO singles out the massive uptake of rooftop solar PV for causing a significant near-term issue – the growth of rooftop solar PV capacity is causing minimum demand levels to plummet and that puts system security at risk.

Here we look at some of the key findings of the WEM ESOO and then delve into the growth of rooftop solar PV and the challenges it creates for the South West Interconnected System (SWIS).

ESOO forecasts excess capacity

The ESOO is prepared annually by AEMO to help market participants, new investors and stakeholders make informed decisions about opportunities in the WEM over a 10-year period. It provides a wealth of data about the market, providing a valuable snapshot of committed capacity, new developments, and emerging issues.

The WEM ESOO also performs an important purpose in determining the RCR, which is the amount of capacity that is required to meet the 10 per cent probability of exceedance (POE) peak demand forecast plus a small margin. The ESOO sets the RCR at 4,396MW for the 2023-24 capacity year, a slight decrease from 4,482MW in 2021-22 and 4,421MW in 2022-23. Interestingly, this means that excess capacity in the market (i.e. total capacity minus the RCR) is expected to increase from 386MW (8.7 per cent) for 2022-23 to 411MW (9.4 per cent) for 2023-24, largely due to lower forecast peak demand.

Sufficient capacity is also expected to be available to meet forecast demand despite the staged retirement of Muja C unit 5 (195MW) in 2022 and Muja C unit 6 (193MW) in 2024. The Minister for Energy, Bill Johnston, has claimed this as a success saying that his "careful planning will keep the lights on for the next 10 years."[1]

The growth of rooftop solar PV

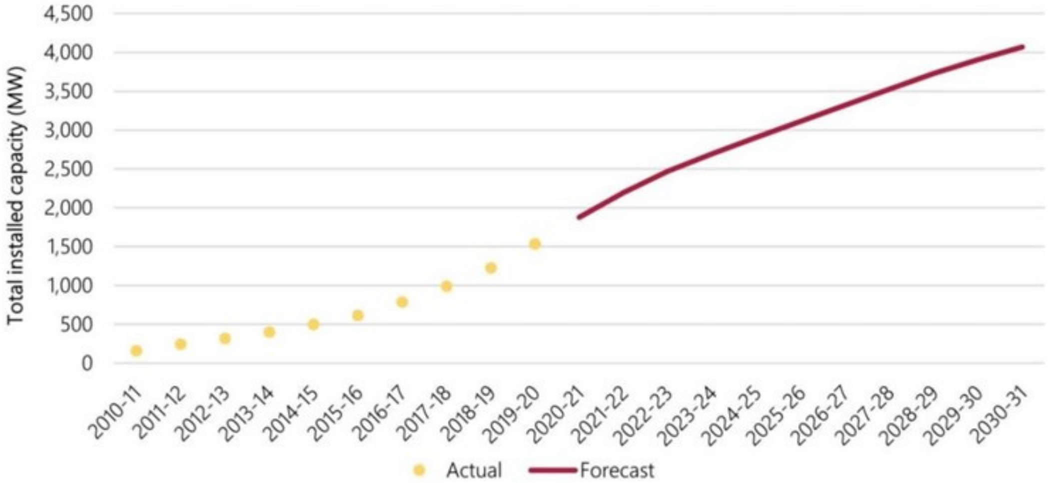
Having excess capacity in the market gives the market some breathing room during peak demand events. The flipside to this are instances of low demand which can threaten the reliability of the system. To start looking at this, it's helpful to consider what contributes to low demand and the ESOO points to one main culprit: rooftop solar PV.

The booming rooftop solar PV market is well documented. The AEC's quarterly Solar Report explains that the amount of new rooftop solar and the size of those installation are steadily increasing. In Western Australia, rooftop solar PV is the largest single generator in the SWIS, with 1.74 GW installed as of April 2021 representing a capacity greater than the sum of the six largest scheduled generators. According to the ESOO, in 2020, there was a 25.3 per cent increase in installed behind-the-meter PV capacity and now over 36 per cent of WA dwellings have behind-the-meter solar PV installations. AEMO expects that technological, commercial, and regulatory factors, as well as increasing environmental awareness, will further drive the strong uptake of rooftop solar PV in the SWIS from 1,740 MW in 2020-21 to an expected 4,069 MW by 2030-31.

The huge growth in rooftop solar PV installation, plus the big jump in the size of each installation, has shifted when consumers are demanding energy from the network. In the past, minimum demand typically occurred during overnight periods when residential and commercial energy consumption was low. However, the growth in rooftop solar PV has brought minimum demand forward to between 10am and 2pm when the solar systems are working at their peak.

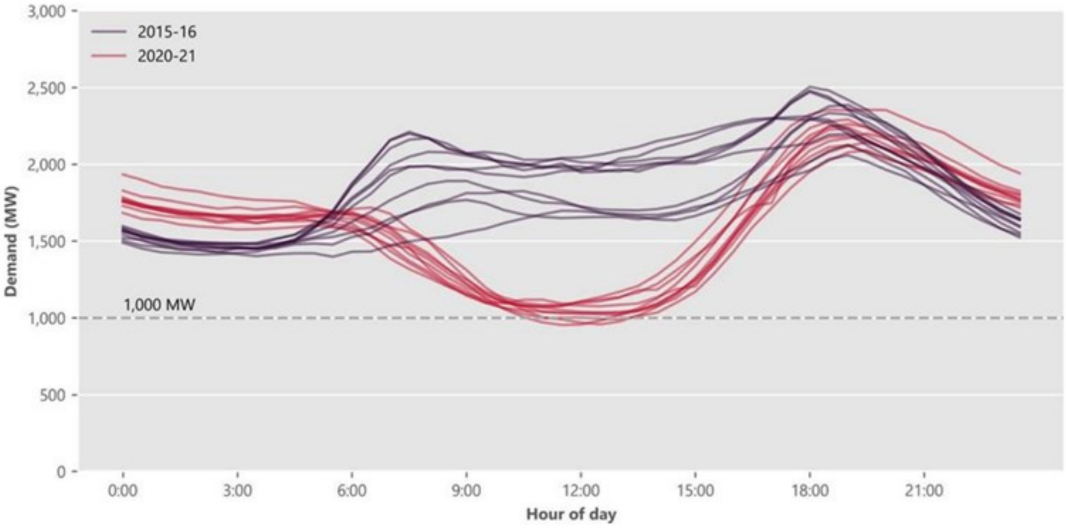
The below figure shows how the time of minimum demand has shifted considerably between 2015-16 and 2020-21, due to the increasing amount of rooftop solar PV, and created the 'duck curve' during the middle of the day.

Figure 1: Actual and forecast total installed behind-the-meter PV, 2010-11 to 2030-31



Source: AEMO, 2021 ESOO

Figure 2: Comparison of demand on the 10 low demand days for 2015-16 and 2020-21



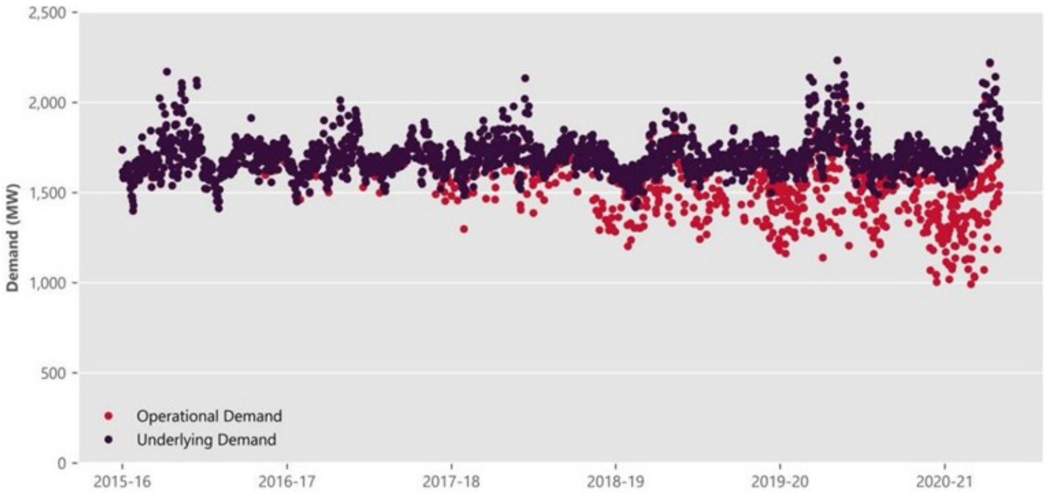
Source: AEMO, 2021 ESOO

Minimum demand records tumble

The pace at which the time of minimum demand has shifted through the day is perhaps a reflection of just how much the energy sector has changed in a short period. However, rooftop solar PV is also having a major impact on the level of minimum demand – and this has far bigger consequences.

According to AEMO, the proliferation of rooftop solar PV has reduced daily minimum demand by 265MW (on average) between October 2020 to February 2021, with annual minimums in demand decreasing at an average annual rate of 7.9 per cent between 2015-16 and 2020-21.This trend has created a growing divergence between underlying demand (i.e. demand from the network plus an estimation of rooftop solar PV and battery storage), which has stayed relatively consistent, and operational demand (i.e. demand from the network) which is declining. Put simply, we are consuming roughly the same amount of energy, but a larger portion of that energy is now coming from rooftop solar PV (see figure 3 below)

Figure 3: Daily minimum load, 2015-16 to 2020-21



Source: AEMO, 2021 ESOO

Highlighting this divergence and the speed of change in the market, the previous minimum demand record of 1,138MW (set on 4 January 2020) in last year's WEM ESOO has now been broken six times. These records occurred on sunny, mild days in the period between late winter and spring when rooftop solar PV is producing full output and there is less need for heating or cooling.

The current minimum demand record now stands at 954MW. This occurred between 11:30am and 12:00 noon on 14 March 2021.This day also set a record for behind-the-meter solar PV reducing demand by 1,130MW.

The problem with low demand

A lot of conversation about 'keeping the lights on' focuses on ensuring there is enough generation capacity to meet peak demand. The reverse situation, when demand is too low, also has major consequences for system stability.

In 2019, AEMO **produced a paper** which considered the security risks and market impacts from falling demand. In that paper, AEMO said that the minimum level of operational demand required for system security is about 700MW.

The latest version of the WEM ESOO forecasts that minimum demand will decline rapidly to 232MW by 2025-26.

The growth of rooftop solar PV and the projected low levels of minimum demand presents a serious challenge for AEMO, generators and Western Power. The huge swings in demand as rooftop solar PV comes offline in overcast conditions requires a quick ramp up from generators to meet operational demand, which is often followed by weather changes and a rapid increase in PV output forcing generators to ramp down. These swings put pressure on a generation fleet featuring some units that aren't suited to quick ramp ups, creating a higher risk of unit failure.

AEMO used an example of an event on 8 December 2020 to highlight the risks associated with changing output from rooftop solar PV forcing quick ramp rates:

"on 8 December 2020, when reserve margins were tight, two large-scale generators went on Forced Outage due to failures following a request to start up, joining another large-scale generator already on Forced Outage for the same reason. This sequence of events did not lead to a supply shortfall, because the forecast peak load was lower than anticipated. However, it does highlight an increasing concern in managing operational challenges."

The other issue that is created when operational demand falls below the minimum level is the power system will fall into an unsecure operating state and it becomes vulnerable to blackouts. AEMO said in its **2019 report:**

"Under these circumstances, the first response would be to constrain off non-synchronous generation and constrain on synchronous generation to prevent system collapse. However, instances can arise, although they are rare, where a level of shedding of DER is required to maintain system security.

"This is clearly a situation that everyone wants to avoid and it partly triggered the Energy Transformation Implementation Unit, which sits within Energy Policy WA (EPSA), to establish the Energy Transformation Strategy (ETS). The aim of the ETS was to deliver secure, reliable, sustainable and affordable electricity to Western Australians while supporting the high penetration of behind-the-meter solar PV and other distributed energy resources. While the ETS has now come to an end (the remaining activities will be led by EPWA), it has implemented a raft of reforms and changes. Some of these have been technical, like changing the Australian Standard for inverters to include a mandatory requirement for all new inverters to have a voltage disturbance ride-through capability to help maintain security and reliability in the SWIS. Others have been more fundamental, including amending the WEM Rules and Electricity Networks Access Code 2004, and a few have been contentious, such as allowing Western Power to have network connected battery storage (See **Will network operators batteries hurt competition?** you can **read more here**). In total, they are addressing an urgent need to maintain system security operating in an environment where rooftop solar PV is pushing down minimum demand levels.

Should we worry?

The WEM ESOO gives a valuable insight into the emerging issues that are worrying AEMO. At least for the short term, it appears that AEMO is comfortable with generation matching demand. More worrying is the explicit nature of AEMO's warning about rooftop solar PV causing minimum demand to drop to new, record levels and the impact that will have on system security.

"As the number of behind-the-meter PV installations continues to grow, AEMO expects that new minimum demand records will continue to be set. As these low demand levels continue, management of the SWIS will become increasingly challenging. AEMO is aware of the need for market and operational intervention to ensure the system stays secure and stable.

"The dilemma is that rooftop solar PV capacity is expected to further grow over the next decade while the system relies on synchronous generators as the backstop, but these units often are not suited to the quick ramp rates required by changes in solar output. The WA Government through EPWA has been addressing this issue head-on over the last few years through a series of reforms and changes. The WEM ESOO makes clear that this issue will remain challenging for some time to come.

It is also worth reflecting on the overall design of the WEM. The RCM underpins the firm generation capacity to meet an extreme demand. The RCM is also the principle economic signal to fund generation capacity, and because of this, the energy and ancillary services markets are capped at low levels, being designed to fund operating costs, rather than capital costs.

However the ESOO shows that in future total amount of firm generation capacity at time of peak is not necessarily the main concern. Characteristics such as ramping and ability to shut down and start quickly are becoming more critical requirements. The nature of the price capping tends to dampen the market's natural signals to encourage investment in these characteristics.

THE FREEZING WINDS OF CHANGE- ACT GOVT ELECTRIFICATION POLICY OF CONCERN TO GAS AND ELECTRICITY NETWORK OPERATORS

Author: Tamatha Smith
Date: 17 June 2021
Source: Energy Networks Australia

Four out of five Canberran households rely on natural gas to heat their homes.

The phrase 'now we are cooking with gas' wasn't born out of nowhere. Natural gas for many families is the preferred energy source for cooking and space heating. It is responsive in cooking and quickly heats homes during those frosty winter nights.

Yes, gas emits carbon – albeit at much lower rates than coal – and needs to be decarbonised, but is turning off gas networks the best way to get to zero emissions? Not if customers want to avoid big hits on power bills, like we will see on 1 July for electricity in Canberra.

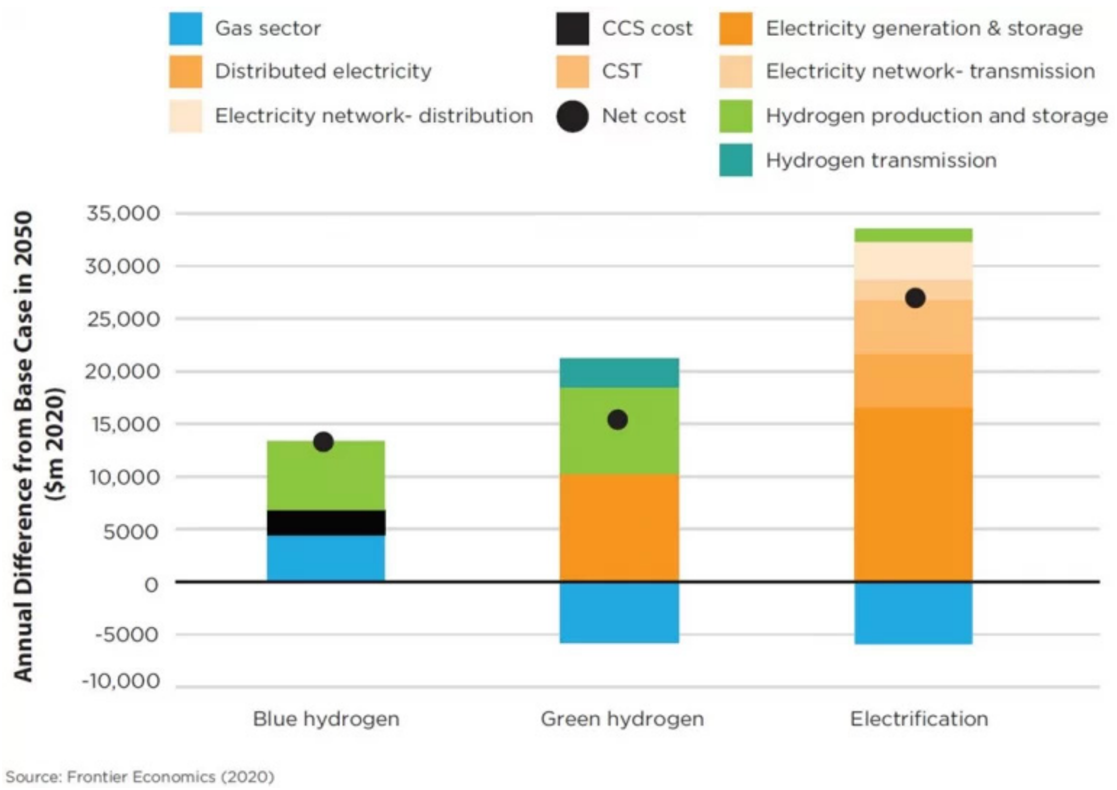
That hike has been caused by increases in the cost of the ACT's large-scale feed-in tariff to reach the 100 per cent renewable electricity target.

Switching from gas to electricity sounds straightforward until you consider that gas provides twice as much energy to the ACT as electricity does. Turning off gas means the ACT electricity system would need to deliver three times the energy it does today. Moreover, gas in the ACT is typically used between May and September so any new electricity infrastructure to replace this heating will be majorly underutilised. Energy efficiency of appliances and homes can decrease that, but it will still be a massive and costly increase.

More power generation and more grid capacity will be required. Paying for these upgrades would significantly increase power bills for electricity users, on top of this year's price hikes. Customers on the gas network will pay for these costs twice: once as an increase on the electricity network but also a price increase from the gas network as fixed costs for gas supply are recovered from fewer connections. More bad news for customers, especially those vulnerable customers who are unable to make the transition to an electrified home without major energy efficiency upgrades.

To be clear, the question is not should we reduce the ACT's emissions from gas use, it's how best to do it.

Research for Gas Vision 2050 – Delivering a Clean Energy Future found that net-zero emissions can be reached at half the cost of electrification by replacing natural gas with renewable gas.



Decarbonisation costs (Source: Gas Vision 2050: Delivering a Clean

This will see gas pipelines and infrastructure used to supply renewable hydrogen. This is a much cheaper option than delivering the additional energy through electricity transmission lines and expansions to the poles and wires network.

The good news is that this is far from a pipe dream – the transition to green gas is underway. Australia's first hydrogen facility for gas networks is in Canberra and has tested the suitability of the network to carry hydrogen. The ACT is also a leader in demonstrating the role for hydrogen fuel cell vehicles.

Just a few weeks ago the NSW Government announced a renewable gas certification pilot scheme which will enable gas users to identify and purchase renewable gas products with confidence.

In South Australia, 700 Mitchell Park households are already cooking with renewable gas, with the blending of hydrogen into the existing gas network. This will be followed by conversions of entire networks to 100 per cent renewable gas in the next few years.

Right around the world engineers are trying to figure how they will manage what the Germans call dunkelflaute – long periods in winter with little electricity generated by solar and wind. Batteries, pumped hydro and demand response are all likely to play a role, but one thing is very clear: if places like Canberra shift all their existing gas heating and cooking load to electricity, managing dunkelflaute will be much harder and more expensive.

It's important we decarbonise our energy supplies using options that harness our natural resources and use existing infrastructure, without hitting customers in the hip pocket. There's no place in the country where renewable gas makes more sense than the ACT.

AER SETTLES LEGAL ACTION AGAINST NEOEN AND PACIFIC HYDRO OVER SA BLACKOUT

Author: Michael Mazengab
Date: 2 July 2021
Source: Renew Economy

Wind farm operators Pacific Hydro and Neoen have agreed to pay fines totalling $1.65 million under a legal settlement to action brought against them by the Australian Energy Regulator after the dramatic state-wide blackout in South Australia in 2016.

The two wind energy companies opted to settle the legal proceedings after conceding there had been breaches of the National Electricity Rules relating to low voltage ride through settings at Pacific Hydro's Clements Gap wind farm and Neoen's Hornsdale wind farm.

The two companies agreed that they had failed to seek written approval from the Australian Energy Market Operator for their settings – but other contraventions alleged by the AER were withdrawn.

Importantly, this included the effective withdrawal of the regulator's assertion that the breaches were a "contributing cause" to the black out.

Under performance standards lodged with energy market regulators, the wind farms were required to maintain the operation of their turbines across a certain number of voltage disturbances before the turbine's safety systems intervened to shut it down.

Regulators alleged that six wind farms operated by Pacific Hydro, Neoen, AGL Energy and Tilt Renewables had an unapproved set of protection settings that saw their shut down protections kick in sooner than expected in the dramatic events of that day, resulting in an unanticipated cut to output.

The AER, which brought legal proceedings against the four wind farm operators, said that the settlement – that included a $1.1 million fine to Pacific Hydro and $550,000 to Neoen – showed the importance of generators obtaining necessary written approvals for changes in operational settings.

"As we become increasingly reliant on new forms of generation with different technical characteristics, it is more important than ever that all generators comply with the rules so households and businesses can keep the lights on," AER chair Clare Savage said in a statement.

"It is paramount that generators obtain written approval for system settings on their generating units from the Australian Energy Market Operator (AEMO) to ensure power system security and the effective operation of the wholesale energy market."

In the lead up to the 2016 South Australian blackout, extreme weather events had caused severe damage to power lines throughout the state, bring down multiple towers and three main transmission lines, which caused voltage disturbances to ripple throughout the grid.

Unbeknown to market operator AEMO, these disturbances triggered protection settings in a number of South Australian wind turbines, causing them to go offline when they were otherwise expected to remain operational.

When the loss of generation from the wind farms were combined with the impacts of downed power lines, and the South Australian grid became unstable, triggering a system black event and leaving around 850,000 homes and businesses without power.

The AER has previously criticised the market operator for a failure to prepare for the anticipated storms, and for committing five breaches. In a 2018 report it said AEMO had failed to take "all reasonable steps" to keep itself informed of the impending storm, and to advise market participants.

AEMO now takes a much more cautious approach in similar circumstances, including dialling down the amount of electricity being transferred on inter-connectors, instead of running it at full tilt as it had in the lead up to the South Australian black out.

In that report, the AER also noted that Origin Energy had "met its obligations," even though its Quarantine power station failed to do what it was paid to do, provide a quick "black start" – a failure that dramatically extended the length of the blackout.

In orders published on Thursday, Federal Court Justice Richard White said that the failure to seek approval for the protection settings contributed to the difficulty for market operators to maintain a stable grid during the extreme weather events.

"Use of non-approved settings in the present case compromised AEMO's ability to discharge its responsibility because it meant that it was making important decisions concerning the secure operating limits of the power system on the basis of incomplete information," Justice White said.

"As the events of 28 September 2016 indicate, a compromise of the security of the power system can have extensive and serious consequences."

The AER had alleged that this represented a breach of the National Electricity Rules, as the wind farm operators had failed to seek written approval from system operators for the actual protection settings of their wind turbines.

Both Pacific Hydro and Neoen conceded that a breach of the National Electricity Rules had occurred and agreed to the fines imposed, and will contribute to the legal costs incurred by the AER and will be required to lodge updates to their respective Generator Performance Standards.

In a statement issued following the judgement, Pacific Hydro said that the legal proceedings commenced against it by the Australian Energy Regulator had been a "distraction", and that the company was now happy to be able to "move on".

"We have decided to settle the proceedings with the AER so we can continue to focus on delivering affordable, clean, renewable energy to the Australian community," CEO Rachel Watson said.

"This dispute has been a distraction and we wish to focus on delivering our clean energy vision and our pipeline of exciting new projects."

Tilt Renewables reached an earlier settlement with the Australian Energy Regulator, agreeing to pay a $1 million fine for breaches relating to the operation of the Snowtown 2 wind farm.

Similar proceedings brought against AGL Energy relating to the Hallett wind farms are ongoing. Likewise, proceedings against the Pelican Point gas generator, operated by Engie, relating to February 2019 blackouts also remain going.

NT GRID HIGHLIGHTS ISSUES WITH CONNECTING LARGE ASYNCHRONOUS GENERATORS

Author: Giles Parkinson
Date: 16 July 2021
Source: Renew Economy

The Northern Territory has an ambitious goal of reaching 50 per cent renewables by 2030. But the plan is off to a bad start – the renewable share has barely moved from around 7 per cent – and the Top End's first four utility-scale solar farms are sitting idle because they cannot gain approval to be switched on.

Three of the four solar farms are owned by Italian multinational ENI – a 25MW facility at Katherine, and two 10MW facilities at Batchelor and Manton. Melbourne-based Merrick Capital owns another 10MW facility at Batchelor, known as Batchelor 2.

All finished construction in 2020, and Katherine at the start of that year. All, however, cannot be switched on because of strict new rules that dictate their bidding behaviour and dispatch, and due to concerns by system control over what might happen if they do. Some suggest the dispute could be heading to the courts.

Two other Department of Defence solar farms have also been delayed by changes in connection rules, a 9.2MW facility at Robertson Barracks, and a smaller 2.5MW facility at the RAAF's Darwin base, even though they are both "behind the meter" and have batteries equivalent to one quarter of their capacity.

The one operating solar farm in the Darwin region of any size is at the Darwin airport, (pictured below) a 5MW facility which also operates behind the meter, but is not allowed to export any power, even to tenants at the airport itself.

It's true that many large scale wind and solar projects also face big delays in Australia's main grid, but as RenewEconomy has written previously, there is a degree of fear and loathing in the Northern Territory over the transition to renewables, which in the case of the NT largely means solar. And it's not about plans for the world's biggest solar farm further south at Newcastle Waters, but how to connect relatively small facilities in the territory's biggest grid.

The problem appears to lie in a mix of old-fashioned scepticism about new technologies, the vulnerability of ageing infrastructure, the particular problems of the Darwin-Katherine grid, and the failure to plan and prepare for the government's clean energy transition target. The lack of modelling and engineering means that many involved are scared of blackouts.

"They don't want to connect it"

"System control is scared of dispatching solar. Under the market rules the "least cost generator" should be dispatched first – that's solar. They just don't want to connect it," says Alan Langworthy, the former head of network company PowerCorp, former head of renewables at multinational ABB, and Chair of the Roadmap to Renewables report that outlined the territory's path to 50 per cent renewables.

Langworthy says the fear of solar is not the fault of solar technology, nor the fault of engineers in System Control, he blames the lack of government planning and a failure to do the necessary dynamic modelling, which would identify what the system needs to handle the shift to solar.

"I've been telling them for years they need to complete a dynamic model of the network," he tells RenewEconomy. "I'm flabbergasted they don't have one, nor the in-house skills to use it. It's a complete failure of leadership from the Government in managing the grid going forward."

Langworthy's frustrations are shared by the NT Utilities Commission, which has criticised the government for not moving fast enough to deal with the major risks to the grid, either by delivering a detailed plan or implementing much needed market reform.

"Time is running out to meet the emerging risks," Utilicom says in a withering assessment in its Electricity Outlook Report, which cites the impending retirement of ageing gas generators, the impact of increasing and uncontrolled rooftop solar, and the need to accommodate new generation, such as solar and storage.

"The Commission is concerned the Territory is lacking a clear framework by which these concerns can be addressed in the most efficient and timely manner," it writes.

"The government, or System Control must urgently and clearly define what services are needed to address current and future security challenges."

What everyone is calling for is the equivalent of an Integrated System Plan that has been prepared by the Australian Energy Market Operator for Australia's main grid, or the Whole of System Plan drawn up for Western Australia.

The Northern Territory clearly has challenges. It has around 170MW of average demand, but already has more than 100MW of rooftop solar. It has to operate significant amounts of gas generation as "spinning reserve" – at great cost – and is making new connections almost impossible.

The companies most affected by the stand-still on the solar farms – developers ENI and Merricks Capital and the retailers Rimfire and Jacana (which have off-take agreements) – would not comment on the record to RenewEconomy.

New rules are "onerous, unprecedented and indefensible"

But ENI, a major international energy company which operates a major offshore gas field near Darwin, has made its frustration well known, accusing the regulators of imposing "onerous, unprecedented and indefensible" forecasting requirements.

It suggests in various submissions to UtiliCom that the reasons for the onerous rules are that the control of system frequency in the Darwin Katherine grid is too slow for a power system of its size.

"The shortcomings of this type of control system require so much inertia as to make it difficult to accommodate renewables and unfortunately the renewables are then unreasonably curtailed, including through the application of onerous, unprecedented and indefensible forecasting requirements," it says.

ENI has already built a 5.7MVA/2.9 MWh battery energy storage system at the Katherine solar farm, but under the strict new bidding rules imposed by PWC that wouldn't be nearly enough.

It estimates it would need 20MW/10MWh of battery to support its 45MW of solar installations, or an upfront cost of $20 million plus maintenance and round trip losses. And it's furious that these new rules apply to its projects that were either complete or under construction before the change.

"EAL (ENI) has strong concerns about the economic and technical inefficiency of the proposed GPS… (but) our main concern is that already sanctioned and committed projects are not being grandfathered, without justification," it writes.

"This precedent would create a degree of regulatory risk which will significantly raise the cost of capital for new renewable energy investment in the NT, a form of energy generation that relies on a low cost of capital, thereby creating an additional unnecessary barrier to market entry."

ENI further notes that it is not the job of individual solar farms and their GPS to ensure a power system has adequate supply of capacity, energy or storage going forward.

"If a shortfall of capacity, for example, presents itself in the DKIS, it is the proper task of government policy to provide the right market or structural incentives to fix," it says.

"Using technical regulations to solve perceived failures or shortcomings of commercial or market arrangements sets a very dangerous precedent."

As Utilicom points out, the problems are magnified by the nature of the Darwin-Katherine grid – relatively small, and dependent on a long stringy line.

"In some power systems the growth of asynchronous generation has been so fast that the market and or market rules have not adapted to avoid the risks to system security and reliability from such rapid growth," Utilicom points out.

"For the Territory's power systems, which are small, isolated, lacking in diversity of renewable energy technologies and without appropriate supporting frameworks, the challenges and opportunities are likely greater and certainly immediate in terms of needing urgent attention to protect the long-term interests of Territory electricity consumers."

But the lament is that leadership is lacking, and bar some exceptions, the talent pool is shallow.

"The four solar farms are the first new generators to be connected to the grid for nearly 20 years," says one observer. "The corporate memory of how it is done is not there. They are focusing only on the short term. They are trying to keep the lights on but the network is held together with duck tape."

And, following the recent blackout in Alice Springs and the subsequent resignations of the territory's two most senior energy executives illustrates, everyone is risk adverse.

Darwin Big Battery won't be big enough

There is some movement. The territory government finally responded to pleas of energy experts and is conducting a tender for a 30MW big battery to be located in or near Darwin.

But the experts say it won't be anywhere near big enough to solve the problems at hand, and its primary focus will be to simply allow one less gas turbine to spin as back-up.

In a statement to RenewEconomy, minister for renewables and energy Eva Lawler said: "The Territory Labor Government continues to invest in delivering affordable, clean, reliable and stable energy for Territorians and these solar power stations will contribute to the Territory's 50% renewables energy target.

"The solar power stations at Katherine and Manton, and one of the Batchelor power stations are connected to the power grid and have been energised. Each are now progressing through the final stages of commissioning and compliance testing to ensure each power station operates in a safe, stable and predictable manner.

"The connection of the second Batchelor solar farm is imminent, after which commissioning and compliance testing will commence."

On the delay in market reform, Lawler said:

"Since the report the Darwin-Katherine System Plan is well progressed, along with our Alice Springs Future Grid project. These will clearly set out Government's pathway to 50% renewables by 2030.

"Earlier this year we released our draft policy position and consultation papers on priority electricity market reforms – which will address system security, reliability and efficiency; encouraging private investment and maximising the amount of renewable power in our network. These papers should be finalised later this year."

It will be interesting to watch. Some observers fear the dispatch restrictions may mean the solar farms will be able to send little power to the grid, if they do manage to complete compliance testing.

Langworthy says there are real fears that a major blackout could affect the Darwin-Katherine grid, such is the lamentable state of the system.

The Utilicom report highlights the weaknesses in the system, including regular and multiple trips of the gas generators. But, of course, if the lights go out, the finger will inevitably be pointed to renewables.

Langworthy says the Roadmap to Renewables Report five years ago spelt out how renewables would provide "downward pressure on the cost of electricity" and it provided a clear set of key actions to be taken by Government to achieve it. But it seems it has fallen on deaf ears.

"I am very cranky, as you can gather," says Langworthy. "This is hopeless."

POWERLINK LOOKS TO BATTERY STORAGE TO HELP SOLVE GRID STABILITY PROBLEMS

Author: Giles Parkinson
Date: 1 July 2021
Source: Renew Economy

Queensland based transmission company Powerlink says it will deploy battery storage to help solve grid stability problems such as system strength as part of a new multi-faceted approach to handling the surge in wind and solar generation.

Battery storage has suddenly emerged as a solution to grid issues that many engineers thought could only be solved by synchronous generation or spinning machines, and the newly affirmed capabilities of battery inverters is good news for the inevitable switch to a grid dominated by wind and solar.

Earlier this week, as RenewEconomy reported exclusively, the Australian Energy Market Operator confirmed that re-tuning of inverters at four solar farms and a wind farm had effectively solved "system strength" issues in north Queensland, meaning machines such as synchronous condensers would not be needed.

See: Groundbreaking solar inverter solution points way to grid free of fossil fuels

Powerlink CEO Paul Simshauser says that a series of studies and reports done with the Australian Renewable Energy Agency, zinc producer and solar farm operator Sun Metals, renewables company Pacific Hydro and GHD, confirmed the key role that battery storage could play.

"The final report demonstrated the role grid forming batteries can play in enabling renewables and supporting the safe and stable operation of the power system," Simshauser said in a statement.

"We've found grid forming batteries can supply system strength, as well as other key services which support the network and assist renewable connections to effectively operate.

"Powerlink will now apply these learnings to reduce the time, cost and risk of renewable connections to the grid, benefiting both Powerlink and customers in the long-term.

"With the recent influx of battery interest by generators and developers in Queensland, we now have a number of opportunities to pilot grid forming batteries and validate our report findings through field studies."

Grid forming batteries create their own frequency and voltage wave forms, which means that rather than following the signals of other installations, they can "hold their own" and maintain stability in the event of a major grid disruption.

They are often used in small off-grid systems, but are now increasingly deployed in larger networks – such as those that power the huge mines in the Pilbara – and are being increasingly deployed in the main grid, including at the Hornsdale Power Reserve, which showed its capabilities after the recent Callide coal explosion.

Battery storage will not be the only technology solution considered by Powerlink to solve system strength, and it also looking at using synchronous condensers, but only where they are centrally located and can provide services for multiple customers.

This is yet another repudiation of the ad hoc, chaotic, expensive and ultimately self defeating "do no harm" rule introduced by regulators several years ago, against the advice of many experts.

That "do no harm" requirement did the opposite of what was intended. It added tens of millions of dollars to the cost of some wind and solar projects, and ultimately served to weaken rather than strengthen the grid, according to transmission companies such as Transgrid.

Simshauser said one of the key findings of its studies confirmed that a centralised synchronous condenser solution could provide significant network and financial benefit when compared to renewable proponents having to provide their own.

Powerlink is looking to provide that capability as a service, presumably at a cost, to new wind and solar projects.

"System strength is a complex issue, with the study highlighting there is no one 'best' form of system strength remediation that can be applied to all renewable projects," Simshauser said in a statement.

"The reports demonstrate the merits of each different approach, but really confirmed that solutions have to be tailored for renewable proponents by thoroughly reviewing the particular circumstances of the network connection.

"Our key goal is delivering a safe, reliable and secure transmission network for Queensland and facilitating the transition to a low carbon future. This study has been another step in the right direction to achieve this."

Battery storage, however, is proving itself capable of providing system services at multiple levels. The six operating batteries in the main grid have successfully captured most of the frequency control market, and a new market – fast frequency control – is being created in recognition of their speed and flexibility.

Batteries such as Hornsdale are now delivering "synthetic inertia" and operate as "virtual synchronous machines", which is the next step up from grid forming inverters, using software to allow the grid forming inverters to co-operate and act as a shock absorber for grid disturbances.

Batteries are also being deployed as "virtual transmission" lines, serving to increase the capacity of existing power lines to absorb heavier loads and more renewables.

The Victoria big battery – which at 300MW/540MWh will be the biggest in the country, and will boost the capacity of the NSW-Victoria transmission link at peak times. It is being built by Neoen using Tesla megapack technology.

Victoria's Powercor is also proposing up to 20 big batteries scattered around its network to support the increase of wind and solar and boost grid security, while networks such as Western Power in WA and Ausgrid in NSW and United Energy in Victoria are using smaller "community" scale batteries to support rooftop solar in their networks.

Queensland currently does not have any big batteries of note in its grid, although the first, a 100MW/150MWh installation at Wandoan South, is being built in southern Queensland.

Many more are proposed or in the pipeline, including next to some of the state's biggest coal generators, some announced in a "battery blitz" that followed the Callide incident.

For more of current and future battery storage projects, please go to RenewEconomy's new battery storage map: Big Battery Storage Map of Australia

UV UPDATES

VOLKSWAGEN TO PHASE OUT COMBUSTION ENGINES IN EUROPE BY 2035

Author: Benjamin Wehrmann
Date: 29 June 2021
Source: The Driven

Europe's largest car brand Volkswagen will end the sale of combustion engine cars in the region by the middle of the next decade, branch manager Klaus Zellmer said in an interview with newspaper Münchner Merkur.

"We prepare for a possible tightening of [EU climate] regulations," Zellmer told the newspaper, adding that Volkswagen will phase out combustion engines in its production lines in Europe between 2033 and 2035.

A similar move would be made in the US and in China "a bit later," whereas a complete shift in Africa or South America would take significantly longer due to lacking infrastructure for e-mobility.

The Volkswagen brand of umbrella company VW, which also owns other brands like Audi, Skoda or Porsche, would increase its share of electric vehicles to 70 percent of total sales in the region by 2030, Zellmer said.

However, he stressed the debate about climate targets would still be "unfinished." The Volkswagen manager said some countries in Europe would ban combustion engines sooner than others, while e-cars would not make sense ecologically in some countries due to a high coal share in power production.

"That's why we need a little wiggle room regarding the use of combustion engines or battery-electric cars." He added that Volkswagen would continue to invest in improving the efficiency of its combustion engines and plans to use diesel fuel technology in the future.

Zellmer also said that the difficulties the European car industry experienced in recent months with procuring sufficient volumes of semiconductors from Asia highlighted the benefits of installing independent European production capacities. "This reduces costs, lowers emissions and allows us to react quickly."

Electric cars will need to account for most new registrations in Germany in just four years and the end of new combustion engine cars will have to begin in 2030, according to a recent report by the National Platform Future of Mobility (NPM) for the Federal Transport Ministry.

In order to achieve the federal government's climate targets in the transport sector, around a third of all vehicles – some 14 million cars – will need to be electric by 2030, the report states. Last year, the German car industry commited to achieving climate-neutrality by 2050, but rejected a sole focus on electric mobility.

NEW ELECTRIC KOMBI SEEN CHARGING AHEAD OF ITS FORMAL 2022 REVEAL

Author: Bride Schmidt
Date: 29 June 2021
Source: The Driven

The upcoming all-electric Kombi – to be known as an ID.Buzz in its passenger format and ID.Buzz Cargo in a commercial format – has been snapped charging its battery at a station in Germany ahead of its 2022 unveiling.

Instagrammer David Red saw the electric Volkswagen charging at a car wash facility in Braunschweig, Germany and posted his photographs of the vehicle to his Instagram account on Sunday (Europe time).

Notably, it was parked next to a T6 Transporter at the time, giving a great opportunity for size comparison.

Red, who drives a Volkswagen electric ID.3 Pro Performance, said in his post: "I was amazed when I noticed the ID.Buzz on the charging station while charging. Somewhat camouflaged and accompanied by a T6. Perfect for size comparison!"

Well, it clearly wasn't camouflaged too well considering it was hooked up to an electric vehicle charger. But nevertheless, the sighting is interesting – not least because Volkswagen has said previously that it will commence testing an autonomous ID.Buzz in 2021.

However, it would appear that this vehicle is not set up to be autonomous – at least not yet.

In March, Volkswagen Commercial Vehicles shared that its plans for an autonomous ID.Buzz would use AI software developed by Argo AI and involve setting up a ride-sharing or carpooling service eventually.

Images shared in that announcement at the time show an ID.Buzz with what appears to be a 360-degree sensor at the top of the vehicle, which the images shown by Red are clearly missing.

Unless Volkswagen has chosen to embed cameras in sensors into the vehicle instead, Tesla-style, we're banking on this being a standard ID.Buzz.

Whether or not the ID.Buzz will make it to Australia after its 2022 launch is something of a mystery.

Volkswagen has previously lambasted the Australian government for impeding a local transition to emissions-free transport – going so far as to call it a "third world" for EV policy – and said that Australia's lack of supportive policy for EV adoption would hold its local arm from importing new electric models like the ID.3 and ID.4 until at least 2023.

But more recent movements in state EV policy have brought it around to a more positive stance.

However, while the introduction of rebates for EV purchases – $3,000 for the first 20,000 drivers in Victoria and up to 25,000 drivers in NSW, along with a range of other incentives – has been welcomed by carmakers including Volkswagen, the elephant in the room is the continuing lack of vehicle emissions regulations in Australia.

This is because it needs to prioritise inventory to Europe – where carmakers face big fines if they don't bring their fleet emissions average to under 95 grams of CO_2 per kilometre.

Australia has no such regulations in place, even though some states are bringing in road user taxes for electric vehicles whilst ignoring the impacts and ensuing social costs that high-emitting combustion engine vehicles have on health, air pollution and climate. Victoria's EV road user taxes come in to play on July 1, 2021 and are tipped to cost drivers an average of $300-500 a year.

PERSUADING EV OWNERS TO FEED INTO GRID MAY BE HARDER THAN WE THINK

Author: James Fernyhough
Date: 30 June 2021
Source: The Driven

Earlier this month, BloombergNEF made the exciting claim that by 2040 electric vehicles could be supplying three times Germany's peak energy demand – so long as they are all fitted with vehicle-to-grid charging equipment.

It's an amazing figure, and shows that if we get a lot of things right, EVs could provide a huge amount of the storage and firming required in a zero-carbon grid dominated by intermittent wind and solar generation.

But that's a key point – we need to get a lot of things right. And this week Scott Chapman, general manager of new market services at the Australian Energy Market Operator, poured a little cold water on the notion that we'll soon all be the enthusiastic owners of our own personal power plant on wheels.

The problem, he said, was persuading EV owners to view their cars as dual purpose power plants rather than just a personal means of transport, which requires a major shift in attitudes before you even consider the cost of the equipment.

His comments were based on the experience of AEMO's new CEO, Daniel Westerman, in the UK. Before joining AEMO in May, Westerman was for many years a senior executive at the UK's main electricity transmission operator, National Grid.

The UK is a leader in EV uptake, with electric cars making up more than 10 per cent of sales last year. A number of utilities and EV companies in the UK have been running vehicle-to-grid pilots, similar to the one currently underway by AGL and Nissan in Australia, but on a bigger scale.

Speaking at an event hosted by the Smart Energy Council on Tuesday, Chapman said Westerman's insights on the UK experience were less than encouraging.

"It was interesting in his opinion, because in the UK, they've been really trying to engage [consumers on vehicle-to-grid], and are having trouble overcoming this idea that consumers have, that the charge in their batteries is exactly like petrol in the tank," he said

"And they wouldn't siphon petrol out of the tank to give to others to help them out, unless it were an extreme set of circumstances. And that sort of seems to be relaying into the whole vehicle to grid debate.

"I'm personally optimistic that Australia will be different, that we can get EV participation, but just that little point of note of the experience in the UK. So will EVs be the solution? I'm not sure, we'll see."

Attitudinal change is only one piece in the puzzle – price is potentially a much bigger one. AGL and Nissan are currently running a pilot scheme testing vehicle-to-grid technology using bi-directional charging equipment that costs around $10,000. Persuading the few consumers that can afford it that it is worth the money will be difficult if not impossible.

But Gabrielle Kuiper, an energy analyst at the Institute for Energy Economics and Financial Analysis who was also speaking at the Smart Energy Council event, said even if vehicle-to-grid was a tough ask, soon the economics would be enough to persuade EV owners to at least use their car batteries to power their homes.

“I do think that people are under-estimating the importance of electric vehicle batteries,” she said.

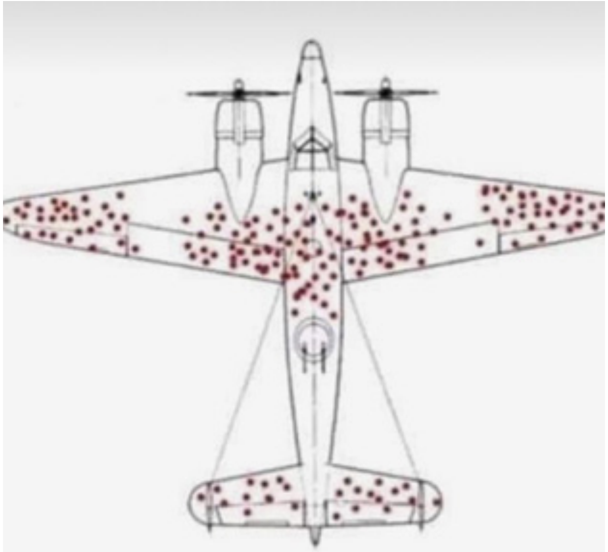
“I think it will be one of those temporary consumer issues until the commercial imperatives are such that people will inevitably – even if they don’t do vehicle-to-grid – be using their car batteries to power their homes. The costs are just going to fall so fast that you’d be foolish not to do so.”

HISTORY LESSON

BULLET HOLES IN PLANES AND SURVIVORSHIP BIAS

Management by fact requires care

Author: Terry Miller
Date: 16 July 2021
Source: Mcdreamiemusings



This is a picture tracking bullet holes on Allied planes that encountered anti-aircraft fire in WW2.

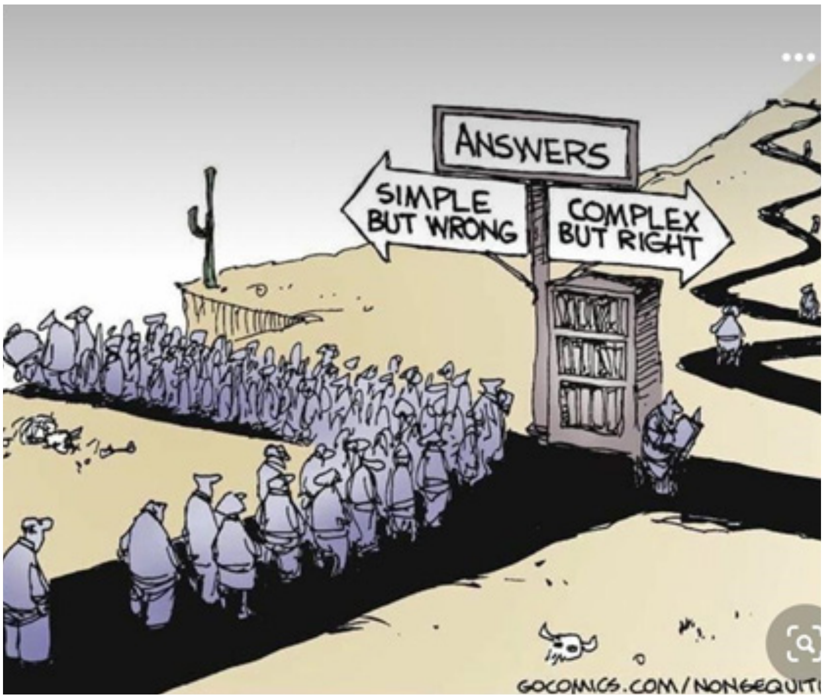
The American military decided to reinforce those areas, because obviously that's where the most damage was observed on returning planes.

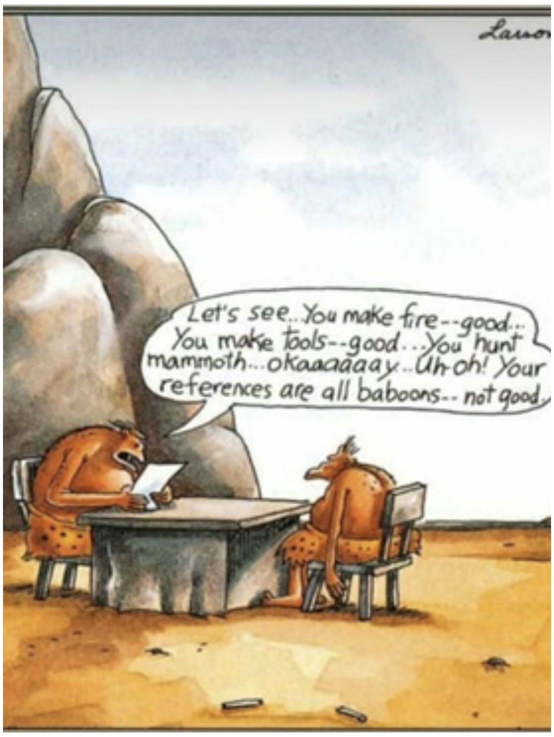
Then Abraham Wald intervened. A Hungarian-born statistician who had fled the Nazis and settled in America, Wald was part of a think tank team - the Statistical Research Group - helping the US military approach military problems with research methodology.

Wald pointed out that this was the damage to the planes that ***made it home***, and the planes should be armoured in the areas where there were no holes at all, because those are the places where the planes won't survive when hit. This phenomenon is called ***survivorship bias***, a logic area where you only look at subjects who have reached a certain point without considering the (often invisible) subjects who haven't. The diagrams of bullet holes actually showed the areas where planes could survive damage and still be able to fly and bring them and their crews home.

Management by fact is good practice. Just make sure that you are using the right facts.

HUMOUR CORNER

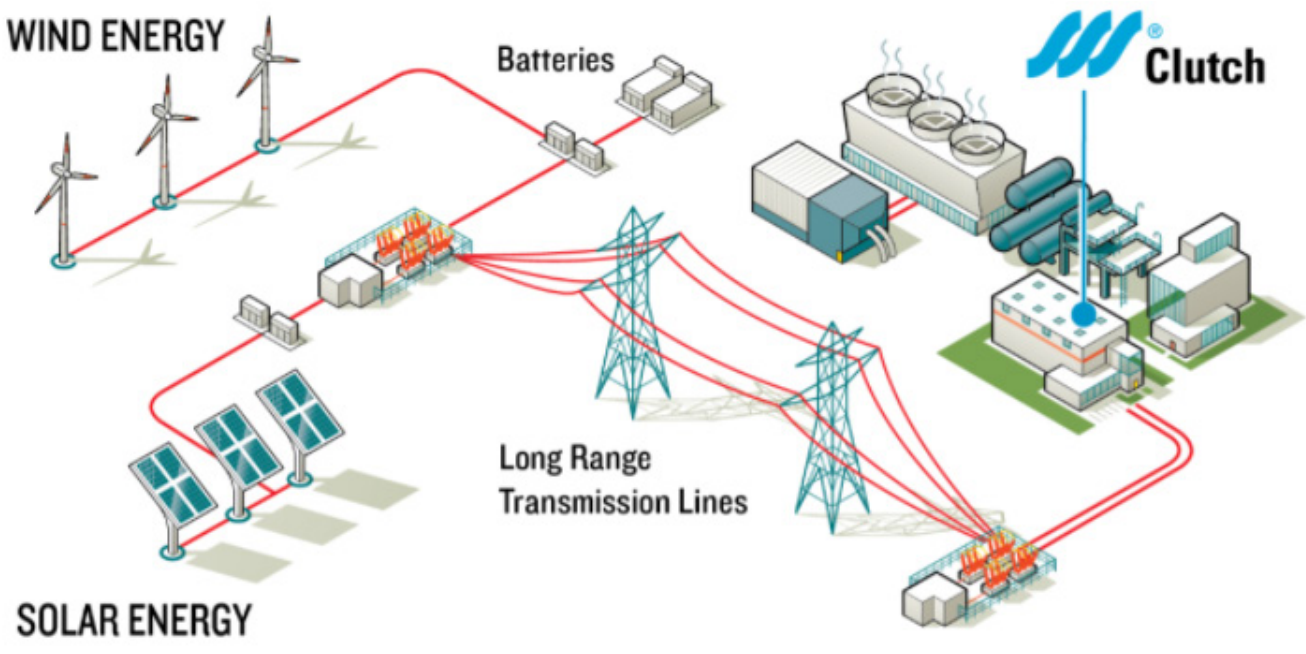




INTERNATIONAL ARTICLES

Balancing a renewable grid: What are the options?

Author: Archie Robb
Date: 13 July 2021
Source: Power Grid International



Existing turbines can be repurposed to provide grid support for renewables by retrofitting a clutch.

Over the past decade or so, the dominant trend has been the retirement of coal plants and the steady advance of renewable sources of generation. The next wave appears to be the phasing out as many natural gas-fired facilities as is feasible as more wind and solar resources are deployed.

But there has been an unintended consequence in this headlong rush to displace rotating generation assets – grid instability. The steam turbines and gas turbines of power coal plants, combined cycle and natural gas peaking facilities play a vital role in terms of grid inertia, stability, and the provision of reactive power in the form of VARs (Voltage Ampere Reactive).

In the UK, for example, the government has committed to phasing out all coal-fired power generation by 2025. Over the past decade, the nation has installed around 20 GW of renewable power. As a result, just over a third (37.1%) of the UK's electricity comes from renewable sources with plans to install a further 40 GW of offshore wind over the next decade. As more wind and solar floods onto the grid, instability and inertia issues will increase.

"Renewable power is connected to the grid electronically rather than directly as a large centralised power station would be," said Mark Tiernan, Head of High Voltage Substations United Kingdom at Siemens Energy. "As a result of the shift away from coal, there are fewer large spinning turbines on the grid, and this has led to a reduction in the amount of inertia in the system. The loss of synchronous gas turbine and steam turbine generators leads to system instability in the form lower system inertia."

Electrical Gear

A variety of approaches are springing up that aim to provide such services in order to maintain and accelerate the pace of renewable adoption. Traditional electrical solutions to this problem include capacitors, static VAR compensators, and static compensators.

Capacitor banks are typically installed at electrical substations. They consist of shunt capacitors. They are relatively cheap, reliable, and easy to install. But disadvantages include their large footprint, and the fact that they can only supply reactive power, they cannot absorb it. When load rapidly increases and voltage drops, the effectiveness of capacitors diminishes.

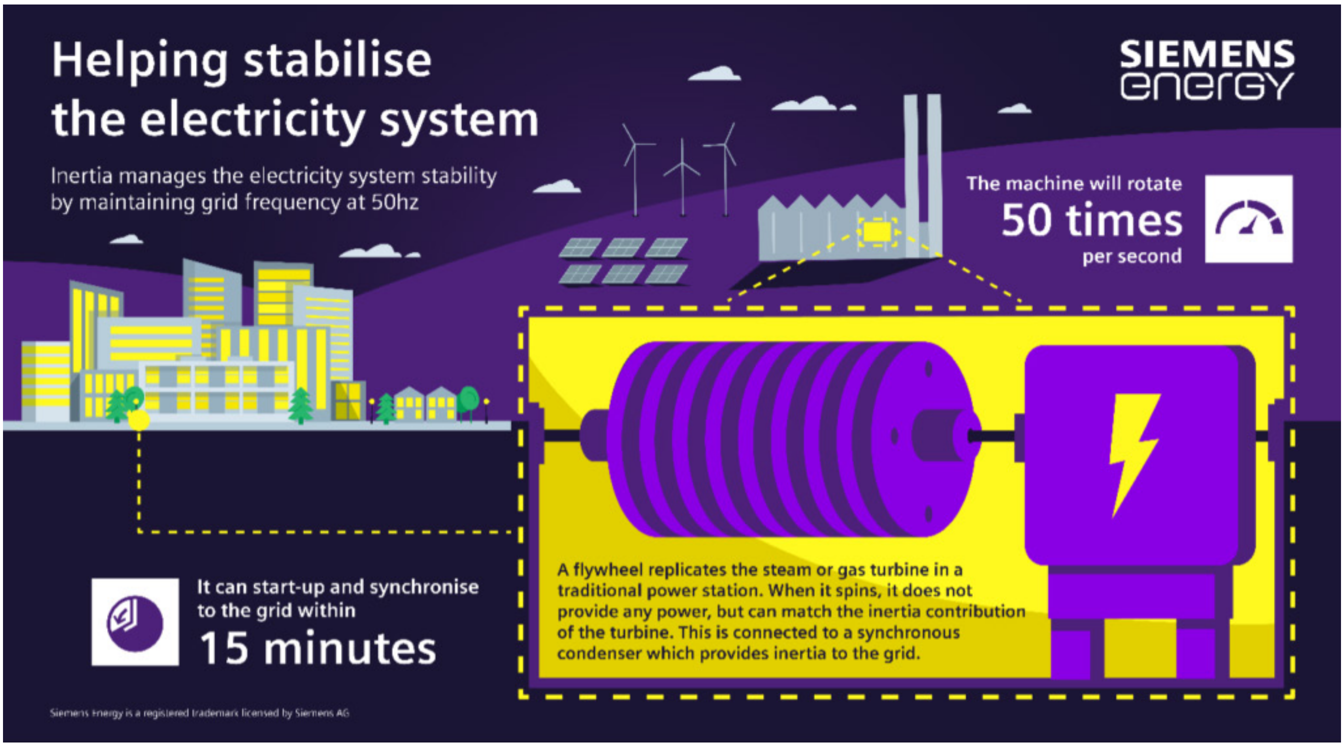
Static VAR Compensators (SVCs) are basically electrical switches. They consist of shunt capacitors and reactors and offer a greater degree of voltage control than simple capacitors. They can absorb and supply reactive power, but struggle in the face of voltage instability or collapse.

Static synchronous compensators (StatComs) make use of sophisticated power electronics rather than capacitors and reactors. They provide a much faster response time (microseconds) and take up less space. But are pricey compared to more basic equipment. Examples include American Superconductor's Dynamic VAR (D-VAR) systems, S&C Electric Company's Purewave DStatCom, and Siemens Energy's SVC Plus.

SVC Plus combines a StatCom and multilevel converter technology. The guts of the system comprise a collection of electrical components such as insulated gate bipolar transistors (IGBT), reactors, capacitors, and AC power transformers. It can quickly inject inductive or capacitive power to stabilize transmission systems and reduce the risk of voltage collapse and blackouts. This Siemens Energy unit is about half the size of a conventional SVC.

German transmission system operator Amprion commissioned Siemens Energy to provide two SVC Plus systems to stabilize the German grid. The plants are for Polsum, North Rhine-Westphalia and Rheinau, Baden-Württemberg. They provide a reactive power range of +/- 600 MVAR and keep the grid voltage in a stable range. Overall, transmission operators calculate that the German grid needs up to 28 GVAR to provide enough stability and inertia.

Italy, too, is adopting this technology. Terna. S.p.A has ordered two SVC Plus systems. They will contribute to interconnections between Italy and Montenegro and mainland Italy and Sardinia. Terna has two similar systems being installed in Italy's Marche region. They will go online gradually between late 2021 and mid-2022.



Synchronous Condensers

Synchronous condensers are another way to address grid instability issues. Once again, there are a variety of systems on offer. Siemens Energy and GE offer competing electrical systems.

The Siemens Energy unit comprises a synchronous condenser to provide inertia to strengthen the grid, short circuit power for reliable operation, and reactive power for voltage control. In essence, the synchronous condenser is a large piece of spinning machinery made up of a generator and a flywheel. When connected to the grid, it provides the inertia by spinning continuously in sync with grid frequency.

Thus, it contributes to the stability of the system, dampening any fluctuations in frequency, just as car shock absorbers dampen a bump in the road. The flywheel is a large wheel that adds additional mass for greater system inertia. It is effectively a means of substituting a flywheel for the rotating mass of a gas or steam turbine.

"By coupling the fly wheel to the rotating mass of the generator's rotor, it provides the short-circuit contribution and enlarge the necessary inertia," said Tiernan. "In this way, they will help stabilizing the networks frequency."

The synchronous generator is connected to the high-voltage transmission network via a step-up transformer. It is started up and stopped with a frequency-controlled electric motor (pony motor) or a starting frequency converter. When the generator has reached operating synchronous speed, it is synchronized with the transmission network, and the machine is operated as a motor providing reactive and short-circuit power to the transmission network.

The UK's National Grid Pathfinder program aims to provide plenty of short-circuit power, particularly in locations in Scotland and Wales. Siemens Energy was awarded three projects as part of this program. Work has begun at a site at Rassau, Ebbw Vale in Wales for Welsh Power. This rotating grid stabilization technology is being installed at the site to manage grid stability. It will be up and running before the end of the year.

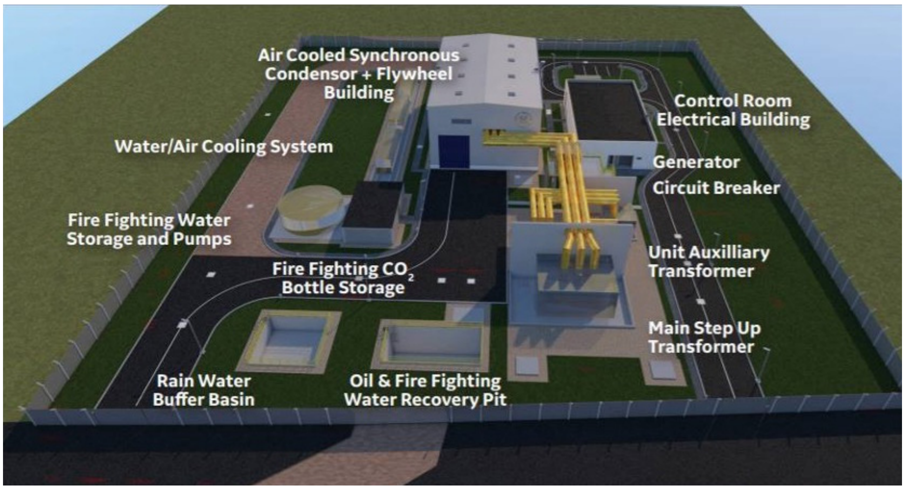
"Within 15 minutes of an instruction, our facility can provide approximately 1% of the inertia needed to operate the grid safely with zero emissions," said Chris Wickins, Director of Grid Services at Welsh Power.

A similar system is being supplied to the Electricity Supply Board (ESB) in Ireland for the Moneypoint power station located in County Clare. ESB is turning the site into a green energy hub, where a range of renewable technologies will be deployed over the next decade.

"Due to the intermittency of wind energy in particular, grid stabilization technologies have an increasingly important role in a successful energy transition," said Paul Smith, Head of Asset Development at ESB Generation and Trading.

GE Steam Power, meanwhile, is touting its own synchronous condensers and flywheel system. It sold two such units to Terna for the Brindisi substation in Italy. Each will supply up to +250/-125 MVAr of reactive power and 1750 MW inertia. They are being installed along the transmission system to keep the power flowing consistently. GE has an additional four 250 MVAr synchronous condenser units under execution with Terna in the Selargius and Maida plants in Sardinia and Calabria. Additionally, GE has delivered two 160 MVAr synchronous condensers for Favara and Partinico Terna Substations in Sicily that have been running since the end of 2015. That adds up to 1,820 MVAr of reactive power for Italy's grid.

"Units consist of either new electrical rotating equiment or existing generators reconfigured to perform as reliable grid stabilizers, that means to stabilize the voltage of the grid," said Chris Evans, Head of Product Management, GE Steam Power. "Flywheels are an add-on feature for additional inertia that can be delivered at the time of the construction of a new plant or added later on during the life cycle of the plant, which instead serve to stabilize the frequency of the grid.



A typical synchronous condensing plant layout consists of one or two synchronous condensers units with flywheel in parallel, step-up transformers, generator circuit breakers, all the electrical and mechanical auxiliaries and balance of plant including the protection and controls systems, monitoring and diagnostic systems. Courtesy of GE.

Existing Generators for Synchronous Condensing

The various systems showcased so far all do the job. But a less capital-intensive approach is available by converting old steam and gas turbines into synchronous condensers. There are many power plants in existence that have aging turbines available. Some have already been decommissioned, and many are running at much lower capacity that in previous years as renewable resources take on a bigger share of power supply. Inevitably, more and more of these units will either be decommissioned or gradually phased out.

Conversion of existing generators to provide synchronous condensing falls into two categories. One is for the machine to be used for peaking power and synchronous condensing by incorporating a synchro self-shifting (SSS) clutch into an existing turbine generator set. Alternatively, an existing turbine generator set such as decommissioned coal plant steam turbine generator can be rapidly converted to a synchronous condenser by removing the turbine and adding an acceleration drive with an SSS clutch (see lead image).

The turbine, or acceleration drive in the case of a generator-only application, brings the generator up to speed. Once the generator synchronizes with the grid, the turbine or acceleration drive disconnects from the generator and shuts down. The generator then uses grid power to keep spinning, constantly providing leading or lagging VARs as needed.

As well as steam turbines and gas turbines, such conversions can be done for reciprocating engines. The clutch acts by completely disengaging the prime mover from the generator when only reactive power is needed. When active or real power is needed, the SSS clutch automatically engages for electric power generation. This enables the unit to absorb or supply reactive power to the grid for voltage control purposes by running the generator as a synchronous motor uncoupled from the gas turbine. New gas-fired power plants being built can also be configured to operate in this way.

"There are significant savings in the fact that an existing generator is in position, connected to the transmission system, and already in working order with controls," said Dave Haldeman, SSS Clutch. "Additionally, this approach provides the system for a backup power or peaking power, which complements the renewable power when required."

The Commonwealth Chesapeake Power Plant in rural Virginia consists of 7 GE LM6000 gas turbines, installed about 20 years ago. They provide power sporadically, depending on the needs of the grid operator. As a result, four of them are equipped with clutches.

These generators are outfitted with clutches that can disconnect from their turbines to enable them to operate as synchronous condensers. In this case, the grid operator pays the plant to have the generator synchronized and spinning but not connected to the power turbine. That offers grid support. Once power is required, it can be on the grid within 10 minutes to respond to generation or transmission outages elsewhere in the network. Control software is used to bring the turbine rapidly up to near-synchronous speed in order to engage or disengage the turbine. When disengaged, the generator continues to spin.

Four units at this U.S. power plant were outfitted with clutches to enable GE LM6000 turbines to provide rapid standby power as well as reactive power support.

Haldeman sees a place for both purely electrical synchronous condensers, as well as those utilizing old engines and turbines. As more renewables are added, the demands for inertia and grid stability will only accelerate.

From a purely economic perspective, money can be saved by utilizing machinery that is already in place. An inexpensive retrofit can add a clutch in a couple of weeks. Transmission lines, switch gear, other electrical gear, as well as permitting are already in place. The money saved can then be used to upgrade other areas of the grid or be invested in more wind and solar projects. Further, existing generators tend to be installed near load centers. In most cases there are already in a location where they can support the need for reactive power and provide the resulting voltage support.

As the turbine is not running in synchronous condensing mode, there is no fuel burn and therefore no emissions. There is a general tendency to paint all sources of emissions with the same brush. But there is a big difference between an aging coal plant and a natural gas fired turbine in terms of emissions.

"Peaking gas turbines have an important role to play in maintaining grid stability by providing inertia, and reactive power support," said Haldeman. "These natural gas peaking units can provide critical standby power when the renewables are at reduced levels, such as a deep freeze or some other extreme weather event. Otherwise they offer synchronous condensing and voltage support which will be in high demand as a greater percentage of renewable assets come online."

Pandemic garbage boom ignites debate over waste as energy

Author: Patrick Whittle
Date: 12 July 2021
Source: Power Engineering

PORTLAND, Maine (AP) — America remains awash in refuse as new cases of the coronavirus decline — and that has reignited a debate about the sustainability of burning more trash to create energy.

Waste-to-energy plants, which produce most of their power by incinerating trash, make up only about half a percent of the electricity generation in the U.S. But the plants have long aroused considerable opposition from environmentalists and local residents who decry the facilities as polluters, eyesores and generators of foul odor.

The industry has been in retreat mode in the U.S., with dozens of plants closing since 2000 amid local opposition and emissions concerns. But members of the industry said they see the increase in garbage production in the U.S. in recent months as a chance to play a bigger role in creating energy and fighting climate change by keeping waste out of methane-creating landfills.

One estimate from the Solid Waste Association of North America placed the amount of residential waste up as much as 8% this spring compared to the previous spring. And more trash is on the way. A 2020 study in the journal Science stated that the global plastic packaging market size was projected to grow from more than $900 billion in 2019 to more than $1 trillion by 2021, growth largely due to the pandemic response.

That trash has to go somewhere, and using it as a resource makes more sense than sending it to landfills, said James Regan, senior director of corporate communications for Covanta, the largest player in the industry. The company currently processes about 20 million tons (18,144 metric tons) of waste a year to power about a million homes, and it could do more, he said.

"If we're going to reach climate goals by 2050, the waste sector really can and should be part of that story," Regan said. "This is low-hanging fruit. So what are we waiting for?"

Waste-to-energy plants are expanding in other parts of the world, as more than 120 plants have been built in the last five years. They're concentrated most heavily in Europe and Asia. But the most recent new plant in the U.S. opened in 2015 in Palm Beach County, Florida.

President Joe Biden, meanwhile, has put a premium on the reduction of carbon dioxide emissions and creation of more renewable energy, and while that push has focused heavily on wind and solar power, the administration has also acknowledged a place for waste-to-energy conversion. The White House said in an April statement that the U.S. "can address carbon pollution from industrial processes" by including waste-to-power in the mix.

Any attempt to build more plants in the U.S. will be met with resistance, said Mike Ewall, director of the Philadelphia-based Energy Justice Network. The plants represent a threat to human and environmental health because they emit chemicals such as mercury and dioxin, he said. Communities have also opposed waste-to-energy plants because of concerns about airborne particulate matter that can have negative health consequences.

"The notion that this industry is going to be building new plants is just ludicrous," Ewall said.

But the fact remains that creation of garbage has increased, and municipalities have to deal with it somehow. One study, published in the scientific journal Environment, Development and Sustainability, attributed the increase to factors such as panic buying and more reliance on single-use items. Medical waste has also increased due to the heavy use of personal protective equipment, the study found.

As the pandemic has abated in many part of the country and the economy has reopened, commercial waste has increased, but residential waste creation has not slowed. In Portland, Maine, residential waste was up 12% and commercial was up 2% in June, said Matt Grondin, spokesman for ecomaine, which operates a waste-to-energy power plant.

Converting all that new garbage to energy is the best available option, Grondin said.

"It's a lot of garbage. You can probably imagine with a lot of people at home, cleaning out, doing projects, that accounts for a lot of the increase," he said. "It has to go somewhere."

Other communities have looked at garbage-to-gas production as a way to get energy from swelling amounts of trash. These plants use strategies such as compacting garbage and sealing it to capture methane that can be used as fuel.

The garbage-to-gas program at the landfill in St. Landry Parish, Louisiana, started as a way to get carbon credits by burning off methane, said Richard LeBouef, executive director of the parish Solid Waste Disposal District.

Now natural gas from the landfill powers contractor Waste Connection's 12 garbage trucks, the landfill's five pickup trucks and six trucks for litter abatement teams. The district has put $2.7 million, plus maintenance, into the system.

"What we're saving monetarily is not super-substantial but in accordance with the green issue I think it's a great thing," LeBouef said.

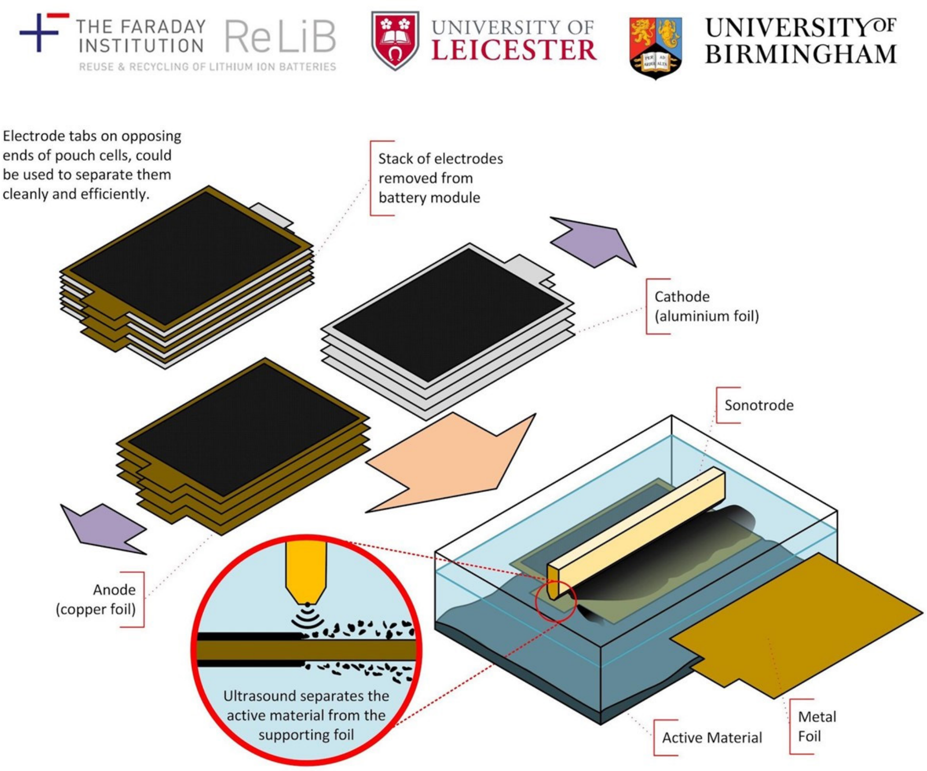
Waste-to-energy plants typically create power by burning the trash at about 2,000 degrees (1,093 degrees Celsius) and using it to boil water that is turned into steam, superheated and sent to a turbine to make electricity.

Attempts to convert more pandemic garbage into energy are likely to be controversial, said Frank Roethel, director of the Waste Reduction and Management Institute at the State University of New York at Stony Brook. But using the trash to make power beats letting it pile up, he said.

"Here you have the Biden administration talking about climate change, and talking about strategies that could help reduce emissions," Roethel said. "And waste to energy doesn't necessarily get the recognition, but it could certainly reduce emissions."

Efficient battery recycling method borrows technique pioneered by dentists

Author: E&T editorial staff
Date: 30 June 2021
Source: E&T Energy and Technology



A new method to recycle electric vehicle batteries has been developed that uses a technique that many will be familiar with from trips to the dentist.

Researchers at the University of Leicester found a way to use ultrasonic waves to separate out valuable materials from electrodes so that the materials can be fully recovered from batteries at the end of their life.

Current recycling methods for lithium-ion battery recycling typically feed end-of-life batteries into a shredder or high-temperature reactor using an inefficient, power-intensive set of physical and chemical processes to produce useable materials again.

But the researchers believe an alternative approach could be taken that sees end-of-life batteries being disassembled rather than shredded, offering the potential to recover more material in a purer state.

The disassembly of lithium-ion batteries has been shown to recover a high yield (around 80 per cent of the original material) in a purer state
than was possible using shredded material.

Recyclers have struggled in the past to remove and separate critical materials such as lithium, nickel, manganese and cobalt from used batteries in a fast, economical and environmentally-friendly way.

The team's ultrasonic delamination technique effectively blasts the active materials required from the electrodes leaving virgin aluminium or copper. The process proved highly effective in removing graphite and lithium nickel manganese cobalt oxides, commonly known as NMC.

Professor Andy Abbott, lead researcher on the Faraday Institution ReLib project, said: "This novel procedure is 100 times quicker and greener than conventional battery recycling techniques and leads to a higher purity of recovered materials.

"It essentially works in the same way as a dentist's ultrasonic descaler, breaking down adhesive bonds between the coating layer and the substrate.

"It is likely that the initial use of this technology will feed recycled materials straight back into the battery production line. This is a real step-change moment in battery recycling."

Professor Pam Thomas, CEO of the Faraday Institution, the UK's flagship battery research programme, said: "For the full value of battery technologies to be captured for the UK, we must focus on the entire life cycle – from the mining of critical materials to battery manufacture to recycling – to create a circular economy that is both sustainable for the planet and profitable for industry."

The research team are in initial discussions with several battery manufacturers and recycling companies to place a technology demonstrator at an industrial site in 2021, with a longer-term aim to license the technology.

The researchers have further tested the technology on the four most common battery types and found that it performs with the same efficiency in each case.

In January, a firm unveiled a new type of battery for electric vehicles that can fully charge in just five minutes.

Cavendish Nuclear joins Rolls-Royce small modular reactor programme

Author: Pamela Largue
Date: 9 July 2021
Source: Power Engineering International

olls-Royce and Cavendish Nuclear have signed a Memorandum of Understanding to explore opportunities to collaborate on the Rolls-Royce Small Modular Reactor programme.

The companies will develop the roles that Cavendish Nuclear can perform in the design, licensing, manufacturing and delivery aspects of Rolls-Royce's factory-fabricated SMR plants, ultimately adding capabilities to strengthen and complement those already within the current supply chain partners.

Dominic Kieran, Managing Director of Cavendish Nuclear, said: "We believe new nuclear build has a critical role to play in achieving the energy system decarbonisation required to address the challenge of climate change.

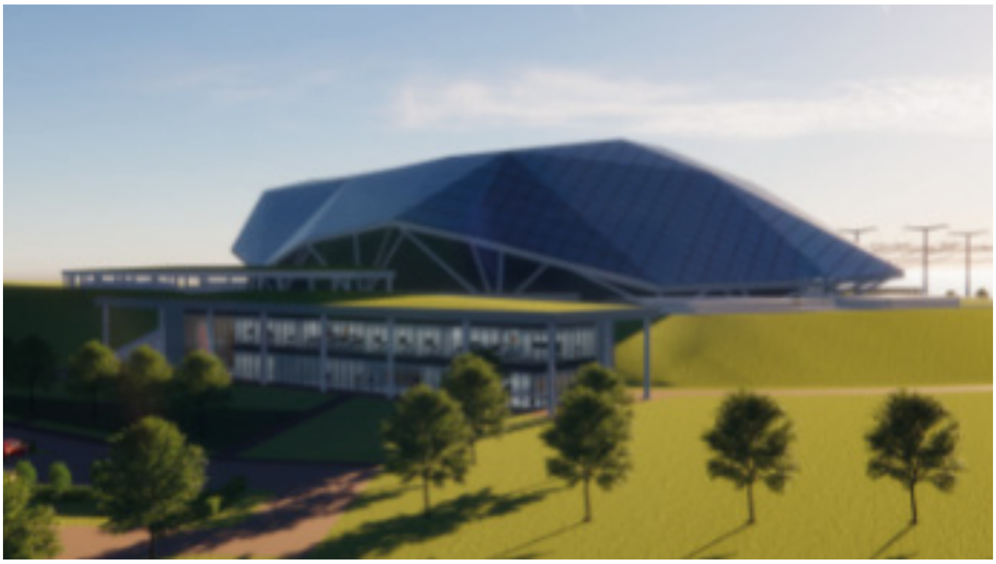


Image credit: Cavendish

"We see the Rolls-Royce SMR programme as a really exciting opportunity for UK technology and the UK supply chain to make a major contribution to achieving net zero both in the UK and internationally.

The agreement was signed by Rolls-Royce in its role as consortium leader on the programme that has been working on the design of the power station for the last two years with support from the UK government through UK Research and Innovation.

The consortium includes; Assystem, Atkins, BAM Nuttall, Laing O'Rourke, National Nuclear Laboratory (NNL), Rolls-Royce, Jacobs, The Welding Institute (TWI) and Nuclear AMRC.

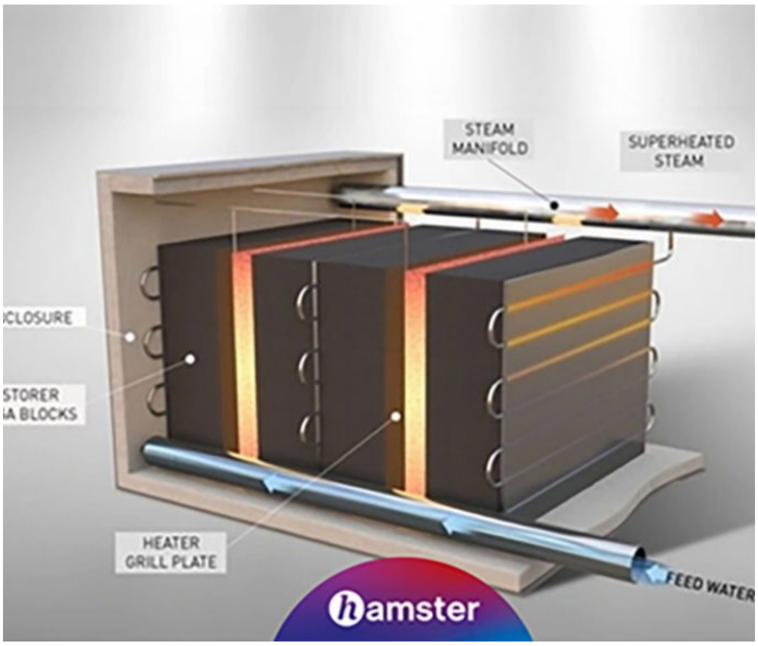
The Rolls-Royce SMR uses a different approach to delivering new nuclear power and takes advantage of factory-built modularisation techniques to drastically reduce the amount of on-site construction, delivering a low cost nuclear solution that is competitive with renewable alternatives, according to Cavendish.

Tom Samson, CEO of the Rolls-Royce SMR Consortium, said Cavendish Nuclear has "world class manufacturing and modularisation capabilities" as well as a "wider nuclear skill set delivering engineering and manufacturing solutions across the new build and decommissioning landscape".

"We are excited at the prospect of bringing those skills and capabilities into our SMR programme and in doing so making a meaningful contribution to the UK's levelling up agenda and our Global Britain ambitions with the export potential of our SMR offering."

Turning coal plants into storage assets

Author: Carlos Hartel
Date: 24 May 2021
Source: Power Engineering International



Four units at this U.S. power plant were outfitted with clutches to enable GE LM6000 turbines to provide rapid standby power as well as reactive power support.

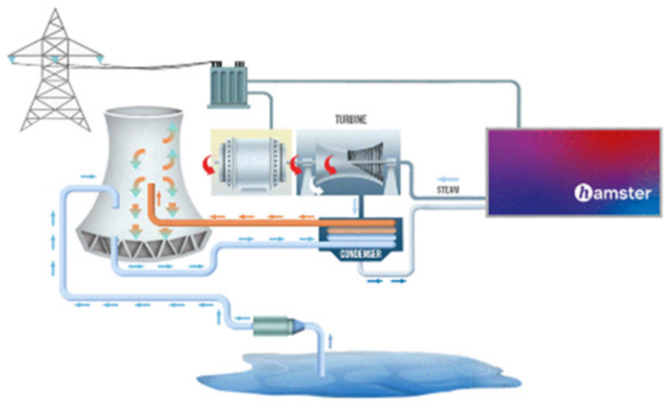


Figure 1. E2S Power's Solution to repurposing coal-fired plants by turning these into energy storage systems. While the boiler is replaced with the thermal storage module, all other plant components can be fully reutilized.

Global energy markets are at the onset of one of their most significant transformations since the invention of electricity.

Today, still more than two-thirds of all electric power is generated from fossil fuels, most of it by plants running on some sort of coal.

Conventional power stations, however, face a very certain future of retirements.

Estimates about the total capacity of thermal power plants to be retired over the next 10 to 20 years vary, but are well in the range of thousands of gigawatts.

Concurrently, renewables keep growing at an undiminished pace. Due to their intermittent and mostly non-dispatchable nature, on the other hand, wind and solar power need energy storage systems enabling them to cope with short- and long-term load variations.

Consequently, their continued expansion is triggering a rapid growth of storage capacity realised by both greenfield and brownfield projects.

At E2S Power, we're developing a storage solution which in time can convert existing coal-fired plants into thermal batteries.

This not only allows reusing existing infrastructure – it also helps to protect local employment, which is a point of major political concern in many regions worldwide.

The extensive installed base of thermal power plants offers an enormous market opportunity for those who develop conversion solutions. The sheer scale of the required ramp-up of storage capacity will necessitate all storage options on the table to contribute to the challenge – not one technology or solution will be able to shoulder it alone.

In regions where a large number of coal plants are still in operation, converting those can be a key contributor to providing the storage capacity required.

Giving otherwise stranded assets a second life in the renewable energy future not only has financial benefits to the owners or operators: the continued use of valuable infrastructure also helps to minimise future CO2 emissions associated with the massive build-up of energy storage capacity, where green-field projects may come with a significant carbon footprint.

How it works

E2S Power's solution basically consists of substituting the boiler with a thermal energy storage system while reusing all of the remaining infrastructure (see Figure 1).

During charging, electrical energy powers the radiating heaters, which raise the temperature of the MGA storage blocks to the required level (which may be plant specific).

During the discharge process, heat stored in the MGA blocks is then transferred to the water running through the steam generators, which create steam of just the right properties so that existing steam turbines can use it to generate electricity.

The conversion of heat to electricity thus happens in about the same fashion as if the plant was still powered by coal.

For each individual brownfield case, the system can be tailored so that it makes use of all existing plant infrastructure, which minimizes costs.

It can be operated at the same voltage and current levels as already present at the generators to feed the electric heaters, use the same high-voltage switchyard, the existing steam turbine, and the accompanying balance of plant like condensers, cooling towers, heat sinks, generators, or transformers.

The steam generators of the E2S Hamster are made of advanced high temperature resistant alloys, which can operate at 700°C and are mounted in between the MGA storage blocks.

Electrical heaters are also specially designed to resist temperatures higher than 1000°C to facilitate the heat transfer to the MGA blocks using thermal radiation.

The MGA elements used for storing the thermal energy are special composites made of graphite and aluminium. The metallic component, i.e. the aluminium, has a melting point of around 660°C, which is lower than the maximum system temperature during the charge-discharge cycle.

The latent heat associated with phase change of the metal during operation is the main reason for the very high energy density our storage technology can achieve.

On the other hand, the melting point of graphite, which forms the matrix and which contains the embedded and finely dispersed metal particles, is significantly above the maximum temperatures in the enclosure at all times.

The matrix therefore remains solid throughout operation, keeping the whole MGA slabs in solid form. From a practical standpoint, this feature of MGAs is a key advantage.

In a sense, the MGA technology allows the utilisation of a metallic phase-change material for heat storage at the simplicity and robustness of systems using e.g. steel or concrete as storage elements.

At the same time, it uses a lot less valuable space than those storage media. Steel and concrete would be three times and 20 times, respectively, the volume of an MGA system at the same temperature level and energy content.

A final yet important point is the fact that the use of the abundantly available and non-toxic base materials graphite and aluminium can help alleviate some of the criticism often raised concerning environmental impact, tight supply chains, and recyclability of the materials built into energy storage devices today.

Complementary not competitive
The high melting point of aluminium enables to perfectly tailor the E2S Hamster to existing thermal plants' infrastructure.

An innovative design of the electric heaters ensures that all existing power electronics equipment in the thermal plant can be utilised without any costly modifications.

Converting an existing thermal plant has modest capital requirements, and projects can be executed swiftly thanks to our modular design, which allows prefabrication of components.

First experiments indicate that the system's storage capacity will experience very little degradation over time, which minimises the need for major outages over the lifetime of the plant.

After a productive supply chain has been built up, adding hundreds of MWh of capacity per month already seems feasible in the mid-term.

It's worth pointing out that our solution is largely complementary to – and not in competition with – Li-ion batteries. The target application for a converted thermal plant is balancing variations in load and supply over the diurnal cycle or a period of several days.

Given the large spinning masses of steamturbine and generator trains, supporting grid stability is possible too, although during the discharge phase only.

Currently, our first technology demonstrator of approximately 500 kWh thermal storage capacity is being tested in Belgrade, Serbia, with one single E2S Hamster cell of MGA coupled with an electric heater and a steam generator.

The system produces steam of up to 700°C, which subsequently is discharged to a condenser. After completion of the test campaign and any design or process refinements it may suggest, we expect the system to be mature for a mid-scale field prototype.

Discussions are under way with power plant operators, who have a need for augmenting their fossil power plant with a thermal storage system for greater flexibility. Commissioning of the prototype could be as early as 2022, preceding the product rollout for the Hamster in 2023.

What it will take to achieve affordable carbon removal

Author: James Temple
Date: 24 June 2021
Source: MIT Technology Review

Another big direct-air-capture plant is moving ahead, but a new study finds we may need to build many more before the economics start to make sense.

A pair of companies have begun designing what could become Europe's largest direct-air-capture plant, capable of capturing as much as a million metric tons of carbon dioxide per year and burying it deep beneath the floor of the North Sea.

The sequestered climate pollution will be sold as carbon credits, reflecting the rising demand for carbon removal as a drove of nations and corporations lay out net-zero emissions plans that rely heavily, whether directly or indirectly, on using trees, machines, or other means to pull carbon dioxide out of the air.

Climate researchers say the world may need billions of tons of carbon dioxide removal annually by midcentury to address the "residual emissions" from things like aviation and agriculture that we can't affordably clean up by then—and to pull the climate back from extremely dangerous levels of warming.

The critical and unanswered question, however, is how much direct air capture will cost—and whether companies and nations will decide they can afford it.

The facility proposed by the two companies, Carbon Engineering and Storegga Geotechnologies, will likely be located in North East Scotland, enabling it to draw on plentiful renewable energy and funnel captured carbon dioxide to nearby sites offshore, the companies said. It's expected to come online by 2026.

"We can't stop every [source of] emissions," says Steve Oldham, chief executive of Carbon Engineering, which is based in British Columbia. "It's too difficult, too expensive, and too disruptive. That's where carbon removal comes in. We're seeing an increasing realization that it's going to be essential."

Getting to $100 a ton
Oldham declines to say how much the companies plan to charge for carbon removal, and he says they don't yet know the per-ton costs they'll achieve with the European plant.

But he is confident the company will eventually reach the target cost levels for direct air capture identified in a 2018 analysis in Joule, led by Carbon Engineering founder and Harvard professor David Keith. It put the range at between $94 and $232 per ton once the technology reaches commercial scale.

Getting to $100 per ton is essentially the point of economic viability, as large US customers generally pay $65 to $110 for carbon dioxide used for commercial purposes, according to a little-noticed May paper by Habib Azarabadi and direct-air-capture pioneer Klaus Lackner, both at Arizona State University's Center for Negative Carbon Emissions. (The $100 doesn't include the separate but considerably smaller cost of carbon sequestration.)

At that point, direct air capture could become a reasonably cost-effective way of addressing the 10% to 20% of emissions that will remain too difficult or expensive to eliminate—and may even compete with the cost of capturing carbon dioxide before it leaves power plants and factories, the authors state.

But the best guess is that the sector is nowhere near that level today. In 2019, the Swiss direct-air-capture company Climeworks said its costs were around $500 to $600 per ton.

What it will take to get to that $100 threshold is building a whole bunch of plants, Azarabadi and Lackner found.

Specifically, the study estimates that the direct-air-capture industry will need to grow by a factor of a little more than 300 in order to achieve costs of $100 a ton. That's based on the "learning rates" of successful technologies, or how rapidly costs declined as their manufacturing capacity grew. Getting direct-air capture to that point may require total federal subsidies of $50 million to $2 billion, to cover the difference between the actual costs and market rates for commodity carbon dioxide.

Lackner says the key question is whether their study applied the right learning curves from successful technologies like solar—where costs dropped by roughly a factor of 10 as scale increased 1,000-fold—or if direct air capture falls into a rarer category of technologies where greater learning doesn't rapidly drive down costs.

"A few hundred million invested in buying down the cost could tell whether this is a good or bad assumption," he said in an email.

Dreamcatcher

The United Kingdom has set a plan to zero out its emissions by 2050 that will require millions of tons of carbon dioxide removal to balance out the emissions sources likely to still be producing pollution. The government has begun providing millions of dollars to develop a variety of technical approaches to help it hit those targets, including about $350,000 to the Carbon Engineering and Storegga effort, dubbed Project Dreamcatcher.

The plant will likely be located near the so-called Acorn project developed by Scotland-based Storegga's subsidiary, Pale Blue Dot Energy. The plan is to produce hydrogen from natural gas extracted from the North Sea, while capturing the emissions released in the process. The project would also repurpose existing oil and gas infrastructure on the northeast tip of Scotland to transport the carbon dioxide, which would be injected into sites below the seabed.

The proposed direct-air-capture plant could leverage the same infrastructure for its carbon dioxide storage, Oldham says.

The companies initially expect to build a facility capable of capturing 500,000 tons annually but could eventually double the scale given market demand. Even the low end would far exceed the otherwise largest European facility under way, Climeworks' Orca facility in Iceland, slated to remove 4,000 tons annually. Only a handful of other small-scale plants have been built around the world.

The expected capacity of the Scotland plant is essentially the same as that of Carbon Engineering's other full-sized facility, planned for Texas. It will also begin as a half-million-ton-a-year plant with the potential to reach a million. Construction is likely to start on that plant early next year, and it's expected to begin operation in 2024.

Much of the carbon dioxide captured at that facility, however, will be used for what's known as enhanced oil recovery: the gas will be injected underground to free up additional oil from petroleum wells in the Permian Basin. If done carefully, that process could potentially produce "carbon neutral" fuels, which at least don't add more emissions to the atmosphere than were removed.

Oldham agrees that building more plants will be the key to driving costs, noting that Carbon Engineering will see huge declines just from its first plant to its second. How sharply the curve bends from there will depend on how rapidly governments adopt carbon prices or other climate policies that create more demand for carbon removal, he adds. Such policies will essentially force "hard-to-solve" sectors like aviation, cement, and steel to start paying someone to clean up their pollution.

IEA Writes The First Draft Obituary Of The Fossil Fuels

Date: July 2021
Source: EEnergy Informer

The agency's latest report seals the fate of the fossil fuel age

Perry Sioshansi in the July edition of EEnergy Informer writes that as reported in the June issue of his newsletter, the International Energy Agency (IEA) did something totally unexpected when it released a report that not only damned all additional investment in fossil fuels but offered a road-map for reducing and eventually eliminating their use in most applications across the globe on a path to a low carbon future . To say that it was a landmark publication, not least coming from what used to be an oil centric and fossil-fuel loving international agency, would be an understatement.

While many in the fossil fuel business as well as fossil-fuel exporting countries were probably caught off guard by the IEA's blunt message, the reception among the environmental and the climate change scientific community was jubilant. The prominent and respected global energy agency said that fossil fuel consumption and associated carbon emissions must be curtailed immediately if the politicians are serious about averting the worst effects of a warming climate.

The IEA's unambiguous message was further reinforced by a G7 motion to essentially end coal financing by the end of 2021 – the most carbon- intensive fossil fuel. The German Federal Constitutional Court's decision further reinforced the message that the time has arrived to take the threat of climate change seriously.

According to the IEA, global investment in energy is set to rebound by nearly 10% in 2021 to $1.9 trillion, reversing most of last year's drop caused by the pandemic. But spending onclean energy transitions needs to accelerate much more rapidly to meet climate goals, according to IEA's World Energy Investment 2021 published in early June.

The IEA expects 2021 to be the sixth year in a row that investment in the power sector exceeds that of traditional oil and gas supply. Global power sector investment is set to increase by around 5% to more than $820 billion, its highest ever level. Renewables are dominating investment in new power generation capacity and are expected to account for 70% of the total this year. The report, however, adds that clean energy investment would need to triple in the 2020s to put the world on track to reach net zero emissionsby 2050.

The path to a sustainable future: More renewables, EVs and efficient energy use

2

Published in mid May 2021, Net zero by 2050: a roadmap for the global energy sector is the "the world's first comprehensive study of how to transition to a net zero energy system by 2050 while ensuring stable and affordable energy supplies, providing universal energy access and enabling robust economic growth."

The IEA says the 2020s needs to be the decade of massive energy expansion, stressing that the technologies needed to achieve the necessary deep cuts in global emissions by 2030 already exist. Policies should be implemented to increase the deployment of clean and efficient technology, such as mandates and standards on energy efficiency to drive uptake, as well as targets and competitive auctions to increase wind and solar deployment.

In tandem with this, fossil-fuel subsidy phase-outs, carbon pricing and other market reforms can ensure appropriate price signals. Disincentives should apply to the use of certain fuels and technologies, such as unabated coal-fired power stations, gas boilers and conventional internal combustion engine (ICE) vehicles. Governments must lead the planning and incentivizing of the massive infrastructure investment, including in smart transmission and distribution grids.

For the final period – 2030 to 2050 – IEA says achieving the level of emissions reductions required for net zero will rely on further rapid deployment of available technologies as well as widespread use of technologies that are not on the market yet. This means that major innovation efforts must occur in the 2020s to bring these technologies to market in time. The pathway finds most of the global reductions in carbon emissions to 2030 come from technologies readily available today, but in 2050, almost half the reductions come from technologies that are currently at the demonstration or prototype phase. This proportion increases when it comes to heavy industry and long-distance transport.

The roadmap has over 400 milestones, including, starting immediately, no investment in new fossil fuel supply projects and no further investments for new unabated coal plants. By 2035, there are no sales of new internal combustion engine passenger cars, and by 2040, the global electricity sector has reached net zero emissions. IEA also urges a ban on new fossil fuel boilers to be introduced globally in 2025, driving up sales of electric heat pumps.

Already major companies including Iberdrola of Spain and Mitsubishi of Japan have formed a partnership to develop renewable industrial energy. While the energy transition is a threat to many incumbents, it offers opportunities to newcomers as well as those willing to shift gears.

What the IEA, and numerous others who have been looking at the trends, are saying is a massive transformation of the global energy infrastructure on an unprecedented scale and speed. According to the IEA, solar PV and wind capacity additions, for example, must be 4 times what they were in 2020 by 2030 while electric vehicle (EV) sales must increase 18 times their current levels by the same time. In the meantime, the energy intensity of the global economy must decline by around 4% per annum

A number of global companies, including a few oil majors, are beginning to recognize the emerging opportunities in clean energy rather than the threats inherent in the energy transition. Ultimately it will be the businesses and the financial sector who will have to make the necessary investments. Governments can help by providing policy clarity.

3

CIGRE UPDATE

Now a virtual centennial session

Author: Philippe Adam
Date: Wed 18th Aug to Fri 27th August 2021

An update from the Philippe Adam , the Secretary General of CIGRE in the July issue of Power Talk.
In the last few weeks, the CIGRE management has taken the decision to organise a virtual event. This decision was mainly justified by the uncertainties on the number of delegates that could come to Paris at the end of August 2021

We are now working on the preparation of what will be the Virtual Centennial Session.

It will be very different from the e-session we organised last year, both in content and format.

Indeed, in order to give all delegates the possibility to participate remotely at reasonable hours wherever they are, we have reduced the duration of a day to 4 hours instead of 8 last year.

Another major innovation compared to last year is that the Group Discussion Meetings (GDM), workshops, panels and forums, will be hosted by the Study Committees present in Paris in television studios set up at the Palais des Congrès.

To limit the duration of the Session, which anyhow will last 8 days, we will broadcast the technical sessions (GDM, workshops, panel…) on five channels running in parallel, and a sixth channel will provide access to two tutorials per day.

The contributors to the GDMs, who will have to register before submitting their contributions, will intervene remotely and live, according to the schedule defined by each Study Committee.

Finally, in order to provide our remote delegates with a more attractive experience, and to immerse them in an environment closer to that of a Session in Paris, we are setting up CIGRE TV which will broadcast every day, before and after the technical programme, non-technical content on the daily programme, the CIGRE, with interviews of its personalities, partners, Session sponsors etc.

I therefore invite you to register very soon for this Centenary Session which will be unique in the history of our Association.

By doing so you will enjoy a new way to share experience and expertise with your peers, while supporting CIGRE in this difficult times.

Thank you for that.

Australian Technical Panel Presentation Update:

These can now be found on our YouTube channel and summarise the work being carried out in each of our 16 Technical fields of work.
E-cigre : The go to site for all CIGRE documentation and Technical Brochures.

Through e-cigre you can search the vast technical database of 14,000 + items, order Green books or view a range of Webinars and search for past Electra editions.

https://e-cigre.org/

Social Media:

CIGRE Australia has several social media channels where we post updates and items of interest.
Follow us to keep up-to-date:
• Linkedin
• Twitter
• YouTube

Paris 2021 Registration and Programme Is now Available.
CLICK HERE for more information.

CIRED UPDATE

BIG DATA CHALLENGES – A MULTIDISCIPLINARY TEAM APPROACH

Paper 1212- CIRED – Madrid June 2019

Isabel FONSECA EDP Distribuição – Portugal
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Abstract

The advent of smart grids created a surge in the quantity of data available to the DSO. Data has become an asset as crucial for grid operation as the grid per se. However, if the first concern is to have data, the second one is to have good data.

This paper aims at demonstrating how data validation rules were built to extract value from Big Data using in- house tools and expertise. It presents a true account on a specific project that involved extracting, crunching and analysing data from multiple sources for a large volume of data and still proceeding when there were no guidelines for dealing with unexpected results.

Download Paper

UPCOMING EVENTS

Energy Storage and Recovery Cell, Lonsdale

Wed, 04 Aug 2021 | WEB | VIEW EVENT

Overview:
This webinar will describe the development of a Thermal Energy Device (TED) which converts electrical energy into latent heat.

The TED stores electrical energy as thermal energy by heating and melting a unique phase change material.

Time:
5:30pm NSW/VIC/ACT/QLD
5.00pm SA/NT
3:30pm WA

Venue:
Online Webinar

Cost:
Member $0.00
EA Member $10.00
Non-Member $10.00

Operation of the Tasmanian power system with a high level of inverter based resources

Tue, 10 Aug 2021 | TAS | VIEW EVENT

Overview:
The presentation will review the current operation of the Tasmanian power system now that 568 MW of wind capacity is installed and in commercial service. We will look at some of the more extreme operating conditions that have been experienced to date and discuss the challenges that have needed to be addressed to maintain power system security with a minimum number of synchronous generators online.

Time:
5:15 pm - 6.30 pm AEST

Venue:
Hydro Tasmania - 4 Elizabeth St, Hobart, Tasmania

Cost:
Member $0.00
EA Member $20.00
Non-Member $30.00

Benefit of Open Architecture for Virtual Synchronous Generator Applications

Thu, 19 Aug 2021 | WEB | VIEW EVENT

Overview:
Inverter Based Virtual Synchronous Generators provide possibility for transitioning towards 100% renewable integration. As the power networks becoming more unstable and each point of connection having different set of technical issues to overcome, application specific controller design has become more critical for a reliable operation.

Time:
11 am - 12 pm NSW, VIC, ACT, QLD, TAS
10.30 am - 11.30 am SA, NT
8 am - 9 am WA

Venue:
Online Webinar

Cost:
Member $0.00
EA Member $20.00
Non-Member $30.00

UPCOMING EVENTS

Engineers Australia Inaugural Climate Smart Engineering Conference

Nov 16 - 17, 2021

NSW/WEB

VIEW EVENT

Overview:
Engineers Australia will host its inaugural Climate Smart Engineering conference on 16–17 November 2021.

With attendance online or in person at the Hilton in Sydney, this conference will enable engineers to explore the relevant risks and opportunities, to network and to hear first-hand from business, finance, government and engineering leaders.

Venue:
Hilton Sydney and Virtual

Host:
New South Wales and Australian Capital Territory

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EESA NATIONAL MENTORING PROGRAM 2021

Electric Energy Society of Australia

The National Group Mentoring Program organised by the Electric Energy Society of Australia (EESA) is committed to empowering the young and upcoming Engineers to flourish across Australia's Electric Energy industry.

Whether mentee or mentor, you will benefit from personal growth and contribute to a culture of positive learning that will support the capability of engineering in the industry today and in the future.

This program is an Australia-wide initiative offering space and opportunity for professional development, reflection, challenge, and self-awareness. Further, constant guidance will be provided to help structure mentee-mentor meetings.

Benefits for Mentors

- Recognition of skills, knowledge and commitment to the profession
- Improve management, leadership and communication skills
- Expand professional network
- Transfer of skills and knowledge
- Reflection on current projects and work practices
- Personal satisfaction from contributing to the Electrical Energy industry
- Accumulate CPD points

Responsibilities of Mentors

- Be open and honest in sharing knowledge, expertise and experiences
- Offer honest feedback in a constructive manner
- Be committed to the growth and development of their mentee through listening and providing guidance, enabling them to make their own decisions
- Understand the opportunities and barriers that Engineers face at different levels in the industry
- Be open minded and non-judgemental

Benefits for Mentees

- Build professional networks and a support system
- Increase confidence and self-esteem
- Learn from industry leaders, experts and peers
- Receive support and guidance to achieve career goals and acquire workplace skills and industry knowledge
- Enjoy the space and opportunity for professional reflection, conversation, challenge and learning
- Accumulate CPD points

Responsibilities of Mentees

- Explore all personal strengths and development needs
- Have a positive attitude and be open to developing self-awareness, personal growth, seeking constructive feedback
- Take responsibility for their decisions and actions
- Be clear about their goals for the mentoring relationship

Join us online

Contact: Ms. Aditi Sachdeva, Event Coordinator - 0470 446 845 | aditi@eesa.org.au | www.eesa.org.au

EESA
Electric Energy Society of Australia

MENTORING IS THE OPPORTUNITY TO BUILD NETWORKS ACROSS SEVERAL DISCIPLINES, GOVERNMENT, AND PRIVATE BUSINESS IN AUSTRALIA'S ELECTRIC INDUSTRY

Mentors and mentees will be matched based on their professional objectives, backgrounds, and interests. We encourage you to take up this opportunity to not only build your mentor relationships virtually but also expand your network to wider Australia.

"I was interested in joining because it gives me true insight into the hopes, expectations, and hurdles of the next wave of engineers. The program so far has been outstanding, giving me the insights, I desire. After the second session, I feel I understand better the cultural constraints of my mentees and hope in some small way I have helped them overcome their "internal talk" barriers."
- Mr. John Wright-Smith (Mentor), 2020

"The sessions have been very open. I have enjoyed the robust discussions around the current state of the power industry and the issues surrounding the future of the Australian power system."
- Ms. Lin Zeng (Mentee), 2020

Eligibility

Mentors must have
- 10+ yrs of experience working in the Electric Energy industry; and/or
- CPEng/NER/RPEQ accreditation holders

Mentees must have
- Undergraduate Electrical Engineering students in their 3rd/4th year of study
- Postgraduate Electrical Engineering students
- Electrical Engineers with less than 5yrs of Graduate work experience

Note: Mentors & Mentees must be EESA members and available to attend all three sessions to receive a certificate post completion counting towards CPD.

How to apply

Applications for both Mentors & Mentees are to be made online via https://forms.gle/QNAt55yBqBcLVL9p6 by 13th August 2021. This round of Mentoring Program is aimed at having max 30 Mentees so first come first served basis applies.

When and where

Session dates and times
- Session 1: 18th August 2021 | 5:30-7:00 pm AEST
- Session 2: 8th September 2021 | 5:30-7:00 pm AEST
- Session 3: 29th September 2021 | 5:30-7:00 pm AEST

Sessions will be held online via Zoom.

Registration is free and exclusive for EESA members.

Applications close on 13th August 2021.

For registration, please click here or scan the QR code.

Notes

We will advise the outcome soon after the applications close. If successful, you will be given the details of your Mentor and invited to the first professional development session.

All Mentors and Mentees are to act ethically and with respect towards other participants and maintain strict confidentiality and professional boundaries.

Contact: Ms. Aditi Sachdeva, Event Coordinator - 0470 446 845 | aditi@eesa.org.au | www.eesa.org.au

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PROGRAM SNAPSHOT

PROGRAM HIGHLIGHT

WA Minster for Energy Hon Bill Johnston MLA is invited to open the Conference.

Violette Mouchaileh, Executive General Manager, Emerging Markets and Services AEMO will deliver the opening keynote address: **Evolution and Challenges in our Electricity Industry.**

TECHNICAL TOURS ANNOUNCED

**Spaces available to full ticket holders only*

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