ISP NEM 2040 Model with VRE drought – will it be reliable?

We recently published an article on the 20-27 May 2024 Variable Renewable Energy (VRE) drought and applied it to AEMO's 2024 Integrated System Plan (ISP) eight-day renewable drought in 2040 scenario for the National Electricity Market, excluding Queensland.

Our conclusion was that the 2024 ISP VRE drought scenario does not transparently or rigorously demonstrate how the grid would perform in a VRE drought. Our concern was that when we modelled a 2040 VRE drought, we could see significant amounts of load shedding even with some simplifying assumptions made for hydro and gas-powered generation (GPG) output. Stress testing how the energy system will cope with VRE droughts well ahead of time is an important task, and the AEC has devoted significant time to developing an internal model. Our purpose in doing this work is to identify issues well ahead of time so that policy makers and market participants can take action.

The AEC's in-house eight-day VRE drought reliability model (the Model) is still under development and refinement, so we would welcome engagement and feedback.[i] Below we outline the model and findings.

We would expect the focus of AEMO's 2026 Integrated System Plan to evolve to include a much greater focus on how the energy system of the future performs during VRE droughts. We would also expect that various constraints we have identified and made simplifying assumptions around would need to be examined in detail. For example, gas availability, transmission constraints could both serve to exacerbate the problems we are seeing in the modelling.

The model we have developed has the following key characteristics:

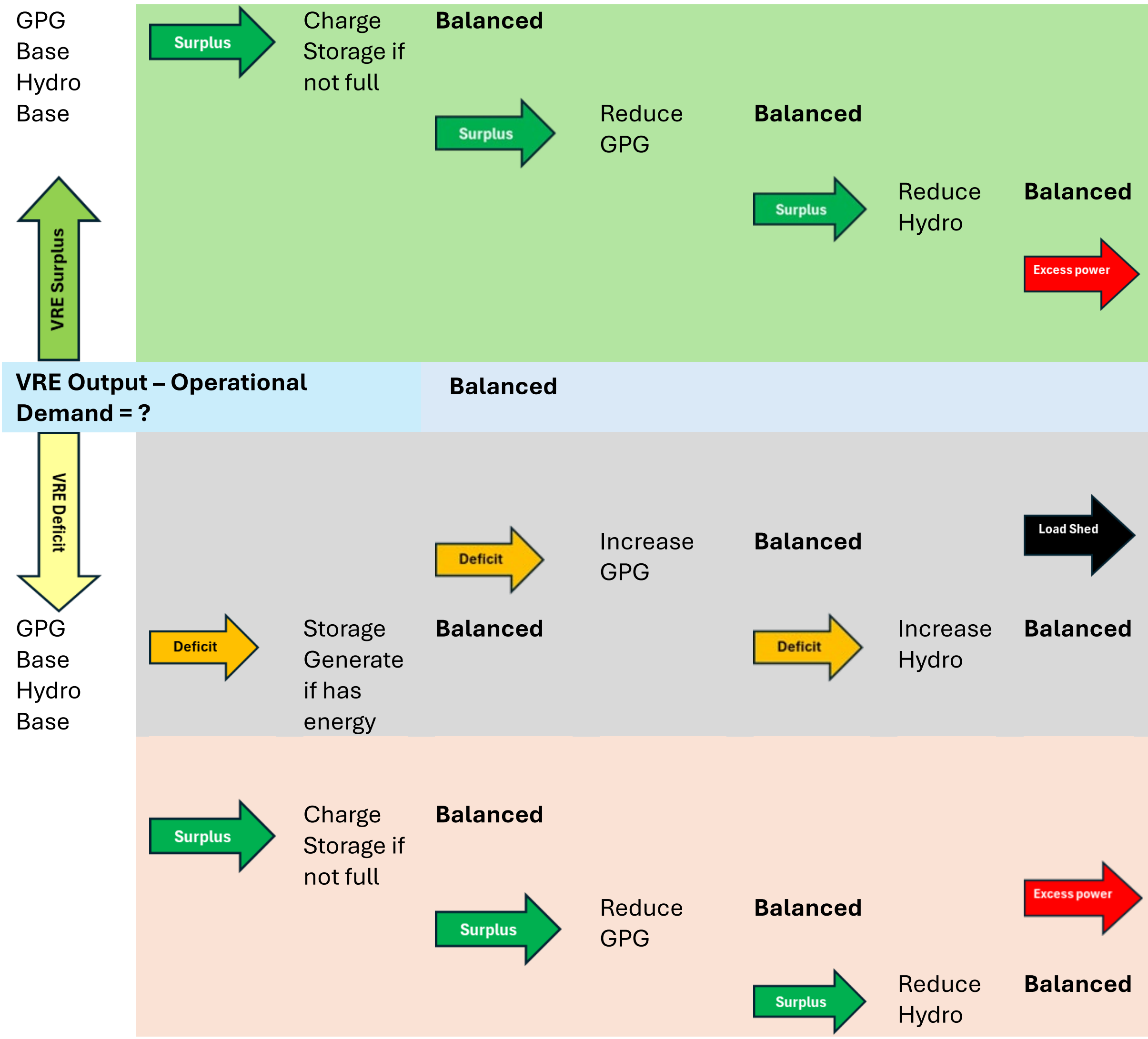
- The average of installed VRE, storage, hydro and GPG capacity across FY40 and FY41 in the 2024 ISP are used for the 2040 scenario and these are set out in Tables 1, 2, 4, 5 and 6.
- The VRE output over the eight days is calculated using the hourly capacity factors by region that were recorded 20-27 May 2024. For the purposes of this analysis VRE generation is a fixed input. However, the model does have the capability to change each regions' wind and solar hourly capacity factors.
- The model solves for every hourly interval.
- Interconnectors are assumed to enable power generated anywhere in the NEM to satisfy any demand. This unrealistic assumption skews the results in favour of the system avoiding blackouts but is necessary because we do not have NEM region load forecasts.

- The Model is dynamic and makes decisions that storage, hydro and GPG are responsive to supply demand imbalances caused by either insufficient VRE generation or excess VRE output.
- The choice of an eight-day demand profile is up to the user. We have used the AEMO 2024 ISP average winter profile, July 2020 high demand and AEMO 2024 ISP average winter plus 4.35 per cent.
- The focus is on operational demand in the 2024 ISP and we have assumed that any impacts on operational demand from Consumer Energy Resources (CER) have been factored in. This is because the publicly available data on CER's relationship to operational demand is limited and would add further complexity and assumptions to the Model. Nevertheless, we are developing a CER module to incorporate in the Model and we will publish the results in the future.
- Both hydro and GPG are water and gas unconstrained respectively. Another assumption that skews the results to avoiding blackouts.
- All storage is full at the commencement of the eight-day VRE drought.

The decision-making process of this model is set out in Figure 1. The first question the Model asks is, what is the supply demand balance of VRE output and operational demand. It is either VRE surplus, VRE deficit or the highly unlikely outcome of equal to demand (Balanced). If it is 'Balanced' then the Model does no more (blue area of Figure 1).

The top green shaded area shows where a surplus will take the model. The VRE surplus is added to any Base generation output from GPG and Base hydro generation. Base levels of generation are selected by the user of the Model. If there is a surplus it is used to charge any storage requirements. If storage uses all the surplus, then supply and demand are in balance at this point. If there is still surplus energy the Base GPG output is reduced and if this does not eliminate the surplus the Base hydro output is reduced. If there is still a surplus, the Model records excess power.

Figure 1 AEC Eight-day VRE Drought Model



The grey shaded area shows where a VRE deficit will take the model. The VRE deficit is adjusted by any Base generation output from GPG and Base hydro generation. If there is still a deficit any storage with charge generates. If this does not resolve the shortfall (ie, Balanced), GPG output is increased and (if necessary) up to its maximum output as selected by the Model user. If there is still a deficit hydro output is increased and up to its maximum if necessary. If this does not achieve supply demand balance there will be load shedding.

The pale orange area shows where a VRE deficit will take the model when it becomes a surplus after the inclusion of Base GPG and base hydro output. The VRE deficit is increased by any Base generation output from GPG and Base hydro generation. If there is still a surplus this is used to charge any storage that is not already full. If after all storage is fully charged there is still surplus energy any Base GPG generation is reduced and down to zero if necessary. Next hydro output is reduced if there is still surplus energy. If this does not achieve supply demand balance there will be excess energy.

Results

Figure 2 sets out the assumptions and outputs from the Model using the ISP's 2040 average winter demand profile. The left-hand side (LHS) assumes 70 per cent as the Base capacity factor for GPG. The top table shows that hydro's average capacity factor is 89 per cent with an assumed Base capacity factor of 90 per cent and 100 per cent maximum. It generates 1.21 TWh. It is questionable whether hydro would be able to run at these levels. GPG's average capacity factor is 63 per cent producing 1.95 TWh (31 per cent of demand) using 21.5 PJ of gas. GPG's hourly running profile is illustrated by the third (grey) chart and what is important to note from this chart is gas usage reaches over 3,300 TJ/day (the black line). Appendix 4 of the 2024 ISP states that maximum seasonal system capacity for GPG in the southern states is expected to be between 1,500 – 1,800 TJ/day in 2044. Anything above this would require switching to liquid fuel (ie, diesel). For the scenarios presented here we have assumed a NEM maximum capacity for GPG of 3,000 TJ/day. The need for diesel in any given hour is determined by exceeding the Maximum Hourly Quantity (MHQ) based on the assumed maximum TJ/day divided by 24 hours. The fourth chart incorporates diesel usage and shows that 28 million litres (ML) are used.

The second chart (in purple) shows how storage operates. The purple area represents stored energy (MWh) where Snowy 2.0 accounts for most of it. The orange line shows how storage capacity (MW) drops when discharging and increases when charging. The table at the bottom of Figure 2 shows storage capacities and stored energy. Cycle efficiency is what proportion of 1 MW/hr of charge adds to energy storage. For example, every MWh Borumba draws from the grid results in 0.76 MWh of energy stored.

Shallow storage has the highest capacity with 9.5 GW or just over half of total storage capacity. However, at maximum output its energy is fully depleted after two hours. Under the 70 per cent Base GPG scenario, shallow storage cycles 8.5 times. Medium storage has the next highest capacity at 3.8 GW and is fully depleted within eight hours. In contrast all the other storage assets have a relatively low capacity when compared to the energy they can store and the Model cycles them less with deep at 1.1 times, Borumba 1.6 times and Snowy 2.0, 0.3 times. Overall storage generates 0.69 TWh and consumes 0.54 TWh noting that they all started fully charged and they finish with less than half of that.

The table at the top of Figure 2 shows 6,874 MWh of load shedding. This represents 0.0025 per cent of 271 TWh of annual operational demand which is above the reliability standard of 0.0002 per cent unserved energy (USE). The first chart in Figure 2, illustrates that this occurs towards the end of the eight days.

Under the 90 per cent Base GPG scenario load shedding is reduced to 1,754 MWh or 0.0006 per cent USE. There is also 1,769 MWh of excess generation. Other key observations include:

- Storage generates and cycles less.
- GPG average capacity factor increases to 69 per cent and fuel consumption by 2 PJ.
- Unconstrained GPG MDQ reaches 3,513 TJ/day and 2,818 TJ/day when diesel is used.
- 101 ML of diesel is consumed.

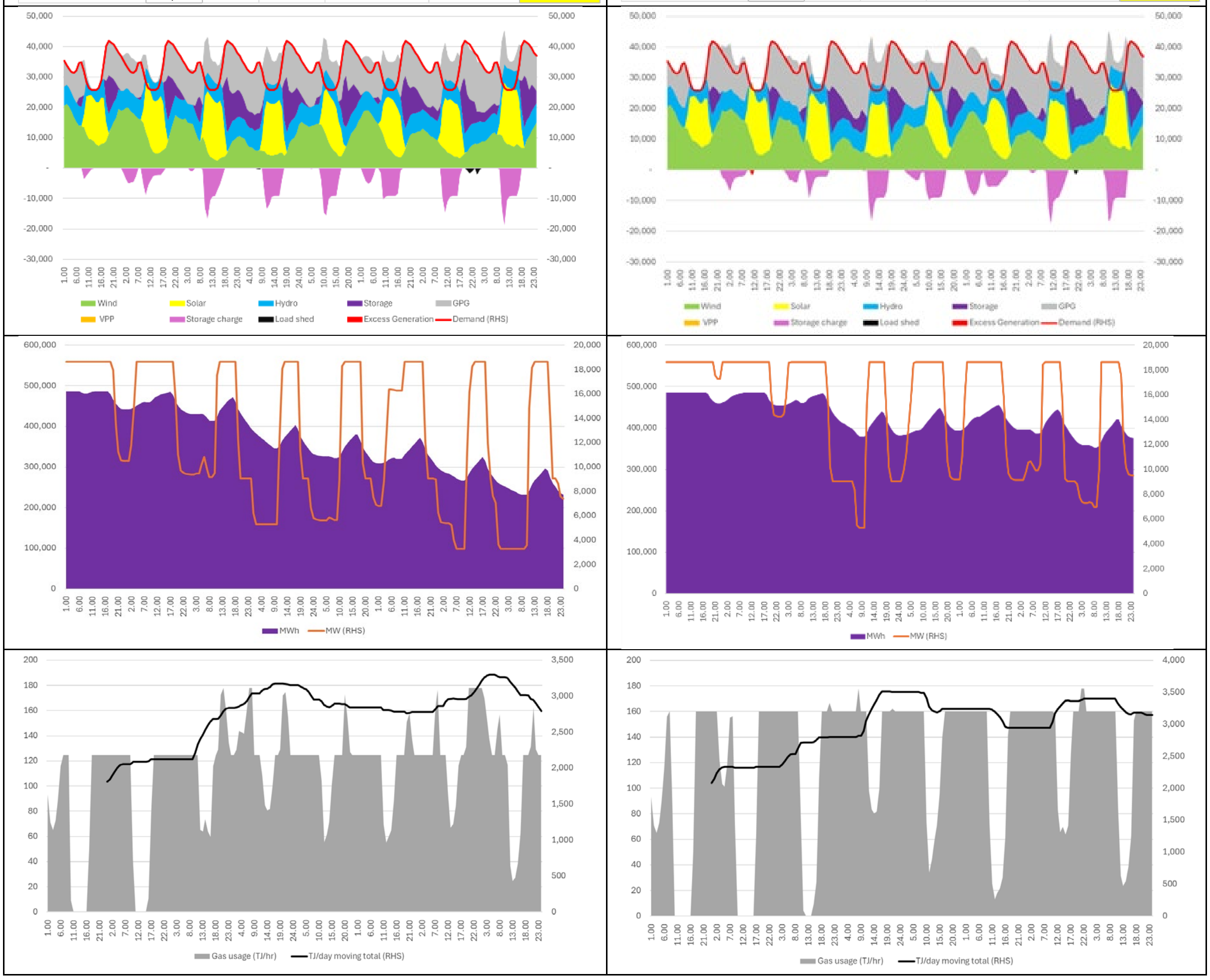
Figure 2: AEMO ISP 2040 average winter demand 70 (left) and 90 (right) per cent Base GPG – Eight-day VRE drought

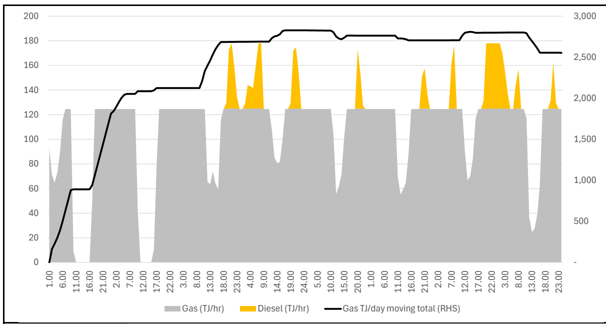
Left (70 per cent Base GPG):

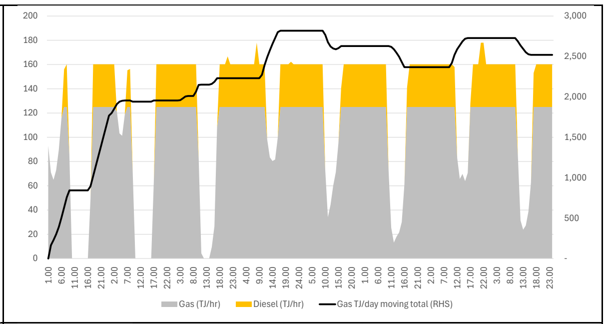
Hydro				Total NEM		
Capacity MW	7,112			Operational demand (TWh/yr)		271
Min	29%				USE	0.0025%
Max	100%			Load shed (MWh)		6,874
Base	90%			Excess generation (MWh)		-
Average	89%			8-day operational TWh		6.40
GWh	1,214					
GPG		ISP	User Adjust	**Fuel**	Gas only	Gas + diesel
Capacity MW	16,183	16,183	-	Total Fuel (TJ)	21,499	21,499
Heat rate GJ/MWh	11			Gas MDQ (TJ)	3,300	2,828
Minimum cap factor	0%			Gas MHQ (TJ)	178	125
Maximum cap factor	100%			Gas (TJ)	21,499	20,273
Base cap factor	70%			Diesel (ML)		28
Average cap factor	63%			Capacity limit (TJ/day)		3,000
Generation GWh	1,954			Diesel lt/MWh		250

Right (90 per cent Base GPG):

Hydro				Total NEM		
Capacity MW	7,112			Operational demand (TWh/yr)		271
Min	0%				USE	0.0006%
Max	100%			Load shed (MWh)		1,754
Base	90%			Excess generation (MWh)		- 1,769
Average	87%			8-day operational TWh		6.40
GWh	1,183					
GPG		ISP	User Adjust	**Fuel**	Gas only	Gas + diesel
Capacity MW	16,183	16,183	-	Total Fuel (TJ)	23,455	23,455
Heat rate GJ/MWh	11			Gas MDQ (TJ)	3,512	2,818
Minimum cap factor	0%			Gas MHQ (TJ)	178	125
Maximum cap factor	100%			Gas (TJ)	23,455	19,015
Base cap factor	90%			Diesel (ML)		101
Average cap factor	69%			Capacity limit (TJ/day)		3,000
Generation GWh	2,132			Diesel lt/MWh		250







	Snowy 2.0	Borumba	Deep Storage	Medium Storage	Shallow Storage	Total
Capacity MW	2,200	1,998	1,097	3,770	9,573	18,639
Storage MWh	349,980	47,952	42,101	28,429	17,932	486,394
Start MWh	349,980	47,952	42,101	28,429	17,932	486,394
Generation MWh	201,206	105,655	72,434	165,111	145,662	690,068
Finish MWh	221,831	319	3,864	5,147	-	231,160
Cycle efficiency	0.76	0.76	0.76	0.85	0.84	
Full charge cycles	0.3	1.6	1.1	5.9	8.5	1.10
Charge gross	96,128	76,344	44,996	166,857	152,059	536,385
Charge net	73,057	58,022	34,197	141,829	127,730	434,834
Loss	23,071	18,323	10,799	25,029	24,329	101,550

	Snowy 2.0	Borumba	Deep Storage	Medium Storage	Shallow Storage	Total
Capacity MW	2,200	1,998	1,097	3,770	9,573	18,639
Storage MWh	349,980	47,952	42,101	28,429	17,932	486,394
Start MWh	349,980	47,952	42,101	28,429	17,932	486,394
Generation MWh	148,549	68,815	37,798	124,353	133,043	512,558
Finish MWh	282,400	39,364	37,384	15,980	448	375,575
Cycle efficiency	0.76	0.76	0.76	0.85	0.84	
Full charge cycles	0.3	1.7	1.0	4.6	7.7	1.02
Charge gross	106,538	79,246	43,528	131,652	137,569	498,533
Charge net	80,969	60,227	33,081	111,904	115,558	401,739
Loss	25,569	19,019	10,447	19,748	22,011	96,794

Figure 3 sets out the results for two alternative demand profiles (where the eight-days of operational demand are 6.66 TWh as opposed to 6.40 TWh under AEMO 2024 ISP average winter demand):

- July 2022 demand profile escalated to 2040 demand;
- AEMO 2024 ISP average winter demand increased by 4.35 per cent.

GPG and hydro are assumed to have Base capacity factors of 90 per cent. For the July 2022 demand profile, key results are:

- 6,303 MWh of load shedding
- GPG average capacity factor of 75 per cent and 90 per cent for hydro
- Maximum Daily Quantity (MDQ) of 3,861 TJ/day
- GPG uses 400 million litres of diesel
- Snowy 2.0 finishes with 290 GWh of energy storage which indicates the Model could be refined to operate it more effectively.

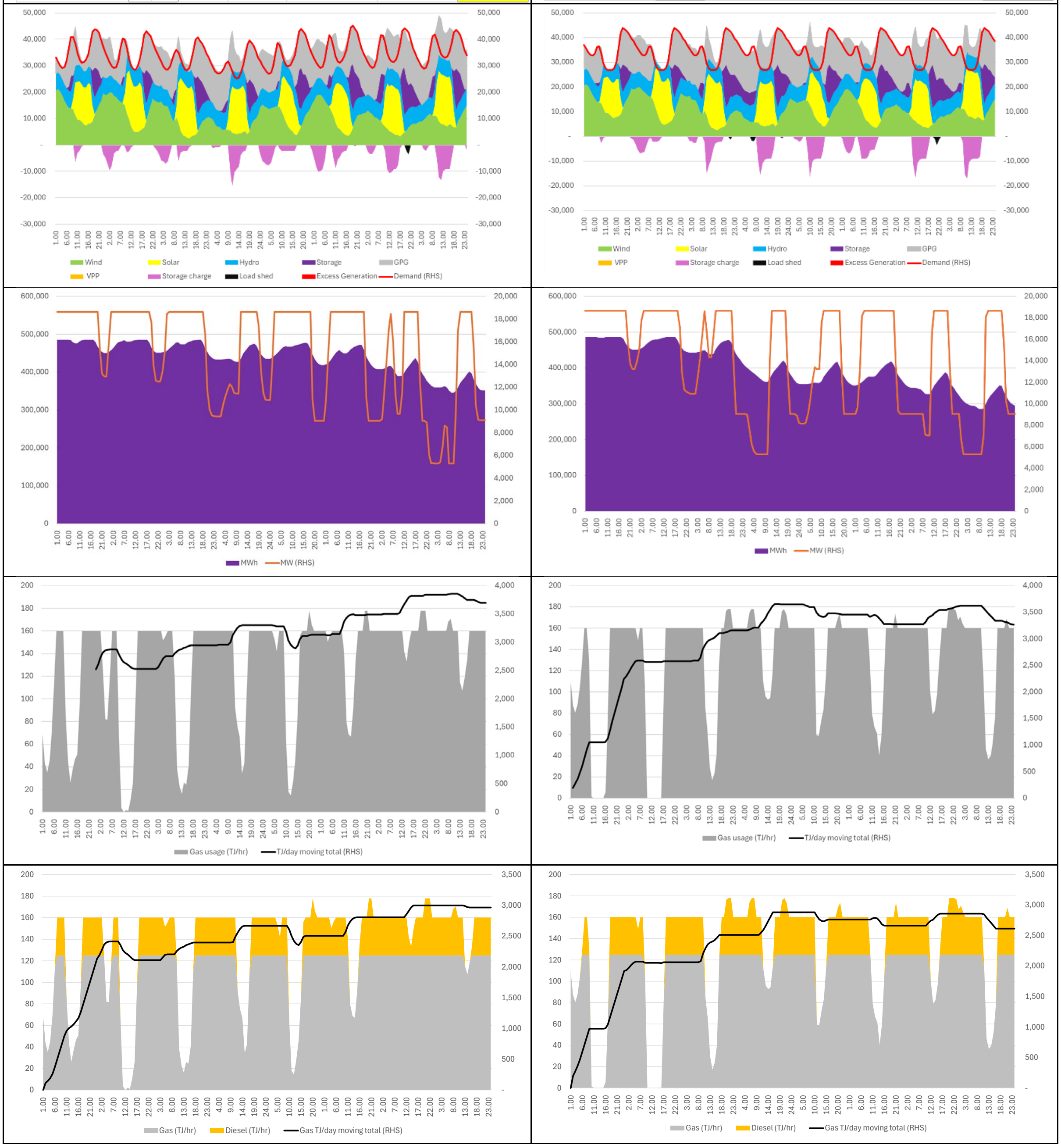
For the AEMO 2024 ISP average winter demand increased by 4.35 per cent scenario:

- 11,689 MWh of load shedding
- GPG average capacity factor of 74 per cent and 90 per cent for hydro
- Unconstrained GPG MDQ of 3,653 TJ/day
- GPG uses 113 ML of diesel
- Snowy 2.0 finishes with 252 GWh of energy storage which indicates the Model could be refined to operate it more effectively.

Figure 3: July 2022 demand profile escalated to 2040 demand (LHS) and AEMO 2024 ISP average winter demand increased by 4.35 per cent (RHS)

Hydro				Total NEM		
Capacity MW	7,112			Operational demand (TWh/yr)		271
Min	82%			USE		0.0023%
Max	100%			Load shed (MWh)		6,303
Base	90%			Excess generation (MWh)		-
Average	90%			8-day operational TWh		6.66
GWh	1,232					
GPG		ISP	User Adjust	Fuel	Gas only	Gas + diesel
Capacity MW	16,183	16,183	-	Total Fuel (TJ)	25,467	25,467
Heat rate GJ/MWh	11			Gas MDQ (TJ)	3,861	3,000
Minimum cap factor	0%			Gas MHQ (TJ)	178	125
Maximum cap factor	100%			Gas (TJ)	25,467	20,590
Base cap factor	90%			Diesel (ML)		111
Average cap factor	75%			Capacity limit (TJ/day)		3,000
Generation GWh	2,315			Diesel lt/MWh		250

Hydro				Total NEM		
Capacity MW	7,112			Operational demand (TWh/yr)		271
Min	22%			USE		0.0043%
Max	100%			Load shed (MWh)		11,689
Base	90%			Excess generation (MWh)		-
Average	89%			8-day operational TWh		6.67
GWh	1,210					
GPG		ISP	User Adjust	Fuel	Gas only	Gas + diesel
Capacity MW	16,183	16,183	-	Total Fuel (TJ)	25,245	25,245
Heat rate GJ/MWh	11			Gas MDQ (TJ)	3,653	2,882
Minimum cap factor	0%			Gas MHQ (TJ)	178	125
Maximum cap factor	100%			Gas (TJ)	25,245	20,272
Base cap factor	90%			Diesel (ML)		113
Average cap factor	74%			Capacity limit (TJ/day)		3,000
Generation GWh	2,295			Diesel lt/MWh		250



	Snowy 2.0	Borumba	Deep Storage	Medium Storage	Shallow Storage	Total
Capacity MW	2,200	1,998	1,097	3,770	9,573	18,639
Storage MWh	349,980	47,952	42,101	28,429	17,932	486,394
Start MWh	349,980	47,952	42,101	28,429	17,932	486,394
Generation MWh	142,857	66,061	36,285	111,201	156,781	513,185
Finish MWh	290,222	23,895	29,664	8,359	37	352,176
Cycle efficiency	0.76	0.76	0.76	0.85	0.84	
Full charge cycles	0.3	1.2	0.7	3.8	9.3	0.97
Charge gross	109,342	55,267	31,380	107,213	167,421	470,623
Charge net	83,100	42,003	23,849	91,131	140,634	380,716
Loss	26,242	13,264	7,531	16,082	26,787	89,907

	Snowy 2.0	Borumba	Deep Storage	Medium Storage	Shallow Storage	Total
Capacity GW	2.200	1.998	1.097	3.770	9.573	19
Storage MWh	349,980	47,952	42,101	28,429	17,932	486,394
Start MWh	349,980	47,952	42,101	28,429	17,932	486,394
Generation MWh	171,098	98,039	53,850	152,350	142,575	617,912
Finish MWh	252,832	9,857	23,400	9,149	-	295,238
Cycle efficiency	0.76	0.76	0.76	0.85	0.84	
Full charge cycles	0.3	1.6	1.1	5.5	8.3	1.08
Charge gross	97,303	78,873	46,250	156,553	148,384	527,363
Charge net	73,950	59,943	35,150	133,070	124,643	426,757
Loss	23,353	18,929	11,100	23,483	23,742	100,607

Supply – variable renewable energy (VRE)

The average of installed capacity across FY40 and FY41 in the 2024 ISP are used for the 2040 scenario and these are set out in Tables 2 and 3. The VRE output over the eight days is calculated using the hourly capacity factors by region that were recorded 20-27 May 2024. As shown in Table 2, NSW, Queensland and Victoria each have approximately 30 per cent of the wind capacity. When the May 2024 capacity factors are applied Queensland contributes 62 per cent of wind output and NSW and Victoria 14 per cent each.

Table 1: 2040 installed wind capacity and generation in eight-day VRE drought

	NSW	QLD	SA	TAS	VIC	NEM
Capacity MW	17,937	18,217	4,052	2,619	18,053	60,877
Av capacity factor	8%	34%	11%	21%	8%	17%
GWh	274	1,204	85	105	277	1,945
% MW	29%	30%	7%	4%	30%	
% GWh	14%	62%	4%	5%	14%	

Source: AEMO 2024 ISP and AEC analysis

Table 3 shows that 83 per cent of solar capacity is in NSW and Queensland. Unlike wind, there are not large differences between regional capacity factors and these two states account for 85 per cent of solar output.

Table 2: 2040 installed utility scale solar capacity and generation in eight-day VRE drought

	NSW	QLD	SA	VIC	TAS	NEM
Capacity MW	14,708	12,542	2,016	3,318	-	32,585
Av capacity factor	18%	19%	18%	16%		12%
GWh	497	455	69	100		1,121
% MW	45%	38%	6%	10%	0%	
% GWh	44%	41%	6%	9%	0%	

Source: AEMO 2024 ISP and AEC analysis

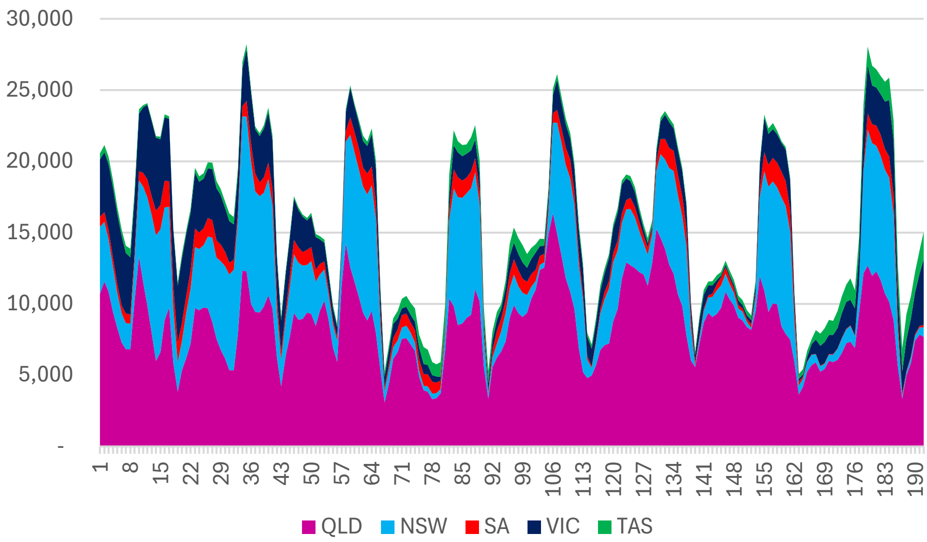
Table 4 shows total VRE output by region and Queensland accounts for half of the NEM's output. At 1,659 GWh the average hourly output of Queensland VRE is just under 9 GWh and this would no doubt fluctuate significantly across the periods which raises the question of whether all of Queensland's surplus VRE could be exported across the interconnector. Our data records 55 hourly intervals greater than 10 GWh and of these nine range between 13 and 17 GWh. The average capacity factor for the NEM is 17 per cent which is significantly higher than the 14 per cent from May 2024 and it is increased Queensland wind capacity and consequential output that has caused this.

Table 3: 2040 installed VRE capacity and generation in eight-day VRE drought

	NSW	QLD	SA	VIC	TAS	NEM
Capacity MW	32,645	30,759	6,067	21,371	2,619	93,462
Av capacity factor	12%	28%	13%	9%	21%	17%
GWh	771	1,659	153	378	105	3,066
% MW	35%	33%	6%	23%	3%	
% GWh	25%	54%	5%	12%	3%	

Source: AEMO 2024 ISP and AEC analysis

Figure 4: Eight-day VRE Drought hourly VRE generation (MWh) by NEM region



Supply – hydro

For this analysis hydro is assumed to have a maximum capacity factor of 100 per cent and in the first instance assumed to run at a Base of 90 per cent. Both of these assumptions can be changed. The Model calculates actual average capacity factor. We have assumed no other constraints on hydro output other than these. The first stage of our model applies these inputs for hydro operation and the second stage curtails hourly output if there is excess generation. Hence, average output may be lower than the base if there is excess generation.

Table 4: Hydro inputs and assumptions

Capacity MW	**7,112**
Max	100%
Base	90%
Average (Model calculated)	89%

Source: 2024 ISP and AEC Model.

Storage

In the model the following assumptions are made for all storages:

- To be full at the start of the 8-days.
- Any excess energy when the storages are not full is used to charge them.
- Preference is given to short duration and if there is more energy than the maximum charging ability of short duration for that hour, this excess will be used to charge medium storage and if there is more energy than the maximum charging ability of medium duration for that hour, the excess is used to charge deep storage. Next it would be Borumba and then Snowy 2.0.
- Storage charges up to its maximum capacity subject to available excess energy. For example, if shallow storage is empty and there are 9,573 MW of excess energy this will the gross amount of charging for that hour. The actual storage in MWh this creates is subject to the charging inefficiency.
- When calculating the rolling hourly storage levels and charge is deflated by the cycle efficiency for the technology. For example, 1,000 MW of small-scale charging would add 840 MWh of storage. The model assumes the MW for charging is at the same rate as discharging but it still takes longer because of the cycling inefficiencies.
- Maximum discharging is assumed to be the same as maximum capacity. For example, Snowy 2.0 has a maximum hourly capacity of 2,200 MW.

Table 5 sets out 2040 utility scale storage capacity assumed in the model.

Table 5: 2040 utility scale storage capacity (MW) and energy (MWh)

	Snowy 2.0	Borumba	Deep Storage	Medium Storage	Shallow Storage	Total
Capacity MW	2,200	1,998	1,097	3,770	9,573	18,639
Storage MWh	49,980	47,952	42,101	28,429	17,932	86,394
Cycle efficiency	0.76	0.76	0.76	0.85	0.84	

Source: 2024 ISP and 2024 IASR

Gas powered generation (GPG)

GPG capacity is as per the 2024 ISP. There is no combined cycle generation and an average heat rate of 11 GJ/MWh is assumed. The model allows the user to select a maximum capacity factor and we have used 100 per cent. When required the model will run GPG at this capacity. A base capacity factor is also required to be inputted. GPG will run up to this rate when its generation is required to meet demand or there is opportunity to charge storage. There is also a minimum capacity factor and we have set this at zero per cent. The model reports the actual average capacity factor. Actual generation and gas usage statistics are reported including maximum hourly quantity (MHQ) and maximum daily quantity (MDQ).

Table 6: GPG inputs and assumptions

Capacity MW	16,183
Heat rate GJ/MWh	11
Minimum cap factor	0%
Maximum cap factor	100%
Base cap factor	90%
Average cap factor (Model calculated)	74%

Source: 2024 ISP and AEC Model.

For unconstrained GPG results MHQ and MDQ are unlimited. MDQ is a 24-hour moving sum of hourly fuel consumption.

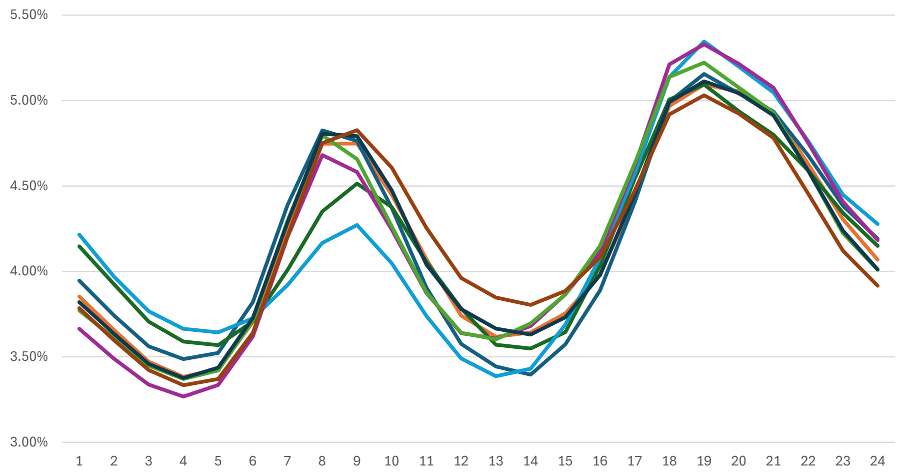
The Model estimates diesel consumption using based on a user specified gas MDQ and this is then divided by 24 to derive MHQ. The need for diesel in any given hour is determined by exceeding the MHQ. The above MHQ fuel demand is met by diesel. The gas TJ/day moving total is shown in the charts as starting in the first hour and once it reaches 24 hours it is a moving total. Importantly any MHQ demand met by diesel is excluded from the calculation.

The calculated TJ of fuel requirement that must be met by diesel are converted to MWh using the assumed heat rate of 11 GJ/MWh.[ii] The volume of diesel required is then calculated by the user selected assumption of lt/MWh and we have assumed 250 lt/MWh.[iii] For a point of reference when considering the diesel usage results, Australia's strategic diesel reserve is 2,485 ML.[iv]

Demand profiles

The July 2022 demand profile has been derived by calculating the maximum eight-day profile in July 2022 which is 14 -21 July. The data we have used is operational as generated. Figure 5 illustrates the profile for each day as a percentage of each day's total demand (classic duck curve). The total demand for the eight days is then measured as a percentage of annual operational demand which is 2.46 per cent. This is used to escalate the demand to 2040 by applying this percentage to the 2040 operational demand (270 TWh). Each day's demand is escalated using this and then the percentage of this for each hour is used to maintain the integrity of the profile.

Figure 5: July 2022 eight days, daily hourly profiles measured as percentage of each day's demand



Source: NEOexpress and AEC analysis

Table 8 sets out the statistics for the three demand profiles. As can be seen, the 2024 ISP average winter demand is 2.36 per cent of operational sent out demand whereas the other two profiles are marginally higher at 2.46 per cent. The July 2022 has the highest hourly maximum GW but is less volatile than the other two.

Table 7: Descriptive statistics of eight-day demand profiles hourly resolution

	ISP FY40 Average Winter	July 2022	ISP Average + 4.35%
Total (GWh)	6,395	6,662	6,673
Average hour (GW)	33.3	34.7	34.8
Coefficient of Variation	15.62%	14.30%	15.62%
Max hourly GW	42.0	45.2	43.9
Min hourly GW	25.8	25.1	26.9
% of operational sent out[v]	2.36%	2.46%	2.46%

Source: AEMO and AEC analysis

Conclusion

This is a first exploratory attempt at dynamically modelling an eight-day VRE drought in 2040 using ISP assumptions, an observed VRE capacity factor profile and three demand scenarios. Most of the assumptions are skewed in favour of avoiding load shedding and the results record significant load shedding. The GPG fuel usage results are concerning because they break the limits of the gas supply chain on a TJ/day basis and an extremely large quantity of diesel is required. Whether this could be achieved is open to question. Hydro also runs extremely hard but if it was short of water this may not be achievable.

The other concern is that Queensland wind accounts for 62 per cent of total output and 52 per cent of VRE output yet the Model assumes this is available anywhere in the NEM where it is needed. In practice some of this output would be unavailable to the rest of the NEM due to the export capability limit of the interconnector with NSW.

On the other side of the equation, the results have shown that there is likely to be scope to refine the Model to utilise Snowy 2.0 more effectively. This could involve treating it like hydro and GPG where it would have a Base generation level. More effective use of Snowy 2.0 would be expected to reduce GPG output and load shedding. Noting that our modelling has assumed Snowy 2.0 is full at the start of eight days.

Another observation is the impact of the 2.2 GW maximum capacity of Snowy 2.0. Scenarios were run where its maximum capacity was doubled and this either eliminated or dramatically reduced load shedding.

CER has been excluded as it is assumed that AEMO's operational demand forecasts already factor in any CER impacts. Nevertheless, as CER is forecast to play a significant role in the future we plan to incorporate it in the Model.

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[i] At this stage, the Model has not been audited or quality assured by a third party.

[ii] The TJ of gas that can't be met by gas in each hour are converted to GJ then divided by 11 to determine how many MW in that hour need to be generated using diesel. These MWh are then translated to diesel usage by multiplying them by 250 lt of diesel.

[iii] Bolivar Power Station Operational Environmental Management Plan and Kurri Kurri technical specifications, https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSI-12590060-MOD-3%2120240906T034810.310%20GMT

[iv] https://www.dcceew.gov.au/energy/security/australias-fuel-security/minimum-stockholding-obligation

[v] Average of 2024 ISP, FY22 and FY23 operational demand as generated