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Roadmap to renewable energy for Boyne Island

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Executive overview

The Queensland Climate Transition Strategy includes a 50% Renewable Energy Target by 2030, a Zero Net Emissions Target by 2050 and an interim carbon dioxide emissions reduction target of 30% below 2005 levels by 2030 as key climate change commitments.

With the first 2 targets due in just over a decade, it is timely to consider potential transition strategies for the Queensland aluminium industry. The investment in wind and solar energy currently underway in Queensland provides the opportunity to investigate the potential for aluminium production using renewable sources of energy. Due to the variable nature of wind and solar energy, their application for industrial use will have to be secured by affordable storage.

There are many technologies that can store energy for use when solar and wind energy are not available. Their capacity for baseload supply however is generally hampered by: prohibitive cost, limited scope for significant scale increases (for instance li-ion or pumped hydro), geographic/geological requirements (for instance compressed air or pumped hydro) which are not known to be available close to Gladstone, and possible sensitivity to drought conditions (e.g. hydro/pumped hydro).

This proposal considers two of the lowest cost storage technologies that could be suitable for a transition strategy for the alumina/aluminium industry located at Gladstone's Boyne Island. Liquid Air Energy Storage (LAES) combines technologies that are related to Liquid Natural Gas processing and is considered to be a relatively mature technology. Molten salt storage combined with Concentrated Solar Thermal Power (CST-TES(16)) provides integrated storage of energy generated from solar energy for 16 hours.

As the Boyne Smelter has a very large load of approximately 1000MW, which fundamentally influences Queensland's ability to transition to net zero emissions, the objective for the industry ultimately will be to source energy from locally available renewable energy. The transition strategy proposed here is to investigate the opportunity for a small 'pilot' to supply 100MW from renewable and storage technologies, with backup from the Yarwun Cogen plant, to meet Queensland Alumina's baseload requirements.

None of the options considered is estimated to be able to supply energy at a cost commensurate with what is estimated as the current average cost for Boyne Smelter. However, the average price currently paid by the smelter is subsidised by both historical wholesale contracts negotiated with the Queensland Government in the 1990s, and protection from past and future carbon costs. Due to the competitive nature of the global aluminium industry, unless national aluminium industries have access to low-cost hydropower, smelters are generally supported by some form of government assistance to lower energy costs. Therefore, this proposal considers likely forms of Queensland Government support for a competitive Queensland aluminium industry.

The most effective of these support mechanisms are preferential Weighted Average Cost of Capital (WACC) and secured Large Generation Certificate (LGC) price. A policy limiting WACC to 6.5% and $50 LGC price combined with investment in PV+CST-TES (16) is estimated to supply energy to QAL at approximately $68/MWh, while investment in VRE + LAES Baseload is estimated at $130/MWh. A cost of $130/MWh is considered too expensive for global competition, and PV+CST-TES (16) is considered to be located too far from Boyne Island and too sensitive to lengthy periods of cloud cover, to be suitable.

The preferred option recommended here is VRE + LAES Managed Baseload, at a cost of under $60/MWh, which sources energy from the grid (ostensibly from contracted renewable sources) but has 5 hours of storage available for dispatch when neither PV nor wind energy is available. LAES storage could also be used for grid stability, renewable energy time shifting, demand response and synchronous inertia.

1. Global aluminium production and electricity

Aluminium smelters are traditionally located in countries with low cost electricity sourced from hydropower or coal-fired generation. Canada, the world's third largest producer of primary aluminium, sources electricity from hydropower for all aluminium production. Russia, the world's second largest producer of primary aluminium, already sources the majority of aluminium from hydropower but Rusal has announced that it intends to source all of its electricity for aluminium production from hydro by 2020, and is marketing its "*Green*" aluminium credentials. The United Arab Emirates (UAE) commenced aluminium production in 2012 and is already producing more aluminium than Australia but is sourcing electricity from natural gas, at prices likely sheltered from international markets, and thus subsidised by the state. The USA, the world's largest aluminium producer until 2000, was reliant on coal-fired electricity for its aluminium production, but in 2000 the USA's dominant position was overtaken by China and the industry in the USA subsequently declined such that it is now a minor producer. Similar to Queensland, 90% of aluminium produced in China is reliant on coal-fired generation at prices subsidised by government.

The Boyne Smelter (BS) exports aluminium mainly to North America and South East Asia and therefore is likely to compete against producers who either source their electricity from low-cost hydropower or against producers in China and the UAE who are subsidised by state policies to underwrite competitiveness. As a result of China's pollution problems, expensive pollution reduction measures, and increasing coal costs, Chinese aluminium producers are facing rising electricity costs, as reported here and here. Although only 10% of Chinese aluminium production relies on hydropower, China is now the world's largest investor in renewable energy, by a long way, which will influence consumption strategies in the future.

It is timely to consider potential transition strategies for the Queensland aluminium industry, away from sourcing electricity from coal-fired generation towards zero marginal cost renewable sources. The investment in wind and solar energy currently underway in Queensland provides the opportunity to investigate the potential for aluminium production using renewable sources of energy.

2. The Boyne Smelter and Gladstone Power Station

Comalco's aluminium smelter on Boyne Island (BS) in Gladstone started operations in January 1982. The smelter's plans included significant growth in electricity consumption into the 1990s, which had influenced decisions on the size of Gladstone Power Station (GPS) (up to 1,650MW), commissioned between August 1976 and February 1982. The Queensland Electricity Commission (QEC) (previously State Electricity Commission of Queensland (SECQ)), also invested in transmission infrastructure for bulk supply to the smelter. The transmission link connecting GPS units 3 and 4 to BS allows continuous power supply to the smelter even in the event of a general power outage. BS is therefore heavily dependent on electricity supplied from Gladstone Power Station (GPS) which is Queensland's oldest and largest coal-fired power station.

A joint venture, including Comalco, purchased GPS from the Queensland Government in March 1994 to secure low electricity prices. There have been a number of confidential agreements between GPS and the Queensland government on the purchase of electricity generated by GPS, bidding GPS energy into the NEM, and obligations to guarantee supply to BS. GPS is currently owned by a consortium including, Pacific Aluminium (42.125%), NRG Energy Inc (37.5%), Southern Cross GPS II Ltd (8.25%), Ryowa II GPS II Ltd (7.125%) and YKK GPS (Qld) Pty Ltd (4.75%).

With significant investment in renewable energy currently underway in Queensland, the Queensland Renewable Energy Target (QRET) of 50% by 2030, and longer term objective of Zero Net Emissions by 2050, it is opportune to consider strategies that will accommodate the retirement of coal-fired power stations as they become surplus to requirement. As GPS is the oldest and now least cost effective coal-fired power station in Queensland, it would be appropriate to consider strategies involving its retirement to:

- avoid heavy investment to maintain operation;
- reduce Queensland's CO_2 emissions from power generation consistent with both medium and longer term state climate change policy objectives; and
- continue to fulfil the requirement of continuous low cost electricity supply to BS.

BS consumes approximately 8 TWh of electricity a year supplied under a long-standing power purchase agreement with the Queensland Government for a continuous 810MW at a discounted price and the remaining 100-150MW negotiated by BS with other generator(s) at prevailing market prices. It is estimated by the authors that the aggregate price paid by BS for electricity in 2017 was less than $50/MWh which was significantly lower than the average spot price of $103/MWh as reported by the Australian Energy Market Operator (AEMO). The long-standing power purchase agreement enjoyed by BS therefore underwrites a significant subsidy for aluminium production.

To avoid investment in a power station that should be scheduled for retirement, facilitate the consumption of energy generated from investment in renewable energy and enable a transition to a low-carbon future, it is opportune to consider baseload power options that utilise energy from solar and wind resources. Meeting the requirement for 900-950MW continuous 24 hour load from solar and wind presents significant challenges but the variability and intermittency of solar and wind power can be counteracted by some form of reliable storage technology.

3. Storage options for baseload generation

As discussed in the ARENA report "Comparison of dispatchable renewable electricity options: Technologies for an orderly transition" (DREO), there are many technologies that can store energy for use when solar and wind power are not available. Baseload options for Queensland are generally hampered by: prohibitive cost, limited scope for significant scale increases (for instance li-ion or pumped hydro), geographic/geological requirements (for instance compressed air or pumped hydro) which are not known to be available close to Gladstone, and possible sensitivity to drought conditions (e.g. hydro/pumped hydro).

In the opinions of the authors, there are only 2 affordable forms of storage to support baseload generation for Boyne Island, and these are molten salt storage when combined with Concentrated Solar Thermal power (CST-TES) or Liquid Air Energy Storage potentially located close to BS, that can address the cost, scale and physical requirements for aluminium production.

Liquid Air Energy Storage (LAES) is a relative new-comer as a storage option although, because it combines technologies that are related to Liquid Natural Gas processing, it is considered to be relatively mature and therefore has reduced early deployment costs. Highview Power has developed the technology and is negotiating with companies to integrate the technology into gas turbine development or deliver pilot implementations.

There are multiple benefits associated with LAES including the ability to act as a synchronous condenser, the ability to ramp to meet load requirements when supply fluctuates, the ability to use waste heat (and cold) to improve round trip efficiency, and the potential to reach utility-scale discharge cost effectively. A further crucial advantage of LAES (and compressed air energy storage), from the perspective of 24/7 baseload supply, is the ability to run charging and discharging operations simultaneously. This technological capacity differs markedly from conventional pumped hydro and battery storage technologies which cannot perform charging and discharging operations simultaneously. The inability to charge and discharge simultaneously limits applications for baseload supply from more traditional storage technologies including battery banks and pumped hydro without investment in duplicate operational capacity; that is one unit to charge and an additional unit to discharge. Specifically, to fulfil a continuous power supply requirement to BS more than one separate pumped hydro or utility-scale battery plant would be required, implying significant overall increase in capital expenditure from traditional storage technologies.

The following sections provide detailed discussion on the potential for meeting Boyne Island baseload requirements from LAES and CST-TES.

4. Potential for LAES implementation

Whilst LAES may be suitable for utility-scale 24 hour energy dispatch, it is a relatively new technological option and therefore likely to still be too expensive for BS to consider as a current source of baseload energy. For this reason, we propose Queensland Alumina (QAL) to be a pilot for proof of concept for future deployment at BS. There are several reasons for selecting QAL as the pilot site, the most important of which are that:

- it is located close to BS such that renewable energy sourced from proximate locations will indicate expected potential energy for the future;
- BS is owned by a consortium of which Rio Tinto Alcan holds 59.39%, and Rio Tinto Alcan holds 80% of QAL, so Rio Tinto Alcan will gain benefit for the group from participating in a pilot for QAL;
- Rio Tinto is already marketing its certified low-CO_2 aluminium, RenewAl, sourced in countries where either hydro, nuclear or geothermal power provide energy for smelting, and have announced a new initiative to produce zero-emissions aluminium in conjunction with Alcoa, the Canadian Government and others, so Rio Tinto will be evaluating the future of production at Boyne Island with respect to the carbon content of its product;
- there is a gas cogeneration plant (154MW) at Rio Tinto's Yarwun plant (100% owned) that could supply energy in the event of lack of either wind or solar energy generated, and potentially waste heat to improve the round-trip efficiency of LAES;
- QAL has approximately 100MW of load, which is a reasonable size to pursue as proof of concept for a 1000MW baseload requirement for BS, whilst also locking in some commercial and technical benefits associated with scale for underlying LAES system specification.

The authors have engaged in detailed discussions with Highview Power and gained information on the technology, capital requirements and costs, to estimate probable levelised costs of energy dispatched from LAES plant. Further, CAPEX costing was determined using base costs for liquefaction and storage equipment sourced from BOC Australia using the '6/10 rule' with Highview Power recommending the use of exponents of 0.6, 0.8 and 0.6 for liquefiers, storage tanks and power generation equipment, respectively.

4.1 Energy resources for QAL LAES pilot

As mentioned previously, there is current investment in both utility PV and wind power in locations not far from Gladstone and close to existing transmission infrastructure. For the purposes of estimating both the solar and wind resource for electricity generation we have estimated generation for Coopers Gap, a 453MW Wind Farm 400km from Boyne Island, and Clarke Creek, a 350MW Solar Farm 300km from Boyne Island for the years 2010, 2011 and 2012.

More generally, it should be recognised that energy for charging the LAES system is drawn directly from the electricity grid and could be supplied from State based public or private VRE energy resources potentially through PPA's or CFD's contracted by the owners of QAL or Queensland's CleanCorp. (There are a number of ownership/business models that could be suitable for the LAES system which are not discussed here but can be considered at a later stage).

In order to store and dispatch 100MW baseload, it is estimated that 183MW of input energy is required for a standalone 24/7 baseload LAES system with round trip efficiency (RTE) of 60%. Further, the 100MW dispatch target is an energy sent-out concept and assuming 10% auxiliary load, would require 111.11MWh of electricity to be produced by the LAES system on an energy generated basis. Although solar resources are relatively predictable, wind resources are less so. For this reason, in order to estimate the aggregate cost of energy for 100MW of baseload, it is assumed that a Power Purchase Agreement (PPA) would be in existence with each of the indicative renewable energy power stations (in this case, Coopers Gap Wind Farm and Clarke Creek Solar Farm) for the first 183MW generated from each power station. Where there is insufficient energy generated from solar and wind to meet 100MW baseload, it is assumed that a PPA will be in existence for the residual energy required from the Yarwun Cogeneration plant.

Two technology scenarios are considered:

> 24 hour storage option: where solar and wind generation only charge LAES and energy for QAL is sourced only from LAES discharges. Where there is a short-fall in energy from solar and wind, energy is sourced from the Yarwun cogen plan. When energy is generated from wind and solar which is surplus to the capacity of the LAES system, it is sold on the spot market. This scenario is called the 'LAES Baseload option'.
>
> 5 hour storage option: where solar generation is directly consumed by QAL as it is generated. Where there is insufficient energy from solar sources to meet load, the additional energy is sourced from wind. When there is wind or solar energy surplus to requirement, this is stored up to a maximum of 5 hours, which can be discharged when there is insufficient energy from wind and solar. Where there is insufficient energy generated from wind and solar and insufficient energy in storage, then energy is sourced from the Yarwun cogen plant. When energy is generated from wind and solar which is surplus to both consumption by QAL and LAES storage, it is sold on the spot market. This scenario is called the 'Managed Baseload option'.

4.2 Initial high-level estimates of costs and revenue streams for LAES

Using solar and wind traces for Clarke Creek and Coopers Gap, energy generation from those facilities have been estimated on an hourly basis for 365 days a year for 2010-12. These have been modelled and applied to the Managed Baseload option and LAES Baseload option. Outcomes for the years 2010-12 are remarkably similar, indicating a reliable solar and wind resource for baseload requirements.

Assumptions have been made about potential cost of PPAs for wind and solar referencing recent announcements. Based on these announcements, it is assumed that PPA prices include the transfer of Large Generation Certificates (LGC) to the purchasing party, such that they can be offset against PPA costs. Equally, average spot price is assumed to be a conservative $35/hour due to the consequences for merit order dispatch when there is a large supply of zero marginal cost energy. The price of LGCs is assumed to be $30 based on the widely held belief that LGC prices will fall in coming years due to the conclusion of the Federal Government's Large Renewable Energy Target (LRET) in 2020. There is little understanding of the potential value of Frequency Control Ancillary Services (FCAS) and Synchronous services, so a small value is included for illustration. The assumptions, detailed below, are listed in Table 1.

Table 1: Assumptions for QAL baseload supply using LAES

Assumptions	Managed Baseload option	LAES Baseload option
Baseload capacity (MW)	100	100
Feedstock capacity (MW)	91.6	183
Storage capacity (hours)	5	24
Storage charging losses (%)	40%	40%
Storage discharge auxiliary use (%)	10%	10%
Capital Cost ($/kW)	$3,406	$7,988
PPA-PV ($/MWh)	$60.00	$60.00
PPA-Wind ($/MWh)	$60.00	$60.00
PPA-Cogen ($/MWh)	$50.00	$50.00
Storage discharge ($/MWh)	$707.92	$151.53
Ave Spot Price for sales ($/MWh)	$35.00	$35.00
LGC ($/MWh)	$30.00	$30.00
Synchronising service value ($/MWh)	$1.00	$1.00

Estimated costs associated with the 2 options are:

- PPAs for the first 183MW generated from each of Clarkes Creek and Coopers Gap for the LAES Baseload option, or the first 91.6MW for the LAES Managed Baseload option
- PPA for energy from Yarwun cogen for the energy required when there is insufficient energy from solar, wind and storage.
- LAES levelised costs (excludes feedstock cost of solar, wind or gas).

The outcome from modelling the solar and wind resources at Clarkes Creek and Coopers Gap are detailed in Table 2.

Table 2: Cost estimates for QAL baseload using LAES

	Managed Baseload option			LAES Baseload option		
	2010	2011	2012	2010	2011	2012
MWh delivered	876,000	876,000	876,000	876,000	876,000	876,000
PPA requirements						
PPA with ClarkeCk for consumption	368,561	380,605	380,109	612,723	653,986	651,091
PPA with CoopersGap for consumption	364,341	347,311	342,701	1,077,410	1,059,170	1,045,034
PPA for surplus energy for storage	289,868	297,540	297,011			
PPA for purchases from Gas Cogen	65,451	69,486	68,225	60,488	64,212	55,678

	Managed Baseload option			LAES Baseload option		
	2010	**2011**	**2012**	**2010**	**2011**	**2012**
Operational flows:						
Discharge from storage	77,647	78,598	84,965	876,000	876,000	876,000
Sell on spot	165,763	174,068	161780	78,680	97,501	81,534
Loss on RTE and auxilliary use	57,883	58,175	62,882	793,549	804,000	794,343
% of baseload from existing cogen	7.5%	7.9%	7.8%	3.5%	3.6%	3.2%
Cost of consumption						
Cost of PPA for ClarkeCk	22,113,654	22,836,288	22,806540	36,763,386	39,239,190	39,065,448
Cost of PPA for CoopersGap for consumption	21,860,450	20,838,650	20,562,047	64,644,626	63,550,178	62,702,045
Cost of PPA for energy for storage	17,392,080	17,852,387	17,820,658			
Cost of Discharge	54,963,933	55,638,358	60,145,270	132,740,280	132,740,280	132,740,280
Cost of PPA for Cogen	3,272,571	3,474,314	3,411,249	3,024,393	3,210,606	2,783,888
TOTAL Cost	119,599,207	120,636,216	124,742,020	237,172,685	238,740,254	237,291,661
Avg/MWh	$136.63	$137.71	$142.40	$270.75	$272.53	$270.88

Table 2 shows that the average cost of energy for the Managed Baseload option is around $140/MWh and in excess of $270/MWh for the LAES Baseload option. The cost of electricity for the LAES Baseload option can be reduced by using heat from the Yarwun Cogen plant, although the associated decrease in levelised cost of energy (LCOE) is relatively minor.

In light of the existing subsidies that are provided to BS, reduced cost can be achieved through applying preferential finance costs for this pilot project. The authors have applied a Weighted Average Cost of Capital (WACC) of 11% for the estimation of LCOE for both scenarios. If the WACC is reduced to 6.5%, the aggregate cost for QAL for the Managed Baseload option reduces to around $123/MWh and the LAES Baseload to approximately $234/MWh.

These are significantly higher costs of electricity than is currently being paid. There are however a number of income streams that can be applied to the cost to reduce the outlays by QAL. These include selling the energy generated that is surplus to requirement, selling the LGCs from the solar and wind generation, earning revenue from participating in the FCAS market, and earning revenue from acting as a synchronous condenser for grid stability.

As Table 3 shows, there is significant income to be earned from selling LGCs[1]. In fact, the adjusted baseload cost for QAL is very sensitive to the LGC price assumption. An assumption of $50 for LGC increases the potential income to $51 million for the Managed Baseload option and $85 million for the LAES Baseload option, decreasing the adjusted baseload cost to $70-75/MWh and $170/MWh respectively.

[1] Another potential source of revenue might be LGC revenue from the sale of the output from the LAES plant itself which contains no carbon emissions, although the Clean Energy Regulator has not confirmed whether this is allowable.

Table 3: Income estimates for QAL baseload using LAES

	Managed Baseload option			LAES Baseload option		
Revenue stream	2010	2011	2012	2010	2011	2012
Sales from excess energy	5,802,047	6,092,629	5,662,608	2,753,796	3,412,521	2,853,695
Synchronisation Services	876,000	876,000	876,000	876,000	876,000	876,000
LGC	30,681,216	30,761,673	30,592,633	50,704,006	51,394,684	50,883,746
Total Cost write-offs	37,359,264	37,730,301	37,131,241	54,333,802	55,683,205	54,613,441
Adjusted Baseload cost to QAL	82,239,943	82,905,915	87,610,779	182,838,883	183,057,049	182,678,219
Avg/MWh	$93.88	$94.64	$100.01	$208.72	$208.97	$208.54

The cost reductions from commercial assumptions resulting from assistance for the pilot project are detailed in Table 4. It is apparent that the Managed Baseload option, with support, reaches a price commensurate with the estimated price paid by BS in 2017. This option offers a more attractive overall energy cost because of the high energy losses and associated costs of the LAES Baseload option, reflecting the underlying 60% round trip efficiency. In effect the Managed Baseload option consumes energy as it is generated and stores energy only when there is a surplus, making it more cost effective than the LAES Baseload option[2].

Table 4: Options for lower costs for QAL baseload using LAES

	Managed Baseload option			LAES Baseload option		
$/MWh	2010	2011	2012	2010	2011	2012
Commercial principles	$93.88	$94.64	$100.01	$208.72	$208.97	$208.54
WACC 6.5%	(15.34)	(15.53)	(16.78)	(38.20)	(38.20)	(38.20)
$50 LGC price	(23.35)	(23.41)	(23.28)	(38.59)	(39.11)	(38.72)
$50 spot price	(2.83)	(2.98)	(2.77)	(1.35)	(1.67)	(1.40)
All preferential terms	$52.35	$52.72	$57.17	$130.59	$129.99	$130.22

However, only using the LAES when there is insufficient wind or solar means that the storage system is functioning at 43% capacity factor which significantly escalates the LCOE of LAES discharges. The LAES system could be reduced in capacity but this would affect its ability to deliver adequate energy to QAL in the

[2] The results suggest that for 100MW, essentially no storage is needed. It is not understood whether managing supply as recommended in the Managed Baseload option would continue to work for the larger BS load of 900+MW on 24/7 basis. However, robust use of LAES in a pilot implementation would help inform the feasibility of "managed baseload" and the benefits compared with LAES Baseload.

event of transmission failure. The sizing of the LAES system is therefore a factor of security and resilience considerations not only optimised cost.

The Managed Baseload option would require a comprehensive energy management and forecasting system which would increase costs.

5. Potential for Concentrated Solar Thermal

Concentrated solar thermal power with molten salt thermal energy storage (CST-TES) for decades has been touted as a combination of technologies that could best schedule dispatch from variable renewable energy sources (VRE). Solar Reserve's Aurora 135MW plant, currently under construction in Port Augusta South Australia, is a CST-TES plant with 8 hours storage capacity, expected to generate 500GWh per annum.

According to the ARENA report "Comparison of dispatchable renewable electricity options: Technologies for an orderly transition", the LCOE for CST-TES for Australia is approximately $130-140/MWh. The authors of this proposal for QAL have however used the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) to estimate the capacity factor (CF) for a CST-TES plant with 8 hours of storage (CST-TES(8)) in Biloela, Lilyvale and Longreach using actual solar data for 2007. Table 5 details the potential capacity factor for each location.

Table 5: Capacity factors of selected locations for CST-TES(8)

	Biloela	Lilyvale	Longreach	Port Augusta
Capacity factor (CF)	41.2%	43.8%	53.8%	46.6%

Although Longreach has a CF of 53.8% it is not connected to the transmission network, and therefore much more expensive when transmission costs are factored in to the investment cost. Lilyvale, being only 400km from Gladstone and close to major transmission infrastructure, could be considered to be the most appropriate site for a CST-TES plant for QAL.

Further modelling for CST-TES(8) at Lilyvale for the years 2007-2015 show CFs for 2007-2015 range from 46.2% to 53.1% except in 2010 where high rainfall and cloud cover reduce CF to 33%. Doubling the storage capacity to 16 hours (CST-TES(16)), improves CF for 2007-15 to be between 60.9% and 70.6% except for 2010 which falls to 43%. Details can be seen in Table 6.

Table 6: Capacity factor for CST-TES plant in Lilyvale with 8 and 16 hours storage

Year	CST-TES(8)	CST-TES(16)
2007	43.77%	57.49%
2008	46.49%	61.22%
2009	45.39%	59.85%
2010	33.27%	43.45%
2011	45.44%	60.30%
2012	46.56%	60.19%
2013	47.61%	62.83%
2014	50.19%	66.48%
2015	53.1%	66.41%
2007-15 average	45.44%	59.80%

CST performance is sensitive to cloud cover, more so than PV, as detailed in this article by Greentech Media. Although storage mitigates against the loss of generation from cloud cover, it does not eradicate the potential for severely reduced output as a result of La Nina weather events like that experienced in 2010. By comparison, the estimated CF for PV for Clarke Creek in 2010 decreased to 25% from 29% in 2011 and 2012 which indicates PV's lower sensitivity to cloud cover.

Output modelled from CST-TES at Lilyvale with greater than 16 hours of storage, showed an increase to an average of 64.4% CF for CST-TES (24) and 66.4% CF for CST-TES (30). This was not considered to deliver enough additional output to justify the increased capital expenditure.

5.1 Initial high level estimates of costs for CST-TES without and with PV

Modelling for CST-TES includes 150MW (gross, 135MW net) of CST generation capacity which is larger than QAL demand of approximately 100MW. This assumption has been made for 2 reasons. The first is due to the lower absolute CF of CST-TES, which makes it necessary to oversize the generation capacity to meet an absolute minimum of 100MW. The second is because this is exactly the size of the Aurora plant in Port Augusta, which ensures that assumptions made with respect to capital costs accurately reflect Australian capital cost expectations for this technology.

Using the solar traces for Lilyvale, generation from CST-TES is estimated on an hourly basis for 365 days a year for the same period 2010-12 as modelled for the LAES options. Levelised cost of energy (LCOE) for CST-TES has been calculated using technical details as published by the US's National Renewable Energy Laboratory (NREL) and Australian cost assumptions from the ARENA DREO report.

As CST-TES does not dispatch 24/7,365 days a year, 16 hours of storage is considered to be a minimum requirement. Energy for any gap in generation is assumed to be sourced from the Yarwun cogen plant at a fixed PPA of $50/MWh. CST-TES(16) requires considerable generation from gas-fired generation to dispatch 24/7, so an option combining CST-TES (16) with PV from Clarke Creek is also modelled. The PPA for PV from Clark Creek is assumed to be $60/MWh. The price of LGCs is assumed to be $30. A small value for FCAS is included for illustration. The assumptions are listed in Table 7.

Table 7: Assumptions for QAL baseload supply from CST-TES

Assumptions	**CST-TES(16)**	**PV + CST-TES (16)**
Baseload capacity (MW)-Net	135	135
-Gross	150	150
Storage capacity (hours)	16	16
Capacity Factor: CST-TES	48 – 67%	48 - 67%
Capital Cost $/kW	$5,565	$6,345
PPA-Cogen ($/MWh)	$50.00	$50.00
PPA-PV ($/MWh)		$60.00
Levelised Cost of Energy ($/MWh)	$218.56	$189.40
LGC ($/MWh)	$30.00	$30.00
Synchronising service value ($/MWh)	$1.00	$1.00

Table 8 shows that the average cost of energy for a Lilyvale CST-TES(16) is $144-183/MWh and $158-202/MWh for PV+CST-TES(16). Like the LAES baseload option, these are still considerably higher than energy costs currently enjoyed by GPS.

Table 8: Cost estimates for QAL baseload using CST-TES

	CST-TES (16)			PV+CST-TES (16)		
	2010	2011	2012	2010	2011	2012
MWh delivered	**876,000**	**876,000**	**876,000**	**876,000**	**876,000**	**876,000**
PPA's required						
PPA with ClarkeCk for consumption				368,561	380,605	380,109
PPA with LilyVale for consumption	570,969	792,339	790,903	570,553	791,173	788,732
PPA for purchases from Gas Cogen	357,474	199,807	200,143	158,055	73,809	87,419
Operational flows:						
CST-TES dispatch	518,526	676,193	675,857	349,384	421,586	408,4723
Sell on spot	51,859	116,731	115,046	219,674	369,252	381,640
% from CST-TES	59.3%	77.1%	77.2%	40.1%	48.2%	46.5%
% from PV				42.1%	43.4%	43.4%
% from Gas cogen	40.8%	22.8%	22.8%	18.0%	8.4%	10.0%
Cost of consumption						
Cost of PPA for ClarkeCk				22,113,654	22,836,288	22,806,540
Cost of PPA for CST	108,141,594	150,069,014	149,797,004	108,062,785	149,848,192	149,385,848
Cost of PPA for Cogen	17,873,710	9,990,370	10,007,168	7,902,750	3,690,750	4,370,974
TOTAL Cost	**126,015,304**	**160,059,384**	**159,804,172**	**138,079,189**	**176,374,927**	**176,563,362**
Avg/MWh	$143.85	$182.72	$182.42	$157.62	$201.34	$201.56

In light of the existing subsidies that are provided to BS, reduced cost can be achieved through applying preferential finance costs for this pilot project. The authors have applied a WACC of 11% for the estimation of LCOE for both scenarios. If the WACC is reduced to 6.5%, the aggregate cost for QAL for CST-TES(16) in 2011 reduces to around $138/MWh and for PV+CST-TES(16) to $157/MWh.

These predicted costs of electricity remain higher than is currently being paid. There are however a number of income streams that can be applied to the cost to reduce the outlays by QAL. These include selling the LGCs, earning revenue from participating in the FCAS market, and earning revenue from acting as a synchronous condenser for grid stability. As Table 9 shows, there is significant income to be earned from selling LGCs. The adjusted baseload cost for QAL is sensitive to the LGC price assumption. An assumption of $50 for LGC increases the potential income to $29-58 million and decreases the adjusted baseload cost in 2011 to $132/MWh for CST-TES(16) or $119/MWh for PV+CST-TES(16).

Table 9: Income estimates for QAL baseload using CTS-TES

	CST-TES (16)			PV + CST-TES (16)		
Revenue stream	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
Sales from excess energy	1,815,059	4,085,591	4,026,618	7,688,576	12,923,812	13,357,392
Synchron. Services	876,000	876,000	876,000	876,000	876,000	876,000

	CST-TES (16)			PV + CST-TES (16)		
Revenue stream	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
LGC Revenue	17,129,080	23,770,171	23,727,086	28,173,424	35,153,338	35,065,231
Total Cost write-offs	19,820,139	28,731,762	28,629,704	36,738,000	48,953,151	49,298,623
Adjusted Baseload cost to QAL	106,195,165	131,327,621	131,174,468	101,341,188	127,421,777	127,264,739
Avg/MWh	$121.23	$149.92	$149.74	$115.69	$145.46	$145.28

The cost reductions from commercial considerations for assistance for the pilot project are detailed in Table 10.

Table 10: Options to lower costs for QAL baseload from CST-TES(16)

	CST-TES (16)			PV + CST-TES (16)		
$/MWh	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
Commercial principles	$121.23	$149.92	$149.74	$115.69	$145.46	$145.28
WACC 6.5%	(32.17)	(44.64)	(44.56)	(32.15)	(44.58)	(44.44)
$50 LGC price	(13.04)	(18.09)	(18.06)	(21.44)	(26.75)	(26.69)
$50 spot price	(0.89)	(2.00)	(1.97)	(3.76)	(6.32)	(6.53)
All preferential terms	$75.13	$85.18	$85.15	$58.64	$68.02	$67.82

Energy sourced from CST-TES, supported by a lower WACC and guaranteed LGCs, could be delivered at a price higher than the estimated price paid by BS in 2017 for both CST-TES(16) and PV+CST-TES(16) but not excessively so. From this analysis it appears PV+CST-TES(16) would be preferable to CST-TES(16) because it generates in excess of 89% of QAL requirements.

This study finds that PV+CST-TES (16) is viable for scheduling power supply from renewable energy, using effectively Queensland's world class solar resource. The combination of PV and CST-TES(16) provides a path towards baseload supply from solar resources, as a promising alternative to combinations of PV and wind as proposed for Hughenden and Kidston energy parks. Given Central and South West Queensland's solar resource and existing well-developed transmission infrastructure, the potential for firming solar energy using this combination should be strongly investigated as part of Queensland's transition to high levels of renewable energy by 2030.

5.2 The Longreach option

Solar resources in Longreach are considerably more reliable for baseload CST generation. In particular, locating CST-TES in Longreach reduces sensitivity to extended cloud cover. For instance, predicted CF for

CST-TES (16) in Longreach in 2009 is 75.2% which drops to 65.8% in 2010, a 12% reduction. By comparison, the CF predicted for Lilyvale in 2010 is 28% lower than 2009.

Across the 9 years predicted, the average CF for CST-TES(8) is 56% and 78% for CST-TES(16). At these CFs, the average cost for CST-TES(8) is predicted to be $177/MWh and $146 for CST-TES(16) using commercial WACC assumptions. Reducing WACC to 6.5%, the cost reduces to $107/MWh for CST-TES(16). Applying cost write-offs of $50 LGCs and synchronous services reduces the average cost for QAL further which implies that CST-TES from Longreach would require less direct support but would require extensive transmission investment to connect to the 275kV high-voltage transmission network.

6. Comparing LAES Baseload and PV+CST-TES(16)

LAES Baseload and PV+CST-TES(16) offer 2 very different options for meeting Boyne Island's electricity supply. Table 11 gives a financial overview of the 2 options.

Table 11: Comparing LAES Baseload to CST-TES(16) in 2011

	LAES BASELOAD	PV+CST-TES(16) (Lilyvale)
LCOE ($/MWh)	$273	$201
Sale of spare electricity	(5)	(15)
Reduced WACC to 6.5%	(38)	(45)
LGC Revenue ($30)	(59)	(40)
LGC Revenue ($50)	(39)	(27)
Other (FCAS)	(2)	(6)
Subsidised Avg cost	$130	$68

Aggregated supply from the different VRE sources for each option are detailed in Appendices D-G.

Comparing the costs associated with baseload generation from LAES or PV+CST-TES shows that PV+CST-TES is a more affordable option. There are, however, a couple of caveats that should be considered in connection with the greater affordability of the PV+CST-TES (16) option for baseload supply to QAL; namely that

a. CST-TES(16) has the potential for considerably reduced generation during periods of extended cloud cover as can be seen in Appendix F figure xxi and Appendix G figure xxvii . This suggests significant risk to supply for Boyne Island during high cloud/rain periods similar to that experienced in November-December 2010. Locating a CST-TES(16) plant in Longreach would mitigate against disrupted supply from cloud cover, but the costs of extending the transmission network to Longreach have to be considered and would be expensive. A further alternative could be to support the construction of an additional CST-TES plant elsewhere (possibly in South West Queensland) which could serve as a backup to the Lilyvale plant, although this significantly increases the absolute amount of investment making CST-TES (16) less attractive.

b. Lilyvale is 400km and Longreach more than 800km from Boyne Island which would increase risk of supply interruption during disruptive weather events like cyclones, heatwaves and monsoons.

For these reasons the proposal here is that either the LAES Baseload or the Managed Baseload option are preferable to the CST-TES (16) or PV+CST-TES (16) options because LAES can be located either at the GPS site or extremely cost to it. This proximity will secure supply for Boyne Island much like the arrangements currently provided by GPS including direct transmission linkages relating to GPS units 3 and 4.

7. Strategic options for transition

The challenge for the Queensland Electricity Supply Industry (QESI) is to absorb significant levels of VRE premised on achievement of the 50% Queensland renewable energy target (QRET) in the next decade. Of particular concern is the reduction in load as a result of high levels of energy generated from rooftop solar. Additional supply from utility solar plant could exacerbate oversupply of energy during the day which could impact coal-fired power stations with little flexibility to adjust to the over-supply of energy. As coal-fired power stations are technically incapable of operating only at night, coal generator bid strategies are likely to reflect negative values to maintain supply when VRE supply is high, leading to spilled energy from VRE and financial hardship for VRE investors. A failure to address these demand-supply imbalances will reduce investment in renewable energy in Queensland as a result of perceived risk of reduced returns on investment.

Thus, if Queensland is to transition to high levels of electricity from VRE, the Queensland Government must consider:

- the impact of high levels of VRE on existing industries;
- the impact of high levels of VRE on existing coal-fired generators;
- strategies to absorb excess supply of VRE;
- strategies to dispatch energy when there is no supply of VRE;
- strategies to provide synchronous inertia;
- strategies to provide emergency reserve for periods of sustained low supply of VRE; and
- strategies to support investment required to meet renewable energy and net zero emission targets.

A stable transition from coal-fired generation to VRE supply requires investment in affordable levels of storage for VRE to shift dispatch to periods of higher demand and lower supply. The options detailed in this proposal have been chosen because of their expected affordable price tag and their ability to meet the particular supply constraints at Boyne Island.

Of the technologies considered, only LAES is capable of absorbing any oversupply of energy during the day thereby contributing to system balancing (by increasing demand associated with charging operations) whilst also potentially supplying synchronous inertia and reducing spillage of low emission power from VRE sources. Further enablers of LAES include the potential for cost reductions in solar PV and wind generation locking in lower PPA off-take agreements over time or relatively low daytime wholesale market prices associated with emergent duck curve effects that might underpin daily charging operations of LAES.

Table 12 sets out the strategic considerations for the LAES and PV+CST-TES options.

Table 12: Comparing strategic benefits of different storage options

Requirement for Boyne Island	LAES	PV+CST-TES (16)
Capital cost	$341 million (5 hours) $800 million (24 hours)	$835 million (8 hours) $952 million (16 hours)
Average cost for: -supply ($/MWh)	Fair. $122 (5); $235 (24)	Good. $157

Requirement for Boyne Island	LAES	PV+CST-TES (16)
-after cost write-offs ($/MWh)	$ 53 (5); $130 (24)	$68
Location proximity to Boyne Island	Excellent. Could be located at GPS.	Fair. Does not allow supply during widespread or localised power outages.
Additional transmission infrastructure requirement	Negligible. Located at GPS	Small. Located near existing transmission infrastructure, unless located at Longreach.
Supply during power outage	Excellent Using existing DC link from GPS to BS.	Not possible Too far for affordable secure link
Adaptability to drought	Excellent	Excellent
Absorb excess VRE	Excellent	Not possible
Scheduled dispatch	Excellent	Very good
Charge/discharge simultaneously	Excellent	Excellent
Support for grid stability	Excellent	Good
Synchronous inertia	Excellent	Excellent
Provide strategic reserve to counter unpredictability of VRE	Excellent	Good
% of gas-fired generation required	3.5 – 7.9%	8 – 18%

PV+CST-TES(16) offers a less expensive option for supplying baseload power once sales of LGCs and additional revenue are considered. Indeed, PV+CST-TES may have many good industrial applications in Central and South West Queensland if provided with appropriate support. It will also help meet many of the strategic requirements for transition to high levels of renewable energy in the next decade including overnight schedulable dispatch, synchronous inertia and frequency control. Whilst PV+CST-TES (16) will facilitate a transition to and beyond a 50% QRET, it is not advised as an energy source for Boyne Island purely for supply security reasons.

LAES Baseload provides maximum security for Boyne Island, although it comes at a higher price tag than is considered affordable by a globally competitive aluminium industry. Reducing the WACC to 3.6%, a rate commensurate with Government funding, would decrease the aggregate cost of supply to $110/MWh. This is still significantly higher than considered affordable for globally competitive aluminium production, so LAES Baseload is not proposed here as an option for a pilot implementation at QAL. However, LAES Baseload may well be a contender for supply for BS in the future because it is possible that the capital cost of LAES baseload could reduce to approximately $537 million assuming 10 doublings of capacity at learning rates equal to 17.5% associated with OCGT technologies (as advised by Highview Power). This would particularly be the case if the cost of solar PV and wind VRE technologies continue to fall implying significantly lower off-take PPA rates than used in the modelling to charge the LAES system. More generally, from a strategic perspective, LAES Baseload should play a major role in the future for supply to BS and also in securing high levels of VRE as required by QRET and the Zero Net Emissions target.

The Managed Baseload option is more affordable and proposed as the option for a pilot implementation at QAL. However it requires an understanding of the absolute minimum proportion of load required to maintain operations at Boyne Island, for the minimum period, to act as the emergency reserve. Utilising LAES in this ‘managed’ way will provide insight into the capacity of the system to provide emergency reserve for QAL, as well as schedule dispatch to benefit from high-price events, provide demand response during high demand events, absorb excess VRE for later dispatch, act as a synchronous condenser and generally support grid stability. Further, experience with the 100MW/500MWh system will provide evidence of LAES's ability to accommodate up-scaling to a full BS scenario likely entailing between 530MW to 900MW as currently provided by GSP. Additional revenue streams associated with LAES would further lower its cost of supply.

Potential business models and ownership structures for a LAES system have not been considered here, but these are important matters for future discussion. Storage can be considered to be critical infrastructure for Queensland to meet its 2030 and 2050 targets. Whoever operates the system will need to provide a strategic/emergency reserve, VRE time shifting, support for ancillary services, demand response or a combination of these services, all of which affect revenue earning capacity. Considering the multitude of disparate services that can be provided from a robust storage system, it is logical to consider a business model centred on one owner, possibly CleanCo or another Queensland Government entity.

In conclusion, in order to safeguard Queensland's target of 50% Renewable Energy by 2030 and Zero Net Emissions by 2050, action needs to be taken now in order to put in place a strategic transition path for continuous supply from VRE. This action should include investment in emergency reserve for Boyne Island ostensibly to secure affordable zero-emission energy for the aluminium industry in Queensland, but also to balance VRE supply with load in Central Queensland, thereby helping to secure investment in VRE that will achieve the 2030 and 2050 targets.

8. The aluminium industry, employment and transition to low-carbon

The size of the entire Gladstone economy is estimated to be $4.77 billion with employment of 30,000. At current production levels of 500,000 tonnes of aluminium at a global price of approximately $2000/t, and approximately 5.5 million tonnes of alumina exported at approximately $400/t, the alumina/aluminium industry is worth roughly 67% of the Gladstone regional economy. The alumina/aluminium industry in Gladstone supports approximately 3000 direct jobs through BS, QAL and Yarwun, making up 10% of regional employment. The continuation of a healthy alumina/aluminium industry is paramount for the Gladstone region.

Historically, protection afforded to the industry from electricity price increases resulting from National Electricity Market (NEM) volatility and the (temporary) implementation of the Carbon Price has held at bay the potential for severe consequences for its continued profitable performance in Gladstone. What of the future, however? In an open economy like Australia's, how long will government intervention be able to counteract the consequences of global carbon reduction commitments, volatile energy prices associated with global demand-supply imbalances and consumer preference for low-carbon content as currently being courted by Rusal and Rio Tinto? In South Australia, a steel industry revival is being underwritten by significant renewable energy investment, forecast by a successful industrialist to decrease the input costs of steel production, not increase them. The BS should be at the forefront of transition plans to a low carbon future for Queensland, not forced to transition as a last consideration.

This proposal, for a pilot plant to investigate the potential for baseload generation from options that include combinations of solar, wind, LAES and a small proportion of gas, seeks to initiate a transition plan to a low-carbon future for the alumina/aluminium industry in Gladstone. The affordability of electricity estimated in this proposal is dependent on the Queensland Government's commitment to favourable terms associated with the cost of capital and the underwriting of income from potential revenue streams like LGCs or some form of shadow carbon incentive and surplus energy. In fact, to meet the Queensland goal of 50% of electricity sourced from renewable energy by 2030, extension of some form of Renewable Energy Target may be necessary to secure Queensland investment, making the underwriting of support for renewable energy investment a necessity. Whilst these measures may be considered by some to be protectionist, they are necessary to support a relatively new technology prior to widespread global deployment and the cost declines that should follow. A successful pilot implementation of this sort for QAL, will prepare the ground for a more comprehensive study to utilise solar, wind and LAES for BS. As the Queensland Government currently subsidises the cost of coal-fired generation supplied to BS, it is not a change of policy to also subsidise a pilot scheme to establish the feasibility of utilising electricity generated from renewable sources to ensure the continued existence of the alumina/aluminium industry in Queensland.

9. The way forward

This proposal is a high-level plan including available technologies, technical requirements for proximity, and the potential costs of implementing an energy storage option to underpin baseload supply for Queensland Alumina from variable renewable energy as proof of concept for a scale-up of the technologies to meet the requirements of the Boyne Smelter.

In order to progress this plan, it is important to initiate a formal project group tasked with overseeing a more detailed technical analysis of the options for baseload energy for Boyne Island. This project group should comprise appropriate Queensland Government officials and seek:

- more detailed weather data from Bureau of Meteorology, predictive weather models and satellite data to understand longer range weather considerations for VRE generation;
- technical guidance about the LAES technology requirements from Highview;
- guidance from BOC about liquefaction technical requirements and costs;
- representation from Boyne Smelter, QAL and Rio Tinto to instruct on specific consumption requirements;
- advice from Australian Renewable Energy Agency on support for strategic investment;
- participation by Powerlink and CleanCo to consider potential business models and investment opportunities;
- participation by Department of Energy to advise on energy policy strategies to meet targets; and
- participation by Department of Environment to guide on adherence to Queensland's Climate Change Adaptation Plan.

The finding here, that PV+CST-TES with policy support, could deliver affordable dispatchable supply from VRE for Central and South West Queensland, suggests that this opportunity has potential to be developed into a viable project plan for Queensland Alumina.

A technology that has not been discussed in this proposal is Compressed Air Energy Storage (CAES). This is because as with CST-TES the technology requires specific geological structures and these are not located close to Boyne Island. In Alabama in the United States and Huntorf in Germany, disused mines have provided the required geology for CAES. A brief discussion with individuals from GeoScience Queensland suggests that the potential for using disused underground mines in the Bowen Basin is negligible. In summary, disused underground mines are either too small, too shallow or unlikely to be able to hold any gas under pressure. For these reasons CAES storage is also not considered.

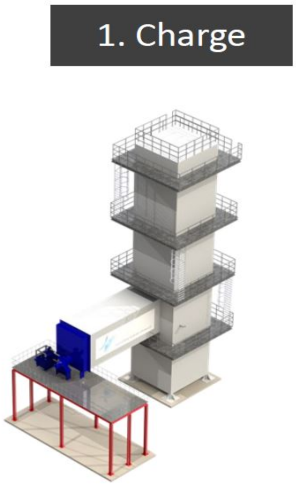
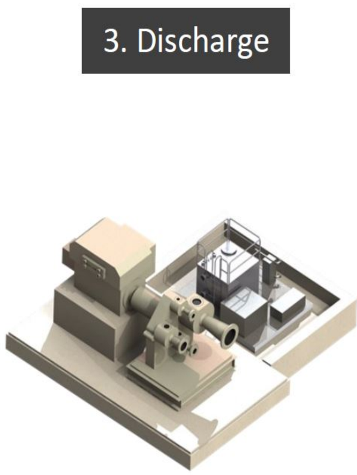
Appendix A : Technical summary on Liquid Air Energy Storage

Figure i: LAES Pilot plant 350kW/2.5MWh

Liquid Air Energy Storage (LAES) has been proposed as a storage mechanism that is capable of providing utility-scale GWh's worth of electrical energy storage. A particular advantage of LAES is that it can be flexibly located anywhere within the existing transmission grid and only requires enough space above ground to store above ground storage tanks.

Conceptually, LAES is similar to Compressed Air Energy Storage (CAES) but with the storage medium and infrastructure being liquid air and insulated above ground tanks such as cryogenic or LNG storage tanks. There are two potential energy carriers in LAES applications: (1) liquid nitrogen; or (2) liquid air. Of the two carriers, liquid nitrogen is the more mature carrier and has a more developed infrastructure and liquefaction capacity. The cost assumptions employed in the LAES modelling in this document is based upon a liquid nitrogen energy carrier concept.

LAES comprises the following <u>three</u> phases:

Phase 1. Charging Phase (producing liquid air or liquid nitrogen) • Run using mains electricity. • Liquefier/s. • Compressor chains. • Air purification – molecular sieves - removes particulates, water vapour, C02 and hydrocarbons from air stream. • Nitrogen generation (for liquid nitrogen carrier) – use molecular sieve to separate nitrogen from the cleaned air stream (from the step immediately above) prior to nitrogen liquefaction. • Store waste heat to improve efficiency of Phase 3.	
Phase 2. Storage Phase (stores liquid air/nitrogen and hot and cold waste thermal energy extracted from internal LAES process) • Liquid air/nitrogen is stored in insulated above ground tanks at low pressure. • Existing cryogenic/LNG tanks can store GWh's of energy.	
Phase 3. Power Recovery Phase (electricity generation) • Release stored liquid air/nitrogen converted to high pressure gas. • Use heat exchangers and stored heat from Phase 1 to improve thermal generation efficiencies. • Turbine chains – radial inlet turbo expanders or steam derivative turbines. • Store waste cold to improve efficiency of Phase 1.	

LAES stores and uses waste hot and cold thermal energy extracted during the internal LAES cycle to improve round-trip efficiency (RTE):

Cold Recycle

- During Phase 3 power recovery stage, very cold air is exhausted and stored for further use in Phase 1 liquefaction stage to improve efficiency

Thermal Store

- Heat is produced during Phase 1 liquefaction stage that is used in the Phase 3 power recovery stage to improve the efficiency of this stage.

Utilising this hot and cold thermal energy produces a ‘standalone’ RTE of 60%. In addition, the use of third-party external cold and heat further improves RTE:

- Heat – e.g. from thermal power generators, steel mills –> RTE: 70%
- Cold – e.g. from LNG regasification -> RTE: 90% -100%
- Combined -> RTE: >100%

Highview Power Adiabatic LAES System:

- Does not use fossil fuels in power recovery phase.
- Utilises favourable density of liquid air and generated heat and cold to improve the efficiency of the process.
- Highview Power (UK) and University of Birmingham Centre for Energy Storage leading proponents:
  - 350kW/2.5MWh Pilot plant operational since 2011.
  - 5MW/20MWh commercial demonstration plant recently commissioned.

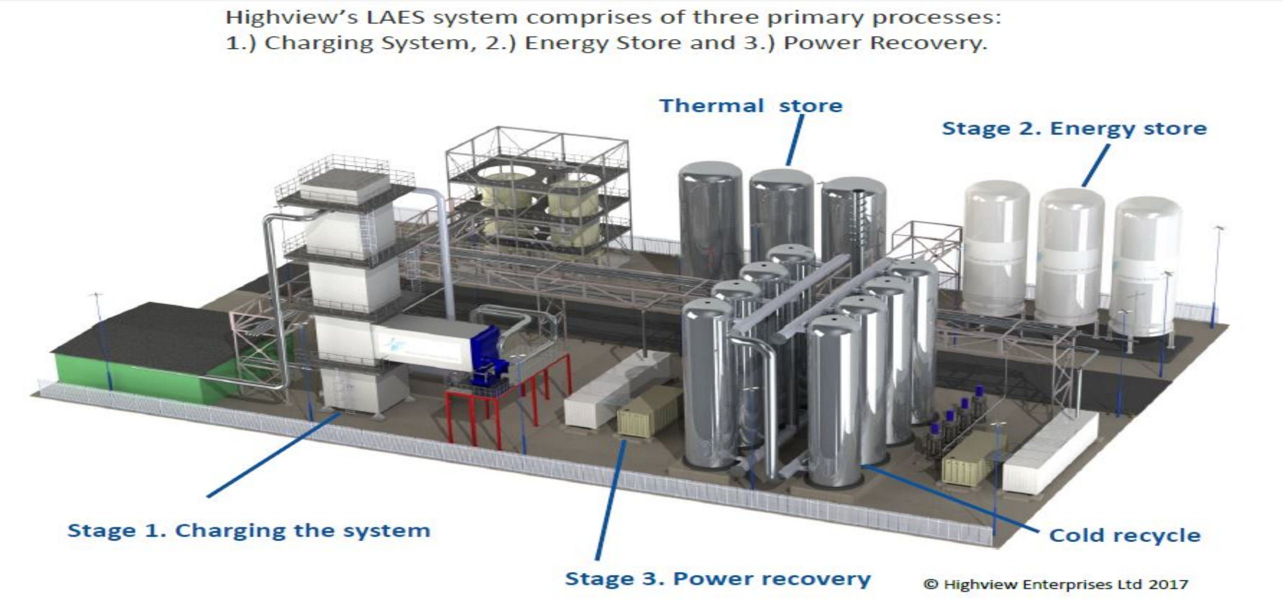


Figure ii: Schematic design of LAES system

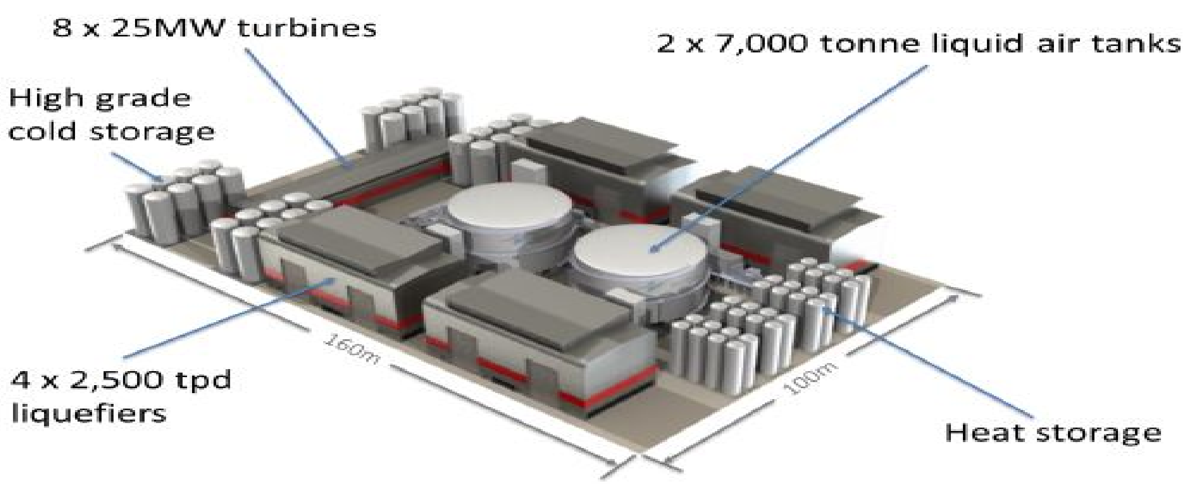


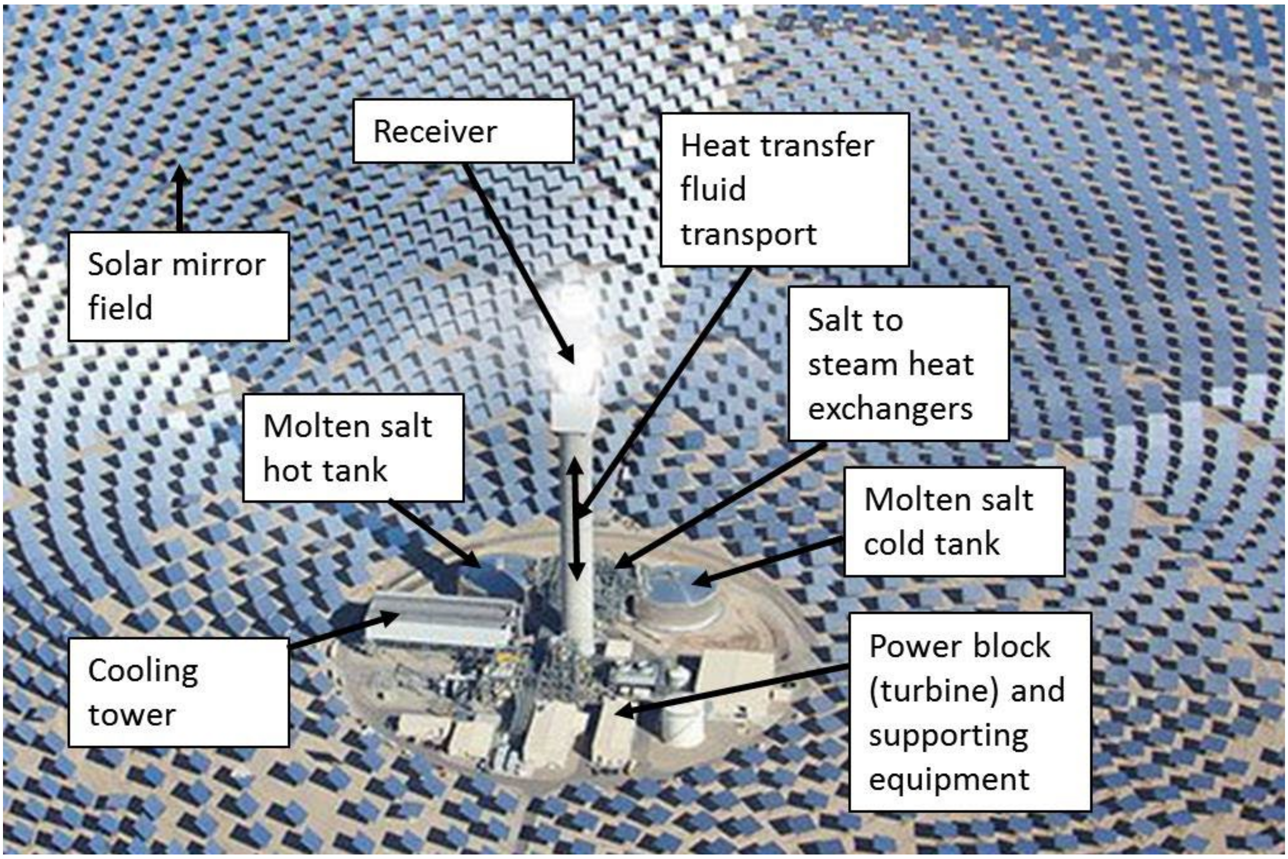
Figure iii: Example of utility scale LAES - 200MW/1.2GWh

Appendix B : Technical summary on Concentrated Solar Thermal with Thermal Energy Storage

This technical summary is extracted from Concentrating Solar Thermal Technology Status: Informing a CSP Roadmap for Australia a report written by ITP Australia in 2018.

"Concentrating Solar Thermal Power (CSP) systems use systems of mirrors to focus direct beam solar radiation to high temperature receivers that capture the energy for power generation. There are four main CSP technologies. In order of deployment volume they are: Parabolic Trough, Central Receiver Tower, Linear Fresnel and Paraboloidal Dish. While trough plants have the longest track record of operation and account for the bulk of systems deployed to date, tower plants are emerging as a more favoured option for power generation, due to the higher temperatures and efficiencies as well as more cost-effective energy storage that has been achieved. Linear Fresnel and Dishes have their own advantages and are also being actively pursued.

CSP plants are complex integrated systems made up of a series of subsystems. This is illustrated for the particular case of a molten salt tower plant in the figure below.



Key subsystems are:

- The mirror field that gathers solar radiation and directs it to a focal point by tracking the sun during the day.

- The receiver that intercepts the radiation and converts it to high temperatures.
- The heat transfer fluid system that takes heat from the receiver and transports it to storage and / or power block.
- The thermal storage subsystem that is typically based on two tanks of hot liquid salt but can use other processes also.
- The power block and associated equipment that is typically based on a steam turbine and electrical generator.

CSP power plants are attracting increasing interest due to their ability to store large amounts of energy and provide dispatchable electricity supply. The current industry standard approach is to use a mix of molten nitrate and potassium salts as a heat storage medium that is moved between a 'cold' tank at around 290ºC to a 'hot' tank at close to 400ºC or 600ºC depending on the concentrator type.

The bulk of the world's electricity is generated with steam turbines. One of the advantages of CSP is the ease with which this new source of heat can be applied to the dominant power generating technology. Consequently the vast majority of the CSP systems presently in operation use steam turbines.

Other power cycles are considered for future application to CSP. These include Stirling engines, Brayton cycles (air turbines) and organic Rankine cycles. Considerable RD&D attention is currently applied to supercritical CO2 turbines. These offer the potential for higher conversion efficiencies and smaller and more modular power blocks.

CSP systems can be hybridised in various ways. Commercial systems have been built which use fossil fuel boosting. Conversely fossil fired generators can have solar thermal fields added to boost output over fossil only operation. Of recent times increasing attention is paid to system developments that hybridise a low cost PV field with a CSP plant with storage, with coordinated operation and connection to the grid.

CSP fields can provide heat for industrial processes other than electricity generation. An attractive approach is to provide both electricity and heat via a combined heat and power configuration whereby steam is only partially expanded in a turbine to produce electricity and then directed at a suitable temperature to the industrial heat use." (ITP, Concentrating Solar Thermal Technology Status: Informing a CSP Roadmap for Australia, 2018, pp9-11)

Appendix C : Potential ownership financing structures for LAES at QAL

No assumptions have been made with respect to ownership structures in the proposal. The table below details the implications of varying ownership structures.

Structure: Govt/Private Partner	CAPEX: Govt ($m)	CAPEX: Private Partner ($m)	Interest Rates: Govt/Private	Annual Payments ($m)	40 Year Total Payments ($m)	Multiple on Initial CAPEX
100/0	798.77	NA	3.6[3]/0.0	36.67	1466.65	1.84
50/50	399.38	399.38	3.6/5.88[4]	43.02	1720.62	2.15
50/50	399.38	399.38	3.6/8.29[5]	50.23	2009.20	2.52
50/50	399.38	399.38	3.6/8.52[6]	50.94	2037.55	2.55
50/50	399.38	399.38	3.6/11.00[7]	58.53	2341.02	2.93

[3] Assumed Government cost of debt.
[4] Real-post-tax WACC.
[5] Real-pre-tax WACC.
[6] Post-tax nominal WACC.
[7] Nominal pre-tax WACC.

Appendix D : Modelling Results for LAES 5 hour option

Results are provided for 2011 and 2010. 2011 is shown as a benchmark for average solar and wind resource whilst 2010 shows the likely output in a year with high cloud cover.

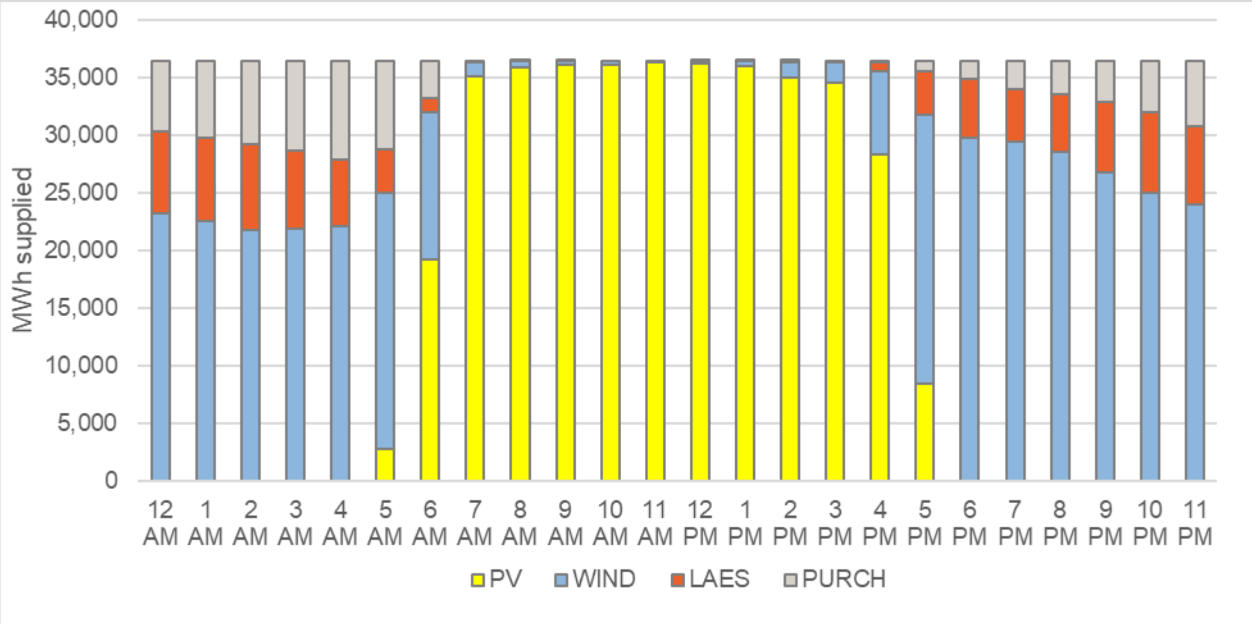


Figure iv: All year energy supply from PV, Wind and LAES discharge: January-December 2011

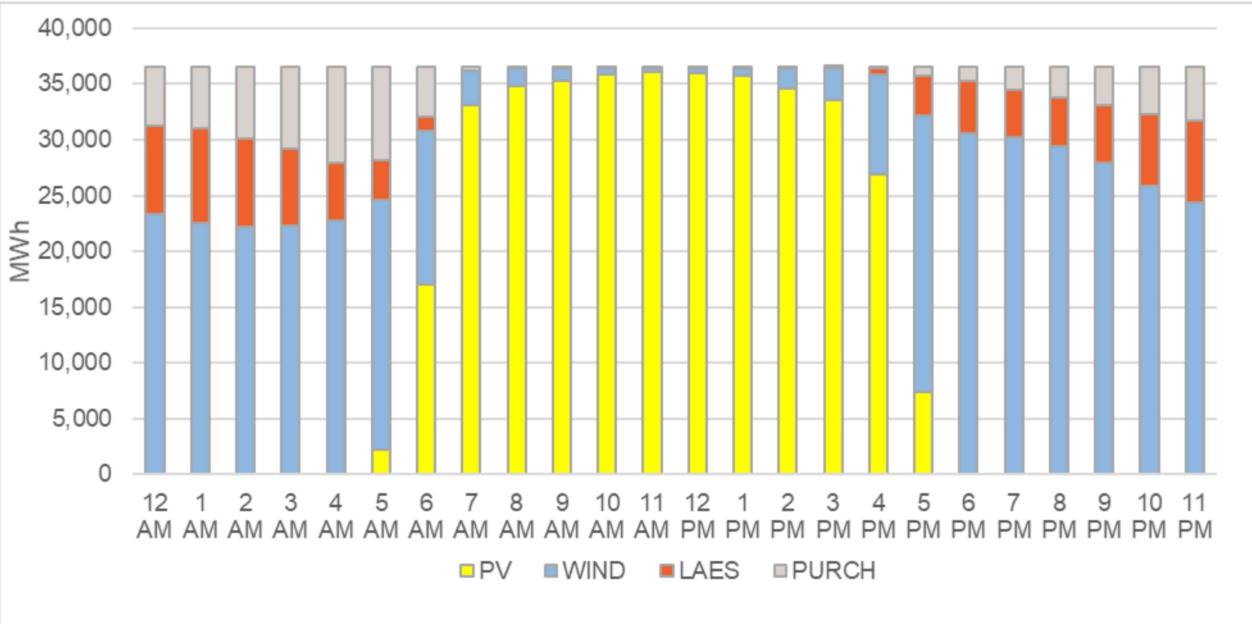


Figure v: All year energy supply from PV, Wind and LAES discharge: January-December 2010

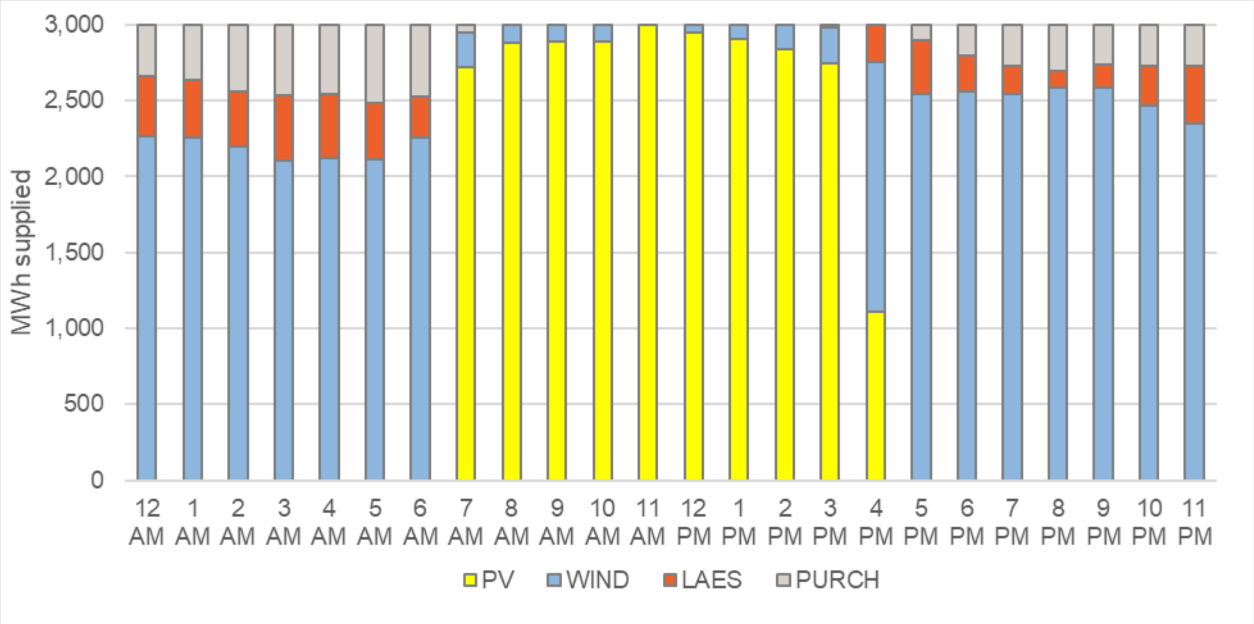


Figure vi: Shortest days energy supply from PV, Wind and LAES discharge: June 2011

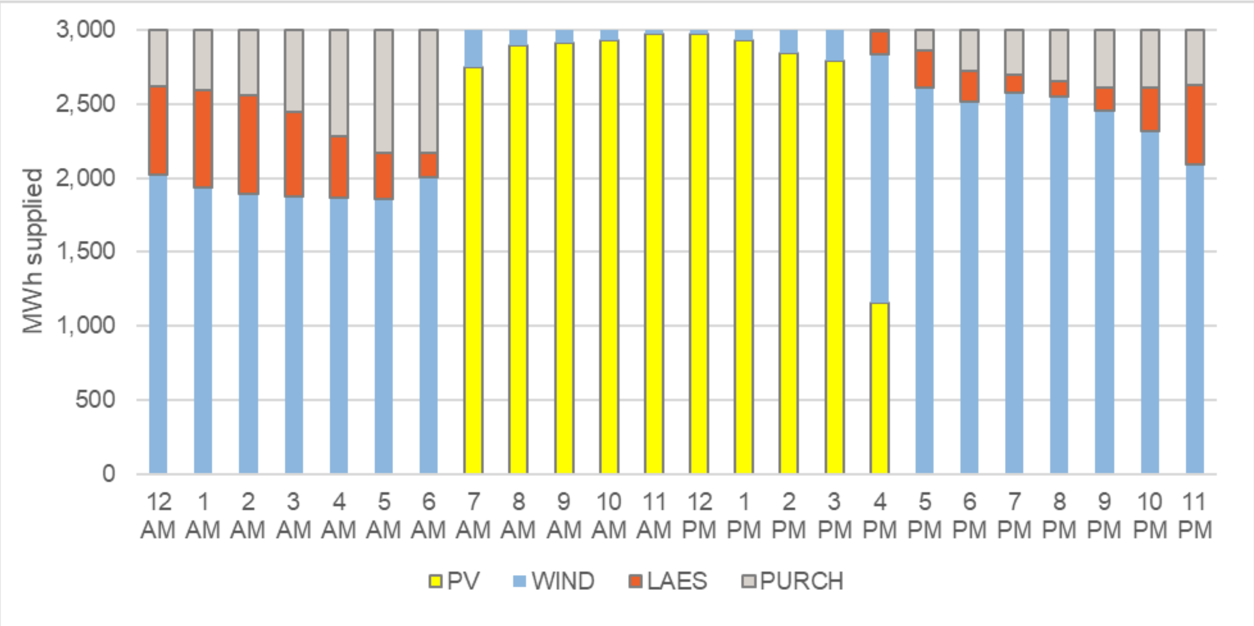


Figure vii: Shortest days energy supply from PV, Wind and LAES discharge: June 2010

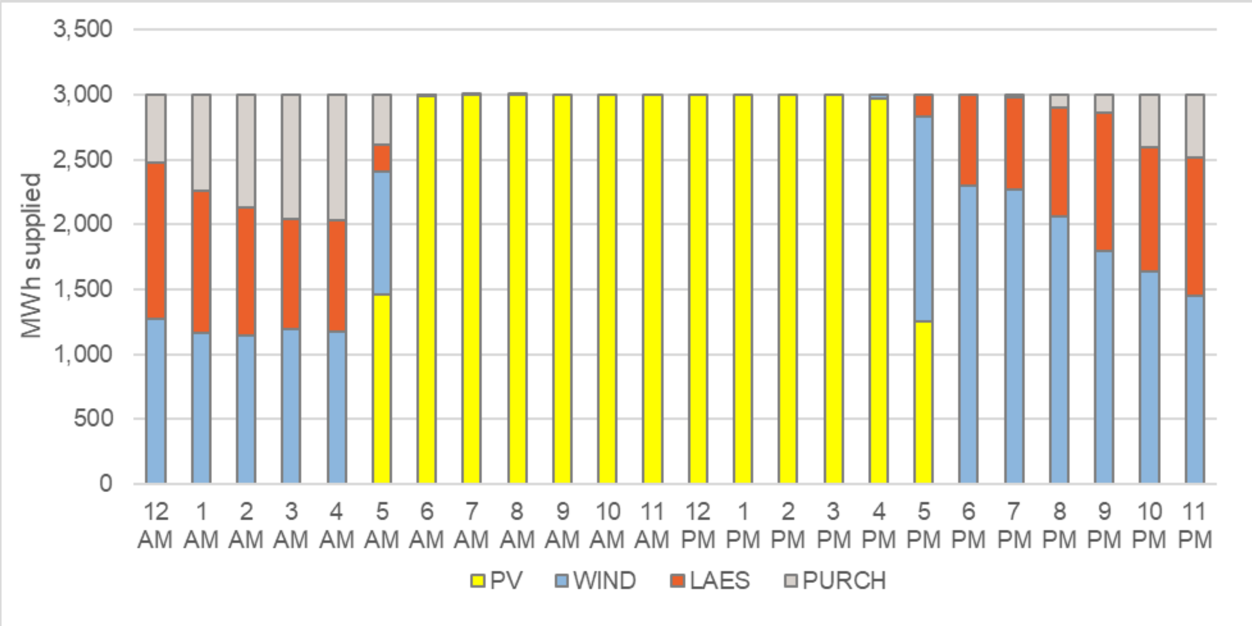


Figure viii: Average November energy supply from PV, Wind and LAES discharge: November 2011

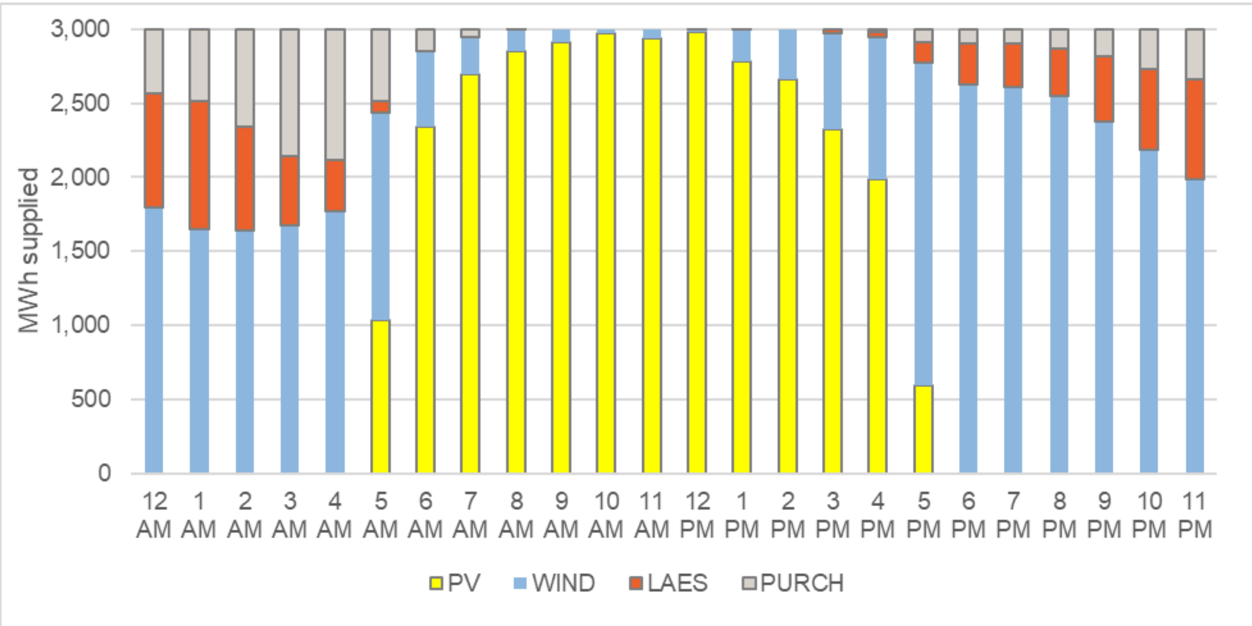


Figure ix: Cloud cover energy supply from PV, Wind and LAES discharge: November 2010

Appendix E : Modelling Results for LAES 24 hour option

Results are provided for 2011 and 2010. 2011 is shown as a benchmark for average solar and wind resource whilst 2010 shows the likely output in a year with high cloud cover.

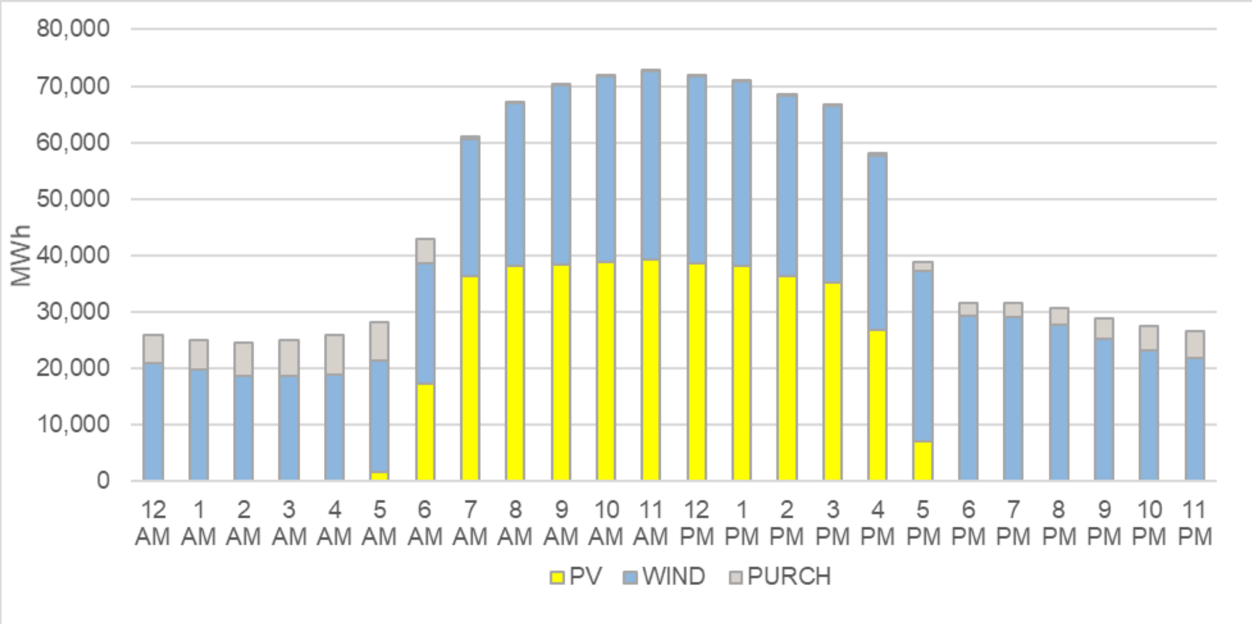


Figure x: All year energy supply to charge LAES: January-December 2011

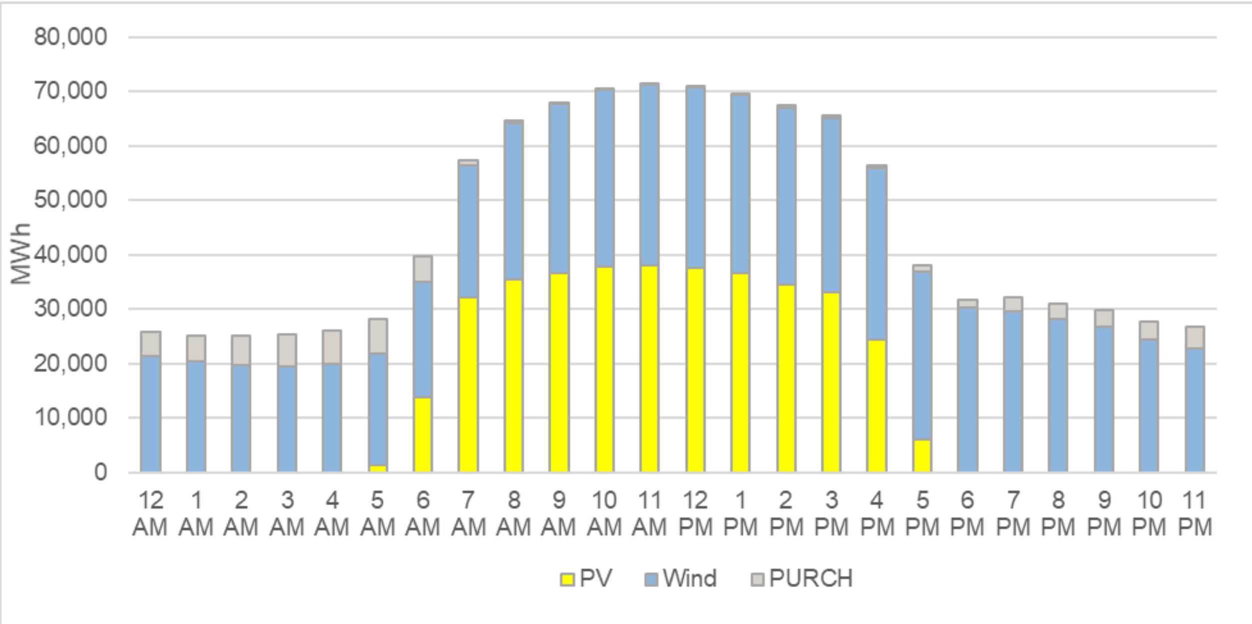


Figure xi: All year energy supply to charge LAES: January-December 2010

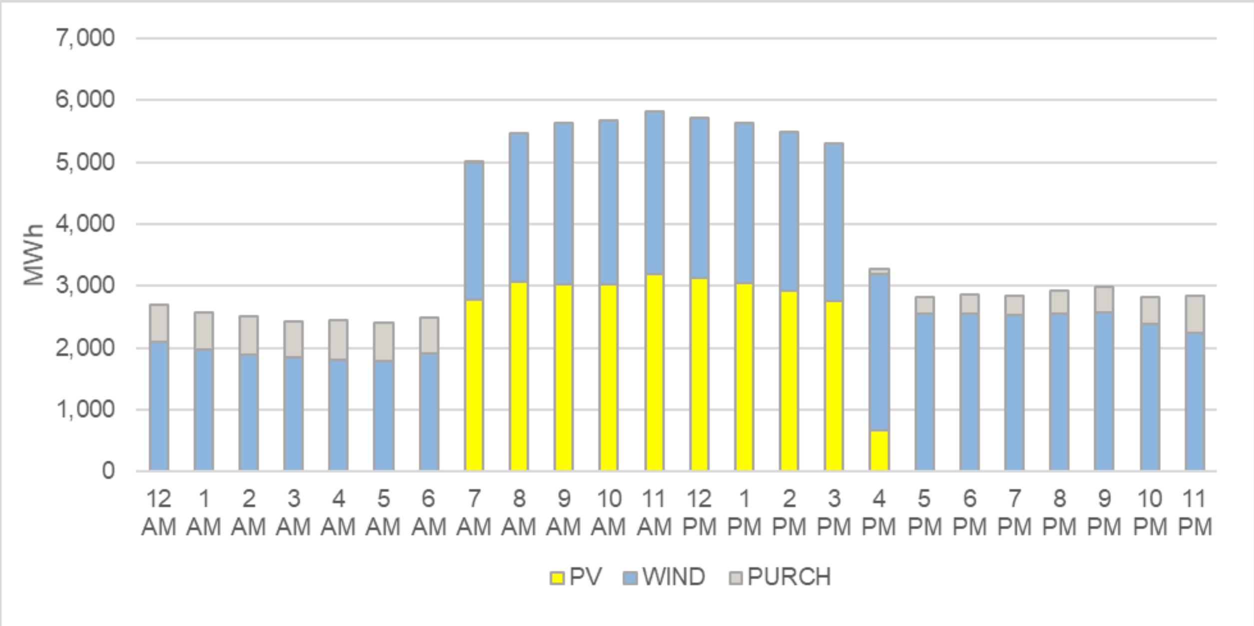


Figure xii: Shortest days energy supply to charge LAES: June 2011

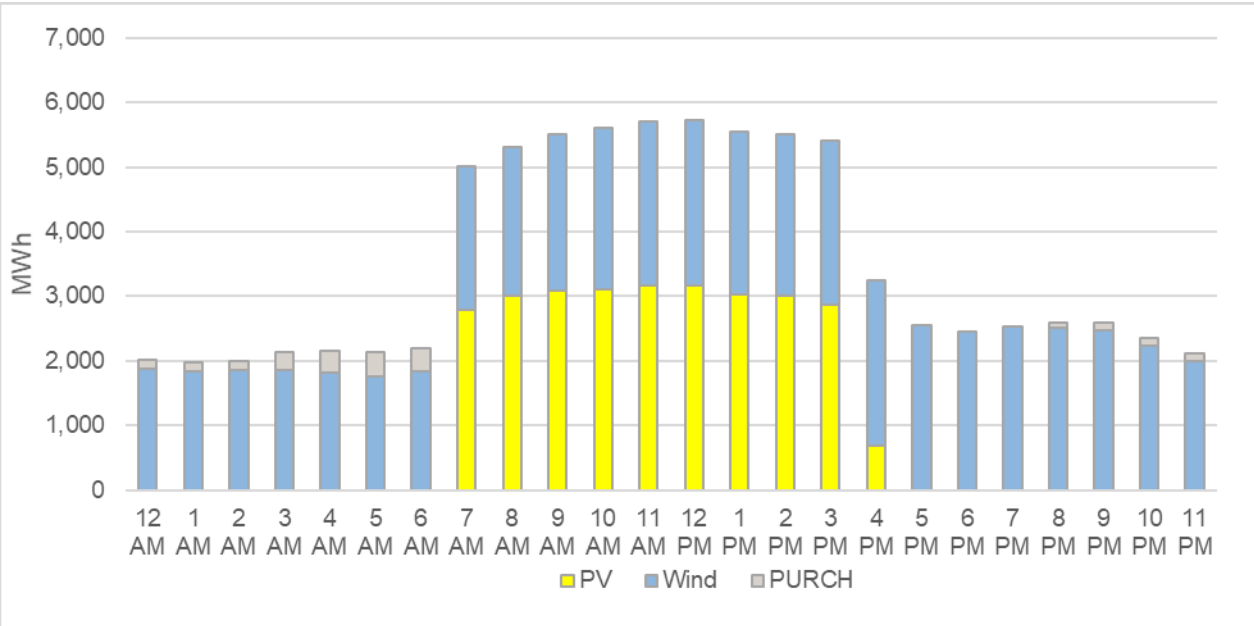


Figure xiii: Shortest days energy supply to charge LAES: June 2010

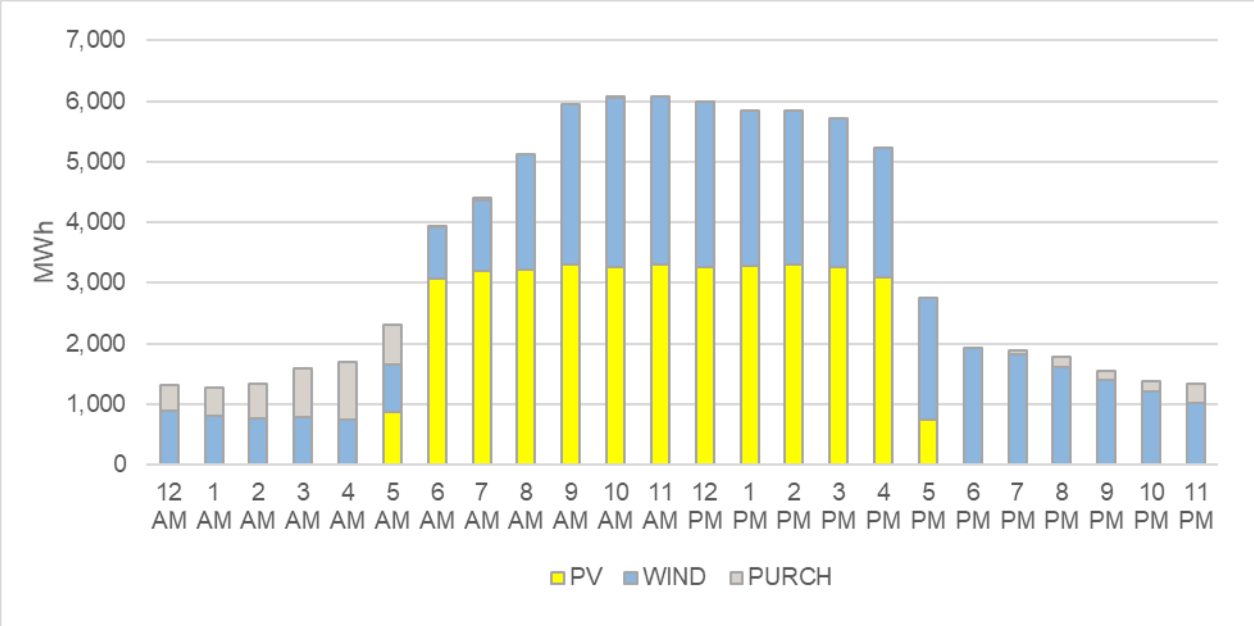


Figure xiv: Average November energy supply to charge LAES: November 2011

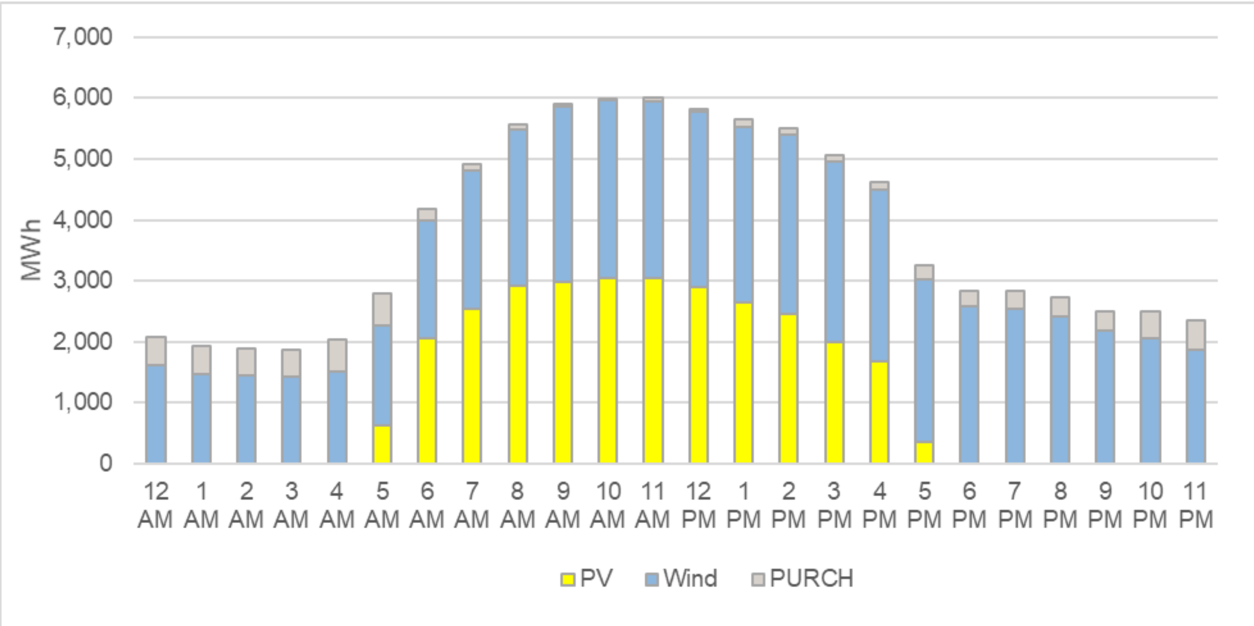


Figure xv: Cloud cover and energy supply to charge LAES: November 2010

Appendix F : Modelling Results for CST-TES(16) option

Results are provided for 2011 and 2010. 2011 is shown as a benchmark for average solar and wind resource whilst 2010 shows the likely output in a year with high cloud cover.

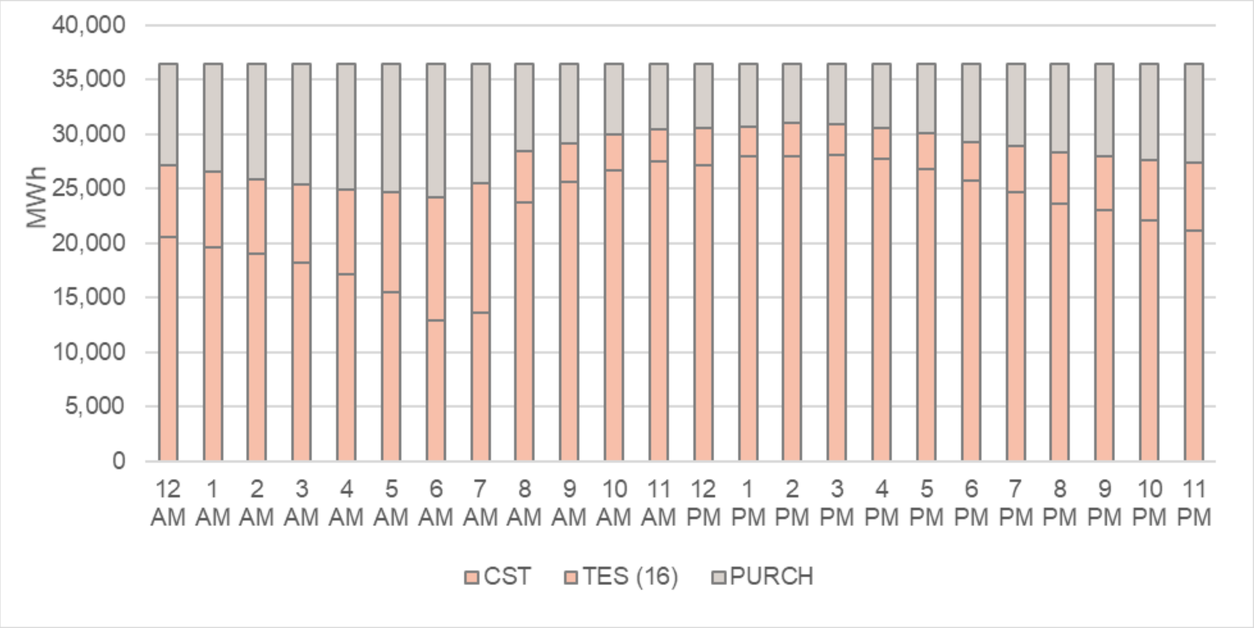


Figure xvi: All year energy supply from CST-TES (16): January-December 2011

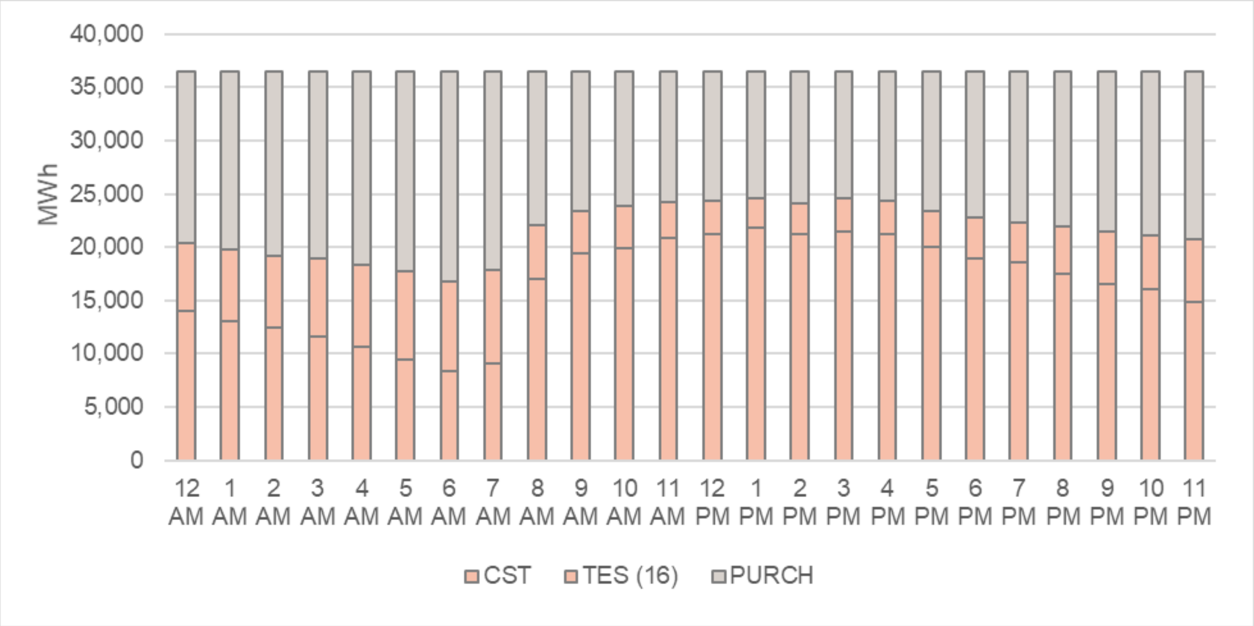


Figure xvii: All year energy supply from CST-TES (16): January-December 2010

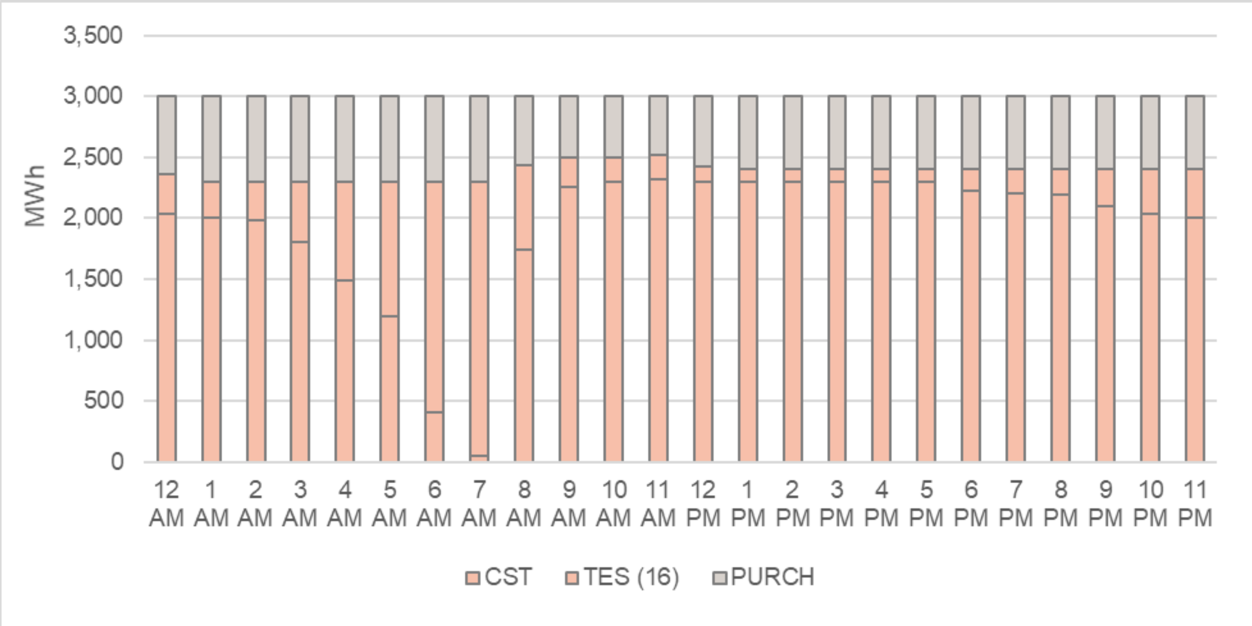


Figure xviii: Shortest days energy supply from CST-TES (16): June 2011

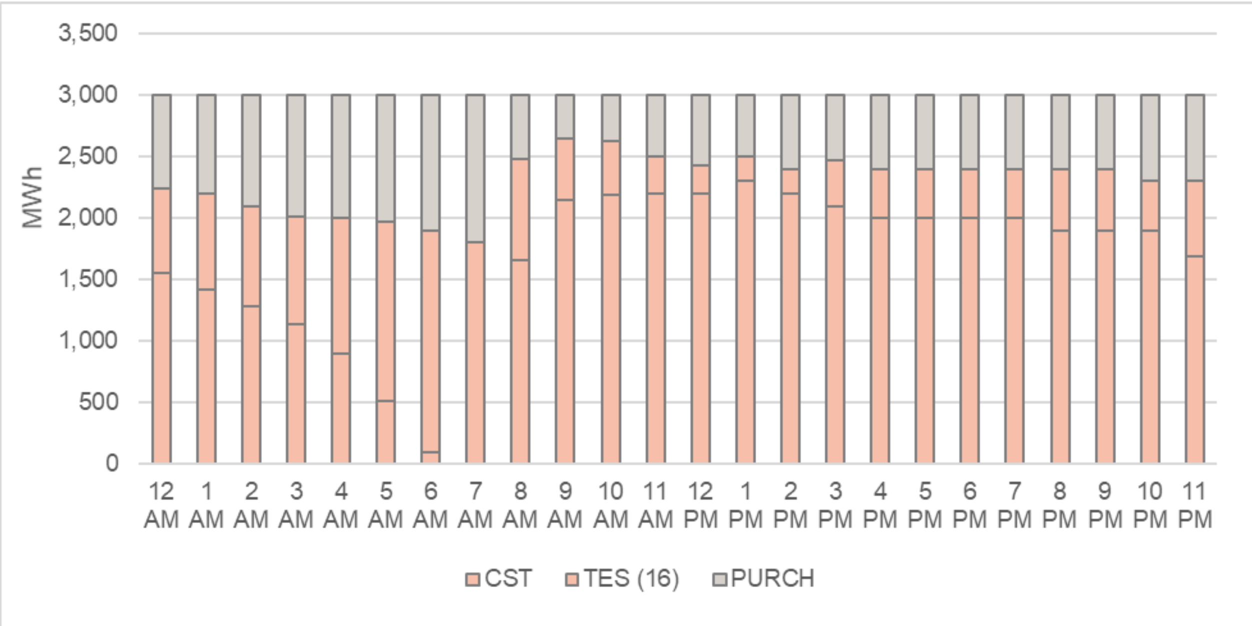


Figure xix: Shortest days energy supply from CST-TES (16): June 2010

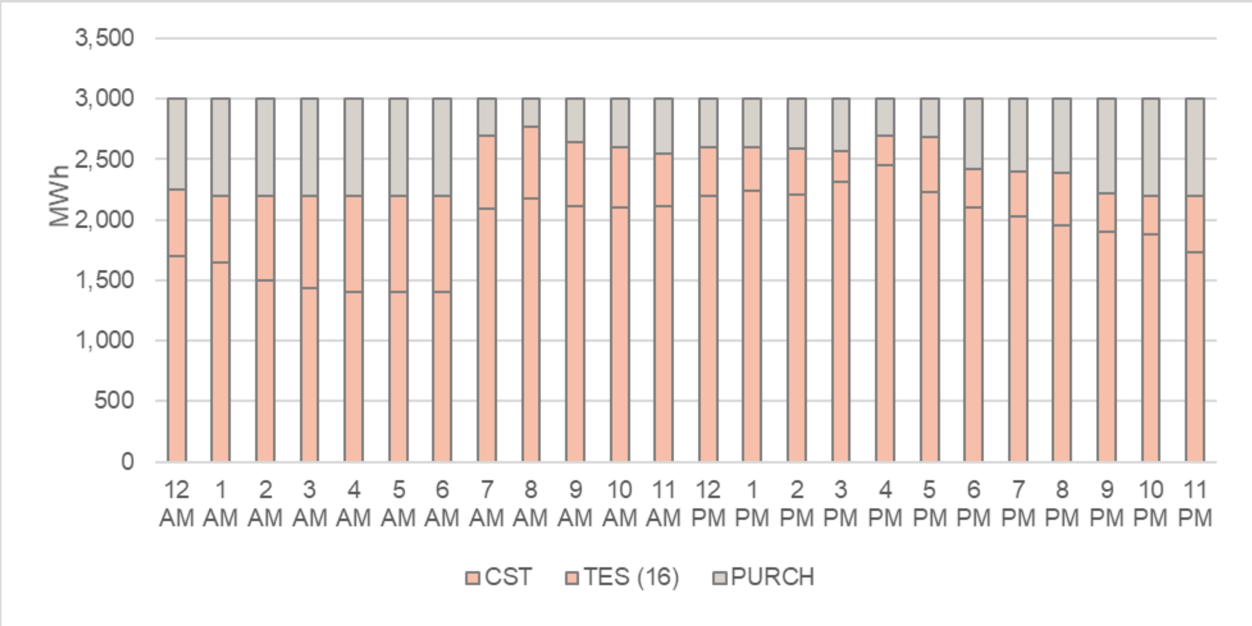


Figure xx: Average November energy supply from CST-TES (16): November 2011

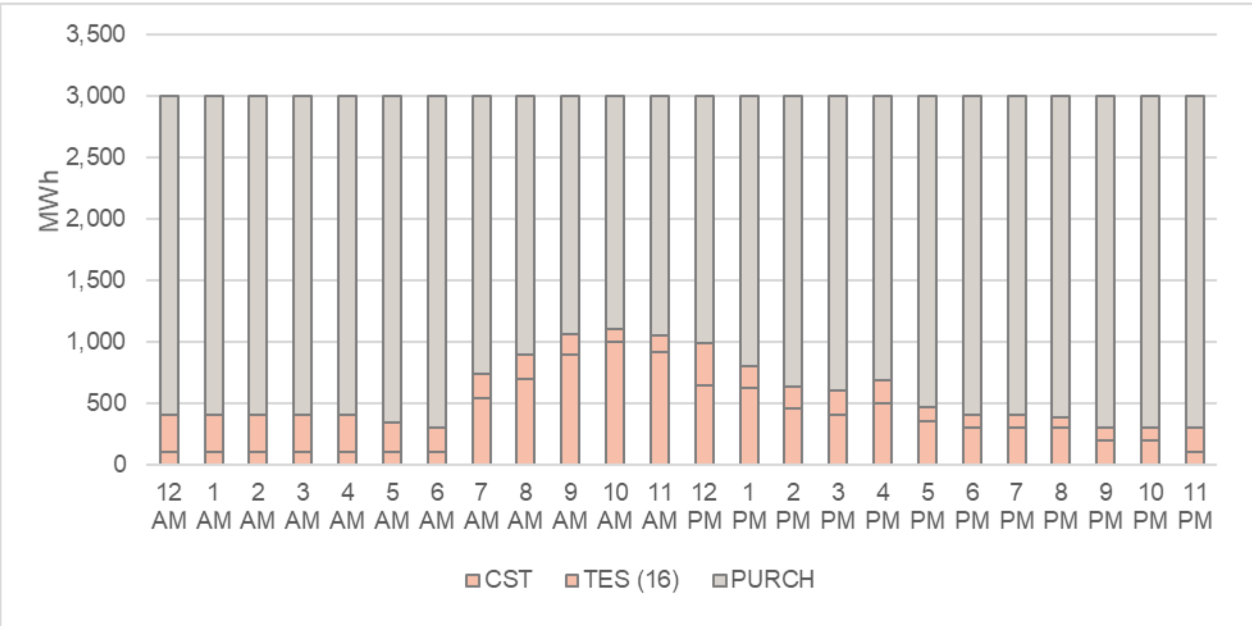


Figure xxi: Cloud cover and energy supply from CST-TES (16): November 2010

Appendix G : Modelling Results for PV + CST-TES(16) option

Results are provided for 2011 and 2010. 2011 is shown as a benchmark for average solar and wind resource whilst 2010 shows the likely output in a year with high cloud cover.

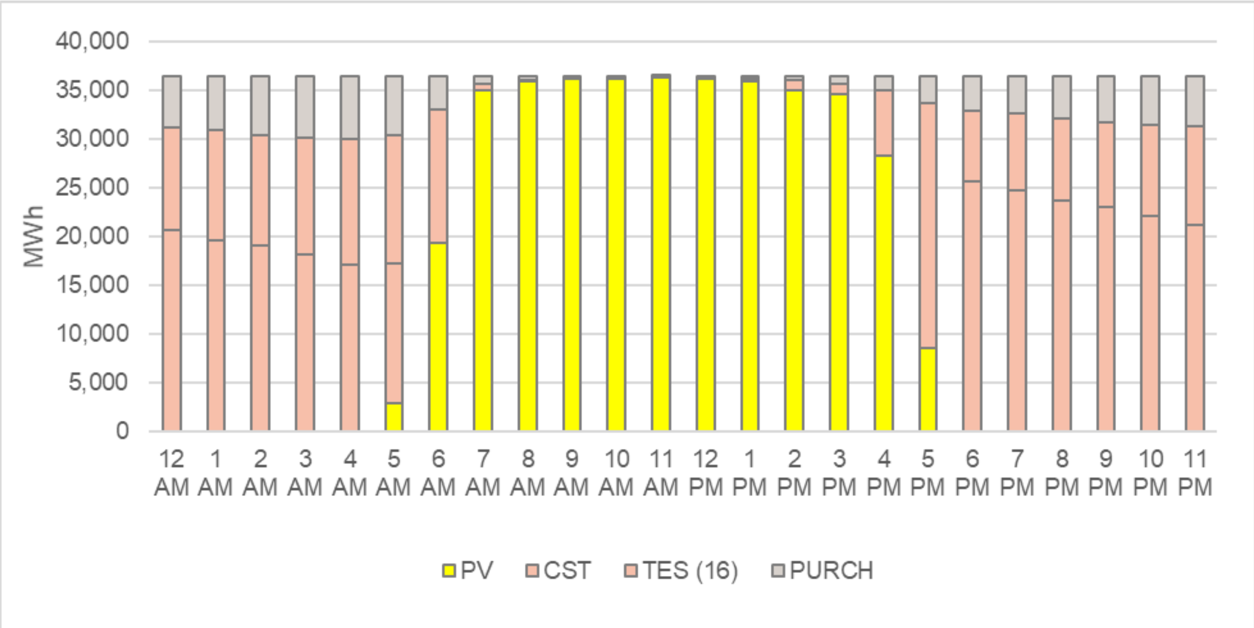


Figure xxii: All year energy supply from PV+CST-TES (16): January-December 2011

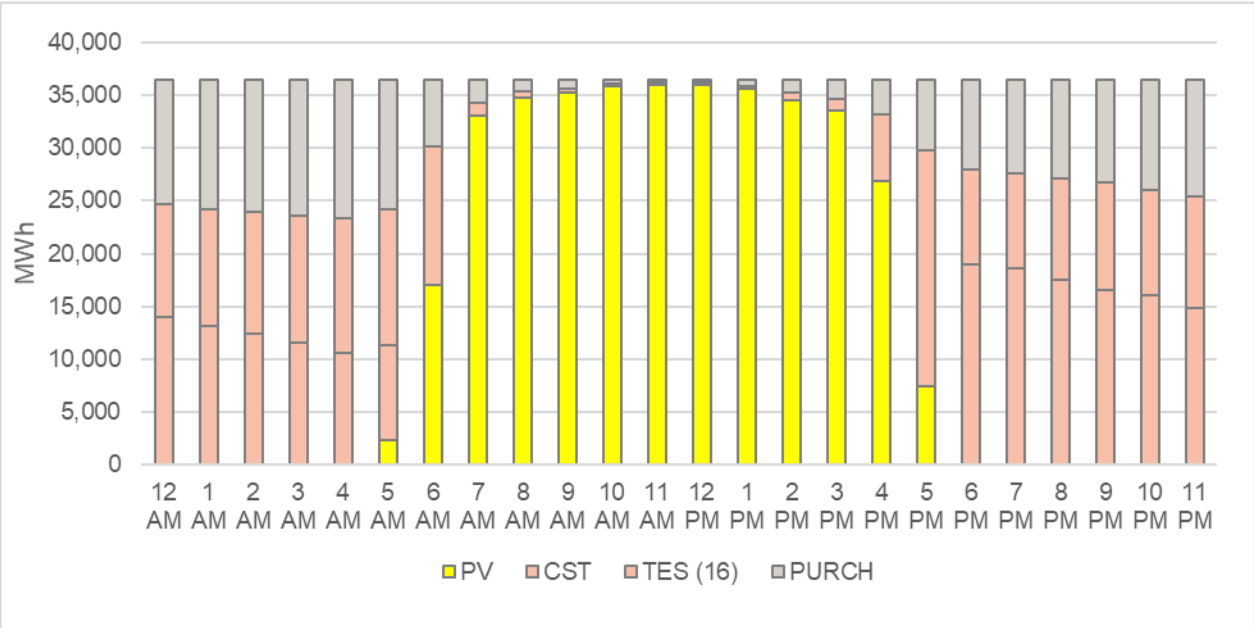


Figure xxiii: All year energy supply from PV+CST-TES (16): January-December 2010

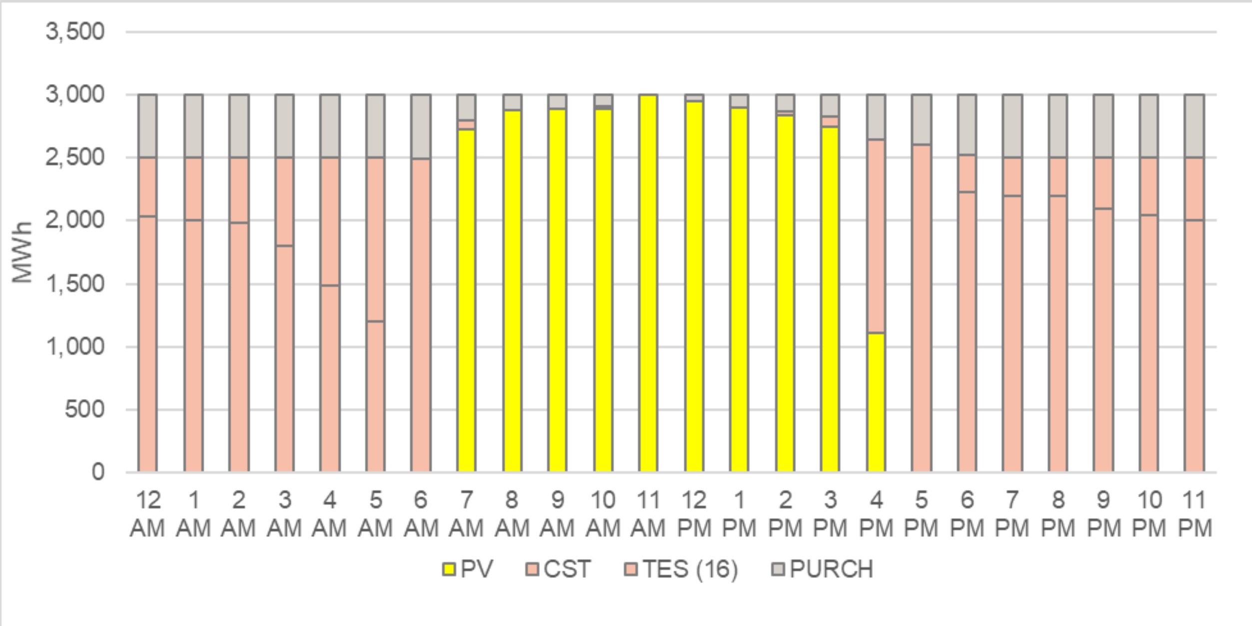


Figure xxiv: Shortest days energy supply from PV+CST-TES (16): June 2011

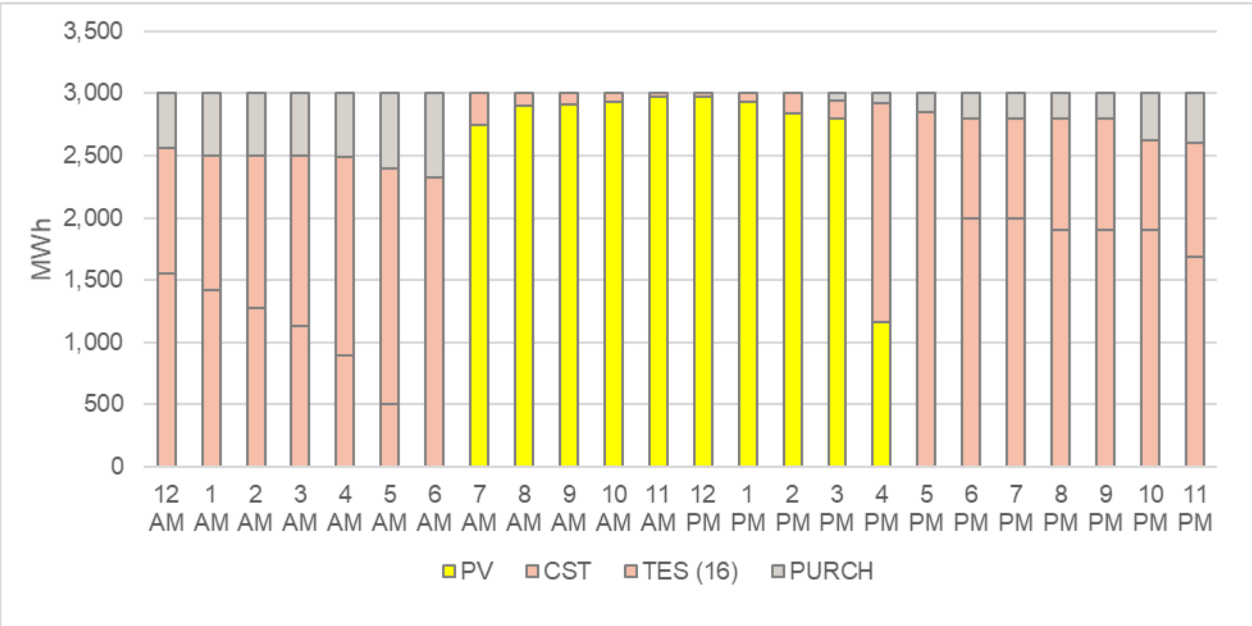


Figure xxv: Shortest days energy supply from PV+CST-TES (16): June 2010

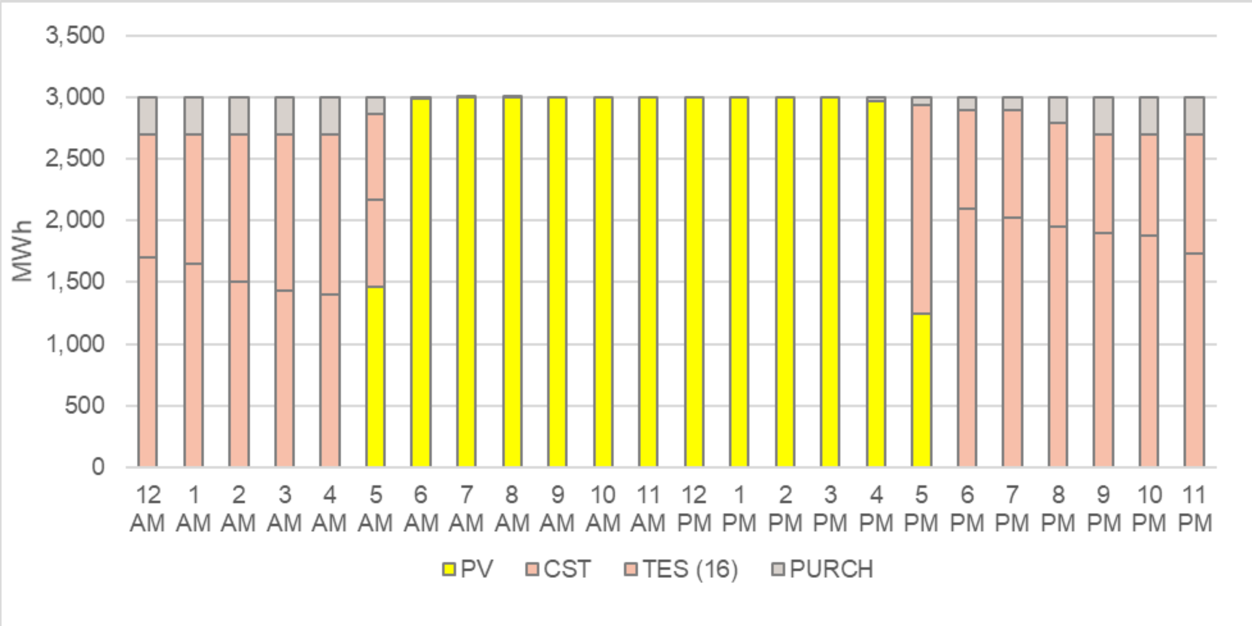


Figure xxvi: Average November energy supply from PV+CST-TES (16): November 2011

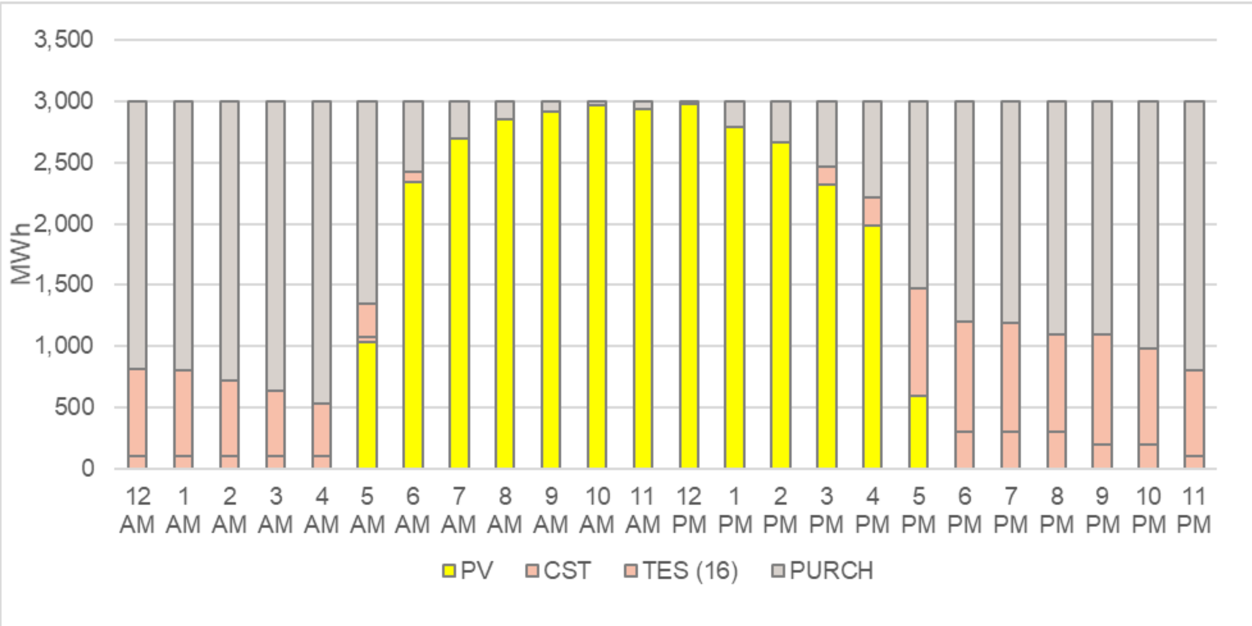


Figure xxvii: Cloud cover and energy supply from PV+CST-TES (16): November 2010

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