Battery storage as peaking capacity: How Alamitos changed the game for California

California | Commissioned at the start of this year, the Alamitos Battery Energy Storage System in California is a landmark project for the industry in having competed against natural gas to provide peaking capacity for the grid. Andy Colthorpe finds out the project's backstory from Fluence's Ray Hohenstein and AES' Mark Miller.

Credit: AES Corporation.

Alamitos BESS in Long Beach, California is part of AES' Southland platform.

When it was first proposed in 2014, at 100MW / 400MWh, Alamitos Battery Energy Storage System was the world's biggest contracted battery project. By the time it came online as scheduled on 1 January 2021 — after a construction period which began in 2019 — it could no longer take that crown, although it is certainly still one of the biggest around.

However, Alamitos was and remains historic for another, arguably even more significant reason. It represents the first time that battery storage has directly come up against natural gas in a competitive solicitation process and won. California investor-owned utility (IOU) Southern California Edison (SCE) picked out the plan designed by power producer AES Corporation as a means of providing essential local capacity following the shutdown of the San Ofre nuclear power plant (see timeline, p.92).

The utility put out an all-source procurement to find 2,200MW of capacity to replace San Ofre's in its energy mix and from a minimum expectation that about 50MW of that would come from battery storage, SCE actually made 235MW of awards. Alongside 135MW of behind-the-meter energy storage, AES Corporation's front-of-meter Alamitos project won out.

The big caveat perhaps is that Alamitos' battery storage will be flanked by two new natural gas plants. These are combined cycle gas turbine (CCGT) plants which provide baseload capacity. As such they are the more efficient and less emissions-intensive cousins of open cycle gas turbines which are commonly used as peaker plants. The CCGTs AES is building at the sites however have a lower emissions profile again and are also 70% less water-intensive than legacy CCGTs and frankly, at this stage, it's a difficult truth that rapidly deploying energy capacity cost-effectively to meet the shortfall created by San Ofre's demise would be extremely challenging without these plants.

Nonetheless, the arrival of Alamitos Battery Energy Storage System (BESS), reduces the need for gas peaker plants in the Greater Los Angeles area: as you probably already know, gas peaker plants may have been the cheapest option to deploy when most of them were built in the 1960s and 1970s, but are expensive to run and typically only go into action very infrequently.

Many peaker plants have a capacity factor of 15% or below. When they are called into action, they are also extremely polluting and due to their need to match peak demand are often in or close to heavily populated areas. Put simply, the BESS at Alamitos will charge at off-peak times and at times of high solar generation and then discharge for up to four hours to meet local energy demand on the grid at peak times.

Back in 2014, after several years of developing and building battery storage projects around the world of about 5MW to 10MW each, AES Corporation wanted to propose, alongside the two CCGT plants, a showcase of large-scale battery storage as "very capable and competitive technology against open cycle gas," Mark Miller, AES' market business leader for California, says.

"When you look back on it, that's almost seven years ago. It's an extraordinary decision, not only by AES to table that and show the confidence in our technology, but even more so to think about what Southern California Edison did in awarding that 100MW, four-hour duration product as a direct competitor to natural gas. We showed that four-hour duration, on a cost basis, was directly competitive with natural gas, so hats off to SCE to actually take that bold step and give us a 20-year power purchase agreement (PPA). From that perspective, it was a very unique opportunity and kind of showed the merits of not only our confidence in technology, but also the ability to deliver."

From a bold decision and a step-change in the understanding of what emissions-free battery technology can do, now that the system has gone into operation, this year will be pivotal in proving the value of batteries to the grid. The California Independent System Operator (CAISO), has said that it expects the amount of battery storage on its transmission network to leap from 250MW last year to about 2,000MW by August 2021 and the majority of that new capacity will be four hour batteries.

Four hours is considered to be the sweet spot for mitigating peak demand on a daily basis as solar ramps down in the late afternoon and evening from about 4pm or 5pm to 8pm or 9pm in California, while four hours is also the sweet spot for lithium-ion batteries to provide that capacity, before the technology starts to become more expensive than other resources like CCGTs (at present). With California having faced a difficult balancing act to meet peak load during last summer's August heatwave, this summer season will be the real test, Mark Miller says.

"That [battery] asset has a lot of flexible technology, from grid support [applications], like frequency support or spinning reserve, but primarily why it was contracted is peaking capacity, and to cover that net peak during the most critical part during the summer season," he says.

"This year is going to be a very interesting period of time, because we'll now have a 100MW, four-hour duration battery in the system operating moving into the peak summer season. We're anxious to see it perform — which we've got a high level of confidence that it will — and SCE by that point will be very, very capable of understanding how they plan to utilise it through that peak period of the summer."

AES believes the project and the way it won out through a competitive solicitation process planted a seed for future deployments, not least of all because SCE

Credit: AES Corporation.

Inside the halls of battery racks at the 100MW / 400MWh 'battery peaker plant'.

Alamitos: A timeline

1968:
Unit 1 at San Onofre Nuclear Generating Station (SONGS) goes into action and remains so until 1992.

JUNE 2013:
Southern California Edison (SCE) announces decision to permanently retire Units 2 and 3 at San Onofre Nuclear Generating Station. The two units were safely shut down in January 2012: unit 2 after a planned routine outage, Unit 3 due to a leaking tube in a steam generator installed in 2010.

"Looking ahead, we think that our decision to retire the units will eliminate uncertainty and facilitate orderly planning for California's energy future," SCE president Ron Litzinger says.

SEPTEMBER 2014:
SCE unveils the Tehachapi Energy Storage Project, part-funded by the US federal Department of Energy (DoE) at Monolith, a substation in the utility's service area close to the Tehachapi Wind Resource Area, supporting the rapid expansion of renewables. At 8MW / 32MWh, using LG Chem batteries, it was a rare four-hour duration utility-scale battery and at the time, the largest battery energy storage system in North America.

"This installation will allow us to take a serious look at the technological capabilities of energy storage on the electric grid. It will also help us to gain a better understanding of the value and benefit of battery energy storage," Dr Imre Gyuk, programme manager for energy storage at the DoE explains at the time.

NOVEMBER 2014:
Meeting local reliability needs as part of that "orderly planning", Southern California Edison awards 2,221MW of contracts — around 10% of the utility's peak load usage — following an all-source procurement for capacity requirements. SCE receives more than 1,800 final offers and selects 69 including energy efficiency, demand response and solar as well as marking the first time the utility has contracted with energy storage projects through a competitive solicitation.

A minimum of 50MW of energy storage is expected to be procured — in the end SCE contracts for 261MW, including a 20-year power purchase agreement (PPA) for AES' 100MW / 400MWh Alamitos project.

The outcome is a "monumental decision" that "demonstrates that energy storage can be competitive with other preferred resources on both performance and value, and that it's now an integral part of the utility planning tool kit in California," says Janice Lin, executive director of the California Energy Storage Alliance.

DECEMBER 2015:
AES signs 1GWh supply agreement with battery manufacturer LG Chem; a deal worth around US$300m according to one analyst at the time. AES' existing pipeline of projects is estimated by the analyst to be about 100MWh.

JULY 2017:
AES closes US$2 billion financing for the Southland Repowering Project, which involves retiring 2,075MW, 1,392MW and 474MW of gas at its Alamitos, Redondo Beach and Huntington Beach facilities respectively, to be replaced by the Alamitos battery system and 1,284MW of combined cycle gas generation.

Also that month, AES and Siemens launch energy storage technology provider and system integrator Fluence. The joint venture is initially a vendor for both AES' Advancion energy storage which up until then had been deployed across 200MW of projects worldwide as well as Siemens' Siestorage products. Later, Fluence launches its own range of branded systems, bringing out its sixth generation in 2020.

JUNE 2019:
Fluence breaks ground on the Alamitos project, setting an expected date for it to be operational at the beginning of January 2021, a year earlier than original plans.

"Alamitos energy storage will stand as the first of a new generation of energy storage procured as stand-alone alternatives to new gas plants. It represents a whole new way to think about capacity and reliability. Its size, flexibility and long duration stand as a benchmark, and showcase energy storage as a mainstream option for peaking power and grid support," explains Fluence chief operating officer John Zahurancik.

1 JANUARY 2021:
Alamitos battery storage project goes online.

itself has made other contract awards for battery storage as a peaking asset since Alamitos, Miller says. Indeed, as of December 2020, SCE said it had procured and contracted for around 2,050MW of energy storage capacity.

Making it look like a conventional asset
Battery storage might be the wave of the future, happening today, but when Alamitos was a twinkle in AES Corporation's eye, the company realised that from a contracting standpoint, it would have to look as much as possible like an asset that a utility could be comfortable with, says Ray Hohenstein, director of business innovation at storage technology provider Fluence.

"One of the big elements of AES' approach was to try to make energy storage, from a contracting standpoint, look and feel as similar as possible to a natural gas plant. To minimise the change from a contracting structure standpoint and from an operations standpoint. The contract is a tolling agreement. That's the typical model you see with fossil fuel plants — and that was deliberate," Hohenstein says.

"It's this idea that basically a utility contracts for the asset's capacity and then they're in charge of bringing in the fuel, which is in this case electricity. A deliberate and smart choice was made to utilise precedent from how gas plants are contracted. Obviously, it worked out and made it a lot easier to make the case economically, contractually and legally for it."

Fluence is of course part-owned by AES Corporation and was the evolution of AES Energy Storage, while also combining the energy storage business of Siemens, its other majority owner. Alamitos was one of the first big projects under the Fluence brand as the company officially launched as its own entity in late 2017.

It sounds daunting to have gone from 10MW projects or smaller, often with much shorter durations than four hours, to a 100MW / 400MWh undertaking, but Hohenstein says this is made simple by the versatility of lithium-ion technology.

"In 2014, we were several generations earlier in our energy storage technology. It was definitely a calculated decision that everything from the density of the system and the layout to how we interact with the grid, these are all concepts that had been tested and proven in the field, but at much smaller scales and it was a bit of a leap to scale it up," he says.

"But, one of the best parts about lithium-ion based energy storage of the type that Fluence builds, is that it is highly modular. It's essentially blocks that are able to be repeated, all linked together with advanced controls, and digital intelligence to oversee the dispatch of the entire system efficiently, but the system can scale up quite easily from a few megawatts to 100MW — without sort of dramatically changing the underlying architecture. In that sense, it actually wasn't nearly as big of a leap, as you know, the scale might seem from the outside."

'No longer economically rational to build gas peakers in Australia'
There's still a disconnect between what's achievable and what is actually being achieved, in the drive to decarbonise.

Credit: Edify Energy.

Large-scale battery storage at Gannwarra solar farm in Victoria, Australia.

During 2020, renewable energy generation in Australia amounted to about 27.7% of the national total, with wind about a third of that, but more than 3GW of small-scale solar was installed in the year and about half as much large-scale solar capacity.

Yet, despite that boom, and despite strong recognition of the potential of renewable energy by several state governments, the national federal government has been criticised for its seeming inability to form a coherent set of long-term decarbonisation goals. Indeed, the mantra during the more recent months of the COVID-19 pandemic, as other countries consider a 'green recovery,' Australia's government line is instead commitment to "a gas-fired recovery".

That commitment is a dangerous one says Lillian Patterson of the Clean Energy Council, a national trade association which recently published a study showing that battery storage can be more effective and 30% cheaper on a levelised cost of energy (LCOE) basis than new-build gas peaking plants.

"Our federal government has committed to a gas-fired recovery. They have been reticent to commit to a climate change and energy policy. This is one of the things that has been really lacking in Australia for a long time: we don't have a long-term climate change policy that considers energy policy as well."

The Australian Energy Market Operator (AMEO), which manages electricity and gas markets to oversee the reliable and affordable transmission of energy, has modelled that the National Electricity Market (NEM), covering the southern and eastern parts of the country will need between 26GW and 50GW of large-scale renewable energy and between 6GW and 19GW of new dispatchable resources by 2040.

The lower end of those figures is what it will take to largely retire coal power generation, but Patterson says the AEMO's Integrated System Plan 2020 doesn't see a role for gas to fill the gap over the next 20 years, it could be filled by a range of different types and scales of energy storage.

When it comes to peakers, the Clean Energy Council's own analysis finds it's no longer economically rational — or necessary — to build gas power plants for peaking capacity when batteries can be "the new clean peaker".

Peaking plants are generally needed in the NEM after 6pm each night for an average of three to four hours as solar systems ramp down and demand hits its peak. Gas peakers are able to ramp up in about 15 minutes; on the other hand, batteries can respond accurately and near-instantaneously to signals from the grid.

"[The paper is] really highlighting that batteries, that storage is offering the services that gas is doing, but it's a cleaner option to do that. It's not [just] the cleaner option, it's also a cheaper option as well," Patterson says.

The Clean Energy Council wanted to "put in a different perspective into the conversation" about the government's gas-fired recovery strategy. And while the study does find that, modelling a 250MW / 1,000MWh 'battery peaker' for the New South Wales region, it's considerably cheaper than gas, what could become even more important is a) the future value of battery storage and b) the economic and policy risk of developing new gas facilities.

"We didn't factor in anything to do with a carbon price, because we don't have a carbon price in Australia, but there is a carbon risk associated with gas as well. That could be a carbon price or similar [policy] within Australia. That would obviously increase the LCOE for gas. We're also seeing the 'carbon border taxes' that are being considered in places like Europe. That's something else that needs to be considered in this as well.

If we produce anything and we want to send it overseas, they're going to recognise that we don't have a carbon price and so therefore, the cost of that could be more expensive."

So the cost differential would be even more significant if carbon taxes were incorporated into analysis. The national Clean Energy Regulator is currently considering the role of a 'carbon exchange,' effectively an exchange trading market for offsets. The other side of the coin is that the additional revenues a battery storage plant could accrue will also alter that differential further.

There is already a frequency control ancillary services (FCAS) market which large-scale batteries and virtual power plants (VPPs) have already benefited from. In April chief rule maker, the Australian Energy Market Commission (AEMC) said it will be introducing a fast frequency response market within a couple of years that will value response times of less than six seconds: an opportunity lithium-ion batteries will be perfectly suited to take part in, where many other resources will not.

The introduction of shorter, five-minute settlement windows in the wholesale market, expected to begin this October, will also change the game. Knowing all of this, who would even want to invest in new gas peaker plants?

"Coal and gas generation have been an important part of our energy mix but we are transitioning, and in moving forward, we need diversity. We need renewables, we need solar and wind, we need energy storage — we need different types of storage. We need shorter duration battery power, we need virtual power plants (VPPs), we need longer duration pumped hydro and we need transmission because as everyone knows the sun doesn't always shine and the wind doesn't always blow." ■