Co-located with Conventional Generation

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1. Overview Section

As California moves towards full implementation of the 33 Percent Renewable Energy Portfolio Standard (RPS) by 2020, there is increasing concern about how high penetration rates of inherently variable resources, particularly from wind and solar, may adversely impact system stability.

An obstacle to achieving higher levels of penetration of utility-scale renewable energy, especially wind and solar, is the variable nature of generation output from these resources. The times of the day when these resources are most productive do not align with the demand curves for utilities, and sudden shifts in weather patterns can cause intermittent output and potentially impacting grid stability. These weather-related variations may be diurnal (i.e., wind blows strongest at night when demand is low), of shorter duration (wind stops and starts abruptly), or even on an instantaneous basis (passing clouds cause solar power intermittency). In the case of diurnal scenario, often load on the grid does not meet the supply by wind power which can cause challenges regarding the operation of base load resources and/or combined cycle generation in the costs associated with turning the machine fully off and restarting the following day.

Another characteristic impacting the grid associated with integrating renewables is its impact on base load generation, particularly the gas fleet. With bursts or sustained periods of renewable generation, base load gas generation is required to back down. It is not ideal, however, to frequently turn off and back on combined cycle generation as this increases operating costs. Particularly at night when wind is plentiful and load is low, a challenge is presented to gas generation operators, and ratepayers are at risk of paying higher prices.

In addition to meeting the integration of 33% renewables, every summer power demand increases due largely to air conditioning use as outside temperatures rise. Unfortunately this is the same time that the gas fleet is operating at its lowest capacity. Outside temperatures impact the performance of gas turbine operation. A gas turbine can lose as much as 20% of its capacity when temperatures are highest. As a result, California often approves and uses rate payer money to purchase 'peaking power plants,' that are intended to operate only during the summer hours when demand increases. These plants are less efficient than the base load combined cycle fleet and are costly. Furthermore, while peaking plants are often capable of assisting in providing ramping capabilities to help integrate renewables, operations and maintenance costs associated with frequent start/stops are a high cost borne by the ratepayer as are the costs associated with new transmission and distribution to service the peaking plant.

2. Use Case Description

This Use Case describes energy storage associated with a hypothetical 500 MW gas turbine that connects to the grid to deliver energy under a long-term power contract.

It is assumed that the resource has successfully connected to the grid under California ISO interconnection rules and possesses CAISO-approved telemetry that allows for remote monitoring of the resource and related factors (i.e., generation output, availability, meteorological data, and circuit-breaker status).

This Use Case assumes a 15% derate of the gas turbine at ambient temperature of 95 degrees Fahrenheit.

2.1 Objectives

Energy storage co-located with gas turbines offers a way to respond to challenges placed on the grid through the integration of renewables by: 1) quickly responding to daytime increases or decreases of power supplied by intermittent renewables; and 2) providing a 'load sink' for either station or grid power when nighttime wind supply is higher than demand. Energy storage co-located with gas turbines can provide these services without the need for additional transmission or distribution, and with a better emissions profile than the alternative.

2.2 Actors

In this Use Case, the storage facility may be owned by 1) the utility, 2) the owner/operator of the gas turbine, or 3) a third party that sells the stored chilled water under an arrangement with the generator/turbine operator (although the third actor option is currently uncommon).

Name	*Role description*
Gas Turbine Owner/Developer	
Storage and Chilled Water Provider	
Utility	

Grid Operator	

2.3 Regulatory Proceedings and Rules that Govern Procurement Policies and Markets for This Use

Agency	Description	Applies to
CPUC	Long-term Procurement Proceeding	Utility
CPUC	Resource Adequacy	Utility
FERC	Order No. 785 Pay for Performance	ISO/RTO, Third-party Owner
Other		

2.4 Location

The energy storage device is co-located at the site of the gas turbine, or just next to it.

2.5 Operational Requirements

The expected delivery of generation from this 500 MW gas power plant is scheduled in advance under a non-binding day-ahead schedule. However, every hour, a new schedule is set, which governs the expectations for the following 24-hour period. At 2 hours prior to the actual operating hour, a binding hourly schedule takes effect.

The 500 MW unit however loses output capacity according to outside temperatures. As the outside temperature reaches 95 degrees Fahrenheit, the 500 MW facility is now only able to bid a total of 420 MWs in the day ahead or real time market. As such, the storage co-located with gas turbines can be used to recover the lost 80 MWs of full capacity if needed by the grid, or, offer flexible ramping services within the 80 MW range.

Judging approximate temperatures the following day, the gas turbine operator will use night time station or grid power then night before to fully charge his storage device through powering chillers to chill water for overnight storage. For a 500 MW power plant, a typical storage device size would be 10 MW. 10 MWs are used at night to charge the storage device and the following day the operator is able to respond to grid prices and needs through either releasing a full amount of chilled water from the storage device to flow over the inlet coils of the turbine for full increased output of 80 MW, or, can release only that amount and temperature of water required to increase the gas turbine's output by the need signaled. The turbine is incredibly sensitive to the temperature (and amount) of chilled water flowing over the air intake and can respond in under a minute. One minute the system can provide the full 80 MWs needed, the following minute it can drop to the new need of only 35 MW, or can go up to 55 MW, and so forth.

Because the ramping up and down of the turbines' output through this storage and chilling device is done through simple pump and temperature adjustment, operations and maintenance costs of the turbine itself are unharmed, and on the storage/chilling system are negligible.

2.6 Applicable Storage Technologies

The only storage device currently known to be capable of delivering increased flexible output to conventional gas generation is some combination of a thermal energy storage unit with a system for chilling water, along with pipes and pumps connected to the gas turbine. Additionally, this storage and chilling solution *only* works on gas turbines.

The system is most economic in conjunction first with combined cycle assets due to its capacity factor, but can be used in conjunction with high use simple cycle facilities as well. The output size ranges from a low option of around 25 MW, and is unlimited in its maximum capacity. The largest facility in construction for the United States is set to deliver more than 100 MWs of additional flexible capacity to a combined cycle asset.

2.7 Non-Storage Options for Addressing this Objective

Among options available to address renewable energy variability and increased summer demand are:

- A Balancing Energy Market to obtain incremental/decremental energy in real-time;
- Demand Response programs that incentivize end-users to increase or decrease consumption under pre-specified conditions;
- Generation with flexible ramping capacity to match changes in renewables output;
- Various technology upgrades to distribution system, such as static-VAR compensators,

and switched capacitor banks to instantaneously adjust to fluctuations in voltage levels cause by abrupt generation variability.

- New installation of simple cycle gas plants to provide added capacity in the summer.

3. Cost/Benefit Analysis

3.1 Direct Benefits

End Use	*Primary / Secondary*	*Benefits/Comments*
2. Spin	P	
3. Ramp	P	
4. Black start	-	
6. Energy arbitrage	P	
7. Resource Adequacy	P	
11. Peak shaving: load shift	P	

3.2 Other Beneficial Attributes

Benefit Stream	*Y/N*	*Assumptions*
Flexibility (Dynamic Operations)	Y	
Reduced Fossil Fuel Use	Y	Compared to the alternative (simple cycle turbine)
Reduced Emissions	Y	Compared to the alternative (simple cycle turbine)
Full use of assets already invested in by ratepayers	Y	

3.2 Analysis of Costs

Cost Type	Description
Installation	On retrofits: $350-450/kw On new sites: $250-350/kw
O&M	

3.3 Cost-effectiveness Considerations

4. Barriers Analysis and Policy Options

4.1 Barrier Resolution

Barriers Identified	Y/N	Venue for Resolution
System Need	N	
Cohesive Regulatory Framework	Y	
Evolving Markets	N	
Resource Adequacy Value	Y	
Cost Effectiveness Analysis	N	
Cost Recovery Policies	Y	Contract mechanism for retrofits currently under contract
Cost Transparency & Price Signals	N	
Commercial Operating Experience	N	
Interconnection Processes	N	

4.1 Other Considerations

5. Real World Example

5.1 Project Description

TAS Energy Generation Storage™ on an Electric Cooperative in Texas ERCOT market added 90 MW of added capacity and an improved heat rate. The ambient design conditions were 95F dry bulb and 75F wet bulb. The system installed included a 6.1 million gallon thermal energy storage tank and a 2x60 Hz chiller supplying 7,800 tons/27,431 kwth. The TES tank supplies chilled water for both combined cycle Units 1 & 2 and allows the plant operator to pull electricity from the grid at night-time hours (and pricing) to chill the water and have it stored for use the following day during the peak demand.

Location	Laurel Mountain, West Virginia
Operational Status	Online 2009
Ownership	Electric Cooperative
Primary Benefit Streams	Capacity
Secondary Benefits	Ancillary Services
Available Cost Information	Total project cost $

5.2 Contact/Reference Materials

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6. Conclusion and Recommendations

Is ES commercially ready to meet this use?

Yes- has been commercially available and viable for over two decades

Is ES operationally viable for this use?

Yes

What are the non-conventional benefits of storage in this use?

Can these benefits be monetized through existing mechanisms?

If not, how should they be valued?

Is ES cost-effective for this use?

What are the most important barriers preventing or slowing deployment of ES in this use?

What policy options should be pursued to address the identified barriers?

Should procurement target or other policies to encourage ES deployment be considered for this use?