Exhibit 4

Sierra Club's April 9, 2015 Comments ("SC Comments") and Exhibits 1 – 12 submitted with SC Comments.

SIERRA CLUB
FOUNDED 1892

April 9, 2015

Henry Krautter
Title V - Permitting Division
Maricopa County Air Quality Department
1001 N. Central Ave., Suite 400
Phoenix, AZ 85004
Henry.Krautter@mail.maricopa.gov

RE: Ocotillo Power Plant – Permit Number V95-007

Dear Mr. Krautter:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 12,500 members in Arizona. The issues addressed below regarding the proposed Draft Permit Renewal and Revision (Draft Permit) are based on publicly available materials, including the March 4, 2015 Technical Support Document (TSD) prepared by the Maricopa County Air Pollution Control District (the County), the draft permit, the permit application (Application), the applicant's January 23, 2015 updated Control Technology Review (Application Appendix B), and the Application for a Certificate of Environmental Compatibility from the Arizona Power Plant and Transmission Line Siting Committee (CEC Application).

The Applicant, Arizona Public Service (APS), is planning to install five new natural gas-fired GE Model LMS100 simple cycle turbines (GTs) at the site of the existing Ocotillo Power Plant. Each of the proposed new GTs have a 102 MW nominal capacity, for a combined capacity increase of 510 MW. The Ocotillo Facility currently consists of two 110 MW steam generators and two 55 MW gas turbines, for a total output of 330 MW. The Facility operates on natural gas supplied by Kinder Morgan's El Paso Natural Gas pipeline system. The Facility is located on about 126 acres in Tempe, Arizona, in Maricopa County. The Applicant proposes to retire the two existing 110 MW steam generators, but will leave in place the two existing 55 MW gas turbines. The Project would nearly double the Facility's total capacity to about 620 MW.

The location of the Ocotillo Power Plant is currently classified as a serious nonattainment area for particulate matter (PM_{10}), and is also classified as a marginal nonattainment area for ozone.

The draft permit includes a permitted greenhouse gas (GHG) emission rate for the GTs of 1,690 lb CO_2e/MWhr (gross) based on a 12-month rolling average. (TSD at 30.) The proposed permit limits would allow the units to operate more than 4,000 hours per year (46% of the time).[1] The total annual project emission limit is 1,029,022 tpy CO_2e.

The Ocotillo Power Plant is subject to greenhouse gas (GHG) prevention of significant deterioration (PSD) regulations. New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a CO_2e basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy CO_2e, are subject to PSD permitting requirements where a PSD permit is otherwise required based on emissions of conventional pollutants. The proposed modifications at the Ocotillo Power Plant will result in new GHG emissions of 1,029,022 tons per year (tpy) of CO_2e. (TSD at 27.) The proposed modifications would emit GHGs at a rate far greater than 75,000 tpy CO_2e and the TSD acknowledges that the project is subject to PSD permitting for Carbon Monoxide (CO), PM, and $PM_{2.5}$.

I. THE PERMIT DOES NOT SATISFY BACT FOR GHG EMISSIONS FROM THE GAS TURBINES

The major source of greenhouse gas emissions (GHG), expressed here as carbon dioxide equivalents (CO_2e) is the gas turbines, which are projected to emit 1,100,640 ton/yr CO_2e, or 99.8% of the total. (TSD, Table 15.) The net increase in GHG emissions, 1,029,032 ton/yr, exceeds the PSD significance threshold of 75,000 ton/yr by a huge amount. (TSD, Table 24.) Thus, BACT for GHG is required under federal PSD regulations. The Application includes a top-down BACT analysis for GHG. (TSD, Appx. A, Chapter 6 and Ap, Appx. B, Chapter 6.)[2]

This analysis concluded that BACT for GHG is the use of "good combustion practices in combination with low carbon containing fuel (natural gas)" satisfied through a three part limit:

- a gas turbine initial heat rate of no more than 8,742 BTU/kWh of gross electric output at 100% load and a dry bulb temperature of 73 F;
- an emission factor of 1,690 lb CO_2/MWh gross electric output, based on a 12-month rolling average; and
- a turbine maintenance plan.

(Ap, Appx. B, p. 50.) The proposed Permit fails to include a limit on initial heat rate. These requirements do not satisfy BACT for GHG because the top-down BACT analysis is fundamentally flawed. The permitted emission rate of 1,690 lb CO_2/MWh is the least-protective limit for any natural gas PSD permit for any simple-cycle natural gas facility identified by the

[1] See Section I.B.1, below, for calculation of permissible operating hours.
[2] Note: Appendix A to the TSD is the same document as Appendix B to the Application. For clarity, these comments refer to the Control Technology Review as Application Appendix B.

applicant,[3] and Sierra Club is aware of no other simple-cycle natural gas facility with a more lenient GHG emission rate in the entire country.

In 2011, EPA issued its *PSD and Title V Permitting Guidance for Greenhouse Gas* ("GHG Guidance") to assist permitting authorities in addressing PSD and Title V permitting requirements for GHGs. Section III of the GHG Guidance addresses the BACT analysis.[4] The GHG Guidance directs permitting authorities to "continue to use the Agency's five-step 'top-down' BACT process to determine BACT for GHGs."[5]

The first step requires the permitting authority to identify all "potentially" available control options.[6] The second step is to eliminate "technically infeasible" options from the potentially available options identified at step 1.[7] In step 3 of the top-down method, the remaining control technologies are ranked and then listed in order of control effectiveness for the pollutant under review, with the most effective alternative at the top. In the fourth step of the analysis, the energy, environmental and economic impacts are considered and the top alternative is either confirmed as appropriate or is determined to be inappropriate.[8] Issues regarding the cost-effectiveness of the alternative technologies are considered under step 4.[9] The purpose of step 4 of the analysis is to validate the suitability of the top control option identified, or provide a clear justification as to why the top control option should not be selected as BACT.[10] Finally, under step 5, the most effective control alternative not eliminated in step 4 is selected and the permit issuer sets as BACT an emissions limit for a specific pollutant that is appropriate for the selected control method.[11]

A. Step 1 of the GHG Top-Down BACT Analysis Is Flawed

In step 1, all control technologies must be identified.[12] The list of control option types that must be considered when establishing a BACT limit includes both "add-on" controls that remove pollutants from a facility's emissions stream and "inherently lower-polluting process or practices that prevent the pollutants from being formed in the first place.[13] The NSR Manual describes the categories as follows:

> Potentially applicable control alternatives can be categorized in three ways:
>
> - **Inherently Lower Emitting Processes/Practices**, including the use of materials and production processes and work practices that

---

[3] See Application at p.35.
[4] GHG Guidance at 17-46.
[5] *Id.* at 17.
[6] Office of Air Quality Planning and Standards, U.S. EPA, *New Source Review Workshop Manual* at B.5 (Draft, Oct. 1990) ("NSR Manual").
[7] *Id*. at B.7.
[8] *Id*. at B.29.
[9] *Id*. at B.31-.46.
[10] *Id*. atB.26.
[11] *Id.* at B.53; *see, generally, In re Prairie State Generating Co.,* 13 E.A.D. 1, 11 (EAB 2006).
[12] NSR Manual, p. B.5.
[13] *In re Knauf Fiber Glass*, 8 E.A.D. at 129.

prevent emissions and result in lower "production specific" emissions; and

- **Add-on Controls**, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.

- **Combination of Inherently Lower Emitting Practices and Add-on Controls**. For example, the application of combustion and post-combustion controls to reduce NOx emissions at a gas-fired turbine.[14]

The Applicant identified the following control technologies for GHG (Ap., Appx. B at p. 36):

1. The use of low carbon containing or lower emitting primary fuels.
2. The use of energy efficient processes and technologies, including:
    a. Efficient simple cycle gas turbine generators,
    b. Combined cycle gas turbines,
    c. Reciprocating internal combustion engine generators.
3. Good combustion, operating, and maintenance practices,
4. Carbon capture and sequestration (CCS) as a post combustion control system

This list is incomplete because it excludes both energy storage and smaller units. Energy storage is a feasible technology under both the category of inherently lower emitting technologies and the category of add-on control technology. The TSD further failed to identify good combustion practice options with lower GHG emissions that are commercially available for the LMS100 turbine, other than the chosen turbine configuration using water injection. These alternatives include using the same LMS100 turbines with: (1) steam injection; (3) dry low NOx (DLN) combustors; and (3) as a Steam Injected Gas Turbine (STIG).[15] Rather than considering these options, the Application and TSD looked only at water injection, which is the least efficient and thus highest GHG emitting combustion option.

1. <u>Energy Storage Options Improperly Omitted</u>

The purpose of the Project, as defined by the Applicant, is to provide temporary peaking capacity to interface with APS's growing renewable portfolio. Because renewable energy is an intermittent source of electricity, APS argues it requires peaking capacity to maintain reliable electric service and maintain grid stability. (Ap., p. 2.) This need could be achieved using energy storage to replace some or all of the proposed LMS100 turbines. Incorporating energy storage

[14] NSR Manual at B.10; see, also, *PSD and Title V Permitting Guidance for Greenhouse Gas* at 25 (March 2011) ("GHG Guidance").
[15] GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, 2003, Available at: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/atechspecs.pdf and GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS1000, June 2004, Available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

units into the Project could serve to lower GHG emissions in two ways: (1) as an add-on technology; and (2) as an inherently lower emitting technology.

There are several types of energy storage technologies available that a project developer can tailor to meet site-specific needs and constraints. Proven storage technologies include batteries, compressed air energy storage (CAES), Liquid Air Energy Storage (LAES), pumped hydro, and flywheels.[16] The first two commercial CAES projects – the 290-MW plant in Huntorf, Germany, built in 1978, and the 110-MW McIntosh, Alabama plant, built in 1991 – have proven the CAES technology is technically feasible. Other projects of varying sizes are rapidly coming online. AES Energy Storage recently announced a power purchase agreement with Southern California Edison to provide 100 MW of battery-based energy storage capable of providing 400 MWh of energy.[17]

Many of these technologies are modular, which allows for scaling them up to meet site-specific needs. Energy storage also acts as both generation and load to enable more than twice the flexible range of a peaker plant on the same interconnection. For example, a 50 MW battery provides 100 MW of load flexibility because it can provide 50 MW of energy and capacity to meet load, and it can also receive up to 50 MW of charge if APS is in a period of over-generation. The technologies can be paired with traditional thermal generating units or renewable generation to provide an independent source to charge the storage and to provide other backup services. Energy storage is always synchronized to the grid and able to provide key reliability services such as frequency regulation, spinning reserves, and renewable integration without a minimum set point.

APS' own 2014 Integrated Resource Plan (IRP) acknowledged several energy storage options that are potentially available for their system, including CAES (100 MW), pumped hydro (900 MW), Li-ion battery (30 MW), flow battery (20 MW) and flywheels (20 MW).[18] Furthermore, the issue of storage <u>in lieu of or in addition to the Ocotillo Project</u> was raised during the state citing process. On September 12, 2014, the Arizona Residential Utility Consumer Office (RUCO) submitted testimony in APS's application for a Certificate of Environmental Compatibility (CEC) before the Arizona Power Plant and Transmission Line Siting Committee. (Docket No. 14-0292-00169.) RUCO reviewed APS's assertion regarding the need for the 500 MW of simple-cycle generation and concluded that APS should have evaluated energy storage technologies to meet those needs.[19] This discussion regarding energy storage as a viable alternative to the LMS100s to meet the project purpose occurred in September 2014. Yet the Applicant's Control Technology Review, which was updated January 23, 2015, does not even mention energy storage as a potential control technology.

---

[16] http://energystorage.org/energy-storage/energy-storage-technologies
[17] http://www.aesenergystorage.com/2014/11/05/aes-help-sce-meet-local-power-reliability-20-year-power-purchase-agreement-energy-storage-california-new-facility-will-provide-100-mw-interconnected-storage-equivalent-200-mw/
[18] Exhibit 1, APS 2014 IRP Presentation, Sept. 11, 2014, p.20.
[19] Exhibit 2, Testimony of Riley G. Rhorer on behalf of RUCO in Response to Application for Certificate of Environmental Compatibility (CEC), Arizona Power Plant and Transmission Line Siting Committee, Dkt. 14-0292-00169 ("Rhorer Testimony") at 11.

2. **Energy Storage as an Add-On Technology**

The Applicant's proposed GHG limit of 1,690 lb CO_2/MWh is the worst GHG rate for a natural gas turbine that Sierra Club has seen in any proposed or final PSD permit. As discussed in more detail below, numerous other facilities using simple-cycle gas turbines have been permitted with GHG emission rates in the range of 1,100 – 1,350 lbs/MWh. (App. Appx. B, at 35.) However, the Applicant and the County both proposed an absurdly high 1,690 lb/MWh GHG limit for the Ocotillo facility. They attempted to justify this limit based on the Applicant's assertion that "the Ocotillo CTs must have the capability to operate continuously at loads as low as 25% of the maximum load." (TSD at 30.)[20] Assuming this need to operate at 25% load was valid – which it is not – the Applicant went on to show in Table B6-9 of Appendix B that a GHG limit of 1,690 lb/MWh is necessary because that is the expected emissions rate at 25% load. That same table shows that at 100% load, the same turbines could meet a GHG emissions rate of 1,090 lb/MWh. Similarly, loads of 75% and 50% could meet GHG emissions rates of 1,160 lb/MWh and 1,300 lb/MWh. (Ap., Appx. B, at 48.) The severe increase in the emission rate for the units is therefore due to the deteriorating efficiency of the units at low loads.

Energy storage has been successfully deployed to address this problem. In Chile, the AES Gener Angamos Power Plant paired two 260 MW thermal units with a 20 MW high-efficiency lithium-ion battery energy storage system. The "hybrid" part of the facility allows the plant to reduce the mandated spinning reserve. Spinning reserve is used during an unexpected transmission loss, the failure of a power generator, or another accident that might otherwise necessitate reducing power to customers.[21] The battery energy storage system therefore allows the plant to operate at increased load. The same application could be used to increase the load of the Octillo plant, which would allow it to operate more efficiently and with fewer emissions.

Interfacing energy storage with gas turbines would eliminate the need to operate the LMS100 turbines at low loads. This configuration would improve overall Project heat rate and efficiency, thus reducing GHG and other criteria pollutant emissions.[22] Energy storage technology is capable of starting nearly instantaneously and changing loads quickly without the need to idle. These capabilities would eliminate the need for the LMS100 units to idle or operate at 25% load when they are not called upon for more efficient capacities. The option of using energy storage to mitigate the need to operate the LMS100s was not considered in the GHG BACT analysis. The GHG BACT analysis should therefore be revised to conduct project- and site-specific analyses of energy storage options.

3. **Energy Storage as an Inherently Lower Emitting Technology**

The County should have considered the use of energy storage as an inherently lower emitting technology. The Applicant's project purpose could be served either by replacing all of the LMS100 units with energy storage, or by pairing energy storage units with fewer LMS100 units. These alternatives are technically feasible options that would have resulted in lower GHG emissions. Unlike peakers, energy storage can provide low- or zero-emissions generation during

---

[20] Sierra Club disputes the validity of this assertion as a basis for the weak GHG limit and addresses that argument in more detail below.
[21] Exhibit 3, *Plant of the Year: AES Gener's Angamos Power Plant Earns POWER's Highest Honor*, available at: http://www.aes.com/files/doc_downloads/sustanaibility/2012PlantOfTheYear.pdf
[22] See Exhibit 2, Rhorer Testimony p. 9.

peak demand by discharging energy stored from efficient natural gas combined-cycle plants, nuclear or renewable generators.

When paired with a traditional generating unit, the total emissions of the an energy storage facility would be much lower than the proposed 1,690 lb/MWh GHG rate of the Ocotillo Facility. Once charged, the energy storage component has a very low marginal cost and would therefore discharge zero-emission or very low-emission power before needing to rely on any reserve combustion generated power.

As an example, three CAES units in Texas already have acquired a signed Interconnection Agreement within ERCOT[23] and received GHG permits from EPA.[24] These technologies use a small amount of natural gas to run their turbines, and therefore are not zero-emission, but they will emit significantly less GHGs than a traditional natural gas plant. Indeed, the EPA itself has approved PSD GHG permits for several CAES units. EPA Region 6 issued a final permit for the Apex Bethel Energy Center in March 2014, another final permit for the Apex Matagorda Energy Center in April 2014, and a final permit for Chamisa CAES at Tulia in March 2014.[25]

The permitted limits of the CAES facilities in Texas, which will serve essentially the same function as the Ocotillo turbines, are dramatically lower than the proposed limit of 1,690 lb CO_2/MWhr (gross) for Ocotillo.

- The GHG BACT limit for the 270 MW Chamisa facility is 575 lb CO_2/MWh on a gross electrical output basis on a 12-operating month rolling average basis.[26]
- The GHG BACT limits for both the 317 MW Apex Bethel Energy plant and the Apex Matagora plant are 558 lb CO_2/MWh (net) for both trains on a 365-day rolling average.[27]

These limits for permitted CAES facilities are nearly <u>one-third</u> the proposed limits for Ocotillo. Other storage technologies, such as batteries, could provide even lower GHG emission rates.

Even if one considers the GHG emissions necessary to charge an energy storage unit, the overall GHG emissions rate of an energy storage unit is lower than the proposed Ocotillo Facility. Energy storage uses electricity as a fuel source and has proven efficiencies greater than 90%. If natural gas combined cycle units that currently turn down or cycle-off overnight are used to charge energy storage, the emissions reduction impact would be 30% lower compared to the

[23] Texas to Host 317 MW of Compressed Air Energy Storage, http://www.greentechmedia.com/articles/read/texas-calls-for-317mw-of-compressed-air-energy-storage2
[24] EPA Grants Permit for Texas Gas Plant, April 17, 2014, Compressed Air Energy Storage Project, http://www.elp.com/articles/2014/04/epa-grants-permit-for-texas-gas-plant-compressed-air-energy-storage-project.html.
[25] http://yosemite.epa.gov/r6/Apermit.nsf/AirP
[26] Exhibit 4. Chamisa CAES Statement of Basis, Prepared by Region 6 February 2014. Available at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP.
[27] Exhibit 5, APEX Bethel Energy Center, LLC Statement of Basis, Prepared by Region 6 November 2013 at page 12. Available at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP; Exhibit 6, APEX Matagora Energy Center, LLC Statement of Basis, Prepared by Region 6 January 2014 at page 12. Available at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP

Ocotillo LMS100 simple cycle unit operated at 50% load,[28] including losses associated with charging and discharging. The first table below illustrates the difference in emissions rates for an efficient natural gas combined cycle plant and the proposed Ocotillo simple-cycle combustion turbine at 50% load. The second table shows the reduction in emissions from replacing one MWh of electricity from the LMS100 with the equivalent amount of electricity from energy storage, charged using a natural gas combined-cycle plant (NGCC).

Emissions Rate (lbs/MWh)		
		CO_2
NGCC		825
Simple-Cycle		1300

An energy storage system with a 90% round-trip efficiency would require 1.11 MWh of energy provided from an NGCC to replace 1.0 MWh of energy from a simple-cycle combustion turbine, but still creates a 30% emissions reduction compared to using the peaker.

Emissions (lbs)		CO_2
Charge (NGCC)		916
Discharge (Simple Cycle, avoided)		(1300)
Reduction		(384)
% Reduction		-30%

These calculations show that a zero-emission discharge energy storage unit such as a battery would provide energy at a 30% lower GHG emission rate, even when considering the re-charge of the battery. The GHG emissions decrease would be even more significant if one assumes that the charge of the battery relies on excess renewable energy generation during periods of over-generation, which is an issue that APS expressly stated is likely to occur on its system.[29] The County must consider modern energy storage units in step 1 of the BACT analysis. The GHG BACT analysis must be revised to include project- and site-specific analyses of both CAES and battery energy storage options.

Energy storage is a zero-carbon or low-carbon alternative that can meet most, if not all, of the peaking capacity needs in this case. If, as the Applicant states, the purpose of the Project is to provide temporary peaking capacity to interface with its renewables portfolio, then energy storage units may provide that service with far lower emissions. Energy storage is particularly attractive for a system such as APS', where a high amount of low-marginal cost solar is frequently available. Any excess generation or low-cost generation from solar during non-peak

[28] For purposes of this calculation, Sierra Club assumes that an energy storage unit would displace operation of the LMS100 at 50% load. The emissions reductions would be even greater where the energy storage unit replaced the LMS100 at 25%, which the Applicant asserts is a necessary capability of the LMS100.
[29] Exhibit 2, Rhorer Testimony at p.8. ("APS identifies over-generation as a concern or 'need' that the proposed Ocotillo Modernization Project will supposedly help to address.")

periods could be used to charge the energy storage units. In turn, when solar is constrained or loads exceed supply, the energy storage units can respond within seconds or milliseconds to provide capacity.

4. **Requirement to Incorporate Energy Storage Does Not Redefine the Source**

Including energy storage, either paired with the LMS100 gas turbines or in lieu of the turbines, does not constitute "redefining the source." A requirement to consider energy storage would not change the underlying business purpose of the facility, nor would it require a completely different fuel source. The Environmental Appeals Board (EAB) recently reminded permitting agencies that they must carefully consider projects that include cleaner fuels or operating configurations. "The Board has cautioned that permitting authorities should not simply dismiss alternative control options, such as cleaner fuels, as constituting redesign, thereby creating an 'automatic BACT off-ramp' from further consideration of the option." *La Paloma Energy Center*, 16 E.A.D. ___, 26 (EAB 2014). The permitting authority must make a case-specific assessment about the feasibility of incorporating energy storage into the design of the Ocotillo Project. The BACT analysis for Ocotillo is completely silent as to energy storage, and as such fails to even consider a feasible control alternative.

Incorporating energy storage into the plant design would increase the overall fuel efficiency and reduce emissions from the plant. Incorporation of energy storage would reduce the air pollution emissions per unit of electricity generated without changing the fundamental purposes of the plant. *See e.g.*, PSD Permitting Guidance for Greenhouse Gases at 30 ("EPA recommends that permitting authorities consider technologies or processes that not only maximize the energy efficiency of the individual emitting units, but also process improvements that impact the facility's energy utilization assuming it can be shown that efficiencies in energy use… lead to reductions in emissions from the facility.").

The applicable law requires that BACT limits be established based on the maximum degree of pollution reduction achievable with a number of specified methods, including cleaner and innovative production processes and cleaner fuels. 42 U.S.C. § 7479(3) (BACT includes "available methods, systems, and techniques, including clean fuels, fuel cleaning or treatment or innovative fuel combination techniques for control of the air contaminant."); 40 C.F.R. § 52.21(b)(12) (same). As a matter of policy, EPA has generally not required a permittee to consider an inherently lower polluting process or practice that would "redefine the design of the source."[30] In determining whether an alternative would redefine the source, the permitting authority should look at "how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application [… and] then take a 'hard look' at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility."[31] In determining the facility's basic design, the permitting authority should look at how the project is

[30] NSR Manual at B.13-.14.
[31] U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases ("GHG Permitting Guidance") 26 (March 2011).

described in the application and supporting materials. *La Paloma Energy Center*, 16 E.A.D. ___, 26 (EAB 2014).

Thus, the "redefining" policy does not shield an applicant from having to alter its design to use a cleaner process, particularly where the redesign would still meet the applicant's basic business purpose. As the Seventh Circuit held, discussing the clean fuels provision in the BACT definition but equally applicable to the cleaner production processes component of the BACT definition, there must be some adjustment allowed to an applicant's design or the BACT definition's requirement to consider cleaner processes, fuels, and methods to reduce pollution would be rendered meaningless. *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007) ("Some adjustment in the design of the plant would be necessary in order to change the fuel source… but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a 'control technique.' Otherwise 'clean fuels' would be read out of the definition of such technology."); see also *In re Desert Rock Energy Company, LLC,* PSD Appeal Nos. 08-03 through 08-06, Remand Order at 63 n.60 (EAB, Sept. 24, 2009) (*quoting Sierra Club*, 499 F.3d at 655); PSD Guidance for Greenhouse Gases at 26 (noting that the redefining policy "does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicant's proposed facility design in order to achieve pollutant reductions…").

The Environmental Appeals Board recently considered this question with respect to Sierra Club's recommendation to consider a hybrid solar energy-natural gas plant. The Board ultimately determined that site-specific constraints eliminated a hybrid alternative. However, the Board noted that the Region cannot reject a hybrid design proposal out of hand, and instead must take a "hard look" at the underlying business purpose of the project and the site-specific constraints that might exist.

> The Region's explanation comes very close to suggesting that adding supplemental solar power generation is always redesign if the applicant does not propose it in the first place. Such a bright line, "automatic BACT off-ramp" approach is not consistent with the NSR Manual, the GHG Permitting Guidance, or Board precedent, all of which suggest that a case-specific assessment of the situation be made in concluding that a proposed control option would redefine a particular source.

La Paloma Energy Center, 16 E.A.D. ___, 29 (EAB 2014).

In contrast to the *La Paloma* recommendation to consider solar power, energy storage is not a fuel; rather, it is a design of the project that would allow the Applicant to meet the project needs with lower or zero fuel combustion, and therefore lower or zero emissions of GHG and other pollutants. The size, modularity, and flexible capabilities of energy storage units match the stated technical requirements of the Project. Furthermore, integrating energy storage into the design of the Ocotillo Power Plant could increase the inherent efficiency of the LMS100 units by mitigating the need to operate at low loads.

APS described its business purpose for the Ocotillo Project in both the Application and in supporting material provided as hearing exhibits during the siting process.[32] As a basis for rejecting various technical options, the Application identified the following technical requirements:

- Ability to achieve peak power of 102 MW.
- High plant efficiency over the operating range of the generators.
- Quick start capability to ramp from 0% output to 100% in 10 minutes or less.
- Must serve peaking loads at all times of the day and night.
- Performance in high ambient temperature conditions.

APS's Director of Resource Planning, James Wilde, described the overall business need for the Ocotillo Project more broadly. Specifically, Mr. Wilde stated that the project was needed for the following reasons:

- APS resource portfolio needs peaking generation.
- Fast-growing renewable generation is variable, requiring the addition of flexible generation resources to respond quickly.
- Flexible generation allows APS and its customers to benefit from market opportunities.[33]

Energy storage units can meet each of these criteria with much lower emissions of both GHGs and other pollutants. Thus, energy storage should have been listed in step 1 of the BACT analysis.

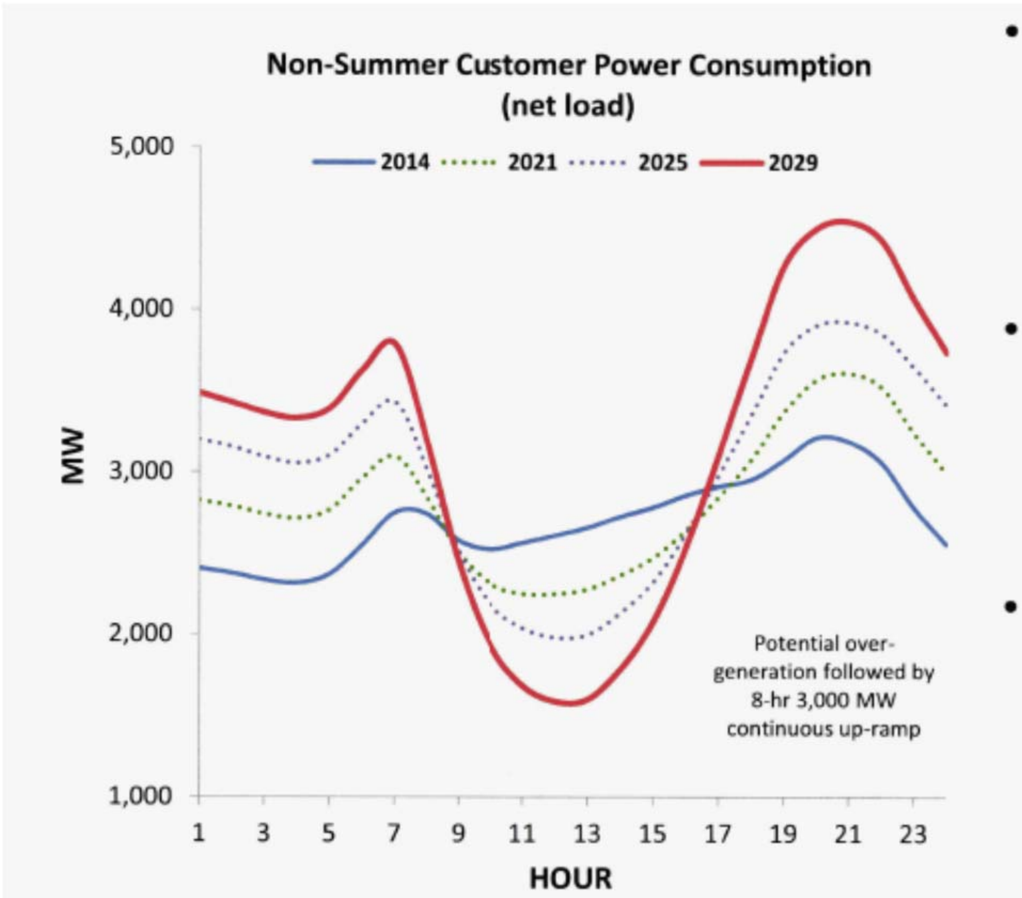
Peaking Generation – Energy storage units can be built in a wide variety of sizes. Many are small and modular, allowing the user to size the project to particular needs. Energy storage can also be paired with natural gas fired thermal units to provide extra peaking capacity while maintaining a lower overall emissions profile and fast response time. For example, PowerSouth's McIntosh Power Plant currently includes four natural-gas fired combustion turbines and a 110 MW Compressed Air Energy Storage (CAES) unit.[34] The plant is specifically designed to meet peaking needs, similar to Ocotillo, though the total plant size is much larger when the attached thermal combustion units are included. Other similarly sized plants include the recently permitted Apex and Chamis CAES plants in Texas, which will be between 270-317 MW.

Other storage facilities demonstrate a high level of flexibility and generation output. Another example is AES's Laurel Mountain facility in West Virginia, which pairs 98 MW of wind generation with the equivalent of 64 MW of integrated battery-based storage resource.[35] AES Energy Storage recently announced a power purchase agreement with Southern California Edison to provide 100 MW of battery-based energy storage capable of providing 400 MWh of

[32] Exhibit 7, Witness Presentation Slides for James Wilde ("Wilde Presentation"), Sept. 9, 2014, Arizona Power Plant and Transmission Line Siting Committee, Dkt. 14-0292-00169.
[33] Exhibit 7, Wilde Presentation at L-3.
[34] http://www.powersouth.com/mcintosh_power_plant
[35] See, Exhibit 8. Available at: http://www.aesenergystorage.com/wp-content/uploads/2014/03/FINDING_THE_HIDDEN_MEGAWATTS_FINAL.pdf

energy.[36] This system could therefore provide 100 MW of peaking capacity for a period of four hours.

Energy storage is well suited to meet peaking needs because, unlike baseload units, peaking units are needed only to meet high loads for a few hours. Mr. Wilde included the following chart in his presentation addressing the need for the Ocotillo Project:[37]



This chart shows the benefits that energy storage can provide to APS' system. The difference between the relatively flat 2014 line and the spiked 2029 line shows the need that the Ocotillo Project is intended to meet. The dip in net load between 9 am and 5 pm in 2029 is the result of over-generation due to renewables. Mr. Wilde noted that during this period, APS would have to significantly reduce dispatch of conventional resources. However, if energy storage were included, those conventional resources could continue to dispatch at higher, more efficient loads so that the energy storage units could be charged. As the peak increases from around 7 PM to 11 PM, both due to increasing demand and lower solar output, the energy storage units could instantly switch to discharge mode and provide a zero-emission peaking resource.

[36] http://www.aesenergystorage.com/2014/11/05/aes-help-sce-meet-local-power-reliability-20-year-power-purchase-agreement-energy-storage-california-new-facility-will-provide-100-mw-interconnected-storage-equivalent-200-mw/
[37] Exhibit 7, Wilde Presentation at L-9.

High Plant Efficiency – APS asserts that it requires high plant efficiency to meet its needs, yet it requested a BACT GHG limit that assumes a low efficiency based on 25% loads. Energy storage units could provide much higher efficiency than the proposed LMS100 units across all operating loads. If paired together with a simple cycle unit, energy storage could fill the gap in generation needs during a peaking event until the LMS100 units were able to come online at 100% load, which would correspond to the LMS100's highest efficiency. Even on its own, a 100 MW energy storage facility could provide peaking capacity for up to four hours or more, depending on how it was designed.

The overall emissions of such a configuration would be vastly improved. Many energy storage units do not use fuel, and therefore the efficiency of the units exceeds the proposed natural gas units over the operating ranges. A 100% battery energy storage plant could discharge with zero emissions. CAES plants use only a small amount of fuel to heat the compressed air as it expands. Even if a hybrid plant is considered, the overall efficiency of the plant would still increase compared to the current proposal because much of the generation supply would be provided with a less or no fuel storage unit. The charge of the unit, as discussed above, would depend on the emissions of the grid feeding into it. If the grid is operating with a high penetration of renewables, as APS claims would be the case, then the overall charge of the battery would be accomplished with a mix of low GHG resources.

Generation Output Turndown – Energy storage units provide greater turndown flexibility than the proposed natural gas units. Battery units are instantly available and have no p-min (i.e. they can turndown to any output). This eliminates the need to idle the LMS100 units at 25% load, which is extremely inefficient. Other types of energy storage technology have comparable or better turndown efficiencies to the proposed LMS100 turbines. Dresser-Rand, the manufacturer of the PowerSouth CAES unit, has noted that the 110 MW CAES unit can turndown to 10 MW[38], which is much lower than the LMS100 turbines, which contrary to assertions elsewhere in the Application, cannot be operated at loads below 50%, or about 50 MW. (Ap., Appx. B at p. 25.) Energy storage units actually provide greater flexibility because, unlike thermal units, they can "go negative" and act as load in times of over-generation.

Quick Start – Many types of energy storage units – such as battery - can ramp in less than one second.[39] Other technologies such as CAES systems are designed to reach full capacity within 10 minutes.[40] Energy storage units are also better than thermal units at cycling because they do not incur the thermal and mechanical penalty associated with quickly ramping up or down. The quick start capabilities also do not produce excess emissions in startup, and therefore there is no emission penalty during quick ramps. In contrast, APS noted in its Application that the LMS100 turbines will not achieve full emissions control until approximately 30 minutes. (Ap., p. 19.) This means that during periods of quick-ramp, the turbines would produce higher

[38] See, Exhibit 9, Dresser Rand CAES Document at page 3. Available at: https://www.dresser-rand.com/literature/general/85164-10-caes.pdf
[39] See, Exhibit 10, CESA Presentation at page 34. Available at: http://www.storagealliance.org/sites/default/files/Presentations/VDE%20Keynote%20Janice%20Lin%202014-03-26%20FINAL.pdf
[40]See, Exhibit 9, Dresser Rand CAES Document at page 3. Available at: https://www.dresser-rand.com/literature/general/85164-10-caes.pdf (page 4)

emissions. The County must consider this emissions penalty in comparing the gas turbines to storage options.

Low Water Usage – Most storage technologies do not require any substantial water usage because the energy is stored either as compressed air, chemically in batteries, or other methods that do not require steam generation. The proposed LMS100 turbines require significant amounts of water for cooling, pumped from existing wells. The CEC Application acknowledges that "[l]ong-term groundwater use is a major concern for APS, as well as the State of Arizona, because of the arid climate and minimal natural recharge in the Phoenix area."[41]

Serving Peaking Loads at Any Time of Day or Night – Energy storage units have a high level of availability 24 hours per day. For example, the Laurel Mountain battery storage unit described above has a 95% availability rating.[42] The intermittent availability of wind or solar resources does not affect energy storage.

Black Start – Black start refers to the initial power supply required to rebuild a power grid after a full blackout. Dedicated, 100-percent-reliable power sources are needed to provide this emergency energy, since standard plants themselves require some electricity for startup operations. A 2011 study by the Boston Consulting Group found that for many storage technologies, including CAES, black starts are both technically feasible and in some instances economical when compared to diesel backup.[43] For Ocotillo, energy storage by itself could provide the necessary black-start capabilities. Similarly, a paired configuration of LMS100 turbines and storage would clearly provide black start capability because both the storage components and the LMS100 components could provide black start capability.

Performance in High Ambient Temperatures – Energy storage typically does not suffer a penalty from high temperature environments. For example, CAES output is not affected by temperature.[44] The proposed LMS turbines, on the other hand, suffer a significant temperature penalty, requiring inlet cooling. (Ap., Appx. B, Tables B6-7 & B6-9.)

Low Load Operation – The GHG emission limit is based on emissions at steady state loads of 25% of maximum output capability of the turbines. Energy storage would eliminate the need to operate the gas turbines at low loads, improving the overall efficiency of the plant and significantly reducing GHG and other criteria pollutant emissions.

Overall, energy storage or a paired energy storage-LMS100 unit design, offers all of the technical attributes required for the Project. Replacing any or all of the proposed five LMS100 gas turbines with storage will reduce GHG and other criteria pollutant emissions from the entire plant.

In addition to meeting all of the technical specifications identified by APS in the Application, energy storage would also provide additional benefits and ancillary services.[45] Energy storage

---

[41] Exhibit 11, CEC Ap., Exhibit B2, p.B2-1.
[42] http://energystorage.org/energy-storage/case-studies/frequency-regulation-services-and-firm-wind-product-aes-energy-storage
[43] See, Exhibit 12, Boston Consulting Group "Revisiting Energy Storage" 2011, at page 7-8. Available at: http://www.abve.org.br/downloads/bcg_-_revisiting_energy_storage.pdf
[44] See, Exhibit 9, Dresser Rand CAES Document at page 3. Available at: https://www.dresser-rand.com/literature/general/85164-10-caes.pdf (page 5)
[45] http://www.aesenergystorage.com/advancion/advantages/

provides more flexibility to allow APS to match its renewables portfolio. It would also protect APS from market risks because it would allow APS to charge the units during periods of over-generation rather than selling surplus power at low to negative prices.[46] Customers could therefore benefit from low or negative priced power. The ability to act as both generation and load provides greater grid flexibility. The marginal cost of providing peaking service is also much lower than the LMS100 gas turbines proposed by APS. When taken together, the generation benefits and ancillary services make energy storage cost competitive with simple-cycle peaking units.

Neither the Applicant nor the County considered either a full energy storage facility or a hybrid energy storage-LMS100 facility. BACT step 1 requires the permitting agency to identify "all available control technologies." Energy storage technology could feasibly meet the business purpose of the Applicant to provide peaking capacity, reliability, and integration of renewable resources. It is also commercially available, as demonstrated by the projects referenced above, as well as numerous other storage projects not addressed. The County must include energy storage as an identified technology for providing energy services for purposes of its GHG BACT analysis.

The County must, at a minimum, consider energy storage as an available technology in step 1 of the BACT analysis, and it may only reject energy storage if it makes a detailed, process- and site-specific showing that the cleaner process does not constitute BACT.

5. Smaller Unit Options Omitted

As discussed above, the Applicant's basis for setting the GHG limit at 1,690 lb/MWh is premised on the asserted need to operate each unit at 25% loads. This is an extremely inefficient use of a simple-cycle turbine and leads to much higher GHG emission rates. The BACT analysis should have considered the incorporation of small units operating at high efficiencies in lieu of allowing the LMS100s to operate at 25% load. The five new LMS100 gas turbines are all 102 MW units. The Applicant asserts that meeting the Project's goals would require partial load operation of one or more of these units when demand is low. A combination of smaller units and a smaller number of 102-MW LMS100 units could meet Project goals while improving efficiency and reliability. Smaller units could be operated at 100% efficiency when demand is low, rather than operating a 102 MW turbine at 25% load. A 25 MW turbine, for example, could be operated at 100% load, rather than operating a 102 MW unit at 25% load. This would greatly improve efficiency, reducing GHG and other criteria pollutant emissions. Further, smaller units could be added incrementally during Project buildout, to more closely align with projected growth.[47]

6. Combustion Options Omitted

The Ocotillo project proposed to use an inefficient configuration of the LMS100 turbines compared to other available options. The BACT analysis lists "good combustion, operating, and maintenance practices" as one of the potential control options for GHGs. (Ap., Appx. B, p. 36.)

[46] Exhibit 7, Wilde Presentation at p. L-11.
[47] Exhibit 2, Rhorer Testimony, p. 9.

However, it does not list individual combustion options, but rather only discusses the option that was selected – the LMS100 turbine using water injection. (Ap., Appx. B, Sec. 6.4.2.)

The LMS100 gas turbines selected for the Project come in different "models" or "configurations" that have different efficiencies, heat rates, and electrical outputs, and thus different GHG and other emissions. The Applicant chose the LMS100, Model PA – 60 Hz, with an efficiency of 43% and a heat rate ISO full load gross of 8,939 BTU/kWh HHV. (Ap., p. 14.) This model uses a water-injected single annular combustor (SAC with water injection). It is the least efficient, and thus highest emitting, of the available LMS100 models. The available LMS models are summarized in Table 1 from a GE brochure:

Table 1
Simple Cycle Gas Turbine 60 Hz Applications[48]

Model	Output (MWe)	Heat Rate (BTU/KWH)	Efficiency %
DLE	98.7	7509	46
SAC (w/Water)	102.6	7813	44
SAC (w/Steam)	102.1	7167	48
STIG	112.2	6845	50

This table shows that the LMS100 also is available with a steam-injected single annular combustor (SAC), a dry low emissions (DLE) combustor, and as a Steam Injected Gas Turbine (STIG).[49] All of these options are capable of fast starts (0 to 100% in 10 minute); high efficiency (>43%); fast response (50 MW per minute ramp-up); high part load efficiency; meet the peak load of 102 MW; are capable of multiple daily starts with no maintenance penalties; and have high availability and reliability. Thus, all of these options, based on the same LMS100 turbine, but with different "low combustion options," satisfy the Project's requirements.

All of these options are more efficient than the LMS100 Model PA-60Hz selected for the Project. Thus, all of the combustion options have lower GHG and other emissions than the selected option, as they are able to produce the same amount of electricity by combusting less natural gas. A proper BACT analysis should have identified all of these options and among them, listed the STIG option as the top LMS100 turbine option.[50] Some of these combustion options

[48] GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, November 2003, Performance at generator terminals: NOx = 25 ppm; 59 F, 60% relative humidity, 0"/0" inlet/exhaust losses and natural gas (LHV = 19,000 Btu/lb). http://www.dec.ny.gov/docs/permits_ej_operations_pdf/atechspecs.pdf

[49] GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, November 2003, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/atechspecs.pdf and GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS1000, June 2004, http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

[50] *See, La Paloma Energy Center, LLC,* 16 E.A.D. ___, PSD 13-10 at 21 (deferring to the permitting authority's discretion to select among various turbine models where the permitting authority had included a rational basis for its determination on the record).

are mentioned in the BACT analyses for PM/$PM_{2.5}$, NOx, and CO, but are improperly eliminated based on misinformation.

The NOx BACT analysis is the most specific, arguing that water injection was selected due to its ability to achieve higher peak power output than steam injection or DLN combustors. The NOx BACT analysis failed to acknowledge STIG. It claimed that water injection increases the mass flow through the turbine, increasing power output, especially at higher ambient temperatures when peak power is often required. While this is true, steam injection and STIG also increase power output for the same reason, but to an even greater degree. The DLN combustor was reported to have a maximum gross electric output of 99 MW, versus 103 MW for water-injected combustors. (Ap., Appx. B, pp. 24-25.) A similar, though less specific peak power argument is made in the PM/$PM_{2.5}$ BACT analysis (Ap., Appx. B, p. 25) and the CO BACT analysis (Ap., Appx. B, p. 13).

The peak power argument asserted by the Applicant for non-GHG emissions is misleading and cannot be used to eliminate the more efficient and lower emissions options of the LMS100 turbines. First, the BACT analyses argue water injection would allow up to 103 MW output, while the CEC Application (CEC Ap., pp. ES-1/2) and Draft Permit both list the LMS100s as 102 MW turbines (Draft Permit, p.33). Further, all of the rejected combustion options, except the DLN combustor, can achieve higher peak output than water injection, while simultaneously achieving lower emission rates, improved energy efficiency, and reduced environmental impacts. Steam injection, for example, achieves a maximum power output of 102.1 MWe and STIG achieves 112.2 MWe, meeting the peak power goal of 102 MW listed in the Draft Permit. (Draft Permit, p.33.) Thus, the peak power goal could be easily met by selecting other LMS100 combustion options, such as STIG, which are more efficient and thus have lower emissions. Further, the record contains no demonstration that peak power goals cannot be achieved using more than one turbine model.

B. Step 2 of the GHG Top-Down Analysis Is Flawed

Step 2 of the BACT analysis directs the permitting authority to eliminate technically infeasible control options. “A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.” NSR Manual, p. B.6. The step 2 analysis in the Ocotillo BACT analysis improperly eliminated combined cycle gas turbines. (Ap., Appx. B, p. 38.)

The GHG BACT analysis concluded that combined cycle turbines were technically feasible for the Project, but rejected them in step 2 on the grounds that they “would change the project in such a fundamental way that the requirement to use these technologies would effectively redefine the Project.” (Ap., Appx. B, p. 36.) However, the record shows that the Applicant has defined the Project specifically to skirt GHG BACT, rather than to satisfy necessary Project goals.

The GHG BACT analysis rejected highly efficient combined cycle plants in step 2 as technically infeasible. (Ap., Appx. B, Table B6-6, p. 42.) The BACT analysis argues that the purpose of the Project “is to construct peaking power capacity” that can start quickly, even under “cold” start conditions, that can repeatedly start and stop as needed, and that can reduce output to provide spinning reserve when necessary. The BACT analysis claimed combined-cycle turbines cannot meet these requirements, even with new fast-start, combined cycle technology, which it asserted requires more than 3 hours to achieve full load, compared to about 30 minutes for the LMS100 simple cycle turbines. (Ap., Appx. B, pp. 38-39.) The factual assertions made by the Applicant regarding fast-start combined cycles are wrong and cannot be used to eliminate combined cycle turbines in the BACT analysis.

Reducing GHG emissions is directly related to minimizing the quantity of fuel required to make electricity. Thus, the more efficient a turbine, the less fuel it uses to generate the same amount of electricity and thus the lower emissions, including GHG, NOx, CO, and PM/PM_{10}. The BACT requirement is defined as "the maximum degree of reduction for each pollutant." 42 USC 7479(3). Therefore, the top-down BACT analysis requires the County to select the lowest emitting technology as the basis for setting the BACT emission limit. In this case, the simple-cycle turbine option, the LMS100, model PA – 60 Hz, selected by the Applicant is much less efficient than other models of the LMS100 (discussed above) and it is less efficient than modern combined-cycle units.

This dismissal of recognizable and achievable energy efficiency gains is contrary to EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*, which expressly addresses an example of energy efficiency at a coal plant:

> In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis. For example, coal-fired boilers operating at supercritical steam conditions consume approximately 5 percent less fuel per megawatt hour produced than boilers operating at subcritical steam conditions.[51]

The EPA guidance makes clear that energy efficiency must be considered in the BACT analysis. The NSR Manual further provides: "The reviewing authority…specifies an emissions limitation for the source that reflects the **maximum degree** of reduction achievable…" (NSR Manual, p.B.2 (emphasis added). Without a showing that the most efficient design is either technically infeasible or that it should be eliminated due to disproportionate site-specific energy, economic or environmental impacts, the County must set the GHG BACT emission rate limit based on the most efficient turbine design.

A lower emitting control technology for generation of electricity from fossil fuels is combined cycle natural gas generation with inlet cooling. As demonstrated below, combined cycle gas turbines commonly perform peaking functions in U.S. generating systems.

There are a number of commercially available units from reputable manufacturers that are capable of (1) greater full load efficiency; (2) greater part load efficiency; and (3) ample ramp

[51] *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p.21 (citing: U.S. Department of Energy, Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2007/1281, Final Report, Revision 1 (August 2007) at 6 (finding that the absolute efficiency difference between supercritical and subcritical boilers is 2.3 percent (39.1 percent compared to 36.8 percent), which is equivalent to a 5.9 percent reduction in fuel use), available at http://www.netl.doe.gov/energyanalyses/pubs/Bituminous%20Baseline_Final%20Report.pdf).

rates to respond to the daily fluctuations in demand. These units range in capacity from less than 100 MW to over 900 MW and include the following:

Table 2
Efficient Combined-Cycle GasTurbines

Unit	MW (net)	CT/HRSG (MW)	Efficiency (net %)	Heat rate (Btu/kWh)	Part Load	Overnight
Alstom KA 24 2x1[52]	664	450/214	59.5	5739	>98% of full load eff. to 80 % load; 95% to 50 % load	450 MW in 10 min.
Mitsubishi M501GAC[53]	404	264/132	59.2	5763		10 min to 264
Mitsubishi 701G	498	334/164	59.3	5755[54]		
Mitsubishi M501J	470	320/140	61.5[55]	5551		10 min to 320/30 min to 460
GE Flex 60	512	339/181	>61	< 5584	>60% efficiency to 87% of load	28 min startup
Siemens SCC6-8000-1S	410	274/136	>60	<5687		<30 min.[56]
Siemens SCC6-5000F (Lodi)	305	232/73	>57	<5989		70 MW in 10 min; hot/warm start 200 MW in <30 min.
Proposed 5xLMS100	510	510/0	43[57]	8939	34% efficiency (80% of full load eff.) at 50% load	10 min.

The County must analyze these combined-cycle units to determine whether the greater achievable efficiencies constitute BACT for the Ocotillo Project. In this case, the County did not consider any of the available combined-cycle units because it improperly concluded in step 2 that combined-cycle units are technologically infeasible to meet the Project purpose as asserted in the Application. The following sections demonstrate that the County's conclusion regarding the technical feasibility of combined-cycle units is factually incorrect. The County must therefore revise its BACT analysis for all criteria pollutants to consider the turbines listed above, as well as any other available turbines that can achieve lower GHG (and other criteria pollutant) emissions.

---

[52] A smaller 1x1 configuration is also available.
[53] http://www.doosan.com/doosanheavybiz/attach_files/services/power/power_plant/turbine_gas.pdf
[54] http://www.mpshq.com/products/gas_turbines/g_series/performance.html
[55] www.mhi.co.jp/technology/review/pdf/e491/e491018.pdf
[56] http://www.energy.siemens.com/hq/pool/hq/power-generation/power-plants/gas-fired-power-plants/combined-cycle-powerplants/scc5-8000H/PowerGen_Asia_2012_Bangkok_OneYearCommercialOperation_HClass_Balling_Sfar_Staedtler.pdf
[57] Ap., p. 14.

1. Operating Hours for Peaking Units Are Too High

The Application states that "the purpose of this Project is to construct peaking power capacity". (Ap., Appx. B, p. 38.) Elsewhere, it argues that the fundamental purpose of the Project is as a peaking power plant (Ap., Appx. B, p. 36) and that the turbines are "peaking GTs" (Ap., Appx. B, p. 23). The BACT analysis eliminates technically feasible options as it alleges they are not capable of peaking operation. (Ap., Appx. B., pp. 38-39.)

However, the Applicant's assertion that it needs a "peaking unit" to operate the Ocotillo plant as a peaking facility is contradicted by the actual operating parameters discussed in the Application and required by the Draft Permit. The proposed operating mode is not consistent with peaking operation, and therefore the assumption that combined-cycle units are not appropriate is unsupported. The record shows that the Applicant intends to operate the facility much more frequently and for longer hours than a traditional "peaking" unit. At those higher operating levels, a combined-cycle unit would provide much better efficiencies while still meeting the basic needs of the project to provide quick start and quick ramping capabilities.

The Application does not disclose the assumed number of hours of operation or the capacity factor of the new turbines, factors that distinguish "peaking" units from "combined cycle" units. In fact, the Application asserts it is not proposing limits on hours of turbine operation nor the number of startups and shutdowns to increase operational flexibility. (Ap., p. 17.) Instead, it proposes emission caps that have been incorporated into the Draft Permit as limits on operation.

The assumed number of hours of operation can be back calculated from the emissions by dividing the tons per year per turbine by the pounds per hour per turbine. (Ap., Tables 3-1, 3-2.) This calculation for the major pollutants yields an average of 3,571 hr/yr of normal operation per turbine.[58] (Ap., Table 3-1.) In addition, each turbine would undergo up to 730 startups/shutdowns per year, each lasting a total of 41 minutes (30 min startup, 11 min shutdown). (Ap. Table 3-2.) This amounts to 499 hours per year per turbine[59] of startup and shutdown. Thus, each turbine is permitted to operate 4,070 hr/yr or 46% of the time.

The Applicant's proposed operation of the Ocotillo plant deviates substantially from the historical operation of "peaking units." The annual operating hours for the proposed Ocotillo turbines are much higher than typical peaking units. The available data show that almost all simple cycle turbines have low operating hours. In contrast, the emission calculations for Ocotillo show that each LMS100 turbine would operate approximately 4,070 hrs/yr. Figure 1 shows this level of planned operation is far too high to be considered a "peaker." The "knee in the curve" in the table below shows that more than 90% of existing simple-cycle units operated at 2,000 hours or less for 2011 (the most favorable[60] year for industry), thus showing that operation greater than 2,000 hours is not consistent with the normal operation of combustion turbines in peaking service.

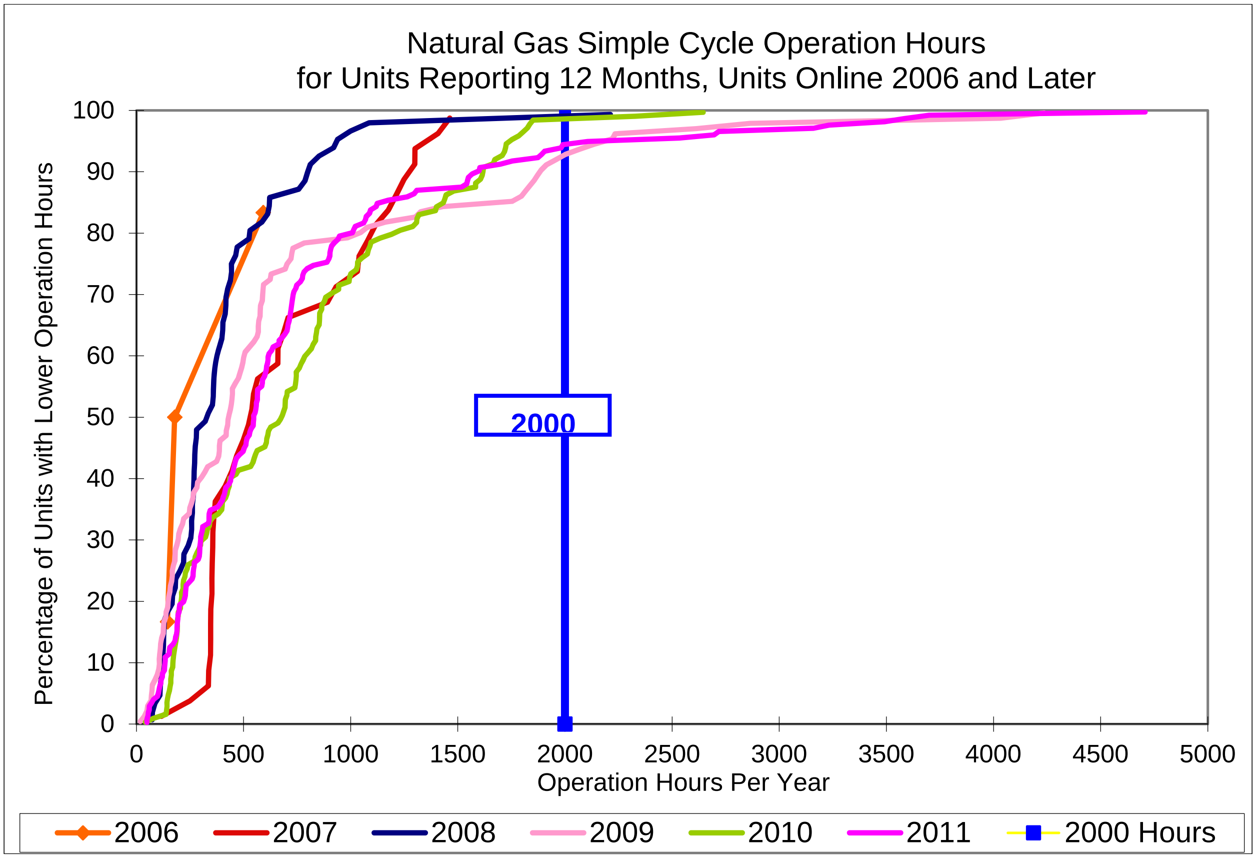
---

[58] Operating hours based on CO_2: (202,438 ton/yr)(2000 lb/ton)/113,467 lb/hr = **3,568 hrs**; CO: (24.1 ton/yr)(2000 lb/ton)/13.5 lb/hr = **3,570 hrs**; NOx (16.5 ton/yr)(2000 lb/ton)/9.3 lb/hr = **3,548 hrs**; VOC (4.7 ton/yr)(2000) lb/ton)/2.6 lb/hr = **3,615 hrs;** PM (9.6 ton/yr)(2000 lb/ton)/5.4 lb/hr=**3,556 hr/yr**. Average: [3568+3570+3548+3615+3556]/5 = **<u>3,571 hrs/yr.</u>**

[59] Startup/shutdown hours: [(31+11)/60]730 = **511 hrs/yr.**

[60] For 2008, it is closer to 1100 hours.

Hours of Operation for Combustion Turbines, by Year[61]



This analysis suggests that the Ocotillo Project is designed to primarily supply base load and intermediate load, rather than peaking load. Thus, the Project's goals could be achieved with different turbines, or a different mix of turbines (e.g. a portion true peakers and a portion of conventional combined cycle turbines). For example, APS could configure two of the five units as a combined-cycle design, thereby increasing the efficiency of those units while maintaining the fast-start capabilities of the simple-cycle units.

General Electric defines "peaking" units in terms of an average hour of operation per startup. GE Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It then defines peak load as operation at 1,250 hours per year with five hours per start.[62] Thus, if APS really wants to build a "peaking" unit – and thereby eliminate other more efficient non-peaking technologies – the County should set BACT limits based on no more than 2,000 operating hours per year to ensure that the proposed simple cycle turbines are used as true peaking units rather than as base load or intermediate load units. If, on the other hand, APS plans to operate the five new LMS100 turbines for more than 2,000 hours per year, then the BACT analysis must consider alternative electricity generation technologies, such as combined cycle,

---

[61] First year of operation 2006 or later, as determined by earliest occurrence of CAMD CEMS data. This data is included in Appendix D.

[62] Brooks, F., GE Power Systems, *GE Gas Turbine Performance Characteristics, GER-3567H*, p.14 (available at: http://www.muellerenvironmental.com/documents/GER3567H.pdf.)

that can operate more efficiently and therefore at lower GHG (and other criteria pollutant) emission rates.

There are numerous examples of other facilities with lower emissions of GHGs that operate in the range of hours proposed by APS for the Ocotillo plant. In comments on EPA's proposed New Source Performance Standards, Sierra Club and other environmental commenters compiled data on the actual emissions performance of all simple-cycles (CTs) and combined cycle (CCGTs) in the United States based on their annual hours of operation in 2012. Those data, split into different operational categories, are below:

Table 3: Aggregate Emissions Data for CTs and CCGTs by Annual Hours of Operation
Source: 2012 CAMD Data Set

2012 Emission rate (lb/MWh) - key statistics	CT + CCGT > 4,000 hrs gross/net	CT + CCGT 1,200-4,000 hrs gross/net (average operating hours)	CT + CCGT < 1,200 hrs gross/net (average operating hours)
average of all units	995/1,025	1,080/1,112 (2,561)	1,368/1,409 (438)
median	879/905	978/1,007 (1,353)	1,321/1,361 (204)
average of top 10 percent	767/790	803/827 (2,692)	1,019/1,050 (589)
90th percentile unit	800/824	827/852 (2,799)	1,131/1,165 (477)
average of top 20 percent	789/813	822/847 (2,994)	1,164/1,199 (528)
80th percentile unit	818/843	849/874 (3,576)	1,189/1,225 (457)
average of bottom 10 percent	1,466	1,501 (2,416)	1,900 (308)
average of bottom 10-20th percent	1,303	1,349 (2,997)	1,582 (346)

This table shows that in the operating range of 1,200 hours to 4,000 hours annually, the <u>average</u> unit that exists in the fleet today achieves a gross emission rate of 1,080 lbs CO_2/MWh (gross). In contrast, for Ocotillo, which could operate roughly 4,000 hour each year as currently proposed, the proposed GHG BACT limit is 1,690 lb CO_2/MWh. This proposed limit is worse than the bottom 10 percent of <u>actual emissions from currently operating</u> natural gas units in the United States. It is contrary to BACT to set an emissions limit for a new major source of GHG emissions at a rate that more than 90 percent of the existing fleet is already exceeding. The NSR Manual suggests that for categories of controls that have a range of emission rates, the most recent permit limits or emission data be used to represent the category.[63] The best-in-class emission rate can then represent the entire class of similar control options all the way through the process to the setting the emission limit without having to determine the bottom of the range for options in the same category.

Even assuming a generous compliance margin, the County should set the GHG emissions limit for Ocotillo based on the top-performers of similarly situated facilities. At a minimum, the County must explain in the BACT analysis why site-specific limitations at the Ocotillo facility prevent it from achieving a 12-month average GHG emission rate that is worse than almost all other natural gas units in the country.

2. Combined-Cycle Turbines Are Technically Feasible to Meet the Project's Generation Requirements

The County and APS improperly rejected combined-cycle technology in step 2 of the BACT analysis on the grounds that allegedly longer startup times are incompatible with the ramping needs of the proposed Project:

> "Even with faster-start technology, new combined-cycle units may require more than 3 hours to achieve full load, as compared to approximately 30 minutes to full electric output for the proposed GE Model LMS100 simple cycle gas turbines. The long startup time for combined cycle units is incompatible with the purpose of the Project which is to provide quick response to changes in the supply and demand of electricity in which these turbines may be required to startup and shutdown multiple times per day." (Ap., Appx. B, p. 39.)

Elsewhere, the BACT analysis relies on a 10-minute startup time to reject combined cycle turbines, even though its emission calculations assume a 30-minute startup time. (Ap., Table 3-2.) The County did not investigate whether the startup time of combined cycle units is 30 minutes or whether there was any evidence to support the need for a 10-minute startup time.[64]

APS cannot simply claim, without providing evidence, that its needs can be met only by this specific turbine design based on startup times. Such a claim is an overly narrow description of the source that would undermine the BACT analysis of other feasible technologies. *See Pio Pico Energy Center*, 16 E.A.D.___, 67 (2013) ("Sierra Club's fear that applicants and permit issuers could so narrowly define the source type they consider in step 2 as to make all other control technologies infeasible is well taken"). Even if there was such a need, the evidence provided below with respect to modern combined-cycle turbine capabilities and the LMS100 STIG option shows that more efficient combined-cycle units are capable of meeting a 10-minute startup.

---

[63] NSR Manual at B.23.

[64] Ap., Appx. B, p. 36 ("…new combined-cycle units may require more than 3 hour to achieve full load, as compared to approximately 10 minutes to achieve the full rated electric output for the proposed GE Model LMS100 simple cycle gas turbines"); p. 51 ("For these GE Model LMS100 simple cycle GTs, the length of time for a normal startup, that is, the time from initial fuel firing to the time the unit goes on line and water injection begins, is normally about 10 minutes..").

In fact, there is substantial evidence demonstrating that this assertion is both inaccurate and unrepresentative of the actual needs of a utility system. It also fails to assess the modern capabilities of combined-cycle units before even reaching the question of costs. The GHG BACT analysis therefore clearly violates BACT.

For the purposes of reliability and renewable integration, combined-cycle units are fully capable of providing fast-response generation. They are therefore fully capable of matching variable renewable output, and can satisfy load-following and immediate dispatch needs in manner comparable, if not identical, to simple cycle units. Siemens has published documentation showing that its Fast Start 30 is capable of 10 minute starts after an overnight shutdown. Longer times necessary to reach full load are limited to circumstances where an operator elects to shut the unit down for more than 48 hours. There is no technological limitation requiring a unit to shut down for that period of time, but an operator may elect to do so if the unit will not be needed for that duration. However, even under this scenario, full output of the combustion turbines that are components of these units are available within 10 minutes.

Sierra Club queried turbine vendors on the specific question of whether combined-cycle units can meet fast-ramping capabilities of simple-cycle plants. In response, a representative from Siemens responded as follows: "With the application of proper HRSG and steam turbine technology, gas turbines can start up and ramp up just as fast in combined cycle configurations as in simple cycle configurations. This capability was demonstrated in aeroderivative gas turbines quite some time ago. In recent years, the advance of HRSG and SCR technology has allowed the fast starting of heavy frame gas turbines."[65]

The Siemens letter also noted that NRG recently commissioned a plant in El Segundo, California in a combined-cycle configuration that is capable of the same startup times (12 minutes) as the same unit in a simple-cycle configuration. A recent press release noted that the El Segundo plant can achieve even faster startup times: "The new plant can deliver more than half of its [550 MW] generating capacity in less than 10 minutes and the balance in less than 1 hour, which is needed as California relies more on intermittent renewable technologies like wind and solar that depend on weather conditions."[66]

Combined-cycle units can act as peakers or load-following units by ramping up their combustion turbines very quickly, while still meeting full load simply by warming up the heat recovery steam generator in anticipation of increased demand. This point is important because the "peak" is rarely a surprise. Utilities are quite good at estimating peak demand based on weather and usage patterns. Thus, operators have sufficient time to warm up a combined-cycle unit to meet full-load needs, while at the same time having sufficient flexibility to dispatch units quickly at more than half of their full-load capacities within 10 minutes if an urgent need arises.

There are several other examples of combined cycle units that can meet fast-start and quick ramping times in a manner comparable to simple cycle units. For example, Footprint Power's Salem Harbor Station will be capable of providing 300 MW of power to the grid "within 10

[65] Exhibit 13, *October 18, 2013 Letter from Rich Batey to Travis Ritchie*; *see, also,* Exhibit 14, *2013 GTW Handbook Price List (Excerpt).*
[66] Exhibit 15, Aug. 2, 2013, *NRG's California El Segundo Natgas Power Plant Enters Service*

minutes" using GE's 7F 5-series gas turbine with its "Rapid Response" package.[67] The plant will reduce greenhouse gases as well as other pollutants including NO_x, SO_2 and mercury.[68] In addition, the plant's operators have touted its "flexibility" to enable integration of renewables onto the grid.[69] *See also 7F 5-Series Gas Turbine Fact Sheet* (indicating a start time of 11 minutes);[70] *7F 7-Series Gas Turbine Fact Sheet* (indicating start time of 10 minutes).[71]

Similarly, the proposed Oakley Generating Station in California has been designed with the capability to start up and dispatch quickly with GE's Rapid Response package.[72] The Rapid Response package will allow the plant to start up from warm or hot conditions in less than 30 minutes. The system achieves fast performance by initially bypassing the steam turbine when the gas turbines are first started up. In a conventional combined cycle system, the gas turbine must be held at low load for a period of time while the HRSG is warmed up and steam is gradually fed into the steam turbine to bring it up to operating temperature. This process must occur slowly in order to minimize thermal stresses on the equipment and to maintain the necessary clearances between the turbine's rotating and stationary components. In the past, this delay necessitated a slow warm-up of the HRSG and steam turbine, which meant that the plant's gas turbine could not increase load as rapidly as a simple-cycle turbine to quickly provide power to the grid. This method also resulted in increased emissions of air pollutants, including $CO_{2,}$ because the combustion turbine remained at low load—where it operated less efficiently—while the HRSG and steam turbine warmed up. Those constraints are avoidable with today's technology. The GE Rapid Response system initially bypasses the steam turbine when the combustion turbines are started, allowing them to ramp up quickly and begin providing power to the grid. The steam turbine can then be warmed up slowly without requiring the combustion turbines to remain at low load (except for a short time during cold startups), which is achieved through the controlled admission of steam from the HRSGs into the steam turbine. The Rapid Response package therefore allows the facility to start up and begin providing power to the grid more quickly than a conventional system, achieving enhanced operational flexibility and reduced emissions associated with startups.

Another example of a currently operating facility that uses this technology is the 300 MW Lodi Energy Center, which came online in 2011 and can deliver 200 MW to the grid in 30 minutes.[73] The plant can also ramp up and down at a rate of 13.3 MW/min. This flexibility

---

[67] Exhibit 16, Press Release, *GE Technology to Repower Footprint Power's Salem Harbor Station, Reducing Emissions and Ensuring Reliable Electric Service for Greater Boston Area* (Nov. 1, 2013), *available at* http://www.genewscenter.com/Press-Releases/GE-Technology-to-Repower-Footprint-Power-s-Salem-Harbor-Station-Reducing-Emissions-and-Ensuring-Rel-43a6.aspx.
[68] *Id.*
[69] *Id.*
[70] GE, *7F 5-Series Gas Turbine Fact Sheet* (2012), *available at* http://www.ge-flexibility.com/static/global-multimedia/flexibility/documents/7F_5-series_Gas_Turbine_Fact_Sheet_FINAL.pdf.
[71] GE, *7F 7-Series Gas Turbine Fact Sheet* (2012), *available at* http://www.ge-flexibility.com/static/global-multimedia/flexibility/documents/7F_7_Series_Product_Fact_Sheet.pdf,
[72] *See* Bay Area Air Quality Mgmt. Dist., *Final Determination of Compliance for Oakley Generating Station* (Jan. 2011), at 12, *available at* http://www.energy.ca.gov/sitingcases/oakley/documents/others/2011-01-21_BAAQMD_FDOC_TN-59531.pdf
[73] *See* Exhibit 17, Isles, *Lodi's 300MW Flex 30 plant ushers in a new era for the US*, Gas Turbine World (Sept./Oct. 2012), *available at* http://www.gasturbineworld.com/assets/sept_oct_2012.pdf ; Exhibit 18, Gawlicki, *Lessons from*

allows the unit to respond quickly to intermittent resources or demand while still complying with stringent California emissions requirements. The Siemens fast-start units are specifically designed to reduce the "thermal shock" or "thermal penalty" associated with ramping combined cycle units up and down. Furthermore, these units are available today, and demand for them is increasing.[74] In April 2013, Siemens was awarded a contract for a Siemens Flex Plant 30 fast-start unit at the Panda Temple II plant in Temple, TX.[75] Financing has been secured and construction of the plant has commenced.[76] Additional fast-response units will be constructed at the Palmdale Hybrid Energy Plant, where they will operate in conjunction with a 50 MW solar facility, and are also planned for inclusion at the proposed Huntington Beach Energy Project.

In addition, units designed by GE and other manufacturers are operating in other countries that, due to higher natural gas prices, have led the way in developing and adopting high efficiency, flexible natural gas-fired electric generating technology. GE asserts that it has orders totaling $1.2 billion for Flex Efficiency for 60 plants in the U.S., Japan and Saudi Arabia – countries that use 60-cycle electricity.[77] Likewise, the Severn Power Plant in Wales is capable of providing full load (834 MWh) within 30-35 minutes with a high degree of flexibility to compensate for intermittent resources such as wind.[78] The plant is the result of concerted efforts by turbine manufacturers to meet demand for flexible units with better efficiencies and lower emissions. Combined-cycle plants with enhanced flexibility and start-up capabilities have also appeared recently in France, England, the Netherlands, and Portugal.[79]

Lastly, data indicates that units such as those described above can meet stringent CO_2 performance standards even when they undergo frequent cycling. As part of its study of the performance of over three hundred NGCC units, EPA evaluated whether units that cycle more frequently exhibit higher CO_2 emission rates. Although the units included in the study pool had a wide range of cycling behavior, ranging from to 1,553 starts per year, EPA found "limited correlation" between the number of starts and CO_2 emission rates. In addition, EPA found that the average CO_2 emission rate of the ten units that cycled most frequently was 883 lb/MWh, which is very close to our recommended standard for intermediate load units. These results

---

Lodi, Public Utilities Fortnightly (Apr. 2010), *available at* http://www.fortnightly.com/fortnightly/2010/04/lessons-lodi, attached

[74] *See* Exhibit 19, *Siemens takes the early lead in the sale of packaged fast-start plants for the US market*, CCJ Onsite-Combined Cycle Journal (Oct. 21, 2012), *available at* http://www.ccj-online.com/siemens-takes-the-early-lead-in-the-sale-of-packaged-fast-start-plants-for-the-us-market-ge-rounds-out-the-activity-a-distant-second/,

[75] *See* Exhibit 20, Press Release, *Siemens receives order for EPC contract for power plant in the United States* (Apr. 04, 2013), *available at* http://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2013/energy/fossil-power-generation/efp201304026.htm.

[76] *See* Exhibit 21, Press Release, *Panda Power Funds Secures Financing for Expansion of Temple, Texas Power Plant* (Apr. 04, 2013), *available at* http://newsroom.pandafunds.com/press-release/panda-power-funds-secures-financing-expansion-temple-texas-power-plant

[77] *See* Exhibit 22, Press Release, *GE Launches Breakthrough Power Generation Portfolio with Record Efficiency and Flexibility with Natural Gas; Announces Nearly $1.2 Billion in New Orders* (Sept. 26, 2012), *available at* http://www.businesswire.com/news/home/20120926005952/en/GE-Launches-Breakthrough-Power-Generation-Portfolio-Record#.VSb92_nF8zs

[78] *See* Exhibit 23, Balling, *Fast cycling and rapid start-up: new generation of plants achieves impressive results*, Modern Power Systems (Jan. 11), at 7, *available at* http://www.energy.siemens.com/hq/pool/hq/power-generation/power-plants/gas-fired-power-plants/combined-cycle-powerplants/Fast_cycling_and_rapid_start-up_US.pdf,

[79] *See id.* at 2.

confirm that load-following units are capable of meeting an emission standard that is much more stringent than the 1,000 and 1,100 lb/MWh standards that EPA has proposed.

These examples demonstrate that the feasibility of fast-start and quick-ramping combined-cycle turbines has advanced substantially. It is factually inaccurate to claim that combined-cycle units are incapable of meeting the technical function of a load-following unit. Advances in HRSG technology have allowed for faster response times with reduced or even eliminated thermal penalties. In short, CTs are unnecessary—and unnecessarily dirty—options for intermediate and load-following services. There is simply no technological basis to reject combined-cycle units for the five new Ocotillo gas turbines.

3. Other Utility Operators of Peaking Units Recognize the Ability of Combined-Cycle Units to Serve as Peaking Units.

While neither the County nor APS evaluated potential natural gas fired alternatives to the GE LMS100, it turns out that another permit applicant has done so, for a facility located in the South Coast Air Quality Management District (SCAMD). The County's BACT/RACT guidance memorandum, "Requirements, Procedures and Guidance in Selecting BACT and RACT,[80] specifically notes the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVAPCD, or the BAAQMD, as BACT, forgoing the need for a top-down analysis. (TSD, p. 29.) The BACT analysis for Huntington Beach Energy Plant (HBEP) below was accepted by the SCAQMD and thus should be accepted as BACT for Ocotillo by the County. The applicant for that facility concluded that the GHG BACT limit should be 1,082 lb CO_2/MWh (gross).[81]

The following is an excerpt from the GHG BACT analysis prepared by CH2MHill for the Huntington Beach Energy Plant (HBEP) peaking project which utilizes[82] a fast response Mitsubishi 3 x 1 501 D CCGT unit:

> The HBEP's design objectives are to be able to operate over a wide MW production range with an overall high thermal efficiency, in order to respond to the fast changing load demands and changes necessitated by renewable energy generation swings. This rapid response is accomplished by utilizing fast start/stop and ramping capability and the use of the duct burners to bridge the MW production when additional combustion turbines are started (as opposed to the duct burner's traditional roll of providing peaking power during periods of high electrical demand). At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for

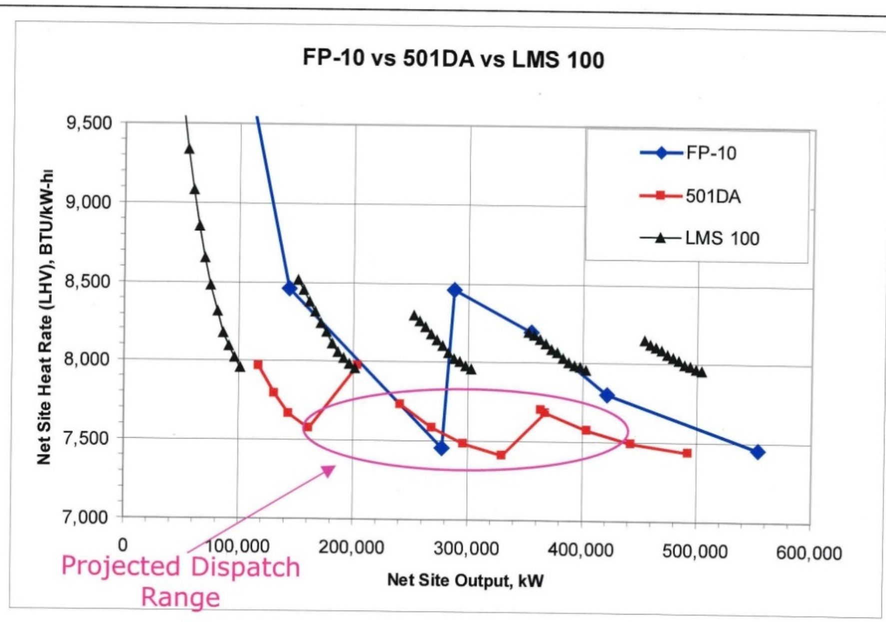
[80] Maricopa County Air Quality Management District, Requirements, Procedures and Guidance in Selecting BACT and RACT , July 2010, http://www.maricopa.gov/aq/divisions/permit_engineering/docs/pdf/BACT%20Guidance.pdf
[81] Available at: http://www.energy.ca.gov/sitingcases/huntington_beach_energy/documents/applicant/AFC/Volume%202%20Appendices/HBEP_Appendix%205.1D_BACT%20Determination.pdf at p.3-25.
[82] The permit applications for the project demonstrate its commercial availability. The project is undergoing California environmental review and commencement of onsite construction is anticipated in 2015.

> decreasing load. At other load points, the load ramp rate is 30 percent. The HBEP start time to 67 percent load of the power island is 10 minutes, and it is projected that the project will operate at an approximate 40 percent annual capacity factor. The HBEP offers the flexibility of fast start and ramping capability of a simple-cycle configuration, as well as the high efficiency associated with a combined cycle. Therefore, comparison of operating efficiency and heat rate of the HBEP should be made with simple cycle or peaking units instead of combined-cycle or more base-loaded units.
>
> *   *   *   *
>
> The HBEP will be dispatched remotely by a centralized control center over an anticipated load range of approximately 160 to 528 MW for each 3-by-1 power island. Over this load range, the HBEP anticipated heat rate is estimated at approximately 7,400 to 8,000 BTU/kWh lower heating value (LHV) (~ 8,140 to 8,800 BTU/kWh HHV). The HBEP will be able to start and provide 67 percent of the power island load in 10 minutes and provide 110 MW/min of upward ramp and 250 MW/min of downward ramp capability. Comparing the thermal efficiency of the HBEP to other recently permitted California projects demonstrates that the HBEP is more thermally efficient than other similar projects that are designed to operate as a peaker unit. Based both on its flexible operating characteristics and favorable energy and thermal efficiencies as compared with other comparable peaking gas turbine projects, the HBEP thermal efficiency is BACT for GHGs.[83]

In the course of its analysis CH2MHill produced an analysis of the heat rate for the 501 DA fast response CCGT proposed compared to the LMS100 units across the anticipated range of outputs. In this analysis it can be seen that as each LMS unit comes on line the system suffers a substantial penalty for part load performance compared to the 501 DA and that across the entire anticipated load range the 501 DA demonstrates a lower (more efficient) heat rate.

---

[83] *BACT Determination for the Huntington Beach Energy Project* http://www.energy.ca.gov/sitingcases/huntington_beach_energy/documents/applicant/AFC/Volume%202%20Appendices/HBEP_Appendix%205.1D_BACT%20Determination.pdf (page 3.24).



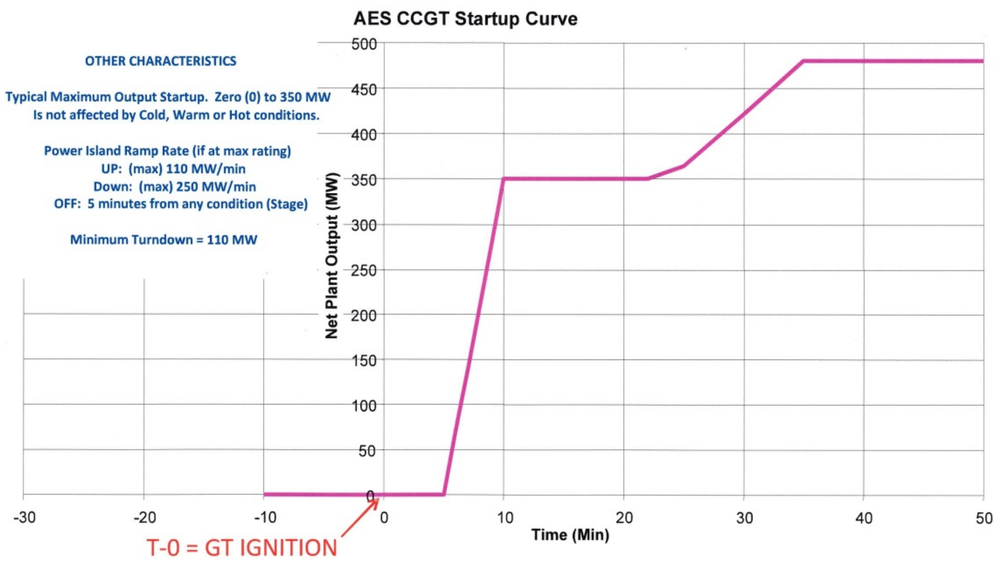
Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 4
Comparison of HBEP and Alternative Design Heat Rates
AES Huntington Beach Energy Project
Huntington Beach, California

IS120911143713SAC_Huntington_AFC

CH2MHILL.

CH2MHill also provided a graphic illustration of the startup and ramp rate of the proposed Mitsubishi fast response unit.



Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 3
HBEP Startup Curve
AES Huntington Beach Energy Project
Huntington Beach, California

IS120911143713SAC_Huntington_AFC

CH2MHILL.

This analysis of the HBEP plant demonstrates that more efficient, lower polluting technology is available for peaking service. The County must consider these data in determining the appropriate BACT limit for the Project. The County cannot simply rely on the Applicant's own assertions and data that its preferred turbine technology constitutes BACT.

4. The LMS100 Can Operate In Combined Cycle Mode

The LMS100 turbine itself can be operated in an approximate combined cycle mode. First, the LMS100 is available as a Steam Injection Cycle (STIG) turbine. This model is known as the "poor man's combined cycle," as it eliminates the steam turbine by taking waste heat from the gas turbine, converting water into steam and then injecting this steam into the gas turbine. This is a steam cycle, similar to combined cycle, without a steam turbine. Thus, it eliminates startup delays that the BACT analysis claims are required to protect the gas turbine. (Ap., Appx. B, p. 39.)

This option results in better full and part-load efficiency and lower GHG and other criteria pollutant emissions than the LMS100 model selected for the Project's turbines and can meet all of the Project's goals. It can generate 112.2 MW with a heat rate of 6,845 BTU/kWh at an efficiency of 50%.[84] See Table 1.

Second, the LMS100 can be used in a classic combined cycle mode.[85] In this mode, it produces 120 MW at 53.8% efficiency. All of the quick start operational flexibility of the LMS100 is available in these combined-cycle configurations, though at a higher cost. These options are technically feasible and must be carried forward into step 3 of the BACT analysis.

C. Step 5 of the GHG Top-Down Analysis Is Flawed

The only "feasible" electric generating option that remained by step 4 was reciprocating internal combustion engines (RICE) and simple cycle turbines. The RICE units were the top ranked technology in terms of GHG emissions. (Ap., Appx. B, Table B6-8.) However, they were eliminated in step 4 based on significant adverse impacts, an alleged factor of five increase in PM_{10} emissions in a severe PM_{10} nonattainment area. (Ap., Appx. B, pp. 45-46.) This left only generic simple cycle gas turbines. Without explaining why the five LMS100 model PA – 60 Hz model turbine selected for the Project is the most efficient simple cycle option (which it is not, as explained elsewhere in these comments), the Applicant included an analysis to select the GHG BACT limit for the specific turbine model it pre-selected.

In step 5, rather than selecting the most efficient simple cycle turbine option based on its own analysis in step 1 -- 1,100 lb CO_2/MWh gross (Ap., Appx. B, Tables B6-4, B6-8) -- APS conducts a different analysis patterned after EPA Region 9's GHG BACT analysis in the Pio Pico case. This new analysis sets the BACT limit at a level achievable during the lowest load, worst-case "normal" operating conditions, asserted to be 25%, to ensure BACT is achieved at all times. See Pio Pico Energy Center, 16 E.A.D.___, 73-82 (2013). The Ocotillo analysis is fundamentally flawed for the reasons discussed below.

1. <u>The County Improperly Based the GHG BACT Limit on 25% Load</u>

The Applicant admits in its application that the LMS100 turbines are capable of achieving much better GHG emission rates than the proposed limit of 1,690 lb CO_2/MWh. In Table B6-9 of the BACT analysis, the Applicant provides a table showing that the LMS100 units can achieve a rate of 1,090 lb CO_2/MWh at 100% load averaged across a temperature average. (Ap., Appx. B, p.48.) However, Applicant and the County justified the GHG BACT limit of 1,690 lb CO_2/MWh based on the Applicant's assertion that it needed to be able to operate the facility at 25% of the maximum load. The 1,690 lb CO_2/MWh limit was calculated as the average over the ambient dry bulb temperature operating range of 20 F to 120 F. The 25% load point was characterized as "the lowest load, 'worst-case' normal operating conditions." (Ap., Appx. B, p. 49 & Table B6-9.) This assumption is completely inappropriate because there is no support in the record that

---

[84] See: Advanced Gas Turbine Power Cycles, pdf 28 at http://www.britishflame.org.uk/calendar/New2008/CH.pdf and Gas Turbine Technology, pdf 18 at http://www.ae.metu.edu.tr/seminar/2008/sanzlecture/sanz-day2.pdf; GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, 2003, Available at: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/atechspecs.pdf and GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS1000, June 2004, Available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

[85] Exhibit 24, Reale, Michael J., LMS100 Platform Manager, General Electric Company, *New High Efficiency Simple Cycle Gas Turbine – GE LMS100*. http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf, June 2004., *GE Spec for LMS100.*

operating at 25% load is necessary. Further, as discussed above, there are several technology alternatives that could eliminate the need to operate at such low loads for any significant period of time.

The Application asserted that "…these GTs will be designed to meet the proposed air emission limits at steady state loads as low as 25% of the maximum output capability of the turbines." (Ap., p. 2); "…the Ocotillo GTs must operate over a wide range of loads from 25% to 100% of the rated turbine capacity.." (Ap., p. 15); "These GTs will be designed to meet air emission limits at steady state loads as low as 25% of the maximum output capability of the turbines." (Ap., p. 33, *et. seq.)* The County accepts this argument, without any independent analysis, parroting that "[t]he new units need the ability to start quickly, change load quickly, and idle at low speed…To achieve these requirements, these GTs will be designed to meet the proposed air emission limits at steady state loads as low as 25% of the maximum output capability of the turbines". (TSD, pp. 4, 30.)

The assumption made by both the Applicant and the County that the GHG BACT limit must be set at the "worst case" scenario to allow the Ocotillo plant to operate at 25% load is improper. As discussed elsewhere, operation at 25% of the LMS100 design load, or about 25 MW, could be achieved by either using hybrid battery or other storage options, or smaller gas turbines, (e.g. 25-MW gas turbines) operated more efficiently at 100% load. This type of configuration or operational parameters would eliminate the need to operate the LMS100 units at 25% loads for any extended periods of time. For this reason alone, the County should not base the GHG BACT limit on the assumption that Ocotillo will need to operate year-round on 25% load.

Furthermore, the Applicant's own documents contradict its claims that the Ocotillo plant is even capable of operating at 25% load for an extended period of time. In another section of the Application, the Applicant asserts that the plant <u>cannot</u> operate at 25% load: "[i]t is important to note that neither DLN combustors nor water injection can operate at loads below approximately 50% of the maximum rated load. Because these are peaking GTs, these units will not be operated at loads below 50% of rated load, except during periods of startup and shutdown." (Ap., Appx. B, p. 25.) Thus, the County improperly set the GHG BACT limit at an instantaneous point through which the turbines pass during startup and shutdown, rather than a normal operating load.

Water injection is used on the Ocotillo LSM100 gas turbines to control NOx during startup before the SCR catalyst comes on line. (Ap., p. 19.) Water injection cannot operate at loads below 50% as it adversely impacts flame stability and combustion dynamics, increasing CO emissions to unacceptable levels. (Ap., Appx. B, p. 51; Ap. p. 19.) Thus, the proposed 25% load basis for setting the GHG BACT limit would occur at an operating point at which the NOx startup limits would be exceeded, i.e., before water injection can be used. Further, if water injection were used below 50% load, contrary to good operating practice, the CO startup limit also would be exceeded. Further, operating at less than 50% load would violate "good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction", in violation of Permit Condition 20. (Draft Permit, p. 19.) Thus, normal operation at 25% load is a misnomer and would not occur. Further, it can be eliminated based on adverse collateral impacts.

The Applicant and the County attempt to justify the GHG BACT limit by extrapolating the methodology applied by EPA Region 9 to its permitting of the Pio Pico facility. Notably, the Region set the Pio Pico GHG limit at 1,328 lb CO_2/MWh based on the "worst-case" assumption that Pio Pico would require operation at 50% load. The limit for Pio Pico is also calculated on a rolling average during 720 operating hours.

The Pio Pico process, developed by Region 9, and upheld by the EAB, is "set at a level achievable during the 'worst-case' of normal operating conditions" within the averaging period. *Pio Pico Energy Center*, 16 E.A.D.___, 77-78 (2013). The EAB deferred to the Region's decision to "set a limit **somewhat lower** than optimal efficiency to ensure continued compliance." *Id.* at 82. The EAB therefore declined to overturn the Region's decision to allow a "somewhat lower" emissions rate so that the Pio Pico facility could ensure that it would continually meet its BACT limit during the 720 hour averaging period.

With the Ocotillo Draft Permit, the County and the Applicant extrapolate the Region's reasoning with regard to Pio Pico to an illogical extreme. Rather than setting a BACT limit based on 50% load, which would have resulted in a limit of 1,300 lb CO_2/MWh, the Applicant asserts without support that it must operate at 25% load. However, operating at 25% load point is not part of "normal operation." To the contrary, as noted above, 25% load operation is only part of startup and shutdown; a load point through which the turbines pass reaching and descending from normal operation. If Ocotillo actually operated below 50% load for any significant period of time during its 12-month averaging period, it would not be capable of operating the water injection, and therefore it would exceed its permitted limits for CO.[86] It is therefore not the case with Ocotillo that a limit of 1,690 lb CO_2/MWh is necessary to meet a level "achievable during the 'worst-case' of normal operating conditions." The operating assumption of 25% load is "worse than worst-case;" it is impossible given other permit limitations at Ocotillo.

It is similarly not the case that the proposed operating limit for Ocotillo is "somewhat lower" than the optimal efficiency. In *Pio Pico Energy Center*, the EAB noted that the GHG limit for Pio Pico at 50% load was 18% lower than optimal efficiency at 100% load. 16 E.A.D.___ at 81. In contrast, the proposed limit at Ocotillo is 36% lower than "optimal efficiency."[87] This deterioration of the permitted GHG limit is twice as severe as the case with Pio Pico. Sierra Club is not suggesting that EAB was attempting to set a bright-line definition of "somewhat lower" at 18%; however, the County's assumption that a two-fold drop in efficiency compared to optimal operation is within the contemplation of the Pio Pico decision strains the presumed tolerance of EAB's deference to permitting authorities.

2. GHG BACT Limit Based On Improper Averaging Time

The Ocotillo Draft Permit is also distinguishable from the Pio Pico limit based on the averaging period used by the permitting authority. For Pio Pico, Region 9 used a shorter averaging period of 720 operating hours; therefore, it was more plausible that the units could conceivably operate at low loads for a long enough portion of the 720-hour averaging period to impact the unit's ability to meet an average GHG limit based on higher efficiency. However, in

---

[86] The start of normal operation for a water-injected, LMS100 gas turbine, is 50% load. Thus, otherwise using APS's analysis, the 50% load GHG limit would be 1,300 lb CO_2/MWh. (Ap., Appx. B, Table B6-9.)
[87] [1,090 @ 100%] / [1,690 @ 50%] = 0.64. *See* Ap., Appx. B at p.48.

the case of the Ocotillo Draft Permit, the County proposed a 12-month rolling average. This longer averaging period would allow any spikes in GHG emission to be smoothed out over the year, which would avoid the concern noted by EAB in Pio Pico that a permitting agency should be allowed to set an emission limit that ensures "continued compliance" over the averaging period.

In reviewing the Pio Pico permit, the EAB has confirmed that the permitting authority had the discretion to set a BACT limit that ensured continued compliance during the averaging period. This raises the question of the proper averaging time to use in setting such a limit. EPA had, in that case, justified setting a less stringent BACT limit on the grounds that "EPA must ensure BACT is achieved **at all times**." *Pio Pico Energy Center*, 16 E.A.D.___ at 77. "At all times" means exactly that: essentially instantaneously, every second and minute and hour of the day. Thus, a GHG BACT limit based on the "at-all-times" rationale should be based on a short-term average. In the Pio Pico case, the GHG BACT limit of 1,328 lb/MWh gross output was based on a 720 rolling operating-hour limit.[88]

However, the Applicant chose, and the County accepted without any further inquiry, a 12-month rolling average. (Ap., Appx. B, p. 49; Draft Permit, p. 17, Table 4.) A 12-month rolling average is not consistent with the "at all times" rationale because it allows very high, non-BACT spikes to be averaged out. This long averaging time means that even when operating at 25% load, the plant could emit at rates far greater than 1,690 lb CO_2/MWh for long periods of time because those periods would be averaged out with many more hours at higher load, when GHG emissions are lower. If the County insists on such a long averaging time, then it should set the GHG BACT limit at a level that recognizes that any aberrant spikes in GHG emission will be smoothed out over the year.

In other words, the Applicant cannot have it both ways. The County must either (i) set a strict BACT limit near the optimal efficiency of the plant and allow a long averaging period, or (ii) set a weak BACT limit and require a short averaging period to avoid spikes in emissions. The Ocotillo permit takes the weakest aspects of both options: it sets a weak BACT limit and allows averaging over a 12-month period. As a result, the Draft Permit is essentially meaningless as a control on GHG emission rates.

For example, the emission calculations assume there will be 730 startups and shutdowns per turbine per year. The 25% load point occurs during these periods. Conservatively assuming the turbines sit at the 25% load point for 5 minutes during each startup and 1 minute during each shutdown, each turbine will operate at 25% load for up to 73 hr/yr.[89] As the proposed GHG limit is based on a 12-month rolling average, a special type of annual average, if a turbine operated at 100% load during the balance of the hours (8760-73=8687), meeting the 100% GHG emission level of 1,090 lb/MWh (Ap., Appx. B, Table B6-9), the GHG emissions during the 25% load portion of the year could be as high as 73,022 lb/MWh,[90] a gross violation of GHG BACT. Thus, to avoid this type of egregious violation of the GHG BACT limit, any limit set to be met "at all times" must be based on a very short averaging time, no more than one hour. Further, to assure

[88] PSD Permit No: SD 11-01, Pio Pico Energy Center, LLC, February 28, 2014, p.7, Condition B.1

[89] The number of hours at 25% load: [730x5+730x1]/60=73 hrs.

[90] (73/8760)x + (8687/8760)(1090) = 1690. Thus, x = (1690 – 1081)/0.00834 = **73,022 lb/MWh**.

that BACT for GHG is met at other loads, an annual emissions cap should be established based on the anticipated operating mode of the plant.

GHG emissions endanger public health and welfare over the long-term by driving climate change. However, Sierra Club recognizes that, unlike criteria pollutants such as SO2, PM, NOx or ozone, GHGs do not pose direct human health risks when emitted in short spikes (although high concentrations of methane can stimulate the development of ozone).[91] Therefore, Sierra Club does not oppose a permit term that permits a source to average its non-methane GHG emissions over a 12-month period. However, such a long averaging period is only acceptable if it is paired with a strict GHG limit that is at or near the plant's optimal efficiency.

3. The BACT Limit Improperly Excludes Startup/Shutdown GHG

The Draft Permit improperly exempts periods of startup and shutdown. BACT applies continuously during all operating conditions. *In re RockGen Energy Ctr*., 8 E.A.D. 536, 553-55 (EAB 1999) (holding that PSD permits may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown); *In re Tallmadge Energy Center*, Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12 (EAB May 21, 2003)("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown"). Thus, Ocotillo's GHG limit must apply during periods of startup and shutdown. The proposed Ocotillo Permit explicitly excludes periods of startup and shutdown from the GHG BACT limit of 1,690 lbs CO_2/MWh. (Draft Permit, p. 17, Table 4.)

The Draft Permit also does not include separate BACT or any separate limits for GHG emissions during the exempted periods of startup and shutdown, while separate limits are set for NOx and CO. (Draft Permit, Tables 2 & 34.) Thus, GHG emissions from the periods when they would be highest are virtually unlimited and would not even be included in averaging the emissions to determine compliance with the 12-month rolling average GHG BACT limit. This is contrary to BACT. The permit must be revised to require that GHG emissions during startup and shutdown be included in the 12-month averaging period.

The Draft Permit also improperly incorporates an affirmative defense provision that purports to limit civil penalties for violating an emissions limit under certain conditions. The DC Circuit invalidated this type of provision in *Natural Res. Def. Council v. E.P.A.*, 749 F.3d 1055, 1063 (D.C. Cir. 2014). The Court held that Clean Air Act Section 304(a) clearly vests authority over private suits in the *courts*, and an administrative body does not have the authority to strip away any potential civil penalties.

4. Setting the GHG Limit Based on Worst Case Conditions Conflicts with the Definition of BACT

The EAB concluded in the Pio Pico case that a BACT limit must be achieved "at all times," to allow permittees to achieve compliance on a consistent basis. However, this does not excuse the permitting agency from complying with the statutory definition of BACT and the applicant from designing its project to meet BACT.

[91] Spikes in GHG emissions are, however, often linked to spikes in other harmful local pollutants. Therefore, permitting limits and averaging times for those harmful pollutants should be set at levels and with averaging times sufficient to protect public health.

BACT is an emissions limit based on the maximum degree of reduction achievable through, among other options, cleaner production processes. 42 U.S.C. § 7479(3) ("best available control technology" means an emissions limitation based on the maximum degree of reduction of each pollutant… achievable for such facility through application of production processes"); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition of BACT). "BACT emission limits or conditions must be met on a continual basis at all levels operation…" NSR Manual, p. B.56. The proposed BACT limit in the Draft Permit is inconsistent with this definition and legally flawed.

The worst-case "normal" operating conditions at Ocotillo do not correspond to the maximum degree of reduction achievable and are not based on cleaner production processes. The Draft Permit's weak limit therefore ensures that the source is not subject to BACT-level emission limits during most operating hours. Specifically, the CO_2 BACT limit in the final permit is based on the high heat rate and low efficiency that occur when the combustion turbines operate at 25% load. This point represents the minimum degree of reduction achievable over the normal operating range, providing a BACT off-ramp. Although the plant will operate at rates above 25% load during many, if not most, of its operating hours, the final permit establishes a BACT-level emission rate for only those hours when the unit operates at 25% load.

The dilemma that led the County to set the BACT limit at a low load, corresponding to the minimum degree of reduction, is created by the "load penalty" experienced by aeroderivative turbines such as the LMS100. This issue should have been, but was not, considered in the GHG BACT analysis. These turbines suffer a greater reduction in power and efficiency at high temperatures and part load operation than frame-based or RICE units.[92] There are three solutions to this problem, which should have been evaluated in the BACT analysis and selected as BACT.

First, the County could set the limit based on a combined cycle configuration. Performance data included in the Ocotillo BACT analysis indicates that at 20 F, the heat rate (LHV) declines from 7,815 BTU/kWh at 100% load, to 9,305 BTU/kWh at 50% load, and to 12,053 BTU/kWh at 25% load. (Ap., Appx. B, Table B6-7, p. 44.) In contrast, the Alstom KA 24 combined cycle turbine has a full load efficiency of approximately 59% and its heat rate is 5,783 BTU/kWh. It maintains that heat rate to below 80% load and at 50% load its heat rate is less than 6,130 BTU/kWh.[93] At full load, the Alstom KA 24 enjoys a heat rate advantage of 2,032 BTU/kWh (7,815-5,783 = 2,032) compared to the LMS100. At 50% load, the Alstom advantage rises to over 3,175 BTU/kWh (9,305-6,130=3,175).[94]

Thus, by using combined cycle units that were improperly eliminated in step 2, the load dilemma, providing the BACT off-ramp, could be resolved. The Alstom KA 24 turbine, in this example, satisfies the BACT definition of the maximum degree of reduction achievable through, among other options, cleaner production processes, as it maintains a high efficiency at low loads. Thus, even assuming arguendo that the "at all times" test applies, the BACT limit would be a lot

---

[92] *See, generally,* 2013 GTW Handbook.

[93] http://www.energiaadebate.com/alstom/Turbina%20de%20Gas%20GT24/GT24%20-%20Technical%20Paper.pdf See also, Alstom's discussion of its low load operation and fast response options and its ability to support the spinning reserve market.

[94] GHG emissions are proportional to the heat rate. The Alstom 24/26 series of turbines have been installed in a number of facilities worldwide, including at the Lake Road, CT generating station (2002). Exhibit 25, Alstom Gas Turbine Brochure, Available at: http://www.alstom.com/Global/Power/Resources/Documents/Brochures/gt24-and-gt26-gas-turbines.pdf

lower if it were established based on this (or other similar) combined cycle turbines because they do not experience the same increase in heat rate (and thus emissions) as loads decline.

Second, as discussed at length above, energy storage coupled with fewer LMS100 turbines could eliminate or reduce the need for low load operation and ramping requirements, thereby improving the efficiency of the LMS100 units by avoiding low load operation.

Third, the Project goals could be met with a different mix of simple cycle gas turbines, sized to provide power at different output levels. For example, if APS anticipated extended operation at 25 MW (or 25% load on a single LMS100), rather than operating one of its 100 MW turbines at 25% load, where GHG emissions are very high, it could employ one or more 25+ MW simple cycle turbine(s) operated at 100% load. These would include: the SwiftPac 25 (25.5 MW 8960 BTU/kWh); the PGT25+ (30.2MW, 8610 BTU/kWh); and the LM2500 PR (30.5 MW, 8854 BTU/kWh). Including a mix of these and many other smaller turbines[95] with the proposed LMS100 turbines would allow Ocotillo to avoid the heat rate penalty.

5. The County's Proposed GHG BACT Limit is Worse than Any Other Similar Facility in the Country

If nothing else, the County failed to consider the degree of GHG emission reductions that are achievable by other similarly configured facilities. Ocotillo's proposed GHG emission rate of 1,690 lb CO_2/MWh (gross) based on a 12-month rolling average would be, to Sierra Club's knowledge, the worst GHG emission rate for any permitted simple-cycle natural gas facility in the United States. The Applicant's own analysis included a table of recent GHG BACT limits for natural gas-fired simple-cycle turbines. (Ap. Appx. B, Table B6-4, p.35.) All of the facilities identified by the Applicant with rate-based limits had lower GHG emission limits than the proposed Ocotillo facility. The following is a list of the facilities with lb/MWh emission limits provided by the Applicant, as well as additional permitted natural gas-fired simple-cycle facilities that the Applicant did not include in its list:

[95] Gas Turbine World 2013 GTW Handbook, vol. 30, vol. 30, p. 43.

Table 4

Facility	State	Permit Date	Limit	Units	Averaging Period
El Paso Electric Montana Power Station (LMS100)	TX	Mar-14	1,100	lb CO2/MWhr (g)	5,000 op. hours
Cheyenne Light, Fuel & Power	WY	Sep-12	1,600	lb CO2e/MWhr (g)	365 day
Pio Pico Energy Center (LMS100)	CA	Nov-12	1,328	lb CO2/MWhr (g)	720 op. hours
York Plant Holding, LLC Springettsbury	PA	2012	1,330	lb CO2e/MWhr (n)	30-day
LADWP Scattergood Generating Station	CA	2013	1,260	lb CO2e/MWhr (n)	12-month
Puget Sound Energy Fredonia GS (LMS100)[96]	WA	Oct-2013	1,138	lb CO2e/MWh (n)	365 day
Shady Hills Generating Station[97]	FL	Jan-14	1,377	lb CO2e/MWh	12-month
Polk Power Station[98]	FL	Dec-2013	1,320	lb CO2e/MWh (g)	3-hour

This chart demonstrates that the typical range of GHG emission limits for recently permitted natural-gas simple-cycle facilities is 1,100 – 1,370 lb CO_2e/MWh. Many of these permitted limits are for facilities that propose to use LMS100 turbines, the same turbine design as the proposed Ocotillo project.

The only permit limit identified by the Applicant that even comes close to such a high limit is the 2012 GHG PSD permit issued to Cheyenne Light, Fuel and Power by Region 8 for the Cheyenne Prairie Generating Station. For that permit, EPA Region 8 set a limit of 1,600 lb CO_2e/MWh for three GE LM6000 PS Sprint turbines. This limit is distinguishable from the Ocotillo project in several ways and should not be used as a basis to justify the <u>even higher</u> proposed rate of 1,690 lb CO_2/MWh for the Ocotillo plant.

First, the Cheyenne Prairie PSD permit was the earliest GHG PSD permit for a simple cycle turbine. In setting its permit limit, Region 8 did not have the benefits of reviewing several other permitting decisions determining that much lower GHG emission rate are achievable.

Second, the permitted facility in Cheyenne proposed to install three GE LM6000 PF Sprint turbines.[99] (The applicant later amended the proposed project in its state siting application to include only one 37 MW simple-cycle turbine.)[100] The single 37 MW GE LM6000 PF Sprint turbine is smaller and less efficient than the LMS100 turbines proposed for the Ocotillo plant.

---

96 http://www.ecy.wa.gov/programs/air/psd/PSD_PDFS/PSE_Fredonia_PSD-11-05_Permit_10212013.pdf

97 http://www.epa.gov/region4/air/permits/ghgpermits/shadyhills/ShadyHillsSignedFinalPermit_011514_reviseddate.pdf

98 http://www.epa.gov/region4/air/permits/ghgpermits/tecopolkpower/TECO_FinalPermit_12-18-2013.pdf

99 See Cheyenne Prairie Generating Station Final GHG PSD Permit. http://www2.epa.gov/sites/production/files/documents/cheyennelightpermit_0.pdf

100 Wyoming Section 109 Permit Application, Cheyenne Prairie Generating Station, April 2012, at p.2-5, available at: http://deq.wyoming.gov/isd/application-permits/resources/cheyenne-prairie-generating-station/

After adjusting for site-specific influences, Region 8 determined that the Cheyenne Prairie CTs could reach an efficiency of only 36.8% in simple cycle mode.[101] In contrast, the Applicant's own documents rate the LMS100 at 43% efficiency. (Ap., p.14.)

Third, Region 8 included a dual limit of emission rate and total tons-per-year. The simple-cycle turbine at the Cheyenne facility is allowed to emit only 187,318 tons of CO_2e per year. In contrast, the Ocotillo permit set an annual GHG emission limit of 1,100,640 tons-per-year based on the Applicant's assertion that each LMS100 turbine had the potential to emit up to 497,498 tons-per-year. (Ap. Appx. B at p.34.) The lower annual limit at the Cheyenne facility would serve as a backstop to excessive emissions permissible from the high lb/MWh rate. Overall, the Cheyenne Prairie Generating Station permit is for a much smaller project using a less efficient turbine. The other projects identified in the table above, particularly those using LMS100 turbines, provide much better examples.

Even if the Cheyenne project were comparable, which it is not, BACT does not allow the permitting authority to scour the permitting record to find the furthest outlier to justify a weak limit.[102] To the contrary, BACT requires the County to set the GHG emission limit "based on the maximum degree of reduction of each pollutant… achievable for such facility…" 42 U.S.C. § 7479(3). The existing BACT limits set for other facilities comparable to the Ocotillo facility does not provide a sufficient basis for the County to conclude that the proposed GHG limit of 1,690 lb CO_2/MWh "reflects the maximum degree of reduction achievable."[103] The County's justification for such a poor GHG limit is particularly disconcerting given the 12-month averaging period for the GHG limit. Even if the facility is required to run from time to time at low loads, the overall GHG emissions of the facility over time would smooth out any GHG emission spikes over the 12-month period. As demonstrated by the permit limits above, as well as the Applicant's own documents showing the LMS100 units can meet an emission rate of 1,090 lb CO_2/MWh,[104] the County must at a minimum revise its GHG BACT limit to at least 1,090 lb CO_2/MWh.

Furthermore, the County must revise its entire top-down BACT analysis to include the options discussed in these comments and to assure that BACT is required for GHG emissions. Such an analysis must include consideration of combined cycle turbines, energy storage, operation using a mix of turbine sizes and operation using a mix turbine sizes combined with storage.

II. THE DRAFT PERMIT IS LESS STRINGENT THAN THE PROPOSED GHG NSPS FOR NEW ELECTRIC GENERATING UNITS.

On September 20, 2013, EPA issued a signed notice of its Proposed Rule for *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495 (GHG NSPS). The GHG NSPS will apply to any

---

[101] Statement of Basis, Greenhouse Gas Prevention of Significant Deterioration Pre-Construction Permit for the Black Hills Corporation/Cheyenne Light Fuel & Power, Cheyenne Prairie Generating Station Permit Number: PSD-WY-000001-2011.001 May 21, 2012, p.14.
[102] NSR Manual, p.B.24 ("The evaluation of an alternative control level can also be considered where the applicant can demonstrate to the satisfaction of the permit agency that other considerations show the need to evaluate the control technology at a lower level of effectiveness").
[103] NSR Manual, p.B.2.
[104] Ap., Appx. B, Table B6-9, p.48.

new electric generating unit that "actually supplies more than one-third of its potential electric output to the grid."[105] For those EGUs that supply more than one-third of their potential electric output to the grid, EPA determined that the "best system of emission reduction" is natural gas combined-cycle (NGCC) technology because it is technically feasible, relatively inexpensive, its emission profile is acceptably low, and it would not adversely affect the structure of the electric power sector.[106] The proposed standard for stationary combustion turbines between 73 MW and 250 MW is 1,100 lb CO_2/MWh (gross).

Section 111(a)(2) of the Clean Air Act defines a "new source" as any stationary source that commences construction or modification after publication of proposed new standards of performance under section 111 that will be applicable to the source. 42 U.S.C. § 7411(a)(2). Under this definition, any new fossil fuel-fired EGU greater than 25 MW that commences construction after September 20, 2013 is a "new source" and will be subject to the CO_2 standard that EPA ultimately promulgates when the source begins operating. *United States v. City of Painesville*, 644 F.2d 1186, 1191 (6th Cir. 1981) (CAA §111(a)(2) "plainly provides that new sources are those whose construction is commenced after the publication of the particular standards of performance in question."). The statute uses the date a standard is proposed to define which sources are subject to the standard. The Ocotillo Project would therefore be considered a "new source" subject to the NSPS because it had not commenced construction of the new turbines prior to September 20, 2013.

The Ocotillo Power Plant would consist of five new 102 MW simple-cycle turbines with a permissible operating limit of more than 4,000 hours on a 12-month rolling basis per turbine. This means that the GHG NSPS, if finalized, would apply to the Ocotillo Power Plant. It also means that the County's proposed BACT limit of 1,690 lb CO_2/MWh (gross) is **higher** than the limit of 1,100 lb CO_2/MWh in the proposed GHG NSPS. This difference fundamentally contradicts the purpose of BACT. The Clean Air Act expressly provides: "In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section [111 or 112 of the Clean Air Act]."[107]

The County acknowledged the proposed NSPS standard in the TSD, but it dismissed the issue because the rule is not final. (TSD at p.18.). Sierra Club agrees that the NSPS would not apply to Ocotillo unless and until the rule is finalized. However, the County must at least consider the level of GHG emissions contemplated by the proposed rule. Ocotillo's proposed GHG limit of 1,690 lb CO_2/MWh is more than 50% greater than the proposed limit of 1,100 lb CO_2/MWh. Clearly the drafters of the proposed rule considered lower emission rates for comparably sized natural gas units achievable. The County must at a minimum take that information into consideration as it sets the BACT limit for the Ocotillo permit.

[105] *Id.* at p.82.
[106] *Id.* at p.287.
[107] Clean Air Act § 169(3), 42 USC § 7479(3).

III. The Permit Does Not Require a Proper BACT Limit For NOx Emissions From The Gas Turbines

The TSD concluded (erroneously) that the Project is not a major modification for NOx emissions and thus is not subject to BACT under the PSD program. However, Maricopa County Rule 241 requires BACT at any new stationary source that emits more than 150 lb/day or 25 ton/yr of NOx. The new gas turbines would emit 688 lb/day or 125.5 ton/yr of NOx. (TSD, Table 15) Thus, the new gas turbines are subject to NOx BACT under Rule 241, Section 301.1. Further, as discussed in Section 7, below, the net increase in NOx emissions triggers non-attainment new source review (NNSR). Thus, federal Lowest Achievable Emission Rate (LAER) is required for NOx.

Maricopa County guidance allows sources that select control technology for the same or a similar source category accepted by air quality management districts in California to opt out of the top-down BACT analysis process required under federal PSD regulations.[108] The Applicant opted out and relied on California BACT determinations. (Ap., Appx. B, Chapter 3, p.16.) Thus, the Application does not contain a top-down BACT analysis for NOx.

The applicant tabulated 19 "recent" BACT NOx limits (2001 – Sept. 2013) for simple-cycle, natural gas fired turbines, which show NOx BACT limits ranging from 2.5 ppm to 5.0 ppm at 15% O2, based on 1-hour to 3-hour averages. (Ap., Appx. B, Table B3-1.) Based on this summary, the Applicant concluded that BACT for NOx is use of water injection in combination with SCR, designed to achieve an emission limit not to exceed 2.5 ppmdv at 15% O2, based on a 3-hour average. (Ap, Appx. B, p. 3.) The County apparently disagreed, and it set the final NOx limit in the proposed Permit at 2.5 ppmdv at 15% O2 based on a 1-hour average. (Draft Permit, p.17, Table 4.) This analysis is fundamentally flawed. As explained below, NOx BACT for these gas turbines is dry low NOx combusters and SCR, designed to achieve a NOx emission limit not to exceed 2.0 ppmdv at 15% O2, based on a 1-hour average.

First, the applicant limited its selection of "similar" facilities to simple cycle gas turbines, excluding all combined-cycle gas turbines because they "cannot be used for the quick start requirements of the Ocotillo Modernization Project." (Ap., Appx. B, p. 17.) This is clear error, as explained in Section I.B.2. Combined cycle turbines can meet all of the Project specifications. Thus, NOx BACT permit limits for combined cycle plants should have been included in the Ocotillo BACT analysis.

Second, the most common reason used to justify a higher NOx emission limit for simple cycle turbines is elevated exhaust gas temperatures compared to combined cycle plants, where heat is recovered to produce steam in the heat recovery steam generator (HSRG). There is some basis for this on standard simple cycle units that have an exhaust gas temperature of at least 800 ^{o}F, and over 1,000 ^{o}F on some models.[109] Special high temperature SCR catalyst formulations may be necessary for these relatively high exhaust gas temperatures.

[108] Maricopa County Air Quality Management District, Requirements, Procedures and Guidance in Selecting BACT and RACT , July 2010, http://www.maricopa.gov/aq/divisions/permit_engineering/docs/pdf/BACT%20Guidance.pdf

[109] Environmental Administrative Decisions: September 1998 to February 2000, p. 18;
J. T. Langaker, S. Voss, and R. Johnson, Take the Heat: Nitrogen Oxide (NOx) Removal in High Exhaust Gas Temperatures, Burns & McDonnell TechBriefs, no. 4, 2003,

However, the LMS100 turbines are not standard simple cycle turbines. The use of an intercooler on the LMS100 turbines results in significantly lower exhaust gas temperatures than typically encountered on simple cycle gas turbines. The exhaust gas temperature of the LMS100 PA model, the water-injected model specified for Ocotillo, is 760 ^{o}F.[110] The relatively low exhaust gas temperature of this turbine means that a standard SCR, similar to those routinely used on combined cycle units and limited to 2.0 ppm NO_x, can also be utilized on the LMS100 without any reduction in performance, regardless of the simple cycle v. combined cycle issue. Thus, the Applicant should have considered NOx limits for combined cycle gas turbines, regardless of whether it meets all Project specifications.

Third, many gas turbines, including simple cycle gas turbines, have been permitted and are operating with a NOx emission limit of 2.0 ppmvd at 15% O2, based on a 1-hour average. These include the following:

Table 5

Tracy Substation Expansion Project	NV-0035	2.0 ppm (3-hour)
Langley Gulch Power Plant	ID-0018	2.0 ppm (3-hour)
Palomar Escondido – SDG&E	2001-AFC-24	2.0 ppm (1-hour); 2.0 ppm (3-hour) with duct burners or transient hour of +25 MW
Warren County Facility	VA-0308	2.0 ppm with or without duct burners
Ivanpah Energy Center, L.P.	NV-0038	2.0 ppm (1-hour) without duct burners; 13.96 lb/hr with duct burners
Gila Bend Power Generating Station	AZ-0038	2.0 ppm (1-hour)
Duke Energy Arlington Valley	AZ-0043	2.0 ppm (1-hour)
Colusa II Generation Station	2006-AFC-9	2.0 ppm (1-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm (1-hour)
CPV Warren	VA-0291	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm/1.5 ppm
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	2.0 ppm (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm (1-hour)

This table includes many gas turbines permitted in California, specifically within air districts that the County's BACT guidance indicates can be relied on for establishing BACT. This information indicates that BACT for NOx emissions from the Ocotillo gas turbines should require a NOx emission limit of 2.0 ppmvd at 15% O2, based on a 1-hr average.

---

http://www.burnsmcd.com/Resource_/Article/5668/PdfFile/article-takingtheheat-034.pdf; I. Morita and others, Latest NOx Removal Technology for Simple Cycle Power Plants, Power-Gen International, 2002, http://www.burnsmcd.com/Resource_/Article/5668/PdfFile/article-takingtheheat-034.pdf
[110] Gas Turbine World, *2012 Performance Specs – 28th Edition*, January – February 2012, Volume 42, No. 1, p. 12.

IV. THE PERMIT DOES NOT REQUIRE BACT FOR PM/PM2.5 EMISSIONS FROM THE GAS TURBINES

The net increase in PM (55.4 ton/yr) and $PM_{2.5}$ (51.3 ton/yr) from the Project exceeds the respective PSD significance thresholds of 25 ton/yr and 10 ton/yr. (TSD, Table 24.) Thus, BACT must be required for both PM and $PM_{2.5}$ from the gas turbines, which are the major source of these emissions. The Application contains a top-down BACT analysis, but it is severely flawed.

A. Step 1 of the PM/PM2.5 Top-Down Analysis Is Flawed

The Applicant conducted a conventional five-step, top-down BACT analysis for PM and PM2.5. In step 1, all control technologies must be identified.[111] The Applicant identified the following control technologies for PM, PM_{10}, and PM2.5 (Ap., Appx. B, p. 22):

1. Good Combustion Practices:
   a. Dry Low NOx (DLN) Combustion
   b. Water Injection (WI)
2. Low Ash/Low Sulfur Fuel (i.e., natural gas)

This list is incomplete for the same reasons previously discussed for GHG emissions. It excludes other good combustion practices commercially available for the LMS100 turbine. These practices include the LMS100 turbine with: (1) steam injection and (2) STIG.[112,113] Either of these configurations would improve the PM/ $PM_{2.5}$ emission rate, and the County must consider those control technologies in its BACT analysis.

B. Step 2 of the PM/PM2.5 Top-Down Analysis Is Flawed

In step 2, technically infeasible control technologies are eliminated.[114] In this step, the Applicant makes two arguments for eliminating DLN combustion and choosing water injection: (1) DLN cannot meet similar peak power capabilities and (2) the emissions are the same. (Ap., Appx. B, pp.24-25.) Neither of these arguments demonstrates technical infeasibility. The NSR Manual notes that "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review." (NSR Manual, p. B.6.) This test is not met for eliminating DLN combustion, steam injection, or even STIG, which is a feasible option that the County failed to identify.

---

[111] NSR Manual, p. B.5.

[112] The Steam Inject cycle (STIG) takes waste heat from the gas turbine, converts water into steam and then injects this steam into the gas turbine. This is a steam cycle, similar to combined cycle, without a steam turbine. This option results in better part-load efficiency and NOx emissions. See: Advanced Gas Turbine Power Cycles, pdf 28 at http://www.britishflame.org.uk/calendar/New2008/CH.pdf and Gas Turbine Technology, pdf 18 at http://www.ae.metu.edu.tr/seminar/2008/sanzlecture/sanz-day2.pdf.

[113] GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, 2003, Available at: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/atechspecs.pdf and GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS1000, June 2004, Available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

[114] NSR Manual, p. B.6.

1. Peak Power Argument Is Invalid

The Applicant asserts that it selected water injection over DLN due to water injection's "ability to achieve higher peak power output levels…" (Ap. Appx. B, p. 24.) However, the BACT analysis is silent as to why it eliminated steam injection and STIG.

The BACT analysis for NOx emissions from the gas turbines makes a similar peak power argument, asserting that water injection was selected due to its ability to achieve higher peak power output than steam injection or DLN combustors. The Applicant argues that the use of water injection increases the mass flow through the turbine, increasing power output, especially at higher ambient temperatures when peak power is often required. The use of LMS100 gas turbines with DLN combustors was reported to have a maximum gross electric output of 99 MW, versus 103 MW for water-injected combustors. (Ap., Appx. B, pp. 24-25.)

The peak power output used in both the $PM/PM_{2.5}$ and NOx BACT analyses is misleading. As an initial matter, the Applicant's claim that water injection allows a capacity of 103 MW is suspect. Chapter 4 of the BACT analysis argues water injection would allow up to 103 MW output; however, both the CEC Application (CEC Ap., pp. ES-1/2) and Draft Permit list the LMS100s as 102 MW turbines. (Draft Permit, p.33.) There is therefore almost no difference in peak capacity between water injection and, for example, steam injection, which achieves a maximum power output of 102.1 MWe. In fact, STIG would achieve an even greater peak capacity of 112.2 MWe.[115] Thus, the peak power goal of the facility could be easily met by selecting other LMS100 options that are more efficient and thus have lower $PM/PM2._5$ emissions. If the lower capacity of DLN combustors is truly an impediment to the design of the facility, there are other LMS100 options that could be selected with lower emission rates, improved energy efficiency, and reduced environmental impacts, while meeting the stipulated peak power. In any case, a slight decrease in peak capacity is not sufficient justification to eliminate a control technology as technically infeasible.

2. $PM/PM_{2.5}$ Emissions Are Not the Same for Water Injection

The Applicant's Step 2 BACT analysis further asserts that "…emissions data does not indicate that PM emissions are substantially different whether DLN or water injection is used. Therefore, for PM emissions, the maximum PM emission rate would be the same for either water injection or DLN combustion." (Ap., Appx. B, p. 25.) This argument would normally be made in step 3, not step 2.

Regardless, this statement is not supported with test data and is not credible. The meaning, for example, of the Applicant's use of the term "substantially different" is not evident and suggests that there is, in fact, a difference. However, the Applicant does not identify how big a differential there is. A small difference in an hourly emission rate could result in a large increase in PM, PM_{10}, and $PM_{2.5}$ emissions over a year. Further, most of the PM is actually PM_{10}, a severe nonattainment pollutant. Small differences are highly significant in severe nonattainment areas. Water injection, for example, increases PM, PM_{10}, and $PM_{2.5}$ emissions compared to DLN combustion for two reasons:

[115] GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS1000, 2004, Table 2.

First, dissolved solids are present in the injected water. These dissolved solids would be emitted as particulate matter in the exhaust gas. Although reverse osmosis will be used to treat the injection water, the Application and TSD are silent on the design total dissolved solid (TDS) level for the injection water.

Second, water-injected LMS100 turbines are less efficient than DLN and other LMS100 turbines, resulting in higher emissions of GHG, PM, PM_{10}, $PM_{2.5}$, CO, and NOx per unit of electricity generated. The Project will use LMS100 PA 60 Hz turbines. (Ap., Table 2-1.) The efficiency of this LMS100 turbine model increases from 43% for water injection to 46% when DLE combustors are used, to 48% with steam, and finally to 50% with STIG.[116] Higher efficiency means lower emissions, as less natural gas has to be combusted to produce the same MW output. Thus, the Applicant has chosen the lowest efficiency option with the highest emissions of all pollutants.

The BACT analysis claims that water injection and DLN have the same particulate matter emissions. (TSD, Appx. A, p. 25). However, this claim is unsupported and likely incorrect, due to the solids content of the injected water and the efficiency differences. Further, this claim just applies to DLN versus water injection and ignores the other two turbine options – steam and STIG.

C. Step 3 of the Top Down Analysis Is Missing

Step 3 requires that all feasible control technologies be ranked by control effectiveness.[117] This step is missing from the County's BACT analysis, and in its place is an unsupported assertion by the Applicant that BACT is satisfied by the use of natural gas and water injection, without justification. (Ap., Appx. B, p. 25.) There is no discussion of control effectiveness, expected emission rates or reductions, energy impacts, environmental impacts, or economic impacts, which are all factors that must be considered in selecting BACT.[118] Rather, the selection of water injection was made in step 2 based on an erroneous and irrelevant peak power argument, without considering steam injection or STIG.

B. Step 4 of the Top Down Analysis Is Flawed

In step 4 of its BACT analysis, the Applicant asserts that it has selected the best available control technology and thus further evaluation is not required. (Ap., Appx. B, p. 25.) However, the BACT analysis did not even identify the most effective control. The use of steam injection and STIG, which both meet peak power and have lower emissions, was not considered in the BACT analyses for any pollutant. In fact, the Applicant selected the LMS100 option with the highest PM/$PM_{2.5}$, GHG, CO, and NOx emissions, turning the top down BACT process on its head. Further, the selected option, water injection, has significant adverse environmental impacts that were not identified. In particular, water injection requires the use of large amounts of water, which for Ocotillo implicates a desert environment with overdrafted groundwater aquifers.

The top-ranked, technically feasible technology in a top-down BACT analysis can only be rejected if adverse energy, environmental, or economic impacts are demonstrated.[119] The

---

[116] GE Power Systems, GE's New Gas Turbine System: Designed to Change the Game in Power Generation, 2003, Available at:
[117] NSR Manual at B-7.
[118] NSR Manual, p. B.8.
[119] NSR Manual, p. B.8.

County's BACT analysis accepted whole-sale the Applicant's analysis, which does not identify any adverse impacts of other more efficient and less polluting options. Instead, the Applicant argues only that water injection is preferable because it can achieve higher peak power output levels. (Ap., Appx. B, p. 24.) This is not a sufficient justification for evaluating the most effective pollution control.

C. Step 5 of the BACT Analysis Is Flawed

The Applicant concluded (Ap., p. 26) and the County agreed (TSD, Table 25) that BACT for PM and $PM_{2.5}$ is 5.4 lb/hr, combined filterable plus condensable. The draft Permit limits PM_{10} total and $PM_{2.5}$ total to 5.4 lb/hr, 1-hr average, each. (Draft Permit, p. 17.) Compliance with the PM_{10} limit is by calculation using monitored fuel flow and emission factors from the most recent performance test for each unit. (Draft Permit, p. 17.)

However, this limit was derived without considering the combustion method. As discussed above, the emissions from an LMS100 turbine depend upon the type of combustion system used. The electrical generation efficiency ranges from 43% for water injection, erroneously chosen as BACT in this case, to 50% for STIG. Thus, PM and PM_{10} emissions would vary, depending on the type of combustor and could be as much as 16% lower for an LMS100 turbine running in STIG mode, compared to water injection assumed in the BACT analysis. Alternatively, if DLN were chosen as BACT, the efficiency would improve and PM/$PM_{2.5}$ emissions from water injection would be eliminated. Thus, there are clear distinctions in PM/$PM_{2.5}$ emissions, based on the combustion option. Step 5 relies solely on EPA's revised Pio Pico analysis, which did not consider combustion options, but rather only looked at permit limits and stack tests based on the same model turbine.

The Applicant concluded 5.4 lb/hr is BACT for each LMS100 turbine, based on EPA's revised BACT analysis for Pio Pico, which concluded that BACT for PM emissions from the same LMS100 turbines is 0.0053 lb/MMBtu. As the rated heat input of each Ocotillo gas turbine is 970 MMBtu/hr, the resulting PM emissions rate is 0.0053 lb/MMBtu x 970 MMBtu/hr = 5.1 lb/hr. The Applicant increased the PM emission rate by 6% to account for potential unspecified differences in the sulfur content of the natural gas. (Ap., Appx. B, p. 26.)

However, the Application fails to explain how the sulfur content of natural gas affects PM and $PM_{2.5}$ emissions and fails to present any basis for raising the Pio Pico PM BACT limit by 6%, rather than some other value. The Application also fails to present any information on the natural gas sulfur content used in the SCAQMD BACT determination compared to the natural gas sulfur content used at Ocotillo. Thus, the upward adjustment is unsupported.

Further, the revised Pio Pico BACT analysis that the Applicant relies on was not based on a top-down BACT analysis in which all good combustion options were considered, but rather only revised step 5, in which stack test data and permit limits were reviewed, without any consideration of the type of combustion controls used at the various facilities. Thus, the Pio Pico analysis did not consider the impact of LMS100 combustor options – DLN, water injection, steam injection, and STIG – on PM/PM_{10}/$PM_{2.5}$ emissions. Therefore, the underlying EPA analysis is fundamentally flawed and cannot be relied on here to establish BACT for Ocotillo.

V. THE PERMIT DOES NOT REQUIRE BACT FOR PM/$PM_{2.5}$ EMISSIONS FROM THE COOLING TOWER

The LMS100 gas turbines use an intercooler between the low pressure compressor and the high pressure compressor to improve the overall efficiency.[120] The cooling tower provides water cooling for the intercooler. (TSD, p. 6.) The BACT analysis for PM/$PM_{2.5}$ emissions from the cooling towers concludes that BACT for total PM and total $PM_{2.5}$ is satisfied by using drift eliminators designed for a drift loss of no more than 0.0005% of the total circulating water flow and total dissolved solids (TDS) in the circulating water of no more than 12,000 parts per million (ppm) on a weight basis. (Ap., Appx. B, p. 56; Draft Permit, p. 17.)

The Project includes a new "hybrid" partial dry cooling system, which includes a new mechanical draft cooling tower with a circulating water flow rate of 6,500 gpm. (Ap., pp. 10, 23.) In this application, hot water from the intercooler is introduced into the top of the tower and moves down through the tower countercurrent to an upward moving air stream. An inducted draft fan blows air up through the stream of hot water. Some of the hot water evaporates, cooling the water. A small amount of water is entrained as droplets or mist in the air stream, passes through a mist eliminator, and the remaining droplets are emitted to the atmosphere. When the droplets evaporate, dissolved solids in the droplets, which originate from the original water supply, become particulate matter, including PM, PM_{10}, and $PM_{2.5}$. Thus, a mechanical draft cooling tower is a source of particulate matter and is subject to BACT.

The Application includes a BACT analysis for this cooling tower, which was adopted by the County without comment. (TSD, pp. 15-16.) The BACT analysis accepted the "hybrid" cooling system as BACT and only evaluated the effect of one cooling tower operating variable, drift loss, on particulate matter emissions. There are two major flaws in this analysis in step 1 which invalidate the BACT decision: (1) it fails to consider other cooling methods with much lower PM/$PM_{2.5}$ emissions; and (2) it fails to consider the concentration of total dissolved solids (TDS) in the circulating water on PM, $PM_{2.5}$, and PM_{10} emission rates.

A. The Analysis Fails To Evaluate Other Cooling Methods

The top down BACT analysis for the cooling tower is fundamentally flawed in step 1 of the top down process because it failed to identify all available control technologies for heat rejection from the gas turbines. Rather, it assumes a hybrid cooling system as the starting point and only looks at drift losses established as BACT for similar systems.

The Project claims it will use a "hybrid" cooling system, which combines a conventional Marley wet tower with an indirect dry tower. (Ap., p.15.) However, PM, $PM_{2.5}$, and PM_{10} emissions from the cooling tower could be almost completely eliminated by selecting a dry tower for the LMS100 turbines. A dry tower uses an air-cooled condenser with a misting system at the ACC fan inlet(s) to saturate the inlet air with moisture to drop the dry bulb temperature to near the wet bulb temperature on hot days. In this configuration, there would be no need for a Marley cooling tower.

[120] Exhibit 26, GE Energy, New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™, Available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

General Electric, manufacturer of the LMS100, offers an air-cooled option to the LMS100. The first LMS100 unit built, in 2006 at Groton Station in South Dakota, was air-cooled. The second LMS100 added at Groton Station is also air-cooled.[121] Many others have followed, including at Astoria in New York[122] and Haynes Generating Station in Long Beach, California, which recently started up six air-cooled LMS100. Air cooling, referred to as the "air-to-air intercooler" in General Electric literature, is a standard option offered by GE on the LMS100, just as DLE combustion is a standard option offered by GE on the LMS100.[123] As explained by GE:

> "In locations where water is scarce or very expensive, the basic LMS100 power plant will contain a highly reliable air-to-air intercooler. This unit will be a tube and fin style heat exchanger in an A-frame configuration which is the same as typical steam condensing units in general conformance with API 661 standards. Similar units are in service in the oil and gas industry today."

Water scarcity is an important collateral impact in Arizona that should have been considered in step 4 of the BACT analysis. However, the County never considered the merits here because it never considered or evaluated alternate cooling options. The CEC Application, for example, acknowledges that "[l]ong-term groundwater use [which is the supply for the cooling tower] is a major concern for APS, as well as the State of Arizona, because of the arid climate and minimal natural recharge in the Phoenix area." (CEC Ap., Exhibit B2, p.B2-1 287.) An air-cooled LMS100, equipped with a water misting system that uses a relatively small amount of water for tempering inlet air on hot days, has an efficiency equivalent to a LMS100 equipped with a cooling tower.[124]

B. The Analysis Fails To Evaluate Makeup Water Treatment

The PM, $PM_{2.5}$, and PM_{10} emissions from a cooling tower are directly related to the amount of total dissolved solids (TDS) in the makeup water supply and the drift loss. (Ap., Appx. B, p. 53, Eq. 1.) The cooling tower BACT analysis evaluated drift loss by compiling losses required in permits for other similar cooling towers. (Ap., Appx. B, Table B8-3.)

However, the BACT analysis did not consider variations in the makeup water supply's TDS concentration in the cooling tower BACT analysis. Rather, the analysis assumes without support or any discussion, a circulating water TDS of 12,000 ppm. The cooling tower will be designed to operate at seven cycles of concentration (COC). (CEC Ap., Exhibit B2, p. B2-7.) Thus, the assumed TDS in the makeup water is 12,000/7 = 1,740 ppm.

The CEC Application indicates that existing groundwater wells will supply makeup water to the cooling tower. (CEC Ap. p. Application-8.) It further reports the raw well water has a

---

[121] CH2MHILL, Basin Electric LMS100-Unit 1 Project, http://www.ch2m.com/corporate/markets/power/assets/ProjectPortfolio/GE_Basin_1.pdf; Groton Generation Station: Record Heat Tests First LMS100 Immediately After COD, Combined Cycle Journal, Fourth Quarter 2006, http://www.artec-machine.com/wp-content/news/basin_electric_130MW_sychronous_clutch.pdf
[122] NYDEC, Permit Review Report, Permit ID: 2-6102-00116/00021, Modification 2, October 16, 2009.
[123] GE Power Systems, November 2003; GE Energy 2004.
[124] GE Energy 2004.

conductivity of 1200 uS/cm and a pH of 8.3. (CEC Ap., Exhibit B2, Table B2-2.) This is equal to a TDS concentration of about 800 ppm.[125] Thus, at seven cycles of concentration, the circulating water TDS should be no more than 5,600 ppm (800x7=5,600), or half that assumed in setting BACT emission limits. BACT is defined as "the maximum degree of reduction for each pollutant." 42 USC 7479(3). Setting the PM/PM2.5 BACT limits based on an untreated water supply with twice as much TDS than is actually present is inconsistent with this definition. The makeup water TDS could be significantly reduced, by more than 95%, by treating the local groundwater using reverse osmosis. Reverse osmosis is proposed to treat the water injected into the combustor to control air emissions. (CEC Ap., Exhibit B2, p.B2-5.) Thus, it is clearly feasible at the site. Removing 95% of the TDS from the cooling tower makeup water would reduce PM, $PM_{2.5}$, and PM_{10} emissions from the cooling tower by an equivalent amount. Thus, clearly, the Draft Permit does not require BACT for PM and $PM_{2.5}$ emissions from the cooling towers because the selected limits were based on a fixed circulating water TDS of 12,000 ppm.

C. The PM_{10}The Analysis Fails To Evaluate Lower Drift Rates

The BACT analysis summarized drift loss control requirements for eight cooling towers, reporting a range of 0.0005% to 0.002%. (Ap., Table B8-3). The lower end of the range, 0.0005% was selected as BACT. However, lower drift losses have been selected as BACT, including for Longview Power: 0.0002%.[126]

VI. THE PM_{10} CAP IS NOT ENFORCEABLE

The Facility is located in an area designated as a serious nonattainment area for particulate matter less than 10 microns (PM_{10}). (TSD, pp. 20, 21.) Under Maricopa County Rule 240, Section 210.1, if PM_{10} emissions exceed 70 ton/yr, Nonattainment New Source Review (NNSR) applies and Ocotillo must install LAER for PM_{10}. (TSD, pp. 21-22.)

To avoid this classification and the attendant requirements, APS is proposing a plant-wide PM_{10} emission cap of 63.0 ton/yr based on a rolling 12-month average to reclassify Ocotillo as a minor source of PM_{10} emissions under County Rule 201. Thus, the Applicant asserts that Ocotillo would not be subject to NNSR or PSD programs for PM_{10} emissions. (TSD, pp. 7, 22.)

However, as demonstrated below, the County cannot rely on this plant-wide emission cap to exempt Ocotillo from NNSR because the cap is not enforceable and does not include all sources of PM_{10} emissions. The sources of PM_{10} emissions due to the Project are identified in the TSD, Table 11 as follows:

- Normal operation GT3-GT7: 48.2 ton/yr
- Startup/Shutdown GT3-GT7: 6.7 ton/yr
- GC Cooling Tower: 2.5 ton/yr
- Emergency Generators: 0.1 ton/yr

These identified new PM_{10} emission sources total to 57.5 ton/yr. In addition, Ocotillo will continue to operate gas turbine units 1 and 2 (GT1, GT2) and a GENRAC 125 hp propane-fired emergency generator (Ap., p 7), which emit an undisclosed amount of PM_{10}. The existing gas

[125] TDS (ppm) = Conductivity uS/cm x 0.67.
http://www.stevenswater.com/water_quality_sensors/conductivity_info.html
[126] Longview Power, LLC, Cooling Tower, RBLC ID: WV-0023.

turbines are GE 501-AA, 55 MW, 915 MMBtu/hr gas turbines installed in 1972. (Draft Permit, p. 33.) The GENRAC generator is not even listed in the Draft Permit.

Thus, to determine compliance with the cap, PM_{10} emissions from each of these sources, including existing sources, must be measured and summed. The proposed permit does not require any testing of PM_{10} emissions from some of these sources and requires inadequate testing from others. Further, the facility will emit PM_{10} from sources that were not included in the PM_{10} cap and are not identified in the draft Permit.

A. The Proposed Cap Is Unsupported and Facially Exceeded

The draft Permit, Table 1, identified the emission units that contribute to the PM_{10} cap as: GT3-GT7, EG1-EG2, GTCG, and GT1-GT2. The record in this case does not explain how the cap of 63 ton/yr was determined. The record discloses the calculation of PM_{10} emissions from Project sources, GT3-GT7, EG1-EG2, GTCG, which total to 57.5 ton/yr, but not the assumed contribution to the cap from existing sources GT1-GT2 at the facility.

The additional potential contribution to PM_{10} emissions from existing gas turbines GT1 and GT2, which would continue to operate, calculated using the method proposed in the Draft Permit, is 9.7 ton/yr. Thus, total PM_{10} emissions from all sources identified in the Draft Permit as part of the cap sum to 67.2 ton/yr (57.5+9.7=67.2), which exceeds the proposed cap. Thus, on its face, it appears that the cap is not plausibly achievable. This is a key concern because the Draft Permit does not require any monitoring for several sources. Thus, it is facially plausible that the cap will be exceeded.

B. GT1 and GT2 PM_{10} Emissions Are Not Enforceable

The PM_{10} emissions from GT1 and GT2 will be calculated using monitored fuel flow data and emission factors from AP-42, unless an alternative emission factor is demonstrated. (Draft Permit, p. 17, Table 4, note (f).) The Draft Permit does not require any testing at all of PM10 emissions from these turbines. Further, the Draft Permit does not require that emissions from startups, shutdowns and malfunction of GT1 and GT2 be included in the emissions. Thus, the contribution of PM_{10} emissions from the existing gas turbines to the PM_{10} cap is unenforceable.

Sierra Club attempted to calculate the expected emissions from the two existing turbines. AP-42, EPA's Compilation of Air Pollutant Emission Factors, has been published since 1972 as the primary compilation of EPA's emission factor information. It contains emission factors and process information for more than 200 air pollution source categories. The emissions factors in the publication are numerous - AP-42 contains 15 chapters.[127] The Draft Permit should therefore specify which AP-42 section and which emission factor(s) are applicable. Presumably, Section 3.1, Stationary Gas Turbines, applies. This section reports a total PM emission factor of 0.0066 (6.6E-03) lb/MMBtu for natural gas-fired turbines.[128] Although not stated in AP-42, essentially 100% of the particulate matter from gas-fired turbines is PM_{10}. The Draft Permit also limits

[127] EPA, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Sources and Area Sources, Available at: http://www.epa.gov/ttnchie1/ap42/.
[128] AP-42, Table 3.1-2a.

combined annual fuel use across gas turbines GT1 and GT2 to 2,928,000 MMBtu/yr (HHV). (Draft Permit, p. 19.) Thus, the total PM_{10} emissions from these two existing turbines is 9.66 ton/yr.[129]

Elsewhere, the Application conducted a netting analysis for $PM/PM_{10}/PM_{2.5}$. The baseline emissions for all three of these particulate matter pollutants are based on a constant emission factor of 0.0075 lb/MMBtu from the two existing steam turbines. (Ap. Tables E-8/10.) Thus, based on the PM_{10} emission factor for these turbines assumed in the Application, the potential to emit PM_{10} from these turbines during normal operation is at least 11.0 ton/yr.[130] Most of the $PM/PM_{10}/PM_{2.5}$ is from the cooling towers, whose baseline emissions are presented in Table E-29 without explanation.

GT1 and GT2 contribute to the total PM_{10} emissions. When calculated as required in the Draft Permit, those units tip the total PM_{10} over the proposed cap of 63 ton/yr. The Draft Permit must be revised to require periodic stack testing of PM_{10} emissions from GT1 and GT2 and include emissions from startup, shutdown and malfunctions at these existing gas turbines.

C. Gas Turbine GT3 – GT7 PM_{10} Emissions Are Not Enforceable

The potential to emit PM_{10} from GT3 to GT7 consists of emissions from two sources: normal operations (48.2 ton/yr) and startup and shutdown (6.7 ton/yr) emissions. Malfunction emissions were inexplicably excluded.

1. Startup, Shutdown, and Malfunction Emissions

The Draft Permit does not require the facility to include startup, shutdown, and malfunction emissions in the PM_{10} cap and does not require any testing to assure that these emissions plus those from other sources comply with the cap. The Draft Permit requires annual stack testing of PM_{10} "under representative operating conditions…Operations during periods of startup, shutdown, and equipment malfunction shall not constitute representative conditions for performance tests unless otherwise specified in the applicable standard or permit conditions." (Draft Permit, p. 24-25, Table 6, note (c).) Proposed Condition 21(b) does not even require that malfunction hours be recorded. Thus, startup, shutdown, and malfunction emissions are explicitly excluded from testing, and the draft Permit does not even require that malfunction hours be identified. (Draft Permit, p. 21, Condition 21(b).) This exclusion is also contrary to BACT requirements. *In re RockGen Energy Ctr*., 8 E.A.D. 536, 553-55 (EAB 1999)(holding that PSD permits may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown); *In re Tallmadge Energy Center*, Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12 (EAB May 21, 2003)("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown"). The County should require continuous monitoring during startup, shutdown and malfunction to ensure that Ocotillo does not exceed the PM_{10} cap.

---

[129] PM10 emissions from GT1 and GT2: (2,928,000 MMBtu/yr)(6.6E-03 lb/MMBtu)/2000 lb/ton = **9.66 ton/yr.**
[130] PM10 emissions from GT1 and GT2: (2,928,000 MMBtu/yr)(7.5E-03 lb/MMBtu)/2000 lb/ton = **10.98 ton/yr.**

2. Normal Operation

PM_{10} testing of gas turbine emissions during normal operation is also inadequate to assure compliance with the PM_{10} cap. The draft Permit stipulates that PM_{10} emissions from new units GT3 to GT7 "shall be calculated using monitored fuel flow and emission factors from the most recent performance test for each unit, unless an alternative emission factor can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions." (Draft Permit, p. 17, Table 4, Note (e).) Elsewhere, the Draft Permit indicates performance tests will only be conducted on all five gas turbines every three years and on only two gas turbines during intervening years (Draft Permit, p. 25, Table 6, note 3):

> Initial PM_{10} and VOC tests shall be performed on all 5 GTs. Subsequent annual PM_{10} and VOC tests shall be performed on at least 2 GTs. The same GT may not be tested in consecutive years and all 5 GTs shall be tested at least once every 3 years. The higher emission rate from the 2 annual PM_{10} and VOC performance tests shall be applied to all 5 GTs until a new emission rate is established by the next annual performance tests.

The cap, designed to avoid NNSR, must be continuously enforceable and can only be enforced through appropriate monitoring, testing and reporting of emissions. An appropriate hierarchy for specifying monitoring to determine compliance is: (1) continuous direct measurement where feasible; (2) initial and periodic direct measurement where continuous monitoring is not feasible; (3) use of indirect monitoring, *e.g.* surrogate monitoring, where direct monitoring is not feasible; and (4) equipment and work practice standards where direct and indirect monitoring are not feasible.[131] The Draft Permit monitoring provisions for the PM_{10} emissions from the gas turbines during normal operation does not comport with this guidance.

The Draft Permit requires CEMS to determine compliance with limits on NOx and CO. CEMS are available for PM, but are not required. While the PM CEMS measures PM, rather than PM_{10}, essentially 100% of the particulate matter from gas turbines is PM_{10}. Thus, a conventional PM CEMS is appropriate in this application. Alternatively, a surrogate, such as opacity, should be considered to assure continuous compliance.

A stack test normally lasts only a few hours (3-6 hours)[132] and is conducted under ideal, prearranged conditions, typically at maximum load. Staged annual or other periodic testing tells one nothing about emissions during routine operation or startups and shutdowns on the other 364 days of the year, or 8,750 plus hours. One 3-hour test per year over a 30-year facility life at 46% capacity (see Comment I.B.1) amounts to testing only about 0.1% of the operating hours. This is a long way from demonstrating continuous compliance with the PM_{10} emission cap.

Further, annual stack testing does not capture spikes caused by normal process operations. Some routine process operations that occur only periodically, from daily to monthly, emit large amounts of PM_{10}. Emissions of PM_{10}, for example, substantially increase during SCR catalyst cleaning or during wind storms that increase particulate matter in inlet air. The annual or less

[131] NSR Manual, pp. H.10, I.3.
[132] The Draft Permit, pdf 30, Table 6, note (g), requires three test run with each run lasting at least one hour.

frequent PM_{10} stack tests are, therefore, likely to significantly underestimate emissions and are not sufficient to assure PM_{10} emissions remain below the cap.

Finally, it is well known that "[m]anual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source."[133] A widely-used handbook on Continuous Emissions Monitoring ("CEMs") notes, with respect to PM_{10} source tests, that: "Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests."[134]

An annual stack test does not provide an adequate method to assure that the PM_{10} cap is met on "continual basis" year in and year out. This issue is particularly relevant in this case because Ocotillo is avoiding NNSR review only because the Applicant has asserted that it will cap PM_{10} emissions. Without the ability to verify that cap, there is a high likelihood that Ocotillo will emit PM_{10} at a rate that would trigger NNSR. The Permit should be revised to require the use of a PM CEMS, include more frequent stack testing for PM_{10} at all turbines, or include continuous indicator monitoring, e.g., opacity, to address those periods when direct stack testing is not conducted.

D. Cooling Tower PM_{10} Emissions Are Not Enforceable

The Application and TSD estimated PM_{10} emissions from the cooling tower, using an equation from AP-42. (Ap., Appx. B, p. 53; TSD, p. 15.) This equation requires four inputs: (1) circulating water flow rate; (2) drift loss; (3) circulating water TDS; and (4) particle size multiplier, i.e., fraction of total particulate matter that is PM_{10}.

The proposed permit allows the cooling tower contribution to be calculated, using exactly the same inputs for these parameters as assumed in the initial emission calculations, namely, a circulating water flow rate of 61,500 gpm, a TDS of 12,000 ppm, a drift loss of 0.0005%, and a particle size multiplier of 0.315. (Draft Permit, p. 18.) To be enforceable, the Permit should be modified to require the facility to confirm cooling tower emissions at least annually using stack testing method.[135] At all other times, PM_{10} emissions should be calculated using the formulae in Condition 18(e) and actual measurements of drift rate, circulating water flow rate, and circulating water TDS.

The compliance method in the Draft Permit is nothing more than a calculation, using all of the same inputs as assumed in developing the PM_{10} cap. Cooling tower PM_{10} emissions are therefore not enforceable. In order to assure that the cooling tower contribution to the PM_{10} cap is enforceable, each of these inputs must be measured and the actual measured values used in the subject equation to confirm that the calculations are representative of actual operations.

---

[133] 40 Fed. Reg. 46,241 (Oct. 6, 1975).

[134] James A. Jahnke, *Continuous Emission Monitoring*, 2nd Ed., John Wiley & Sons, Inc., New York, 2000, at p. 241.

[135] See Pio Pico Permit, pdf 11, Condition G.1.ii. Available at: http://www.epa.gov/region9/air/permit/pdf/piopico/final-permit-pio-pico-2012-02.pdf

a) <u>TDS Concentration</u>

The proposed Permit requires daily monitoring of conductivity and monthly monitoring of TDS. (Draft Permit, p. 22.) The Permit should be revised to require that this measured data be used in the cooling tower equation to estimate cooling tower PM_{10} emissions.

b) <u>Circulating Flow Rate</u>

The Draft Permit does not require that the circulating water flow rate be monitored. The Permit must be modified to require monitoring of the circulating water flow rate and the actual monitored flows must be used to calculate cooling tower PM_{10} emissions.

c) <u>Drift Loss</u>

The Draft Permit, Condition 20(b) requires that the cooling tower vendor certify the drift eliminators to achieve less than or equal to 0.005% drift. (Draft Permit, p. 19.) However, the Draft Permit does not require monitoring to confirm that this standard is met and is continued to be met over the operational life of the facility. Drift can be measured using Modified Method 306 or Cooling Technology Institute Acceptance Test Code (ATC 140) – Isokinetic Drift Measurement Test Code for Water Cooling Tower. Drift testing is commonly required for cooling tower permits.[136]

d) <u>Particle Multiplier</u>

The particles multiplier is the fraction of the total emitted particulate matter that is PM_{10}. As explained elsewhere in these comments, the particle size multiplier assumed in the TSD calculations is inconsistent with test data and represents a significant underestimate of PM_{10} emissions from cooling towers. This factor can and should be measured with standard tests.

E. PM_{10} Emissions From The Cooling Tower Underestimated

The Applicant estimated PM_{10} emissions from the new cooling tower assuming that 31.5% of the cooling tower PM emissions is PM_{10}, "consistent with the majority of power plants in Maricopa County." (TSD, pp. 15, 16.) This 31.5% is the "k factor" in the equation in the Draft Permit specified to estimate cooling tower PM10 emissions. (Draft Permit, p. 18.) This factor is required to calculate PM_{10} emissions from the cooling tower, but the draft Permit does not require that it be measured.

The use of 31.5% substantially underestimates PM_{10} emissions from the cooling tower. A Cooling Tower Institute (CTI) study demonstrates scientifically that all particulate matter exiting cooling towers is PM_{10}.[137] The California Energy Commission ("CEC"), the agency responsible for all environmental impact evaluation and permitting of power plants in California, has adopted a regulatory assumption that all cooling tower particular emissions are PM_{10}.[138]

---

[136] Pio Pico Energy Center PSD Permit November 2012, p. 11, Condition G.1.c.v.

[137] Weast, T.E., Stich, N.M., Israelson, G., *Reduction of Cooling Tower PM10 Emissions Due to Drift Eliminator Modifications at a Chemical Refining Plant*, CTI Paper No. TP92-10, Cooling Technology Institute Annual Meeting, Houston, TX, February 1992.

[138] California Energy Commission, *Preliminary Staff Assessment, Palomar Energy Project, Application For Certification (01-AFC-24) San Diego County*, August 27, 2002, Air Quality Table 10, pg. 4.1-22.

F. PM_{10} From Ammonia Emissions Excluded

The NOx emissions from the six new gas turbines will be controlled with selective catalytic reduction (SCR). SCR emits ammonia, known as "ammonia slip". The Applicant has proposed an ammonia slip limit of 10 ppm. The ammonia is converted into particulate matter, including PM_{10} in both the gas stream and in the atmosphere. In fact, elsewhere, the Applicant admits that SCR is a potential source of PM emissions. (Ap., Appx. B, p. 22.) Thus, PM_{10} emissions from ammonia slip must be included in the PM_{10} cap. The County did not include these emissions.

Excess residual ammonia downstream of the SCR system can react with SO_3, NO_2, and water vapor in the stack gases and downwind in the atmosphere to form ammonium sulfate, ammonium bisulfate, and ammonium nitrate according to the following reactions.[139] [140] [141]

$$SO_3 + 2\ NH_3 \leftrightarrows (NH_4)_2SO_4 \qquad (1)$$
$$SO_3 + NH_3 \leftrightarrows NH_4HSO_4 \qquad (2)$$
$$NO_2 + OH + NH_3 \leftrightarrows NH_4NO_3 \qquad (3)$$

These equations can be used to estimate secondary PM_{10} formation from ammonia slip. Secondary PM_{10} can be formed by reaction of ammonia with SO_3 and NO_2 emitted by the gas turbines and present in the stack gases and plume as well as additional SO_3 and NO_2 that are present downwind in the atmosphere. Additional ammonium nitrate could form from the reaction of NO_2 in the atmosphere with any emitted ammonia.

VII. NOX EMISSION CAP IS NOT ENFORCEABLE

The Project area is designated nonattainment for the 2008 8-hour ozone standard, classified as marginal. (TSD, p. 20.) The NNSR significance threshold for NOx is 40 ton/yr. (TSD, Tables 18 & 24.) If NOx emissions equal or exceed 40 ton/yr, NNSR is triggered, which would require LAER for NOx and VOC emissions. Thus, to avoid NNSR review for NOx, the Applicant is proposing a NOx emission cap of 125.5 ton/yr across the proposed new gas turbines and emergency generator so that Ocotillo does not exceed the NNSR significance threshold of 40 ton/yr. (TSD, p. 7 and Tables 18 & 24; Draft Permit, Table 1.)

A. The Increase In NOx Emissions Due to the Project Were Not Properly Rounded

The net increase in NOx emissions is reported as 39.5 ton/yr in the TSD (Table 24, p. 27) and as 39.6 ton/yr in the CEC Application. (CEC Ap., Exhibit B1, Table B1-3, p.B1-3.) In either case, the net increase in NOx emissions rounds up to 40 tons/yr, the significance threshold for

---

[139] John H. Seinfeld and Spyros N. Pandis, Atmospheric Chemistry and Physics, John Wiley & Sons, Inc., New York, 1998 (Seinfeld and Pandis 1998), pp. 529-534;.

[140] S. Matsuda, T. Kamo, A. Kato, and F. Nakajima, Deposition of Ammonium Bisulfate in the Selective Catalytic Reduction of Nitrogen Oxides with Ammonia, Ind. Eng. Chem. Prod. Res. Dev., v. 21, 1982, pp. 48-52 (Matsuda *et al*. 1982). *See also* South Coast AQMD 6/12/98, p. 3-3.

[141] J.M. Burke and K.L. Johnson, Ammonium Sulfate and Bisulfate Formation in Air Preheaters, Report EPA-600/7-82-025a, April 1982 (Burke and Johnson 1982).

NNSR and PSD. If emissions equal or exceed 40 ton/yr, NNSR is triggered. In this case, using just the Applicant's calculations, NOx emissions equal 40 ton/yr, which triggers both PSD and NNSR.

The NOx NNSR significance threshold of 40 ton/yr is reported to two significant figures, or arguably, one.. Further, the NOx netting calculations (TSD, Table 24) that derived the net increase in NOx emissions include factors and calculations based on only two significant figures. (Ap., Appx. E.) Thus, the results of the netting calculations should be reported to no more than two significant figures, not three significant figures (39.5 or 39.6 ton/yr). The County has ignored standard engineering procedures for reporting results of calculations, taught in basic math, statistics and science courses, in EPA air pollution courses, and in air district guidance. The number of significant figures is simply the number of figures that are known with some degree of reliability. It is well established among professional engineers and scientists that the result of a calculation should be written with no more than the *smallest* number of significant figures of any of the factors included in the calculation. "The product often has a different precision than the factors, but the significant figures must not increase."[142] This is standard practice throughout the engineering and scientific professions.[143] This rule is taught in EPA air pollution training courses.[144] The EPA Manual instructs: "When approximate numbers are multiplied or divided, the result is expressed as a number having the same number of significant digits as the expression in the problem having the least number of significant digits. In other words, if you multiply a number having four significant digits by a number having two significant digits, the correct answer will be expressed to two significant digits."[145] The San Joaquin Valley Air Pollution District's (SJVAPCD) Guidance APR 1105, *Guidelines for the Use of Significant Figures In Engineering Calculations* is in accord. The Guidance instructs that "Rounding off is accomplished by dropping the digits that are not significant. The digits 0, 1, 2, 3, and 4 are dropped without altering the preceding digit. The preceding digit is increased by one when a 5, 6, 7, 8, or 9 is dropped."

Thus, the results of the multiplications and additions used in the County's emission calculations should have been rounded off to the same number of significant figures as the factor with the least number of significant figures in the underlying calculations, which is two. Further, the significance threshold itself is reported to just two significant figures (and perhaps just one). Therefore, the results of the NOx netting analysis in TSD Table 24 should have been reported to no more than **two** significant figures, corresponding to the number of significant figures in the underlying factors used in the calculations, not to **three** significant figures, or 39.5 or 39.6 ton/yr,

---

[142] E.A. Avallone and T. Baumeister III (Eds.), Marks' Standard Handbook for Mechanical Engineers, 10th Ed., McGraw-Hill, New York, 1996, p. 2-4.
[143] See, *e.g.*, Philip R. Bevington, Data Reduction and Error Analysis for the Physical Sciences, McGraw-Hill, Inc., 1969, pp. 4, 9; Lothar Sachs, Applied Statistics. A Handbook of Techniques, 2nd Ed., Springer-Verlag, New York, 1984, p. 21.
[144] U.S. EPA, APTI Virtual Classroom, Course SI 100: Mathematics Review for Air Pollution Control, Available at: Lesson 2 Significant Figures and Rounding off, Available at: http://yosemite.epa.gov/oaqps/EOGtrain.nsf/DisplayView/SI_100_0-5?OpenDocument and Lesson 2, Available at: http://yosemite.epa.gov/oaqps/EOGtrain.nsf/fabbfcfe2fc93dac85256afe00483cc4/4939717614a0227e85256f400062252e/$FILE/Lesson2.pdf.
[145] EPA Manual, p. 2-5/2-6.

in an attempt to avoid NNSR review. Rounding of 39.5 or 39.6 to two significant figures yields 40 ton/yr. This equals the NNSR significance threshold, requiring NNSR review for NOx.

Further, we note that the netting analysis in the TSD is based on Project NOx net emission increases of 125.4 ton/yr. (TSD, Table 24.) However, the proposed NOx cap in the Draft Permit is based on 125.5 ton/yr. Assuming, arguendo, that the claimed creditable decrease are accurate, the net increase in NOx emissions allowed by the draft Permit is 125.5 – 85.9 = 39.6 ton/yr, consistent with the CEC Application.

B. Compliance Provisions Exclude Gas Turbine Malfunction and Emergency Generator Emissions

The NOx cap of 125.5 ton/yr includes all new NOx emissions from GT3 – GT7 plus EG1 and EG2. (Draft Permit, p. 16, Table 1.) Note (c) to this table indicates that compliance would be determined using CEMS for normal operations, startup/shutdown periods, and tuning/testing periods for GT3 to GT7. However, the Draft Permit does not require that NOx emissions from malfunctions or from the emergency generators be measured and included in the NOx cap emission summary. Thus, there is no assurance that NOx emissions will remain below the cap.

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

Original signed by:

Travis Ritchie
Associate Attorney
Sierra Club
85 Second Street, Second floor
San Francisco, CA 94105
(415) 977-5727
travis.ritchie@sierraclub.org

Exhibit 1 to Sierra Club's April 9, 2015 Comments

2014 Integrated Resource Plan

Arizona Corporation Commission Workshop

September 11, 2014

Jim Wilde
Director, Resource Planning

aps

2014 IRP Summary

- **Natural gas generation will play increasingly important role**
  - Economics
  - Operational flexibility
- **Cleaner energy mix**
  - Customer resources such as roof-top solar and energy efficiency projected to triple
  - Environmental regulations
- **Advanced technology will change the electricity grid**
  - Integration of renewable energy
  - Communication and automation

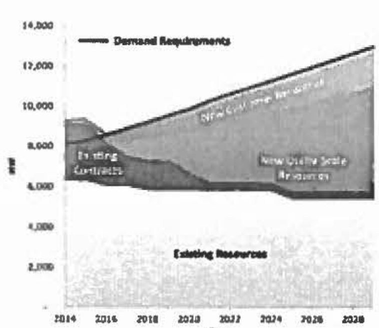
aps

2014 IRP Supplement

- Modify chosen portfolio from the Selected Portfolio (April 2014 Selected Portfolio) to the Coal Reduction Portfolio (September 2014 Selected Portfolio)
- Currently in talks with EPA, ADEQ and PacifiCorp to craft a resolution for Cholla:
  - Retire Unit 2 in 2016
  - Retire Units 1 and 3 in mid-2020's (at end of coal contract) or convert to natural gas
- Modification based on economics of required environmental upgrades to comply with MATS and Regional Haze
  - Similar to Four Corners 1-2-3, environmental upgrades cannot be supported given lack of economies of scale
- Portfolio modification will produce cost savings to customers and reduce environmental impacts
- IRP Supplement will be filed with the ACC

aps

Supply-Demand Gap

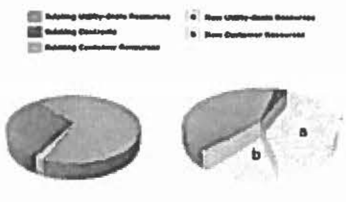


- Growth in customer energy requirements expected to resume
- Customer resources expected to triple over planning horizon
- Expiring purchase contracts means APS will need additional resources by 2017
- Additional resource needs anticipated to be met by increasingly diverse and efficient technologies

aps

Expected Future Resources

Sept 2014 Selected Portfolio



2014
8,124 MW
peak requirement
100% met with existing resources

2029
12,982 MW
peak requirement
45% met with existing resources

2014-2029 (forecast)

Future Additional Resources
7,267 MW Expected at Peak

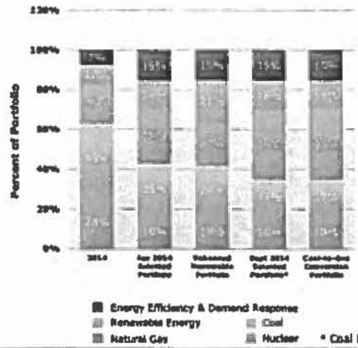
a. **New Utility-Scale Resources**
Natural Gas
4,817 MW
Renewable Energy
467 MW

b. **New Customer Resources**
Energy Efficiency
1,447 MW
Distributed Energy
261 MW
Demand Response
275 MW

aps

Energy Mix

2014 vs 2029 Comparison

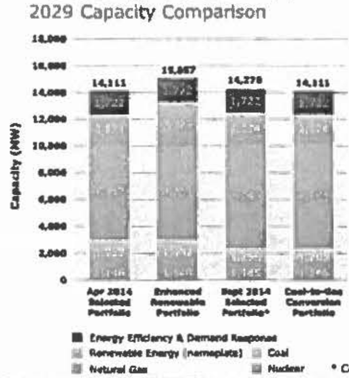


- Of the four portfolios considered, all have a diverse resource mix
- Renewables and coal primary resources being flexed in portfolio analysis
- Natural gas resources used to balance out remaining needs by providing summer capacity and operational flexibility

aps

Portfolios Considered

2029 Capacity Comparison



- Sept 2014 Selected Portfolio is being chosen because it provides better combination of:
  - Overall cost
  - Operational flexibility to support grid reliability and renewable energy integration
- Provides for discussion of uncertainties in upcoming coal fleet decisions

aps

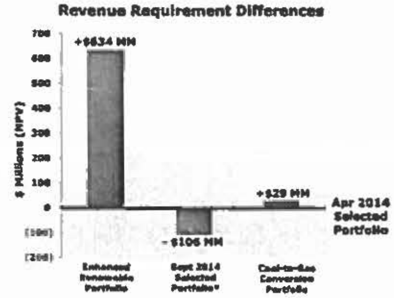
Comparative Revenue Requirements

Differences from Apr 2014 Selected Portfolio in 2029

Portfolio	2029 Revenue Requirement B (NPV)
Apr 2014 Selected	$29.3
Enhanced Renewable	$29.9
Sept 2014 Selected*	$29.2
Coal-to-Gas Conversion	$29.3

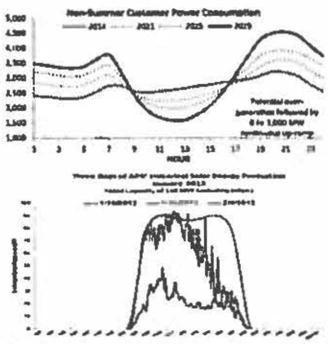
* Coal Reduction Portfolio

Revenue Requirement Differences



aps

Evolving Customer Demand



- Growth of solar PV changes customer energy consumption patterns
- Generators must be able to start and stop multiple times per day
- Fast starting and ramping capability is required in responding to intermittent output of renewable resources

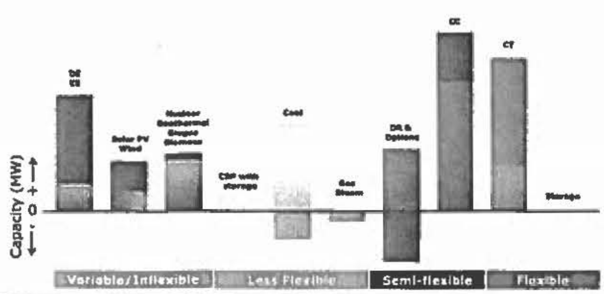
Future Technology Drivers

Transition Towards Integrating Evolving Energy Resource Portfolio

- **System Drivers**
  - Increasing amounts of intermittent generation
  - Need for peaking resources and summer time capacity
  - Cost of compliance with environmental regulations
  - Stable natural gas prices
- **Potential Benefits**
  - Increased resource diversity
  - Flexible gas generation meets peak needs and enables renewable energy integration
  - Reduced environmental impacts
- **Potential Risks**
  - Cost of resource diversity for newer technologies
  - Technology maturity and uncertain reliability
  - Maintaining balance between variable/inflexible resources and flexible resources

Variability Requires Flexibility

Balancing Growth at Both Ends of Flexibility Spectrum



Sample of Potential Future Energy Storage Options

- **Battery Storage**
  - Uses off-peak/dump energy from grid to charge battery
  - Discharges energy when needed
- **Flywheel/Rotary Uninterruptible Power Supplies (UPS)**
  - Very short-term energy and voltage stabilization
- **Pumped Hydro**
  - During periods of high demand, power is generated by releasing water from an upper reservoir through turbines in the same manner as a conventional hydropower station
  - During periods of low demand, the upper reservoir is recharged by using lower-cost electricity from the grid to pump water from a lower reservoir back to the upper reservoir
- **Compressed Air Energy Storage (CAES)**
  - CAES potential in helping provide back up for solar and wind generation
  - Geologic and permitting concerns

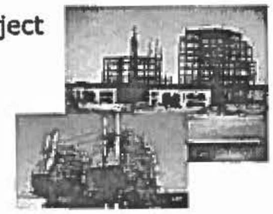
Solana – Energy Storage Today

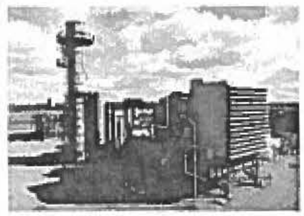
Developer – Abengoa
Location – 10 miles west of Gila Bend, AZ
Capacity/Generation – 250 MW, annual energy approximately 900,000 MWhs
In-Service – October, 2013

- Thermal energy storage
  - Six hours at full capacity
  - Increased hours of storage at lower capacity levels
- 100% solar power availability at time of peak
  - Solar PV has reduced levels of capacity at time of peak
- Operational flexibility
  - Start before sunrise and run for morning peak by holding energy in storage from previous day
  - Continue to run for evening peak (after sunset)

Ocotillo Modernization Project

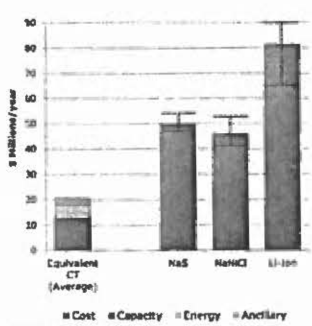
- Retire aging, large steam units constructed in 1960
- Replace steam units with modern technology





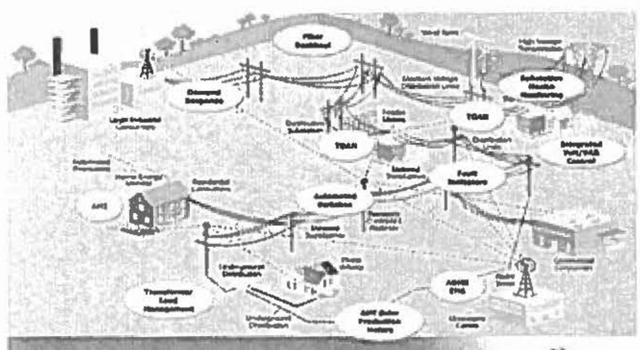
- Maintain Valley reliability
- Responsive unit operations
- Environmental attributes
- In-service planned for summer 2018

Battery Storage vs Equivalent CT Costs



- Primary technologies
  - Sodium Sulfur (NaS)
    - 15 year battery life, 6 hour capability
  - Sodium Nickel Chloride (NaNiCl)
    - 15 year battery life, 5 hour capability
  - Lithium Ion (Li-Ion)
    - 15 year battery life, 5 hour capability
- Not a viable capacity solution at this time
  - High costs relative to other options
  - Value will increase as reliability is proven and costs come down
  - Limited number of utility scale sites
- Will be evaluated in future IRPs
  - Significant resource needs for 2019 and beyond
  - Near term opportunities for pilot projects

Proliferation of Distributed Generation Demands A More Advanced Grid

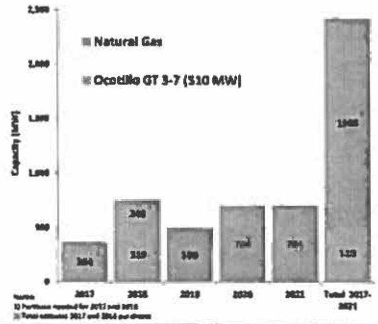


aps

www.aps.com/resources

www.azenergyfuture.com

Incremental Near-Term Natural Gas Resource Needs



- Of the 3,800 MW needed by 2021, the 2014 IRP calls for 2,400 MW to come from natural gas resources
  - Capacity from Ocotillo Project represents roughly 20% of near term natural gas resource needs, and roughly 13% of total need
  - Significant reliance on markets

APPENDIX

2013 IRP Conventional Generation Technologies Assumptions (2017 Installation)

[illegible]

Potential Future Resource Technologies

- **Nuclear (SMR)**
  - Small modular reactors (SMR) will be nuclear technology of choice after 2025 (EIA)
  - Typically smaller than 300 MW
  - Built off-site in a modular arrangement, shipped to plant, and set up on plant foundation
- **Coal**
  - Ultra-supercritical steam turbines (USC) are an early commercial technology
  - Integrated gasification combined cycle (IGCC) integrate coal gasification with combined-cycle technology
- **Solar Tower Systems**
  - Field array of mirrors reflect sunlight onto a central receiver located at top of tower
  - Could be competitive with parabolic trough with thermal energy storage, if proven reliable & cost-effective
- **Fuel Cells**
  - Types include alkali (AFC), phosphoric acid (PAFC), molten carbonate (MCFC), proton exchange membrane (PEM), solid oxide fuel cell (SOFC), and direct carbon (DCFC)
  - Unsuitable for distributed generation or smart-grid applications until reliability improves, costs are reduced, and cell-stack life is extended
- **Natural Gas (CC & CT)**
  - Clean burning
  - Efficient
  - Simple cycle combustion turbines (CT) have quick start & fast ramping capability
- **Customer-Side Resources**
  - Energy Efficiency (EE)
  - Distributed Generation (DG)

aps

Planning Considerations

Load Forecast

Existing Resources

Customer Resources

Future Resource Options

Regulation

Stakeholders

Cost

Environmental Impact

Reliability and Safety

aps

Exhibit 2 to Sierra Club's April 9, 2015 Comments

0000155883

BEFORE THE ARIZONA POWER PL... AND TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES 40-360 ET SEQ., FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE OCOTILLO MODERNIZATION PROJECT, WHICH INCLUDES THE INSTALLATION OF FIVE 102 MW GAS TURBINES AND THE CONSTRUCTION OF TWO 230-KILOVOLT GENERATION INTERCONNECTIONS AND OTHER ANCILLARY FACILITIES, ALL LOCATED WITHIN THE BOUNDS OF THE EXISTING OCOTILLO POWER PLANT SITUATED ON PROPERTY OWNED BY ARIZONA PUBLIC SERVICE COMPANY AND LOCATED AT 1500 EAST UNIVERSITY DRIVE, TEMPE, ARIZONA, IN MARICOPA COUNTY.

Docket No. L-00000D-14-0292-00169

Case No. 169

ORIGINAL

RECEIVED
2014 SEP 12 A 8: 57
AZ CORP COMMISSION
DOCKET CONTROL

RUCO'S NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the testimony of Riley G. Rhorer, and the Witness Summary of Lon Huber, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 12th day of September, 2014.

Daniel Pozefsky
Chief Counsel

Arizona Corporation Commission
DOCKETED
SEP 12 2014

DOCKETED BY	

AN ORIGINAL AND TWENTY-FIVE COPIES of the foregoing filed this 12th day of September, 2014 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ mailed this 12th day of September, 2014 to:

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Thomas Campbell
Lewis Roca Rothgerber LLP
201 E. Washington St., Suite 1200
Phoenix, Arizona 85004

Melissa M. Krueger
Linda J. Benally
Pinnacle West Capital Corporation
Law Department
400 N. 5th St., MS 8695
Phoenix, Arizona 85004

John Foreman
Arizona Power Plant and Transmission
Line Siting Committee
Office of the Arizona Attorney General
PAD/CPA
1275 W. Washington St.
Phoenix, Arizona 85007

Patrick J. Black
Fennemore Craig, P.C.
2394 E. Camelback Rd, Suite 600
Phoenix, Arizona 85016

Rebecca Turner
100 S. Ashley Drive, Suite 1400
Tampa, Florida 33602

By Cheryl Fraulob
Cheryl Fraulob

Summary Testimony
RUCO witness Mr. Lon Huber

I plan to provide an overview of RUCO's approach to resource planning and the policy implications associated with such an approach. My testimony will touch on how RUCO views the changing electric utility landscape and the opportunities and risks consumers may face in the years ahead. It will conclude with a discussion on the proposed Ocotillo Modernization Project.

I will begin my testimony with a high level discussion on the following subjects:

- Emerging energy technologies
- System adaptability
- Consumer choice and empowerment
- Stranded costs

Following the above overview, I plan to comment on assumptions that may become more significant in current and future resource planning decisions than in years past. These include:

- Load growth projections
- Proper cost comparisons
- Projections around technology development and cost
- Consumer participation

Next, I will touch on the policy implications of RUCO's approach to resource planning in the changing utility environment. Topics will be:

- Resource procurement strategies
- Risk mitigation strategies

Finally, I plan to discuss why the proposed Ocotillo Modernization Project may not be the optimal choice for ratepayers given the above views on resource planning in a changing electric utility landscape.

I may supplement my oral testimony with a PowerPoint presentation.

DIRECT TESTIMONY OF

RILEY RHORER

RELATING TO APS' PROPOSED OCOTILLO MODERNIZATION PROJECT

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Riley Rhorer. My business address is 160 N. Pasadena, Suite101, Mesa, Arizona 85201.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am an electric utility consultant with the firm of K. R. Saline & Associates, PLC.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND GENERAL PROFESSIONAL ENGINEERING EXPERIENCE.

A. I graduated from Texas A&M University in May 1969, receiving a Bachelor of Science Degree in Electrical Engineering. I am a registered professional engineer in the states of California and Arizona. I have 42 years of experience in the electric utility industry, including 30 years as a consultant.

Q. PLEASE STATE YOUR EXPERIENCE IN POWER SUPPLY AND ELECTRIC TRANSMISSION.

A. I have worked as an employee of two utilities, the Los Angeles Department of Water and Power ("LADWP") and the Public Utilities Board of Brownsville, Texas

("BPUB"). At the LADWP, I was employed as a transmission engineer and planner. The LADWP transmission system includes extensive AC and DC transmission facilities. My experience as a transmission engineer included transmission design work, as well as responsibility for planning transmission systems improvements.

Following my years as a transmission engineer, I joined a newly formed planning group whose special purpose was to study power pooling and various power interchange arrangements between interconnected utilities and to initiate and provide support for the LADWP's contractual arrangements for power interchanges with other utilities. While in this group, I evaluated power purchase and sales opportunities for LADWP, as well as opportunities to jointly participate in generating projects remote from the LADWP's service area.

At BPUB, I served as Director of Engineering and Planning, where my duties included management and supervision of all planning and engineering activities related to BPUB's electric power and water supply, transmission and distribution facilities, and its wastewater collection and treatment facilities. I also had management responsibilities for the power plant, and I represented BPUB in its participation in various committee meetings of the Electric Reliability Council of Texas ("ERCOT").

As a consultant, I have performed engineering services for clients in the states of Texas, New Mexico, Louisiana, Oklahoma, Missouri, Kansas, Utah, Colorado, South Dakota, Arizona, California and Florida. These services have included a variety of economic analyses, planning studies, contract analyses, power supply recommendations and negotiations related to power supply and transmission arrangements.

I have presented testimony before the Federal Energy Regulatory Commission, the Public Utilities Commission of Texas ("PUCT"), the New Mexico Public Utilities Commission and the California Energy Resources Conservation and Development Commission.

In 2007, I presented testimony before the PUCT on the establishment of Competitive Renewable Energy Zones ("CREZs"). My testimony was provided on behalf of several large wind developers and included recommendations and support for transmission solutions that would enable my clients to development specific CREZs.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Residential Utility Consumers Office ("RUCO").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to highlight concerns with the power supply planning upon which Arizona Public Service ("APS") has relied to identify and evaluate alternatives to the proposed Ocotillo Modernization Project and to recommend what APS should do to address those concerns. Until these concerns are addressed and the need for the additional 290 MW clearly established as well as all alternatives exhausted RUCO cannot recommend anything beyond replacing the 220 MW steam turbines.

Q. WHAT DO YOU MEAN BY ADDRESSING THESE CONCERNS?

A. I mean APS needs to do more than explain away resource options such as energy storage and to do more than just screen out unit options such as the Wartsila 18V50 because it does not meet a questionable size requirement or because APS has failed to consider important beneficial characteristics of competing options while ignoring detrimental characteristics of the selected LMS100s.

Q. HAVE YOU PERFORMED ANY ANALYSES IN SUPPORT OF YOUR TESTIMONY?

A. While I have performed some high-level calculations, using the tabulated data from APS presentation materials, I have not performed any independent analyses, sufficient to recommend alternatives to the Ocotillo Modernization Project. The compressed time-line for reviewing the APS presentation materials and preparing pre-filed testimony has precluded my doing more than making some general observations and recommending areas that deserve further analysis by APS. To illustrate the limitations, we just received a bulk of data requests back from APS on the 10^{th} of September. In any regard, my review of the APS presentation materials has led me to conclude that APS has not (or at least has not shown that it has) evaluated certain alternatives to the Ocotillo Modernization Project.

Q. WHAT APS PRESENTAION MATERIALS DID YOU REVIEW IN SUPPORT OF YOUR TESTIMONY?

A. For my testimony, I reviewed portions of the following documents:

- APS Ocotillo Modernization Project Ten Year Plan Filing, Ocotillo Modernization Project Load Flow, Transient Stability, Post-Transient, Short Circuit, and MLSC Analysis, April 2014
- APS 2014 IRP, April 2014
- APS 2012 IRP, March 2012
- APS Ocotillo Modernization Project Reliability, Location, Technology Technical Review Packet, July 2014
- APS Combustion Turbine Expansion Plan, March 2012
- APS Ocotillo CT 3-7 Expansion Study
- APS' presentation, entitled "Ocotillo Expansion Technology Selection for Peaking Service Duty"
- Revised Attachment D.3 of APS 2014 IRP
-

Q. COULD YOU PROVIDE A BRIEF DESCRIPTION OF THE POWER SUPPLY PLANNING PROCESS?

A. In its most basic form, power supply planning involves the identification of power supply needs and the evaluation of the various means to satisfy those needs with the goal of developing a resource plan that is estimated to provide maximum benefit to APS' ratepayers. Because most of the resource options available to APS require lead times, the resource plan must identify power supply needs for future years. The resource plan also should take into account APS' interaction with the market on behalf of its ratepayers.

Q. DO YOU HAVE CONCERNS WITH THE WAY APS HAS IDENTIFIED ITS POWER SUPPLY NEEDS?

A. Yes. In its 2012 IRP, APS projected its total peak load requirements in 2014 to be 8,644 MW, whereas the 2014 IRP projects 2014 total peak load to be only 8,124 MW.[1,2] Moreover, taking into account additional emphasis on Energy Efficiency ("EE") Standards and distributed generation ("DG") programs, APS' forecasted growth rate of over 3% per year appears to be too high.[3] APS has also identified 1,400 MW of expiring power purchase contracts.[4] This magnitude of contract retirements will free a lot of capacity on the market and likely places APS in a good position to either renew such contracts or arrange new contracts under favorable conditions. APS should evaluate (which apparently has it has not done[5]) and present the potential for securing favorable purchase power contracts to replace those that are expiring. Finally, APS has asserted a number of resource-specific needs that require more scrutiny.

Q. COULD YOU PLEASE IDENTIFY AND DISCUSS THE RESOURCE-SPECIFIC NEEDS WITH WHICH YOU TAKE ISSUE?

A. The resource specific needs with which I take issue are enumerated and discussed below.

---

[1] APS 2012 IRP, Attachment F.1(a)
[2] APS 2014 IRP, Attachment F.1(a)(1)
[3] The 3% growth rate is calculated from APS 2014 IRP, Attachment F.1(a)(1)
[4] APS 2014 IRP, page XVI.
[5] APS 2014 IRP at page 77. APS' "plans to deploy a combination of market-based solutions, along with additional capacity at Ocotillo" is not a substitute for assessing the potential of securing favorable purchase power contracts.

(1) First, APS has focused its evaluations on resources that can be added within the Phoenix Valley Load Pocket ("PVLP"). I believe that this should be considered as a positive factor in evaluating resource options, not as a "need" that precludes consideration of resource options outside the PVLP. It is my understanding that: (i) the currently planned transmission system, provides adequate import capability in the form of maximum load serving capability ("MLSC") well into the future;[6] (ii) APS and others have plans to improve future transmission import capability; (iii) the additional MWs of the Ocotillo Modernization Project apparently reduces the MLSC in 2023;[7] and (iv) voltage support, if needed, can be provided by other means such as converting one or more retiring Ocotillo units to synchronous generator duty or adding a quick-response variable voltage device.

(2) Another "need" that APS has asserted is that construction of all five proposed LMS100's must be completed in a relatively short period of time (by summer 2018) because the costs increase dramatically if the schedule of the last three units is delayed either for 18 months or three years.[8] Again, I believe that this construction requirements should not be evaluated as a "need' but, rather, as a negative factor in evaluating resource options. APS should evaluate the estimated capital costs of delaying other resource options in a similar manner, including in this evaluation such options as the Wartsila unit listed in Table 1, page 2 of the Technical Review

---

[6] The Phoenix Valley is a constrained area meaning there is not enough transmission capacity to bring in all of the load requirements, thereby requiring some generation to operate. The MLSC is the maximum amount of load that can be served in a constrained area with the highest combined use of transmission imports and generation is utilized.

[7] See APS – Ocotillo Modernization Project Ten Year Plan Filing, , Exhibit B "Ocotillo Modernization Project Load Flow, Transient Stability, Post-Transient, Short Circuit, and MLSC Analysis", page 20, Table 15, filed in Docket No. IE-00000D-13-0002, linked at http://images.edocket.azcc.gov/docketpdf/0000153362.pdf

[8] See Ocotillo Modernization Project Reliability, Location, Technology Technical Review Packet ("Technical Review Packet"), dated July 2014, at page 13.

Packet. Moreover, while APS has evaluated the costs of construction delays, it is not evident that APS has evaluated the benefits to ratepayers of delaying the construction of the last three units or, for that matter, the entire Ocotillo Modernization Project. These potential benefits could include cost savings from delaying construction until APS could more fully utilize the entire amount of capacity being constructed. This is critical information that should be considered before approving a six to seven hundred million dollar project.

(3) APS identifies over-generation as a concern or "need" that the proposed Ocotillo Modernization Project will supposedly help to address.[9] This problem generally occurs when loads are low, renewable generation output is high and thermal generation (needed for system stability) is at a minimum. Although the LMS100 units can be turned off, re-started and ramp quickly, their role appears to be one of staying off-line until the over-generation condition is corrected by increased loads. System stability during such periods requires on-line resources that are contributing to system inertia that can react in seconds not minutes. Consequently, assuming the LMS100s are operated in the start/stop mode suggested by APS, they will not mitigate the over-generation condition; they will simply not exacerbate it. Moreover, APS asserts that "highly flexible generation [is] needed to facilitate market purchases" during low load periods where Palo Verde market prices are low and may even be negative during non-summer periods.[10] I believe this is misleading since APS may have little ability to purchase when loads are as low as

[9] *Id*. at page 6 and 7.
[10] *Id.* At page 6.

APS has indicated they may be.[11] APS should fairly and fully evaluate energy storage resource options that actually mitigate the over-generation condition and, in fact, do facilitate market purchases when prices are low or even negative.[12] Energy storage would add load when it is most needed, reduce the ramping requirement and improve the efficiency of thermal units that are otherwise operated at their minimum levels. Assuming the types of pricing suggested by APS, especially negative pricing, the savings in energy costs could easily outweigh the higher capital costs for energy storage.

(4) APS asserts that "system reliability and projected growth suggest an optimum size for additions in the range of 50 to 125 MW."[13] How this "need" for an optimal sized unit relates to growth is unclear since APS wants to install all 500 MW by 2018 even though it is in excess of the capacity that is needed for growth out to 2018. APS' growth assertion is even more unclear since smaller units can be added incrementally to closer align with resource needs over time. As for reliability, smaller units increase reliability by presenting a smaller impact when any unit is out of service whether for maintenance or forced outage. Finally, smaller units provide even more flexibility and efficiency (at least, in the case of the Wartsila units) in dealing with the type of solar variability that APS suggests is possible, "depending on cloud cover".[14] I believe that APS has unfairly penalized the smaller units in its evaluations.[15]

---

[11] *Id.* At page 6.
[12] APS would be paid to store the energy when prices are negative at Palo Verde.
[13] See APS' presentation, entitled "Ocotillo Expansion Technology Selection for Peaking Service Duty" at page 4.
[14] Technical Review Packet at page 7.
[15] See APS' presentation, entitled "Ocotillo Expansion Technology Selection for Peaking Service Duty" at page 7.

(5) APS has listed pumped storage as requiring a 10-year lead time. Surely, APS is aware of the ongoing Longview Energy Exchange ("LEE") project scheduled to be in service by 2021.[16] Ostensibly, the LEE project would provide many of the generating characteristics APS identified as desirable. APS could likely serve its interim resource needs by any number of other means such as contract extensions, delayed retirements and/or market purchases during the summer months.

(6) APS has penalized the Wartsila units for air emissions even though their data shows that CO_2 emissions for the LMS 100s and the Wartsila 18V50 are 1,115 lbs/MWh and 1,021 lbs/MWh, respectively.[17,18] Also, APS notes that has the Wartsila units consume no water, but apparently did not consider this fact in screening out the Wartsila units from further evaluation.[19,20]

Q. WHAT ARE YOUR CONCERNS WITH THE WAY APS PLANS TO MEET ITS POWER SUPPLY NEEDS?

A. I've addressed APS' needs assessment above, including resource-specific needs. Of equal concern is APS' approach to addressing alternatives to the Ocotillo Modernization project (i.e, eliminating them without evaluation) and presenting the case for the Ocotillo Modernization Project. For instance, APS' presentations selectively take into account APS' interaction with the market. On the one hand, APS provides a "stand-alone" load duration curve of its system load requirements

[16] See http://www.westconnect.com/filestorage/2152012_Longview_Energy_Exchange_SWAT_Presentation_Final.pdf.
[17] APS Revised Appendix D.3 – Generation Technologies from APS 2014 IRP, page 286
[18] APS Ocotillo CT3-7 Expansion Report, Table 1 – Combustion Turbine Screening Results
[19] APS Revised Appendix D.3 – Generation Technologies from APS 2014 IRP, page 286
[20] APS Ocotillo CT3-7 Expansion Report, Table 1 – Combustion Turbine Screening Results

to demonstrate a need for peaking capacity.[21] Then, on the other hand, APS asserts that "highly flexible generation [is] needed to facilitate market purchases" at the Palo Verde market hub.[22] It would be better if APS evaluated (if it has not done so) and presented preferred and alternative resource plans in a way that addresses these two "needs" in a more unified manner. Essentially, APS' system is not isolated and, in my view, it makes no sense to evaluate or to present "needs" as if it were. APS' evaluations should include a realistic expectation of how APS' resource decisions will take into account the market on behalf of its ratepayers.

Q. WHAT ALTERNATIVES ARE YOU RECOMMENDING THAT APS FULLY AND FAIRLY EVALUATE?

A. APS' selection of LMS100s may turn out to be the best resource option; but I am not convinced, based on the concerns stated above. I am recommending that APS evaluate the following alternatives to the Ocotillo Modernization Project:

(1) Given the over-generation circumstances that APS has described, APS should evaluate energy storage options, including the LEE pumped storage project discussed above. Also, other energy storage technologies should be given further consideration. For example, Liquid Air Energy Storage ("LAES") which is also known as Cryogenic Energy Storage ("CES") is an option. "Although novel at a system level, the components and sub-systems of LAES systems are mature technologies available from major OEMs and, as a whole, the technology draws

[21] Technical Review Packet at page 4.
[22] *Id.* At page 6.

heavily on established processes from the power generation and industrial gas sectors, with known costs, performance, and life cycles."[23]

(2) From my review, as discussed above, APS may have: (i) unjustly penalized the Wartsila 18V50 units, (ii) not considered some of their benefits and (iii) possibly ignored "penalty factors" that should have been applied to the LMS100 units. APS should re-assess the Wartsila units, and especially the possibility of staging their deployment over time to more closely align with APS' growing needs.

(3) Given the rapidly changing environment in the electric power industry (e.g., Energy Imbalance Market implementation, emphasis on renewables and energy storage, etc.), APS should evaluate resource plans that postpone thermal resource additions at this time. These "postponement plans" could include any combination of delayed retirements, transmission improvements, contract renewals and interim market purchases in lieu of the Ocotillo Modernization Project as proposed. It is critically important to understand the cost consequences to the ratepayers of constructing more capacity than is needed, especially with respect to sensitivities such as lower than expected load growth. Also, APS has described possible over-generation conditions that energy storage is more suitable at addressing as discussed above. It is therefore important to understand how resource technology decisions now can adversely affect APS' ability to make more appropriate resource technology decisions (e.g., energy storage) in the not-too-distant future.

[23] See http://energystorage.org/energy-storage/technologies/liquid-air-energy-storage-laes.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. The following are my conclusions, based on a review of APS presentation materials.

(1) APS' forecasted growth rate of over 3% per year appears be too high.

(2) APS has the opportunity and, therefore, should evaluate and present the potential for securing favorable purchase power contracts to replace those that are expiring.

(3) APS should not exclude consideration of resource options outside the Phoenix Valley Load Pocket.

(4) APS should consider resource options that do not have as severe cost consequences as the proposed LMS100s when staged over a longer period of time; and APS should evaluate the cost benefits to ratepayers of delaying construction of new thermal additions until APS could more fully utilize the entire amount of capacity being constructed.

(5) APS should fairly and fully evaluate energy storage resource options that actually mitigate the potential over-generation condition that APS has identified and facilitate market purchases when prices are low or even negative at the Palo Verde hub.

(6) APS has unfairly penalized smaller units in its evaluations.

(7) APS' assertion that pumped-storage requires a 10-year lead time does not apply to the ongoing Longview Energy Exchange project; therefore APS should evaluate participation in this energy storage project along with suitable means of meeting APS' interim requirements until its projected in-service date of 2021.

(8) APS' evaluations should include a realistic expectation of how APS' resource decisions will take into account the market on behalf of its ratepayers.

(9) APS should re-assess the Wartsila 18V50 units, and especially the possibility of staging their deployment over time to more closely align with APS' growing needs.

(10) APS should evaluate resource plans that postpone thermal resource additions at this time.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit 3 to Sierra Club's April 9, 2015 Comments

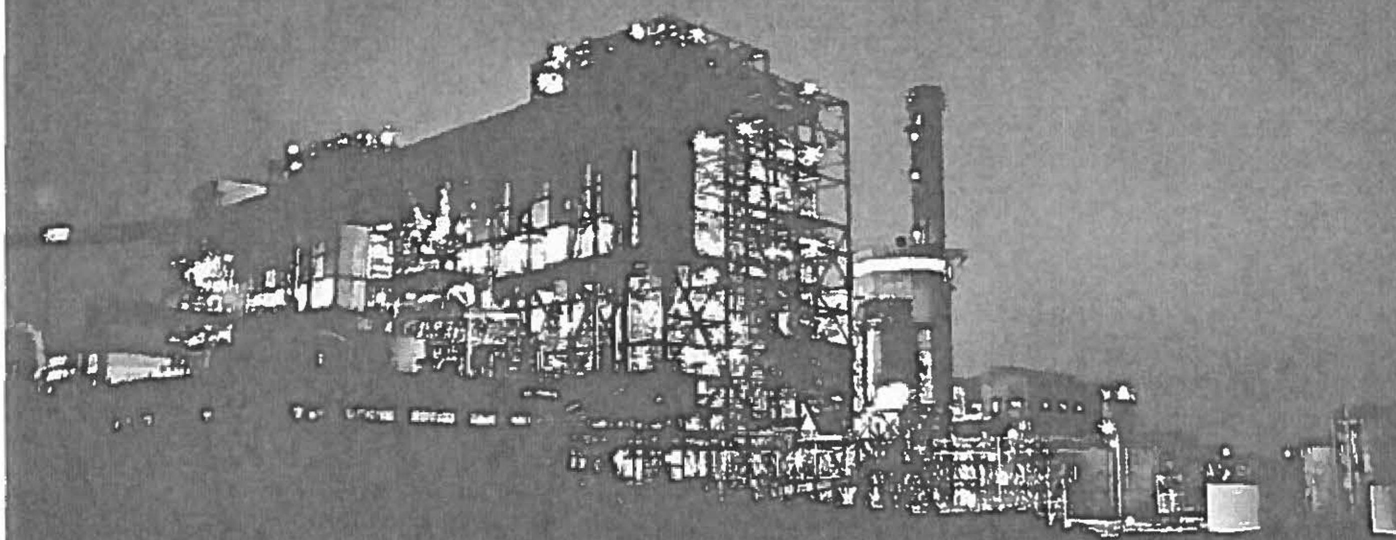
POWER

BUSINESS AND TECHNOLOGY FOR THE GLOBAL GENERATION INDUSTRY

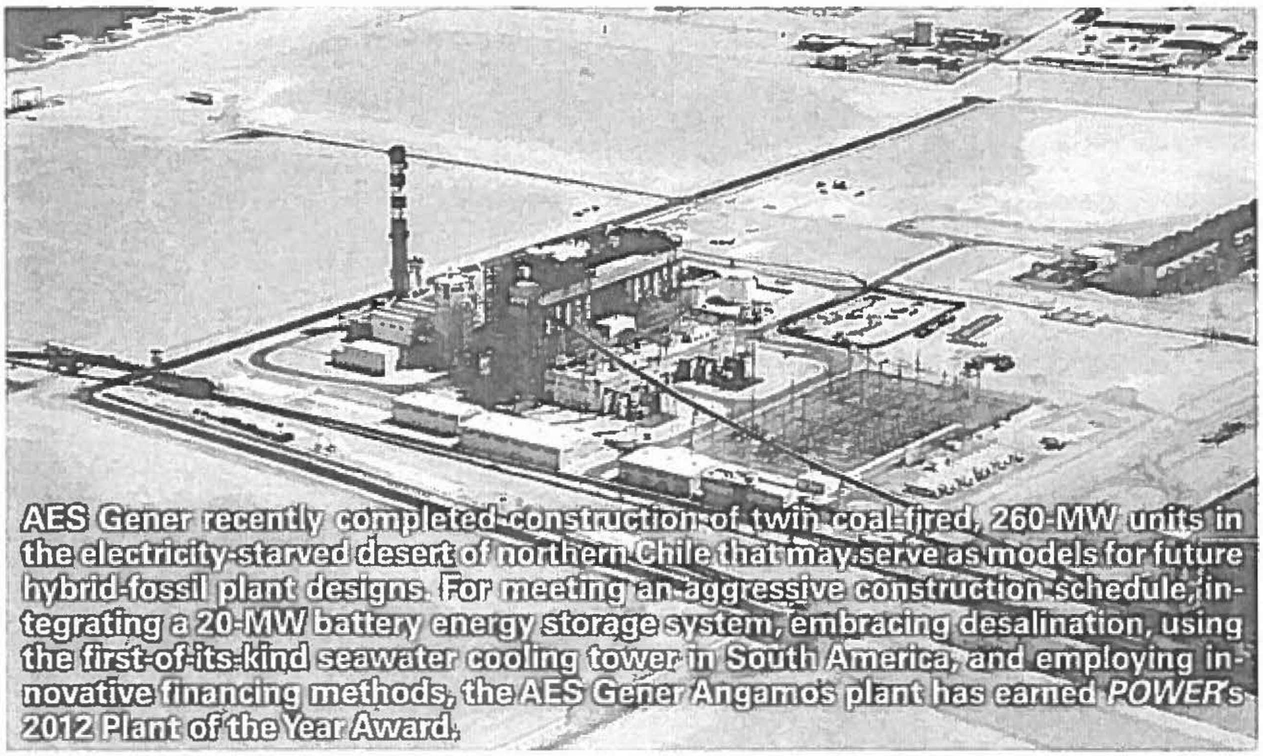
www.powermag.com

Vol. 156 • No. 8 • Electronically reprinted from August 2012

2012 Plant of the Year: AES Coal-Hybrid Plant in Chile



AES Gener's Angamos Power Plant Earns *POWER*'s Highest Honor



AES Gener recently completed construction of twin coal-fired, 260-MW units in the electricity-starved desert of northern Chile that may serve as models for future hybrid-fossil plant designs. For meeting an aggressive construction schedule, integrating a 20-MW battery energy storage system, embracing desalination, using the first-of-its-kind seawater cooling tower in South America, and employing innovative financing methods, the AES Gener Angamos plant has earned *POWER*'s 2012 Plant of the Year Award.

By Dr. Robert Peltier, PE

Courtesy: AES Corp

AES Gener S.A. is a Chilean publicly listed power generation company that has invested heavily in the future of the Chilean economy. The sixth and seventh most recent units to enter service as part of AES Gener's $3 billion, 1,638-MW power plant expansion plan were the two units at the Angamos Power Plant (Angamos) on the Pacific coast of northern Chile. Before examining the unique design features of this coal-hybrid plant, it's useful to look at the Chilean electricity industry and the important role that independent power producers (IPPs) play in the country's economy.

AES Gener, 71% owned by U.S.-based AES Corp., is the second-largest electricity generating company in Chile. Pension funds (14%) and public investors (15%) hold the remaining stock. AES, based in Arlington, Va., is one of the largest global power companies. It operates 13 utilities and 121 generation facilities in 28 countries.

The Chilean government contracts with AES Gener for the supply of electricity in two principal markets: the Central Interconnected System (SIC) and the Greater Northern Interconnected System (SING) in Chile. These separate regions were formed with the privatization of the Chilean electricity sector in the 1980s, when all generation, transmission, and distribution systems were turned over to private ownership. AES Gener, one of the largest IPPs in Chile, operates 16 power plants in the country, accounting for 3,821 MW of capacity—2,241 MW in the SIC and 1,465 MW in the SING.

AES Gener enjoys a 22% share of the Chilean electricity market based on installed capacity. In the SING, where electricity consumption is dominated by mining (90%), the company's market share is approximately 32%. Mining interests represent about half of the country's industrial infrastructure. In the SIC, which covers over 92% of Chile's population, including the densely populated Santiago metropolitan area, the company's market share is 19%. As of March 15, 2012, AES Gener's market capitalization was approximately $5 billion.

In Chile, AES Gener's diverse generation portfolio—consisting of hydroelectric, coal, gas, diesel, and biomass facilities—allows it to flexibly and reliably operate under a variety of market and hydrological conditions. The company's power plants are located near the principal electricity consumption centers, including Santiago, Valparaiso, and Antofagasta, extending from Antofagasta in the north to Concepción in south-central Chile.

Shifting Fuel Mix

The availability of low-cost natural gas from Argentina delivered via pipelines built across the Andes Mountains in the late 1990s prompted construction of five combined cycle plants that were used to provide baseload generation to the SING. In 2004, Argentina began to curtail gas deliveries to Chile. The interruptions became increasingly severe over the next several years until gas deliveries were essentially halted in 2007. Dual-fuel combustion turbines allowed generators to switch to more-expensive fuel oil and continue to operate, but at much higher market prices.

The mines in northern Chile, which produce about 35% of the world's copper, were struggling to find enough electricity to support current operations at the time—never mind support aggressive expansion plans to meet the rapidly rising global demand for copper. Mining in Chile, though very competitive globally, requires significant electricity, particularly for pumping water to the mines, which are located in arid desert areas.

In sum, the loss of natural gas supplies and rising demand for power by the mines made construction of a new coal-fired power plant complex a necessity. AES Gener set out to build a new, two-unit coal plant, and so much more.

An International Project

In August 2008, AES Gener, through its subsidiary Empresa Eléctrica Angamos S.A., began construction on the greenfield, two-unit 520-MW (470-MWnet) Angamos Power Plant (Figure 1). A critical part of the project was construction of the 140-kilometer (km) Angamos-Laberinto transmission line and expansion of the Laberinto and Nueva Zaldívar substations, which were necessary for startup of the plant's transmission system. When completed in late 2011, the $1.3 billion Angamos plant was the first power plant constructed in the SING in more than 10 years. Table 1 lists key project milestones.

The expected average generation of the plant is 3,500 GWh/year. Its primary cus-

1. Treasure in the desert. AES Gener recently completed construction of the $1.3 billion, two-unit, 520-MW Angamos Power Plant in the desert of northern Chile. Located near the ocean, the plant features a water desalination plant and seawater cooling towers. The coal-hybrid plant includes 20 MW of electricity storage to stabilize local grid operations. *Courtesy: AES*

Table 1. Key milestones for the AES Angamos project. *Source: AES Corp.*

Project milestones	Date
Contract signed	Oct. 17, 2007
Limited Notice to Proceed 1, 2	Dec. 20, 2007
Limited Notice to Proceed 3	Dec. 30, 2007
EPC contract commencement date	Apr. 4, 2008
Boiler drum lift (Unit 1)	July 2009
Boiler drum lift (Unit 2)	Nov. 2009
Receive backfeed power	Jan. 2010
Initial firing (Unit 1)	Oct. 2010
Initial firing (Unit 2)	Mar. 2011
First synchronization (Unit 1)	Dec. 2010
First synchronization (Unit 2)	June 2011
Substantial completion (Unit 1)	Apr. 2011
Substantial completion (Unit 2)	Oct. 2011
Commercial operation	Unit 1: Apr. 11, 2011 Unit 2: Oct. 10, 2011

Table 2. Key Angamos performance parameters. *Source: AES Corp.*

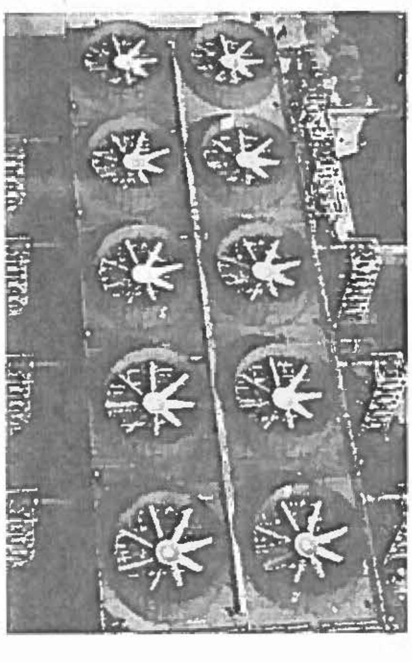
Parameter		Details
Net single unit output		230.7 MW guarantee. Test: Unit 1, 242.8 MW; Unit 2, 244.1 MW
Net plant heat rate (HHV)		10,478 Btu/kWh guarantee. Test: Unit 1, 9.849; Unit 2, 9,941
Turbine throttle conditions		2,220.6 psig/1,049 F main steam
		573 psig/1,049F reheat steam
Fuel		Pulverized coal facility using blended coals: Bituminous (min. 54%) and subbituminous (max. 46%)
Emissions	NO_x	500 mg/Nm³
	SO_2	200 mg/Nm³
	PM10 (filterable)	50 mg/Nm³
Boiler	Type	Subcritical
	Steam pressure	2,220.6 psig
	Steam temperature	1,049F
	Maximum continuous rating	741.4 tons/hr
Turbine	Rating	270 MWh
	Type	Single-flow high-pressure turbine, double-flow intermediate-pressure (reheat) turbine, four flow low-pressure condensing turbines
	Rotational speed	3,000 rpm
	Condenser vacuum	2.3 inches HgA
	Feedwater heaters	6 stages of feedwater heating, including deaerator
Generator	Voltage	18 kV
	Capacity	330 MVA @ 0.85 PF
Boiler feed pump configuration		3 x 50%-sized pumps
Cooling water system		Seawater cooling towers
Water pretreatment system		Desalinated water plant for service water; demineralized water plant for boiler feedwater makeup

tomers are BHP Billiton of Australia subsidiaries Minera Escondida and Minera Spence—both large copper mines. A long-term power purchase agreement was essential for obtaining long-term financing for the project, which is discussed later.

South Korea's POSCO Engineering & Construction Co., Ltd. (POSCO) was the engineering, procurement, and construction (EPC) contractor. Doosan Heavy Industries

2. Clean air was a priority. A full complement of air quality control system (AQCS) equipment—an electrostatic precipitator, fabric filter, and spray dryer absorber for removing SO_2 from the stack gas—was included on both units. It was the first use of this AQCS in South America. *Courtesy: AES*

3. Ocean cooling. The desert location of the Angamos plant did not allow using potable water for the cooling tower. Instead, a seawater cooling tower was used, which runs at about two cycles of concentration. *Courtesy: AES Corp.*



& Construction supplied the two coal-fired steam boilers outfitted with low-NO_x burners, and Italian manufacturer Ansaldo Energia provided the steam turbines and the two 350-MVA air-cooled generators. (See Table 2 for key performance characteristics of the project.)

Other key components—such as the coal- and ash-handling systems and air quality control system (AQCS), including electrostatic precipitators (ESP) and fabric filter (to remove particulates from the flue gas) and spray dryer absorber flue gas scrubber (to remove 95% of the SO_2)—were supplied by POSCO Plantec and other South Korean manufacturers. The AQCS used was the first of its kind in South America and was designed to meet the latest emissions standards, published in Chile in June 2010 (Figure 2).

POSCO received the notice to proceed for construction of the plant on Apr. 7, 2008.

Earlier, on Oct. 17, 2007, AES Gener had signed a turnkey EPC contract with POSCO valued at $870 million. Although POSCO started engineering the project at contract signing, actual construction at the site did not begin until June 2008. The groundbreaking ceremony was held on August 27, 2008, with more than 150 participating, including Energy Minister of Chile Marcelo Tokman, Korean Ambassador to Chile Lim Chang-Soon, POSCO E&C CEO Han Soo-Yang, AES Gener Chairman Andres Gluski, and President Felipe Creron. "Angamos coal-fired power station with a generation capacity of a large scale will contribute to Chile's economic growth," said Soo-Yang in his congratulatory speech.

Unit 1 was first synchronized to the SING grid on Dec. 21, 2010, and entered commercial service in April 2011, approximately two weeks ahead of the scheduled completion date. The second unit entered commercial service in October 2011, also several weeks ahead of schedule. This represents a significant achievement, especially given that a magnitude 8.8 on the Richter scale earthquake hit southern Chile in February 2010 and delayed construction by about a month because 70% of the workers lived in the affected area. Even so, POSCO completed both units early and earned a $7 million schedule bonus. In addition, unit performance tests found that the net output of both units was about 5% higher and the heat rate about 6% lower than the contract guarantee.

During the inauguration of Unit 1 in August 2011, the subsecretary of energy of Chile said, "This project meets the three basic conditions of energy policies with which we work in our country since it is competitive, it gives energy supply security and meets the highest environmental standards. Angamos complies with all environmental standards promulgated by President Sebastián Piñera last February and meets the requirements of Latin-American and are at the same level of the European Union in terms of exigency."

Unique Design Features

Fuel supply represented a special challenge because coal deliveries for Angamos are made by sea through a dry bulk terminal that was constructed in Mejillones, north of Angamos Port. Construction of the port coal-handling facilities was completed in January 2011. Bituminous and subbituminous coal, purchased on the global market, is transported to the plant's transfer tower, from which it is distributed across the coal pile. The port's solids-handling capacity is 1,500 metric tons (mt)/hour. It can receive cargoes up to 80,000 mt and has unloading rates between 17,000 and 20,000 mt/day.

Ash collected from the ESP hoppers is conveyed to a silo, where it is stored. The ash is then removed by truck and deposited in a special landfill or used in the construction industry as raw material for cement.

Although Angamos is located on the Pacific coast of northern Chile, 55 km north of Antofagasta and 1,300 km north of Santiago, it is situated in the 1,000 km–long Atacama Desert, the driest desert in the world, according to NASA. Annual rainfall in this desert is less than 0.004 inches, and some areas have gone hundreds of years with no rainfall. That makes water supply a major concern.

The Angamos plant is the first of its kind in South America to use seawater cooling towers (Figure 3). About 6,000 cubic meters/hour of seawater are supplied from a seawater makeup pumping station with siphon and submarine discharge pipe. This pumping station also supplies seawater to the thermal vapor compression (TVC) desalinization plants to produce boiler makeup water, firewater, potable water, service water, and water for other facility uses.

Demineralized water is produced by a multiple-effect distillation system as well as with the TVC unit. Desalinated water is next treated in a new demineralization plant using electro-deionization units to produce boiler-quality makeup water. Given the arid location, this water system is cost-effective and sustainable for a plant located close to the ocean.

A containerized portable reverse osmosis plant was shipped from South Korea to provide potable water during construction.

Table 3. Major contractors and equipment suppliers to the Angamos project. *Source: AES* Corp.

What	Who
Plant engineering and design	Hyundai Engineering Co., Ltd.
Plant construction	Sigdo Koppers S.A.
Steam generator	Doosan Heavy Industries Co., Ltd.
Steam generator erection	Ansaldo Energia/Sigdo Koppers S.A.
Steam turbine generators	Ansaldo Energia
BESS battery supplier	A123
Cooling tower	Hamon Korea
Fabric filter	STX
Material handling	Baekdoo
Semi-dry flue gas desulfurization	Gia Niro/STX
Distributed control system	Emerson Korea Inc.
Sootblowers, furnace wall cleaning	Doosan HHI
Condensers	Bumwoo Eng. Co., Ltd.
Feedwater heaters	Bumwoo Eng. Co., Ltd.
Condensate pumps	Hyundai Heavy Industries Co., Ltd.
Boiler feedwater pumps	Hyundai Heavy Industries Co., Ltd.
Fuel handling	Posco Machinery & Engineering Co., Ltd.
Auxiliary transformers	Hyundai Heavy Industries Co., Ltd.
Large power transformers	Hyundai Heavy Industries Co., Ltd.
Dry ash handling	Baekdoo Industry Machinery Co., Ltd.
Wet ash handling	Baekdoo Industry Machinery Co., Ltd.
Limestone preparation	Niro/STX
Water systems	GTF/GE

4. Battery storage lockers. Inside the Angamos BESS are about one million advanced lithium-ion battery cells, divided between 10 2-MW battery containers and five 4-MW power controls containers—plus the power electronics to manage the system operation. *Courtesy: AES Corp.*

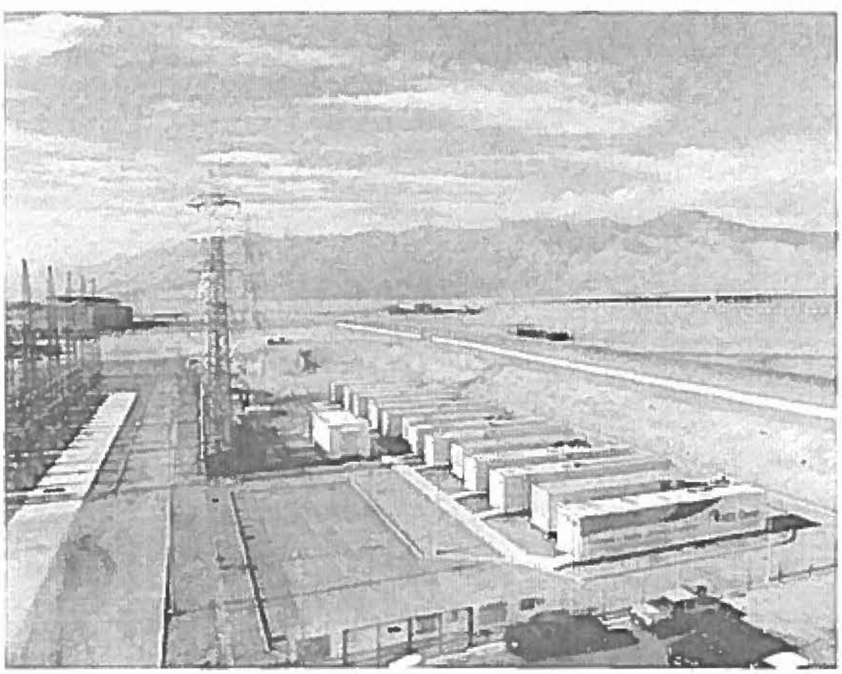


Table 3 lists the major contributors to the success of Angamos.

Because Chile is seismically active, the plant was designed to withstand a medium-intensity earthquake without tripping the plant offline. Should a severe earthquake occur, the plant design includes features that will minimize the length of a forced outage.

Buy the BESS

In close proximity to the Angamos plant, a 20-MW high-efficiency lithium-ion battery energy storage system (BESS) was installed. The advanced reserve capacity provided by the BESS enables Angamos to generate an additional 20 MW—that would otherwise be tied up to maintain the plant's grid spinning reserve—for up to 15 minutes virtually any time of the year. (Spinning reserve is used during an unexpected transmission loss, the failure of a power generator, or another accident that might otherwise necessitate reducing power to customers.) This "hybrid" part of the plant allows the plant to reduce the mandated spinning reserve, thus allowing the plant to operate at increased load. The BESS increases generation from the Angamos plant by 4%, or about 130 GWh each year. The BESS entered commercial service in May 2012 (Figure 4).

The Angamos project built on the success of an initial partnership between AES Gener and AES Energy Storage, both subsidiaries of AES Corp., to develop and install a 12-MW BESS associated with AES Gener's Norgener power plant, also in the SING, 172 km from Angamos, in only 15 months.

"As one of the largest power generators in Chile, we're consistently looking for ways to unlock [the] value of our existing plants while maintaining grid reliability and flexibility," said Felipe Ceron, CEO of AES Gener. "Since 2009, we've been working with AES Energy Storage to free up generating capacity at our Norgener plant by employing a battery-based installation to meet the power system's obligations for spinning reserve. That project has been in commercial operation for nearly three years, and we're now applying the service on a larger scale with Angamos."

AES Energy Storage worked with AES Gener throughout design, development, and installation of the Angamos BESS. Both entities worked with the CDEC-SING operator and other partners to configure the Angamos BESS to meet performance requirements of the electrical system operator and enable it to respond autonomously within established parameters. The BESS features system monitoring, SCADA, and integration with other operational systems. A123 Systems supplied the lithium-ion batteries for the project. ABB provided the power controls modules.

People First

Angamos is a significant contributor to the development of Chile's energy sector and the entire country. It also benefited the region by creating more than 3,000 jobs during the construction phase. Hiring local manpower was a priority, and some of the workers are staying with the company as plant operators.

To integrate the project with the local community, the company has developed a cooperation agreement with municipal schools to align students' capabilities with project needs. In addition, as part of the company's social responsibility program, it committed to enhancing the infrastructure of the Municipal Sport Center to improve the quality of life.

AES Gener maintains strict environmental and safety standards at its operations. Maintaining a workplace free of safety incidents was a remarkable challenge for a project that took around 14 million man-hours in a multicultural environment. The project recorded no fatalities and achieved 5 million man-hours without a lost-time accident and without a fatality. The achievement of that milestone demonstrated the strength of the programs and culture at the construction facility, such as proactive AES actions that include safety walks and work activity observations. The development of 10 Safety Management System action plans and completing each of them was a strong indication of the company's dedication to continuous safety improvement. Making the construction safety requirements a priority and the routine identification of workplace hazards was certainly a key to the milestone achievement.

Awards and Honors

AES Gener was named international recipient of the 85th Annual Edison Electric Institute's Edison Award on June 4, 2012, the electric utility industry's most prestigious honor, for its "distinguished leadership, innovation and contribution to the advancement of the electric industry for the benefit of all."

"AES Gener made the completion of the Angamos coal-fired power plant one of its highest priorities, and in doing so, illustrated the kind of contributions our industry is capable of making to customers," EEI President Thomas R. Kuhn said during the presentation.

"We are very proud of AES Gener for winning this prestigious award. The Angamos project combines low-cost, reliable power with our innovative lithium-ion batteries to increase available capacity and efficiency," said Andres Gluski, president and CEO of AES. "By delivering innovative projects such as Angamos, AES helps meet a growing demand for affordable energy in the markets we serve."

Financing the \$1.3 billion Angamos plant represented a significant challenge, as the process was initiated in 2008 and closed in the midst of the international financial crisis. However, a syndication of international banks, reassured by the financial strength of AES Gener, the EPC contractor, and the offtakers, allowed AES Gener to secure nearly \$1 billion under a 72/28 debt-to-equity project finance structure just months after the debt market meltdown in September 2008. Notably, \$675 million was guaranteed by Korea Export Insurance Corp. Financing also was guaranteed by two long-term contracts: with Minera Escondida, for 340 MW for 18 years, and with Minera Spence, for 90 MW for 15 years.

The Angamos project was also recognized as the Best Deal of the Year by *LatinFinance, Project Finance International,* and *Infrastructure Journal* in 2008.

Environmental Concerns

AES Gener, in partnership with several companies in the nearby city of Mejillones, formed the "Fundación para la Sustentabilidad del Gaviotin Chico" (Foundation for Sustainability of the Small Tern) with the aim of instituting measures that will preserve bird migration. It was the first time in Chile that the public and private companies joined together to contribute to the conservation of an ecosystem affected by the development of large infrastructure projects.

The foundation has found that the population of Gaviotin Chico has remained stable in the area of Mejillones, where the birds have found new nesting sites. With input from specialists working for this organization, companies and private citizens better understand the life cycle and migratory patterns of this bird species and have taken concrete actions to control the hazards that might affect them. ■

—Dr. Robert Peltier, PE is POWER's editor-in-chief.

Exhibit 4 to Sierra Club's April 9, 2015 Comments

Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Chamisa CAES at Tulia, LLC

Permit Number: PSD-TX-108130-GHG

February 2014

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On November 6, 2012, Chamisa CAES at Tulia, LLC (Chamisa) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On February 28, 2013, Chamisa submitted additional information for inclusion into the application. In connection with the same proposed construction project, Chamisa submitted an application for a Standard Permit for Electric Generating Facilities for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 5, 2013. The project proposes to construct a bulk energy storage system that will use compressed air energy storage (CAES) to produce up to 270 megawatts (MW) of electrical power. The Chamisa facility will be located near Tulia in Swisher County, Texas. The Chamisa facility will consist of two 135 MW trains. Each train will use CAES technology developed by Dresser-Rand and will be equipped with selective catalytic reduction (SCR) and catalytic oxidation units. Exhaust emissions from the turbine trains comprise the majority of air emissions from the plant site, with smaller emissions from an associated emergency generator engine, the natural gas and ammonia supply equipment, electrical equipment, and two cooling towers. After reviewing the application, EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the Chamisa facility.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant plans to comply with the requirements.

EPA Region 6 concludes that Chamisa’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Chamisa, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Chamisa CAES at Tulia, LLC
2300 North Ridgetop Road
Santa Fe, New Mexico 87506

Facility Physical Address:
1,000 meters west of I-27 intersection with SH 86.
Tulia, Texas 79088

Contact:
Alissa Oppenheimer
Managing Director
Chamisa Energy
2300 North Ridgetop Road
Santa Fe, New Mexico 87506
(505) 467-7800

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

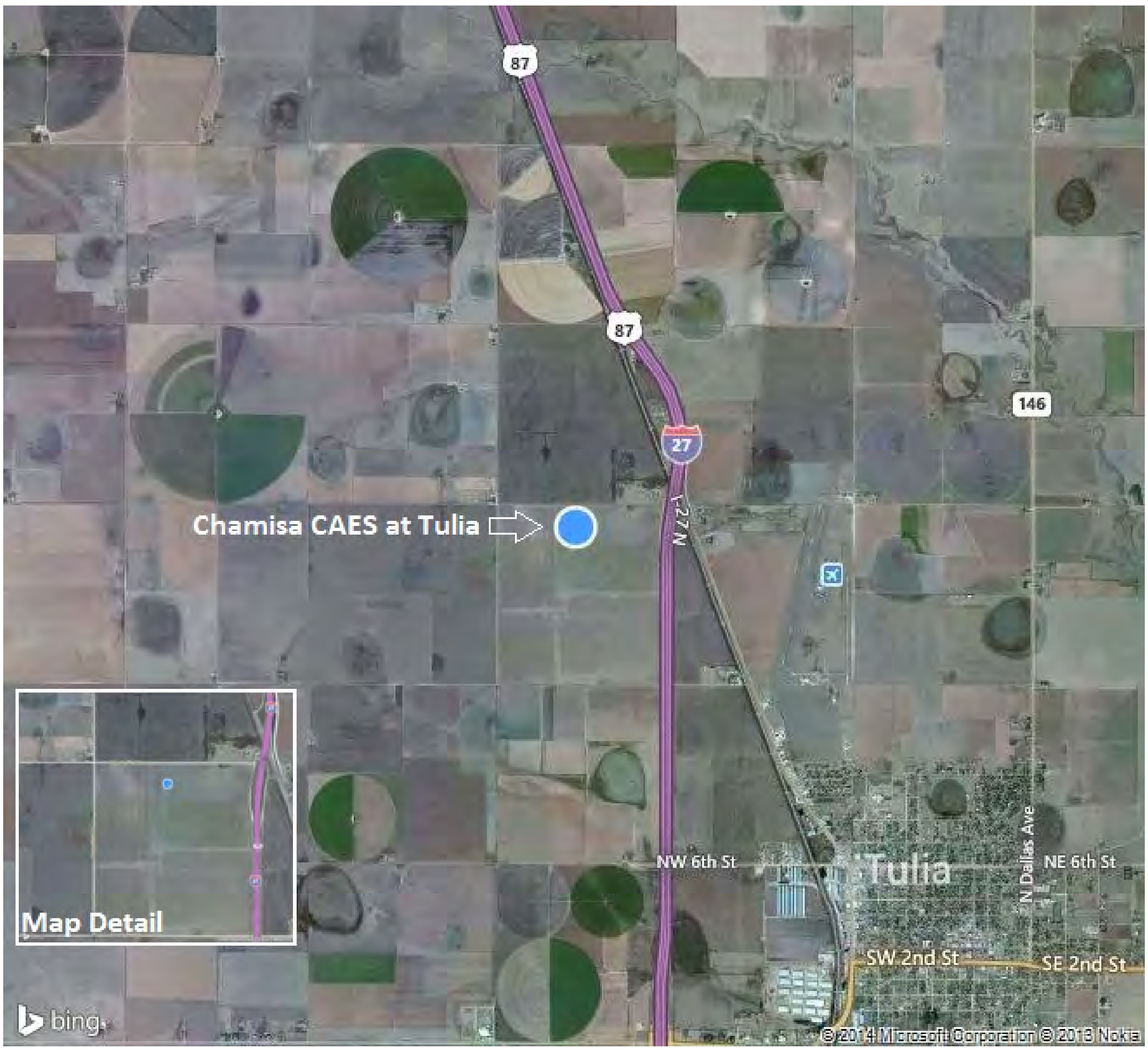
Facility Location

The Chamisa CAES at Tulia facility is located in Tulia, Swisher County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Wichita Mountains Wildlife Refuge, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows

Latitude: 34º 31' 14.46" North
Longitude: -101º 48' 17.77" West

Below, Figure 1 illustrates the proposed facility location for this draft permit.

Figure 1. Chamisa CAES at Tulia Location (Blue Circle)



IV. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that Chamisa's application is subject to PSD review for the pollutant GHGs as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, the potential GHG emissions are calculated to exceed the major source threshold of 250 TPY on a mass basis, as provided at 40 CFR § 52.21(b)(1), and the applicability threshold of 100,000 tpy "CO_2-equivalent" (CO_2e) potential to emit (Chamisa calculates CO_2e emissions of 401,326 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has issued the standard permit for electric generating facilities for non-GHG pollutants.[1]

EPA Region 6 takes into account the policies and practices reflected in the EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with recommendations in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR 52.21(o) and (p), respectively. Instead, EPA has determined that compliance with the selected Best Available Control Technology (BACT) is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules, with respect to emissions of GHGs. The applicant has, however, submitted an analysis to evaluate the additional impacts of the non-GHG pollutants to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project.

V. Project Description

The proposed GHG PSD permit, if finalized, would authorize Chamisa to construct a new compressed air energy storage (CAES) power plant near Tulia in Swisher County, Texas to produce up to 270 MW of electrical power. The facility will be known as Chamisa CAES at Tulia, LLC, referred to within this document as "Chamisa". The Chamisa facility will comprise two nominally rated 135 MW trains. Each train will use CAES technology developed by Dresser-Rand and will be equipped with selective catalytic reduction (SCR) and catalytic oxidation units. CAES technology can use electrical power from the utility grid (produced by

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

renewable and conventional power generation facilities) to operate multi-stage electric compressors to compress ambient air to pressures as high as 1,838 psia in underground storage caverns. Once stored, the compressed air is released as needed, heated by mixing and combusting it with natural gas, and exhausting it through an expansion turbine which drives an electrical generator to produce electricity. Bulk storage facilities such as Chamisa can hold weeks of megawatt-scale energy production capacity and provide an array of grid support services. Unlike traditional natural gas fired power plants, Chamisa will consume little water in its every day operations and use less fuel and produce fewer emissions than typical natural gas fired generators.

Exhaust emissions from the turbine trains comprise the majority of air emissions from the plant site, with smaller emissions from an associated emergency generator engine, the natural gas and ammonia supply equipment, electrical equipment, and two cooling towers. The compressed air for the project will be stored in caverns developed at the site.

Gas Expansion Turbine Trains (EPNs: TURB1 and TURB2)

Compressed air withdrawn from the storage caverns will first be preheated in a recuperator with hot exhaust gases from the process. Natural gas will be combusted with the pre-heated air in high-pressure combustors before entering a high-pressure expanding turbine stage. Water will be injected into the turbine stages at higher production capacities to maximize power production and help reduce the formation of nitrogen oxides. After expansion in the turbine, the turbine gases will be cooler and at a lower pressure. The exhaust gases will enter low-pressure combustors where additional natural gas will be combusted. The gases will then enter a low-pressure expanding turbine stage. Exhaust gases from that turbine will exchange heat with the incoming cavern air in a recuperator, and pass through a catalytic oxidation unit (for reduction of carbon monoxide and volatile organic compounds) and a selective catalytic reduction (SCR) unit (for reduction of nitrogen oxides) before exhausting to the atmosphere through two stacks. The electrical generators driven by the expansion turbines are rated to produce nominally 135 MW per turbine train, with a peak gross production of 140 MW.

Emergency Generator

A natural gas-fired generator with a capacity of 1,400 kW will provide emergency power when necessary. This generator will be equivalent to a Caterpillar SR4B-DM5498 generator set equipped with a G3516B LE (low emission) engine. The generator set will operate in non-emergency mode less than 100 hours per year for purposes of maintenance checks and readiness testing.

Cooling Towers

Heated cooling water from each compressor train and the generator set will be cooled in mechanical draft cooling towers equipped with high-efficiency mist eliminators to minimize drift emissions. The cooling towers do not have any GHG emissions.

Piping Equipment Fugitives

Fugitive methane emissions occur from piping equipment carrying natural gas at the site. Chamisa will use a Leak Detection and Repair (LDAR) program to help control the fugitive methane emissions.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The circuit breakers associated with the proposed units will be insulated with sulfur hexafluoride (SF_6). SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 2,920 lbs of SF_6. Instrumentation and an LDAR program will be utilized to identify and/or prevent leaks from the circuit breakers.

VI. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted by following the "top-down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in the top-down BACT process are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VII. Applicable Emission Units for BACT Analysis

The majority of the GHGs associated with the project are from emissions at combustion sources (i.e., gas expansion turbines and emergency engines). The project will have fugitive emissions from piping components which will account for 100 TPY of CO_2e, or less than 0.01% of the project's total CO_2e emissions. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following equipment is included in this proposed GHG PSD permit:

- Gas Expansion Turbine Trains (EPNs: TURB1 and TURB2)
- Emergency Generator (EPNs: EMERGEN)
- Natural Gas Fugitives (EPN: NG-FUG)
- Natural Gas Maintenance Purges (EPN: NG-PURGE)
- SF_6 Insulated Equipment (EPN: SF6-FUG)

VIII. Gas Expansion Turbine Trains (EPNs: TURB1 and TURB2)

There will be two expansion turbine trains (TURB1 and TURB2). The electrical generators driven by the expansion turbines are rated to produce nominally 135 MW per turbine train, with a peak gross production of 140 MW.

As part of the PSD review, Chamisa provided in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. EPA has reviewed Chamisa's BACT analysis for the gas expansion turbine trains, which is part of the record for this permit (including this Statement of Basis), and we also provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identify All Available Control Options

<u>Energy Efficiency Processes, Practices, and Design</u>

<u>Gas Expansion Turbine:</u>

- *Turbine Design* – The turbine models selected by Chamisa are highly efficient turbines, in terms of their heat rate (expressed as number of BTUs of heat energy required to produce a kilowatt-hour of electricity), which is a measure that reflects how efficiently a generator uses heat energy.

- *Reduction in Heat Loss* – Insulation is applied to the combustion turbine casing. This insulation minimizes the heat loss through the combustion turbine shell and helps improve the overall efficiency of the machine.
- *Instrumentation and Controls* – The control system is a digital type “model based control” supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full load and part-load conditions on a real time basis by ensuring good combustion.
- *Cooling Water* – Cooling water will be used to cool the electric generator sets.
- *Carbon Capture and Storage (CCS)*

Auxiliary Energy Efficiency Processes

Chamisa has proposed other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Continuous Emission Monitoring System (CEMS)* – The CEMS unit monitors and records data on effluents from the gas expansion turbine trains. Employing CEMS to monitor performance of the turbines provides data to optimize operations of the turbines and to keep track of the emissions from the turbines.
- *Operating Procedures and Practices* – Vendor specified operating procedures and practices will be used to ensure efficient operation of the equipment. Implementing Standard Operating Procedures (SOPs) formulated with guidance from vendor specified operating manuals and maintenance standards will be used to ensure proper maintenance of equipment and promote efficient operation.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for CCS.

Carbon Capture and Storage (CCS)

Chamisa estimated the CO_2 concentration at maximum production in the turbine exhaust stacks would be approximately 3.25%, based on fuel consumption and stack flow of 328,320 scfm (at standard temperature of 60 ^{o}F) and a discharge temperature of 210 ^{o}F. At lower production levels, the CO_2 concentration declines to a low of 1.80% at 25% capacity, and the discharge temperature is slightly higher at 232 ^{o}F. The exhaust flow rates at lower capacities are nearly proportional to the production level. CCS has not been demonstrated in practice on low CO_2 concentration emission streams such as this. EPA expects that the technical challenges of capturing a 3.25% CO2 stream are exacerbated when a combustion turbines unit is operated intermittently and therefore the CO_2 stream is more cyclic in nature rather than steady state. CCS has not been demonstrated in practice on streams derived from combustion turbines operating in a peaking capacity mode with a limited number of operable hours in a given year. Although CCS technology is generally available from commercial vendors, we do not have information indicating that this technology can be applied to dilute emissions streams generated from combustion sources with limited operable hours such as a CAES facility which will operate in a peaking capacity mode with as many as 700 startup and shutdowns throughout the year for each turbine. Fluor has built a new demonstration project in Germany to capture CO_2 in a flue stream from a coal-fired power station where the key feature of the pilot plant is a "one button start/stop" concept that allows the plant to automatically come on line when the power plant operator wants to capture CO_2. Since this type of "start/stop" operational process has not yet been demonstrated for combustion turbine power plants that operate intermittently when dispatched for peak demand electricity, we do not believe CCS is technically feasible for the proposed Chamisa project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The energy efficiency (and therefore emission control effectiveness) of many of the control options that remain in Step 2 cannot be directly quantified. Since these options are not mutually exclusive, and Chamisa proposes to implement them all for this project, this analysis does not rank and compare their effectiveness. We will proceed to consider the impacts of these control options in BACT Step 4.

Step 4 – Evaluation of Control Options in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Energy Efficiency Measures</u>

None of the Energy Efficiency Measures have been eliminated from the BACT review based on adverse economic, environmental, or energy impacts. The Chamisa facility has a low heat rate (conversely, a high energy efficiency) due to the use of a recuperator to recover heat from the turbine exhaust gas and use it to heat incoming air, and the use of modern gas turbine technology. By minimizing fuel usage, these techniques also minimize the release of GHGs. The Chamisa facility will achieve heat rates over a range of operating rates of 50-100% of capacity of 4,502-4,581 Btu (HHV basis) per net kWh produced. Furthermore, the other energy efficiency measures proposed by Chamisa make the suite of Energy Efficiency options the preferred option for BACT.

Worldwide there are two operating CAES plants. One of which is the Huntorf CAES Plant in Germany, and the other being PowerSouth's McIntosh CAES Plant located in McIntosh, Alabama. Huntorf, completed in 1978, is a 290 MW facility designed and built by Brown Boveri Corporation (now a component of Asea Brown Boveri (ABB)). Huntorf was originally built to provide peaking power service, as well as black start capability for nuclear power units in the region. Today the plant has increasingly seen use to help balance wind generation in North Germany. The Huntorf CAES Plant in Germany is not equipped with a recuperator leaving only the McIntosh CAES Plant for comparison. McIntosh was placed in commercial operation in 1991 as a single train CAES facility, rated at 110-MW output. McIntosh used a novel "motor/generator", whereby a single electrical machine fulfilled dual roles as a motor for compressing, and as a generator when operating in the expansion mode. The McIntosh recuperator incorporates features to improve tolerance to high-sulfur fuels. The Chamisa recuperator will perform at a higher level of heat recovery due to the plant's use of only low-sulfur fuel gas. The McIntosh recuperator was designed for a nominal effectiveness of 70%, the Chamisa recuperator is designed for a nominal effectiveness of 90%. In addition, Region 6 has proposed a GHG PSD permit for the APEX Bethel Energy Center in Tennessee Colony, TX. Data for the proposed Chamisa facility, the two existing CAES facilities, and the proposed APEX CAES facility are summarized in the table below.

	Chamisa CAES	**APEX[1]**	**McIntosh[2]**	**Huntorf[2]**
Power Production Capacity, MW	280 (total of 2 trains)	317 (total of 2 trains)	110	290
Heat Rate at Maximum Production, BTU (HHV)/kWh	4,389 (gross)-4,502 (net)	4,262 (gross)-4,390 (net)	4,555	6,175
Design Recuperator Efficiency,%	90	90	70	N/A (no recuperator)
No. of Expanders	2	3	2	2
Cavern Pressure, psig	940-1,800	1,900-2,830	1,100	600-1,000
Hours of Storage	36 - 48	100	26	3-4

[1]APEX Bethel Energy Center is a current Region 6 permit application that is being processed for a permit.
[2]Both of these plants are operating.

As with Chamisa and APEX Bethel, the compressors are electrically driven with no GHG emissions and the expanders are natural gas combustors. It should also be noted that the cavern air storage pressures are considerably higher for APEX which also provides for additional storage for extended power generation.

The expander train's design features, the high pressure (HP) and low pressure (LP) expanders, and the associated combustors at Chamisa and APEX are very similar to the McIntosh equipment with one exception, that the APEX design has an additional HP topping turbine to accommodate the higher cavern well head pressure. Additionally, the Chamisa and APEX combustors will use water injection for NO_X control, whereas McIntosh does not use water injection.

The most important contributor to optimizing the energy efficiency for Chamisa is the improved recuperator efficiency at CAES at Tulia (90% for Chamisa versus 70% for McIntosh). The APEX Bethel Energy Center also proposes a recuperator efficiency of 90%. Other design changes, such as cooling water use and periodic tuning, have a meaningful impact on output (and hence capital cost on a $/kW basis) and specific air consumption, but they do not affect heat rate materially. The heat rate advantage of Chamisa shown in the table above is that Chamisa will have an energy conversion efficiency higher than CAES units currently in existence. The Chamisa CAES will be slightly less efficient than the proposed APEX Bethel facility. APEX is proposed to have a BACT limit of 558 lb CO_2e/MWh (gross) on a 365-day rolling average. Chamisa's proposed BACT limit is 575 lb CO_2/MWh (gross) on a 12-month rolling average. This Chamisa limit is slightly higher than APEX, due to the use of a third expander at APEX which allows a higher cavern well-head pressure, making the APEX facility slightly more efficient with a corresponding lower BACT limit than Chamisa.

Separating the compressor from the combustion expander and generator, in a CAES system, has additional advantages such as utilizing an electric compressor with no GHG emissions during non- peak hours for the compression of air, and when necessary, for additional power generation by having both compression and generation operations at the same time.

Additional BACT considerations are for the operations to use good combustion practices, good operating and maintenance practices to ensure complete combustion of the natural gas fuel, maximize heat recovery by monitoring the exit flue gas temperature and optimizing the air/fuel ratio in the combustors. The design will take into consideration insulation materials to minimize heat loss from the expanders, combustors, ducts, and the recuperator. Heat loss from the expanders and combustors will be further mitigated by the fact that these components will be housed within a building – i.e. not exposed to the elements.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the gas expansion turbine trains:

- Combustion Turbine Energy Efficiency Processes, Practices, and Design
  - Highly Efficient Turbine, Compressor, and Combustor Design
  - Use of Recuperator with 90% Efficiency
  - Periodic Turbine Burner Tuning
  - Reduction in Heat Loss
  - High Thermal Efficiency

  - Instrumentation and Model Based Controls
  - Cooling Water
- Auxiliary Energy Efficiency Processes, Practices, and Design
  - Use of CEMS
  - Efficient Operating Procedures
  - Personnel Training

BACT Limits and Compliance:

Chamisa requested the BACT limit for the gas expansion turbine trains to be an output-based efficiency limit expressed in pounds of CO_2 per megawatt hour (lbs CO_2/MWh). The GHG BACT limit for the Chamisa facility is 575 lbs CO_2/MWh on a gross electrical output basis on a 12-operating month rolling average basis. The limit proposed takes into account the range of loads from the lowest sustainable load of 25% to 100% load which reflects the highest production rate of CO_2 over the full operational range. These values reflect a maximum 3% deterioration in turbine performance between overhauls. Over the operating range of 50% to 100% load, the vendor performance data indicates a heat rate of 4,389 to 4,667 Btu (HHV)/kWh (gross). At lower loads, the heat rate would gradually increase to a maximum of 4,925 Btu (HHV)/kWh (gross) at the lowest sustainable load. The proposed BACT limit of 575 lbs CO_2/MWh (gross) includes a 2% contingency factor and directly measures and reflects the overall process efficiency of the gas expansion turbine trains.

The heat recovery performance of the Chamisa recuperator will be monitored continuously during plant operation. Pressure and temperature measurements of the air at the recuperator inlet and recuperator outlet, and of the combustion gas at the turbine exhaust will be monitored and compared to expected values based on the gas expansion train's air mass flow and gas fuel input.

On January 8, 2014, the EPA proposed New Source Performance Standard (NSPS), 40 CFR Part 60 Subpart TTTT, that would control CO_2 emissions from new electric generating units (EGUs).[2] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. The EPA proposed that new EGUs greater than 73 MW and equal to or less than 250 MW meet an annual average output based standard of 1,100 lb CO_2/MWh, on a gross basis. The proposed CO_2 emission rates from the Chamisa turbine trains are well within the emission limit of the proposed NSPS at 40 CFR Part 60 Subpart TTTT.

Chamisa will demonstrate compliance with the CO_2 BACT limit by the use of a CO_2 continuous emission monitoring system (CEMS) and also by recording the heat input to and the gross power output from the turbine. Chamisa shall install, calibrate, and operate the CO_2 CEMS and

[2] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 79 Fed Reg 1430, January 8, 2014. Available at http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. To demonstrate compliance with the CO_2 BACT limit using CO_2 CEMS, the measured hourly CO_2 emissions are divided by the net hourly energy output and averaged daily.

Chamisa proposes to determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6

The equation for estimating CO_2 emissions as specified in 40 CFR 75.10(3)(ii) is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour
MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole
Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor
H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5
Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

Chamisa is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR 75, Appendix D, which include:

- Fuel flow meter- meets an accuracy of 2.0%, required to be tested once each calendar quarter pursuant to 40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))
- Gross Calorific Value (GCV) - determine the GCV of pipeline natural gas at least once per calendar month pursuant to 40 CFR Part 75, Appendix D, §2.3.4.1

Additionally, this approach is consistent with the CO_2 reporting requirements of 40 CFR Part 98, Subpart D- GHG Mandatory Reporting Rule for Electricity Generation. Furthermore, Chamisa proposed CO_2 monitoring method is consistent with the recently proposed New Source Performance Standards, Subpart TTTT- Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (40 CFR 60.5535(c)) which allows for electric generating units firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected electric generating unit and using a site specific Fc factor determined in accordance to 40 CFR Part 75, Appendix F.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the combustion turbines and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month, rolling average.

An initial stack test demonstration will be required for CO_2 emissions from TURB1 and TURB2. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are approximately 0.01% of the total CO_2e emissions from the combustion turbines. Repeat testing shall be performed every 5 years, plus or minus 6 months, of when the pervious performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later to verify continued performance at permitted emission limits.

IX. Emergency Engine (EMERGEN)

The Chamisa facility will be equipped with one 1,400 kW natural gas-fired emergency generator to provide electricity to the facility in the case of power failure.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes engines powered by natural gas, or liquid fuel, such as gasoline or fuel oil.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, such as periodic readiness testing, and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Low Annual Capacity Factor* – Limiting the hours of non-emergency operation reduces the emissions produced. The emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engine is to provide a power source during emergencies, which includes outages of the combustion turbines. Natural gas is the lowest carbon fuel available and will be used as fuel in the emergency generator.
- *Good Combustion Practices and Maintenance* – Is considered technically feasible.
- *Low Annual Capacity Factor* – Is considered technically feasible since the engine will only be operated either for readiness testing or for actual emergencies.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engine, a ranking of the control technologies is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engine, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the natural gas-fired emergency generator:

- *Low Carbon Fuel* – The emergency engine will be natural gas-fired.
- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engine will not be operated more than 100 hours per year for non-emergency use. It will only be operated for maintenance and readiness testing, and in actual emergency operation.

Using the BACT practices identified above results in an emission limit of 107 tpy CO_2e for the Emergency Generator. Chamisa will demonstrate compliance with the CO_2 emission limit using the default emission factor and default high heating value for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(1)(i) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Mass or volume of fuel combusted per year, from company records.
HHV = Default high heat value of the fuel, from Table C-1 of 40 CFR Part 98 Subpart C.
EF = Fuel specific default CO_2 emission factor, from Table C-1 of 40 CFR Part 98 Subpart C.
1×10^{-3} = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the volume of fuel combusted.

X. Natural Gas Fugitive Emissions (NG-FUG)

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. The additional methane and CO_2 emissions from process fugitives have been conservatively estimated to be 85 tpy as CO_2e. Fugitive emissions are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of leak-less and/or seal-less equipment;*
- *Implementing a leak detection and repair (LDAR) program using a handheld analyzer;*
- *Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring; and*
- *Implementing an auditory/visual/olfactory (AVO) monitoring program.*

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless/Sealless Technology – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Diaphragm valves are not available for the high pressures in the gas supply system. Complete elimination of flanges and threaded connections in the fuel system would significantly increase the cost of initial installation, as well as cause increased downtime for maintenance. Other components such as flanges and valves inherently cannot be leakless, and the facility cannot be constructed, operated, or maintained without the use of flanges and valves. Therefore, installing leakless technology is technically infeasible for controlling process fugitive GHG emissions from flanges and valves.

Instrument LDAR Programs – LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in CH_4 service.

Remote Sensing – Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as an effective means for identifying leaks of hydrocarbon.

AVO Monitoring – Leaking components can be identified through AVO methods. AVO programs are common and in place industry and are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrumented monitoring can identify leaking CH_4, making identification of components requiring repair possible. This is the most effective of the controls.

Remote sensing using an infrared imaging has proven effective for identification of leaks. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[3]

As-observed AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify. This method, due to frequency of observation, is effective for identification of larger leaks.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.05% of the total project's proposed CO_2e emissions. Leak monitoring quarterly using instrument monitoring would cost approximately $6,000 annually. Leak monitoring using a camera (remote sensing) would cost approximately $16,000 annually. Leak repair costs are estimated to be approximately $5,000 per year. Leak monitoring using a camera could result in an overall reduction of 85% of the CO_2e emissions from equipment leaks. This would result in a cost effectiveness of $150 - $290 per ton of CO_2e. The 28LAER program credits a 97% control efficiency for valve leak reduction and a 75% control efficiency for flange/connector reduction. With an overall control efficiency of approximately 92%, costs for a 28LAER LDAR program would be $140 per ton CO_2e. Accordingly, given the costs of implementing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

[3] 73 FR 78199-78219, December 22, 2008.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas and natural gas piping components, Chamisa proposes to incorporate AVO as BACT for the piping components associated with this project in fuel gas and natural gas service. The proposed permit contains a condition to implement an AVO program on a weekly basis. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the AVO program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XI. Natural Gas Maintenance Purges (EPN: NG-PURGE)

During the first year of operation, the facility may have up to 8 maintenance purges from the natural gas supply which has been estimated at 1.7 tons/yr of methane, and 42.5 tons/yr of CO_2e. After the first year of operation, the facility will perform a quarterly maintenance purge from the natural gas supply which has been conservatively estimated at 0.85 tons/yr of methane, and 21 tons/yr of CO_2e.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of a Flare or other Control Device*
- *Minimization of Purges*

Step 2 – Elimination of Technically Infeasible Alternatives

Both options are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flaring of maintenance purges would reduce CH_4 and other hydrocarbons by 98%, CO_2e emissions would be reduced by 81% since the combustion of the hydrocarbon emissions would result in the formation of CO_2.

Minimizing purges would cause fewer emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Rental and operation of a portable flare once per quarter for the maintenance purge would cost approximately $3,500 per quarter or $14,000 annually. This results in a cost effectiveness of $810 per ton CO_2e.

Neither option has any significant adverse energy or environmental impacts.

Step 5 – Selection of BACT

Due to the high cost of flaring, flaring is not considered BACT for the maintenance line purges. Gas volumes in the system will be minimized through use of the shortest and smallest diameter line sizes consistent with the turbine performance requirements, and components such as filters and valves will be selected to maximize intervals between scheduled service and to minimize entrapped volumes of gas. The system will be designed so that components that may require more frequent service can be isolated, minimizing the volume of gas that may be lost during maintenance operations. BACT is determined to be the minimization of the number of purges performed in a year. Chamisa will be limited to performing no more than 4 purges per year after the first year of operation. Chamisa may perform up to 8 purges during the first year of operation.

XII. SF_6 Insulated Electrical Equipment (EPN: SF6-FUG)

The circuit breakers will be insulated with sulfur hexafluoride (SF_6) gas. SF_6 is commonly used in circuit breakers associated with electricity generation equipment. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 2,920 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of new and state-of-the-art circuit breakers that are gas-tight and require less amount of* SF_6
- *Evaluating alternate substances to* SF_6 *(e.g., oil or air blast circuit breakers)*
- *Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible*

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture…it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment". Therefore, there are currently no technically feasible options besides the use of SF_6.

Of the control technologies identified, only substitution of SF_6 is determined as technically infeasible. All other control technologies are technically feasible. The traditional LDAR program using a flame ionization detector (FID) will not detect SF_6. An infrared camera can detect leaks of SF_6 if calibrated for SF_6. The alternate leak detection program of a low pressure alarm, lockout and inventory accounting program (40 CFR § 98.303(a), equation DD-1), is an alternate operation for the enclosed pressure circuit breakers. Chamisa proposed to implement these methods to reduce and control SF_6 emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since Chamisa proposed to implement feasible control options, ranking these control options is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

No adverse energy, environmental, or economical impacts are associated with the technically feasible control options.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the SF_6 Insulated Electrical Equipment:

- The use of state-of-the-art enclosed-pressure SF_6 circuit breakers.
- The use of an LDAR program. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[4]

Chamisa will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[5] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation

[4] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.
[5] See 40 CFR Part 98 Subpart DD.

DD-1 of Subpart DD. Chamisa will implement a comprehensive leak detection and disposition program. This program will involve inventory-and-use tracking, leak detection by handheld halogen detectors, and low-gas density alarms. It will also include a recycling program so that SF_6 is evacuated into portable cylinders rather than vented to the atmosphere.

XIII. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Chamisa CAES, LLC ("Chamisa"), and its consultant, Blanton and Associates, Inc, ("Blanton"), and adopted by EPA.

A draft BA has identified three (3) species listed as federally endangered or threatened in Swisher and Castro counties, Texas:

Federally Listed Species for Swisher and Castro counties by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Whooping Crane	*Grus americana*
Mammals	
Black-Footed Ferret Grey Wolf	*Mustela nigripes* *Canis lupus*

EPA has determined that issuance of the proposed permit will have no effect on any of the three listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by Blanton on behalf of Chamisa submitted on December 10, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the proposed construction of the power generation facility on a 512-acre property and up to 19.5 miles of transmission lines. Blanton conducted a desktop review within a 1,000 meter radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review within the APE, several cultural resources survey was previously performed within the general of the APE and two previously recorded archaeological and historical sites were identified within 1000 meters of the APE. Both sites are potentially eligible for listing on the National Register; however both are outside of the APE. Based on the results of the field survey, that includes shovel testing, no archaeological resources or historic structures were found within the APE.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Chamisa will not affect properties potentially eligible for listing on the National Register.

On January 8, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVI. Conclusion and Proposed Action

Based on the information supplied by Chamisa, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Chamisa a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following:

Table 1 Annual Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
TURB1 TURB2	TURB1 TURB2	Gas Expansion Turbine Train 1 and Train 2	CO_2	397,144[4]	400,932[4]	575 lb CO_2/MWh (gross)[5] on a 12-operating month rolling average for each turbine. See Special Condition III.A.1.a.
			CH_4	28.5[4]		
			N_2O	9.96[4]		
EMERGEN	EMERGEN	Emergency Generator	CO_2	86	107[4]	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Condition III.B.2.
			CH_4	0.84		
NG-FUG	NG-FUG	Natural Gas Fugitives	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO program. See Special Condition III.C.
			CH_4	No Numerical Limit Established[6]		
NG-PURGE	NG-PURGE	Natural Gas Maintenance Purges	CO_2	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Limit to 4 purges per year, after the first year of operation. See Special Condition III.D.1.
			CH_4	No Numerical Limit Established[7]		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[8]	No Numerical Limit Established[8]	Instrumented monitoring and alarm/ LDAR. See Special Condition III.E.
Totals[9]			**CO_2**	**397,230**	**CO_2e 401,326**	
			CH_4	**34.2**		
			N_2O	**9.96**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. These values are for both turbine trains combined and is based on each turbine train operating for 5,000 hours per year at maximum production and includes MSS emissions. Each turbine train could operate at greater hours at lower production levels or at maximum production if the other train operated fewer hours.
5. The electrical output shall be measured at the generator terminals.
6. Natural gas fugitive emissions from EPN NG-FUG are estimated to be 0.04 TPY CO_2, 4 TPY of CH_4, and 100 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
7. Natural gas maintenance purge emissions from EPN NG-PURGE are estimated to be 0.018 TPY CO_2, 1.7 TPY of CH_4, and 42.5 TPY CO_2e during the first 12 months of operation. After the first year, the emissions are estimated to be 0.009 TPY CO_2, 0.85 TPY CH_4, and 21 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. SF_6 fugitive emissions from EPN SF6-FUG are estimated to be 0.0073 TPY of SF_6 and 166 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
9. Total emissions include the PTE for maintenance purges (first year) and fugitive emissions (including SF6). Totals are given for informational purposes only and do not constitute emission limits.

Exhibit 5 to Sierra Club's April 9, 2015 Comments

Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
For APEX Bethel Energy Center, LLC

Permit Number: PSD-TX-104511-GHG

November 2013

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR § 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On June 21, 2012, APEX Bethel Energy Center, LLC (APEX) submitted to the EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project known as the Bethel Energy Center (Bethel) in Anderson County, Texas. On October 12, 2012, APEX submitted additional information for inclusion into the application. In connection with the same proposed construction project, APEX received Standard Permit No. 104511 for its non-GHG pollutants from the Texas Commission on Environmental Quality (TCEQ) on August 24, 2012. The project proposes to use the compressed air energy storage (CAES) technology developed by Dresser-Rand to produce up to approximately 317 MW of electrical power. The Bethel plant will consist of two expansion turbines/generating trains each rated at 158.34 MW. GHG pollutants occur primarily from the exhaust emissions from the natural gas combustion turbine trains, with minor emissions from fugitive sources and an emergency generator engine. The turbines will use selective catalytic reduction (SCR) for reduction of nitrogen oxides and catalytic oxidation to reduce carbon monoxide. After reviewing the application, the EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the APEX Bethel facility.

This SOB documents the information and analysis the EPA used to support the decisions the EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant will comply with the requirements.

The EPA Region 6 concludes that APEX’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. The EPA's conclusions rely upon information provided in the permit application, supplemental information requested by the EPA and provided by APEX, and the EPA's own technical analysis. The EPA is making all this information available as part of the public record.

II. Applicant

APEX Bethel Energy Center, LLC
3200 Southwest Freeway, Suite 2210
Houston, Texas 77027

Facility Physical Address:
Intersection of County Rd. 2504 and F.M. 2706
Tennessee Colony, Texas 75861

Contact:
Stephen Naeve
Chief Operating Officer
APEX Compressed Air Energy Storage, LLC
(713) 963-8104

III. Permitting Authority

On May 3, 2011, the EPA published a federal implementation plan that makes the EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Bonnie Braganza
Air Permitting Section (6PD-R)
(214) 665-7340

Facility Location

The APEX Bethel Energy Center will be located near Tennessee Colony, Anderson County, Texas, and this area is currently designated “attainment” for all criteria pollutants. The nearest Class I area is the Wichita Mountains Wildlife Refuge, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows. Figure 1 illustrates the proposed facility location for this draft permit.

Latitude: 31º 53’ 16” North
Longitude: -95º 54’ 48” West

FIGURE 1
APEX Bethel Energy Center

IV. Applicability of Prevention of Significant Deterioration (PSD) Regulations

The EPA concludes APEX Bethel's application is subject to PSD review for the pollutant GHG, as described at 40 CFR § 52.21(b)(1) and (b)(49)(v). Specifically, under the project, the potential GHG emissions are calculated to exceed the major source threshold on a mass basis, as provided at 40 CFR § 52.21(b)(1), and 100,000 tpy "CO_2-equivalent" (CO_2e), as provided at 40 CFR § 52.21(b)(49)(v) (APEX calculates CO_2e emissions of 459,040 tpy). The EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). The applicant has indicated that the power generation will be limited to the NOx emissions in the TCEQ permit. At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has issued the standard permit for electric generating facilities for non-GHG pollutants.[1]

In evaluating this permit application, the EPA Region 6 considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, the EPA has determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. The applicant has submitted an impacts analysis of non- GHG pollutants to meet the requirements of 40 CFR §52.21(o), as it may otherwise apply to the project.

V. Project Description

The proposed GHG PSD permit, if finalized, would authorize APEX to construct a new compressed air energy storage (CAES) power plant near Tennessee Colony in Anderson County, Texas to produce up to 317 MW of electrical power. The facility will be known as the APEX Bethel Energy Center, LLC, referred to within this document as "APEX Bethel". CAES technology involves two major processes:

(1) Air compression and storage, and
(2) Air release for electricity generation.

During the air compression and storage process, electric motor driven compressors are used to inject air into an underground cavern for storage under high pressure. Electricity is generated by releasing the high-pressure air, heating it with natural gas combustion and expanding the air through sequential turbines (i.e., expanders), which in turn drive an electrical generator.

The site for the plant was selected to accommodate the high pressure storage of air in local underground caverns. The compressed air storage for APEX Bethel will be created by drilling a "cavern well" having a cemented well casing at a terminal depth of approximately 3,750 feet. Fresh water withdrawn from local groundwater wells will be pumped down the well to dissolve salt, creating the storage cavern. Salt brine withdrawn from the cavern during this "leaching" process will be injected into existing permitted brine disposal wells on nearby property. This leaching process is carefully controlled to produce a cavern of the desired capacity and shape. The cavern is expected to operate over a wellhead pressure range of approximately 1,900 to 2,830 psia (static pressure range). If full, the cavern will support approximately 100 hours of generation at near full rated output without recharge.

The CAES is a hybrid peaking power process using the energy of high pressure compressed air supplemented by natural gas fired multistage expansion turbines to generate electricity. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. Even though the CAES design includes the features similar to an industrial turbine, the design significantly differs from a conventional gas turbine. While the operation of the expander section for the conventional gas turbine operates at about the same pressure (254 psia) as the lowest pressure (third stage) expander for the CAES turbine/generator, a conventional gas turbine has a compressor and expander operating on a single shaft, resulting in a much

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

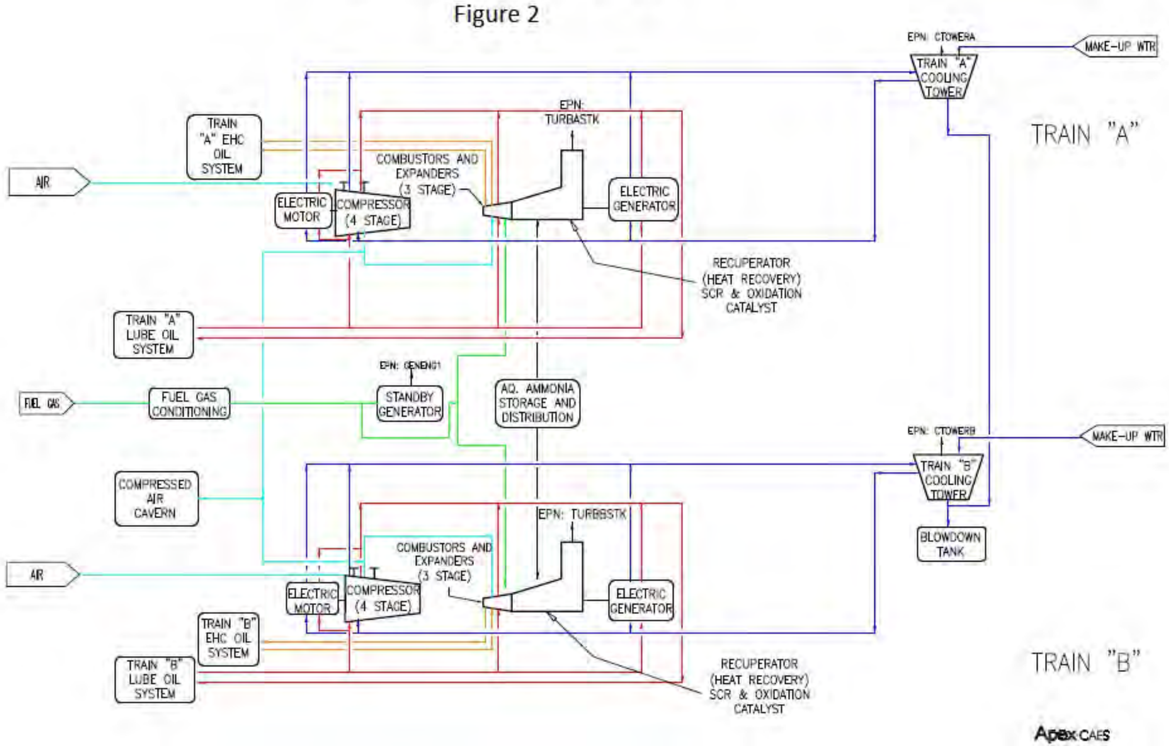
narrower turndown ratio than the APEX Bethel CAES design. The separation of the compression and expansion functions allows for greater operating flexibility for APEX Bethel to meet the Electric Reliability Council of Texas (ERCOT) market demands for energy during peak hours. The CAES multistage turbines operate from a 10% load range to full load at 100% with the ability to reach the required output within 5 minutes.

The APEX Bethel facility will comprise two Dresser-Rand CAES compression trains, each consisting of a set of multi-stage compressors driven by a dedicated 150 MW (nominal rating) electric motor. Each compression train will be capable of producing up to 1.4 million pounds per hour of air at a compressor outlet pressure of up to 2,830 psia. The process flow diagram for APEX Bethel is in Figure 2. It depicts the compressors, operating at design basis compression, under summer ambient conditions, and further assuming a “near” full cavern. Compression occurs in four stages. Because compression of air results in an increase in temperature, it is necessary to cool the air between the stages. Such cooling is accomplished via two heat rejection processes – an “air to air” heat exchanger and conventional shell and tube air to water heat exchangers, with the cooling duty split approximately 50/50 between each cooling method. Heated water from this process will be cooled in a conventional mechanical draft cooling tower. Make-up water to the cooling tower will be sourced from fresh water wells to be drilled in advance of plant operation to provide water for the cavern leaching process. Cooling tower blowdown will be discharged to the Trinity River. Maximum daily water consumption is expected to be approximately 1.8 million gallons. Annual water requirements are expected to be approximately 400 acre feet.

For power generation, the Bethel plant will consist of two Dresser –Rand expansion turbine/generator (ETG) trains (FIN/EPN TURBTRNA/TURBASTKA & TURBTRNB/TURBASTKB), each rated at 158.34 MW output at full load. The total generating capacity of the plant will be 317 MW (nominal power rating). High pressure air from the cavern passes sequentially through the three expanders, performing work (accompanied by a reduction in pressure) as the air flows through each stage of expansion.

Apex Bethel Train Flow Diagram

Figure 2



Each expansion train at the Bethel Energy Center will use three expanders, operating on a single shaft, connected to the generator during the expansion/generation process. High pressure (HP) air from the cavern passes sequentially through the three expanders (accompanied by a reduction in pressure) as the air flows through each stage of expansion. The APEX Bethel facility uses a HP topping turbine as the first stage of expansion followed by the HP intermediate stage and the low pressure (LP) stage of expansion operates at an inlet pressure of 228 psia.

At maximum generator output, approximately 400 lbm/second of air from the cavern header passes through a recuperator, where the air is preheated to a temperature of 600°F (degrees Fahrenheit) before entering the topping turbine, at a turbine inlet pressure of approximately 2,170 psia (at full rated output). Air is expanded in the topping turbine, resulting in a temperature and pressure drop. The air next flows to one of two high-pressure (HP) combustors. Pipeline quality natural gas is burned with the preheated air (from the recuperator) in the combustors, and the resultant heated gases enter the HP expanders at approximately 1,000°F and 800 psia. The gases exit the HP expanders to the last stage LP combustor, where additional natural gas is burned to increase the gas temperature for further expansion in the LP expander. Energy efficiency for this process is increased by making use of the heat from the flue gas to preheat the air to the combustors via the recuperator. The gases from the recuperator exhaust to the stack (EPN TURBASTK & TURBBSTK).

The addition of a topping turbine is a design feature unique to the Bethel plant and is made possible by the high pressure of the cavern in the plant. APEX Bethel chose this location on the basis of numerous site-specific geological and economic parameters, including ERCOT power market considerations, which is distinctively different from the existing CAES installation in McIntosh, Alabama (or at other sites which have been studied for CAES installation).

The proposed APEX Bethel Energy Center will also have a 740 kW emergency generator engine fired with natural gas (rich burn) and will utilize non-selective catalytic reduction (NSCR) for NOx reduction. The permit will restrict operations of the generator that includes maintenance and reliability testing to 50 hours per year.

There will be minor GHG fugitive emissions from equipment leaks and sulfur hexafluoride from the circuit breakers. Also there will be maintenance emissions from the natural gas pipeline/metering station that will vent 4 times a year.

Non-GHG emitting equipment consists of the cooling towers that cool compressed air and a 10,000 gallon 19% aqueous ammonia solution used for SCR to control NOx emissions from the combustors. The ammonia tank will be filled by vapor balance and will not have open vents; therefore, the ammonia delivery system only has fugitive emissions.

VI. BACT Analysis

The EPA conducted the BACT analyses as suggested in the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines five steps for conducting a top-down BACT analysis. Those steps are listed below:

1) Identify all available control options;
2) Eliminate technically infeasible control options;
3) Rank remaining control technologies;
4) Evaluate the most effective controls and document the results;
5) Select the BACT

Before discussing the BACT for the individual pieces of equipment, APEX Bethel provided a discussion on the need for grid level energy storage in the power (ERCOT) market for a quick response capability to supply electricity during peak demand. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. APEX indicates that at this time there are only two technologies, CAES and hydroelectric, that are commercially available and can provide sufficient storage capacity to be of value at the bulk power level. APEX conducted an evaluation of more than 20 potential sites in west and southeast Texas to identify potential cavern creation opportunities before selecting the Bethel Energy Center site. The Bethel Energy Center site was chosen for development of a CAES facility due to the presence of suitable geologic conditions, existing gas and electric transmission lines crossing the property, existing infrastructure to support cavern creation, and availability of groundwater as a water source.
Other commercially available technologies such as conventional gas turbine generation, wind, and solar are intermittent power sources and do not always provide the grid operator's need for flexible "standby"resources capable of responding quickly to deviations in system frequency. Therefore these technologies will not be evaluated in this BACT discussion, since the proposed project utilizing CAES meets all the APEX Bethel Energy Center requirements for economic operation within the ERCOT market. This is consistent with the EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily

include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26). Nonetheless, it should be noted that the APEX Bethel Energy Center is intending to provide secure, reliable capacity to the grid, assisting the grid operator in coping with the intermittent nature of solar and wind generation, and other renewable generation.

Applicable Emission Units for BACT Analysis.

The units/activities that directly or indirectly emit GHG emissions are:

- Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)
- Fugitives (EPN: FUG1))
- Natural Gas Maintenance Purges (EPN: MAINT1)
- Emergency Generator (EPN: GENENG1)

1. Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)

The APEX Bethel Energy Center will have two expansion turbine trains, with each train having a separate exhaust stack with a CO_2 analyzer. The turbines will utilize pipeline quality natural gas for combustion. APEX has estimated that the Bethel plant will have a maximum annual throughput of 7,807,409 MMBtu of natural gas for the combined trains with total CO_2 emissions of 456,296 tpy. The does not include natural gas usage at other sources such as emergency generator. The combustion turbines will be using SCR and oxidation catalyst which will increase the GHG pollutants by a small amount. The estimated emissions from the turbines of N_2O and CH_4 as CO_2e comprise about 0.54% of the total CO_2e from the turbines. Therefore the BACT analyses will focus primarily on technology to reduce CO_2 emissions. As part of the PSD review, APEX provided a five-step top-down BACT analysis for the combustion turbines in the GHG permit application. The EPA has reviewed APEX Bethel's BACT analysis for the gas expansion turbine trains, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit as summarized below.

Step 1 – Identify All Available Control Options

- *Carbon Capture Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Use of a Low Carbon Fuel for Combustion*
- *Electrical Generation Conversion Efficiency* – the formation of GHGs can be mitigated by design and selection of ultra-efficient combustion units.
- *Operational Energy Efficiency – Good combustion, operating and maintenance practices are a potential control option for improving the fuel efficiency of affected combustion units.*

Carbon capture and storage is a GHG control process that can be used by facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).[2] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine facility; the third approach, post-combustion capture, is available to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for CCS.

- **Carbon Capture and Storage (CCS)**

APEX estimated the CO_2 concentration in the turbine exhaust stacks would be in the range of 1.7 – 3.5%, based on fuel consumption and stack flow of 99,000 to 453,000 acfm at a temperature of 230^0F. CCS has not been demonstrated in practice on emissions streams like this that are more dilute in CO_2 concentration. Although CCS technology is generally available from commercial vendors, we do not have information indicating that this technology can be applied to more dilute emissions streams. Thus,

[2] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)
[3] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

we do not have sufficient information at this time to determine CCS to be technically feasible for the exhaust streams at this facility.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Other than CCS, which was eliminated in Step 2 above, the remaining technologies to reduce GHG are being evaluated for this project and we will rank these measures in Step 4.

Step 4 – Evaluation of Control Options in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Use of a Low Carbon Fuel

APEX proposes to use natural gas for combustion in the turbine expanders. The only other low carbon combustion fuel is hydrogen and this is not commercially available at this particular site. Typically hydrogen gas is a byproduct process vent gas in large chemical and refining plants and enters the plant fuel grid system. In this project, there are no processes that produce hydrogen and therefore natural gas is the commercially available low carbon fuel for combustion.

Energy Efficiency Design Measures for the Turbines/Generators

The APEX Bethel plant is designed to utilize high-efficiency, state-of-the-art, expansion turbines and associated combustors. Table 4 lists designs of CAES power generation plants.

Table 4

	APEX	**Chamisa CAES**[1]	**McIntosh**[2]	**Huntorf**[2]
Power Production Capacity, MW	317 (total of 2 trains)	280 (total of 2 trains)	110	290
Heat Rate at aximum Production, BTU (HHV)/KWH	4,262 (gross)- 4,390 (net)	4,389 (gross)- 4,502 (net)	4,555	6,175
Design Recuperator Efficiency,%	90	90	70	N/A (no recuperator)
No. of Expanders	3	2	2	2
Cavern Pressure, psig	1,900-2,830	940-1,800	1,100	600-1,000
Hours of Storage	100	36 - 48	26	3-4

1. *Chamisa is a current Region 6 permit application that is being processed for a permit*
2. *Both of these plants are operating*
3. *The APEX and Chamisa heat rates do not reflect the 3% adjustment for performance degradation*

Energy efficiency is normally expressed in terms of heat rate. The APEX turbine trains have an estimated heat rate of 4,390 BTU/kWh at maximum load and 4,773 BTU/kWh at low load (HHV basis). The heat rates have been adjusted to reflect a 3% degradation between system overhauls (per Dresser-Rand guidance). The energy efficiency for APEX Bethel are reflective of heat input divided by generator output measured at the generator terminals. Performance figures for APEX reflect site conditions at 60°F. There are two CAES facilities in operation worldwide: McIntosh, in Alabama, and the Huntorf facility in Germany. The addition of a topping turbine is a design feature not present in the two operational CAES plants and therefore allows for greater efficiency. Huntorf, completed in 1978, is a 290 MW facility designed and built by Brown Boveri Corporation (now a component of Asea Brown

Boveri (ABB)). Huntorf was originally built to provide peaking power service, as well as black-start capability for nuclear power units in the region. Today the plant has increasingly seen use to help balance wind generation in northern Germany. Huntorf was constructed without a recuperator in order to minimize system start-up time. The table above also lists one proposed facility (Chamisa CAES at Tulia, LLC) currently going through the construction permitting process. The Chamisa facility will have a two stage expander like McIntosh.

McIntosh was placed in commercial operation in 1991 as a single train CAES facility, rated at 110-MW output. McIntosh used a novel "motor/generator", whereby a single electrical machine fulfilled dual roles as a motor for compressing, and as a generator when operating in the expansion mode. As with APEX Bethel the compressor is electric driven with no GHG emissions and the expanders are natural gas combustors from Dresser-Rand. It should also be noted that the cavern air storage pressures are considerably higher for the APEX plant which also provides for additional storage for extended power generation.

The expander train design features the HP and LP expanders and associated combustors at APEX which are very similar to the McIntosh equipment with one exception - the APEX design has an additional HP topping turbine to accommodate the higher cavern well-head pressure. Also, the APEX-HP expander will operate at a higher full load inlet pressure than McIntosh (800 psia vs. 630 psia at McIntosh). Additionally, the APEX combustors will use SCR for NO_X control unlike the McIntosh plant.

The most important contributor to optimizing the energy efficiency for APEX is the improved recuperator efficiency at Bethel Energy Center (90% for APEX versus 70% for McIntosh). Other design changes have a meaningful impact on output (and hence capital cost on a $/kW basis) and specific air consumption, but they do not affect heat rate materially. The heat rate advantage of APEX in table 4 above supports a determination that APEX will have energy conversion efficiency higher than CAES units currently in existence.

As shown in table 4, the heat rate for APEX represents a 31 percent improvement in comparison to Huntorf, and a 6 percent improvement in comparison to McIntosh. The design heat rate for APEX (not adjusted for equipment degradation) was used for this computation, to be consistent with data available for the other two operating and one proposed CAES installations.

Separating the compressor from the combustion expander and generator has additional advantages such as utilizing an electric compressor with no GHG emissions during non-peak hours for the compression of air and, when necessary for additional power generation, having both operations (compression and generation)at the same time.

Operational Energy Efficiency

Additional BACT considerations are good operating and maintenance practices to ensure complete combustion of the natural gas fuel, maximize heat recovery by monitoring the exit flue gas parameters to optimize the air/fuel ratio in the combustors. The design and maintenance will take into consideration insulation materials to minimize heat loss from the expanders, combustors, ducts, and the recuperator. Heat loss from the expanders and combustors will be further mitigated by the fact that these components will be housed within a building – i.e. not exposed to the elements.

Step 5 – Selection of BACT

The following are the specific BACT limits and conditions for the combustion turbines.

1. BACT output limit of 558 lbs CO_2/MWH (net) for both trains on a 365-day rolling average.
2. Combustion efficiency of 4773 BTU/kWh for all combustors on a 365-day rolling average.
3. Good maintenance practices according to the vendor's recommendation attached to the permit.
4. Insulation and maintenance of insulation on all combustors and recuperators for minimizing heat loss.
5. Process controls and instrumentation to optimize fuel/air rations and minimize fuel gas use.

The proposed BACT limit of 558 lbs CO_2/MWh directly measures and reflects the overall process efficiency of the gas expansion turbine trains. The limit proposed takes into account the range of loads from the lowest sustainable load of 25% to 100% load, which reflects the highest production rate of CO_2 over the full operational range. These values reflect a maximum 3% deterioration in turbine performance between overhauls. Over the operating range of 44% to 100% load, the vendor performance data indicates a heat rate of 4,390 to 4,499 Btu (HHV)/kWh, inclusive of the aforementioned degradation adjustment. At lower loads, the heat rate would gradually increase to a maximum of 4,773 Btu (HHV)/kWh(net) at the lowest sustainable load (11%), which is the permit limit in the draft permit.

On March 27, 2012, the EPA proposed a New Source Performance Standard (NSPS), 40 CFR Part 60 Subpart TTTT that would control CO_2 emissions from new electric generating units (EGUs).[4] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. The EPA proposed that new EGUs meet an annual average output based standard of 1,000 lb CO_2/MWh, on a gross basis. The proposed emission rate for the APEX gas expansion turbine trains on a net electrical output basis is 558 lb/MWh. The proposed CO_2 emission rates from the APEX turbine trains are well within the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

2. Emergency Engine (EPN: GENENG1)

In addition to the two combustion turbine trains planned for the Bethel Energy Center, one natural gas-fired emergency generator (nominal 1,053-BHP engine with estimated emissions of 23 CO2e tpy) will operate at the plant.

Step 1 – Identification of Potential Control Technologies

The available control technologies for the natural gas generator are identical to those identified for the combustion turbines. These options include

- Carbon Capture and Storage Systems (CCS)
- Generator Engine Design Efficiency
- Use of a Low Carbon Fuel

Step 2 – Elimination of Technically Infeasible Alternatives

[4] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed Reg 22392, April 13, 2012. Available at http://www.epa.gov/ttn/atw/nsps/electric/fr13ap12.pdf

- *Carbon Capture and Storage* – As discussed above, CCS for GHG control has been eliminated as a not technically feasible control option for an emergency generator that has intermittent operations for only 50 hours/year. Therefore, CCS is eliminated from further consideration for natural gas emergency generator engine GHG reduction.

- *Generator Engine Design Efficiency* – The natural gas generator engine for the Bethel Energy Center will incorporate a high-efficiency design. The table below provides a comparison of similar sized gas fired units from different manufacturers. The annual CO_2e emissions difference between the two units is approximately 1.1 tons per year. The Caterpillar unit selected by APEX, prior to add-on NSCR controls, provides lower NOx and VOC emissions than the Waukesha counterpart. With the addition of NSCR controls, the NOx, VOC, and CO emissions are substantially lower. Thus, the criteria pollutant emissions reductions were determined to be an acceptable trade-off, with more overall benefit to the environment, than a slightly better efficiency (Btu/bhp-hr) with the Waukesha unit.

	Selected Generator Caterpillar G3516SITA	Similar Generator Waukesha VHP7100G
kW (bhp)	740 (1,053)	725 (1,025)
Btu/bhp-hr	7,391	7,223
Fuel Use (scf/hr)	8,600	8,181

- *Efficient Use of Energy* – The natural gas generator engine will not be operated continuously, but only during maintenance testing and during emergencies for backup power generation. Therefore, energy will be utilized in an efficient manner.

- *Use of Low Carbon Fuel* – The generator will use natural gas for fuel instead of diesel that is typically used for emergency generators. The use of natural gas yields the lowest emissions of GHG.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technically feasible GHG control technologies for the Bethel Energy Center are "Efficient Use of Energy" and "Use of Low Carbon Fuel." These technologies are equally important toward minimizing GHG emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

The remaining technically feasible GHG control technologies are "Efficient Use of Energy" and "Use of Low Carbon Fuel." These technologies will be implemented for the generator engine.

Step 5 – Selection of BACT

The following are the BACT requirements for the diesel-fired emergency generators:

- *Low Carbon Fuel* – The emergency engine will be natural gas-fired.

- *Efficient Use of Energy* : Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing, and operations within the recommended air to fuel ratio, as specified by its design. Engines have an operational limit of 50 hours per year.

3. Fugitive Emissions (EPN: FUG1)

In addition to the combustion sources planned for the Bethel Energy Center, there are hydrocarbon emissions from leaking piping components, which include methane emissions from the natural gas pipeline. There are also sulfur hexafluoride (SF6) leaks from circuit breakers. Although this is a small source with an estimated 248 tpy CO_2e or 0.05 percent of the total site emissions, for completeness, fugitive emissions are addressed in this BACT analysis.

a. CH_4 Fugitives from piping and equipment components

Step 1 – Identification of Potential Control Technologies for GHGs

The available control technologies for process fugitive emissions are as follows
- Installing Leakless Technology and high quality components and materials of construction to minimize fugitive emission sources
- Implementing a Leak Detection and Repair (LDAR) Program using traditional flame ionization detector (FID), new infrared (IR) camera technology or handheld analyzer to detect methane emissions.
- Comprehensive Maintenance program consisting of a monthly walk-through to check for leaks, with repairs or replacement completed within 15 days and records documenting the program and leaks made available upon inspection.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless Technology – APEX will use welded piping where possible, high quality components and materials for design and construction of the Bethel Energy Center. The cost of implementing this will be included in the cost of construction. Other components such as flanges and valves inherently cannot be leakless, and the facility cannot be constructed, operated or maintained without the use of flanges and valves. Therefore installing leakless technology is technically infeasible for controlling process fugitive GHG emissions from flanges and valves.

LDAR Programs – LDAR programs are a technically feasible option for controlling process fugitive GHG emissions from components in natural gas service.

The *Comprehensive Maintenance* program is feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All the above BACT technologies with the exception of leakless design for flanges and valves are technically feasible and effective to minimize GHG emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

LDAR Programs – There are varied levels of stringency in LDAR programs for controlling volatile organic compound (VOC) emissions, using an organic detector.

Although technically feasible, the use of an LDAR program to control less than .06% of GHG emissions is not cost effective, as shown below. The estimates were from a company utilizing the LDAR program for a small gas plant subject to 40 CFR Part 60, Subpart KKK with around 600 components to monitor quarterly. The cost would be as follows:

- $16,000 for the first year, which includes tagging and initial monitoring.
- $12,000 for annual monitoring.

At an estimated cost of $176/ton GHG, the use of an LDAR or LDAR like program would not be cost effective for the Bethel Energy Center.

Comprehensive auditory, visual and olfactory (AVO) *Maintenance Program* – Another option for minimizing fugitive emission is to apply a comprehensive equipment maintenance program. The cost of this program would be rolled into the normal operation and maintenance of the facility. The comprehensive equipment maintenance program will have similar reduction percentages to a LDAR program and the associated costs can be rolled into normal operations without additional capital. Therefore, an LDAR program can be eliminated.

The comprehensive maintenance program proposed by APEX will include periodic inspections for leaks using (AVO methods to find leaks. Elements of the program include at a minimum the following:

- Walk through using AVO to identify leaks;
- First attempt to repair within 5 days and repair or replace within 15 days;
- Exceptions for components that require a process unit shut down or waiting on parts to repair or replace;
- Records of leaks and repairs shall be kept and made available upon request.

Step 5 – Selection of BACT

BACT is determined to be the comprehensive maintenance program as proposed by APEX using AVO to determine leakers on a daily basis.

b. SF_6 Insulated Electrical Equipment

SF_6 is commonly used in circuit breakers associated with electricity generation equipment. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 2,190 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Evaluating alternative substances to SF6 (e.g., oil or air blast circuit breakers);*
- *Use of new and state-of-the-art circuit breakers that are gas-tight and require less* SF_6
- *Implementing a leak detection program, such as a LDAR program or an equivalent program to identify and repair leaks and leaking equipment as quickly as possible.*

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425[5], SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture…it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment". Therefore, there are currently no technically feasible options besides the use of SF_6.

The traditional LDAR program using a Flame ionization detector (FID) will not detect SF_6. An Infrared camera can detect leaks of SF_6 if calibrated for SF_6. The alternate leak detection program of a low pressure alarm, lockout and inventory accounting program (40 CFR §98.303(a), Equation DD-1), is an alternate operation for the enclosed pressure circuit breakers.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness
The remaining control options are not mutually exclusive and are all evaluated in Step 4.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Energy, environmental, or economic impacts are not addressed because the use of alternative, non-greenhouse gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

Step 5 – Selection of BACT

The following are the specific BACT requirements for the SF_6 Insulated Electrical Equipment:

- The use of state-of-the-art enclosed-pressure SF_6 circuit breakers. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) and C37.013 standard for high voltage circuit breakers.[6]
- Installation of a low pressure alarm and low pressure lockout device. This alarm will function as an early detector that will detect potential fugitive SF_6 emission problems before a substantial portion of the SF_6 is released. The lockout prevents any operation of the breaker due to the lack of " quenching and cooling" SF_6 .
- Adoption of an inventory accounting program per 40 CFR §98.303.

4. Natural Gas Maintenance Purges (EPN: MAINT1)

Quarterly maintenance purges from the natural gas supply have been conservatively estimated at 0.015 tpy of methane, equivalent to .26 tons/yr of CO_2e.

Step 1 – Identification of Potential Control Technologies for GHGs

[5] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

[6] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

- *Use of a Flare or other Control Device*
- *Minimization of Purges*

Step 2 – Elimination of Technically Infeasible Alternatives

Both options are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Flaring of maintenance purges would reduce CH_4 and other hydrocarbons by 98%, CO_2e emissions would be reduced by 81% since the combustion of the hydrocarbon emissions would result in the formation of CO_2.

- Minimizing purges would cause fewer emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Rental and operation of a portable flare once per quarter for the maintenance purge has been estimated by APEX to cost approximately $3,500 per quarter or $14,000 annually. The cost to reduce the methane emissions by 98% (0.0125tpy) is approximately $1,1200,000/ton. Therefore this alternative has been eliminated in this step.

Step 5 – Selection of BACT

BACT consists of good design to minimize the length of piping to be purged, and minimizing the purging to once every quarter. The purges are a necessity for safe operation of the plant.

VII. Compliance Monitoring:

<u>Turbine Generators</u>:

1. All continuous emission monitoring, instrumentation and metering equipment should meet specification requirements of 40 CFR § 75.10 and 40 CFR § 98.34 and subpart D requirements.
2. CO_2 analyzer in the stack to meet requirements of 40 CFR § 75.10(a)(3)-(5).
3. Monitor the fuel flow rate to the turbines to meet requirements in 40 CFR § 75.10, with an operational non-resettable elapsed flow meter.
4. Determine the specific fuel factor for the Fc and the Gross Calorific Value (GCV)(HHV) on a semi-annual basis using the equation F-7b in 40 CFR Part 75, Appendix F § 3.3.6.
5. Monitor and record the startup and shutdown events to include the duration and CO_2 emissions per event.
6. Use the CO_2 CEMS to determine compliance with the 558 lbs CO_2/MWH on a 365 daily rolling average.
7. Monitor and record the MMBTU/kWh to be less than 4773 on a 365-day rolling average.
8. Monitor the fuel flow rate to each turbine combustor as not to exceed the maximum heat input of 695.1MMBtu/hr calculated on a 365 daily rolling average.

9. Maintain the turbines according to manufacturer's recommendation for optimum performance. Keep all records of maintenance.
10. Conduct an initial test to demonstrate the turbine efficiency according to the conditions specified in the permit. Determine and record the stack temperature, flow rate and other parameters at various turbine rates of 11%, 50% and 75% capacity.

Emergency Generator:

1. Monitor and record the fuel flow rate and duration in hours used for reliability testing.
2. Monitor and record the fuel used and duration in hours used for emergency events.
3. Maintain and operate according to manufacturer's requirements. These documents should be readily available at the plant site and provided to an inspector.

Fugitive and Maintenance Emissions:

1. Keep records of the monitoring of the fugitive emissions of the natural gas pipelines to include the dates, the number of leakers, attempt at repair, and when repair was completed.

2. Keep records of the duration and number of events of pipeline purging for maintenance.

3. For SF_6, the emissions shall be calculated annually in accordance with the mass balance approach provided in 40 CFR § 98.303(a), Equation DD-1. All reports of maintenance performed and compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures in 40 CFR § 98.304.

4. Keep records of the low pressure alarms and lockout occurrences and of possible releases to the atmosphere of SF_6 using the equation on 40 CFR §98.303(a), Equation DD-1, and the action taken to fix the problem.

VIII. Endangered Species Act (ESA)

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, the EPA is required to insure that any action authorized, funded, or carried out by the EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, the EPA is relying on a Biological Assessment (BA) prepared by the applicant, APEXAPEX, and its consultant, CH2M Hill, and adopted by the EPA.

A draft BA has identified nine (9) species listed as federally endangered or threatened in Anderson County, Texas:

Federally Listed Species for Anderson County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Interior least tern	*Sterna antillarum anthalassos*
Piping plover	*Charadrius melodus*
Red-cockaded woodpecker	*Picoides borealis*
Sprague's pipet	*Anthus spragueii*
Whooping crane	*Grus americana*
Reptile	
Louisiana pine snake	*Pituophis ruthveni*
Plant	
Earth fruit	*Geocarpon minimum*
Mammals	
Louisiana black bear	*Ursus americanus luteolus*
Red wolf	*Canis rufus*

The EPA has determined that issuance of the proposed permit will have no effect on any of the nine listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of the EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires the EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, the EPA relied on a cultural resource report prepared by William Self Associates, Inc. (WSA) on behalf of APEX's consultant, CH2M Hill, submitted on March 20, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 213.5 acres of land that contains the construction footprint of the project, a proposed water/wastewater line route, a proposed alternate wastewater line route, a proposed water/wastewater reroute and a proposed brine line route. WSA conducted a field survey, including shovel testing, of the property and desktop review within a 0.5-mile radius APE. This review included a search of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA). Based on the desktop review for the site, within a 0.5-mile radius of the area of potential effect, sixteen (16) architectural/archaeological sites, including a cemetery, were identified; three (3) of the sites are eligible or potentially eligible for listing in the National Register (NR), all of which are outside of the APE. Based on the results of the field survey of the APE, one newly recorded historic-age archaeological site and two previously recorded sites were identified; however, none of these sites were recommended to be eligible for listing on the NR.

The EPA Region 6 determines that while there are cultural materials of historic age identified within the 0.5-mile radius of the project area, issuance of the permit to APEX will not affect properties eligible or potentially eligible for listing on the National Register. Additionally, no historic properties are located within the APE and that a potential for the location of archaeological resources is low within the construction footprint itself.

On April 19, 2013, the EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with the EPA in the Section 106 process. The EPA received no requests from any tribe to consult on this proposed permit. The EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

X. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by the EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which the EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XI. Conclusion and Proposed Action

Based on the information supplied by APEX, the GHG PSD Permit Application and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHG under the terms contained in the draft permit. Therefore, the EPA is proposing to issue the PSD permit for GHG for the APEX Bethel Energy Center, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by the EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits[1]

EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
			TPY[2]		
TURBASTK TURBSUA, TURBSDA and TURBBSTK TURBSUB, TURBSDB	Combined Gas Expansion Turbine Train A and Train B	CO_2	456,296	458,769	i. BACT of 558 lb CO_2/MWh[5] on a rolling 365-day average. ii. See Special Condition III.A. iii. Maximum heat input to one train is 695.1MMBtu/hr. iv. Work practice standards in Section III.A.
		CH_4	12.66		
		N_2O	7.12		
FUG1	Fugitives	CO_2	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of AVO program. See Special Condition III.B.
		CH_4	No Numerical Limit Established[4]		
		SF_6	No Numerical Limit Established[4]		
GENENG1	Natural Gas-Fired Emergency Generator	CO_2	23	23	Good Combustion and Operating Practices. Limit to 50 hours of operation per year. See Special Condition III.C.
MAINT1	Maintenance	CO_2	0.01	0.26	See Special Condition III.D.
		CH_4	0.014		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations to include startup and shutdown activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_20 = 310, SF_6 = 23,900. On January 1, 2014, the EPA anticipates the GWP for CH_4, N_2O and SF_6 will change to 25, 298, and 22,800 respectively. This change will impact the CO_2e calculations and the currently proposed emission limits will be revised to reflect the new CH_4 GWP in the final permit
4. Fugitive emissions (EPN FUG1) are estimated to be 0.27 tpy CO_2, 5.56 tpy CH_4 and 0.0065tpy SF_6 for a total of 248 tpy CO_2e. The emission limit will be a design/work practice standard as specified in the permit
5. Electrical output shall be measured at the generator terminals.

Exhibit 6 to Sierra Club's April 9, 2015 Comments

Statement of Basis
Draft Greenhouse Gas
Prevention of Significant Deterioration
Preconstruction Permit for
Apex Matagorda Energy Center, LLC

Permit Number: PSD-TX-107055-GHG

January 2013

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR § 52.21 that will apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On November 27, 2012, Apex Matagorda Energy Center, LLC (Apex) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On May 28, 2013, Apex submitted additional information for inclusion into the application. In connection with the same proposed construction project, Apex submitted an application for a Standard Permit for Electric Generating Facilities for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ). The project proposes to construct a bulk energy storage system that will use compressed air energy storage (CAES) to produce up to 317 MW of electrical power. The Apex facility will be located near Clemville in Matagorda County, Texas. The project proposes to use the compressed air energy storage (CAES) technology developed by Dresser-Rand to produce up to approximately 317 MW of electrical power. The Matagorda facility will consist of two expansion turbine/generating trains each rated at 158.34 MW. GHG pollutants occur primarily from the exhaust emissions from the natural gas combustion turbine trains with minor emissions from fugitive sources and an emergency generator engine. The turbines will be also use selective catalytic reduction (SCR) for reduction of nitrogen oxides and catalytic oxidation to reduce carbon monoxide. After reviewing the application and all pertinent and additional applicant's information, EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the Matagorda facility.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Apex's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Apex, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Apex Matagorda Energy Center, LLC
3200 Southwest Freeway, Suite 2210
Houston, Texas 77027

Facility Physical Address:
County Road 417, 0.3 miles south of the intersection of County Road 417 and FM 1468
Clemville, Texas 77414

Contact:
Stephen Naeve
Chief Operating Officer
Apex Matagorda Energy Center, LLC
3200 Southwest Freeway, Suite 2210
Houston, Texas 77027
(713) 963-8104

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA Region 6 Permit Writer is:

Bonnie Braganza
Air Permitting Section (6PD-R)
(214) 665-7340
Braganza.bonnnie@epa.gov

Facility Location

The Apex Matagorda Energy Center facility is located in Clemville, Matagorda County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 areas are the Wichita Mountains Wildlife Refuge, Big Bend National Park, and Breton Wilderness, which are located approximately 400 miles from the site. The geographic coordinates for this proposed facility site are as follows. Figure 1 illustrates the proposed facility location for this draft permit.

Latitude: 28° 59' 14" North
Longitude: -96° 08' 20" West

FIGURE 1
Apex Matagorda Energy Center

IV. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that Apex's application is subject to PSD review for the pollutant GHG, as described at 40 CFR § 52.21(b)(1) and (b)(49)(v). Specifically, under the project, the potential GHG emissions are calculated to exceed the major source threshold on a mass basis, as provided at 40 CFR § 52.21(b)(1), and 100,000 tpy "CO_2-equivalent" (CO_2e), as provided at 40 CFR § 52.21(b)(49)(v). (Apex calculates CO_2e emissions of 459, 131 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has issued the standard permit for electric generating facilities for non-GHG pollutants.[1]

In evaluating this permit application, EPA Region 6 considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011).

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. The applicant submitted an impacts analysis of non- GHG pollutants to meet the requirements of 40 CFR §52.21(o), as it may otherwise apply to the project.

V. Project Description

The proposed GHG PSD permit, if finalized, would authorize Apex to construct a new compressed air energy storage (CAES) power plant in Clemville, Matagorda County, Texas to produce up to 317 MW of electrical power. The facility will be known as the Apex Matagorda Energy Center, LLC, referred to within this document as "Apex" or the "Matagorda facility". CAES technology involves two major processes:

(1) Air compression and storage, and
(2) Air release for electricity generation.

During the air compression and storage process, electric motor driven compressors are used to inject air into an underground cavern for storage under high pressure. Electricity is generated by releasing the high-pressure air, heating it with natural gas combustion and expanding the air through sequential turbines (i.e., expanders), which in turn drive an electrical generator.

The site for the plant was selected to accommodate the high pressure storage of air in local underground caverns. The compressed air storage for Apex will be created by drilling a "cavern well" with a cemented well casing at a terminal depth of approximately 3,750 feet. Fresh water withdrawn from local groundwater wells will be pumped down the well to dissolve salt, creating the storage cavern. Salt brine withdrawn from the cavern during this "leaching" process will be injected into existing permitted brine disposal wells on nearby property. This leaching process is carefully controlled to produce a cavern of the desired capacity and shape. The cavern is expected to operate over a wellhead static pressure range of approximately 1,900 to 2,830 pounds per square inch absolute (psia). If full, the cavern will support approximately 100 hours of generation at near full rated output without recharge.

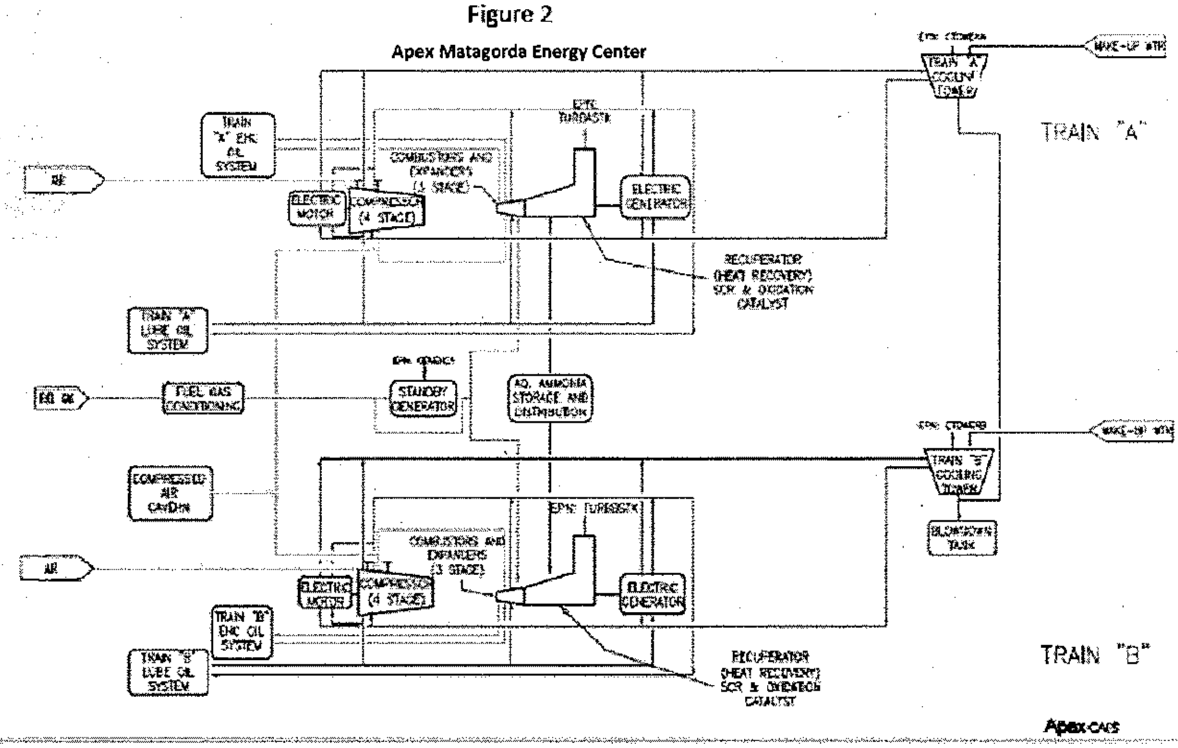
The CAES plant is a hybrid peaking power process using the energy of high pressure compressed air supplemented by natural gas fired multistage expansion turbines to generate electricity. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. Even though the CAES design includes the features similar to an industrial turbine, the design significantly differs from a conventional gas turbine. While the operation of the expander section for the conventional gas turbine operates at about the same pressure (254 psia) as the lowest pressure (third stage) expander for the CAES turbine/generator, a conventional gas turbine has a compressor and expander operating on a single shaft, resulting in a much narrower turndown ratio than the Apex CAES design. The separation of the compression and expansion functions allows for greater operating flexibility for Apex to meet the Electric Reliability Council of Texas (ERCOT) market demands for energy during peak hours. The CAES multistage turbines operate from a 10% load range to full load at 100% with the ability to reach the required output within 5 minutes.

The Matagorda facility will be comprised of two Dresser-Rand CAES compression trains, each consisting of a set of multi-stage compressors driven by a dedicated 150 MW (nominal rating) electric motor. Each compression train will be capable of producing up to 1.4 million pounds per hour of air at a compressor outlet pressure of up to 2,830 psia. The process flow diagram for the Matagorda facility is shown in Figure 2. It depicts the compressors operating at design basis compression under summer ambient conditions and assuming a "near" full cavern. Compression occurs in four stages. Because compression of air results in an increase in temperature, it is necessary to cool the air between the stages. Such cooling is accomplished via two heat rejection processes – an "air to air" heat exchanger and conventional shell and tube air to water heat exchangers, with the cooling duty split approximately 50/50 between each cooling method. Heated water from this process will be cooled in a conventional mechanical draft cooling tower. Make-up water to the cooling tower will be sourced from fresh water wells to be drilled in advance of plant operation to provide water for the cavern leaching process or from the Lower Colorado River. Cooling tower blowdown will be discharged to Tres Palacios River. Maximum daily water consumption is expected to be approximately one million gallons. Annual water requirements are expected to be approximately 400 acre feet.

For power generation, the Matagorda facility will utilize two Dresser Rand expansion turbine/generator trains (FIN/EPN TURBTRNA/TURBASTKA, TURBTRNB/TURBASTKB), each rated at 158.34 MW output at full load. The total generating capacity of the plant will be 317 MW (nominal power rating). High pressure air from the cavern passes sequentially through the three expanders, performing work (accompanied by a reduction in pressure) as the air flows through each stage of expansion.

Figure 2

Apex Matagorda Energy Center



Each expansion train at the Matagorda Energy Center will use three expanders, operating on a single shaft, connected to the generator during the expansion/generation process. High pressure (HP) air from the cavern passes sequentially through the three expanders (accompanied by a reduction in pressure) as the air flows through each stage of expansion. The Matagorda facility uses a HP topping turbine as the first stage of expansion followed by the HP intermediate stage and the low pressure (LP) stage of expansion operates at an inlet pressure of 228 psia.

At maximum generator output, approximately 400 lbm/second of air from the cavern header passes through a recuperator, where the air is preheated to a temperature of 600°F (degrees Fahrenheit) before entering the topping turbine at a turbine inlet pressure of approximately 2,170 psia (at full rated output). Air is expanded in the topping turbine, resulting in a temperature and pressure drop. The air next flows to one of two HP combustors. Pipeline quality natural gas is burned with the preheated air (from the recuperator) in the combustors, and the resultant heated gases enter the HP expanders at approximately 1,000°F and 800 psia. The gases exit the HP expanders to the last stage LP combustor, where additional natural gas is burned to increase the gas temperature for further expansion in the LP expander. Energy efficiency for this process is increased by making use of the heat from the flue gas to preheat the air to the combustors via the recuperator. The gases from the recuperator exhaust to the stack (EPN TURBASTK & TURBBSTK).

The addition of a topping turbine is a design feature unique to the Matagorda facility and is made possible by the high pressure of the cavern at the plant. Apex chose this location on the basis of numerous site-specific geological and economic parameters, including ERCOT power market considerations, which is distinctively different from the existing CAES installation in McIntosh, Alabama (or at other sites which have been studied for CAES installation).

The proposed Apex Matagorda Energy Center will also have a 740 kW emergency generator engine fired with natural gas (rich burn) and will utilize non-selective catalytic reduction (NSCR) for NOx reduction. The permit will restrict operation of the generator, including maintenance and reliability testing, to 50 hours per year.

There will be minor GHG fugitive emissions from equipment leaks and sulfur hexafluoride from the circuit breakers. Also there will be maintenance emissions from the natural gas pipeline/metering station that will vent four times a year.

Non-GHG emitting equipment consists of the cooling towers that cool compressed air and a 10,000 gallon 19% aqueous ammonia solution used for SCR to control NOx emissions from the combustors. The ammonia tank will be filled by vapor balance and will not have open vents; therefore, the ammonia delivery system only has fugitive emissions.

VI. BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

1) Identify all available control options;
2) Eliminate technically infeasible control options;
3) Rank remaining control technologies by control effectiveness;

4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and

5) Select BACT.

Before discussing the BACT for the individual pieces of equipment, Apex provided a discussion on the need for grid level energy storage in the power (ERCOT) market for a quick response capability to supply electricity during peak demand. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. Apex indicates that at this time there are only two technologies, CAES and hydroelectric, that are commercially available and can provide sufficient storage capacity to be of value at the bulk power level. Apex conducted an evaluation of more than 20 potential sites in west and southeast Texas to identify potential cavern creation opportunities before selecting the Matagorda Energy Center site. The Matagorda Energy Center site was chosen for development of a CAES facility due to the presence of suitable geologic conditions, existing gas and electric transmission lines crossing the property, existing infrastructure to support cavern creation, and availability of groundwater as a water source.

Other commercially available technologies such as conventional gas turbine generation, wind, and solar are intermittent power sources and do not always provide the grid operator's need for flexible "standby" resources capable of responding quickly to deviations in system frequency. Therefore these technologies will not be evaluated in this BACT discussion, since Apex determined that the proposed project utilizing CAES meets all the Matagorda Energy Center requirements for economic operation within the ERCOT market. This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26). Nonetheless, it should be noted that the Apex Matagorda Energy Center is intending to provide secure, reliable capacity to the grid, assisting the grid operator in coping with the intermittent nature of solar and wind generation and other renewable generation.

Applicable Emission Units for BACT Analysis

The units/activities that directly or indirectly emit GHG emissions are:

- Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)
- Fugitives (EPN: FUG1))
- Natural Gas Maintenance Purges (EPN: MAINT1)
- Emergency Generator (EPN: GENENG1)

1. Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)

The Apex Matagorda Energy Center will have two expansion turbine trains, with each train having a separate exhaust stack with a CO_2 analyzer. The turbines will utilize pipeline quality natural gas for combustion. Apex has estimated that the facility will have a maximum annual throughput of 7,807,409 MMBtu of natural gas for the combined trains with total CO_2 emissions of 456,296 tpy. This does not include natural gas usage at other sources such as the emergency generator. The combustion turbines will be using SCR and oxidation catalyst which will increase the GHG pollutants by a small amount.

The estimated emissions from the turbines of N_2O and CH_4 as CO_2e comprise about 0.54% of the total CO_2e from the turbines. Therefore the BACT analyses will focus primarily on technology to reduce CO_2 emissions. As part of the PSD review, Apex provided a five-step top-down BACT analysis for the combustion turbines in the GHG permit application. EPA has reviewed Apex's BACT analysis for the gas expansion turbine trains, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit as summarized below.

Step 1 – Identify All Available Control Options

- *Carbon Capture Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Use of a Low Carbon Fuel for Combustion*
- *Electrical Generation Conversion Efficiency* – the formation of GHGs can be mitigated by design and selection of ultra-efficient combustion units.
- *Operational Energy Efficiency* – Good combustion, operating and maintenance practices are a potential control option for improving the fuel efficiency of affected combustion units.

Carbon capture and storage is a GHG control process that can be used by facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).[2] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine facility; the third approach, post-combustion capture, is available to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for CCS.

- **Carbon Capture and Storage (CCS)**

Apex estimated the CO_2 concentration in the turbine exhaust stacks would be in the range of 1.7 – 3.5%, based on fuel consumption and stack flow of 99,000 to 453,000 acfm at a temperature of 230^0F. CCS has not been demonstrated in practice on emissions streams like this that are more dilute in CO_2 concentration derived in a peaking capacity mode with a limited number of operable hours in any given year. EPA expects that the technical challenges of capturing a 3.5% or less concentrated CO_2 stream are exacerbated when a combustion turbine unit is operated intermittently and therefore the CO_2 stream is more cyclic in nature rather than steady state. Currently, the technical feasibility of operating a CCS system in a "start/stop" mode has not been demonstrated. Fluor has built a new demonstration project in Germany to capture CO_2 in a flue stream from a coal-fired power station where the key feature of the pilot plant is a "one button start/stop" concept that allows the plant to automatically come on line when the power plant operator wants to capture CO_2. Since this type of "start/stop" operational process has not yet been demonstrated for combustion turbine power plants that operate intermittently when dispatched for peak demand electricity, we do not believe CCS is technically feasible for proposed Apex project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Other than CCS, which was eliminated in Step 2 above, the remaining technologies to reduce GHG are being evaluated for this project and we will rank these measures in Step 4.

Step 4 – Evaluation of Control Options in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Use of a Low Carbon Fuel

Apex proposes to use natural gas for combustion in the turbine expanders. The only other low carbon combustion fuel is hydrogen and this is not commercially available at this particular site. Typically hydrogen gas is a byproduct process vent gas in large chemical and refining plants and enters the plant fuel grid system. In this project, there are no processes that produce hydrogen and therefore natural gas is the commercially available low carbon fuel for combustion.

Energy Efficiency Design Measures for the Turbines/Generators

[3] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

The Matagorda facility is designed to utilize high-efficiency, state-of-the-art, expansion turbines and associated combustors. Table 4 lists designs of CAES power generation plants.

Table 4

	Apex	Chamisa CAES[1]	McIntosh[2]	Huntorf[2]
Power Production Capacity, MW	317 (total of 2 trains)	280 (total of 2 trains)	110	290
Heat Rate at Maximum Production, BTU	4,262 (gross)-4,390 (net)	4,389 (gross)-4,502 (net)	4,555	6,175
Design Recuperator Efficiency,%	90	90	70	N/A (no
No. of Expanders	3	2	2	2
Cavern Pressure,	1,900-2,830	940-1,800	1,100	600-1,000
Hours of Storage	100	36 - 48	26	3-4

1. *Chamisa is a current Region 6 permit application that is being processed for a permit*
2. *Both of these plants are operating*
3. *The Apex and Chamisa heat rates do not reflect the 3% adjustment for performance degradation*

Energy efficiency is normally expressed in terms of heat rate. The Apex turbine trains have an estimated heat rate of 4,390 BTU/kWh at maximum load and 4,773 BTU/kWh at low load (HHV basis). The heat rates have been adjusted to reflect 3% degradation between system overhauls (per Dresser-Rand guidance). The energy efficiency for Apex is reflective of heat input divided by generator output measured at the generator terminals. Performance figures for Apex reflect site conditions at 60°F. There are two CAES facilities in operation worldwide: McIntosh in Alabama and the Huntorf facility in Germany. The addition of a topping turbine is a design feature not present in the two operational CAES plants and allows for greater efficiency. Huntorf, completed in 1978, is a 290 MW facility designed and built by Brown Boveri Corporation (now a component of Asea Brown Boveri (ABB)). Huntorf was originally built to provide peaking power service, as well as black-start capability for nuclear power units in the region. Today the plant has increasingly seen use to help balance wind generation in northern Germany. Huntorf was constructed without a recuperator in order to minimize system start-up time. The table above also lists one proposed facility (Chamisa CAES at Tulia, LLC) currently going through the construction permitting process. The Chamisa facility will have a two stage expander like McIntosh.

McIntosh was placed in commercial operation in 1991 as a single train CAES facility, rated at 110-MW output. McIntosh used a novel "motor/generator", whereby a single electrical machine fulfilled dual roles as a motor for compressing and as a generator when operating in the expansion mode. As with Apex the compressor is electric driven with no GHG emissions and the expanders are natural gas combustors from Dresser-Rand. It should also be noted that the cavern air storage pressures are considerably higher for the Apex plant which also provides for additional storage for extended power generation.

The expander train design features the HP and LP expanders and associated combustors at Apex, which are very similar to the McIntosh equipment with one exception – the Apex design has an additional HP topping turbine to accommodate the higher cavern well-head pressure. Also, the Apex HP expander will operate at a higher full load inlet pressure than McIntosh (800 psia vs. 630 psia at McIntosh), and, the Apex combustors will use SCR for NO_X control unlike the McIntosh plant.

The most important contributor to optimizing the energy efficiency for Apex is the improved recuperator efficiency at Matagorda Energy Center (90% for Apex versus 70% for McIntosh). Other design changes have a meaningful impact on output (and hence capital cost on a $/kW basis) and specific air consumption, but they do not affect heat rate materially. The heat rate advantage of Apex in table 4 above supports a determination that Apex will have energy conversion efficiency higher than CAES units currently in existence.

As shown in table 4, the heat rate for Apex represents a 31 percent improvement in comparison to Huntorf and a 6 percent improvement in comparison to McIntosh. The design heat rate for Apex (not adjusted for equipment degradation) was used for this computation, to be consistent with data available for the other two operating and one proposed CAES installations.

Separating the compressor from the combustion expander and generator has additional advantages such as utilizing an electric compressor with no GHG emissions during non-peak hours for the compression of air and, when necessary for additional power generation, having both operations (compression and generation) at the same time.

Operational Energy Efficiency

Additional BACT considerations are good operating and maintenance practices to ensure complete combustion of the natural gas fuel maximize heat recovery by monitoring the exit flue gas parameters to optimize the air/fuel ratio in the combustors. The design and maintenance will take into consideration insulation materials to minimize heat loss from the expanders, combustors, ducts, and the recuperator. Heat loss from the expanders and combustors will be further mitigated by the fact that these components will be housed within a building, i.e., not exposed to the elements.

Step 5 – Selection of BACT

The following are the specific BACT limits and conditions for the combustion turbines.

1. BACT output limit of 558 lbs CO_2/MWh) for both trains on a 12-month rolling average.
2. Combustion efficiency of 4773 BTU/kWh for all combustors on a 12-month rolling average.
3. Good maintenance practices according to the vendor's recommendation attached to the permit.
4. Insulation and maintenance of insulation on all combustors and recuperators for minimizing heat loss.
5. Process controls and instrumentation to optimize fuel/air rations and minimize fuel gas use.
6. Maximum heat input to the turbine will not exceed 695MMBtu/hr.

The proposed BACT limit of 558 lbs CO_2/MWh directly measures and reflects the overall process efficiency of the gas expansion turbine trains. The limit proposed takes into account the range of loads from the lowest sustainable load of 25% to 100% load, which reflects the highest production rate of CO_2 over the full operational range. These values reflect a maximum 3% deterioration in turbine performance between overhauls. Over the operating range of 44% to 100% load, the vendor performance data indicates a heat rate of 4,390 to 4,499 Btu (HHV)/kWh, inclusive of the aforementioned degradation adjustment. At lower loads, the heat rate would gradually increase to a maximum of 4,773 Btu (HHV)/kWh) at the lowest sustainable load (11%), which is the permit limit in the draft permit.

2. Emergency Engine (EPN: GENENG1)

In addition to the two combustion turbine trains planned for the Matagorda Energy Center, one natural gas-fired emergency generator (nominal 1,053-BHP engine with estimated emissions of 23 CO_2e tpy) will operate at the plant.

Step 1 – Identification of Potential Control Technologies

The available control technologies for the natural gas generator are identical to those identified for the combustion turbines. These options include:

- Carbon Capture and Storage Systems (CCS)
- Generator Engine Design Efficiency
- Use of a Low Carbon Fuel

Step 2 – Elimination of Technically Infeasible Alternatives

- *Carbon Capture and Storage* – As discussed above, CCS for GHG control has been eliminated as a not technically feasible control option for an emergency generator that has intermittent operations for only 50 hours/year. Therefore, CCS is eliminated from further consideration for natural gas emergency generator engine GHG reduction.
- *Generator Engine Design Efficiency* – The natural gas generator engine for the Matagorda Energy Center will incorporate a high-efficiency design. The table below provides a comparison of similar sized gas fired units from different manufacturers. The annual CO_2e emissions difference between the two units is approximately 1.1 tons per year. The Caterpillar unit selected by Apex, prior to add-on NSCR controls, provides lower NOx and VOC emissions than the Waukesha counterpart. With the addition of NSCR controls, the NOx, VOC, and CO emissions are substantially lower. Thus, the criteria pollutant emissions reductions were determined to be an acceptable trade-off, with more overall benefit to the environment, than a slightly better efficiency (Btu/bhp-hr) with the Waukesha unit.

	Selected Generator Caterpillar G3516SITA	Similar Generator Waukesha VHP7100G
kW (bhp)	740 (1,053)	725 (1,025)
Btu/bhp-hr	7,391	7,223
Fuel Use (scf/hr)	8,600	8,181

- *Efficient Use of Energy* – The natural gas generator engine will not be operated continuously, but only during maintenance testing and during emergencies for backup power generation. Therefore, energy will be utilized in an efficient manner.
- *Use of Low Carbon Fuel* – The generator will use natural gas for fuel instead of diesel that is typically used for emergency generators. The use of natural gas yields the lowest emissions of GHG.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technically feasible GHG control technologies for the Matagorda Energy Center are "Efficient Use of Energy" and "Use of Low Carbon Fuel." These technologies are equally important toward minimizing GHG emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

The remaining technically feasible GHG control technologies are "Efficient Use of Energy" and "Use of Low Carbon Fuel." These technologies will be implemented for the generator engine.

Step 5 – Selection of BACT

The following are the BACT requirements for the diesel-fired emergency generators:

- *Low Carbon Fuel* – The emergency engine will be natural gas-fired.
- *Efficient Use of Energy*: Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing, and operations within the recommended air to fuel ratio, as specified by its design. Engines have an operational limit of 50 hours per year and will meet the NSPS 40 CFR 60 JJJJ requirement.

3. Fugitive Emissions (EPN: FUG1)

In addition to the combustion sources planned for the Matagorda Energy Center, there are hydrocarbon emissions from leaking piping components, which include methane emissions from the natural gas pipeline. There are also sulfur hexafluoride (SF6) leaks from circuit breakers. Although this is a small source with an estimated 248 tpy CO_2e or 0.05 percent of the total site emissions, for completeness, fugitive emissions are addressed in this BACT analysis.

a. CH_4 Fugitives from piping and equipment components

Step 1 – Identification of Potential Control Technologies for GHGs

The available control technologies for process fugitive emissions are as follows

- Installing Leakless Technology and high quality components and materials of construction to minimize fugitive emission sources
- Implementing a Leak Detection and Repair (LDAR) Program using traditional flame ionization detector (FID), new infrared (IR) camera technology or handheld analyzer to detect methane emissions.
- Comprehensive Maintenance program consisting of a monthly walk-through to check for leaks, with repairs or replacement completed within 15 days and records documenting the program and leaks made available upon inspection.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless Technology – Apex will use welded piping where possible, high quality components and materials for design and construction of the Matagorda Energy Center. The cost of implementing this will be included in the cost of construction. Other components such as flanges and valves inherently cannot be leakless, and the facility cannot be constructed, operated or maintained without the use of flanges and valves. Therefore installing leakless technology is technically infeasible for controlling process fugitive GHG emissions from flanges and valves.

LDAR Programs – LDAR programs are a technically feasible option for controlling process fugitive GHG emissions from components in natural gas service.

The *Comprehensive Maintenance* program is feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All the above BACT technologies with the exception of leakless design for flanges and valves are technically feasible and effective to minimize GHG emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

LDAR Programs – There are varied levels of stringency in LDAR programs for controlling volatile organic compound (VOC) emissions. However, because of the extremely small amount of GHG emissions from the fugitive sources, an LDAR program would not be considered for control of GHG emissions alone but in conjunction with an already existing LDAR program. This evaluation does not compare the effectiveness of different levels of LDAR programs.

Although technically feasible, the use of an LDAR program to control the small amount of GHG emissions from the fugitive sources at the Matagorda Energy Center is not cost effective.
Based on an estimate from an LDAR company, assuming that this site would be similar to a smaller gas plant subject to 40 CFR Part 60, Subpart KKK with around 600 quarterly components to monitor the cost would be as follows:

- $16,000 for the first year, which includes tagging and initial monitoring
- $12,000 for annual monitoring

Control costs are evaluated based on cost effectiveness calculated as annual cost per ton of pollutant removed. Additional costs would be incurred for multiple calibrations of the IR camera if used to also detect leaks of SF_6 which have not been included. Based on this cost estimate, Apex believes the use of an LDAR or LDAR like program would not be cost effective for the Matagorda Energy Center. The comprehensive equipment maintenance program will have similar reduction percentages and costs can be rolled into normal operations without additional capital. Apex suggests the comprehensive equipment maintenance program will be more cost effective. Therefore, an LDAR program can be eliminated based on economic feasibility

Comprehensive auditory, visual and olfactory (AVO) *Maintenance Program* – Another option for minimizing fugitive emission is to apply a comprehensive equipment maintenance program. The cost of this program would be rolled into the normal operation and maintenance of the facility. The comprehensive equipment maintenance program will have similar reduction percentages to a LDAR program and the associated costs can be rolled into normal operations without additional capital. Therefore, an LDAR program can be eliminated.

The comprehensive maintenance program proposed by Apex will include periodic inspections for leaks using AVO methods to find leaks. Elements of the program include at a minimum the following:

- Daily walk through using AVO to identify leaks;
- First attempt to repair within 5 days and repair or replace within 15 days;
- Exceptions for components that require a process unit shut down or waiting on parts to repair or replace;
- Records of leaks and repairs shall be kept and made available upon request.

Step 5 – Selection of BACT

BACT is determined to be the comprehensive maintenance program as proposed by Apex using AVO to determine leakers on a daily basis.

b. SF_6 Insulated Electrical Equipment

SF_6 is commonly used in circuit breakers associated with electricity generation equipment. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 2,190 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Evaluating alternative substances to SF6 (e.g., oil or air blast circuit breakers);*
- *Use of new and state-of-the-art circuit breakers that are gas-tight and require less* SF_6
- *Implementing a leak detection program, such as a LDAR program or an equivalent program to identify and repair leaks and leaking equipment as quickly as possible.*

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425[4], SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "...various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture...it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment". Therefore, there are currently no technically feasible options besides the use of SF_6.

The traditional LDAR program using a Flame ionization detector (FID) will not detect SF_6. An Infrared camera can detect leaks of SF_6 if calibrated for SF_6. The alternate leak detection program of a low pressure alarm, lockout and inventory accounting program (40 CFR § 98.303(a), Equation DD-1), is an alternate operation for the enclosed pressure circuit breakers.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining control options are not mutually exclusive and are all evaluated in Step 4.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with

Consideration of Economic, Energy, and Environmental Impacts

Energy, environmental, or economic impacts are not addressed because the use of alternative, non-greenhouse gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

Step 5 – Selection of BACT

The following are the specific BACT requirements for the SF_6 Insulated Electrical Equipment:

- The use of state-of-the-art enclosed-pressure SF_6 circuit breakers. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) and C37.013 standard for high voltage circuit breakers.[5]
- Installation of a low pressure alarm and low pressure lockout device. This alarm will function as an early detector that will detect potential fugitive SF_6 emission problems before a substantial portion of the SF_6 is released. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6.
- Adoption of an inventory accounting program per 40 CFR §98.303.

4. Natural Gas Maintenance Purges (EPN: MAINT1)

Quarterly maintenance purges from the natural gas supply have been conservatively estimated at 1.01tpy of methane, equivalent to 25.25 tons/yr of CO_2e.

[4] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

[5] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current.*

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of a Flare or other Control Device*
- *Minimization of Purges*

Step 2 – Elimination of Technically Infeasible Alternatives

Both options are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Flaring of maintenance purges would reduce CH_4 and other hydrocarbons by 98%, CO_2e emissions would be reduced by 81% since the combustion of the hydrocarbon emissions would result in the formation of CO_2.
- Minimizing purges would cause fewer emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Rental and operation of a portable flare once per quarter for the maintenance purge has been estimated by Apex to cost approximately $3,500 per quarter or $14,000 annually. This cost will reduce methane emissions by 98% 0.0125tpyI and is eliminated as being not economical since minimizing the duration of the purges by good design in minimizing the length of piping to be purged and limiting the purges to four per year will yield the same reductions . This is a better alternative than the environmental logistics for rental of a portable flare.

Step 5 – Selection of BACT

BACT consists of good design to minimize the length of piping to be purged and minimizing the purging to once every quarter. The purges are a necessity for safe operation of the plant.

VII. Compliance Monitoring:

Turbine Generators:

1. All continuous emission monitoring, instrumentation and metering equipment should meet specification requirements of 40 CFR § 75.10 and 40 CFR § 98.34 and subpart D requirements.
2. CO_2 analyzer in the stack to meet requirements of 40 CFR § 75.10(a)(3)-(5).
3. Monitor the fuel flow rate to the turbines to meet requirements in 40 CFR § 75.10, with an operational non-resettable elapsed flow meter.
4. Determine the specific fuel factor for the Fc and the Gross Calorific Value (GCV)(HHV) on a semi-annual basis using the equation F-7b in 40 CFR Part 75, Appendix F § 3.3.6.
5. Monitor and record the startup and shutdown events to include the duration and CO_2 emissions per event.
6. Use the CO_2 CEMS to determine compliance with the 558 lbs CO_2/MWH on a 12 month rolling average.
7. Monitor and record the MMBTU/kWh to be less than 4773 on a 12 month rolling average.

8. Monitor the fuel flow rate to each turbine combustor as not to exceed the maximum heat input of 695.1MMBtu/hr.
9. Maintain the turbines according to manufacturer's recommendation for optimum performance. Keep all records of maintenance.
10. Conduct an initial test to demonstrate the turbine efficiency according to the conditions specified in the permit. Determine and record the stack temperature, flow rate and other parameters associated with the recuperator at various turbine rates of 10%, 50% and 90% capacity.
11. Compliance during startup and shutdown activities. BACT applies during all periods of turbine operations and monitoring of the duration of the startup and shutdown activities. The fuel rate and duration of startup should be monitored during the event and should be minimized by limiting the duration of the operation. The total emission rate of 458,886 tpy CO_2e is estimated based on 365 startups/shutdowns for each turbine per year. Each startup will be limited to duration of 30 minutes and shutdowns to 3 minutes per event.
12. Regular maintenance on the turbine trains as specified in the permit and manufacturer's recommendations.

Emergency Generator:

1. Monitor and record the fuel flow rate and duration in hours used for reliability testing.
2. Monitor and record the fuel used and duration in hours used for emergency events.
3. Maintain and operate according to manufacturer's requirements. These documents should be readily available at the plant site and provided to an inspector.

Fugitive and Maintenance Emissions:

1. Keep records of the monitoring of the fugitive emissions of the natural gas pipelines to include the dates, the number of leakers, attempt at repair, and when repair was completed.
2. Keep records of the duration and number of events of pipeline purging for maintenance.
3. For SF_6, the emissions shall be calculated annually in accordance with the mass balance approach provided in 40 CFR § 98.303(a), Equation DD-1. All reports of maintenance performed and compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures in 40 CFR § 98.304.
4. Keep records of the low pressure alarms and lockout occurrences and of possible releases to the atmosphere of SF_6 using the equation on 40 CFR § 98.303(a), Equation DD-1, and the action taken to fix the problem.

VIII. Endangered Species Act (ESA)

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, APEX Matagorda Energy Center, LLC ("APEX"), and its consultant, CH2M Hill, and adopted by EPA.

A draft BA has identified seventeen (17) species listed as federally endangered or threatened in Matagorda County, Texas:

Federally Listed Species for Matagorda County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Northern Aplomado Falcon	*Falco femoralis septentrionalis*
Piping plover	*Charadrius melodus*
Eskimo Curlew	*Numenius borealis*
Sprague's pipet*	*Anthus spragueii*
Whooping crane	*Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mollusks	
Smooth Pimpleback*	*Quadrula houstonensis*
Texas Fawnsfoot*	*Truncilla macrodon*
Mammals	
Louisiana black bear	*Ursus americanus luteolus*
Red wolf	*Canis rufus*
Ocelot	*Leopardus pardalis*
Marine Mammals	
West Indian Manatee	*Trichechus manatus*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Atlantic Hawksbill Sea Turtle	*Eretmochelys imbricata*

*listed as federal candidate species

EPA has determined that issuance of the proposed permit will have no effect on any of the nine listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by William Self Associates, Inc. (WSA) on behalf of APEX's consultant, CH2M Hill, Inc. (CH2M Hill), submitted on April 18, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 61.3 acres of land that contains the construction footprint of the project, two water well locations, a proposed wastewater pipeline route, a proposed compressed air pipeline route, and a proposed freshwater/brine pipeline route. WSA conducted a field survey, including shovel testing, of the property and desktop review within a 0.5-mile radius area of potential effect (APE). This review included a search of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA). Based on the desktop review for the site, eight (8) architectural/archaeological sites, including an irrigation ditch and pump house that are components of a larger NHRP-eligible irrigation system, were identified; only the irrigation ditch and the pump house are potentially eligible or eligible for listing in the National Register (NR). All of the sites except for the ditch are outside of the APE. Based on the results of the field survey of the APE, one newly recorded historic-age archaeological site was identified; however, this site was recommended to be ineligible for listing on the NR.

EPA Region 6 determines that while there are cultural materials of historic age identified within the 0.5-mile radius of the project area, issuance of the permit to APEX will not affect properties eligible or potentially eligible for listing on the National Register. Additionally, no historic properties are located within the APE and that a potential for the location of archaeological resources is low within the construction footprint itself.

On December 31, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP

X. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by the EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which the EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XI. Conclusion and Proposed Action

Based on the information supplied by Apex, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHG under the terms contained in the draft permit. Therefore, EPA is proposing to issue Apex a PSD permit for GHG for the Matagorda facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comment. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Table 1. Facility Emission Limits[1]

Annual emissions, in tons per year (tpy) on a 12-month total, rolling monthly, shall not exceed the following:

EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
			TPY[2]		
TURBASTK TURBBSTK	Combined Gas Expansion Turbine Train A and Train B	CO_2	456,296	458,734	i. BACT of 558 lb CO_2/MWh[5] on a 12-month rolling average ii. Special Condition III.A. iii. Maximum heat input to one train is 695.1MMBtu/hr. iv. Work practice standards in Section III A.
		CH_4	12.66		
		N_2O	7.12		
FUG1	Fugitives	CO_2	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of AVO program. See Special Condition III.B.
		CH_4	No Numerical Limit Established[4]		
		SF_6	No Numerical Limit Established[4]		
GENENG1	Natural Gas-Fired Emergency Generator	CO_2	23	23	Good Combustion and Operating Practices. Limit to 50 hours of operation per year. See Special Condition III.C.
MAINT1[6]	Maintenance	CO_2	No Numerical Limit Established	No Numerical Limit Established	See Special Condition III.D. Maintenance purges of the natural gas pipeline is limited to 4/year.
		CH_4	No Numerical Limit Established		
Total	Facility wide			458,757	

1. Compliance with the annual emission limits (tpy) is based on a 12-month total, rolling monthly.
2. The tpy emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations to include startup and shutdown activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_20 = 298, SF_6 = 22,800 as of January 1, 2014, 40 CFR 98 Table 1-A.
4. Fugitive emissions (EPN FUG1) are estimated to be 0.27 tpy CO_2, 5.56 tpy CH_4 and 0.0065 tpy SF_6 for a total of 288 tpy CO_2e. The emission limit will be a design/work practice standard as specified in this permit.
5. Electrical output shall be measured at the generator terminals.
6. Maintenance emissions are estimated to be 1.01 tpy CH_4 and 0.4 tpy CO_2, for a total of 25.65 tpy CO_2e.

Exhibit 7 to Sierra Club's April 9, 2015 Comments

0000155823

ORIGINAL

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES 40-360 ET SEQ., FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE OCOTILLO MODERNIZATION PROJECT, WHICH INCLUDES THE INSTALLATION OF FIVE 102 MW GAS TURBINES AND THE CONSTRUCTION OF TWO 230-KILOVOLT GENERATION INTERCONNECTIONS AND OTHER ANCILLARY FACILITIES, ALL LOCATED WITHIN THE BOUNDS OF THE EXISTING OCOTILLO POWER PLANT SITUATED ON PROPERTY OWNED BY ARIZONA PUBLIC SERVICE COMPANY AND LOCATED AT 1500 EAST UNIVERSITY DRIVE, TEMPE, ARIZONA, IN MARICOPA COUNTY.	DOCKET NO. L-00000D-14-0292-00169 Case No. 169 **ARIZONA PUBLIC SERVICE COMPANY'S NOTICE OF FILING EXHIBITS**

RECEIVED
2014 SEP -9 P 3: 01
AZ CORP COMMISSION
DOCKET CONTROL

Pursuant to Paragraph 11 of Chairman Foreman's August 1, 2014 Procedural Order, Arizona Public Service Company is pre-filing its exhibits in the above-referenced matter. Copies of the exhibits will be distributed to the Line Siting Committee prior to the hearing set for September 16, 2014 in Tempe, Arizona.

RESPECTFULLY SUBMITTED this 9th day of September, 2014.

LEWIS ROCA ROTHGERBER, LLP

Linda Benally for

Thomas H. Campbell
201 East Washington Street, Suite 1200
Phoenix, Arizona 85004
Attorney for APS

Arizona Corporation Commission
DOCKETED
SEP 9 2014
DOCKETED BY

ARIZONA PUBLIC SERVICE COMPANY

Melissa M. Krueger
Linda J. Benally
Pinnacle West Capital Corporation
Law Department
400 North 5th Street, MS 8695
Phoenix, Arizona 85004
Attorneys for APS

ORIGINAL and twenty-five (25) copies of the foregoing filed this 9th day of September, 2014, with:

The Arizona Corporation Commission
Hearing Division – Docket Control
1200 W. Washington Street
Phoenix, Arizona 85007

COPY of the foregoing delivered/mailed this 9th day of September, 2014, to:

John Foreman
Arizona Power Plant and Transmission Line
Siting Committee
Office of the Arizona Attorney General
PAD/CPA
1275 West Washington Street
Phoenix, Arizona 85007
John.Foreman@azag.gov

Lyn Farmer
Administrative Law Judge
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

Janice Alward
Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

COASH & COASH
1802 North 7th Street
Phoenix, Arizona 85006

Daniel Pozefsky
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Patrick J. Black
Fennemore Craig, P.C.
2394 E. Camelback Road, Suite 600
Phoenix, Arizona 85016

Rebecca Turner
100 S. Ashley Drive, Suite 1400
Tampa, Florida 33602

Ocotillo Modernization Project

APPLICATION FOR CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Hearing Exhibits

Docket No. L-00000D-14-0292-00169

Prepared for

State of Arizona Power Plant and Transmission Line Siting Committee

Arizona Corporation Commission

Submitted by

Arizona Public Service

aps

OCOTILLO MODERNIZATION PROJECT
Docket No. L-00000D-14-0292-00169
Case No. 169

EXHIBIT LIST

Tab Number	Exhibit Number	Description
Tab 1	APS-1	Application for Certificate of Environmental Compatibility, filed July 31, 2014 (previously distributed)
Tab 2	APS-2	Placemat
Tab 3	APS-3	Witness Presentation Slides for Brent Gifford, APS
Tab 4	APS-4	Witness Presentation Slides for James Wilde, APS
Tab 5	APS-5	Witness Presentation Slides for Bob Smith, APS
Tab 6	APS-6	Witness Presentation Slides for Charles Spell, APS
Tab 7	APS-7	Witness Presentation Slides for Jennifer Frownfelter, URS
Tab 8	APS-8	Physical Power Plant Tour Protocol and Tour Stop/Descriptions
Tab 9	APS-9	Proposed Certificate of Environmental Compatibility
Tab 10	APS-10	Final Newsletter mailed August 25, 2014
Tab 11	APS-11	Photographs of Notice of Hearing signs posted at site and map
Tab 12	APS-12	Affidavits of Publications: *Tempe/Ahwatukee Republic*, August 8, 2014 *East Valley Tribune*, August 10, 2014
Tab 13	APS-13	ASU's The State Press: Website top banner advertisement and advertising receipt
Tab 14	APS-14	Proof of Delivery of CEC Application to Public Locations: Tempe Public Library Noble Library at Arizona State University Tempe Kiwanis Recreation Center
Tab 15	APS-15	Letter of Support – City of Tempe
Tab 16	APS-16	Letter of Support – Tempe Chamber of Commerce

TAB 4

Right Slide Blank

James Wilde

Director, Resource Planning

Arizona Public Service

Ocotillo Modernization Project
Docket No. L-00000D-14-0292-00169

Right Slide Blank

Background

- Educational Background
  - Master of Business Administration
  - Bachelor of Science Degree in Corporate Finance
- Professional Background
  - 24 years of energy industry experience
    - 11 years with Arizona Public Service Company
      - Director of Resource Planning (Current)
      - Director of Enterprise Risk Management
    - 7 years with Duke Energy Trading and Marketing
      - Merchant generation and commodities trading
    - 6 years with Salt River Project
      - System Operations

Right Slide Blank

Outline of Testimony

- Context for Project Need – Integrated Resource Plan (IRP)
- APS resource portfolio needs peaking generation
- Fast-growing renewable generation is variable, requiring the addition of flexible generation resources to respond quickly
- Flexible generation allows APS and its customers to benefit from market opportunities
- Ocotillo Modernization Project serves these needs

aps

Right Slide Blank

aps

2014 IRP Overview

- **Natural gas generation will play increasingly important role**
  - Operational flexibility
  - Economics
- **Cleaner energy mix**
  - Customer resources such as roof-top solar and energy efficiency planned to be largest growth segments
- **Advanced technology will change the electricity grid**

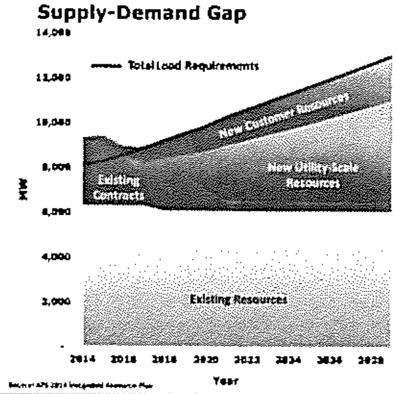
aps

Right Slide Blank

aps

2014 IRP Overview

Supply-Demand Gap



- Growth in energy requirements expected to resume
- Expiring purchase contracts means APS will need additional resources by 2017, and needs grow thereafter
- Customer resources expected to triple over planning horizon
- Additional resource needs met by increasingly diverse and efficient technologies

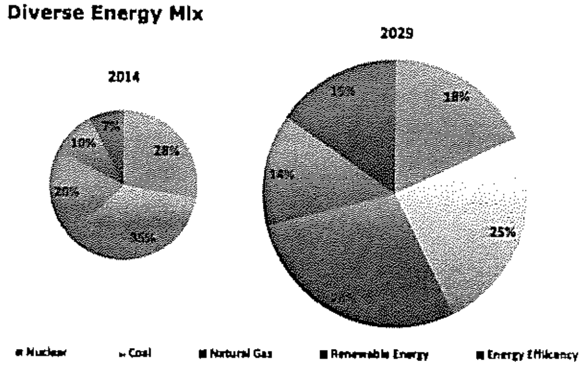
aps

Right Slide Blank

aps

2014 IRP Overview

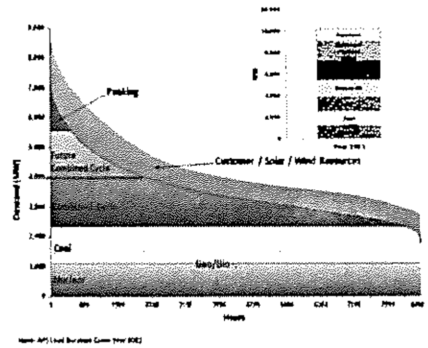
Diverse Energy Mix



aps

Right Slide Blank

Resource Portfolio Need for Peaking Generation

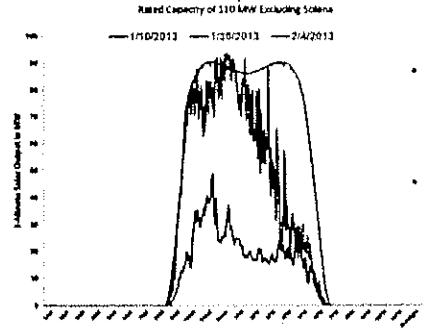


- Flexible peaking capacity is needed to meet changing load patterns and customer demand
- CCs are essentially being forced to play limited role, idling much of the time, or shut down in non-summer months
- Capacity from Ocotillo Project represents roughly 20% of near term natural gas resource needs, and roughly 13% of total need

Right Slide Blank

Renewable Generation is Variable

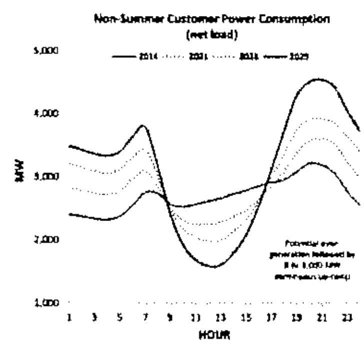
Solar Production



- Depending on cloud cover, solar production can vary greatly minute by minute
- Fast starting generation that can adjust output quickly is needed to respond to solar output variability
- Solar energy and flexible, responsive natural gas generation are complementary resources
  - Growth in renewable energy cannot take place without the ability to integrate it onto the grid

Right Slide Blank

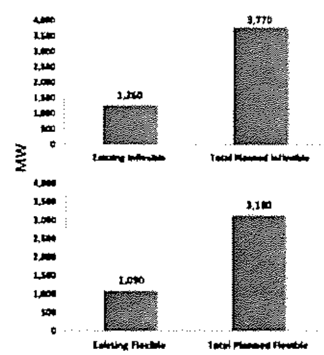
Variability Requires Flexibility



- At the peak of solar output (around noon), conventional resources will have to be significantly reduced to make room for self-dispatching solar
- Quick starting and fast ramping generation needed
  - Respond to solar variability, multiple starts per day and market purchase opportunities
- In 2025 on an average April day, renewables could represent up to 51% of customer demand

Right Slide Blank

Variability Requires Flexibility
Balancing Growth in Resources

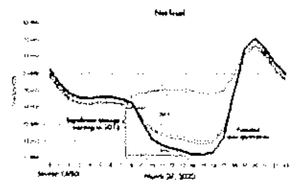


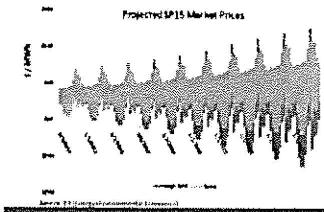
- Inflexible resources cannot be dispatched by utilities
  - Projected to have the highest growth
- Flexible resources are complementary to inflexible resources for balancing each other
  - Required to integrate variable renewable energy output into the utility system
- Flexible resources are able to start and adjust output quickly, and are capable of multiple starts per day
  - Ocotillo Project quick starting GTs

Right Slide Blank

Flexible Generation and Market Opportunities

- California Independent System Operator (CAISO) has identified concerns with upward and downward ramping and the need for flexible resources to respond quickly to these system changes





- Due to the potential for over-generation, utilities may have to sell surplus power at low to negative prices
- The Ocotillo Project provides the ability for customers to benefit from low or negative priced power

Right Slide Blank

Summary

- Integrated Resource Plan envisions growth being met with diverse set of resources including peaking generation
- Customer demand and markets are evolving as more variable resources such as solar are added to the grid
- Growth in variable resources must be balanced by growth in flexible generation
- Ocotillo Modernization Project part of overall need for flexible, responsive generation

Exhibit 8 to Sierra Club's April 9, 2015 Comments

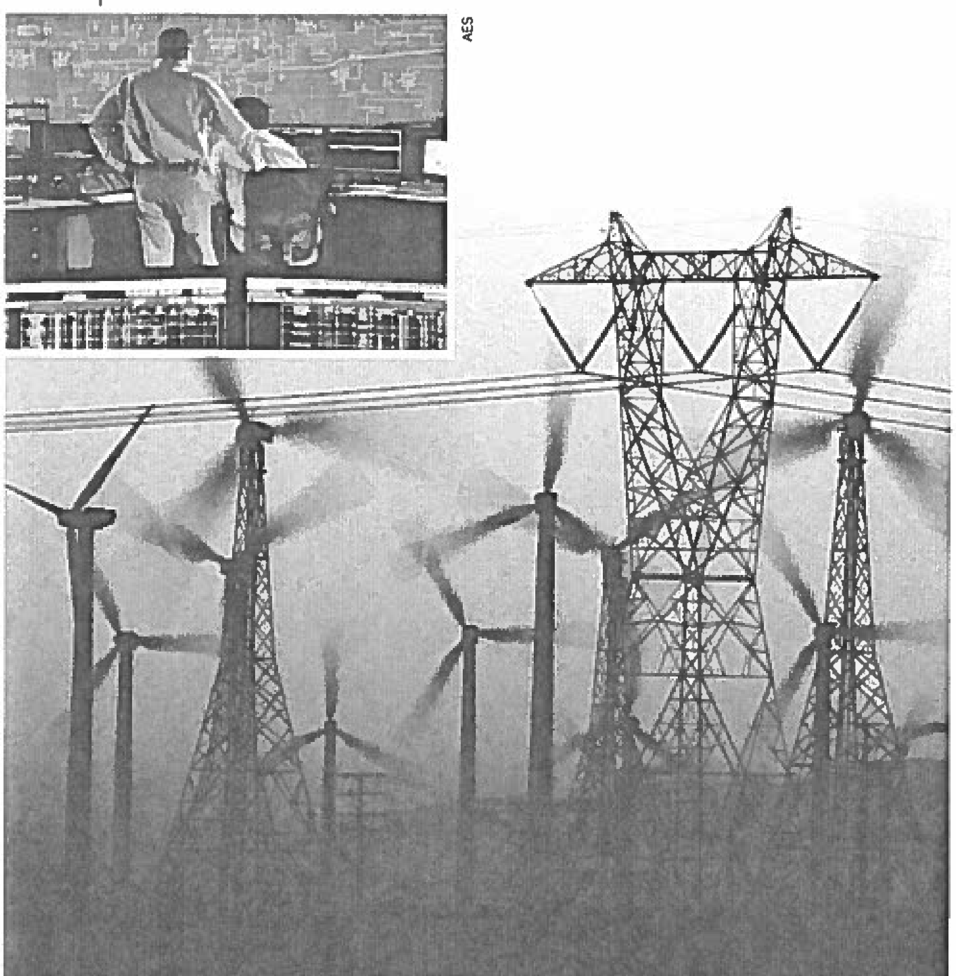
ENERGY STORAGE

Finding the Hidden Megawatts

By Chris Shelton

Opinion

In February 2013, six years after AES began working on advanced battery storage projects and while developing a new project in a large power market in the United States, a member of AES' storage team was presented with a problem. In order to register the planned facility in the market, he had to fill out the "Resource Asset Registration Form" (RARF). This form is required of all resources performing in the market as a way for the grid operator to properly model those resources in the system. It was unclear how one would fill out the form for a storage facility, so he called the grid operations help desk. (See box at right.)



AES

EDISON INTERNATIONAL

As president of AES Energy Storage, LLC, Chris Shelton leads the energy storage efforts of the AES Corporation, a company with over 200 megawatts (MW) of advanced energy storage resources in operation and construction and 2,000 MW of projects in near-term development. He also is a past chairman of the Electricity Storage Association. The views expressed herein are those of the author.

AES:

"Hello, my name is Dauren from AES. I am filling out this registration form for my 40-megawatt battery storage project. I just want to be clear that I should fill out this form as a generator."

Grid Operator:

"Yes. If you are supplying power to the grid you will need to complete the Resource Asset Registration Form or RARF."

AES:

"OK. But what about when I am charging from the grid?"

Grid Operator:

"Will we be controlling your battery while it is charging?"

AES:

"Yes. The system is built specifically to serve the market."

Grid Operator:

"OK, sir. You will need to fill out another form for your controllable load resource, essentially the load RARF."

AES:

"Two forms for one facility? How many megawatts should I put on each form?"

Grid Operator:

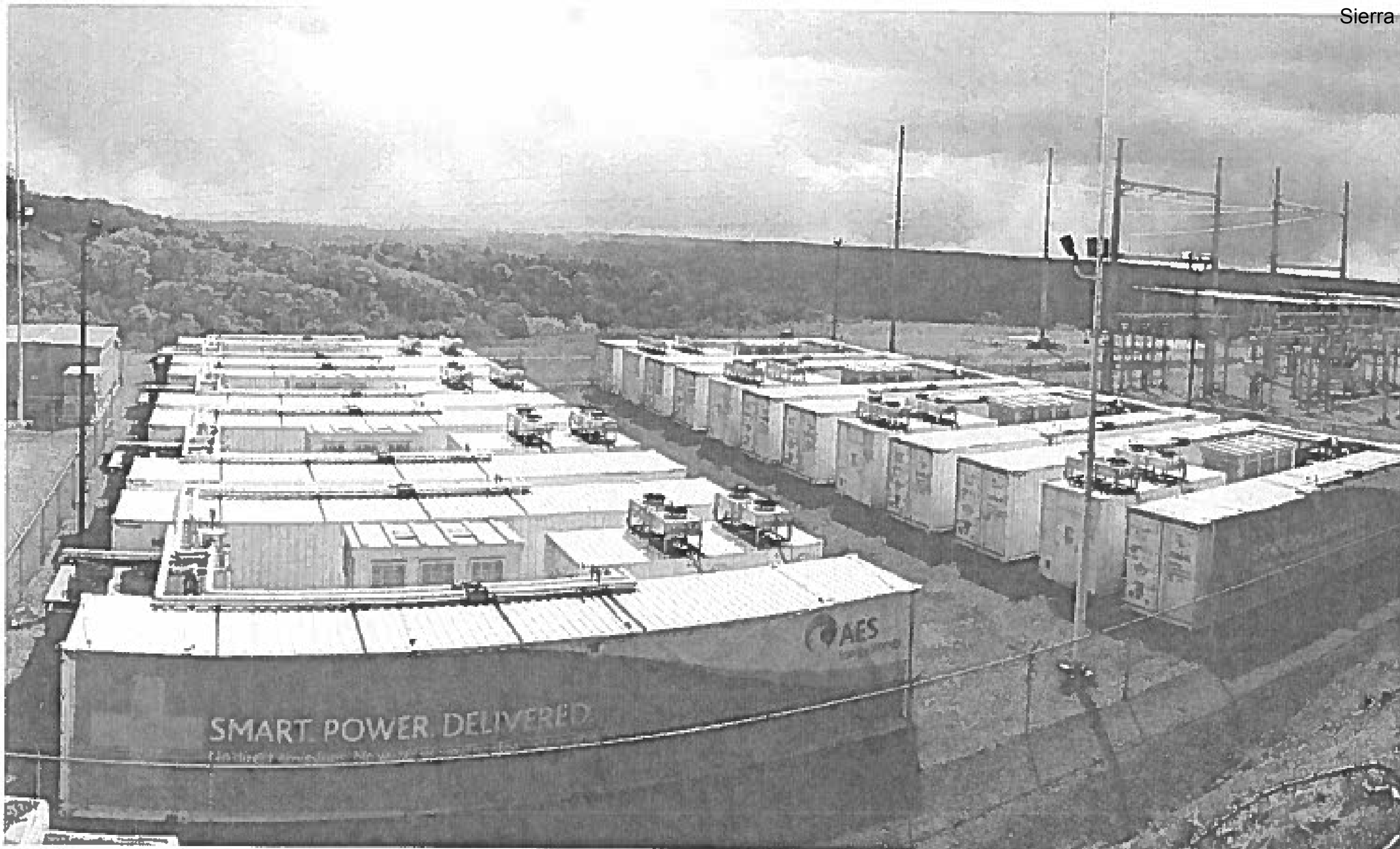
"If you can charge and discharge at the 40 megawatts you mentioned, you will need to put 40 megawatts on each form."

AES:

"So that means this is 80 megawatts of resource? Are you sure this is correct?"

Grid Operator:

"That is how we model it in the system—it is two 40-megawatt resources to us—supply and load."



AES

After many years of insightful work and nearly ten storage interconnections in various markets, our storage team at AES had never thought about the facilities we now owned and operated in this way. This experience was a bit humbling and is told here to encourage other stakeholders to examine how little we have considered energy storage in our ecosystem.

From Power Plants to Grid Resources

When an organization wants to connect a facility like a power plant or a large customer site to the grid, it needs to "interconnect" to the grid. This interconnection is rated at a certain size and is often just referred to as a number of megawatts (MW) of power flow. If an independent power producer builds a 500-MW power plant, a 500-MW interconnection to the grid will be required. The same is true on the customer side of the grid. A large data center, for example, may require a 50-MW interconnection in order to withdraw sufficient power for all its servers. The former is injecting power into the grid and the latter is drawing power from the grid.

In the power plant case, that resource is controlled by instructions from the regional grid operator, and in recent years, our industry has begun actively controlling customer loads as well. As more loads have entered the picture, the industry has started generically referring to all of these end-points that serve the grid as "resources." This language is now commonplace for most of the electricity industry stakeholders working on demand-side programs.

For most facilities, the megawatt of interconnection rating and the megawatt of resource rating are nearly always the same number. A 100-MW power plant can supply 100 MW of power and has a 100-MW interconnection over which to do so—the same for both supply resources and load resources. As storage has been added to the grid, this convention has continued unquestioned. I think this convention of interconnection size driving resource designation is erroneous for storage, which we need to explore.

Inception Becomes Conviction

With the remarkable insight that one of the largest power markets in the world was convinced that our planned 40-MW storage facility was actually an 80-MW resource composed of two 40-MW resources, we challenged ourselves to consider whether the whole industry had gotten it wrong. If this RARF insight were comprehensive, then our previously designated 32-MW project at Laurel Mountain in West Virginia should be 64 MW of resource (even though it was located in another market where there is no RARF form). (See the sidebar, "A Unique Combination.")

An engineer on our team made a simple, compelling thought experiment. He said, "Try to do the job our Laurel Mountain battery is doing with a power plant or a load resource. How much would you need? Your answer is our resource equivalence."

A Unique Combination

Located in West Virginia, the AES Laurel Mountain facility is comprised of 98 megawatts (MW) of wind generation and 64 MW of integrated battery-based energy storage resource. The facility supplies emissions-free renewable energy and clean, flexible, regulation service to the PJM Interconnection. AES Laurel Mountain began commercial operation in 2011 as a fully integrated portion of the Laurel Mountain Wind Farm and is among the first wind generation facilities to supply critical grid stability services to help maintain the reliability of the power grid.

I asked the team to develop the concept, and they came back with a mildly technical answer, but one that is abundantly clear.

Since Laurel Mountain provides flexibility to the grid operator, it has the capability to fully discharge, fully charge, or do anything in between at the grid operator's command. That means it can go from plus-32 MW to minus-32 MW. (See Figure 1.) Since power plants cannot "go negative" in order to respond to the same range of signals from the grid operator, the plant would need to be running at a level well above 32 MW to be able to reduce output by 32 MW for the negative dispatch. The plant also would need to be able to increase output by at least 32 MW of head room to take the positive dispatch. Similarly, a large load-side resource like an industrial site would need to be consuming at a rate of at least 32 MW and be able to increase consumption by another 32 MW. Considered together, that is clearly at least 64 MW of resource in each case.

These trends are driving a focus on a grid of the future that is more flexible and fault-tolerant and able to handle rapid changes in load and supply.

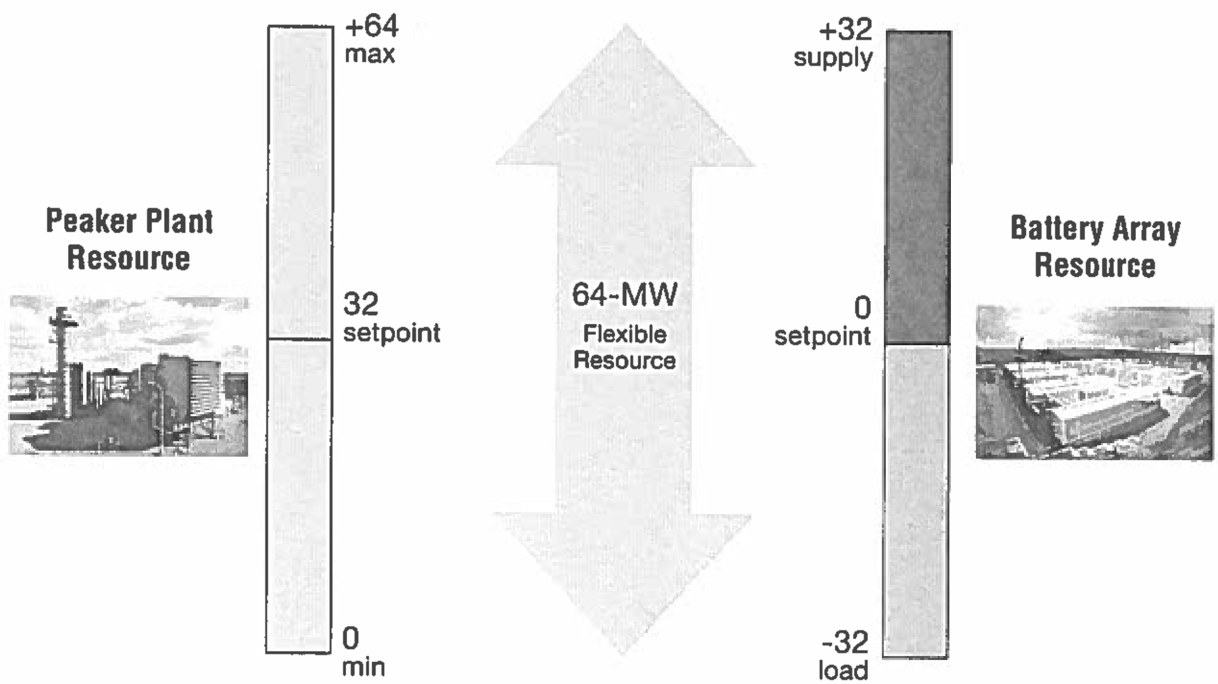
We found that the thought experiment for Laurel Mountain holds broadly for highly controllable advanced storage solutions. Convinced by this insight, we have chosen to move to a new designation for all storage facilities. We now refer to our facilities (and those owned by others) in terms of megawatt of power plant equivalent resource or megawatt of resource in short form. We also maintain the old size with a new designation of megawatt of interconnection. So the Laurel Mountain advanced battery array is a 64-MW resource on a 32-MW interconnection. The same can be said of all similar resources. Based on the growing needs of the industry, this revelation could have a profound impact on future grid resource selections.

Flexible Resource Needs

In the past five years, our industry has seen significant growth in the adoption of variable renewable energy sources like wind and solar. At the same time, we have seen an increasing number of weather-related impacts on the grid and an increased focus on resiliency from a homeland security perspective. These trends are driving a focus on a grid of the future that is more flexible and fault-tolerant and able to handle rapid changes in load and supply. Power plant manufacturers are focused on adding "flex" to their machines, and the demand-side community is highlighting the flexibility of controllable loads like water heaters.

California has launched an entire process to explicitly add the consideration of resource flexibility to their resource adequacy procurement processes. The Energy Information Administration forecasts in its "2013 Annual Energy Outlook" that more than 38,000 MW of combustion turbines will be installed over the next 15 years. Many utilities have said when they

FIGURE 1
TWO 64-MW FLEXIBLE RESOURCES



*For simplicity, minimum load for the power plant is assumed zero, although all conventional power plants have minimum load levels.

plan for and procure peaker plants that many of these plants will be required primarily for flexibility. With this focus on procurement of flexible resources, the evaluated size of energy storage resources becomes very important in the determination of their cost effectiveness.

The utility industry has a clear way of evaluating power resources on a common basis. It uses [dollars of capital investment required to install a facility] divided by [kilowatts (kW) of power of the facility]. This results in $/kW installed. So a 100-MW power plant that costs $90 million to build would be roughly $900/kW.

In the past when storage facilities were compared to power plants, the interconnection megawatt would be used. As discussed, this is inappropriate as it only counts half the power plant equivalent resource of the storage facility and half the flexibility capability available. If a facility like Laurel Mountain costs $32 million to install, and we only count it as 32 MW, the evaluated cost would be $1,000/kW. However, if we use the fair comparison of 64 MW of resource, the facility is only $500/kW.

The Need for Targets

This doubling of the denominator in the procurement calculation will have a profound effect on which resources are chosen in future procurements.

Of particular interest are the procurement targets set out in California for energy storage. Many readers may be aware that the California Public Utilities Commission has defined targets for grid storage in the resource mix that require the three large utilities in the state to procure 1.35 gigawatts of storage resources by 2020. These resources will need to compete with other resources like power plants to meet the state's need for resource adequacy, and the expectation is that the inclusion of storage will help add much needed flexibility to the grid to assist with meeting the state's renewable targets. In the lead-up to the definition of these storage targets, several stakeholders asked me, "If storage is competitive, why does it need targets?"

This story of latent resource value in storage systems that AES had already built years prior indicates that we as an industry can do a better job evaluating how these technologies can serve our grid. Targets that are also held to a competitive process, like those planned in California, are a great way to encourage thorough evaluation of this value. If the procurement process counts the resource appropriately with its full power plant equivalence, storage will have no problem being seen as one of the least costly resources available to meet California's flexible resource needs.

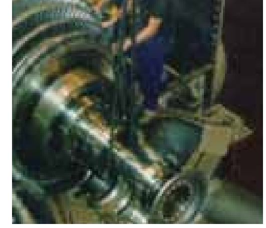
It is surprising how our legacy technologies and processes have created inadvertent barriers for new technologies and solutions. Hopefully, with the nudge of policy and regulatory change, we will be able to fully embrace these amazing technologies and encourage their continued development through more rapid adoption. ◆

Exhibit 9 to Sierra Club's April 9, 2015 Comments

DRESSER-RAND

Bringing energy and the environment into harmony.℠

COMPRESSED AIR ENERGY STORAGE (CAES)



Unique load management and generation "on demand"

Unmatched experience makes Dresser-Rand your partner of choice.

This CAES equipment built by Dresser-Rand has been performing reliably in McIntosh, Alabama since 1991.

FROM CAES PIONEER TO CAES LEADER

Dresser-Rand is uniquely qualified to deliver total demand management and power generation using Compressed Air Energy Storage (CAES) solutions. We designed and supplied the entire turbomachinery train and controls for the first CAES plant in North America. Only the second of its type in the world, Power South's McIntosh, Alabama, USA facility has been building an impressive record of starting reliably more than 90 percent of the time, and demonstrating greater than 95 percent reliable operation since 1991.

FLEXIBLE SOLUTIONS FROM A SINGLE SOURCE

Dresser-Rand can supply the entire CAES train. Our teamwork reduces your project management time, and single-source packaging minimizes transaction and transportation costs.

We custom-engineer each CAES train to provide you with a system designed specifically to meet your site's operating and geologic requirements. We select and fine-tune standard Dresser-Rand components for your project, then we make sure that all components will work together to maximize efficiency, and reduce installation and start-up times. Systems can be configured for salt caverns, hard-rock caverns, aquifers, or depleted natural gas fields on land or sea.

FUTURE OPPORTUNITIES FOR CAES SOLUTIONS

Ever alert to workable solutions, Dresser-Rand engineers recently secured a patent for a sub-sea CAES concept that combines a conventional CAES facility with a sub-sea piping and compressed air storage system. Such a structure could bring CAES technology to a wide range of coastal locations that represent nearly 80 percent of the world's demand for electricity.

Furthermore, the growing interest in wind and solar energy has spurred interest in CAES technology. Wind farms typically generate more electricity at night when there already is a surplus of electricity. The ability to "bottle" this electric energy for daytime use (when it is most valuable) is an attractive consideration. Likewise, electricity from photo-voltaic farms in "sunny" regions could be sent through high-voltage DC transmission lines to CAES facilities elsewhere, where turbines would generate electricity year-round.

CAES technology gives utility operators the means to operate their base load plants more efficiently and provides a solution for balancing the grid. And it enables green technologies such as solar cells and wind turbines to be matched with daily and weekly demand requirements for electricity.

DRESSER-RAND

Bringing energy and the environment into harmony.℠

Unmatched experience.

The only CAES plant operating in North America, the Power South facility continues to meet its peak load demands on a daily basis. To date, the train has started reliably more than 90 percent of the time, and demonstrated greater than 95 percent reliable operation (running).

As changing market forces make CAES increasingly attractive, this ongoing success makes the Power South plant's major equipment supplier, Dresser-Rand, the logical choice for developing the next generation of CAES facilities.

CAES Plant Builds Impressive Record

Since 1991, a CAES plant in McIntosh, Alabama has been producing up to 110 MW of electrical power during periods of high peak demand. The plant's owner, Power South, uses it to boost its power capabilities during the peak daytime periods when demand for electric energy skyrockets. "Our load is primarily residential," says plant manager Lee Davis. "CAES fits well with our load shape. Basically, I'm very much for the CAES concept."

The facility uses excess electricity generated by a Power South coal-fired plant during off-peak hours (when electricity costs are lowest) to compress air for storage. It then uses that air to generate electricity and sell it at a higher price during peak periods. "We buy low and sell high," Davis says.

"Normal startup for us is 14 minutes to reach 110 MW," says Davis. "I can run down to 10 MW. It's just a better regulating tool." A dispatcher controls both the plant's compression and power generation cycles via microwave from 90 miles away.

The 140-foot train, one of the longest in the world, is almost exclusively Dresser-Rand equipment. It is technically derived from Dresser-Rand product lines that have been time- and field-tested for decades in other applications. The equipment includes single-stage turbines, standard multi-stage turbines, packaged geared turbine generators and engineered turbine generators, centrifugal and axial compressors, gas turbines, and reciprocating compressors.

The train has a centrally located motor/generator with clutches on both sides. On one side, a low-pressure compressor, intermediate compressor and high-pressure compressor work to store air in a salt dome at pressures up to 1100 psig. Four stages of compression and three inter-coolers are used to enhance cycle efficiency by minimizing compressor power.

When electric power demand peaks during the day, the process is reversed. The compressed air is returned to the surface, heated, and run through high-pressure and low-pressure expanders to power the motor/generator to generate electricity.

Power South uses an underground salt dome for compressed air storage. "We solution mined it for 629 days," Davis recalls. "That created 19 million cubic feet of cavern storage."

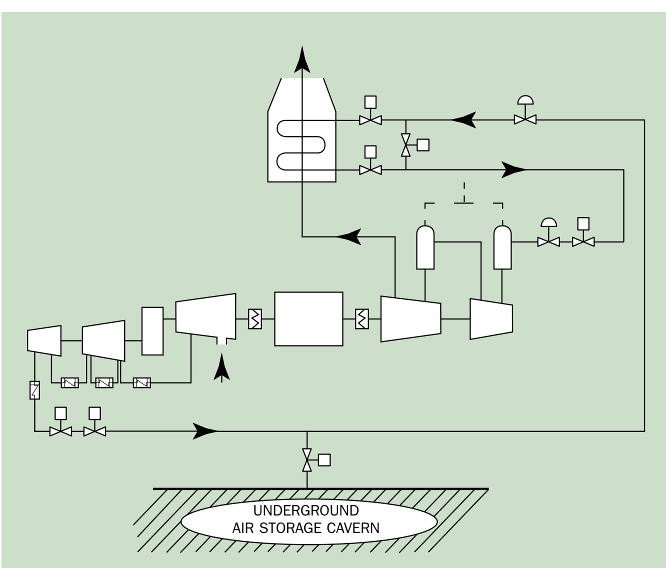
13-YEAR AVERAGE RELIABILITY			
COMPRESSION		GENERATION	
Starting	Running	Starting	Running
92.7%	99.6%	91.6%	96.7%

CAES

A Smart Choice for Many Utilities

Increases efficiency and extends base load unit life— CAES facilities enable you to optimize your base load units by minimizing load swings to maximize efficiency and extend unit life. Storing energy lets you use off-peak power to meet peak demand. This is less expensive than using traditional gas turbine peaking units or purchasing power from other sources.

Responds quickly—A CAES generator is designed to be started and brought to full load in as little as 10 minutes, eliminating the need for intermediate-load plants and providing a cost-effective way to meet spinning reserve requirements. CAES generators also have excellent load-following capability and very good part-load efficiency. Compressors can be engaged quickly to absorb load rather than reducing your base load generation.



Schematic of traditional CAES process showing air flow into and out of the storage cavern.

Flexible cycling options— The CAES system is available for compression duty when it's not in power generation mode, and can be configured for daily, weekly, or extended cycles. This allows you to "grid balance," and use inexpensive power for air storage (charging).

Environmentally friendly— CAES has environmental advantages compared to conventional gas turbines because its combustors use as little as two-thirds the fuel. Furthermore, CAES can be an attractive alternative to the costly modifications required to make coal-burning plants comply with increasingly stringent fossil fuel emissions requirements.

A CAES PRIMER

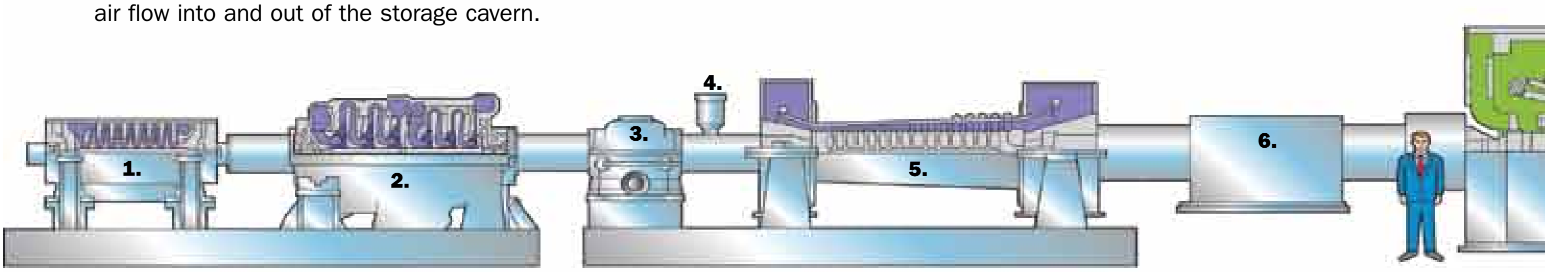
In a CAES plant, available off-peak electricity is used to power a motor/generator that drives compressors to force air into an underground storage reservoir at high pressures. This process (called "charging") usually occurs at night, and during weekends when utility system demands and electricity costs are low.

During intermediate electrical demand periods, the air is released from the reservoir, and without further compression is heated and expanded through gas- or fuel oil-fired combustion turbines to drive the same motor/generator to produce electrical power.

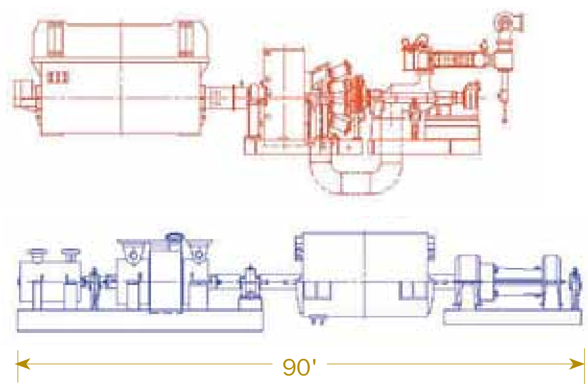
Compressed air may be stored in certain reservoirs created by solution mining bedded or domed salt formations; conventionally mining solid rock; or in aquifers and depleted natural gas fields. These formations can be found around the world.

LONG-TERM SERVICE AGREEMENTS (LTSA)

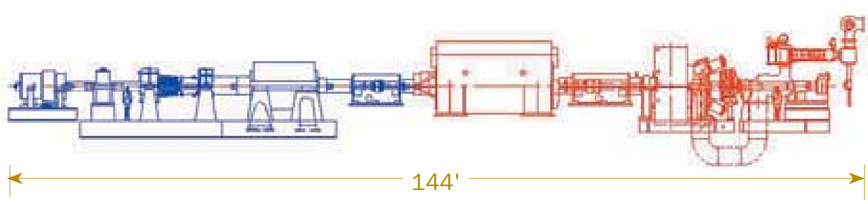
Dresser-Rand offers long-term service agreements (LTSA) to clients who require personnel to supplement or replace their maintenance organizations. A typical LTSA includes project management, technical services, field crews, and support from our OEM technical resource network. Our field teams are OEM-trained, fully equipped, committed to safety, and logistically prepared to provide professional and timely services to keep your critical equipment on-line, or restore it to full operation.



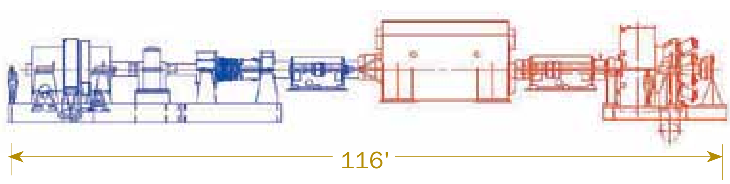
MODULAR DESIGN ALLOWS EACH SYSTEM TO BE CONFIGURED FOR MAXIMUM EFFICIENCY



Increased flexibility for simultaneous compression and power generation and quicker transition time between power generation and compression.



Matching power generation with compression flow requirements for air storage in salt domes or hard rock caverns.



Matching power generation with lower discharge pressure requirements for air storage in aquifers.

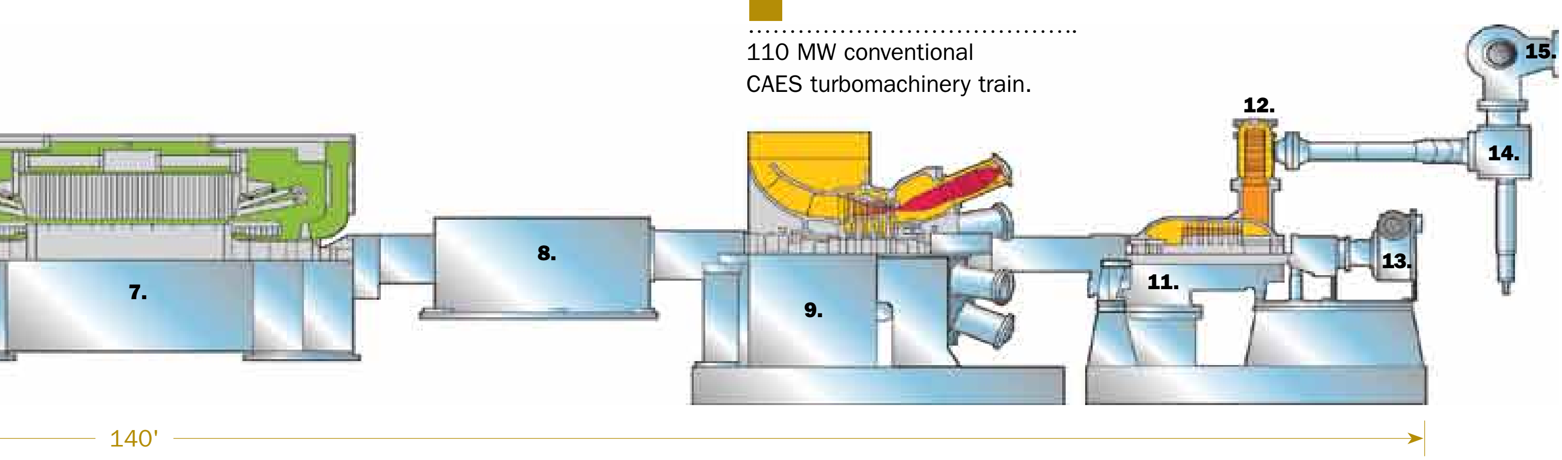
FLEXIBLE OPERATION TO MEET CUSTOM REQUIREMENTS

- Modular, single-shaft train uses proven equipment designed to meet stringent American Petroleum Institute (API) standards
- Flexible operation modes available
- Low operation and maintenance life cycle costs achieved by:
  - Smaller, less expensive turbine components
  - Standard modules and replacement parts
  - Longer time between overhauls (compared to conventional high-temp gas turbines)
  - Lower fuel consumption (less than two-thirds that of equivalent gas turbines)
  - Wide turn-down (load) with only moderate reductions in efficiency
  - Higher efficiency at partial load
- Only a portion of the plant capacity is lost if a module of the CAES system is down for maintenance (compared to plants with large steam turbine units)
- Incremental capacity—development of storage sites
- Short lead times
- Rapid start—in as little as 10 minutes to full load
- Motor/generator can be used as a synchronous condenser to improve the system's power factor
- Output not affected by ambient temperatures

LEGEND

1. High-pressure compressor
2. Intermediate-pressure compressor
3. Speed-increasing gear
4. Turning gear
5. Low-pressure compressor
6. Clutch
7. Motor/generator
8. Clutch
9. Low-pressure expander
10. Low-pressure combustors
11. High-pressure expander
12. High-pressure combustors
13. Turning gear
14. Air throttle valve
15. Air trip valve

110 MW conventional CAES turbomachinery train.



SMARTCAES™

Enhanced Renewable Energy Solutions

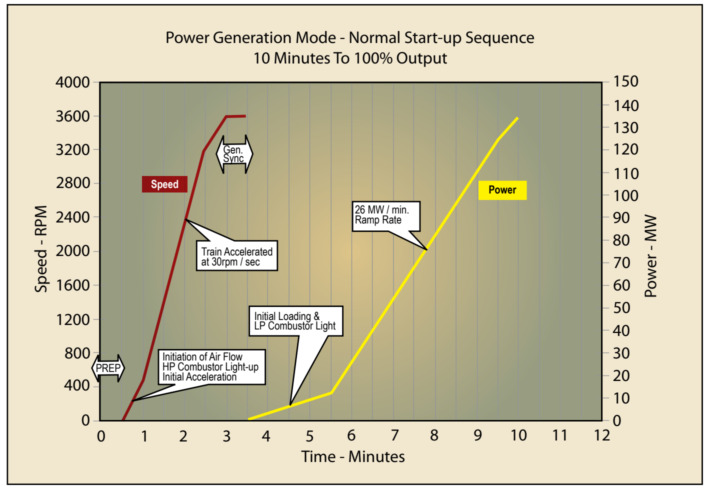


FIGURE 1: Power generation mode—normal start-up sequence

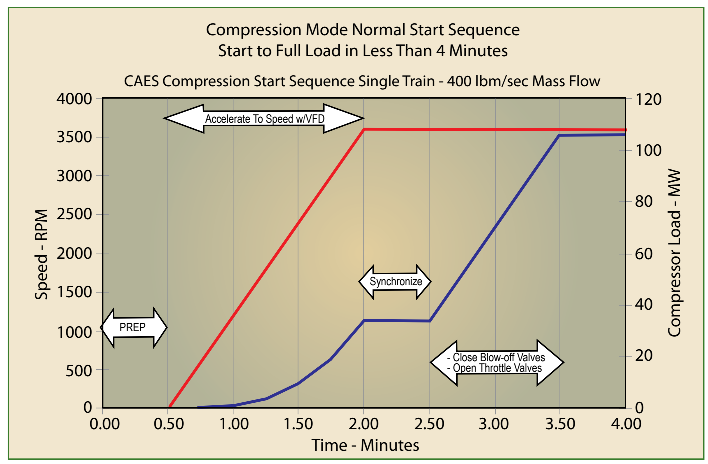


FIGURE 2: Compression mode normal start sequence

Dubbed ***SMART***CAES™ equipment and services, this enhanced offering is more than a name; it's a reflection of Dresser-Rand's unique qualification to deliver the total integrated rotating equipment system—a "one-stop" CAES solution. This solution includes not only the rotating equipment, but all ancillary services as well—the heat exchange equipment, pollution abatement system, and the plant controls—complete with performance guarantees (both compression and power generation modes).

Over the years, related research and development from other Dresser-Rand products have been incorporated into our CAES offering (e.g., DATUM® compressor technology enhancements), and these ever-improving technologies have put CAES at the "head of its class" on every relevant subject.

SMART ON TECHNOLOGY

Technological advancements achieved since first introducing the CAES design for the McIntosh facility bring a range of benefits to Dresser-Rand's ***SMART***CAES equipment, including operating flexibility, increased power output, reduced fuel and air consumption, improved compressor efficiency, noise reduction, and improved recuperator design.

Operating flexibility—*SMART*CAES equipment offers shorter startup times to achieve rated output in power generation mode, higher load ramping rates in power generation mode, faster compression start-up times, and faster transition between compression and power generation modes.

In power generation mode, the system is designed to start-up in less than 10 minutes to ramp output up to the rated 135 MW. Once synchronized, any output from 15 to 100 percent of rated load can be sustained indefinitely. Within this range, output may be ramped up or down at 20 percent of rated load per minute, or 27 MW per minute.

A variable speed drive system provides for rapid compression starts requiring less than 3.5 minutes. Once air is flowing to storage, the compressors may be turned down to any load between 65 and 100 percent of rated power, using variable inlet guide vanes, at a rate of 35 percent per minute (see figures 1 and 2).

For single train systems using a combination motor-generator, the variable frequency drive (VFD) system can be used to speed up the transitions between power generation and compression modes. Transitioning from power generation to compression can be achieved in five minutes, while adjusting from compression to power generation requires about 13 minutes. Multiple train systems, with separate motors for compression and generators for power production, eliminate mode transition time. The maximum transition time equals startup time in the desired mode.

Power output—The output of ***SMART***CAES turbo expanders was increased from 110 MW to 135 MW. Combining modern analytical techniques and upgraded materials, the calculated safety factors for both the high-pressure and low-pressure turbines' flowpaths remain virtually unchanged, despite a total output increase exceeding 20 percent.

Fuel and air consumption—Turbine and system enhancements such as better recuperator effectiveness result in a two percent heat rate improvement, coupled with a 1.2 percent reduction in specific air consumption (SAC), across the design operating range from 20 MW to 135 MW. The heat

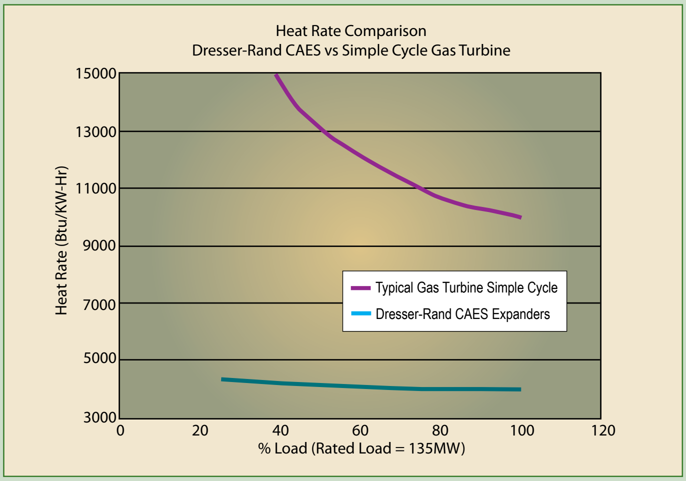


FIGURE 3: Heat rate comparison

rate of the Dresser-Rand ***SMART***CAES expanders is low and flat over a wide range of turndown from 100 percent load to 25 percent load because the expanders operate independent of the air compressors (see figure 3).

Compressor efficiency—Dresser-Rand's DATUM centrifugal compressor technology, more advanced axial compressor flowpath aerodynamics and careful design of the intercooled compression cycle all provide significant improvements in overall efficiency. Depending on final parameters, overall compression train flange-to-flange polytropic efficiency is in the mid-80 percent range in terms of energy consumption. The efficiency of the Power South CAES compressor train installed and operating in McIntosh is in the low 80 percent range (approximately three percent lower than Dresser-Rand's current CAES offering).

Noise reduction—Our patented noise reduction technology (D-R® duct resonator array) can achieve up to a 10 dB reduction in noise levels compared to centrifugal compressors that do not utilize this acoustic technology.

Recuperator design—The exhaust recuperator is a simpler design, with 85 percent heat transfer effectiveness compared to 75 percent in the earlier design. Strategically placed rows of stainless steel tubes avoid corrosion and exfoliation problems, and the entire recuperator is designed to operate at maximum air storage pressure, eliminating the cost and maintenance of pressure reducing valves. This change also makes sliding pressure cycles feasible where advantageous.

SMART ON THE ENVIRONMENT

The technological improvements to ***SMART***CAES equipment and services offer emission control options capable of meeting all current regulatory requirements for NO_x and CO limits. With features that can meet current emissions requirements, ***SMART***CAES equipment can do its part to reduce the buildup of greenhouse gases in the atmosphere and combat climate change.

A simple diffusion flame combustor with H_2O injection for primary NO_x control, coupled with an exhaust selective catalytic reduction system for final NO_x control, provides stable operation at high turndown ratios. It's possible to achieve final exhaust emission levels of 2 ppm NO_x and 2 ppm CO, corrected to 15 percent O_2. This means, depending on the operating profile, many potential CAES sites would fall under small-source emission limit rules. In addition, the VFD system reduces the compression start time, eliminating expander emissions from compression starts.

When used in conjunction with renewable energy such as wind or solar, ***SMART***CAES equipment has one-third the emissions of a conventional gas turbine.

SMART ON BUSINESS

The world's increasing focus on cleaner, greener energy use presents Dresser-Rand with an ideal opportunity to successfully integrate our CAES technology into new markets.

We recently secured a patent for a concept to combine a conventional CAES facility with a sub-sea piping and compressed air storage system. Such a structure could bring CAES technology to a range of coastal locations that represent nearly 80 percent of the world's demand for electricity.

The growing popularity of wind and solar energy could also spur interest in ***SMART***CAES solutions. Wind farms typically generate more electricity at night, when there's already a surplus, and the ability to "bottle" electric energy for daytime use is an attractive option. Within the solar market, electricity from photo-voltaic farms in sunny regions could be transmitted to facilities that use ***SMART***CAES equipment in other areas, where turbines would generate electricity year-round.

The world would benefit from increased use of renewable energy sources, such as wind and solar, however, a common reality is that they are inherently intermittent and to some degree unreliable. ***SMART***CAES equipment provides an excellent tool for "smart grid" management by having excellent load following capability, helping base load assets to be more efficiently utilized during off-peak times, and by being able to provide ancillary services such as VAR support, regulation and reserve.

The dynamics of the worldwide energy market are changing, and ***SMART***CAES solutions are one example of how Dresser-Rand is repositioning its offerings to address global needs. Renewable energy sources can benefit from the bulk energy storage capabilities that ***SMART***CAES equipment offers. ***SMART***CAES equipment is also complementary to energy conservation and development efforts associated with the "smart grid," giving utility operators the means to run their base load plants more efficiently.

Considering the careful research, advancements and efficiencies surrounding ***SMART***CAES equipment and services, its potential benefits are an obvious choice for creating an efficient power generation system.

For a complete list of products and services, visit www.dresser-rand.com or contact the following:

CORPORATE HEADQUARTERS

Dresser-Rand
West8 Tower, Suite 1000
10205 Westheimer Road
Houston, Texas 77042
Tel: (Int'l +1) 713-354-6100
Fax: (Int'l +1) 713-354-6110

Dresser-Rand
112, Avenue Kleber
Cedex 16
Paris 75784 France
Tel: (Int'l +33) 156 26 71 71
Fax: (Int'l +33) 156 26 71 72

Email: info@dresser-rand.com

REGIONAL HEADQUARTERS

The Americas
West8 Tower, Suite 1000
10205 Westheimer Road
Houston, Texas 77042
Tel: (Int'l +1) 713-354-6100
Fax: (Int'l +1) 713-354-6110

EMEA
(Europe, Middle East & Africa)
Dresser-Rand S.A.
31 Boulevard Winston Churchill
Cedex 7013
Le Havre 76080, France
Tel: (Int'l +33) 2-35-25-5225
Fax: (Int'l +33) 2-35-25-5366/5367

Asia-Pacific
Dresser-Rand Asia Pacific Sdn Bhd
Unit 9-4, 9th Floor
Bangunan Malaysian Re
17 Lorong Dungun
Damansara Heights
50490 Kuala Lumpur, Malaysia
Tel: (Int'l +60) 3-2093-6633
Fax: (Int'l +60) 3-2093-2622

DRESSER-RAND

Bringing energy and the environment into harmony.℠

Form 85230

Exhibit 10 to Sierra Club's April 9, 2015 Comments

Energy Storage Applications and Benefits

What will drive the market? Capturing and monetizing benefit!

CESA CALIFORNIA ENERGY STORAGE ALLIANCE

GESA Global Energy Storage Alliance

Janice Lin
Co-Founder & Executive Director, CESA
Managing Partner, Strategen Consulting

March 27, 2014

STRATEGEN STRATEGIES FOR CLEAN ENERGY

CESA CALIFORNIA ENERGY STORAGE ALLIANCE

CESA STEERING COMMITTEE MEMBERS

EAST PENN manufacturing co., inc. · ecoult · POWERTREE · res · SolarCity · Invenergy · era ENERGY · SUMITOMO ELECTRIC · UET · XP Xtreme Power

CESA 2014 MEMBERSHIP (NOW 80+ STRONG!)

1 Energy Systems, A123 Energy Solutions, AES Energy Storage, Alton Energy, American Vanadium, Aquion Energy, AU Optronics, Beacon Power, Bosch Energy Storage Solutions, Bright Energy Storage, BrightSource Energy, CALMAC, ChargePoint, Christenson Electric Inc., Clean Energy Systems Inc., CODA Energy, Customized Energy Solutions, Deeya Energy, DN Tanks, Duke Energy, Eagle Crest Energy, EaglePicher, East Penn Manufacturing Co., Ecoult, EDF Renewable Energy, Energy Cache, EnerSys, EnerVault, EVGrid, FAFCO Thermal Storage Systems, FIAMM Group, FIAMM Energy Storage Solutions, Flextronics, Foresight Renewable Systems, GE Energy Storage, Green Charge Networks, Greensmith Energy Management Systems, Gridtential Energy, Halotechnics, Hecate Energy LLC, Hitachi Chemical, Hydrogenics, Ice Energy, ImMODO Energy Services, Innovation Core SEI, Invenergy, K&L Gates LLP, KYOCERA Solar, LightSail Energy, LG Chem Ltd., NextEra Energy Resources, NRG Energy, OCI Company Ltd., OutBack Power Technologies, Panasonic, Parker Hannifin, PDE Total Energy Solutions, Powertree Services, Primus Power, RedFlow Technologies, RES Americas, Rosendin Electric, S&C Electric Co., Saft America, Samsung SDI, SeaWave Battery Inc.,Sharp Labs of America, Silent Power, SolarCity, Sovereign Energy Storage LLC, Stem, Stoel Rives LLP, Sumitomo Corporation of America, —TAS Energy, Tri-Technic, UniEnergy Technologies, Xtreme Power, and Wellhead Electric Co.

Strategen

Strategic thinking and industry expertise creates profitable clean energy businesses

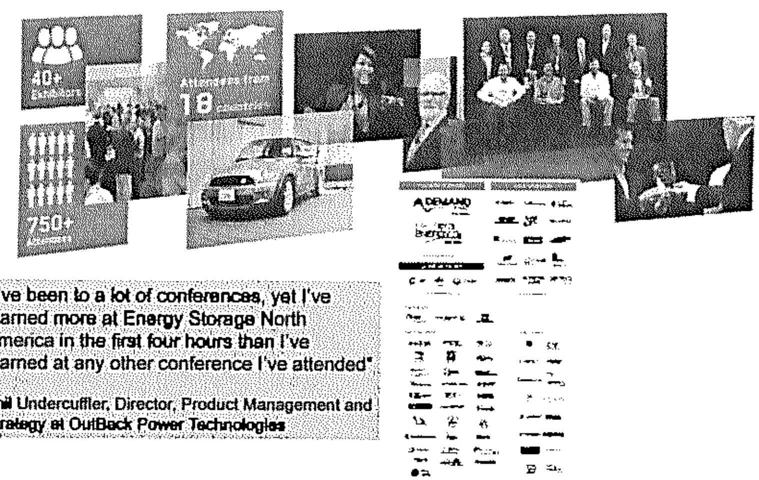
A sampling of our clients:

BOSCH Invented for life	CESA	CALCEF	Energy Solutions
FLUIDICENERGY	FMC	GAF	DMB A Passion for Great Places
HUDSON CLEAN ENERGY	RECURRENT ENERGY	ROCKPORT CAPITAL	SHARP solar electricity
SUNPOWER	U.S. Department of Energy	Walmart	3M

CESA

Successful Launch in September 2013

ENERGY STORAGE NORTH AMERICA



"I've been to a lot of conferences, yet I've learned more at Energy Storage North America in the first four hours than I've learned at any other conference I've attended"

Phil Undercuffler, Director, Product Management and Strategy at OutBack Power Technologies

CESA

Join us in San Jose on September 30 – October 2, 2014

JOIN THE INDUSTRY LEADERS

HIGHLIGHTS

- 3 Days
- Workshops
- 80 Speakers
- Site Visits
- 6 Tracks
- Awards

3 FOCUS AREAS

INTEGRATION

MARKETS

POLICY

Mike Florio
Commissioner – California Public Utilities Commission

Peter Rives
Co-Founder & CTO
Solar City

John Norris
Commissioner
Federal Energy Regulatory Commission

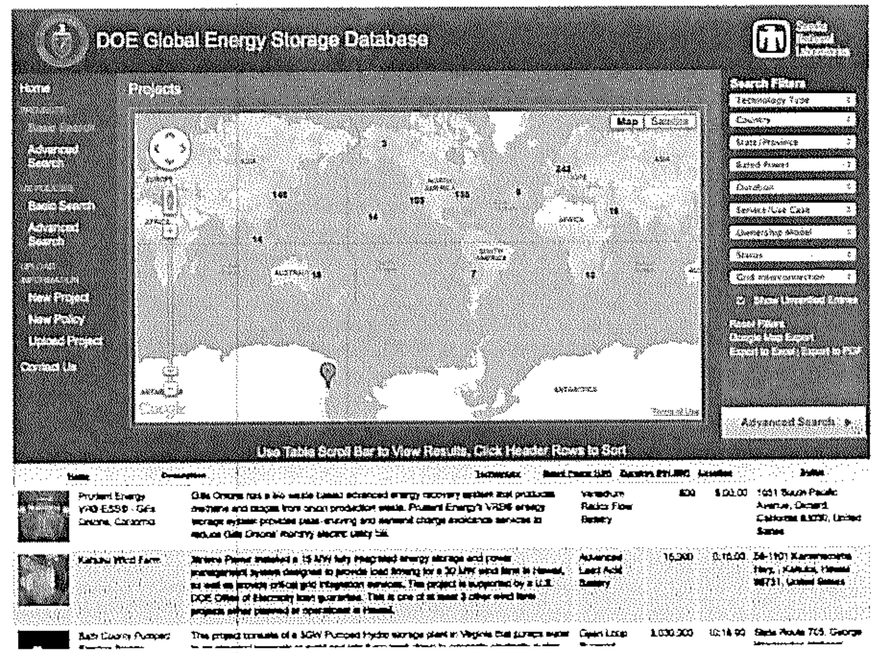
Carla Peterman
Commissioner – California Public Utilities Commission

Eric Schmitt
Vice President, Operations
California ISO

Fong Wan
Senior Vice President, Energy Procurement
Pacific Gas & Electric

Mateo Jaramillo
Director of Powertrain Business Development
Tesla Motors

CESA



Global Energy Storage Alliance – New Global Non Profit

GESA
Global Energy Storage Alliance

GESA Mission

"Advance education, collaboration, knowledge and proven frameworks about the benefits of energy storage and how it can be used to achieve a more efficient, cleaner, reliable, affordable and secure electric power system globally"

ENERGY BVES CESA CNESA IESA

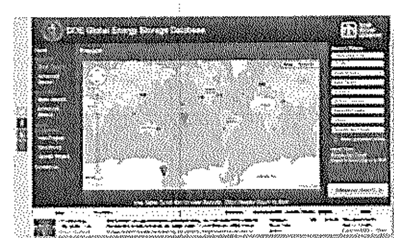
GESA

US DOE Global Energy Storage Database

U.S. DEPARTMENT OF ENERGY

DOE Global Energy Storage Database (GESDB)
Market Development Through Access To Quality Information
www.sandia.gov/ess/database

Sandia National Laboratories



Special thanks to

- Dr. Imre Gyuk, US Department of Energy, Office of Electricity Deliverability and Energy Reliability
- Georgianne Huff, PE, PMP, Sandia National Laboratories

Overview & Mission Statement

- Provides free, up-to-date information on grid-connected energy storage projects and relevant state and federal policies
- Database went live in May 2012
- 60+ data fields for each project, 50+ energy storage technologies, 3rd party verification process, data is exportable to MS Excel or PDF

Milestones & Progress to Date

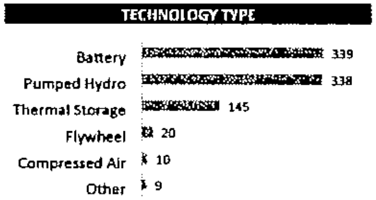
- 145 GW of energy storage, 850+ projects, 57 countries, 18 federal and state policies
- Over 450K page views from 161 countries

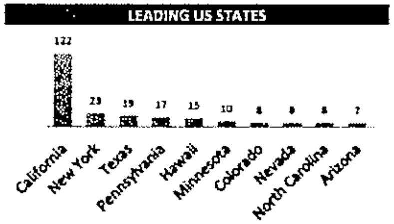
2014 Plans

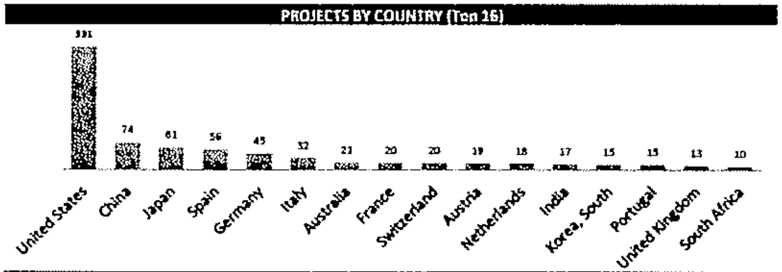
- International partnerships
- Grow policy coverage internationally
- Include codes & standards
- Increase publicity and visibility
- Improve usability

STRATEGEN

March 2014: 861 Projects Worldwide, 185 GW

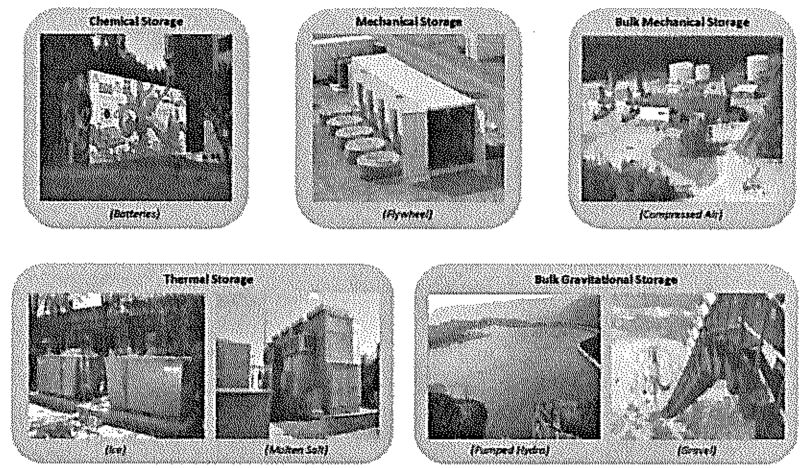






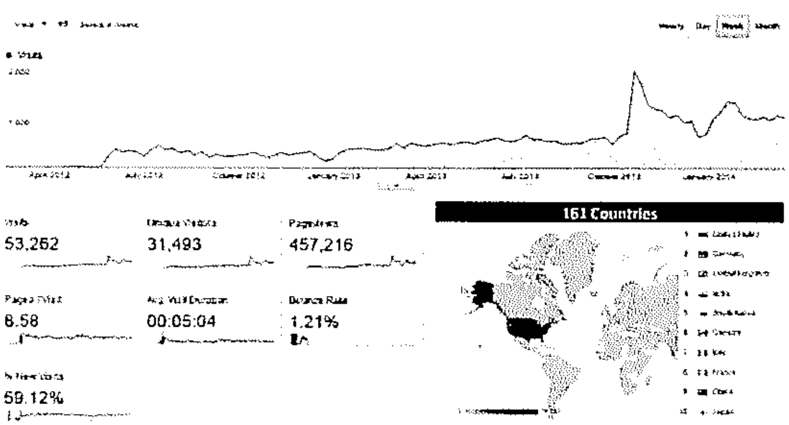
STRATEGEN

Energy Storage Is A Very Broad Asset Class



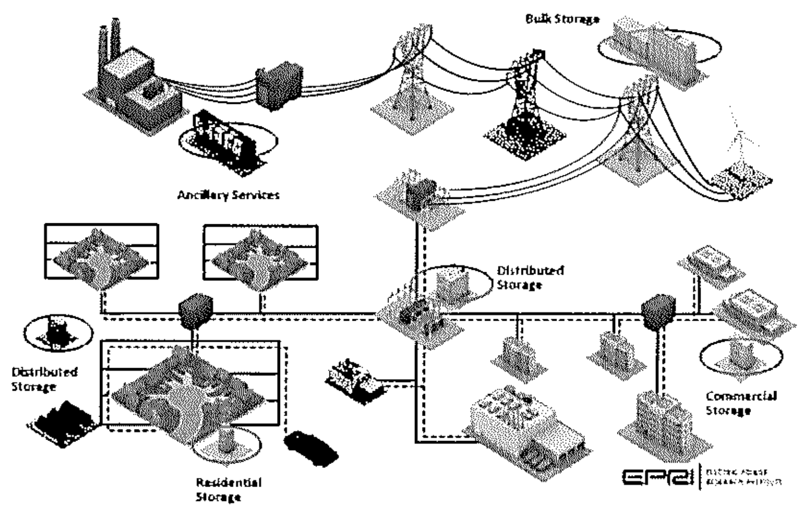
CESA

Users: 31,000 visitors – 161 Countries – 450,000 page views



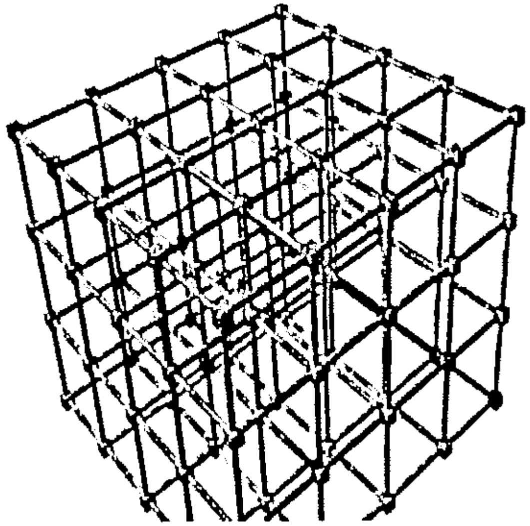
STRATEGEN

Diversity & Modularity = Broad Electric Power System Applicability



CESA

What is the framework for value and cost effectiveness?



CESA

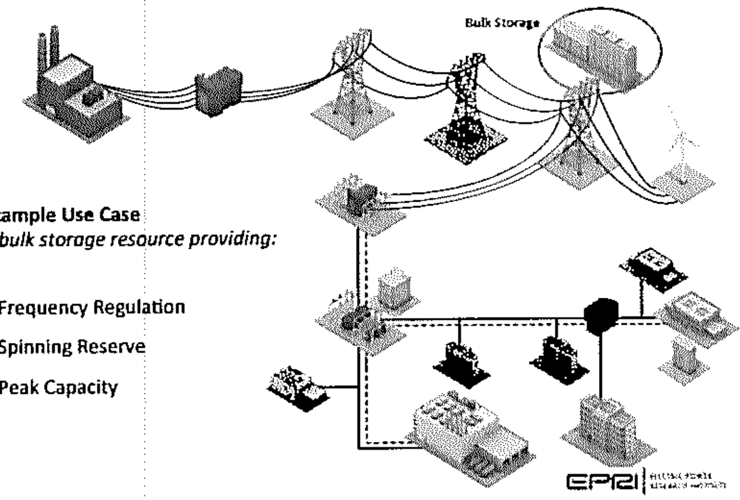
Definition of Energy Storage "application" or "use case"

We followed Southern California Edison's definition of an application/use case as:

"A collection of benefits that can be captured by a single storage device sited in a particular place and used in a particular way"

CESA

Application Example 1



Example Use Case
A bulk storage resource providing:

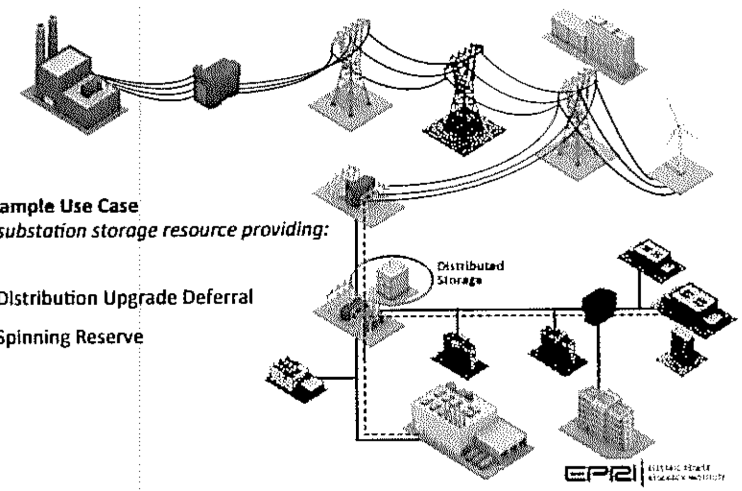
» Frequency Regulation

» Spinning Reserve

» Peak Capacity

CESA

Application Example 2



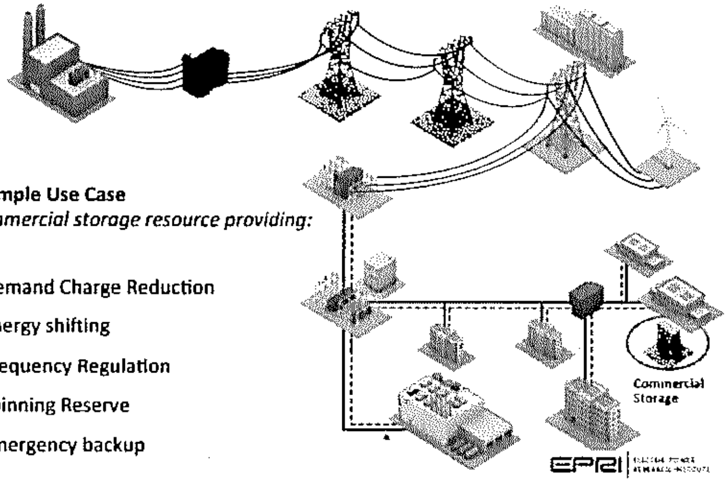
Example Use Case
A substation storage resource providing:

» Distribution Upgrade Deferral

» Spinning Reserve

CESA

Application Example 3



Example Use Case
Commercial storage resource providing:

» Demand Charge Reduction
» Energy shifting
» Frequency Regulation
» Spinning Reserve
» Emergency backup

CESA

What are the possible benefits of grid storage?

Market Services	Generation Services	Additional Grid Benefits
Electric Energy Time-Shifting	Intermittent Resource Integration (Ramping & Voltage Support)	Reduced fossil fuel use
Frequency Response		Increased renewables
Frequency Regulation Up	Variable Energy Resource Shifting, Voltage Sag, Rapid Demand Support	Grid Reliability
Frequency Regulation Down		Faster build time
Ramping	Supply Firming	Modularity/incremental build
Real-Time Energy Balancing		
Synchronous Reserve (Spin)	**Transmission/Distribution**	Mobility
Non-Synchronous Reserve	Peak Shaving: Load Shift	Flexibility of purpose
Black Start	Transmission Peak Capacity Deferral	Optionality
	Transmission Operation	Locational flexibility
Capacity Products	Transmission Congestion Relief	Multi-site aggregation
System Electric Supply Capacity	Distribution Peak Capacity Deferral	
Local Electric Supply Capacity	Distribution Operation (Voltage/VAR Support)	
Resource Adequacy		

CESA

So what are these benefits?

Frequency Regulation

Reliability

Time Shifting

Transmission Upgrade Deferral

Demand Charge Reduction

Voltage Support

Distribution Upgrade Deferral

CESA

Some are compensated under current CA rules

Market Services	Generation Services	Additional Grid Benefits
Electric Energy Time-Shifting	Intermittent Resource Integration (Ramping & Voltage Support)	Reduced fossil fuel use
Frequency Response		Increased renewables
Frequency Regulation Up	Variable Energy Resource Shifting, Voltage Sag, Rapid Demand Support	Grid Reliability
Frequency Regulation Down		Faster build time
Ramping	Supply Firming	Modularity/incremental build
Real-Time Energy Balancing		
Synchronous Reserve (Spin)	**Transmission/Distribution**	Mobility
Non-Synchronous Reserve	[redacted]	Flexibility of purpose
Black Start	Transmission Peak Capacity Deferral	Optionality
	Transmission Operation	Locational flexibility
Capacity Products	Transmission Congestion Relief	Multi-site aggregation
System Electric Supply Capacity	Distribution Peak Capacity Deferral	
Local Electric Supply Capacity	Distribution Operation (Voltage/VAR Support)	
Resource Adequacy		

CESA

Some may be partially compensated

Market Services
- Electric Energy Time-Shifting
- Frequency Response
- Frequency Regulation Up
- Frequency Regulation Down
- Ramping
- Real-Time Energy Balancing
- Synchronous Reserve (Spin)
- Non-Synchronous Reserve
- Black Start

Capacity Products
- System Electric Supply Capacity
- Local Electric Supply Capacity
- Resource Adequacy

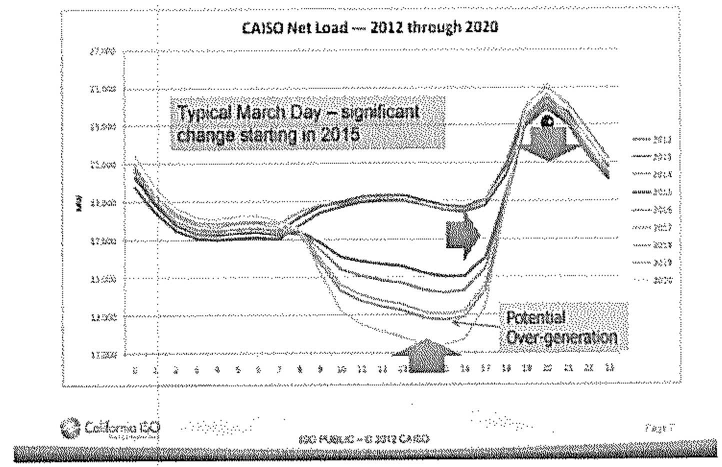
Generation Services
- Intermittent Resource Integration (Ramping & Voltage Support)
- Variable Energy Resource Shifting, Voltage Sag, Rapid Demand Support
- Supply Firming

Transmission/Distribution
- Peak Shaving: Load Shift
- Transmission Peak Capacity Deferral
- Transmission Operation
- Transmission Congestion Relief
- Distribution Peak Capacity Deferral
- Distribution Operation (Voltage/VAR Support)

Additional Grid Benefits
- Reduced fossil fuel use
- Increased renewables
- Grid Reliability
- Faster build time
- Modularity/incremental build
- Mobility
- Flexibility of purpose
- Optionality
- Locational flexibility
- Multi-site aggregation

CESA

New Requirements in California: Flexible Capacity



CESA

Other benefits are not yet captured

Market Services
- Electric Energy Time-Shifting
- Frequency Response
- Frequency Regulation Up
- Frequency Regulation Down
- Ramping
- Real-Time Energy Balancing
- Synchronous Reserve (Spin)
- Non-Synchronous Reserve
- Black Start

Capacity Products
- System Electric Supply Capacity
- Local Electric Supply Capacity
- Resource Adequacy

Generation Services
- Intermittent Resource Integration (Ramping & Voltage Support)
- Variable Energy Resource Shifting, Voltage Sag, Rapid Demand Support
- Supply Firming

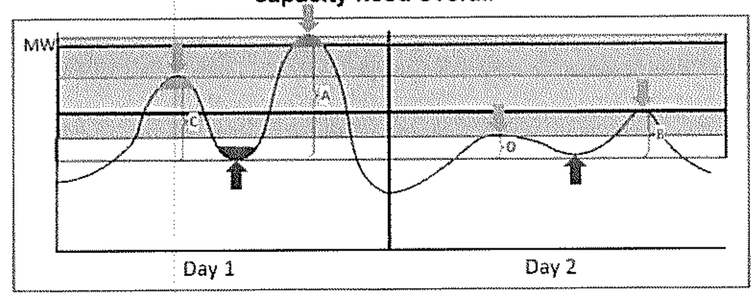
Transmission/Distribution
- Peak Shaving: Load Shift
- Transmission Peak Capacity Deferral
- Transmission Operation
- Transmission Congestion Relief
- Distribution Peak Capacity Deferral
- Distribution Operation (Voltage/VAR Support)

Additional Grid Benefits
- Reduced fossil fuel use
- Increased renewables
- Grid Reliability
- Faster build time
- Modularity/incremental build
- Mobility
- Flexibility of purpose
- Optionality
- Locational flexibility
- Multi-site aggregation

CESA

Storage effect on flexible capacity

Longer duration energy storage can shift larger amounts of energy, adding flexible capacity while reducing the flexible capacity need overall[1]



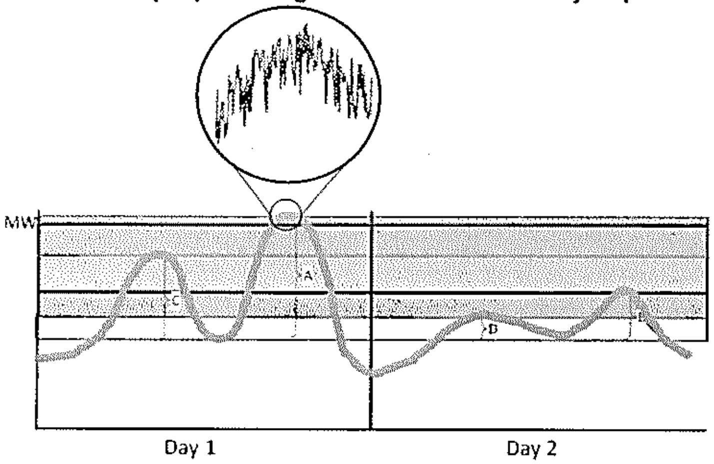
Reducing the need for flexible capacity (raising the red line) will lead to a cleaner grid due to a greater reliance on long-duration energy sources

1. Using CAISO's proposed structuring of flexible capacity, from the fifth FRAC-MOO straw proposal

CESA

Fast storage contribution to the three hour ramp

Regulation is a key component of flexible capacity, though it only makes up a percentage of the overall flexibility requirement



CESA

Example Application: Regulation Storage

Grid Service	Primary/ Secondary	Benefits/Comments	Additional Benefits: Attribute	Additional Benefits: Benefits/Comments
1. Frequency regulation	P	Earn revenues in Fast Acting Regulation market	Modularity/ Incremental build	Improve system upgrade efficiencies by purchasing only the capacity needed
			Faster build time	Reduce project logistics and project financing costs
			Locational flexibility / Mobility	Site systems at source of grid challenge
			Multi-site aggregation	Command transmission level capacity from network of locally sited systems
			Optionality	Solve multiple grid challenges with one solution; Adapt services to needs

CESA

Example Application: Distributed Peaker

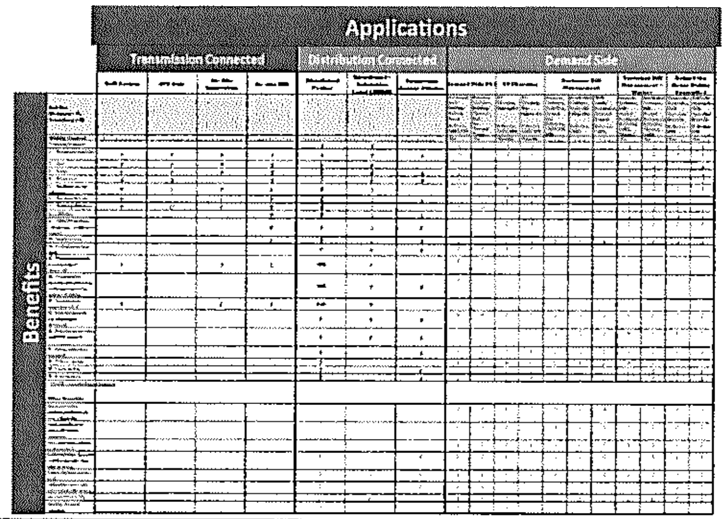
End Use	Primary/ Secondary	Benefits/Comments
1. Frequency regulation	S	Earn revenues in Fast Acting Regulation market
2. Spin	S	If it can qualify
3. Ramp	S	Adds flexible supply capacity in milliseconds at nameplate.
4. Black start	S	
5. Real-time energy balancing	S	Discharge energy in the real-time energy markets
6. Energy arbitrage	S	Earn revenues from discharging during periods of peak demand and charging when prices are low
7. Resource Adequacy	S	If it can provide on a firm basis.
8. VER / wind ramp/volt support	S	
9. VER/ PV shifting, Voltage sag, rapid demand support	S	
10. Supply firming	S	
11. Peak shaving: load shift	P	Automatically discharge energy when local distribution lines reach capacity to reduce peak load
15. Distribution peak capacity support (deferral)	P	Defer expensive distribution infrastructure upgrades by increasing efficiency and reducing peak demand of distribution system
16. Distribution operation (volt/VAR support)	P	Instantly improve local power quality by providing reactive power and responding to voltage fluctuations
17. Outage mitigation: micro-grid	S	They are currently doing this now on a micro-grid.
18. TOU energy mgt	S	Ex. Non-utility owned: peak shaving for industrial / Commercial customers to manage demand charges.
19. Power quality	S	Inject or absorb real or reactive power instantly and accurately to help with local power quality issues
20. Back-up power	P	Immediately discharge to continue supplying energy to loads in the event of an outage

Additional Benefits

Attribute	Benefits/Comments
Modularity/ Incremental build	Improve system upgrade efficiencies by purchasing only the capacity needed
Faster build time	Reduce project logistics and project financing costs
Locational flexibility / Mobility	Site systems at source of grid challenge
Multi-site aggregation	Command transmission level capacity from network of locally sited systems
Optionality	Solve multiple grid challenges with one solution; Adapt services to needs

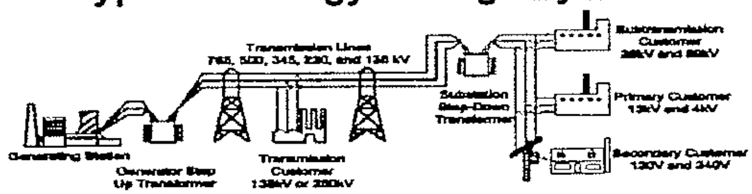
CESA

'Application Framework' - Define applications by their benefits



CESA

Types of Energy Storage Systems

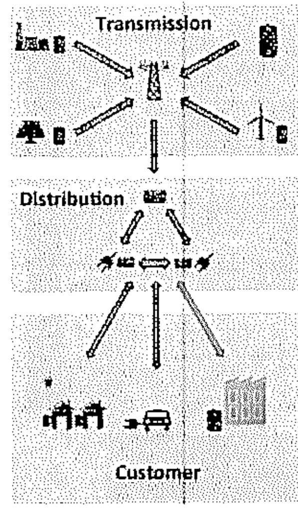


Bulk Generation		Transmission	Distribution	Behind-the-Meter
Generation –Sited Storage	Transmission Connected Bulk Storage	Transmission Grid Storage	Distribution Grid Storage	Customer-Sited Storage
• CSP • Wind + Storage • CCGT+ TES	• A/S • Peaker • Load following	*FERC Jurisdiction*	• Substation Level Storage • Distributed Peaker • Community ES	• Bill mgt / PLS • Power quality • EV

←== Transmission-Connected ==→

Source: CPUC IOU Solicitation Application Workshop Intro Presentation 3/14/14

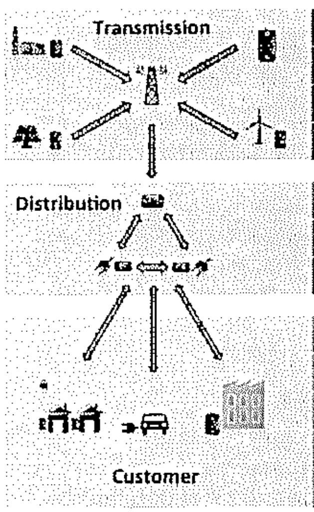
Some applications are utility controlled



- Bulk Peaking Power Plant
- Regulation Only
- On-Site Generation
- On-site Variable Energy Resource
- Distributed Peaking Power Plant
- Distributed Energy Storage - Substation Level
- Community Energy Storage
- Demand Side Permanent Load Shifting
- Behind the Meter Utility Controlled

CESA

Prioritize applications appropriate to the market



- Bulk Peaking Power Plant
- Regulation Only
- On-Site Generation
- On-site Variable Energy Resource
- Distributed Peaking Power Plant
- Distributed Energy Storage - Substation Level
- Community Energy Storage
- Demand Side Permanent Load Shifting
- EV Charging
- Customer Bill Management
- Customer Bill Management + Market Participation
- Behind the Meter Utility Controlled

CESA

Storage Procurement Targets

Energy Storage Procurement Targets (in MW)[11]

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

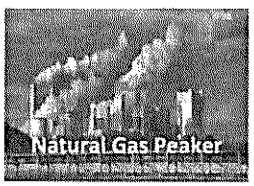
Source: CPUC IOU Solicitation Application Workshop Intro Presentation 3/14/14

What about ownership/operation/financing models?

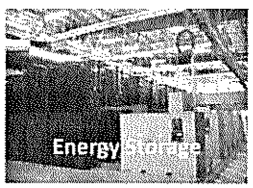
Ownership	Siting	Procurement
Utility	Utility	Rate Based
		Financed
	Third Party	Financed
	Customer	Rate Based
		Financed
Third Party (IPP)	Utility	Financed
	Third Party	Financed
	Customer	Financed
Customer	Customer	Financed
		Purchased

CESA

Comparing Energy Storage With The Status Quo



vs.



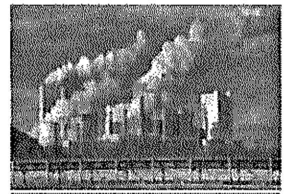
Key Criteria to Consider

- Siting Constraints
- Installation Speed
- Available Flexible Range
- Capacity Factor (hours of operation/ year)
- Multiple Value Stream Capture
- Ramp/Response Rate
- Total Emissions
- Water Usage

CESA

Summary

Energy storage can provide much greater benefits per MW as a flexible resource!



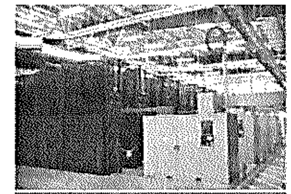
100 MW Gas Turbine

10 minute ramp
50 MW flexible range
2768 useable hours/year[1]
6500 gallons per hour
Status quo GHG emissions

vs.

Energy Storage Benefits

>600x the ramp rate
>4x the flexible range
>3x the operational hours
Less water usage on many sites
Lower GHG emissions



100 MW Energy Storage

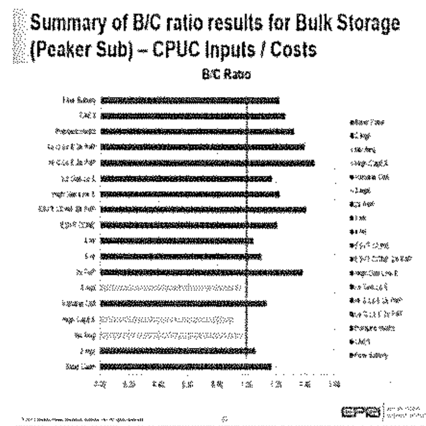
<1 second ramp
200 MW of flexible range
>8300 useable hours/year
Little to no water usage
Reduces GHG emissions by up to 90%[2]

[1] Excluding start-up and shutdown time
[2] http://www.energy.ca.gov/2011_energypolicy/documents/2011-02-15_workshop/comments/California_Energy_Storage_Alliance_03032011_TN-59863.pdf

CESA

Cost Effectiveness Results: Bulk Peaking Power Plant Use Case

Preliminary results by EPRI using stakeholder input showed a benefit to cost ratio over one for nearly every scenario



- Projects were assumed to be utility scale projects starting in 2015 and 2020
- Cost effectiveness results did not include GHG benefits of storage or GHG costs due to AB32 implementation
- High renewable penetration cases had the highest benefit to cost ratios for storage.
- GHG benefits for storage are greater the more renewables we have on the grid.

CESA

More Information

» Contact : Janice Lin
- Email: jlin@strategen.com
- Office: 510 665 7811 extension 101
- Mobile: 415 595 8301

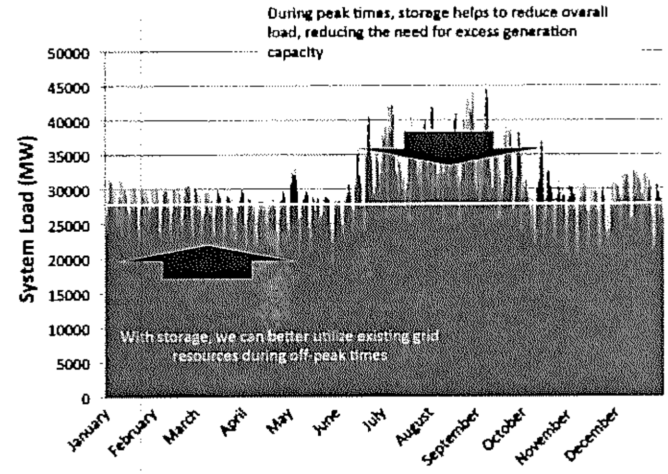
» Strategen – custom consulting advisory
- http://www.strategen.com

» CESA Membership
- http://www.storagealliance.org/

» GESA information
- http://www.globalesa.org

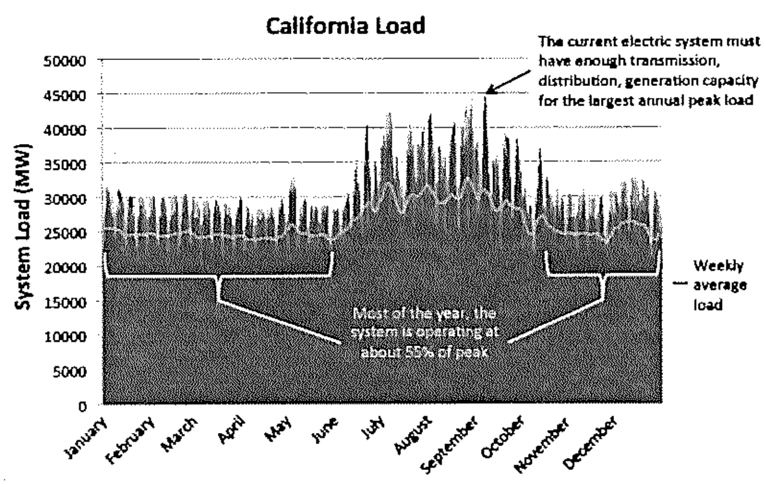
» Energy Storage North America
- Sep 30-Oct 2, 2014 San Jose Convention Center CA
  http://www.esnaexpo.com/

Storage lets us utilize the system assets we have more efficiently



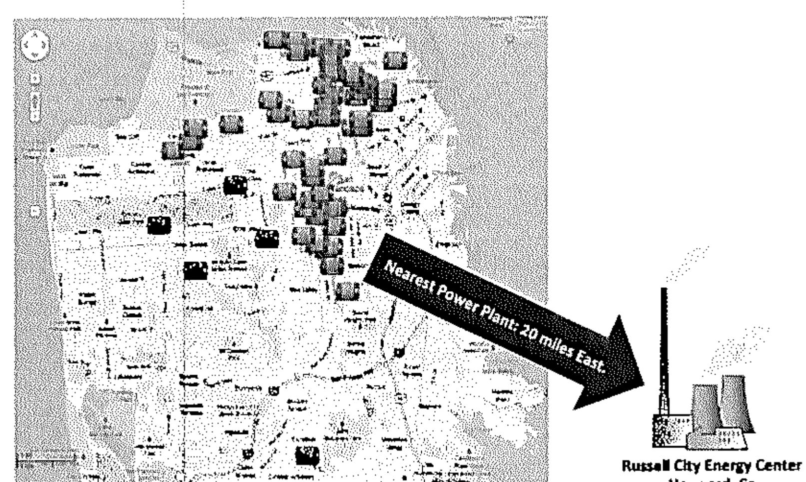
Data Source: CAISO OASIS Data – Graph is for demonstration purposes only

California's Electric System Is Not Being Efficiently Utilized



Data Source: CAISO 2013 OASIS Data – Graph is for illustration purposes only

Energy Storage Can Be Sited Closer to the Load

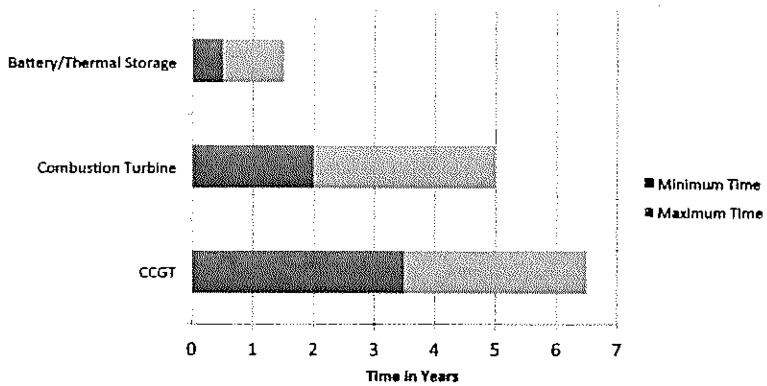


ES Siting Source: Powertree Integrated Energy Services

Energy Storage: Diverse, Modular, Faster to Install!

Battery and thermal storage resources can be installed much more quickly than traditional resources, reducing risk and increasing technology flexibility

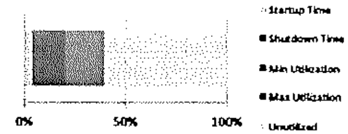
Siting, Permitting, and Installation Time by Resource

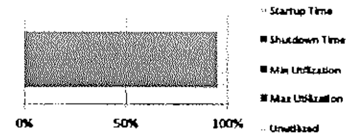


CESA

Energy Storage: Three Times the Utilization

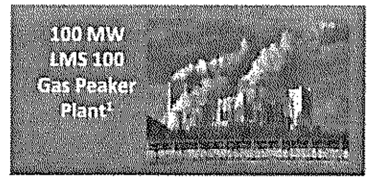
Energy storage can be utilized more fully throughout the year

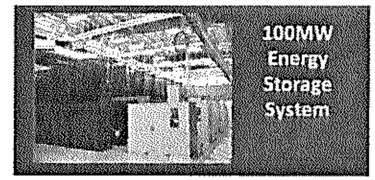




20%-40%
Utilization

>95%
Utilization



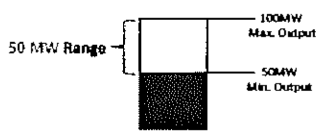


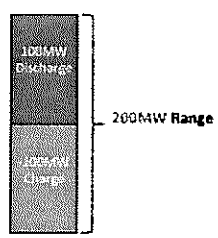
1. Source: [illegible]

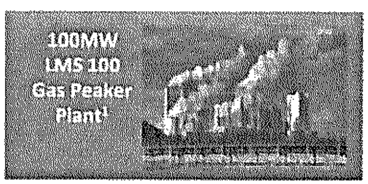
CESA

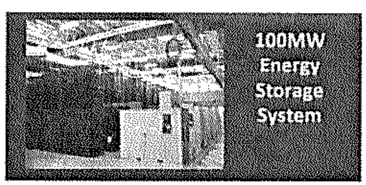
Energy Storage: Four Times the Flexible Range

Important to compare benefits, not megawatts









1. Source: [illegible]

CESA

Status Quo: CT Operation at EME Walnut Creek Energy Park

State of the art LMS 100 installations require significant start-up and shutdown operating hours, accounting for at least 20% of operations:

EME Walnut Creek Energy Park SCAQMD Analysis[1]	
Capacity Factor - min	20%
Capacity Factor - max	40%
Operating Hours - Normal	2768
Operating Hours - Start-up	350
Operating Hours - Shutdown	350
Service Factor - Normal	32%
Service Factor - Total	40%
Minimum load	50%
Average load	75%
Starts/year	350
Max starts/day	2
Max start-ups/year	350
Start-up time (minutes)	35

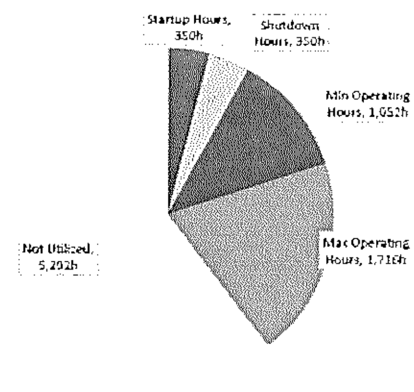


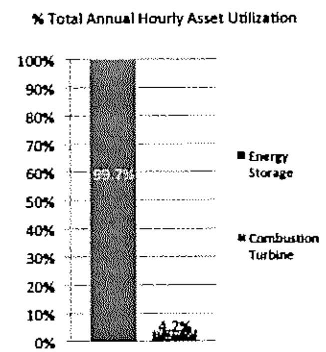
Chart of Annual Plant Operation

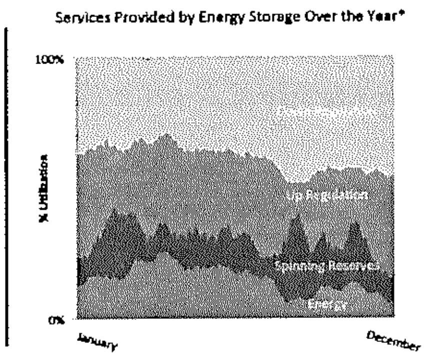
1. [illegible]

CESA

Energy Storage Can Capture Multiple Value Streams

Energy storage can be fully utilized throughout the year, providing multiple services from a single asset





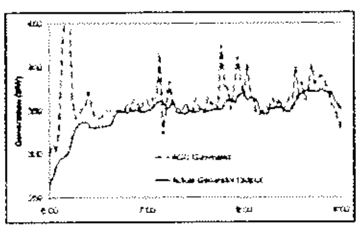
Energy storage is a cost effective way to provide numerous benefits to many stakeholders, few of which can be monetized today.

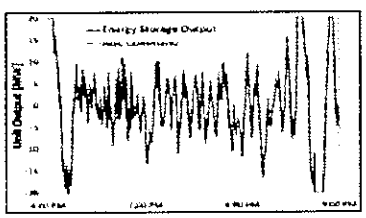
Graphs based on EPRI cost effectiveness model data, "Bulk Peaker substitution application" CPUC Workshop March 25, 2013

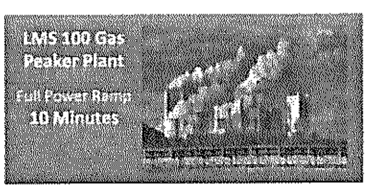
*All services include charging and discharging bids

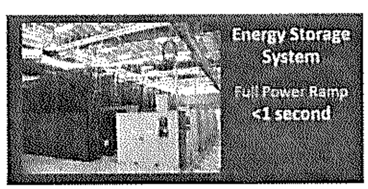
Energy Storage Can Respond Faster and is More Effective

Energy storage responds far more quickly and is more effective









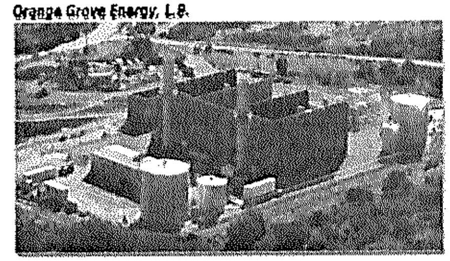
Graph Source: Kirby, B. "Ancillary Services: Technical and Commercial Insights," Wartsila, July 2007, pg 13

Conventional Peakers are Expensive and Use Tons of Water

J-Power Orange Grove Peaking Plant

- 100 MW (2 x LM6000)
- $174/kW-year in capacity revenue (Source: FERC EQR)
- 25 year tolling agreement with SDG&E

Orange Grove Energy, L.P.



"Water delivery will require approximately one [6500 gallon] truck per hour for fresh water and one truck per hour for reclaimed water during times when the plant is operational."[1]

1) Source: CEC

Even Repowered Peakers are Expensive

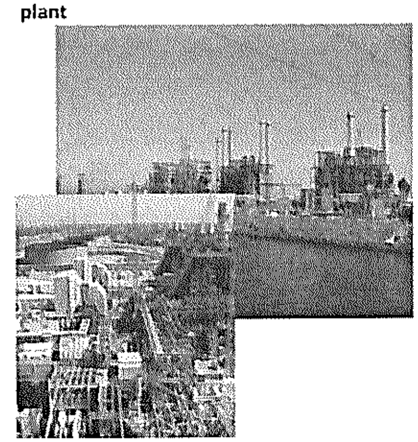
Repower: Building a new power plant on the same site as an old, decommissioned plant

LADWP Haynes Repower
6 x LMS100
$782M / 577.8 net MW

Cost: **$1353/kW[1]**

Due to repower, cost excludes:

- Land aquisition & permitting
- New transmission infrastructure
- Site access construction



1) Source:

Emission Impacts Due to Cycling CCGTs & CTs

NREL concluded that cycling conventional power plants has significant impacts on emissions

CO_2 Emissions Penalties[1]			
Power Plant Type	Part-Load[2]	Ramping[3]	Start/Stop
Gas Combined Cycle (CCGT)	15%	1%	30%
Gas Combustion Turbine (CT)	17%	1%	40%

NO_x Emissions Penalties[1]			
Power Plant Type	Part-Load[2]	Ramping[3]	Start/Stop
Gas Combined Cycle (CC)	29%	8%	610%
Gas Combustion Turbine (CT)	16%	1%	180%

1) Listed as percentage penalty over the equivalent full-load operation for one hour
2) Assumes operation at 50% of capacity
3) Ramping leads to far less emissions compared to startups, but occurs more often

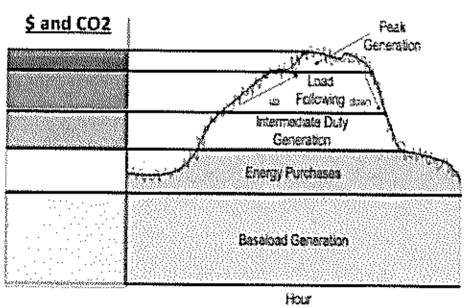
Source: National Renewable Energy Laboratory (NREL/PR-6A20-55828): *Impacts of Renewable Generation on Fossil Fuel Unit Cycling: Costs and Emissions* (May 20, 2012)

Storage Can Help Optimize Existing Fossil Assets

Build cleaner CCGT's, let them run at max efficiency

» Generation comes on "in order"
» Cheaper & cleaner "baseload" is always on
» More expensive, dirtier "peakers" turn on in succession.
» Let storage be load following
» Energy Storage can even cut costs & reduce emissions!

Daily System Energy Demand

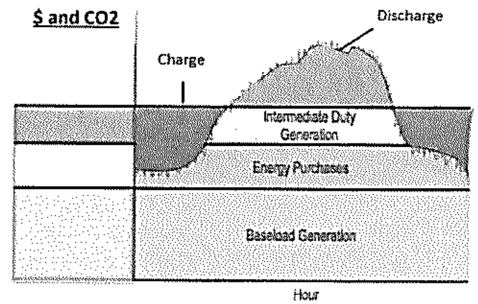


Storage Can Help Optimize Existing Fossil Assets

Build cleaner CCGT's, let them run at max efficiency

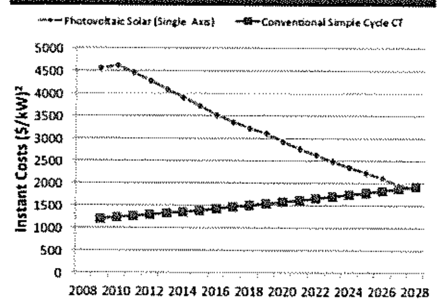
» Generation comes on "in order"
» Cheaper & cleaner "baseload" is always on
» More expensive, dirtier "peakers" turn on in succession.
» Let storage be load following
» Energy Storage can even cut costs & reduce emissions!

Daily System Energy Demand

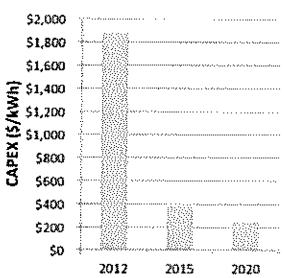


Why Renewable Energy + Energy Storage Is the Future

Upfront Cost of Solar vs. Traditional Generators[1]



NEDO/DOE 2010 Li Ion Cost Projections



Key Trends
» **Industry is tracking DOE & NEDO cost reductions for Li-ion (10X improvement in ten years)**
» **Upfront costs for traditional generators are increasing**
» **Renewable costs are decreasing, reducing the charging costs for energy storage**

1. Source: California Energy Commission
2. 2009 starting dollars, escalated at 2.5% per year

Exhibit 11 to Sierra Club's April 9, 2015 Comments

(*Excerpted portions due to size constraints*)

ORIGINAL

0000154031

NEW APPLICATION

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES 40-360 ET SEQ., FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE OCOTILLO MODERNIZATION PROJECT, WHICH INCLUDES THE INSTALLATION OF FIVE 102 MW GAS TURBINES AND THE CONSTRUCTION OF TWO 230-KILOVOLT GENERATION INTERCONNECTIONS AND OTHER ANCILLARY FACILITIES, ALL LOCATED WITHIN THE BOUNDS OF THE EXISTING OCOTILLO POWER PLANT SITUATED ON PROPERTY OWNED BY ARIZONA PUBLIC SERVICE COMPANY AND LOCATED AT 1500 EAST UNIVERSITY DRIVE, TEMPE, ARIZONA, IN MARICOPA COUNTY.	DOCKET NO. L-________ Case No. L-00000D-14-0292-00169 **NOTICE OF FILING**

RECEIVED
2014 JUL 31 P 1:03
AZ CORP COMMISSION
DOCKET CONTROL

Arizona Public Service Company ("APS") files its Application for a Certificate of Environmental Compatibility ("Application") as required by A.R.S. § 40-360.03. In its Application, APS seeks a Certificate of Environmental Compatibility authorizing the installation of five 102 MW gas turbines (nominal), including two 230-kilovolt generation interconnections and other ancillary facilities (collectively, the "Ocotillo Modernization Project").

Pursuant to A.R.S. §§ 40-360 through 40-360.13 and A.A.C. R14-3-201 through R14-3-220, enclosed are 25 copies of APS's Application. Pursuant to A.R.S. § 40-360.09, the filing fee is also enclosed.

Communications concerning the Application (including data responses) should be addressed to:

Thomas H. Campbell
Lewis Roca Rothgerber LLP
201 East Washington Street, Suite 1200
Phoenix, Arizona 85004

Arizona Corporation Commission
DOCKETED
JUL 30 2014
DOCKETED BY

Ocotillo Modernization Project

APPLICATION FOR CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Prepared for

State of Arizona Power Plant and Transmission Line Siting Committee

Arizona Corporation Commission

Submitted by

Arizona Public Service

aps

EXECUTIVE SUMMARY

Arizona Public Service Company ("APS") owns and operates the Ocotillo Power Plant ("Power Plant") in Tempe, Arizona. The Power Plant includes two (2) steam turbine generators that began commercial operations in 1960. The steam generators have become increasingly costly and difficult to maintain, and as a result, APS is proposing to modernize the Ocotillo Power Plant by installing five (5) new gas turbines ("GTs"), and subsequently removing the two (2) steam units, which collectively comprise the Ocotillo Modernization Project ("Project").

PROJECT PURPOSE

Given the Power Plant's key location on the transmission system, having reliable, and flexible, generation at that location is critical. The need to upgrade the Power Plant stems from the key role the Power Plant plays within APS's transmission system and the Phoenix area load-pocket. The existing steam turbine generators played a significant role in bringing power to the Phoenix area over the past 54 years; however, they are relatively inefficient, less responsive, and less flexible than the modern generating technologies now available. All of this, coupled with the evolving landscape of integrating renewable energy into the grid, makes the need to modernize the Power Plant with fast-starting, fast-ramping technology compelling on many levels.

- Resource need: By 2021, APS anticipates needing over 3,800 megawatts ("MW") of additional resources to replace expiring purchase contracts and meet expected growth. This additional capacity is anticipated to come from a diverse portfolio of resources including energy efficiency, renewables, and natural gas combined-cycle and simple-cycle gas turbines.
- Enhanced flexibility of APS portfolio: The state-of-the-art combustion turbine technology proposed for this Project will provide APS added flexibility to further integrate increasing levels of renewable energy and quickly respond to system contingencies. The new combustion turbine technology would add operational flexibility to respond to the variability of renewable energy because the units can connect to the grid in less than six (6) minutes.
- Use of existing infrastructure: The Power Plant has the available land as well as capability through existing transmission and natural gas pipeline infrastructure to support the additional generation.
- Uniquely situated: Valley load-serving capability is enhanced by the Power Plant due to its location on the transmission system and proximity to the Metro Phoenix area. This proximity affords dynamic voltage support, reduced system energy losses, and impact mitigation from transmission line contingencies.

PROJECT DESCRIPTION

The Power Plant is currently comprised of two (2) steam generators which each produce 110 MW; and two (2) GTs, each producing 55 MW, for a total output of 330 MW. The Power Plant operates on natural gas supplied via Kinder Morgan's El Paso Natural Gas pipeline system. The Power Plant is located on approximately 126 acres at 1500 East University Drive in Tempe, Arizona. Within the bounds of the existing Ocotillo Site, APS proposes to install additional generation comprised of five (5) approximately 102 MW (net) GTs fueled by natural gas. The five (5) new GTs would be aligned from south to north along the western edge of the Ocotillo Site, where three (3) large abandoned fuel oil tanks currently are located (the plant no longer uses fuel oil). The Project's proposed new GT units, if approved, would be constructed and put into service consecutively, with all units placed into commercial operation before Summer of 2018. The removal of the two (2) steam generators is anticipated to commence by the Fall of

2018. Once complete, the Ocotillo Power Plant would be capable of generating approximately 620 MW with five (5) new and two (2) existing GTs.

The proposed new GT units are a hybrid of a conventional industrial gas turbine and an aero-derivative gas turbine, which improves efficiency and increases capacity. These advanced technology gas turbines would be cooled with a hybrid cooling system that utilizes both dry air-to-air heat exchangers and conventional wet-cooling towers. As a result, the combination of new GTs and decommissioning of the aging steam units is expected to reduce water use at the Power Plant from an average of 1,007 gallons per megawatt-hour ("g/MWh") to approximately 141 g/MWh.

In addition to the new GTs, the Project will be connected to the existing 230-kilovolt substation on the Project site with two new "Generation Interconnections". Other ancillary facilities include the cooling towers, GT Collector Substation, support buildings, and water treatment facilities. Similar to the GTs, the additional Project facilities would be located onsite.

ENVIRONMENTAL STUDIES AND PUBLIC OUTREACH OVERVIEW

The process of evaluating the Project began in 2012. This process included evaluation of potential environmental impacts on existing and future land uses (Exhibit A), air and water quality (Exhibit B), biological resources (Exhibits C and D), visual and cultural resources (Exhibit E), recreation (Exhibit F), noise levels (Exhibit I), and existing plans (Exhibit H).

The environmental studies and impact conclusions in the attached exhibits demonstrate that the Project is environmentally compatible as outlined below:

- Land use impacts are not expected because the existing site is already an operational power plant within its industrial land use designation. In addition, the Project is compatible with existing plans and future developments in the vicinity of the Ocotillo Site.
- Emission rates from the power plant (measured in pounds per kilowatt-hour) will decrease as a result of the more efficient GTs.
- The rate of water use (measured in gallons per kilowatt-hour of power produced) will decrease.
- There will be no impacts on special status species or unique habitats; none occur within the site.
- The lower profile of the GT units and removal of steam units will decrease the overall visual dominance of the Power Plant. There are no designated scenic areas in the vicinity; therefore, no impacts on scenic areas would occur.
- Historic sites and structures, and archaeological sites are not expected to be adversely impacted by the Project.
- Noise conditions associated with Power Plant operations are not expected to significantly change, and may be improved to some extent. The Project will meet all applicable noise ordinances.

A public outreach and participation process was conducted to communicate with the general public and agencies, and consider their comments and concerns about the Project. The public participation process has included communication with various tribal, state, and local agencies, planning jurisdictions, landowners, and elected officials. No material environmental concerns have been identified through comments received on the Project.

CONCLUSION

The Project will create a cleaner-running, more efficient Power Plant by installing advanced technology GTs and decommissioning the two 1960s-era, natural gas-fired steam generators. The Project will help APS integrate renewable energy and meet increasing customer demand by nearly doubling the Power Plant's total capacity to approximately 620 MW from its current 330 MW with quick starting and fast ramping GTs. By using the best-available commercial technology, the new GTs will use natural gas more efficiently, reducing emission rates for NOx and CO and decreasing water use rates at the Power Plant. The modernized Power Plant will also have nearly twice its current generating capacity without increasing noise levels. In essence, the Project, once approved, provides benefits for APS electric service reliability that other resources cannot provide. Accordingly, APS requests that the Arizona Transmission Line and Power Plant Siting Committee and the Arizona Corporation Commission grant a Certificate of Environmental Compatibility for the Project.

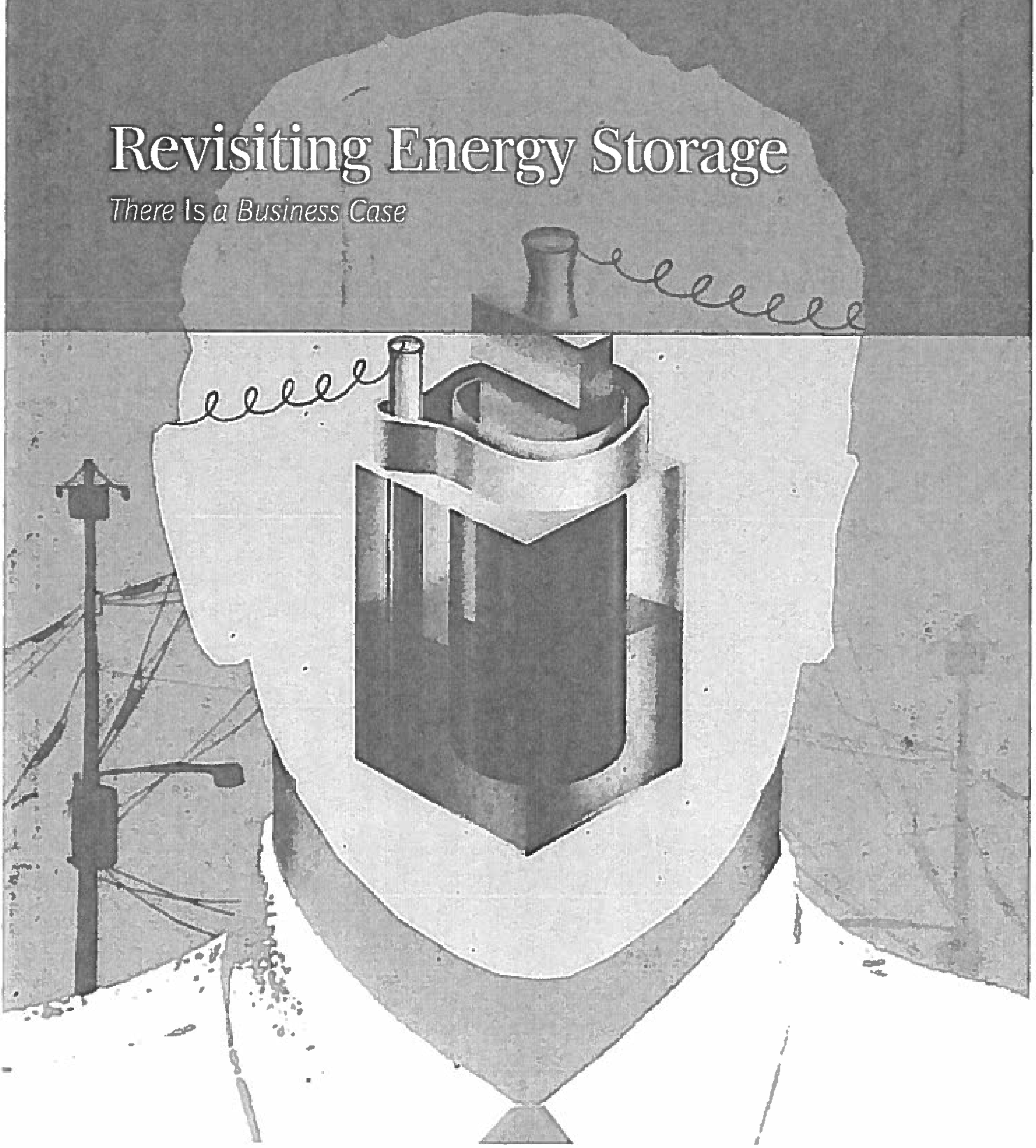
Exhibit 12 to Sierra Club's April 9, 2015 Comments

BCG

THE BOSTON CONSULTING GROUP

Revisiting Energy Storage

There Is a Business Case



BCG
THE BOSTON CONSULTING GROUP

Revisiting Energy Storage

There Is a Business Case

Cornelius Pieper and Holger Rubel

February 2011

AT A GLANCE

Batteries and other forms of energy storage will be crucial to the large-scale deployment of fluctuating renewable energy worldwide. As the use of renewable energy grows and technologies mature, the market for storage will gradually increase, reaching approximately €10 billion annually by 2020 and offering strong first-mover advantages to a range of potential stakeholders.

Storage Applications

Analysis of the business case for eight storage applications combined with different storage technologies—assuming 2015–2020 costs and no subsidies or other additional sources of revenue—shows that good financial returns are possible, especially for facilities that provide balancing energy, conventional-generation stabilization, and island and off-grid electricity storage.

Potential Business Opportunities

There are business opportunities in energy storage for utilities and other power-system stakeholders, for suppliers of raw materials (such as lithium), batteries, and energy and RE technology, for end-product companies such as automotive OEMs, and for financial players such as venture capital and private-equity firms—and the time to start evaluating such investments is now, before the best lots are claimed.

STRONG GROWTH IN FLUCTUATING renewable-energy (RE) generation, such as wind and photovoltaic (PV), is producing an increasing need for compensation mechanisms. (See *Electricity Storage: Making Large-Scale Adoption of Wind and Solar Energies a Reality*, BCG White Paper, March 2010.) While some markets saw a dip in RE growth rates during the financial crisis in 2009, overall growth continued. Some countries, such as the U.K. and China, have even defined more ambitious growth targets.

We believe that once the share of wind and PV has increased to around 20 percent or more of actual electricity generation, compensation power in the range of 30 to 40 percent of the average vertical grid load will be required to balance RE fluctuations. Compensation capacity can be provided, as shown in our previous paper, through grid extension to achieve interregional balancing and through flexible conventional backup, demand-side management, and electricity storage. We consider electricity storage to be a key enabler of the large-scale deployment of fluctuating RE generation capacity around the world.

Our analysis of the business case for various storage applications suggests that a mix of technologies will be required. Pumped hydro will continue to be the leading storage technology in terms of installed capacity, but various types of stationary batteries will become increasingly important because of their flexibility, especially in smaller, decentralized applications. (See *Toward a Distributed-Power World: How Renewables and Smart Grids Will Reshape the Energy Sector*, BCG White Paper, June 2010.) The success of stationary batteries will largely depend on technology cost reductions, which are expected to take place across the board. Our analyses show that there could also be noteworthy business potential for compressed-air energy storage (CAES) as an interim solution in the coming years in a number of centralized applications. CAES has relatively moderate investment costs, and it seems to provide a feasible technological solution. Nonetheless, we continue to have some reservations regarding this technology because of its continued reliance on fossil fuels, its low efficiency, and its limited operational flexibility. We also believe that after 2020, hydrogen storage technology could partially replace CAES (and to a degree even pumped hydro), since it offers greater operational flexibility and can store larger amounts of energy at efficiency levels not distinctly lower than that of CAES. As a result, the market potential of CAES will likely decline by about 2020.

In this paper, we will assess electricity storage from a business point of view, arguing the case from a bottom-up perspective. We believe that growth will be driven by individual projects once potential investors find the technology sufficiently attractive financially. And since a positive business case can be demonstrated for a fair share of storage applications, we believe that there is a bright future ahead for electricity storage in the next decades—driven mainly, but not solely, by the growth of fluctuating renewable energy.

Storage Applications

Electricity storage is neither a new technology nor a novel application within power grids. More than 100 gigawatts of pumped-hydro storage exist today globally. More than 1 GW of stored power relies on technologies such as CAES or batteries, and an additional 4 GW of electricity storage projects have been announced. Storage infrastructure can be built and operated in a very large variety of applications, both centralized and decentralized.

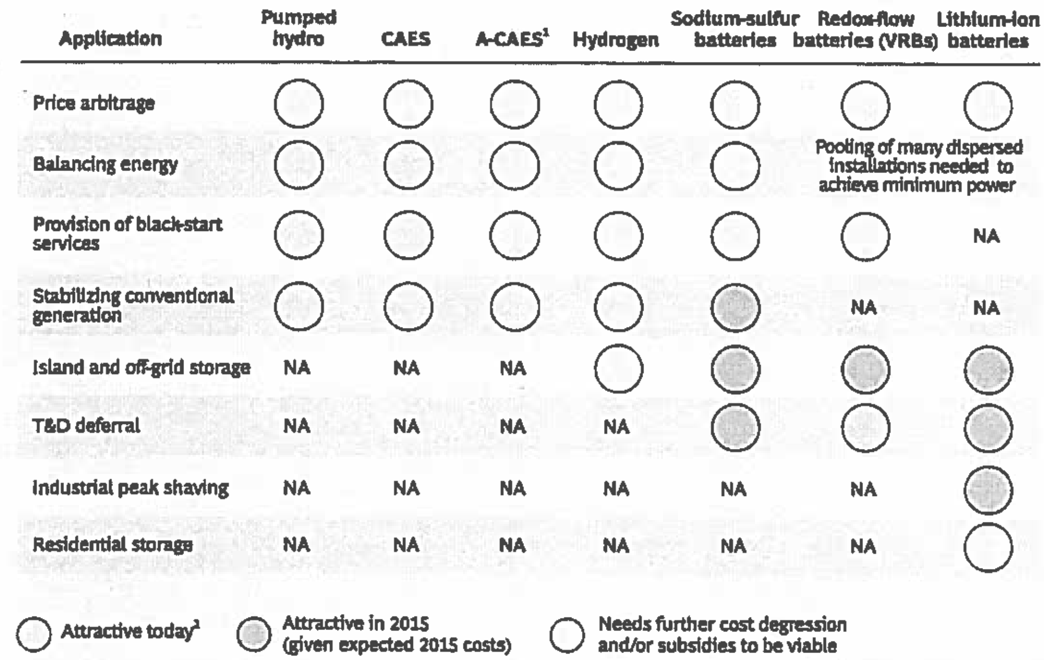
Centralized applications are usually connected to the high-voltage transmission grid (typically more than 110 kilovolts) and are designed to buffer fluctuations originating from a large number of sources on both the generation and the demand side. The advantage of centrally located storage facilities is that they can leverage the "self balancing" of independent fluctuation patterns. For example, if a sudden increase in wind generation coincides with a sudden rise in demand, essentially no storage may be needed. However, this scenario would require a strong grid infrastructure across the "catchment area" and large storage facilities in terms of power and energy, which only pumped hydro, CAES, and hydrogen storage can provide. Decentralized storage applications are tightly integrated into the distribution grid and are often dedicated to balancing fluctuations induced by a smaller number of sources and/or sinks (such as solar- or wind-power-plant installations). Decentralized deployment reduces grid capacity requirements because fluctuations are dealt with near their origin, but the overall utilization of individual storage facilities may be lower than that of centralized facilities.

Since a positive business case can be demonstrated for a fair share of storage applications, we believe there is a bright future ahead for electricity storage in the next decades, driven mainly by the growth of fluctuating renewable energy.

We have classified storage applications into eight groups. For each one, we defined an illustrative business case in order to test whether an investment in a storage facility would yield an acceptable return on investment and thus offer an attractive business opportunity for the operator. In these calculations, we maintained a true cost/revenue perspective; that is, we did not consider any subsidies or additional sources of revenue that would provide a financial upside and strengthen the business case. Also, we assumed individual projects without any dependence on other types of assets, such as grids or generation assets. We based our calculations on technology cost assumptions for the period 2015 to 2020. We did not consider further cost reductions, especially in battery technologies, that could present an additional upside. On the other hand, for each of the applications, we calculated the internal rate of return (IRR) for a representative setup in which fluctuations in generation and demand occur as assumed for 2015 on, without the impact of future storage assets being factored in. We assume that these two assumptions more or less cancel each other out.

The following sections describe these eight applications and our findings regarding their financial attractiveness. (See Exhibit 1.)

EXHIBIT 1 | Financial Attractiveness of Electricity Storage Applications and Related Technologies



Source: BCG analysis.
[1]A-CAES is the second generation of CAES technology. It includes a thermal storage unit to avoid thermal energy losses during compression and decompression, thereby potentially increasing round-trip efficiency to approximately 70 percent. The technology is not yet mature and faces several challenges.
[2]Expected IRR of 7 percent or more.

Price Arbitrage. This application refers to the leveraging of the price spread of electricity between peak and off-peak periods by storing when prices are low and discharging when prices are high. Our analysis showed that price differences are generally not large enough for a sustained period to generate a sufficient return on investment. We tested this finding by simulating much higher price variations than those that exist today; the resulting business case was still not attractive. Adding to the challenge is the fact that it is virtually impossible to make perfect decisions about price developments before the fact; moreover, this application has a tendency to self-destruct, since price differences tend to disappear as the number of players aiming to leverage them increases. Hence, price arbitrage does not appear to be a viable standalone business case for storage. It can, however, be combined with other applications. Notwithstanding certain size requirements for participation in power markets, price arbitrage can be utilized with any storage technology that is connected to the transmission or distribution grid.

Balancing Energy. Provision of balancing energy is one of the most attractive business cases for storage at present. Given the power and energy required to participate in the balancing-energy market (for example, the minimum required power for minute reserves in Germany is currently 15 MW), financially attractive electricity-storage applications based on balancing energy could be implemented within the next few years. A precondition is obviously the presence of a market mechanism for balancing energy. Such mechanisms are in place in several developed power markets in Europe and the U.S. (such as in PJM's grid and other U.S. locations to follow). The underlying drivers of this business case are the price paid up front for the provision of balancing energy, the price paid for the actual energy provided, and, to a lesser extent, the amount of time that balancing energy is called for by the grid operator.

The principle is straightforward. Because generation and demand in power grids need to be matched perfectly at all times, transmission grid operators must be able to balance continuous and unforeseeable fluctuations both in generation (caused, for example, by the sudden technical failure of a power plant) and in load (caused by a sudden increase in demand). To provide the required flexibility, operators maintain sufficient reserves, which they obtain from generators and other providers—both negative balancing energy (for example, to mitigate a sudden electricity surplus) and positive balancing energy (to react to a sudden electricity deficit). With the rise of fluctuating RE generation, the need for balancing energy tends to increase.

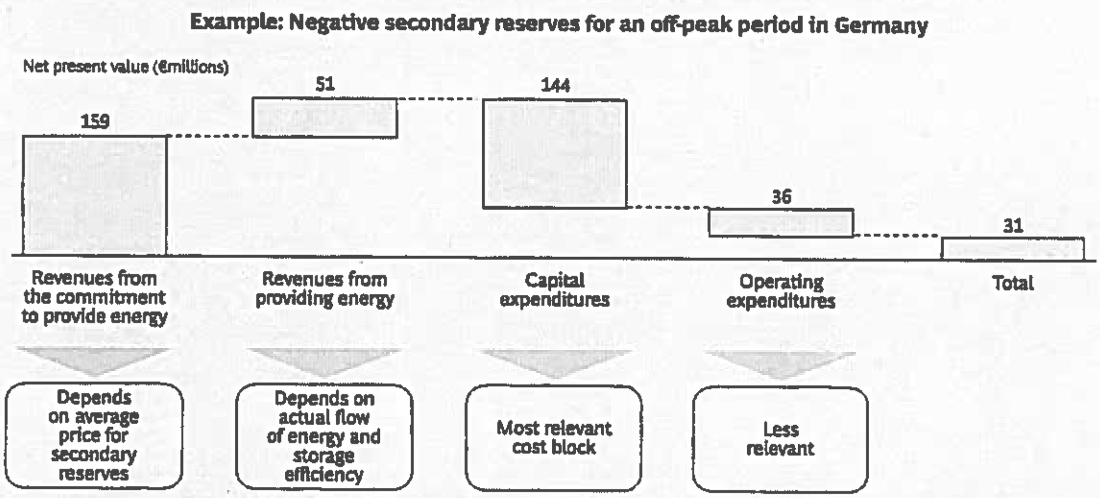
These reserves can be called on at short notice (within milliseconds to several minutes) and, because of the technical and reliability requirements that must be met, they usually command prices independent of—and higher than—those of the main power market. In Germany, for instance, balancing energy is auctioned in various tranches according to the required reaction time: primary balancing reserves for immediate response (within milliseconds), secondary balancing reserves (for response within 30 seconds), and minute reserves (for response within approximately 15 minutes). Auctioned prices for minute reserves in the markets that we analyzed (Germany and the U.S.) are in the range of €10 to €30 per MW per hour throughout the year, with average monthly prices as high as €58 per MW per hour (in January 2010) and peak prices of more than €100 per MW per hour; minute reserves are usually auctioned for the next day. Primary and secondary balancing reserves receive even higher prices and are usually auctioned for an entire month.

The beauty of providing negative balancing energy is that the storage facility can use surplus energy taken from the grid at nighttime, for example (for which the facility is paid), to generate additional revenues by selling it on the power market at peak prices 12 hours later.

In general, the advantage of balancing-energy pricing is that the bulk of the revenue is generated by the commitment to provide energy if and when it is needed. It is not necessarily linked or limited to the actual provision of energy. The business case for this application is therefore quite attractive. (See Exhibit 2.) At current price levels, large storage facilities using pumped hydro and CAES achieve an IRR of around 10 percent, especially when their focus is on providing negative balancing energy.

The beauty of providing negative balancing energy is that the storage facility can use surplus energy taken from the grid at nighttime, for example (for which the facility is paid as agreed to in the balancing-energy tariff), to generate additional revenues by selling it on the power market at peak prices 12 hours later. This option of being double-paid is not available to other providers of balancing energy. Developing the optimum operating model for the provision of balancing energy through electricity storage is a complex problem, since numerous combi-

EXHIBIT 2 | The Business Case for Balancing Energy Is Quite Attractive



Assumptions:

- Small CAES storage (100 MW)
- Average price for negative secondary reserves (off-peak): €10/kW/month
- Provision of balancing energy during off-peak periods only
- Average price difference between charging and discharging: €.05/kWh
- Time share with actual flow of energy: 25%
- Discount rate: 7%

Source: BCG analysis.

nations of time slots are possible and the auction mechanism needs to be well understood for best results.

This application is, in our view, a great opportunity for any storage operator and is available in some markets already. In the future, the need for balancing energy—and hence its price—is likely to rise as RE generation causes fluctuations on the supply side to increase, and more and more power markets will introduce sophisticated market mechanisms for the procurement of balancing energy. Both factors result in a very positive outlook, although it may be slightly dampened by stronger competition going forward.

Provision of Black-Start Services. Black start refers to the initial power supply required to rebuild a power grid after a full blackout. Dedicated, 100-percent-reliable power sources are needed to provide this emergency energy, since standard plants themselves require some electricity for startup and operation. Usually power plants rely on diesel generators, but given the rare occurrence of blackouts, these are used more for insurance than for actual energy generation. All highly developed power grids require black-start services, and contracts are often negotiated bilaterally between grid operators and providers. In the U.S., a number of independent system operators have implemented transparent mechanisms for the procurement of black-start services.[1]

Our research on black-start services as an application for electricity storage indicates that revenues of €5 per kW per month are realistic for the next few years, the price of the service being the key driver of profitability.[2] Another important driver is the amount of energy needed, which corresponds to the number of hours that the black-start power supply is required in case of emergency—the fewer the better for the storage-based business case.

While provision of black-start services is certainly not a prime storage application—diesel generators yield better returns—it deserves consideration as a source of additional revenues. It is characterized by low-frequency utilization but is technically easy to implement. All that is required is the setting aside of a certain share of the charged energy for blackout emergencies. This is a particularly interesting option for storage technologies in which power is not fully discharged on a daily basis. Batteries, for example, achieve a higher number of cycles when the depth of discharge is less than 100 percent, and in pumped hydro, the impact on the shoreline of the upper reservoir is less when the water level is not reduced by the maximum amount. Obviously, this application makes sense only for storage technologies in which there is no or nearly no self-discharge. In addition, regulations in some countries require certain power plants to provide their own black-start capacity, reducing the opportunities for external providers.

Stabilizing Conventional Generation. Existing storage facilities are frequently used for an application that is a core element of many energy markets today—and will be even more so in the future: stabilizing power generation in order to make the best use of conventional and renewable generation assets. This can be accomplished by minimizing ramping (in the case of conventional power plants) and minimizing throttling (in the case of renewables).

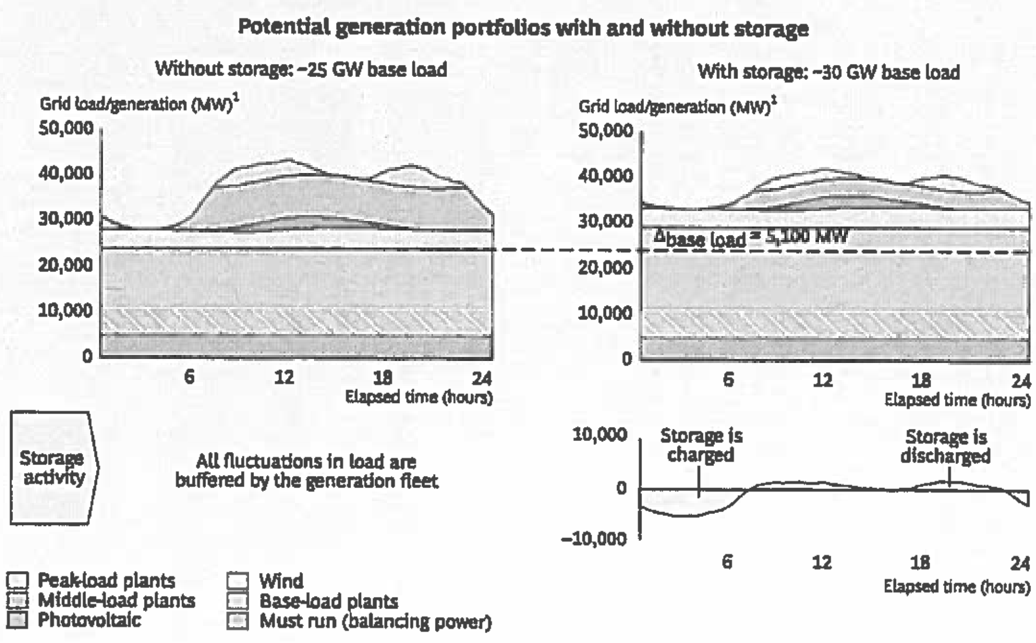
The underlying rationale is straightforward. Any energy-generation system must be able to react flexibly to changes in load and generation. Some of this flexibility is provided by balancing energy, as described above with respect to sudden, momentary fluctuations. Longer fluctuations—lasting hours or days—can be accommodated by ramping conventional power generation up and down or by throttling peaks in renewable generation. But with RE-induced fluctuations growing, this procedure is becoming increasingly uneconomical because of ramping losses, reduced utilization of the plant, and lost RE generation. Whereas peak-load power plants are designed to ramp up and down quickly several times a day, older, conventional power plants are restricted in their ability to do so—and, even if they can operate more flexibly, they are restricted in their ability to achieve better results under continuous operation. For example, with demand dropping significantly, many U.S. utilities are operating their coal-powered plants like midcycle plants, which is uneconomical. Operating them more steadily would have a strong economic upside and reduce reliance on gas peakers, whose variable cost of generation is substantially higher.

Existing storage facilities are frequently used for an application that is a core element of many energy markets today—and will be even more so in the future: stabilizing power generation to make the best use of conventional and RE generation assets.

There are substantial economic benefits to stabilizing conventional generation or, to put it differently, to maximizing the share of base-load generation. Flexible assets such as pumped-hydro storage can be used to "soak up" fluctuations, resulting in a less steep load-duration curve. This is nothing new—many pumped-hydro stations are doing exactly that today—but with flexibility requirements increasing due to RE generation, a larger share of flexible assets is needed. In fact, such assets are currently being built, especially gas peakers. But our calculations show that storage facilities are equally up to the task of providing flexibility and buffering the base-load fleet. Indeed, they have a clear advantage because they can store excess RE electricity generated during periods of low demand (such as at night) and feed it back into the grid when demand rises (at noon)—as opposed to the uneconomical throttling of excess RE generation, which is otherwise hard to avoid. This would allow fewer conventional power plants to be ramped down at night, lowering overall generation costs—and also overall CO_2 emissions. (See Exhibit 3.)

Given the large amounts of power and energy required to buffer conventional generation assets, the use of storage facilities in this application is mainly relevant to large-scale CAES and pumped-hydro storage. According to our calculations, CAES can—despite its technological limitations—provide an IRR of more than 15 percent in certain scenarios, with approximately 80 percent of revenues originating from saved generation costs and approximately 20 percent from saved CO_2 emissions costs.[3] It is important to note, however, that this calculation, rather than viewing each asset as an isolated profit center optimizing itself against the market, which is common practice at many utilities today, assumes several integrated generation assets taken together.

EXHIBIT 3 | Storage Can Increase the Share of Base-Load Power Generation



Sources: Amprion; 50Hertz; EnBW; Transpower; BCG analysis.
Note: In this illustrative example, we assumed constant fluctuating RE generation; we modeled several alternative cases with similar results. The load profile is based on average data for January and June 2009 in Germany.
[1]Energy flowing through public grids only, without direct industrial consumption.

The main lever in this application is increasing—or, despite growth in fluctuating RE, maintaining—the share of base-load power generation in order to leverage its low marginal costs (and reduce ramping costs), thus increasing utilization and reducing the levelized cost of electricity of the total fleet. The degree and characteristics of the fluctuations in any given power grid are the main drivers: the more frequent and steep the fluctuations in residual load, the greater the benefit of buffering them. We analyzed this application for five days in Germany under varying weather conditions, first with 2009 RE installed power (10 GW PV and 25 GW wind) and then with RE installed power forecasted for 2015 (36 GW PV and 44 GW wind). The application worked on all but one of the sample days, and the benefits of using storage facilities increased over time in terms of generation cost savings. Dena (the German Energy Agency) had similar results in its assessment of a planned pumped-hydro facility in southwestern Germany.[4]

Using electricity storage in combination with RE sources, especially wind and PV, in island and off-grid settings is a straightforward application that not only offers an attractive financial upside but also entails an impressive reduction in CO_2 emissions.

Island and Off-Grid Storage. Today, diesel generators ensure electricity generation in many island and off-grid settings, despite their high generation costs of around €0.25 per kWh or more, simply because there is no simple, feasible alternative. This is a sizable market, representing an installed fleet of 600 GW of diesel generation capacity.[5] Using electricity storage in combination with RE sources, especially wind and PV, in island and off-grid settings is a straightforward application that not only offers an attractive financial upside but also entails an impressive reduction in CO_2 emissions. Even when the cost of an emergency backup diesel generator is included, a positive return on the overall investment (RE generation plus storage plus backup diesel) can be realized, since storage involves negligible variable costs. Batteries are well positioned for this storage application given its usual size, and we considered four different types: lead-acid, sodium-sulfur, redox-flow (VRB), and lithium-ion. They all returned positive business cases; the ideal technology is likely to vary according to the specific on-site conditions.

As a base case, we assumed power supplied exclusively by diesel generator. The first alternative was a combination of RE generation and diesel generator, with the diesel generator operating whenever RE generation was insufficient to meet power demand. Excess RE generation was throttled. The second alternative was a combination of RE generation and battery storage plus backup diesel, with almost the entire power demand being satisfied by (partly stored) RE generation. We found that with diesel prices higher than €0.20 per liter, both alternatives were clearly more financially attractive than the base case.

We then analyzed the two alternatives under different weather conditions, given a sample load pattern, and found that in almost all cases, the storage solution yielded better returns than the solution without storage, especially in cases with high fluctuations in residual load. In every case, there was a positive return on the storage investment, particularly in settings with a high share of wind generation (which is generally less aligned than PV generation with power demand). The IRR for various RE and storage combinations in island and off-grid settings ranged from 3 percent to as high as 50 percent and more under conditions of high wind.

As noted above, an additional highly attractive aspect of this application is its direct positive impact on emissions, especially CO_2, since the use of diesel generators is almost completely replaced by RE generation. Assuming a 600 GW installed fleet of diesel generators running an average of only 5 percent of the time (that is, approximately 400 hours per year), reduction of CO_2 emissions would equal approximately 200 million tons per year—the equivalent of half the emissions of France.[6]

T&D Deferral. Transmission and distribution (T&D) deferral uses electricity storage as a means of either avoiding or deferring an investment in grid infrastructure—an investment that becomes necessary when the maximum load is exceeded during peak hours owing to an increase in power demand. The principle is simple: instead of increasing the capacity of an existing power line to meet peak demand, a suitably sized battery is installed near the load, discharging at peak times and charging at off-peak times. This storage application is already being used in the U.S.—since 2007 in Charleston, West Virginia, for example. (Such installations often serve additional purposes, such as frequency stabilization, which are not considered here.) The T&D deferral application is particularly useful and attractive under the following circumstances:

- Transmission bottlenecks can be clearly identified.
- Grid infrastructure is not particularly dense or close to overloading at the bottlenecks of concern.
- Demand for electricity is growing, either continuously or on a one-time basis (for example, because of new housing or industrial infrastructure), ideally at the end of the transmission line.

Given these conditions, two main parameters determine the attractiveness of setting up a storage facility instead of upgrading the power line: the additional capacity required and the length of the power line requiring upgrade.

Where power ratings are relatively low, batteries are the technology of choice for this application. Our initial calculations show that storage can also be beneficial under certain circumstances in higher-power settings, such as optimizing the linkage of a wind park to the transmission grid. Depending on the size of the wind park, CAES (for offshore wind, located near the landing point) or sodium-sulfur batteries (for onshore wind) are the best-suited technologies.[7] Besides the pure economics, government subsidies incentivizing the feed-in of less-fluctuating wind power are a key driver of such installations, as is the case in Japan, where feed-in tariffs for wind energy depend on the current demand/supply profile and vary between ¥9 and ¥27 per kWh.

Assuming a 600 GW installed fleet of diesel generators running about 400 hours per year, battery storage in island or off-grid applications could reduce CO_2 emissions by approximately 200 million tons per year—the equivalent of half the emissions of France.

Industrial Peak Shaving. Peak shaving aims to flatten industrial power demand and is particularly relevant for companies whose demand varies greatly throughout the day. The power tariff in most markets comprises a fixed component, determined by the maximum, or peak, power required at any point in time, and a variable component, which is the actual energy consumed. Exceeding the agreed-upon maximum power can result in severe penalties, depending on the contract, and shaving the peaks can significantly reduce the fixed component. When more load is needed than can be taken from the grid according to the delivery contract, a battery serves as the temporary source of extra power in this application.

While peak shaving can be financially viable, depending on individual load and tariff patterns, demand-side management provides an attractive and easily implemented alternative with a similar result. Shutting down some of the equipment, such as the ventilation system, for a few minutes when the hydraulic press is operating can prevent the power ceiling from being exceeded just as effectively and with hardly any investment required.

Residential storage is frequently discussed in connection with the impressively dynamic development of residential PV installations, especially in Germany but increasingly in other countries as well, but we believe it unlikely that subsidies for self-consumption will increase relative to conventional feed-in.

When demand-side management is not an option, however, and when load fluctuations are infrequent and steep, peak shaving can be advantageous. Our calculations show that for various types of lithium-ion batteries, an IRR of 10 percent or more can be achieved if suitable load characteristics are present. In addition, once the battery is installed, there is great potential for combination with other applications, such as price arbitrage.

Residential Storage for Self-Consumption. Residential storage is frequently discussed in connection with the impressively dynamic development of residential PV installations, especially in Germany but increasingly in other countries as well, such as Italy. A small lithium-ion battery in the basement stores excess electricity generated at around noon and retains it for the afternoon and evening, increasing self-consumption and reducing strain on the distribution grid. In Germany, self-consumption of PV generation receives a bonus of approximately €0.08 per kWh. However, the required 7 kWh battery and two-way meter together cost €3,500 or more—far more than can be offset by the self-consumption incentive.

We believe it unlikely that subsidies for self-consumption will increase relative to conventional feed-in. Currently, the grid infrastructure is paid for by all users; that is, every kWh carries a grid usage fee. As almost all electricity is carried across the transmission and distribution grid, the (fixed) grid costs are spread across a relatively large number of total users, making the cost per kWh bearable (currently approximately one-third of the retail price). Were more and more customers to become self-sufficient in their power supply, fewer kWh would be delivered via the power grid, although self-suppliers would likely retain their grid connection for backup. Hence, the (unchanged) grid costs would be borne by fewer people, providing a further incentive to self-supply. Eventually, it would no longer be possible to allocate the grid costs.

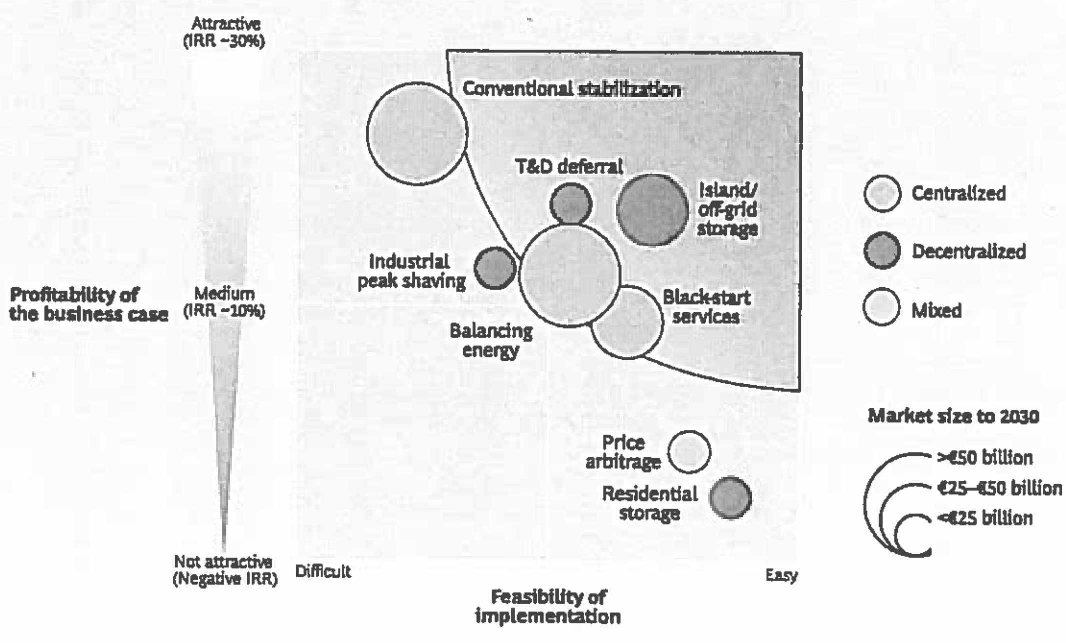
Assessment Methodology and Conclusions

In our analyses of the preceding storage applications, we used sensitivity analysis, where possible, to assess the impact of changes in some of the relevant parameters. And while our analyses give a good indication of the business opportunities for these applications, only a thorough assessment of specific projects, their context, and the details of key operational parameters will provide a reliable basis for investment decisions. Exhibit 4 provides an overview of the feasibility and financial attractiveness of each storage application. The size of the bubbles indicates the cumulative market potential for each one to 2030. We assessed feasibility qualitatively according to four criteria: the availability of technical alternatives, the technical complexity of the implementation, its match with long-established business models (for example, those of utilities), and general opposing or supporting trends. Feasibility as well as profitability may of course vary by regional or project-specific context.

We analyzed the business cases individually, assuming that a given storage facility will be used for a single storage application. However, storage facilities can be used to generate revenues from different sources, either by assigning parts of the capacity to different applications (horizontal combinations) or by using different applications at different times of day (vertical combinations). The benefit is essentially a higher utilization of the storage infrastructure and (as described in the discussion of balancing energy) the ability to leverage excess electricity to generate double revenues. Price arbitrage, T&D deferral, and industrial peak shaving (in addition to balancing energy) are especially suited to vertical combinations.

Several key insights can be drawn from our assessments. First, storage applications can, under favorable conditions, be profitable today. Cost degressions, especially in the case of stationary batteries, will significantly improve profitability in a number of additional applications, as discussed above. However, in most applications, the underlying drivers of the business case have to be analyzed very carefully on a

EXHIBIT 4 | Four or Five Storage Business Cases Will Be Attractive in the Near Future



Source: BCG analysis.

project-by-project basis. Thus, in the case of T&D deferral, for example, financial attractiveness varies with distance, required power, and load pattern.

Second, although any storage technology can theoretically be used for almost any application (by pooling several smaller units, for example), performance characteristics and costs point to a number of obvious combinations of technologies and applications, such as off-grid settings combined with batteries, or stabilization of conventional generation combined with pumped hydro or CAES. Our calculations also indicate that, under favorable conditions, large-scale storage technologies such as pumped hydro and CAES—despite the latter's technological shortcomings—are already financially attractive today, while decentralized applications using batteries will become so within the next five years or so.

Making the most of an investment in any storage facility requires sophisticated operational optimization and experience, suggesting strong first-mover advantages for the operators of new facilities.

Third, given the many parameters influencing storage revenues and the countless horizontal and vertical combinations that are possible, successful operation of a storage facility is a complex task. Hence, making the most of an investment in any storage facility requires sophisticated operational optimization and experience, suggesting strong first-mover advantages for the operators of new facilities.

The Market for Storage

To forecast the overall business potential of relevant storage technologies, we took the overall demand for a specific application as a starting point. For example, the overall demand for balancing energy can be quantified as a share of the total vertical grid load in a particular energy system (for example, 5 percent in Germany, given actual amounts for 2010). For an off-grid application, our starting point was the installed capacity of diesel generators worldwide (approximately 600 GW), of which 50 percent was assumed to be used for continuous off-grid power generation. These calculations allowed us to estimate the overall storage capacity needed if electricity storage were to satisfy 100 percent of demand (which will never be the case).

We then calculated the actual market potential of electricity storage for each application by assessing the financial attractiveness of the storage business case, the complexity of implementation, and the availability of alternatives to storage for the specific application. Finally, we calculated the share of each storage technology to 2030, again on the basis of financial attractiveness as well as technical requirements, using forecasts of the underlying parameters for 2020 and 2030. As noted earlier, however, our initial business-case calculations were made using technology cost parameters for 2015 to 2020; further cost reductions beyond 2020, which are likely, could provide additional upside potential. On the other hand, the initial deployment of storage facilities may have an effect on the business case of those that follow, exerting a dampening effect on overall market potential. We assume that these two effects more or less cancel each other out.

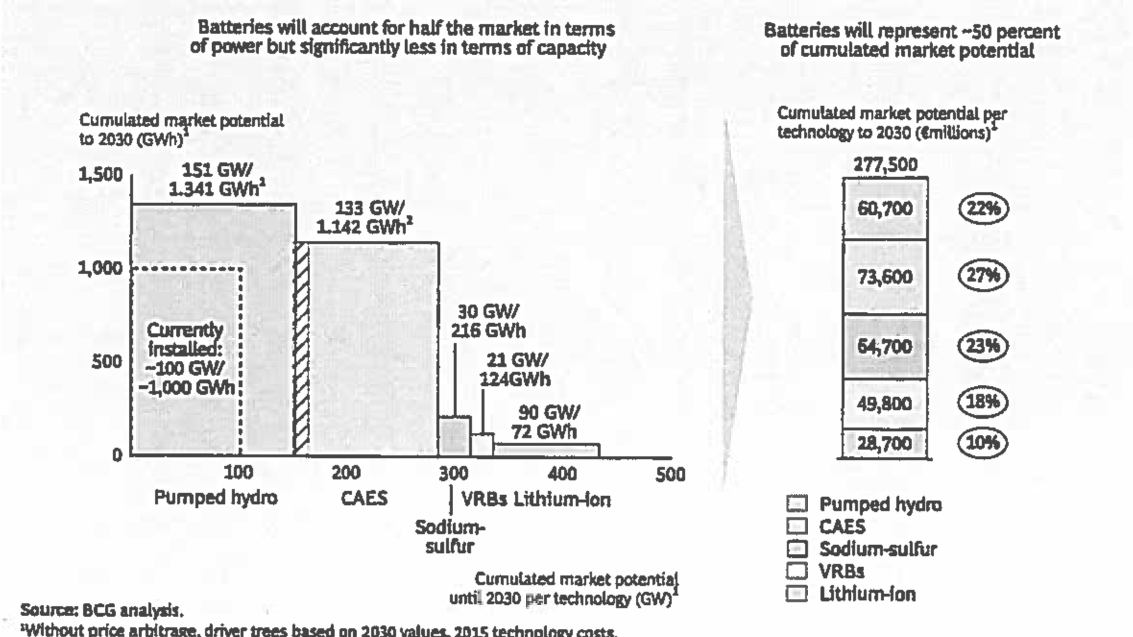
On the basis of these considerations, we calculated the overall market potential of the eight applications and storage technologies to 2030. On top of the approximately 100 GW of storage that exists today, we forecast an additional market potential for approximately 330 GW of storage distributed among the different technologies.

This translates into an additional *cumulated* investment need of approximately €280 billion to 2030, including replacement. Balancing power will drive approximately one-third of the market potential; in terms of regional distribution, Western Europe, the U.S., and China will take the largest shares. Batteries will account for almost 50 percent of this market in terms of financial investment, although they will represent a very small part of the storage energy capacity needed by 2030. (See Exhibit 5.)

We believe that a gradual increase in the storage business will take place over the next few years, driven by increasing penetration of RE generation and the need to manage fluctuations and by the growing technological maturity of the key storage technologies, especially batteries. Today, the storage market is worth around €1 billion per year. We expect annual global market volumes of €2 billion to €3 billion per year in the next few years, increasing to €4 billion to €6 billion per year after 2015 and to more than €10 billion per year after 2020.

As already noted, our calculations were made purely from a cost perspective, omitting the potential beneficial effects of storage-related regulation. Such regulation is currently being discussed in several countries with high or quickly growing shares of RE generation, such as Germany, the U.S., Japan, and China, and its implementation has the potential to boost the storage business well beyond the forecasted volumes. We are therefore convinced that a sizable and sustainably growing market is unfolding in the stationary-storage arena. While business in

EXHIBIT 5 | Market Potential of the Storage Technologies



Source: BCG analysis.
[1]Without price arbitrage, driver trees based on 2030 values, 2015 technology costs.
[2]The future split between pumped hydro and CAES will be driven largely by site restrictions; the gradual replacement of both technologies by hydrogen storage is expected after 2020.

absolute terms will be small in the next few years, we forecast strong and continued growth after 2015 that can best be tapped by taking the right steps now.

Potential Business Opportunities

Electricity storage offers a wide range of business opportunities to a wide range of stakeholders. Obvious market participants are utilities, in their capacity as operators of storage facilities, and technology providers. However, other players—in the chemical industry and in the automotive sector, for example—and even financial investors may discover that storage is an attractive means of entering a new segment of the energy business in which stakes are yet to be claimed. Indeed, one-third of venture capital companies polled in January of 2010 listed electricity storage as their number-one investment focus.[8] While this indicates that some of the relevant technologies are still in their infancy, it also shows that now is the time to start considering storage-related business opportunities, before the best lots are taken.

There are four main groups of potential stakeholders that might want to consider entering this market: power generation players, suppliers, end-product companies, and financial players.

One-third of venture capital companies polled in January 2010 listed electricity as their number-one investment focus, indicating that some of the relevant technologies are still in their infancy but also that now is the time to start considering storage-related business opportunities, before the best lots are taken.

Power Generation Players. In addition to power generation companies such as utilities, power system stakeholders such as municipalities and grid operators may benefit from running electricity storage facilities—to mitigate grid bottlenecks through T&D deferral, for example, or to better leverage their existing generation assets through stabilization of conventional generation.

Suppliers. Business opportunities exist for raw-material sellers, for battery producers, and for technology companies that serve the energy industry, including the following:

- Producers of lithium, in particular, but also of vanadium (for redox-flow batteries) and copper (for cabling), and, to a lesser extent, mining companies and raw-material producers interested in greening their remote operations through the use of RE generation paired with batteries for reliability

- Battery producers that are building up large production capacities in anticipation of the takeoff of the e-car market and are looking to broaden their footprint by supplying batteries for stationary applications in what is likely to become an even more profitable sector

- Producers of energy technology and components such as pumps, compressors, turbines, inverters, switchgear, and other devices (such as ABB, whose Dynapeaq product line—available today—integrates high-voltage switchgear with battery storage solutions)

- Manufacturers of RE technology such as wind turbines and PV modules, as well as project developers and operators (such as IPPs) seeking to integrate their fluctuating-generation assets, either voluntarily or owing to potential changes in legislation

End-Product Companies. Energy storage capacity could enable these companies to provide more innovative products to their clients and to enhance their own operations. In particular, many automotive OEMs are looking into leveraging their e-car capabilities in the grid storage arena. Using e-cars for vehicle-to-grid energy storage may become an option as soon as a sufficient fleet of e-cars is on the road. While there are a number of challenges to be overcome (such as the control system, consumer interest and privacy issues, and the capacity of the charging infrastructure), innovative business models are being developed around the use of decentralized e-car batteries as virtual storage facilities.

Financial Players. In addition to venture capital companies, private equity will come into play once the market has matured. The renewable-energy sector has been attractive to private-equity players, helped by generous feed-in tariffs for RE generation.

Identifying Potential Business Opportunities

While all of these players will identify and evaluate potential storage-related business opportunities from a different perspective and with a different focus, we propose a general four-step approach.

Step one: Thoroughly understand the storage technologies and their potential applications and operational models. Given the many independent parameters involved in determining the operational profitability of individual applications, this is a precondition for identifying business opportunities. For example, there are currently five competing lithium-ion battery technologies under consideration in the market. Since each one has different implications for raw-material and component requirements, stakeholder companies need to understand each technology in order to make sound investment decisions.

Step two: Analyze and quantify the relevant end market. This involves the analysis of key trends, market drivers, and growth factors. On the basis of the analysis, realistically quantify market demand, starting from the relevant applications and taking into account regional focus and specific regulations. This step is, of course, particularly important for power-generating companies. But it is equally important for private-equity players, whose investment success depends on, among other things, selecting the right setting and timing their market entry—not too early, when the market is not yet mature owing to high technology costs and low RE generation, and not too late, when the presence of many players means that the best claims are already staked.

Step three: Identify the technology that best meets market demand. Given the technical requirements of the particular application, select the most suitable storage technology. Alternatively, a company may choose to leverage a particular technology because of existing in-house capabilities or in response to external factors such as government or financial incentives. In that case, the potential applications of the chosen technology must be identified. Both approaches are legitimate and depend on the individual company's starting position. Whereas future operators will in most cases start by singling out relevant applications,

A company can select the most suitable technology on the basis of the particular application's technical requirements, or it may choose to leverage a particular technology because of existing in-house capabilities or in response to government or financial incentives.

potential technology providers will most likely start with a specific storage technology.

Step four: Determine the implications for the relevant market of each stakeholder. Technology providers will analyze storage technology road maps in order to determine and assess the related investment case. A mining company, for example, can look at the attractiveness of the identified commodities relevant to the chosen technology and determine the profitability of any corresponding capital-expenditure projects. An automotive OEM will develop a view on the timeline of available storage technologies and apply that to its view on the development of the e-car market. It then can tailor its e-car strategies accordingly.

ELECTRICITY STORAGE OFFERS an exciting option for a much wider range of market players than is generally assumed. Corporate electricity-storage strategies based on a thorough assessment will have the best chance of succeeding in this field of business. Because the financial return on a storage investment is strongly contingent on finding a location with a suitable set of parameters, we believe there is a clear first-mover advantage for the operators of energy storage facilities. It is therefore essential to evaluate opportunities in this sphere quickly.

NOTES

1. See Alan Isemonger, "The Viability of the Competitive Procurement of Black Start: Lessons from the RTOs," *Electricity Journal*, vol. 20, issue 8, October 2007.
2. In the U.S., the New England independent system operator, ISO-NE, is paying at a rate of $4.58 per kW per year until 2011 (see, for instance, http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html). Others, such as PJM, CAISO, and NYISO, quantify the direct costs and allocate them to the general power tariff; ERCOT uses an auction system. In Europe, bilateral agreements between generators and grid operators are in place.
3. We assumed emission costs of €15 per ton. When phase III of the European Union's Emissions Trading Scheme goes into effect in 2013, EU power generators will have to pay for their emission certificates (with certain exceptions for Eastern European power plants). See http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/tackling_clima/emissions/eu_ets/phase_iii/phase_iii.aspx.
4. See http://www.dena.de/de/themen/thema-esd/projekte/projekt/psw-integration-ee/.
5. This is the cumulated market for 1980 to 2010, representing an installed capacity of diesel generators with a nominal power of 500 kW or greater and assuming a 30-year generator lifetime. See Power Systems Research at http://www.powersys.com/.
6. Emissions calculations assume specific emissions of 0.27048 kilogram CO_2 per kWh diesel and 35 percent generator efficiency. See U.N. Millennium Development Goals Indicators, http://mdgs.un.org/unsd/mdg/Data.aspx.
7. A reference site is already operational at Rokkasho, Japan, where 34 MW of sodium-sulfur batteries were installed by NGK in May 2008 alongside a 51 MW wind park in the north of the main island of Honshu. See http://www.ngk.co.jp/english/products/power/nas/installation/index.html.
8. For details, see http://graphics.thomsonreuters.com/0110/US_CLNTCH0110.gif.

About the Authors

Cornelius Pieper is a principal in the Cologne office of The Boston Consulting Group. You may contact him by e-mail at pieper.cornelius@bcg.com.

Holger Rubel is a partner and managing director in the firm's Frankfurt office. You may contact him by e-mail at rubel.holger@bcg.com.

Acknowledgments

The authors would like to thank Jan-Nicolas Garbe and Jan Nopper for their contributions to the research, as well as Maurice Berns, Philipp Gerbert, Stephan Lehrke, Iván Martén, and Pattabi Seshadri for critical comments. They also thank Kim Friedman and Gina Goldstein for editorial and production assistance.

For Further Contact

If you would like to discuss this report, please contact one of the authors.

For a complete list of BCG publications and information about how to obtain copies, please visit our website at www.bcg.com/publications.

To receive future publications in electronic form about this topic or others, please visit our subscription website at www.bcg.com/subscribe.

BCG

THE BOSTON CONSULTING GROUP

Abu Dhabi
Amsterdam
Athens
Atlanta
Auckland
Bangkok
Barcelona
Beijing
Berlin
Boston
Brussels
Budapest
Buenos Aires
Canberra
Casablanca
Chicago
Cologne
Copenhagen
Dallas
Detroit
Dubai
Düsseldorf
Frankfurt
Hamburg
Helsinki
Hong Kong
Houston
Istanbul
Jakarta
Kiev
Kuala Lumpur
Lisbon
London
Los Angeles
Madrid
Melbourne
Mexico City
Miami
Milan
Minneapolis
Monterrey
Moscow
Mumbai
Munich
Nagoya
New Delhi
New Jersey
New York
Oslo
Paris
Perth
Philadelphia
Prague
Rome
San Francisco
Santiago
São Paulo
Seoul
Shanghai
Singapore
Stockholm
Stuttgart
Sydney
Taipei
Tel Aviv
Tokyo
Toronto
Vienna
Warsaw
Washington
Zurich

bcg.com

Exhibits 13-25 to Sierra Club's Comments Omitted