Economic and Greenhouse Gas Emission Assessment of Utilizing Energy Storage Systems in ERCOT

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Technical Update, November 2009

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NOTE

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PRODUCT DESCRIPTION

The United States has vast wind generation potential; and state renewable portfolio standards (RPS), tax incentives, and national climate policy could lead to dramatic increases in new wind generation. While wind generation could result in significant reductions in emissions from existing fossil generation, the challenges imposed by intermittency and balancing transmission of power to load centers may limit the effective use of wind capacity additions. Electricity storage may play a pivotal role in overcoming this challenge, with compressed air energy storage (CAES) a potentially attractive option for bulk energy storage solutions. Optimal use of electric energy storage systems is expected to play a key role in supporting wind integration, relieving transmission and distribution (T&D) congestion, and improving the balance of supply and demand. However, there have been very limited in-depth regional analysis and integrated portfolio and T&D assessments to best estimate how much storage and what type of storage systems are optimal and what locations are the most promising. The goal of this project is to evaluate the system benefits of bulk and distributed energy storage system deployment under high wind penetration scenarios.

Results and Findings

This report summarizes market-based analysis of the impacts of three energy or electricity storage technologies: CAES, Bulk and Distributed batteries, and liquid air energy storage in the Electric Reliability Council of Texas (ERCOT) market. It includes the impacts of these electricity storage systems on locational marginal prices (LMP), CO_2 emissions, and wind curtailment. It calculates the impacts of these systems on both the investors (power producers) and on society. Natural-gas-based, 2nd generation CAES systems were found to provide attractive rates of return using installed capital costs of $ 750 per kW. Bulk battery systems assumed to be installed for $ 1250 / kW were not found as economic due to their current high capital costs. Advanced 2 MW distributed energy storage systems assumed to be installed for $ 1600/kW strategically located around the key load centers were also found to be not economic. However, these distributed systems were found to provide very large societal system benefits in ERCOT. In the one case studied, liquid air storage systems co-located near an existing combustion turbine was not found to be economic due to their current high capital costs

Challenges and Objectives

The objective of this study is to analyze the economic benefits of installing various energy storage technologies in the ERCOT region. Specific objectives were to:

- Assess how compressed air energy storage systems (CAES) could increase wind utilization and penetration in ERCOT
- Estimate the emissions impact of deployment of CAES and battery systems

- Estimate the impacts and interplay of CAES investments on wind curtailment, transmission congestion, and societal / system benefits
- Assess similar impacts and the costs and benefits of deploying bulk battery energy storage system and distributed battery systems near Texas load centers
- Assess the value of emerging liquid air energy storage systems (LAES)

Applications, Values, and Use

The study results will be of value to utility system planners, strategic planners, and managers dealing with large wind integration and associated T&D investments. Results can be used to form the basis for follow-on market-based, regional integrated portfolio analysis of wind penetration, T&D investments, and energy storage. Policy makers can use the findings to understand the societal benefits of energy storage and to develop possible market integration strategies with renewable generation.

EPRI Perspective

This project is one element of EPRI's Energy Storage Program to understand the role and economic value of energy storage systems to the electric enterprise and to society. This report is a follow-up to work initiated in 2008 (EPRI Report 1016014**).** Market simulations in ERCOT indicate that storage would lead to a marginal increase in GHG emissions due to interaction with coal generation and a reduction in minimum load issues during off-peak hours resulting in increased coal generation. When CAES units are added, there is less congestion in the transmission lines, thereby enabling approximately 100 GWh more wind energy to be delivered annually. The study also showed the societal and system benefits of small-battery distributed energy storage systems can be very significant when storage systems are targeted at specific load centers where there are high LMP nodes on the system. Since this study was based on the Texas post Competitive Renewable Energy Zone (CREZ) 2 scenario assumptions, where a large build out of the transmission system has already taken place, the research findings in this report may underestimate the value of energy storage in relieving congestion and in reducing local marginal prices. Further studies of this type should be undertaken in regions in the United States where there is high wind penetration and T&D investments are planned.

Approach

The ERCOT system was chosen for these energy storage system assessments. The study examined energy storage deployment under post (CREZ) Scenario 2 conditions that assume an ambitious 18.5 GW of new wind energy supported by ERCOT's already approved $4.9 billion investment in transmission system infrastructure. The project team conducted the assessment the UPLAN market simulation model and its underlying suite of databases as the analytical platform. EPRI provided estimates of cost and performance of the energy storage options, which included 1st and 2nd generation CAES, bulk battery and distributed battery systems, and a liquid air energy storage system.

Keywords

Compressed Air Energy Storage
Energy Storage
Renewable Integration
Wind Integration

EXECUTIVE SUMMARY

Introduction

The United States has vast wind generation potential, and state renewable portfolio standards (RPS), tax incentives, and national climate policy could lead to dramatic increases in wind generation. While this could result in significant reductions in emissions from existing fossil generation, the challenges imposed by intermittency and transmission to load centers may limit the amount of wind capacity additions. Electricity storage may play a pivotal role in overcoming this challenge, with several storage technologies being potential contenders for bulk energy storage solutions. Many industry experts believe energy storage systems will play a key role in supporting frequency regulation, ancillary services, wind integration, relieving transmission and distribution (T&D) congestion and improving the balance of supply and demand. However, there are very limited regional studies and analyses available which estimate: the effectiveness of energy storage in improving wind integration; and the capacity and location of storage required in each region under various wind penetration assumptions.

Project Objectives

The goal of this project is to investigate regional system benefits of energy storage under high wind penetration scenarios. Specific objectives are to:

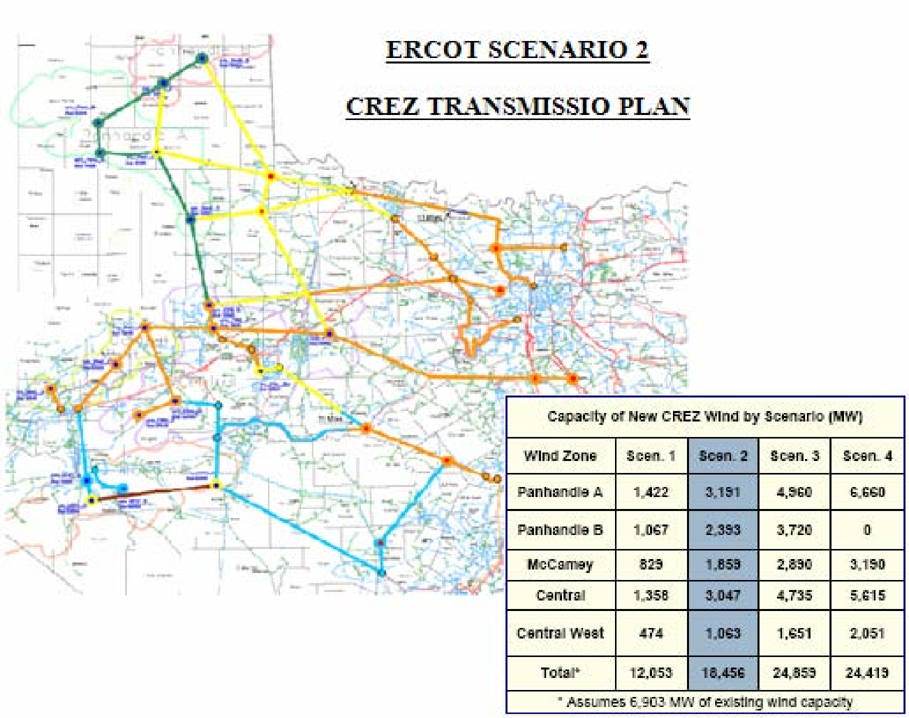
1. Assess how first and second generation Compressed Air Energy Storage Systems (CAES) could increase wind utilization and penetration in ERCOT,
2. Estimate green house gas emissions impacts of deployment of CAES systems,
3. Estimate the impacts and interplay of CAES investments on wind curtailment, Transmission congestion and the societal / system benefits,
4. Assess similar impacts and the costs and benefits of deploying bulk battery energy storage system and distributed battery systems in ERCOT, and
5. Assess the value of emerging energy storage systems like liquid air energy storage (LAES),), which involves compressing and cooling air into a liquid for storage prior to entering the expansion process.

Approach

The ERCOT electricity system which covers 75% of Texas and manages 85% of its load was chosen for the energy storage assessments. Due to the favorable regulatory environment and future investments in transmission infrastructure, new wind generation is projected to continue its current trend of rapid development. The study examined energy storage under the post CREZ

Scenario 2 conditions (Figure ES-1). Under this scenario the Public Utility Commission of Texas has proposed an ambitious 18,456 MW of new wind energy and approved $4.946 billion investment in transmission system infrastructure

The assessment of value and impacts of energy storage systems was conducted by using the UPLAN market simulation model to aid in the understanding of how energy storage alternatives, such as Compressed Air Energy Storage (CAES), battery systems, and Liquid Air Energy Storage (LAES) could be used to support the electrical network and provide economic benefit to the producer, consumer and to society as a whole.[1]



Capacity of New CREZ Wind by Scenario (MW)				
Wind Zone	Scen. 1	Scen. 2	Scen. 3	Scen. 4
Panhandle A	1,422	3,191	4,960	6,660
Panhandle B	1,067	2,393	3,720	0
McCamey	829	1,859	2,890	3,190
Central	1,358	3,047	4,735	5,615
Central West	474	1,063	1,651	2,051
Total*	12,053	18,456	24,859	24,419

* Assumes 6,903 MW of existing wind capacity

Source: ERCOT and PUCT

Figure ES-1 ERCOT CREZ Scenario 2

The UPLAN model enables a fundamental, granular simulation of ERCOT market dynamics based on very detailed characterization of generators and the transmission network along with realistic representation of market protocols.

The assessment of the energy storage systems was carried out in four phases:

- Phase I: Base case simulation (without any storage systems) in the post- CREZ Scenario 2
- Phase II: Compressed Air Energy Storage Analysis

[1] UPLAN Network Power Model
http://www.energyonline.com/products/npm.asp and
http://www.energyonline.com/products/uplane.asp

– CAES I – First generation CAES unit of 268 MW was located at a wind farm site in West Texas. This system is typical of the unit in Alabama operated by the Alabama Electric Cooperative (Figure ES-2). The capital costs have been updated.

– CAES II – Two Second generation CAES units of 200 MW each were located at a wind farm site in West Texas. This is an improved design which features the use of a conventional gas turbine system. This system is being planned for demonstration within the next two years (Figure ES-3)

- Phase III: Battery Storage Analysis

– Bulk Battery – This scenario utilizes the CAES II scenario with 100 MW of CAES storage capacity replaced by a 100 MW bulk battery. Characteristics of an Acid-Lead (A-Pb) battery were used in this scenario. While and A-Pb battery was assumed, the results are applicable to any bulk storage option such as a flow battery with similar characteristics.

– Distributed Battery Storage – This scenario employs 240 MWs of distributed energy storage systems. 120 batteries of 2MW each were placed at different demand buses across all the four zones in Texas. These buses were optimally chosen to provide the greatest arbitrage to the distributed storage. The buses were identified from the base case based on the locational marginal prices (LMPs) and are expected to represent the highest arbitrage with the greatest spreads between off-peak and peak electricity prices. Characteristics of emerging lilthium ion (Li-ion) batteries were used for this analysis, but again the results and findings are applicable to any energy storage system with similar characteristics.

Phase IV: This case examined the value of a novel Liquid Air Energy Storage cycle (LAES) – An 84 MW LAES unit was located in the Houston Zone where there was an existing underutilized simple cycle gas turbine.

Figure ES-2 110 MW – 26 hr 1st generation CAES system at Alabama Electric Cooperative

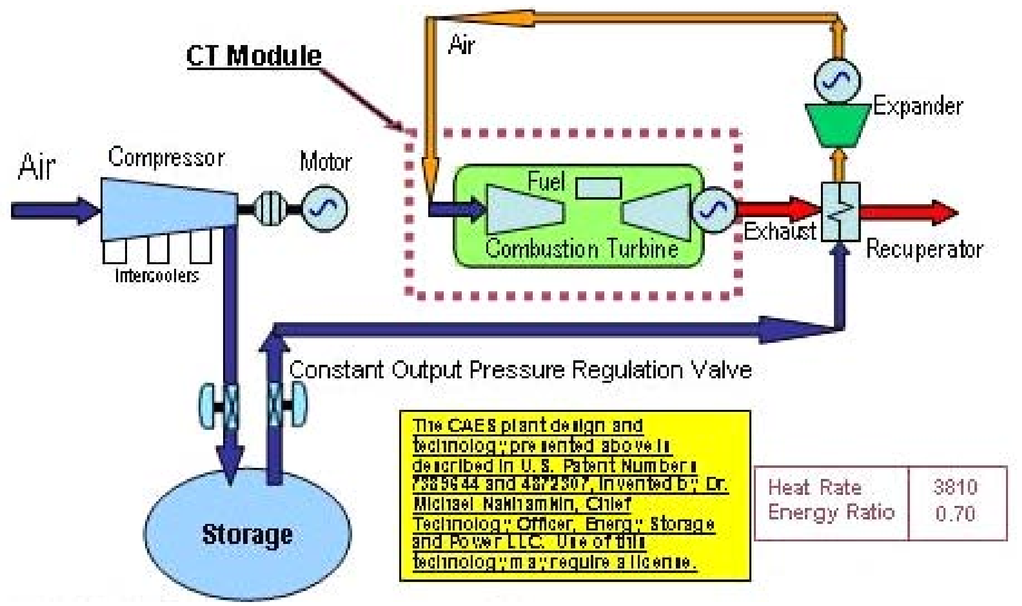


Figure ES-3 Schematic of 2nd Generation CAES Design

Energy Storage System Assumptions

Energy storage system characteristics and the key cost and operationally assumptions are listed in Tables ES-1, ES-2, and ES-3.

Table ES-1 Operating Parameters of the CAES Units

Characteristics of the two different CAES configurations are summarized below:

Operating Parameters	**CAES I (1st generation)**	**CAES II (2nd generation)**
Generating Capacity	268 MW	400 MW
Compressor load	200 MW	288 MW
Heat Rate (LHV)	4424 Btu/kWh	3696 Btu/kWh
Ramp Rate	Full load in 10 minutes	Full load in 10 minutes
Energy factor (MWh consumed for compression/ MWh generated)	0.75	0.69
Working Storage Capacity	5000 MWh	5000 MWh
Variable O&M Fixed O&M	$ 3-4 / MWH $ 4/ kW-yr	$ 3-4 / MWH $ 4 / kW-yr
Total installed capital costs (Salt Geology)	$ 1100 / kW	$ 750 /kW
Ability to provide ancillary services	Regulation up and regulation down; Spinning reserve; non spin reserve; start-up time 10-15 min	Regulation up and regulation down; Spinning reserve; non spin reserve; start-up time 10-15 min

Table ES-2 Operating Parameters of the Battery Storage system

Characteristics of the battery systems are shown in the table below:

Operating Parameters	**Bulk battery (A-Pb)**	**Distributed battery (Li-ion)**
Size (per battery)	100 MW	2 MW
No. of batteries	1	120
Energy Efficiency ac/ac	85 %	85 %
Storage capacity	0.47 GWh	0.01 GWh
Pumping Size	100 MW	2 MW
Discharge hours	4 hrs	4 hrs
Total Installed cost	$ 1250 / kW	$ 1600 / kW
Variable O&M	$ 2.9 / MWH	$ 1.9 / MWH
Fixed O&M	$ 0.63 / kW-month	$ 0.42 / kW-month
Ability to provide ancillary services	Regulation up and regulation down; Spinning reserve; non spin reserve; fast response	Regulation up and regulation down; Spinning reserve; non spin reserve; very fast response

Table ES-3 Operating parameters of the Liquid Air Energy Storage System (LAES)

Characteristics of the liquid air energy storage system are shown in the table below:

Operating Parameters	LAES
Size	84 MW
Storage Capacity	0.8 GWh
Pumping Size (MW)	80 MW
Energy Ratio	80 %
Heat Rate	3200 – 4050 (Btu/ kWh)
Ramp rate	1608 (MW/ hr)
Charging hours (hrs)	10 hrs
Variable O&M Fixed O&M	$ 3 / MWH $ 0.3 kW-month
Cost of Storage Capacity	62.5 $/ kWh
Cost of Charging / Discharging equipment Waste heat version	$ 1200 / kW
Total Capital Cost	$ 1795 / kW

Results and Findings

UPLAN simulations produce the total revenues, costs and net income of all the generators in the system. The total revenues account for the energy revenues, the ancillary services (A/S) revenues and other revenues such as no load and startup revenues[2]. The total costs incurred include fuel costs, fixed and variable O&M costs, and startup costs.

Compressed Energy Storage (CAES)

Investor benefits

The benefits of CAES from an investor's perspective are assessed by calcuating the net operating income. Net operating income is driven by the operating costs and revenues from selling energy and ancillary services, all influenced by the simultaneously projected ERCOT-wide generator dispatch and day-ahead energy and ancillary service market prices. These benefits are displayed in the table below:

Description	**CAES I (1st Generation)**	**CAES II (2nd Generation)**
Total Operating Revenue ($ M)	66.70	108.43
Total Operating Cost ($ M)	40.30	64.13
Total Net Income ($ M)	26.40	44.30
Internal Rate of Return (%)	3.94	12.11

The net operating income is operating revenues less operating costs. CAES II has a higher net income compared to CAES I because of a higher capacity installed. Net operating income generally increases with more availability of wind as it increases the supply of low-cost electricity for compression during off peak hours. The internal rate of return (IRR) is higher for the CAES II system compared to CAES I due to higher efficiency and lower capital cost. UPLAN simulations were carried out for the year 2015 only. However, the IRR calculations are based on operating life of 15 years for the storage unit. It was assumed that the 2015 simulation is representative of the entire operating life of 15 years.

Societal Benefits

From a societal standpoint, the decreased congestion and correspondingly lower cost of meeting energy demand due to CAES represents a net benefit to the system. Investments in CAES increase the efficiency of the electricity system, lower the costs to the consumers, modify the amount and allocation of producer's profits and make the system more reliable. CAES I and CAES II units yield a net societal benefit of approximately $6.5 M and $16.3 M respectively.

CAES arbitrages and profits from higher wind generation and also aids in optimizing transmission utilization. Addition of CAES I resulted in 0.15% lesser wind curtailment compared to the case without any storage and addition of CAES II resulted in 0.19% lesser wind

[2] For generators committed by the ISO that do not recover their costs in the real time market are made whole by the ISO.

curtailment (100 GWh of additional wind energy generation). However, in addition to the increase in wind generation, coal fueled generation has also increased due to the availability of energy storage helping reduce off-peak minimum load issues. As a result, the annual system wide CO2 emission increased by 0.07% with CAES I and 0.10% with CAES II. The decrease in wind curtailment and emission reductions may be greater at higher levels of wind and storage penetration.

Battery Storage Systems

The batteries have significantly different operating and economic characteristics but behave similarly to the CAES units in charging during low price off peak hours and discharging during high price peak hours. The batteries are also capable of moderating the occasional peaks and valleys in the prices. In the hybrid Scenario with Bulk battery and CAES II units, bulk battery performs at an annual average capacity factor of 17.75% and the CAESII_1 and CAESII_2 units perform at an annual average capacity factor of 41.32% and 41.33% respectively, similar to the CAES_II scenario.

In case of distributed batteries scenario, the average capacity factors of the emerging lithium-ion batteries are categorized by zones and are 19.5%, 21.62%, 20.04% and 21.51% for the Houston, North, South and West Zones respectively.

Investor Benefits

The benefits to the investor found in the bulk and distributed battery scenarios are summarized in the table below:

Description	Bulk Battery	Distributed Batteries
Total Operating Revenue ($ M)	15.17	0.45
Total Operating Cost ($ M)	6.31	0.15
Total Net Income ($ M)	8.86	0.30
Internal Rate of Return (%)	0.78	4.60

Batteries due to their low storage capacities and high capital cost yield lower returns than CAES systems as shown in the IRR. With further subsidies, improvements in technology and lower costs, these investments may prove feasible from an investor's standpoint. Increased wind penetration may also result in better arbitrage and revenue potential for the bulk batteries. For distributed batteries, the collective benefits of the best performing 2 MW Li-ion battery are shown above. On average, the batteries earn an annual net income of $0.28 million.

Societal Benefits

From a societal benefit standpoint, distributed batteries have the potential to provide significant benefits over the other options evaluated. Distributed batteries specifically provide approximately $170.5 M in annual savings to the system as a result of peak shaving, reducing peak hour locational marginal prices (LMPs), and lowering consumer payments. The 100 MW bulk battery experiences insufficient arbitrage opportunity and also does not provide any considerable benefits to the system.

Other benefits of the distributed storage systems, besides peak shaving and ancillary services, may include the deferral of capital investments for upgrading transmission and distribution equipment locally to improve grid reliability. These potential benefits were not included in this analysis.

The addition of 100 MW bulk battery to the system reduces the curtailment in wind generation by an average of 0.18% annually, whereas the amount of wind curtailment remains the same with the addition of 240 MW of distributed batteries which were primarily located in the demand zones rather than in wind areas. Due to the fact that there are only a twelve batteries of small size distributed in the West Zone , there is no impact of these batteries on reducing transmission congestion or wind curtailment.

Similar to the compressed air simulations, coal fueled generation increases marginally pushing CO2 emissions higher by 0.093% and 0.73% for bulk battery and distributed batteries respectively.

Liquid Air Energy Storage

In the Liquid-Air Energy Storage (LAES) cycle air cooled,compressed, liquefied and stored. During the off-peak hours the liquid air is stored at atmospheric pressure in a large tank. This is analogous to how liquefied natural gas is stored. During on-peak periods this liquid air is pumped and heated by the flue gases of a combustion turbine in Houston that was otherwise performing at a capacity factor less than 2%.

The LAES unit charges for 2875 hours and discharges for 2345 hours in the entire year, constituting an annual average capacity factor of about 26.%. The operation of the LAES unit is similar to any other storage system, with charging taking place during off-peak hours and discharging during peak hours.

Investor Benefits

Investor/owner benefits through operating net income coming from the 125 MW LAES plus CT is summarized in the table below:

Description	**LAES**
Total Operating Revenue ($ M)	27.15
Total Operating Cost ($ M)	16.58
Total Net Income ($ M)	10.57
Internal Rate of Return (%)	0.64

Societal Benefits

From a societal benefit standpoint, LAES provides approximately $10.9 M in annual savings to the system as a result of reducing peak hour LMPs and lowering consumer payments.

Summary of the Results

The performance and cost competitiveness of the storage options evaluated in this study is outlined in Table ES-4 below.

Table ES-4 Summary of results[3]

	CAES I (268 MW)	CAES II (400 MW)	Bulk Battery (100 MW) + CAES II (300 MW) ***	Distributed Batteries (240 MW)	LAES (125 MW)
Capital Cost ($/kW)	1100	750	1250	1600	1795
Present Value of Net Income ($/kW) *	672	755	603	1020	857
Present Value of Societal Benefits ($/kW)	243	263	240	4833	881
IRR (%) **	3.9	12.1	0.78	4.6	0.64
Overall Benefit/Cost	0.22	0.35	0.28	3.02	0.33

* Operating life of 15 yrs; Discount factor=12%

** Operating life 15 yrs

*** Hybrid scenario with CAES II

Overall Benefit/Cost = PV Societal Benefit/Capital Cost

Out of all the storage technologies evaluated in this study, CAES I, CASE II and distributed batteries provide internal rate of return of 3.9%, 12.1% and 4.6% respectively while the bulk battery and LAES offer less than 1% IRR for the location chosen in this study. From an investors' point of view, CAES II provides an attractive rate of return of 12.1% based on the input assumptions and may be considered for further analysis to optimize its location to yield greater benefits.

The societal benefit to cost ratio (B/C ratio) is calculated using the present value of societal benefits over a period of 15 years. The B/C ratio of first and second generation CAES units was 0.22 and 0.35 respectively. The results indicate that, for the post-CREZ scenario, investment in CAES does not yield significant societal benefits.

The B/C ratio of bulk battery and distributed batteries is 0.28 and 3.02 respectively. Distributed batteries yield significant societal benefits, mainly through peak shaving (lowering prices) and also in making the generators in the system dispatch more efficiently. The availability of distributed storage reduces the commitment of inefficient generation and reduces system commitment and production costs. Distributed storage not only benefits the system as a generation resource but also as a transmission resource. A transmission investment with a B/C ratio of greater than one typically receives FERC approval and warrants capital cost recovery.

[3] Societal benefit is the total savings to the entire system due to reduced production cost and losses in the transmission system. The savings in the production cost is due to displacement of the high cost energy for some of the generators and increase in the utilization of the more efficient generators. In the case of distributed batteries which are located at approximately 60 nodes, the transmission congestion is mitigated and more efficient units can supply the loads. The output of less efficient units is further reduced due to their displacement less costly units.

The results indicate that investment in distributed storage does yield significant societal benefits and may warrant societal support for making the investment attractive.

The present value of net income over a period of 15 years is presented in Figure ES-4. The annual societal benefit of each storage option has also been included.

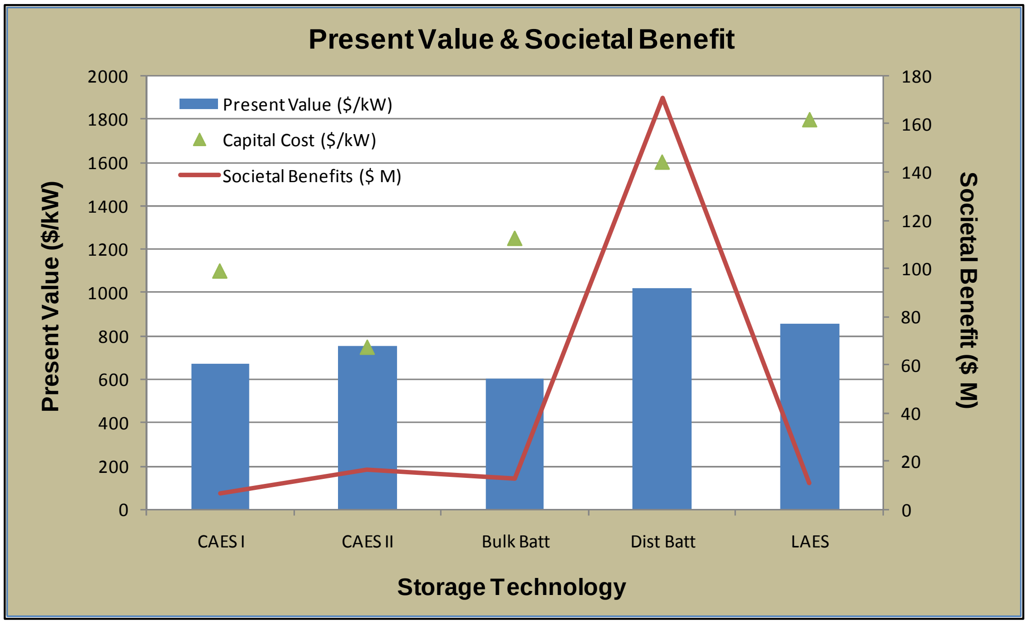


Figure ES-4 Present Value and Societal Benefit of Storage Technologies

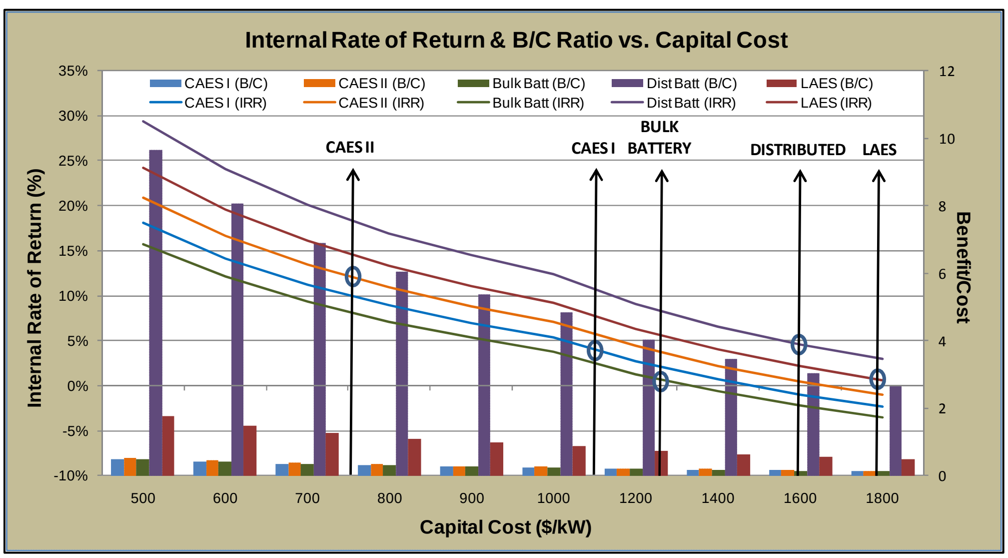


Figure ES-5 Internal Rate of Return (IRR) and Benefit/Cost ratio versus Capital Cost for various storage technologies

Recommendations

- In view of the large amounts of new wind generation anticipated to be deployed in the U.S. over the next 20-30 years, detailed granular market based regional and portfolio assessments and simulations of energy storage are needed – especially in the CAISO, PJM, MISO, and NYISO areas to estimate just how much energy storage is needed, the best locations for storage systems, and the interplay with T&D investments as a function of wind penetration.

- Second Generation CAES systems should be built and demonstrated to validate their installed cost and operating parameters.

- Lower cost non-CAES bulk energy storage options should be monitored and evaluated and demonstrated as they could be sited in T&D congested areas. These systems should be evaluated in applications where wind penetration is potentially significant but geological conditions required for CAES does not exist.

- Given the estimated large societal benefits of targeting distributed energy storage systems at key node points in Texas, further market based analysis of distributed systems in other US regions should be conducted including an assessment of policy and incentive considerations which could balance the societal benefits of distributed energy storage against the near-term high capital costs of such systems. As a first approximation, it appears that a 40% reduction in capital costs would be needed to overcome investment hurdles based on the assumptions used in this study including those related to ERCOT's post CREZ-2 scenario.

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INTRODUCTION AND BACKGROUND

Introduction

The goal of this study is to better understand the impacts of electrical energy storage systems, such as Compressed Air Energy Storage (CAES), advanced battery systems and Liquid Air Energy Storage (LAES) on the electric sector's economics, emissions and wind integration. A regional analysis is conducted to assess the value of these storage alternatives. ERCOT market acts as a perfect test bed for the analysis based on its pace of expansion and the body of public information. All the necessary simulations were done using the UPLAN network power model as an analytic platform.

Objectives

This project will conducts research and analysis to answer the following questions:

1. To what extent can first and second generation CAES systems increase wind utilization and penetration in ERCOT?
2. What are the emissions benefits of deployment of CAES systems?
3. Understand impacts of CAES in other regions in the US where coal generation is more significant than in ERCOT using the findings,
4. How can CAES investments interplay with transmission investments needed for wind penetration,
5. What are the economic benefits in terms of arbitrage, provision of ancilliary services (A/S) and reserve capacity and others?
6. What are the costs and benefits of a bulk battery energy storage system and the benefits of distributed battery systems in ERCOT?
7. What is the value of novel energy storage systems like liquid air energy storage (LAES)?

ERCOT Overview

ERCOT electricity system encompasses 75% of Texas' total land area and 85% of its load. It includes over 550 generation units, 40,000 miles of transmission lines and serves 22 million

Texas customers. Due to the favorable regulatory environment and future investments in transmission infrastructure wind energy is projected to continue its current trend of rapid development. It is likely that ERCOT's wind expansion is going to exceed forecasts, with growth encouraged by strong support of renewable energy in the form of the Production Tax Credit (PTC), Renewable Energy Credit (REC) and an extension of the Investment Tax Credit (ITC).

The Public Utility Commission of Texas (PUCT) is proactively supporting wind energy expansion plan via the Competitive Renewable Energy Zone (CREZ) process. PUCT has proposed an ambitious 18,456 MW of wind energy (Scenario 2) and approved 4.946 billion dollar investment in transmission system infrastructure. Texas is becoming a laboratory for studying the impact of large-scale wind energy implementation for years to come.

The corresponding phased transmission expansion is presented in Figure 1-1, which the regulatory body expects to be in service within four or five years. Large storage units can either defer the transmission investment or allow large amount of wind as envisioned in Texas CREZ Scenario 4.

Capacity of New CREZ Wind by Scenario (MW)				
Wind Zone	Scen. 1	Scen. 2	Scen. 3	Scen. 4
Panhandle A	1,422	3,191	4,960	6,660
Panhandle B	1,067	2,393	3,720	0
McCamey	829	1,859	2,890	3,190
Central	1,358	3,047	4,735	5,615
Central West	474	1,063	1,651	2,051
Total*	12,053	18,456	24,859	24,419

* Assumes 6,903 MW of existing wind capacity

Figure 1-1
ERCOT CREZ Scenario 2

Energy Storage Technologies

Today, different types of energy storage options are being developed of which some are available commercially while others are still in the experimental stage. The power and discharge ratings of different storage technologies and their applications can be seen in Figure 1-2. Energy storage systems placed in high wind areas should provide value by storing energy at times of low prices and generating at times of high prices. Out of the many technologies mentioned in Figure 1-2, only a few of them are capable of meeting the requirements of storing energy for wind balancing as well as being cost effective. Though advanced technologies such as flywheels and ultra-capacitors have the capability to provide short duration services related to power quality and stabilization, they are not cost effective options for wind generation support, whereas CAES and large battery systems are suitable for both long duration (tens of hours) as well as utility scale (100's to 1000's of MW) applications.

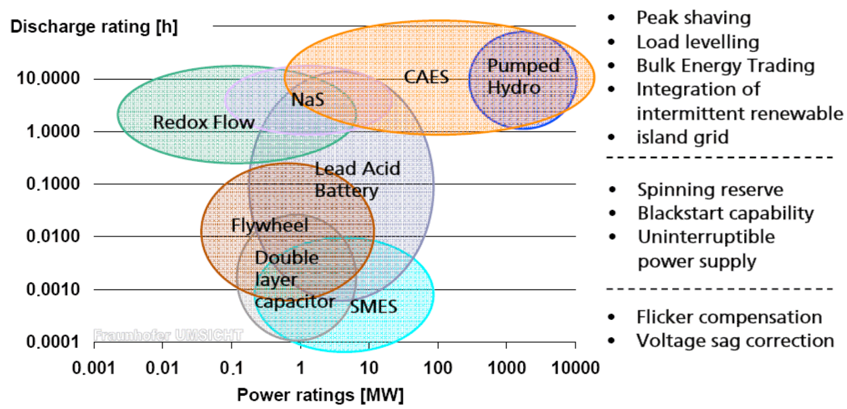

Figure 1-2:
Applications of different storage technologies[4]

Given the scope and objectives of this study, the goal was to focus on a limited set of energy storage options. CAES, Battery systems and Liquid Air Energy Storage (LAES) are selected for this study, based on their capability to support integration of renewable generation as well as their cost effectiveness. A brief description of each of these technologies is given below:

Compressed Air Energy Storage

CAES is designed to draw electricity off the grid to compress air in an underground storage cavern and then release the high-pressure (typically over 1000 psi) air at a later time to enable combustion turbine-based generation using much less fuel than would otherwise be required, since there is no need to compress the already-compressed air. In effect CAES "stores electricity" for injection to the grid at a later time.[5],[6]

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[4] C. Doetsch, S. Berthold, D. Wolf, T. Smolinka, J. Tulbke, P. Bretschneider, and P. Radgen, "Electrical energy storage from 100 kW – state of the art technologies, realizations, fields of use," in Second International Renewable Energy Storage Conference (IRES II) Bonn, Germany, 2007.

[5] See " Compressed Air Energy Storage State of Science", EPRI Technical Brief, 1020444, 2009.

[6] See " Compressed Air Energy Storage Technical Cost Update" EPRI 1016004, 2008.

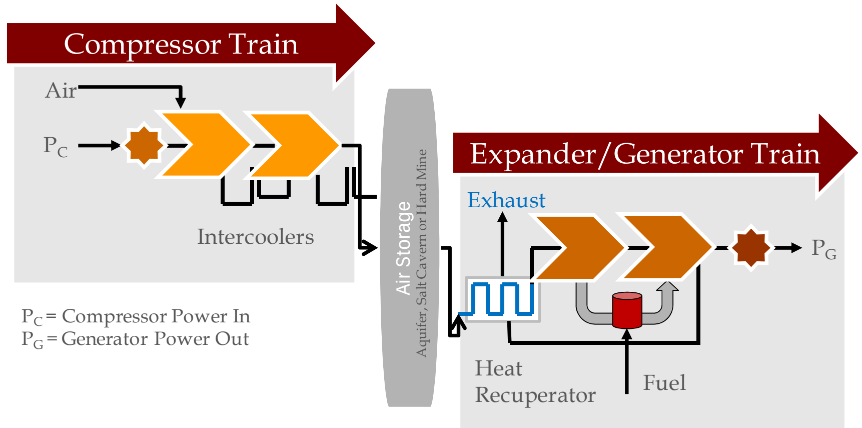


Figure 1-3
CAES System Concept

To be economical, the charging of the CAES must occur when the market prices are low enough and discharge at a later time when the prices are high. This represents the "shaping" or "temporal arbitrage" value of CAES . Additionally, because it can be dispatched when needed (as long as there is compressed air in storage) and has a quick response time, CAES can also be valuable for providing ancillary services such as regulation, spinning or non-spinning reserve, and can provide long-term dependable capacity that a load serving entity might otherwise have to procure elsewhere at a cost. Finally, transmission credit may be attained due to reduced transmission line capacity requirement at peak wind. This study examined two CAES system options: 1st generation systems which are commercially available and have been proven; and 2nd generation CAES systems which offer improved efficiency, and lower capital costs but have not been demonstrated at this time.

First Generation CAES systems are typical of the Alabama Electric Cooperative 110 MW – 26 hr system which has been in commercial operation. Second Generation CAES systems represent an improved design which features the use of a conventional gas turbine system and enables lower costs and improved efficiency. The system shown in Figure 1-1 modeled in this study is planned to be demonstrated by 2013 by EPRI and a consortium of electric utilities.

Battery Storage

Utility scale batteries are made of stacked cells and the desired battery voltage and current levels are obtained by electrically connecting these cells in series or parallel. The batteries are rated in terms of their energy, capacity, efficiency, life span (stated in terms of number of cycles), operating temperature, and charge and discharge rates.

Among them, the lead-acid battery is the oldest and most mature technology, which has been used for a majority of power system applications. Advanced lead acid batteries offer improvements in cycle life and durability and are being demonstrated in early field trials. The sodium-sulfur (NaS) and several types of Redox flow batteries are the most mature and commercial, while lithium-ion (Li-ion) batteries are still emerging and represent the leading technologies in high-power-density battery applications. Since these types of cells are being considered for PHEV and EV transportation applications, these cells possess the greatest potential for future development and optimization. In addition to small size and low weight, these batteries also offer the highest energy density and storage efficiency, which makes them ideally suited for portable devices. However, one of the major drawbacks of Li-ion technology is high cost due to high materials and manufacturing costs.

Although lead-acid batteries can supply excellent pulsed power, they are large and bulky, have limited cycle life and suffer from severe self-discharge. Several advanced lead acid battery systems are now under development and ready for field demonstration, which offer improved costs and cycle life.

The flow batteries (such as Zn / Br and vanadium redox) are also promising for applications that require long duration storages. For the ERCOT battery simulation, a bulk battery system was assumed using characteristics of an advanced lead acid or flow battery, however, the results are applicable to any battery with the assumed characterizes, cycle features and costs. Characteristics of Li-ion batteries were assumed for the distributed energy storage analysis, but again the results are applicable to any battery or storage systems with the assumed fcharacteristics, cycle features and costs. Characteristics of Li-ion batteries were assumed for the distributed energy storage analysis, but again the results are applicable to any battery or storage system with the assumed featuers. .

Liquid Air Energy Storage

Liquid air storage cycles (LAES) store air in liquid form. Working of the LAES is almost similar to that of the CAES except that during off-peak hours air is cooled and liquefied and stored at atmospheric pressure, much like liquefied natural gas, and during peak periods this stored liquid air is pumped and fed to the combustor of the gas turbine.

Figure 1-4 shows the schematic of the Liquid Air Energy Storage (LAES) system. At the off-peak hours when the demand is less, excess electric power is used to compress the air and this compressed air is cooled as it passes through the cool storage unit. The cool compressed air that is obtained is expanded to atmospheric pressure, liquefied and stored in the storage tank. During the peak demand hours, the stored liquid air is pumped up to high pressure and heated by the flue gas of the combustion turbine. Electricity can be produced by both expansion of this heated air and combustion and expansion in the gas turbine. This process utilizes only about 5% of the power that is consumed by an ordinary compressor to produce almost double the power that is normally generated by a gas turbine.

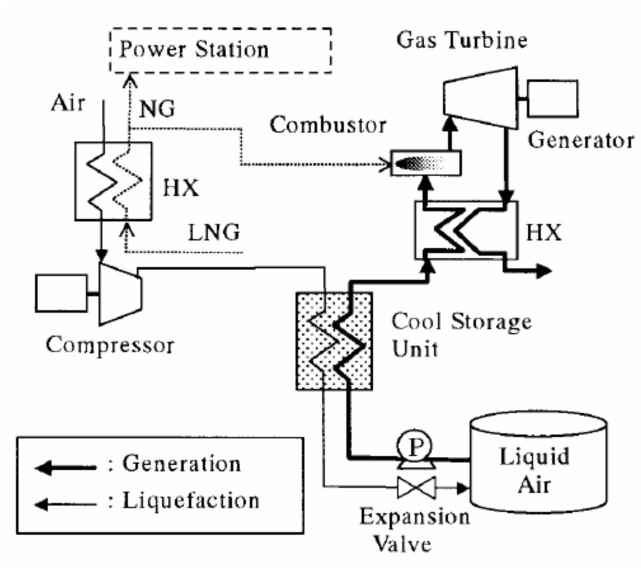


Figure 1-4
Example of Liquid – Air Energy Storage[7]

Report Organization

The remaining sections of this report are organized as follows:

Chapter 2 describes the modeling approach of the ERCOT system, assumptions related to the generators, load, transmission and the fuel prices that were used in the study.

Chapter 3 presents an overview of the characteristics, assumptions, location and performance of CAES. The impacts of CAES on LMPs, wind curtailment, transmission utilization and CO_2 emissions are also discussed The results of cost and revenue analysis of CAES are summarized including the investor and societal benefits.

Chapter 4 presents the battery storage analysis including operational and cost assumptions for the bulk and distributed battery scenarios. It also includes their performance and impacts and describes in detail the economic analysis performed.

Chapter 5 deals with the analysis of liquid-air energy storage in the ERCOT region. This chapter discusses the working, modeling methodology and operation of LAES. Results of the economic assessment have also been included.

Chapter 6 suggests potential areas for further research.

[7] Hidefumi Araki, Mitsugu Nakabaru, and Kooichi ChinoPower & Industrial Systems R & D Laboratory, Hitachi, Ltd., Japan, “Simulation of Heat Transfer in the Cool Storage Unit of a Liquid–Air Energy Storage System”, (journal name), Page 284, Heat Transfer – Asian Research, 31 (4), 2002 Wiley Periodicals, Inc.

2
ERCOT SYSTEM

Competitive Renewable Energy Zones (CREZ)

The Texas Renewable Portfolio Standards (RPS) have led to a steady rise in the state's wind capacity. The major obstacle in the development of wind energy in ERCOT is inadequate transmission capacity to carry wind from the wind rich areas in West Texas to the loads in the South and East areas. Competitive Renewable Energy Zones (CREZ) have been created as a part of SB20 to ensure that there is sufficient transmission infrastructure to move renewable energy to the energy markets. Large transmission lines will be added to better accommodate the needs of the wind generation.

After evaluating the potential for wind generation, in July 2007 the PUCT designated eight areas as CREZ. These were then combined into five zones in the areas around McCamey, Abilene and Sweetwater, and the Panhandle.

Table 2-1
Wind Capacities for different ERCOT CREZ Scenarios

	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 3 (MW)	Scenario 4 (MW)
CREZ Wind Capacity	5,150	11,553	17,956	17,516
Base Case Wind	6,903	6,903	6,903	6,903
Total Wind	12,053	18,456	24,859	24,419

The ERCOT system planning report that was published in April 2008 outlined four scenarios for building the CREZ transmission lines, based on the cost and number of wind farms built. A large portion of the proposed new wind energy is from the Panhandle region and most of it flows to the Dallas/Fort Worth load center since it follows the path of least resistance.

This study focused on the post-CREZ 2 scenario where transmission investments were already assumed to be made. In view of this assumption, the results and findings presented later in this report may underestimate the value of energy storage for regions where transmission investments have yet to be made.

The CREZ wind capacities that are considered for the different scenarios are presented in Table 2-1. As mentioned, this study is based on Scenario 2. The estimated total cost of this scenario is about $4.946 billion and the estimated collection cost is in the range of $580 to $820 million. In this plan, 820 MW of existing wind generation was moved to new interconnection locations. 2334 miles of new 345 kV and 42 miles of new 138 kV lines will be used to transfer most of the CREZ wind. The other characteristics of this scenario are listed in

Table 2-2. The model used for the study includes detailed transmission representation including approximately 5000 potential contingency lines that dictate power flow and congestion management.

Table 2-2
Transmission characteristics of CREZ Scenario 2

Characteristics	Value
No. of transmission lines	7,160
Congestion Management Zones	4
N-1 Contingency Lines	4,550
N-2 Contingency Lines	682
N-3 Contingency Lines	32
N-4 Contingency Lines	10
Special Protection Schemes	54

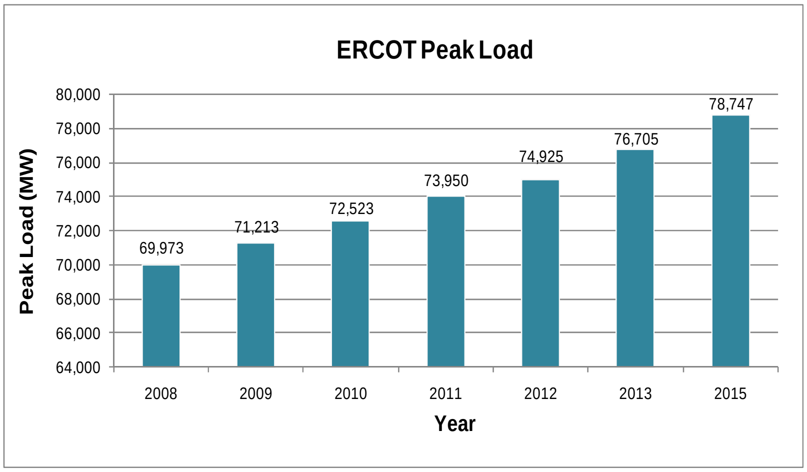
Source: LCG Consulting

Key Assumptions

The UPLAN model and its associated proprietary database was used as the analytic framework for this study. The model consists of the latest projections of the generation, loads, transmission, contingencies, special protection schemes and Locational Marginal Price (LMP) data for the ERCOT electricity system. EPRI provided cost and performance inputs related to CAES systems, liquid air, bulk energy storage, and distributed energy storage systems.

Electricity Demand

The total peak demand and the total energy demand that have been used in this study are based on the projected peak load data published by ERCOT up to the year 2012. Using historical profiles and these forecasted peak values, loads for the study year 2015 were developed using a load growth rate of 1.8%. The peak demands for the years 2008 – 2015 are shown in Figure 2-1.



Source: LCG Consulting

Figure 2-1
Peak load (MW) for years 2008 - 2015

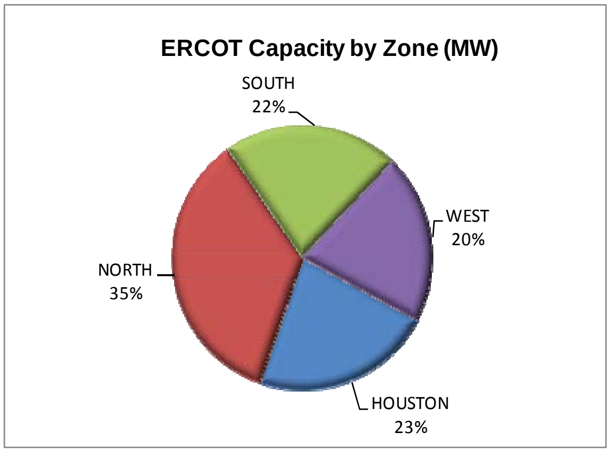
The transmission network modeled in UPLAN consists of 5,770 buses out of which 3,160 are load buses. Chronological (8,760 hours/year) load shapes are developed from the hourly load data published by ERCOT in its Transmission and System Planning Report. Using this shape for each demand area, load is distributed based on a fixed load distribution factor (LDF) to all the load buses in that area. The reserve requirements are also included in the load forecast for each demand area.

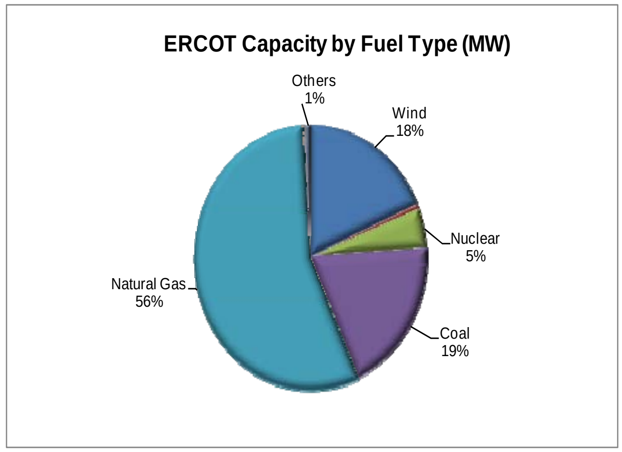
Generation

ERCOT generation for 2015 by fuel type and by zone is shown in Figure 2-2. As can be seen, generation in the ERCOT region will continue to be dominated by fossil fuel powered generators. By 2015 the wind capacity would increase from 10% to 17% of total installed capacity.

About 640 generators, including the future (expansion) units, are characterized in detail in LCG's PLATO database and are incorporated in UPLAN electricity market simulations. Generator operations are modeled using more than 100 electrical and economic parameters such as fuel type, heat rate, ramp rates, emission factors, outage rates and capability to provide different ancillary services.

One of the major tasks in this study is the modeling of wind energy generation. The output of wind turbines is not controllable and dispatchable. In West Texas, wind tends to blow the highest in spring and generally lowest in the summer-early fall periods when the ERCOT load is the highest. The daily wind profile in West Texas is such that most of the wind is available during night and off peak hours and there is less wind during the peak demand hours. Figure 2-3 shows that the wind pattern across Texas is out of phase to the electrical load.



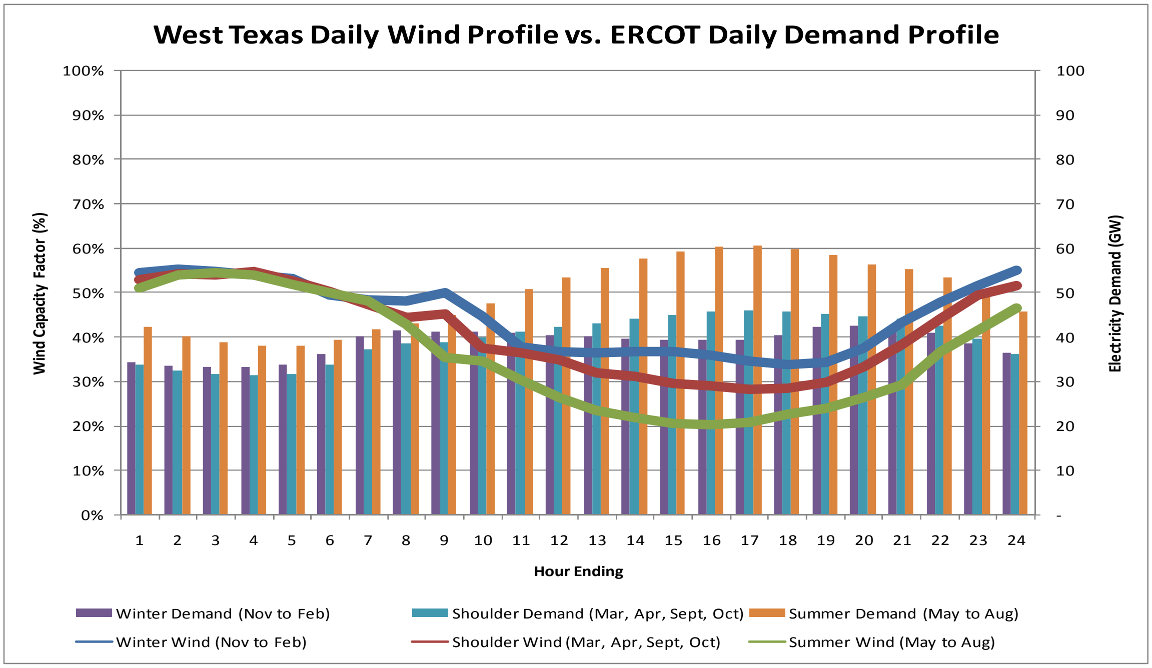


Source: LCG Consulting

Figure 2-2
ERCOT generation by zones and fuel type for the year 2015

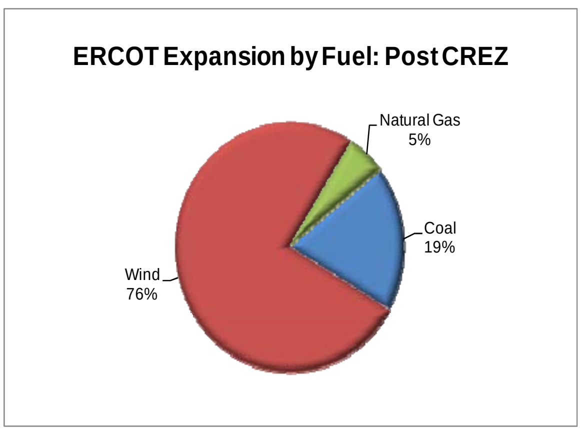
In this study, wind generators dispatch is based on hourly wind profiles published by ERCOT. Due to incentives such as production tax credits, wind generators in the West Zone have been observed to place negative bids at times gain dispatch preference over competing resources to utilize scarce transmission. In the post-CREZ scenario, negative bidding may not be necessary as adequate transmission will be available. Consequently, there is no variable cost that is assumed for the wind generators and they are bid as price takers. There are no forced outages modeled for these wind farms either.

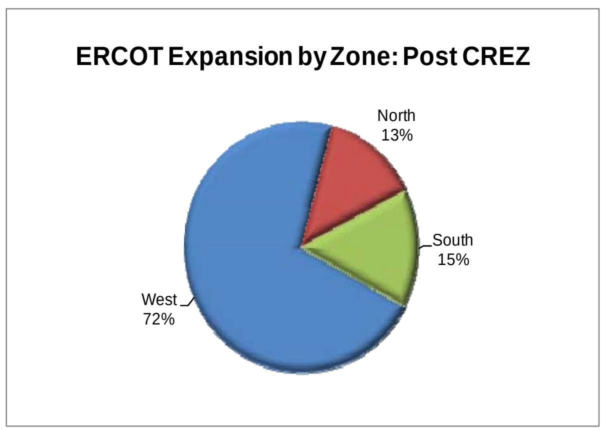
In order to assess the impact of storage on emissions (especially CO_2) emission rates for each generator in the ERCOT system were specified. However, no carbon cost was assumed to alter the nature of generator dispatch. Additional scenarios with different a carbon cost could be analyzed to quantify the effect on storage performance and emissions. Generation expansion in the Post CREZ scenario by fuel type and by zone is shown in Figure 2-4.



Source: LCG Consulting

Figure 2-3
West Texas wind profile vs. ERCOT daily demand profile





Source: LCG Consulting

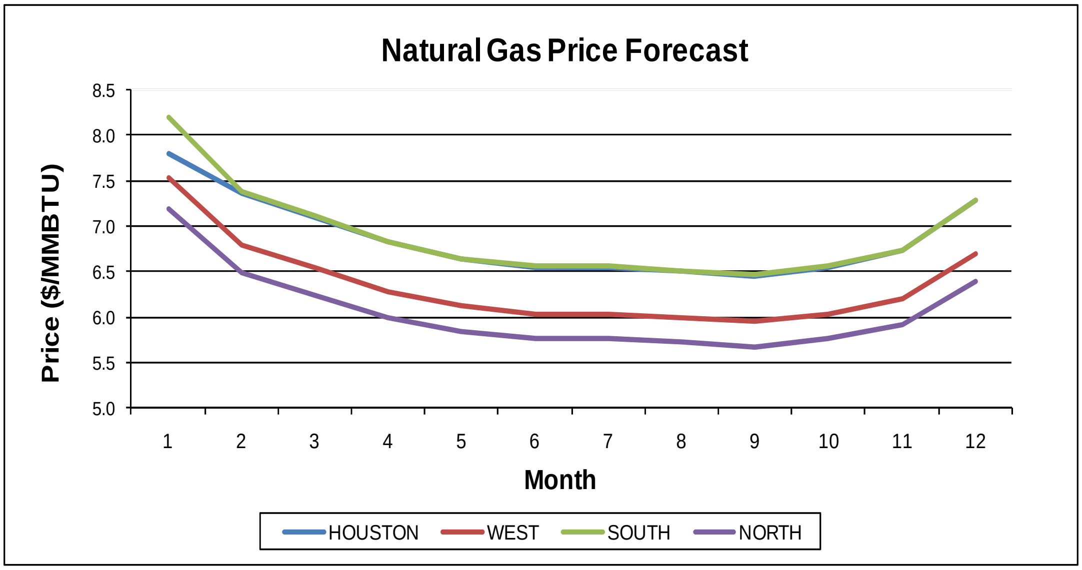
Figure 2-4
Generation expansion – CREZ Senario 2

Fuel Prices

The fuel price forecasts are developed from a number of sources, including DOE forecasts, NYMEX future contracts, hub delivery indices and other publicly available information on fuel costs.

Natural Gas Prices

With natural gas comprising the majority of the installed capacity, energy costs by zone can fluctuate greatly with the natural gas prices. Natural gas prices forecasted by LCG for the study year 2015 is shown in Figure 2-5. In order to simplify the presentation of electricity prices, they are converted to $/MMBTU.



Source: LCG Consulting

Figure 2-5
Natural Gas Price Forecast for 2015 by zones

Coal and Fuel Oil Prices

The coal and distillate fuel oil (FO2) prices used in this study were obtained from EIA's Annual Energy Outlook 2009. As only the gas generators are on the margin most (90%) of the time, the price of coal does not have much impact on ERCOT market prices.

Transmission network

The simulation consisted of nearly 7,000 network elements which include the already existing elements as well as the upgrades as proposed in the CREZ scenario 2. The power flow case for study year 2015 developed by ERCOT was used for network simulations. The model contains 4,469 N-1 contingencies, 685 N-2 contingencies, 32 N-3 contingencies and 10 N-4 contingencies. Special Protection Schemes (SPSs) are employed by ERCOT to meet system performance requirements even under the occurrence of the specified N-x contingencies that might otherwise require redispatch to maintain network security. About 41 SPSs were used in the simulation to maintain network security. These SPSs were identified and published by ERCOT as part of its transmission planning studies.

3
COMPRESSED AIR ENERGY STORAGE ANALYSIS

Overview of the Simulations

This study represents a fundamental simulation of market dynamics that is performed based on very detailed characterization of the ERCOT generators and transmission network along with realistic representation of the market protocols. The analysis of energy storage devices in the ERCOT market is carried out in two phases:

- Base case simulation (without any storage device)
- Simulations with first and second generation CAES units

The base case simulation depicts a detailed, chronological simulation of the day-ahead market for the entire ERCOT system that includes load growth, generation expansion, generation retirements, transmission upgrades (based on CREZ Scenario 2) and fuel forecasts for 2015. The simulation projects the system-wide hourly LMPs, ancillary services, capacity factors, costs and revenues. The values obtained from the base case scenario provide a baseline to evaluate the benefits of CAES.

Both the CAES evaluation scenarios are built from the base case scenario with different CAES configurations. The first scenario consists of a 268 MW first generation CAES placed at bus INDN4A in West Texas and the second scenario consists of two 200 MW second generation CAES units placed at the same bus, INDN4A. The performance of these units and their impacts on the system are presented in the following sections.

Operational Characteristics of CAES

This study analyzes the impact of two different CAES configurations and their operating characteristics are given in Table 3-1. The 1st generation CAES (CAES I) is commercially available and proven while the 2nd generation system (CAES II) is planned to be demonstrated in 2-3 years by EPRI and a consortia of electric utilities.

The size of CAES units plays a major role in the assessment of their value to the system. Bigger sizes can result in higher depression of peak LMPs thereby making it more attractive than it actually is. Degradation of LMPs means that when electricity is used for compression, the off-peak LMPs are elevated and when there is generation from the CAES, the LMPs are depressed. Selecting lower CAES sizes might have limited value in enhancing the ERCOT market system. Therefore a minimum size of 268 MW is taken for CAES I and two identical units of 200 MW each are taken for CAES II. As presented in Table 3-1, the second generation CAES II units have better operating characteristics than CAES I.

Table 3-1
Characteristics of CAES I[8] and CAES II[9][10]

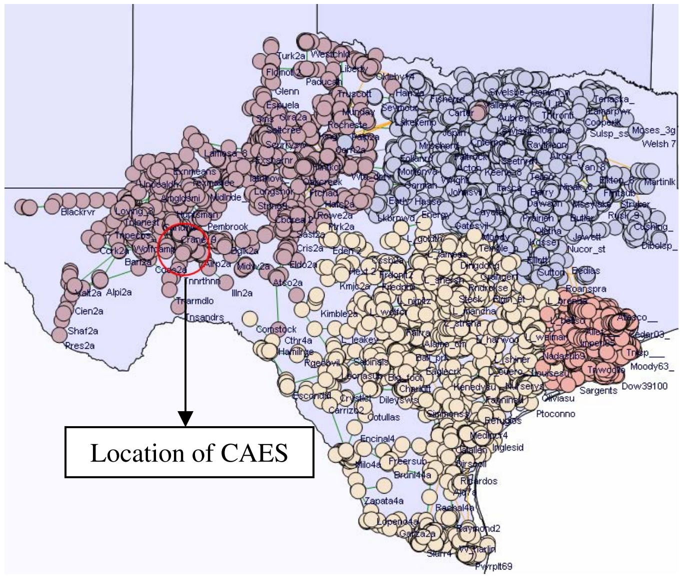
Operating Parameters	CAES I (1st generation)	CAES II (2nd generation)
Generating Capacity	268 MW	400 MW
Compressor load	200 MW	288 MW
Heat Rate (LHV)	4424 Btu/kWh	3696 Btu/kWh
Ramp Rate	Full load in 10 minutes	Full load in 10 minutes
Energy factor (MWh consumed for compression/ MWh generated)	0.75	0.69
Working Storage Capacity	5000 MWh	5000 MWh
Ability to provide Ancillary Services	Regulation Up & Down, Spinning Reserve, Non-Spinning Reserve (Startup time 10-15 minutes)	Regulation Up & Down, Spinning Reserve, Non-Spinning Reserve (Startup time 10-15 minutes)
Installed Capital Cost (Salt Geology)	$1100/kW	$750/kW
O&M costs Fixed Variable	 $3.6/kW-Yr $3/MWh	 $3.6/kW-Yr $3/MWh

Type and Location of CAES Storage Structures

The primary types of air storage structure within the West Texas close to the wind resources are salt beds, depleted gas fields and aquifers. Geological studies indicate that solution mined salt beds are a better option for air storage. The major reasons that make salt beds desirable are their location near the major wind development areas (McCamey area in Upton and Pecos County) and their geological condition to support the full CAES design pressure. The cost effectiveness of any storage device depends greatly on two factors - physical feasibility and cost of the added storage, both of which are site specific. The location selected for placement of CAES units in this study is bus INDN4A (ERCOT ID: 6584) in the McCamey region (Figure 3-1).

[8] Compressed Air Energy Storage Feasibility and Risk Assessment, LCG Consulting Study, 2004
[9] New Utility Scale CAES Technology: Performance and Benefits (Including CO2 Benefits). Robert B. Schainker (EPRI, USA), Michael Nakhamkin (ESPC), et al.

[10] See “ Compressed Air Energy Storage Technical Cost Update” EPRI 1016004, 2008.



Source: LCG Study for suitable storage locations

Figure 3-1
Location of CAES units in the ERCOT region. The small circles are the electricity grid nodes.

Modeling Methodology of CAES in UPLAN

LCG has developed a fully integrated simulation of CAES within the overall electricity market-network model based on locational electricity prices, security constrained commitment and dispatch and interaction of energy and ancillary service markets. The CAES simulation considers the following CAES operational parameters and constraints:

- Maximum storage capacity (MWh),
- Hourly maximum charging and discharging MW capacity,
- Efficiency of the unit (MWh consumed/ MWh generation),
- Initial storage in MWh, and
- Ramp rate

The simulation involved a realistic projection and evaluation of the market prices to optimize the operations of CAES units. The price feedback mechanism and internal CAES optimization work together to represent CAES load during off-peak hours and CAES generation using storage during on-peak hours. Optimization of the CAES operation takes place in three steps:

Determine initial LMPs: The LMPs at all the nodes are produced by running UPLAN's Day-Ahead market model. The initial LMPs along with the CAES characteristics are used in the next Initial Optimization step.

Initial optimization of operation: The prices obtained from the previous step are used to set up the LP optimization program. This program optimizes the total profit resulting from the operation of the storage which is subject to hourly charging and discharging constraints. The solution obtained thereby provides optimal schedules of charging and discharging for each hour of the year 2015 taking into account the maximum storage capacity and efficiency of the storage.

Price feedback: The schedule obtained in the optimization step is optimal. But this may not be always feasible due to transmission security constraints. Moreover, the LMP at the CAES bus may change due to the charging and discharging of CAES. Thus, the actual (simulated) optimization of CAES operation is based on each day's day ahead market and any necessary day-of adjustments, reflecting a host of influences on markets and dispatch.

Results: Performance of CAES

The performance of CAES units in the ERCOT market is highly dependent on their size and location. Two different sizes and configurations of CAES units were considered in this study. The first generation 268 MW CAES unit placed at bus INDN4A, achieves an annual capacity factor of 34.36% whereas the two 200 MW second generation CAES units, CAESII_1 and CAESII_2, which were also placed at bus INDN4A achieve an annual capacity factor of 40.24% and 40.35% respectively.

Irrespective of the configuration of the units, the capacity factor was high during peak demand months which reflect the increase in the number of favorable hours of operation and thus arbitrage during those months.

In the UPLAN market simulation, hourly operation of CAES is optimized using the look-ahead logic in order to maximize the income. As expected the CAES units charge during off-peak hours when the LMPs are low and discharge during the peak hours when the LMPs are high. CAES has the ability to moderate the occasional high peak prices by lowering them during the summer peak load. Similarly it also moderates strong dips in the off peak prices that occur in the McCamey area.

In addition to selling into the energy market, CAES also supplies the ancillary services (A/S). In order to participate in the ancillary services market, sufficient reserves have to be maintained in storage. The CAES units are well suited to provide regulation, spinning and non-spinning (quick start) reserves. The A/S markets provide considerable revenues, mostly during the summer months, and improve the net revenues of CAES. CAES operations are typically driven by greater a energy arbitrage during the high wind months due to greater wind and lower off-peak LMPs. In the summer months, in addition to energy arbitrage, CAES also participates in the A/S markets due to higher A/S prices (higher opportunity costs in summer due to higher LMPs).

Results: Impacts of CAES

Locational Marginal Prices (LMPs)

The value of CAES is evaluated taking into consideration the peak and off peak prices at the bus INDN4A where it is placed. CAES operation seems to moderately increase the off-peak prices and decrease the peak prices. These price differences are greater with CAES II than with CAES I primarily due to efficiency differences.

Transmission Utilization and Wind Curtailment

In CREZ Scenario 2, minimal wind curtailment is projected due to the availability of adequate transmission to support the planned wind expansion. ERCOT will incur a significant cost of approximately $4.9 billion in transmission builds to support this generation, primarily to reduce wind curtailment during off-peak hours. The planned transmission is underutilized during the peak hours. CAES serves as an alternative and its addition helps in reducing curtailment at increased levels of wind penetration and aids in deferring transmission investment. These effects are quite small when adequate transmission is available. Addition of CASE I resulted in 0.15% lesser wind curtailment compared to the case without any storage and addition of CAES II resulted in 0.19% lesser wind curtailment. However, at increased levels of wind penetration beyond Scenario 2 (pre-CREZ with insufficient transmission or CREZ Scenario 3 wind generation capacity at nearly 25,000 MW), high wind generation during off-peak hours will increase wind curtailment. This occurs when off-peak wind generation overwhelms export transmission capacity. CAES arbitrages and profits from higher wind generation and also aids in optimizing transmission utilization.

The reason for reduced curtailment is that when CAES units are added, there is lesser congestion in the CREZ lines thereby enabling approximately 100 GWh more wind energy to be delivered annually. During the off peak hours, CAES draws power to charge which is reflected by high forward flow (towards INDN4A) and lesser reverse flow (away from INDN4A). During the peak hours the stored energy is generated by CAES and hence the reverse flow is high and forward flow is less. Since both the CREZ lines and non CREZ lines are used to serve the loads during peak hours, there is reduction in the transmission utilization with CAES compared to the base case. The annual reduction in the transmission utilization is 12% with CAES I and 8% with CAES II.

CO_2 and Other) Emissions

As part of the study, the impact of CAES on emissioins of CO2, NOx and SOx were also analyzed. UPLAN calculates the total emissions of each generator based upon their fuel consumption. The emission data obtained from EPA and ERCOT Long Term System Assessment Report used in the emission calculation is summarized in Table 3-2.

Table 3-2
Summary of Input Data for Emission Calculations

	CO_2 (lb/mmbtu)	NO_x (lb/mmbtu)	SO_x (lb/mmbtu)
Lignite	217	0.10	0.50
Sub-bituminous Coal	205	0.05	0.10
Combined Cycle	118	0.03	-
Combustion Turbine	118	0.03	-
CAES	118	0.03	-

In addition to the increase in wind generation, coal fueled generation has also increased to serve storage loads, as a consequence helping reduce off-peak minimum load issues. As a result, annual system wide CO2 emission have increased by 0.07% with CAES I and 0.10% with CAES II. These small changes in wind curtailment and emission reductions may be greater at higher levels of wind and storage penetration.

The simulations demonstrate a clear interaction of storage with fossil based generation, especially coal. Interestingly, even with the 400 MW pilot CAES unit, coal generation benefits from storage capability in the ERCOT system and marginally increases emissions. In other regions such as MISO and PJM, where coal is the dominant fuel and wind generation continues to surge, storage may have a more significant impact on wind intermittency management, mitigating of backing down and minimum lower operation of coal units due to excess wind. Greater benefits to storage might be seen from energy arbitrage and increased ancillary services requirements. Further market based analysis in regions such as MISO, PJM, CAISO and NYISO is necessary to adequately understand the system benefits of storage in regions with different mixes of generation and other influences.

Cost and Revenue Analysis

Cost Assumptions for CAES

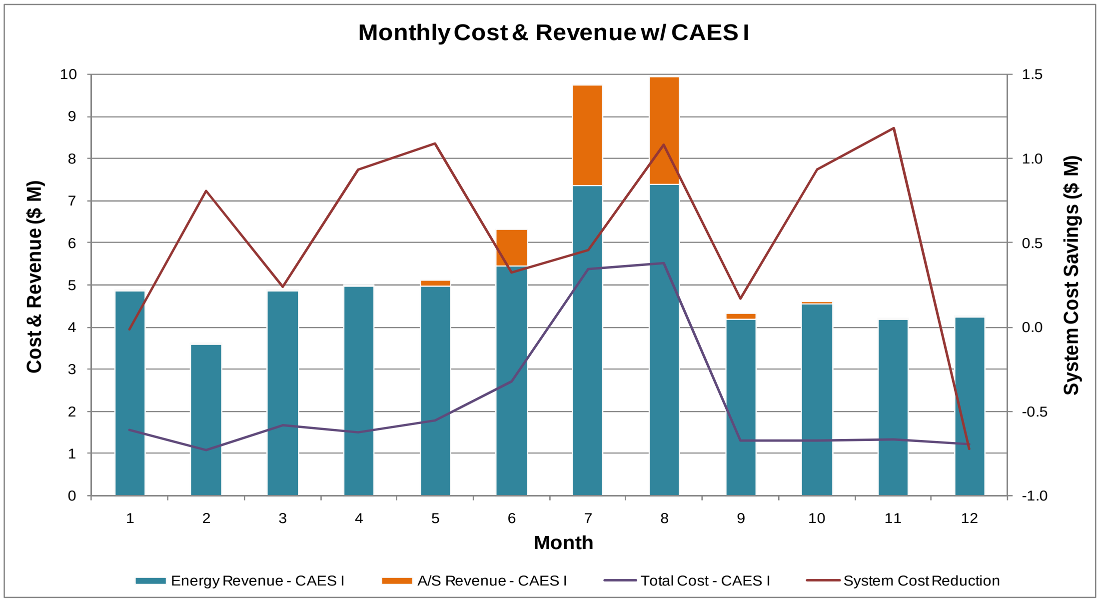
The input cost data used in the economic analysis of CAES is summarized in Table 3-3. The data is based on EPRI studies, a review of other studies and LCG's independent research.

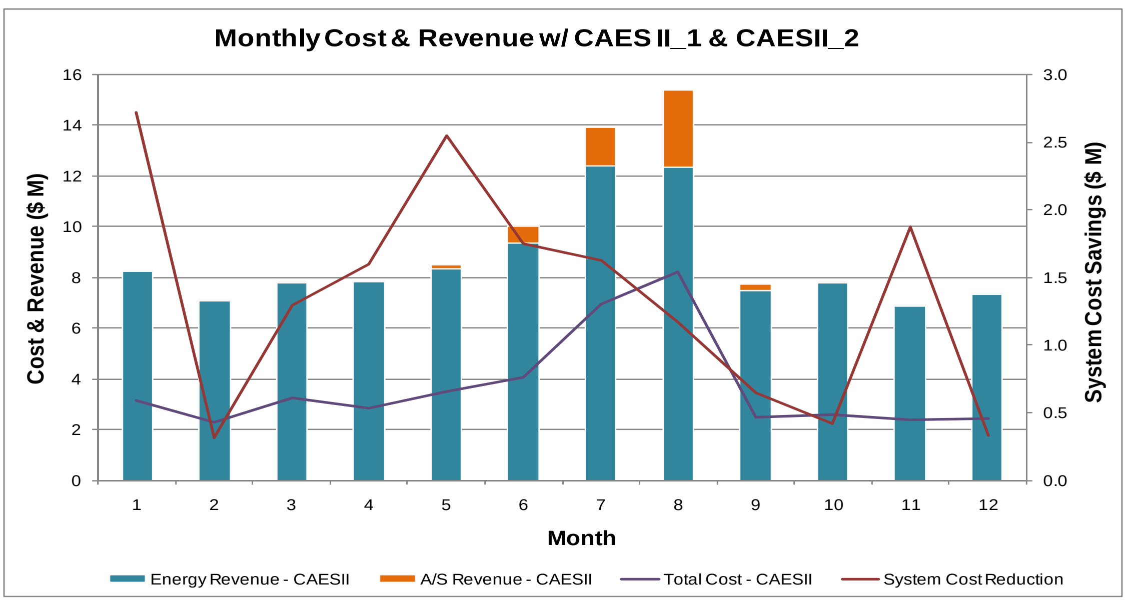
Table 3-3
Summary of cost data for CAES economic analysis

Description	Value
Variable O & M	$ 3 – 4/ MWh
Fixed O & M	$ 4/ kW-yr
Investment Cost	CAES I - $ 1100/ kW CAES II - $ 750/ kW

Costs and Revenues

UPLAN simulation produces the total revenues, costs and net income of all the generators in the system. The total revenues accounts for the energy revenues, the A/S revenues and other revenues such as no load and startup revenues. The total costs incurred include fuel costs, fixed and variable O&M costs, and startup costs.





Source: LCG Consulting

Figure 3-2
Monthly Costs and Revenues with CAES I and II

The system production cost decreased with the addition of CAES. CAES competes with other generation in ERCOT to displace inefficient generation and lower the system production cost. The annual savings in the production cost is nearly $6.5 M with CAES I and $16.32 M with CAES II. Figure 3-2 shows the costs, revenues and savings in production cost by month for both configurations of CAES.

Benefits

The economic benefits with the addition of CAES are presented in this section.

Investor Benefits

The benefits of CAES from an owner's or investor's perspective are assessed by means of the net operating income. The net operating income is driven by the operating costs and revenues from selling energy and ancillary services, all influenced by simultaneously derived ERCOT-wide generator dispatch and day-ahead energy and ancillary service market prices. Table 3-4 outlines these benefits.

Table 3-4
Investor Benefits with CAES I and CAES II

Description	CAES I	CAES II
Total Operating Revenue ($ M)	66.70	108.43
Total Operating Cost ($ M)	40.30	64.13
Total Net Income ($ M)	26.40	44.30
Internal Rate of Return (%)	3.94	12.11

The net operating income is operating revenues less the operating costs. As seen in Table 3-4, CAES II has a higher net income compared to CAES I because of a higher capacity installed. Net operating income generally increases with more availability of wind as it increases the supply of low-cost electricity for compression during the off peak hours. The internal rate of return (IRR) is higher for CAES II compared to CAES I due to its higher efficiency and a lower capital cost. UPLAN simulations were carried out for 2015 only. However, the IRR calculations are based on operating life of 15 years for the storage unit. We assume that the 2015 simulation is representative of the entire operating life of 15 years. In a commercial analysis of such an investment, year by year analysis of performance under multiple uncertainties would be undertaken to develop a fuller appreciation of risk and returns.

Societal Benefits

From a societal standpoint, the decreased congestion and correspondingly lower cost of meeting energy demand due to CAES represents a net benefit to the system. Investments in CAES increase the efficiency of the electricity system, lower the costs to consumers, modify the amount and allocation of producer's profits and make the system more reliable. CAES I and CAES II units yield a net societal benefit of approximately $6.5 M and $16.3 M respectively. Results on storage performance and the calculation of societal benefits are summarized in Tables 3-5 to 3-8.

For consumers, surplus is the difference between the amount they pay for the electricity (market prices or zonal LMPs) and the amount that they would be willing to pay (demand bid). Considering that the demand bids are the same, the changes in consumer surplus is the difference in the amount that the consumers pay for electricity with and without CAES. For the producers or generators, the surplus is measured by the difference between their revenues and their production costs.

Summary

A summary of the results for first and second generation Compressed Air Energy Storage options is included below.

Table 3-5
Storage Performance for First Generation CAES

	# Charging hours	# Discharging hours	Capacity factor	Energy Rev.	A/S Rev.	Net Income	Societal benefit
	(hrs)	(hrs)	(%)	($ M)	($ M)	($ M)	($ M)
CAES I	3060	3029	34.36	60.47	6.23	26.40	6.50

Table 3-6
Societal Benefits for First Generation CAES

System Wide Savings	CAES I ($ M)
Production Cost Savings/ Net Societal Benefit	6.50
Changes in Producer Surplus	-70.61
Changes in Consumer Surplus	103.59
Congestion Cost Savings	26.48

Table 3-7
Storage Performance for Second Generation CAES

	# Charging hours	# Discharging hours	Capacity factor	Energy Rev.	A/S Rev.	Net Income	Societal benefit
	(hrs)	(hrs)	(%)	($ M)	($ M)	($ M)	($ M)
CAES II_1	3425	3584	40.24	51.23	2.98	22.19	16.32
CAES II_2	3431	3587	40.35	51.37	2.85	22.11	

Table 3-8
Societal Benefits for Second Generation CAES

System Wide Savings	CAES II ($ M)
Production Cost Savings/ Net Societal Benefit	16.32
Changes in Producer Surplus	-21.95
Changes in Consumer Surplus	78.64
Congestion Cost Savings	40.37

The benefit to cost ratio (B/C ratio) was calculated using the present value of societal benefits over a period of 15 years. The B/C ratio of first and second generation CAES units was 0.22 and 0.35 respectively. This indicates that, for the post-CREZ scenario, investment in CAES does not yield significant societal benefits or warrant societal support for cost recovery.

4 BATTERY STORAGE ANALYSIS

This section includes the analysis and impacts of bulk as well as distributed battery storage and generation on the ERCOT system.

Simulation Scenarios

The analysis involves two scenarios:

Bulk Battery – This study scenario utilizes the CAES II scenario with 100 MW of CAES storage capacity replaced by a 100 MW bulk battery. Characteristics of and advanced lead acid (A-Pb) battery are used in this scenario. While an A-Pb battery was assumed, the results are applicable to any bulk storage option such as a flow battery, a sodium-sulfur (NaS), or an emerging system like Zinc - Air. The objective was to better understand the cost competitiveness of current and emerging bulk options for wind-integration applications.

Distributed Battery Storage – This scenario employs 240 MW of distributed storage and generation capacity. 120 batteries of 2MW each were placed at different demand buses across all the four zones. These buses were optimally chosen to provide the greatest arbitrage to the distributed storage and were identified from the base case based on the LMPs and are expected to provide the highest arbitrage with the greatest spreads between off-peak and peak electricity prices. Characteristics and projected costs of emerging lithium-ion (Li-ion) batteries are used for this analysis. Again, the results could be applicable to any distributed energy storage system which meets the technical and cost assumptions in Table 4-1.

Input Data and Assumptions

The operating characteristics used for the batteries are shown in Table 4-1.

Table 4-1
Technical characteristics of Bulk and Distributed batteries

Operating Parameters	Bulk battery (A-Pb)	Distributed battery (Li-ion)
Size (per battery)	100 MW	2 MW
No. of batteries	1	120
Energy Ratio (AC/AC efficiency)	85 %	85 %
Storage capacity	0.47 GWh	0.01 GWh
Pumping Size	100 MW	2 MW
Discharge hours	4 hrs	4 hrs

Source: Electric Power Research Institute

Operating parameters of the second generation CAES units used in the bulk battery scenario were presented in Table 3-1.

The bulk battery is placed at the same INDN4A bus at which the CAES units are placed. For the distributed storage scenario, two 2MW batteries are placed at 60 different buses spread across the Houston, North, South and West zones.

Table 4-2
Distribution of Li-ion batteries in ERCOT for distributed storage analysis

Zone	Number of 2 MW Li-ion batteries
Houston	42
North	38
South	28
West	12

Results: Performance of Batteries

In the bulk battery simulation, the battery and the CAESII unit were placed at the same bus. The annual capacity factor of the bulk battery was 17.75% and the CAESII_1 and CAESII_2 units perform at an annual average capacity factor of 41.32% and 41.33% respectively, similar to the CAES_II scenario.

In case of distributed batteries, the average capacity factors of the lithium-ion batteries are categorized by zones and are 19.5%, 21.62%, 20.04% and 21.51% for the Houston, North, South and West Zones respectively.

The batteries have significantly different operating and economic characteristics but behave similarly to the CAES units in charging during low price off peak hours and discharging during high price peak hours. The batteries are also capable of moderating the occasional peaks and valleys in the prices.

Results: Impacts of Batteries

Locational Marginal Prices

There is a marginal decrease in the peak LMPs by approximately $1.50/MWh at bus INDN4A at which the bulk battery and CAES II units are located and there is a marginal increase in the off peak LMPs, comparable to the changes in the CAES II scenario. This difference is consistent during the high load summer months whereas there are slight fluctuations in the off peak LMPs during the other months.

In the distributed battery scenario, the peak LMPs at the highest price buses decrease considerably in all the zones. The distributed storage units maximize their revenue opportunity by supplying the demand buses during peak load conditions and reducing the prices at their nodes in the process. For example, the bus with the highest arbitrage in North zone sees a drop of $3.50/MWh on average. The distribution of storage in the network can be further optimized based on changes to the network.

Wind Curtailment

The addition of Bulk batteries and CAESII units to the system reduces the curtailment in wind generation by an average of 0.18% annually, whereas the amount of wind curtailment remains the same with the addition of distributed batteries. It is known that most of the wind generation in the CREZ Scenario 2 is in the West Texas region. Due to the fact that only a dozen of the relatively small batteries are distributed in the West Zone, there is no impact of these batteries on reducing transmission congestion or wind curtailment.

Emissions

With A-Pb battery and CAES units, the CO2 emissions increase by 0.093 %. This is due to the increase in the amount of coal fueled generation and the additional emissions due to natural gas at CAES unit. In the distributed battery scenario, increase in the coal fueled generation, with no additional wind generation has resulted in an increase in the CO2 emission by 0.73% compared to the base case.

Results: Economic analysis

Cost Assumptions

The cost data that was used for this analysis is given in Table 4-3. The cost inputs of the CAES units used with the bulk batteries is outlined in Table 3-1. The costs shown below are assumed total installed costs for such systems; actual current systems costs may be much higher.

Table 4-3
Summary of cost data for Battery analysis[11]

Description	Bulk battery (A-Pb)	Distributed battery (Li-ion)
Variable O & M	$ 2.9/ MWh	$ 1.9/ MWh
Fixed O & M	$ 0.63/ kW-month	$ 0.42/ kW-month
Investment Cost	$ 1,250/ kW	$ 1,600/ kW

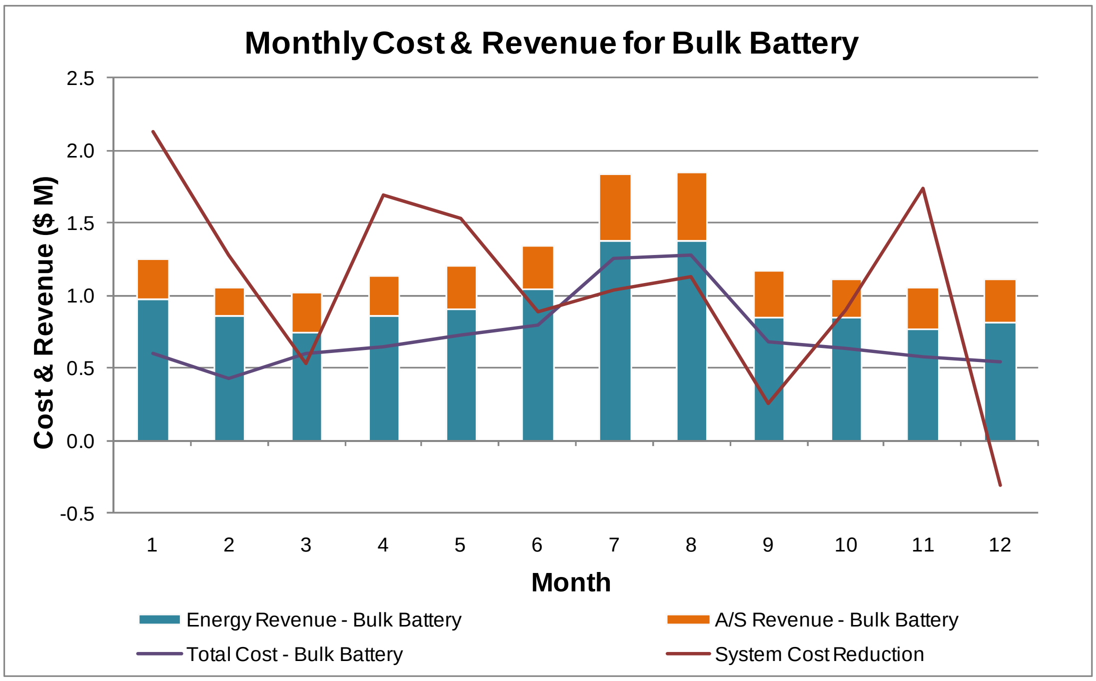
[11] Electric Power Research Institute

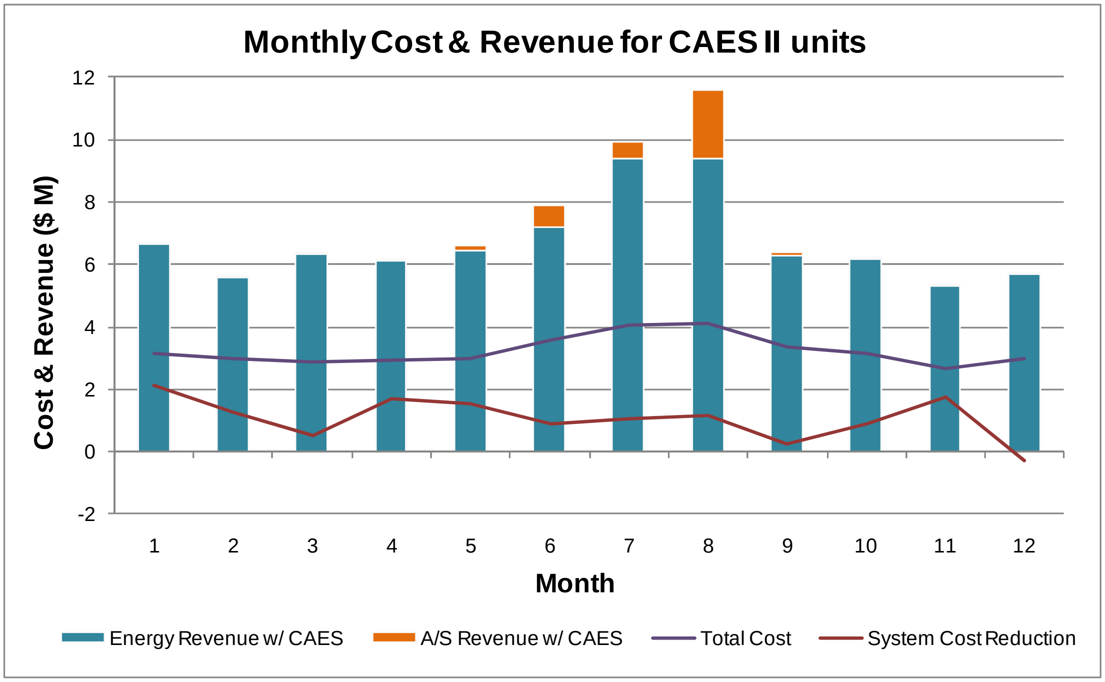
Costs and Revenues

The costs and revenues of the bulk battery and CAES units are presented in Figure 4-1.

The CAES units operate at a higher capacity factor than the battery due to a higher storage capacity and greater arbitrage potential. In the A/S market, the performance of the bulk battery is better compared to the CAES which participates in the A/S market only during the summer months. Therefore the bulk battery earns more A/S revenue than the CAES.

The overall system production cost is reduced by $12.83 M with both the bulk battery and second generation CAES units in operation.

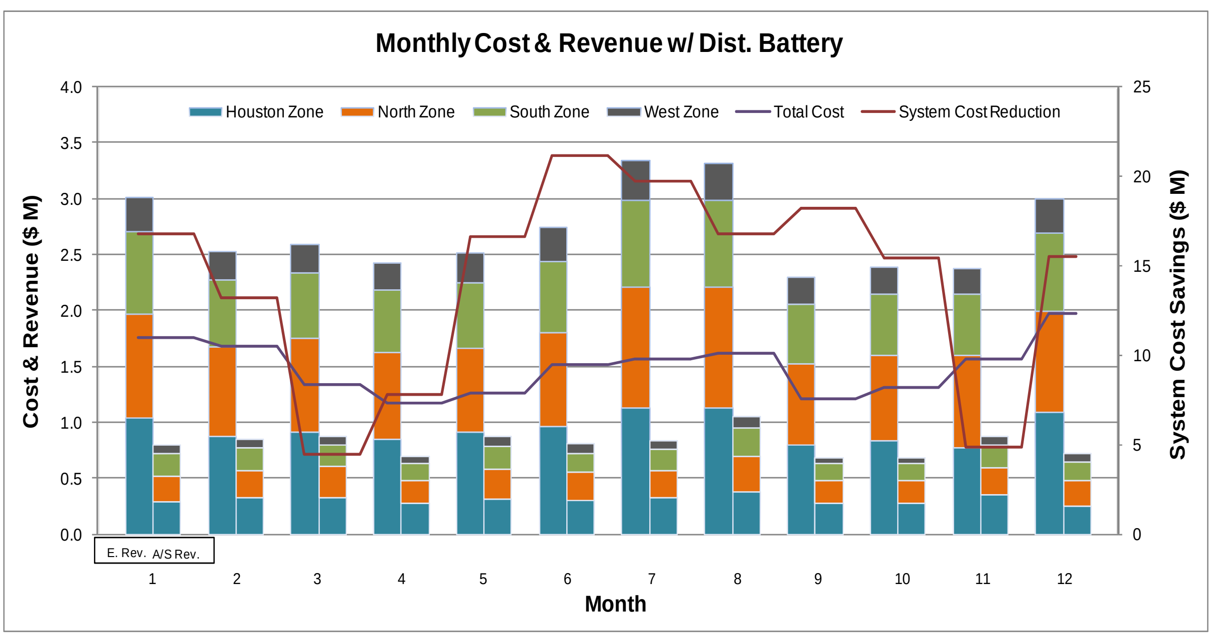




Source: LCG Consulting

Figure 4-1
Monthly Costs and Revenues with Bulk Battery and CAES units

The costs and revenues of distributed batteries are analyzed by zones as shown in Figure 4-2. The total reduction in the system cost which is equivalent to the net societal benefit is approximately $170.5 M due to the distribution of 240MW of Li-ion batteries in the ERCOT region. The performance of the batteries and the cost savings is greater during the high demand summer months.



Source: LCG Consulting

Figure 4-2
Monthly Costs and Revenues with Distributed Batteries (By Zone)

Benefits

The process of evaluating the investor and the societal benefits is same as explained in the previous chapter.

Investor Benefits

The benefits to the investor due to the addition of bulk and distributed battery scenarios are summarized in Table 4-4 below.

Table 4-4
Investor Benefits with Battery storage

Description	Bulk Battery + CAESII	Distributed Batteries
Total Operating Revenue ($ M)	15.17	0.45
Total Operating Cost ($ M)	6.31	0.15
Total Net Income ($ M)	8.86	0.30
Internal Rate of Return (%)	0.78	4.60

Batteries due to their low storage capacities and high capital cost yield lower returns than CAES as shown in the IRR. With further subsidies and improvements in technology, these investments may prove feasible from an investor's standpoint. An increased wind penetration may also result in better arbitrage and revenue potential for the bulk batteries. For distributed batteries, the benefits of the best performing 2 MW Li-ion battery are shown above. On average, the batteries earn a net income of $0.28 million.

Societal Benefits

From a societal benefit standpoint, distributed batteries have the potential to provide significant benefits. Distributed batteries specifically provide approximately $170.5 M in annual savings to the system as a result of peak shaving, reducing peak hour LMPs, and lowering consumer payments. The 100MW bulk battery experiences insufficient arbitrage opportunity and also does not provide any considerable benefits to the system.

Other benefits of distributed storage besides peak shaving and ancillary services may include the deferral of investment in upgrading transmission and distribution equipment locally to improve grid reliability.

Summary

A summary of the results for bulk battery and distributed batteries is included in Tables 4-5 to 4-8.

The benefit to cost ratio (B/C ratio) was calculated using the present value of societal benefits over a period of 15 years. Societal benefit is the total savings to the entire system due to reduced production cost and losses in the transmission system. The savings in the production cost is mainly due to displacement of the high cost energy for some of the generators and increase in the utilization of the more efficient generators. Since the batteries are distributed at approximately 60 nodes, the transmission congestion is mitigated and more efficient units can supply the loads. The output of less efficient units is further reduced due to their displacement less costly units. The societal benefit[12] essentially measures the total benefit to the whole system. The benefits accrued by individual participants are not the same. The generators' share of the benefit may increase (efficient units) or may decrease (inefficient units) and similarly the customers may see an increase or decrease in their payments due to their location (based on whether they are on the congested side). The societal benefit is calculated by simulating the ERCOT system with and without the distributed batteries. The difference between the total system cost is the societal benefit. It can be shown that the societal benefit is the total savings in the production cost of the system which equals the sum of the producers' and the consumers' benefit.

The B/C ratio of bulk battery and distributed batteries is 0.28 and 3.02 respectively. Distributed batteries yield significant societal benefits, mainly through peak shaving and also in allowing generators dispatch more efficient. The availability of distributed storage reduces the commitment of inefficient generation and reduces system commitment and production costs. Distributed storage not only benefits the system as a generation resource but also as a transmission resource. A transmission investment with a B/C ratio of greater than one typically receives FERC approval and warrants capital cost recovery. The results indicate that investment in distributed storage does yield significant societal benefits and warrant consideration for societal support for cost recovery.

Table 4-5
Storage Performance for Bulk battery and second generation CAES

	# Charging hours	# Discharging hours	Capacity factor	Energy Rev.	A/S Rev.	Net Income	Societal benefit
	(hrs)	(hrs)	(%)	($ M)	($ M)	($ M)	($ M)
A-Pb Batt.	1992	1885	17.75	11.45	3.72	8.86	12.83
CAES II_1	3525	3667	41.32	53.81	2.60	23.10	
CAES II_2	3525	3667	41.33	26.91	1.24	11.49	

12 See LCG reports -

a) http://www.energyonline.com/Reports/ViewReport.aspx?ReportID=64&Evaluation_of_Valley-Rainbow_Interconnect_Transmission_Project

b) http://www.energyonline.com/Reports/ViewReport.aspx?ReportID=65&Valuing_Transmission_Investments:_The_Big_Picture_and_the_details_Matter

Table 4-6
Societal Benefits for Bulk battery and second generation CAES

System Wide Savings	Bulk Battery + CAES II ($ M)
Production Cost Savings/ Net Societal Benefit	12.83
Changes in Producer Surplus	117.88
Changes in Consumer Surplus	-61.30
Congestion Cost Savings	43.76

Table 4-7
Storage Performance for distributed batteries

Zone	# Units	# Charging hours (Average)	# Discharging hours (Average)	Capacity factor (Average)	Energy Revenue (Average)	A/S Revenue (Average)	Net Income (Average)	Total Societal Benefit
		(hrs)	(hrs)	(%)	($ M)	($ M)	($ M)	($ M)
Houston	42	2024	1964	19.50	0.27	0.18	0.30	170.51
North	38	2237	2133	21.62	0.27	0.15	0.27	
South	28	2096	2018	20.04	0.27	0.16	0.28	
West	12	2257	2149	21.51	0.28	0.15	0.29	

Table 4-8
Societal Benefits for distributed batteries

System Wide Savings	Li-Ion Batteries ($ M)
Production Cost Savings/ Net Societal Benefit	170.51
Changes in Producer Surplus	119.64
Changes in Consumer Surplus	113.09
Congestion Cost Savings	62.22

5 LIQUID - AIR ENERGY STORAGE ANALYSIS

Modeling Methodology of LAES in UPLAN

The Liquid-Air Energy Storage (LAES) analysis methodology that was developed involves waste heat from an existing combustion turbine (CT) in the Houston area. The step by step approach for the LAES simulation using UPLAN is outlined below:

Step 1: Start with the Base Case – CREZ Scenario 2 for the year 2015

Step 2: Select an existing CT unit in the Houston area

Step 3: Run UPLAN to determine the hourly LMPs for the selected CT node

Step 4: Use the hourly LMPs at the CT node to schedule LAES

Step 5: Use EPRI input data to specify the performance and cost of LAES unit

Step 6: Determine heat rate and efficiency of LAES based on the CT unit size and heat rate

Step 7: Specify availability indicators to designate charging and discharging hours

Step 8: Run UPLAN, iterate until the operation of LAES and the CT unit are optimized

Data Assumptions, Location and Performance

The operating characteristics of LAES are summarized in table 5-1 below:

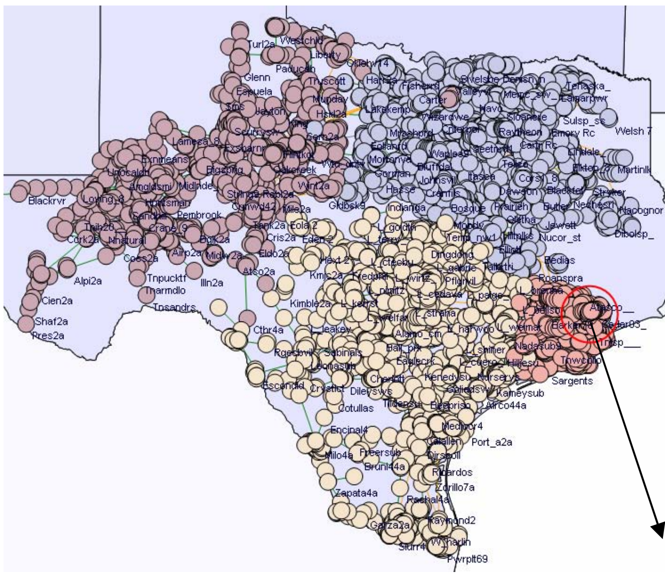
Table 5-1
Operating characteristics of LAES

Operating Parameters	LAES
Size (MW)	84
Storage Capacity (GWh)	0.8
Pumping Size (MW)	80
Energy Ratio (%)	80
Heat Rate (Btu/ kWh)	3200 – 4050

Ramp rate (MW/ hr)	1608
Charging hours (hrs)	10

The existing CT had a rating of 40 MW; the addition of 84 MW of LAES gave the new case a $ 124 MW rating.

With the characteristics mentioned in Table 5-1, the LAES unit charges for 2875 hours and discharges for 2345 hours in the entire year, constituting an annual average capacity factor of 26.05%. The operation of the LAES unit is similar to any other storage device, with charging taking place during the off-peak hours and discharging during the peak hours.



Location of LAES

Source: LCG Consulting

Figure 5-1
Location of LAES Unit in the ERCOT Region

The LAES unit is selected to be positioned in the Houston Zone at bus LPE_GT3_ (ID: 48513), as shown in Figure 5-1. An existing but inefficient CT unit in Houston that has had less than a 2% capacity factor was chosen to operate along with the LAES. LAES helps in improving the efficiency of the CT plant and its performance. . It should be noted that by being located in the Houston area and not in proximity of a wind farm, the LAES system considered in this analysis is better suited to alleviate the variability in the demand than in the supply. This has a significant impact on the benefits reported herein. Different results might be obtained by locating the LAES system in an area similar to the one chosen for CAES.

Apart from the energy market, the LAES unit is also suited to supply the ancillary services market and it provides regulation, spinning and non-spinning reserves. The performance of LAES in the ancillary market is better during the summer peak load months compared to the other months.

Locational Marginal Prices

With LAES, the monthly peak LMPs decrease by a significant amount compared to the base case. The off-peak LMPs decrease marginally only during the summer months whereas the other months witness a slight increase in the off-peak LMPs.

Wind Curtailment and Emission

Though there is reduction in the wind curtailment during the summer months, there is a marginal increase in curtailment during the other months which results in an increase in the annual wind curtailment by 0.03% compared to the base case.

The CO2 emissions increase by an average of 0.09% with LAES compared to the base case. The reason for this is the slight increase in wind curtailment and a nominal increase in coal generation.

Economic Analysis

Cost Data

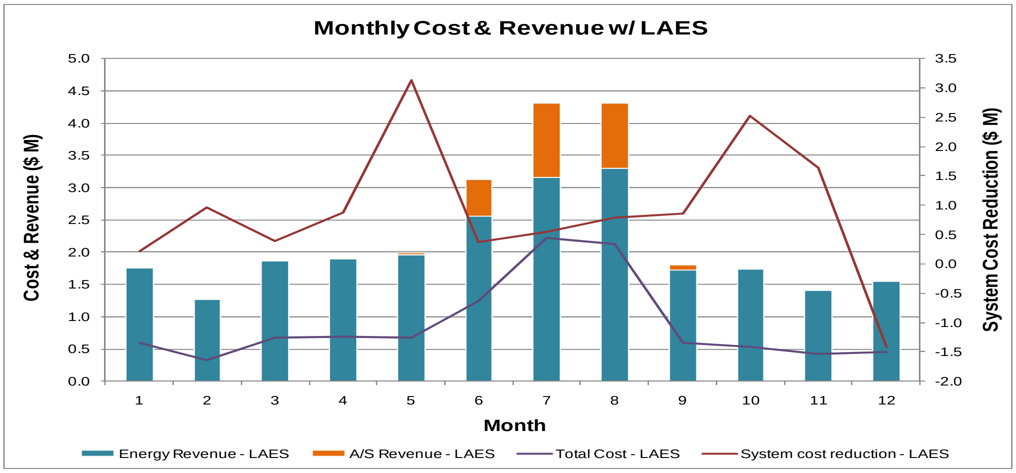
The input cost data for LAES presented in Table 5-2 is obtained from different sources viz. Praxair Inc., LCG's independent research and review of various other studies.

Table 5-2
Summary of cost data for LAES analysis

Description	LAES
Variable O & M ($/MWh)	3
Fixed O & M ($/kW-month)	0.3
Cost of storage capacity ($/kWh)	62.5
Cost of Charging/ Discharging Equipment Waste heat version ($/kW)	1200
Capital Cost ($/kW)	1795

Costs and Revenues

Figure 5-2 below represents the revenue earned by the LAES unit in the energy as well as A/S markets and the total cost of LAES. The savings in the total production cost with the LAES analysis is $ 10.9 M.



Source: LCG Consulting

Figure 5-2
Monthly Costs and Revenues with LAES

Investor Benefits

The investor/owner benefits through operating net income coming from the 125MW LAES is summarized in Table 5-3 below.

Table 5-3
Investor Benefits with LAES

Description	**LAES**
Total Operating Revenue ($ M)	27.15
Total Operating Cost ($ M)	16.58
Total Net Income ($ M)	10.57
Internal Rate of Return (%)	0.64

Societal Benefits

From a societal benefit standpoint, LAES provides approximately $10.9 M in annual savings to the system as a result of reducing peak hour LMPs and lowering consumer payments.

Summary

Results for the LAES installation are sumarized below.

Table 5-4
Storage Performance for LAES Unit

	# Charging hours	# Discharging hours	Capacity factor	Energy Rev.	A/S Rev.	Net Income	Societal benefit
	(hrs)	(hrs)	(%)	($ M)	($ M)	($ M)	($ M)
LAES	2875	2345	26.05	24.24	2.91	10.57	10.89

Table 5-5
Societal Benefits for LAES Unit

System Wide Savings	LAES ($ M)
Production Cost Savings/ Net Societal Benefit	10.89
Changes in Producer Surplus	-11.25
Changes in Consumer Surplus	63.01
Congestion Cost Savings	40.87

6 FURTHER RESEARCH

Energy storage systems may play a vital role in managing large quantities of variable renewable generation as well as end-user peak loads. Storing available low-cost energy when not needed enables the management of variability and peak loads while enhancing grid support and reliability. In transmission constrained networks, storage enhances wind integration and can further help reduce greenhouse gas (GHG) emissions.

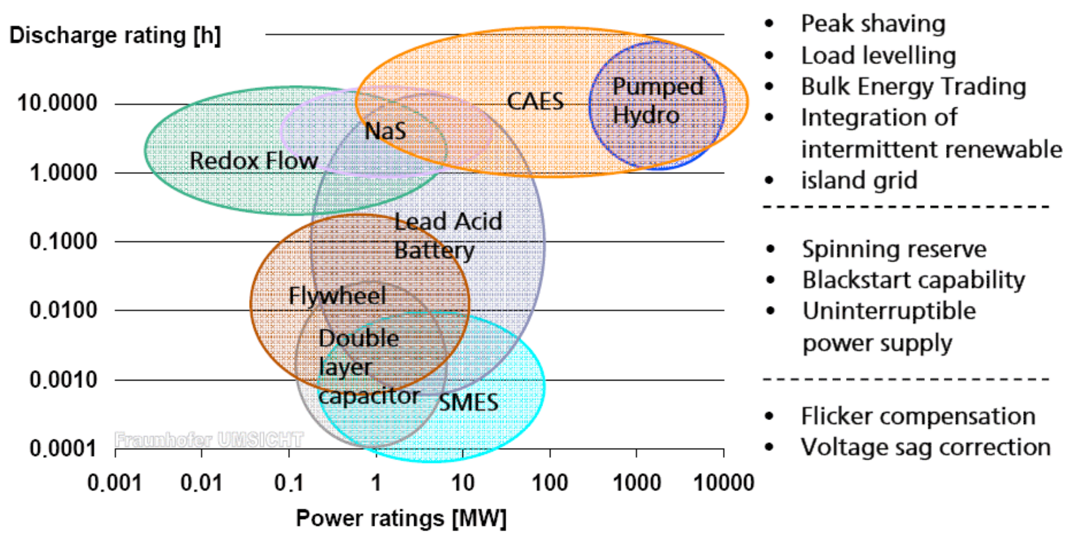


Figure 6-1
Applications of Different Storage Technologies[13]

Chapter 1 provided different types of storage technologies which should be actively investigated for their availability and efficacy in providing grid stability and energy efficiency.

Bulk and distributed storage systems can add value to ISOs and utilities by improving management of peak loads and mitigating impact of outages, which can in turn improve relationships with end use customers. The technologies that need to be investigated further include large-scale bulk storage options such as pumped hydro, nonfuel, adiabatic compressed air storage as well as many types of battery storage technologies such as sodium-sulfur (NaS), lithium-ion (Li-ion), zinc-air (Zn-Ar), zinc-bromine (ZnBr), and other emerging flow battery systems.

[13] C. Doetsch, S. Berthold, D. Wolf, T. Smolinka, J. Tulbke, P. Bretschneider, and P. Radgen, "Electrical energy storage from 100 kW – state of the art technologies, realisations, fields of use," in Second International Renewable Energy Storage Conference (IRES II) Bonn, Germany, 2007.

Cost-effective and reliable bulk energy storage are needed to help balance supply and demand and optimize the operation of bulk power resources — including nuclear, fossil, and renewable resources. Federal and state renewable portfolio standards (RPS) may result in a high penetration rate of intermittent renewable resources. Utilities need bulk power storage solutions to effectively manage the variability of wind and effectively reap the emissions reduction potential of wind and solar power and the ability to store base-load energy for use during peak times. In this study, LCG has assessed the benefits of CAES. This storage solution still requires fossil fuels. LCG recommends examining the potential for non-fuel options such as advanced adiabatic CAES, new pumped hydro technologies and large (100 MW) flow-battery systems.

Energy storage and distributed generation options are becoming increasingly popular for grid support, distribution planning and end-user energy management. Transportable energy storage systems based on technologies such as ZnBr, grid support applications such as NaS and advanced lead acid batteries and other emerging options such as Li-ion and Zn-Air could become key assets in the future smart grid configuration. In CAISO, PJM, MISO and NYISO where wind integration studies and transmission and distribution planning activities are still underway, energy storage and distributed generation solutions may have to be given considerable importance.

Further analysis is needed to better understand how much energy storage by region to support high renewable energy penetration and the trade-offs and needs for bulk vs. distributed energy storage systems. While the most cost-effective storage solutions might be used to avoid expensive transmission and distribution investments, their more likely role will be to extract greater efficiencies from existing or future transmission configurations. It seems likely that transission will be developed to manage large scale wind penetration, thus the value of storage may come, not so much at the initial T&D stage, but later, when these technologies enable peak shaving (the primary source of price reductions), possibly greater utilization of T&Dsytems, and greater wind development than otherwise. In ERCOT, for example, additional insights would be gained by evaluating the incremental benefits of bulk and distributed storage systems to support higher wind scenarios with a fixed transmsion network (e.g the CREZ Scenario 2 transmission infracturcture).

Specific Recommendations

- In view of the large amounts of new wind generation anticipated to be deployed in the U.S. over the next 20-30 years, detailed granular market based regional and portfolio assessments and simulations of energy storage are needed – especially in the CAISO, PJM, MISO, and NYISO areas to estimate just how much energy storage is needed, the best locations for storage systems, and the interplay with T&D investments as a function of wind penetration.

- The role of storage in mitigating fossil plant cycling/wear and tear also needs further analysis to gauge the scale of such benefits against the majore operational impacts on fossil generation that are occurring from wind expansion.

- Second Generation CAES systems should be built and demonstrated to validate their installed cost and operating parameters in a wind – integration application.

- Lower cost non-CAES bulk energy storage options should be monitored and evaluated and demonstrated as they could be sited in T&D congested areas. These systems should be evaluated in applications where wind penetration is potentially significant but the geology for CAES does not exist.

- Given the estimated large societal benefits of targeting distributed energy storage systems at key node points in Texas further market based analysis of distributed storage systems in other US regions should be conducted including an assessment of policy and incentive considerations to address and balance the societal benefits of distributed energy storage against the near-term high capital costs of such systems.

- In such benefit cost assessments, a key element is the potential change in capital costs of the technology. The social benefits indicate a directional incentive, whereas quantitative analysis helps spell out how great such incentives could be before the social cost (subsidies for example) outrun benefits over some reasonable pay back period. Through uncertainty analysis, sometimes called volatility analysis, it is possible to define the option value of making such social investments.

- The current assessments are based on single market scenarios. Actual investment in any technology must recognize the risk/opportunities associated with alternative futures. In this regard, assessing the economic payoffs and IRRs under a wider range of conditions and uncertainties will allow the results to be translated into options. In such calculations, it is possible to identify the market conditions and physical configurations where the technologies offer the greatest returns and it is easier to see the insurance value of investing in, and installing, advanced technologies.

A UPLAN NETWORK POWER MODEL

The UPLAN model used in this study was developed by LCG Consulting who has developed models covering both short-term operational and long-term planning for the electric and gas utility industry. LCG's proprietary UPLAN Network Power Model (UPLAN-NPM) along with its PLATO-ERCOT database was used for the market simulations in this project.

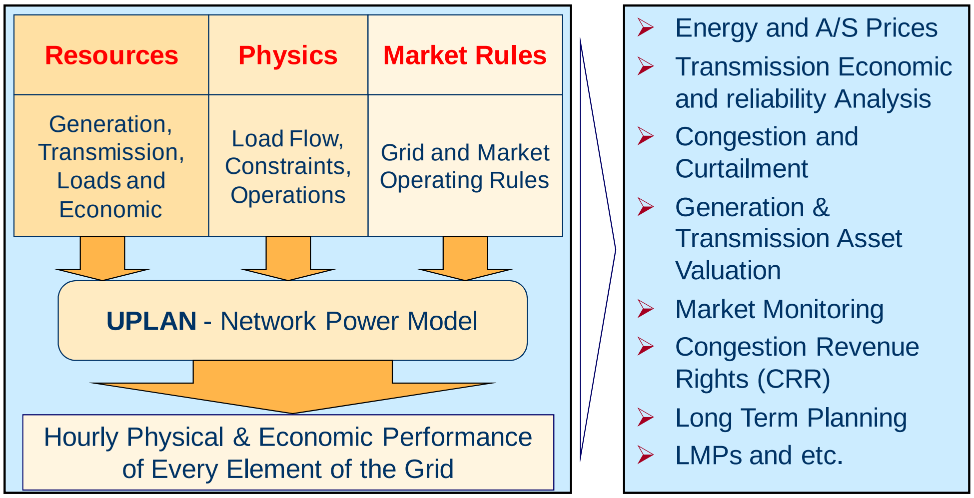
UPLAN-NPM is a full network model developed to replicate the engineering protocols and market procedures of an operator, and captures the commercial activities, such as bidding, trading, hedging, and contracting, of all players in a restructured power market. It projects detailed physical and financial operations of electricity markets conditions ranging from traditional regulation to today's post-restructuring competitive market structures.

UPLAN-NPM provides a detailed, integrated representation of physical features of the electric generators, loads and transmission, financial characteristics and system operation. It provides a realistic projection of what is going to happen physically and financially throughout a region, for assessing the engineering, economic, and financial implications of spatial and temporal changes in operations, reliability, production costs, and resources.

UPLAN-NPM integrates an electricity market simulation with a full (AC or DC) network transmission model and projects hourly Locational Market Prices (LMP). It performs coordinated marginal (opportunity) cost-based energy and ancillary service procurement, congestion management, full-fledged contingency analysis using Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) similar to those used by most market operators in the country.

In the first step of the SCUC, the model schedules day-ahead resources in appropriate amounts and locations to meet forecast energy (load) and ancillary service (reserve) requirements, while also taking into account region-specific operating protocols and transmission constraints. The Optimal Power Flow (OPF) simulation is then used to ensure that the final unit commitment can obey all transmission constraints, including line contingencies and generator outages.

The generators are dispatched to meet load in the most economical manner based on generator bids (costs) and subject to transmission constraints. It determines the hourly injection from the output levels of individual generators including renewable. The OPF simulation may utilize either DC or AC power flow, and the system will be optimally re-dispatched to manage congestion while obeying transmission constraints. The schematics of UPLAN are presented in Figure below.



Source: LCG Consulting

Figure A-1
Approach to Market Simulation in UPLAN

UPLAN is capable of simulating all different types of generators such as thermal, hydro, wind and renewable, cogeneration and many other technologies. An in-line hydro scheduler dispatches hydro, pumped storage and CAES units daily and hourly to maximize net income.

UPLAN has been used extensively to simulate and analyze competitive energy markets as PJM, New York, New England, MISO, ERCOT, and California in the U.S. and abroad such as Spain, U.K., and Russia as well as for integrated demand and supply side analysis under the regulated environment. UPLAN-NPM provides the consistent, structured framework, as well as the detailed quantitative inputs and results, required to evaluate the full implications of different fundamental drivers and market participant decisions.

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