2015

Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts

Submitted to the Illinois General Assembly and the Illinois Commerce Commission Pursuant to PA 97-0658

Illinois Power Agency

4/1/2015

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IPA

ILLINOIS POWER AGENCY

Anthony M. Star, Director

April 1, 2015

The Honorable Members of the Illinois General Assembly
State House
Springfield, Illinois

The Honorable Chairman and Commissioners of the Illinois Commerce Commission
527 E. Capitol Avenue
Springfield, Illinois

Dear Honorable Members of the Illinois General Assembly and the Illinois Commerce Commission:

Pursuant to 20 ILCS 3855/1-75(c)(5) and 220 ILCS 5/16-115D(d)(4), the Illinois Power Agency submits the attached *2015 Annual Report on The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts*.

The data and analyses contained herein provide important insight into the impacts of Illinois' Renewable Portfolio Standards on electricity consumers and on the State overall, as well as policy guidance on future renewable resource procurement activity.

Sincerely,

Anthony Star

Anthony M. Star

Director

160 North LaSalle Street, Suite N-504, Chicago, Illinois 60601

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ANNUAL REPORT ON THE COSTS AND BENEFITS OF RENEWABLE RESOURCE PROCUREMENT IN ILLINOIS UNDER THE ILLINOIS POWER AGENCY AND ILLINOIS PUBLIC UTILITIES ACTS

APRIL 1, 2015

I. Executive Summary and Key Findings

Public Act 97-0658, effective January 13, 2012, established the following reporting requirements for the Illinois Power Agency ("IPA") with respect to renewable resources procurement:

Utility Renewable Resource Costs and Benefits

Beginning April 1, 2012, and each year thereafter, the Agency shall prepare a public report for the General Assembly and Illinois Commerce Commission that shall include, but not necessarily be limited to:

> *(A) a comparison of the costs associated with the Agency's procurement of renewable energy resources to (1) the Agency's costs associated with electricity generated by other types of generation facilities and (2) the benefits associated with the Agency's procurement of renewable energy resources; and*
>
> *(B) an analysis of the rate impacts associated with the Illinois Power Agency's procurement of renewable resources, including, but not limited to, any long-term contracts, on the eligible retail customers of electric utilities.*

The analysis shall include the Agency's estimate of the total dollar impact that the Agency's procurement of renewable resources has had on the annual electricity bills of the customer classes that comprise each eligible retail customer class taking service from an electric utility. The Agency's report shall also analyze how the operation of the alternative compliance payment mechanism, any long-term contracts, or other aspects of the applicable renewable portfolio standards impacts the rates of customers of alternative retail electric suppliers.[1]

Alternate Retail Electric Supplier ("ARES") Renewable Resource Costs and Benefits

Beginning April 1, 2012 and by April 1 of each year thereafter, the Illinois Power Agency shall submit an annual report to the General Assembly, the Commission, and alternative retail electric suppliers that shall include, but not be limited to:

> *(A) the total amount of alternative compliance payments received in aggregate from alternative retail electric suppliers by planning year for all previous planning years in which the alternative compliance payment was in effect;*
>
> *(B) the amount of those payments utilized to purchased [sic] renewable energy credits itemized by the date of each procurement in which the payments were utilized; and*
>
> *(C) the unused and remaining balance in the Agency Renewable Energy Resources Fund attributable to those payments.*[2]

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[1] 20 ILCS 3855/1-75(c)(5).

[2] 220 ILCS 5/16-115D(d)(4).

This report is submitted in accordance with these provisions of the Illinois Power Agency Act and Public Utilities Act. Its analysis includes the costs and benefits associated with the following renewable resource purchases facilitated by the IPA under procurements enabled or mandated by Illinois law or conducted in accordance with IPA procurement plans reviewed and approved by the Illinois Commerce Commission ("ICC"), described below:

Ameren Illinois Company (Ameren) Procurements

05/18/09	Renewable Energy Credit ("REC") Procurement
05/18/10	REC Procurement
12/10/10	20-Year Bundled REC and Energy Procurement
05/18/11	REC Procurement
02/16/12	Rate Stability REC Procurement
05/10/12	REC Procurement

Commonwealth Edison Company (ComEd) Procurements

05/11/09	REC Procurement
05/18/10	REC Procurement
12/10/10	20-Year Bundled REC and Energy Procurement
05/18/11	REC Procurement
02/16/12	Rate Stability REC Procurement
05/10/12	REC Procurement

Renewable Energy Resources Fund

Winter/Spring 2014	Purchase of Curtailed RECs

Additional information about these procurements is included in Appendix A.

Deliveries under some of these procurement events are to be made beyond the period for which actual costs are reported herein. The report includes discussion of the contracted costs and deliveries which are analyzed in terms of specific rate impacts. Renewable energy rate impacts on a cents per kWh basis depend upon the kWh deliveries in each rate class.

Key Findings

- Although multiple renewable energy resource procurements are scheduled for 2015, there have been no new procurements of renewable energy resources since the issuing of the 2013 edition of this Report. As reported in previous versions of this Report, in the ComEd territory, the average cost of purchasing renewable energy resources ranged from a high of $19.27/MWh in the IPA's first procurement in 2009 to a low of $0.88/MWh in the 2012 procurement. In the Ameren territory, the average cost of purchasing renewable energy resources ranged from a high of $15.86/MWh in the 2009 procurement to a low of $0.92/MWh in the 2011 procurement.

- Energy storage resources may be important in controlling and mitigating integration challenges presented by increasing penetration of wind and solar power. The IPA has reviewed how energy storage technologies could potentially be applied to help better meet the needs of Illinois electric customers. At least one other state has set a sizable target for procurement of energy storage. Requests for proposals (RFPs) or requests for offers (RFOs) for energy storage have already occurred in several states.

- A number of studies of "renewable integration costs" were reviewed in the *2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois*. There appears to be only minor concern over the operational impacts of penetration rates below 10%. Illinois currently obtains 5.0% of its generation from these intermittent sources.

- In previous *Annual Reports on the Costs and Benefits of Renewable Resource Procurement in Illinois,* the Agency reviewed evidence that the Illinois Renewable Portfolio Standard (RPS) appears to have enabled significant job creation and economic development opportunities as well as environmental benefits. These results cannot be extrapolated indefinitely, and uncertainty in the load serving responsibility will affect the cost-effectiveness of further additions to the renewable resource generation stock in Illinois and will have an impact on procurement options that are available as incentives for any further build-out of renewable resources.

- The IPA's renewables procurements on behalf of the utilities are limited to the dollar amount of the utilities' renewable resources budget (limited by the share of load served and a 2.015% rate impact cap). If customers depart bundled service for other supply options, then the utilities – through no action of their own or the IPA's – could have renewables purchase obligations in excess of their budget caps. Such a situation occurred in delivery years 2013-14 and 2014-15, when ComEd was required to curtail its purchases of energy and RECs from its Long-Term Power Purchase Agreements. Customers' return to utility service means that there will be no curtailment of those contracts during the 2015-16 delivery year.

- The IPA may also procure RECs using the Renewable Energy Resource Fund ("RERF"). The Renewable Energy Resources Fund is collected from Alternative Retail Electric Suppliers ("ARES") on an annual basis through alternative compliance payments ("ACPs"), prior to any procurements or expenditures being made. It therefore does not have a rate cap (or rate impact), but annual contributions can vary widely depending on the Alternative Compliance Rate, the market share of the ARES, and the percentage at which ARES choose to contribute (a minimum of 50% of their compliance obligation). The IPA has been authorized to spend up to $30 million for RECs from solar resources, and the first procurement under that authorization will occur in June 2015. Additional use of the RERF beyond that authorization may require additional legislative action.

- The Agency further notes that Public Act 99-0002 reallocates $98 million from the RERF to the General Revenue Fund and thus makes those funds unavailable for their intended purpose of purchasing RECs. Any future legislation that further reallocates funds from the RERF to other purposes would likewise constrain the IPA from purchasing additional RECs and meeting the renewable energy goals of the state, including purposes of the RERF as set forth in the Illinois Power Agency Act and Public Utilities Act.

II. Report Methodology

This Report draws upon publicly available data regarding electric utility load, procurement results, and ACP fund reporting. Although the Renewable Portfolio Standard (RPS) has been in place since June 1, 2008, the Agency was not required to conduct a renewable energy resource procurement event until 2009, for delivery beginning June 1, 2009. Given the statutory directive to examine "the Agency's procurement,"[3] this report focuses its analysis on the period from June 2009 through January 2015. There is no specific definition of either "costs" or "benefits" in the IPA Act. For the purposes of this report, tabulated "costs" are defined as the final amount settled for a renewable resource as publicly reported, and "benefits" are defined as both quantitative and qualitative economic and societal impacts. The report also includes discussion of costs that could potentially be incurred in the future but which have either not yet become significant (intermittency and renewables integration) or depend on policy or procurement choices (energy storage).

This Report also includes estimates of bill impacts based on eligible customer class load, numbers of customers, and bill estimates contained in publicly available utility tariff and rate case filings.[4] For the purposes of determining the total bill impact, this Report includes the same costs included in the statutory RPS spending cap: "the total amount paid for electric service [which] includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes."[5] The bill impacts are presented both in terms as a percentage of an average customer bill for that class and as cents per kilowatt-hour.

For background information on the Illinois Power Agency, the Illinois Renewable Portfolio Standard, and Alternative Retail Electric Supplier compliance with the RPS, please see Section II of the 2012 edition of this Report which is available on the IPA website at: http://www.illinois.gov/ipa/Documents/April-2012-Renewables-Report-3-26-AAJ-Final.pdf.

The IPA would like to thank ComEd and Ameren for their assistance in providing data necessary for this Report. The IPA also would like to thank PA Consulting Group, the Agency's procurement planning consultant, for their assistance in preparing this Report.

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[3] 20 ILCS 3855/1-75(c)(5).

[4] For ComEd, this includes ICC Docket Nos. 07-566 and 10-0467; for Ameren, this includes ICC Docket Nos. 07-0585, 09-0306 and 11-0279 (later withdrawn).

[5] 20 ILCS 3855/1-75(c)(2).

III. Renewable Resource Procurement Impact

A. Cost Comparison

"[T]he Agency shall prepare a public report … that shall include … a comparison of the costs associated with the Agency's procurement of renewable energy resources to (1) the Agency's costs associated with electricity generated by other types of generation facilities."[6]

Results are presented for the 2014-2015 delivery year for each electric utility below. Historical results are presented in Appendix B. In order to place the costs of renewable resources and conventional supply resources on a level footing, procurement costs are compared for RECs and electricity contracted or delivered to the utility's bundled rate customers during each delivery year. For each delivery year, the following costs are tabulated:

- The weighted average cost of RECs procured by the Agency;
- The weighted average cost of electricity procured by the Agency from conventional supply sources;
- The 2010 Long-Term Power Purchase Agreements ("LTPPAs") purchase costs broken down to show the imputed REC and electricity prices[7], beginning with the 2012-13 delivery year, which is the first year of delivery under those agreements; and
- The 2012 Rate Stability Procurement costs of RECs and electricity, beginning with the 2013-14 delivery year, which is the first year of delivery under those agreements.

With regard to the 2010 LTPPAs, the contracts contain bundled pricing for electricity and RECs. REC prices are "imputed" by subtracting an electricity price from the bundled price. The electricity prices are based on a forward energy curve calculated at the time of the procurement event. The process of imputing these REC prices is described in Appendix K to the Agency's 2010 Procurement Plan.[8]

Although the Agency's costs associated with procuring RECs are compared to the Agency's costs associated with procuring electricity below, it should be noted that these costs are not for equivalent products. RECs represent only the value of the environmental attributes of a certain amount of electricity produced from renewable energy resources, not the value of the underlying electricity. On the other hand, the values shown for electricity procured represent prices of actual electricity procured for delivery and use by the end customer. In general, the REC costs are additive to the conventional supply costs when calculating individual customer rate and bill impacts.

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[6] 20 ILCS 3855/1-75(c)(5)(A).

[7] In its December 19, 2012 Order the ICC allowed for the release of the previously confidential "Appendix K" imputed REC prices. The conformed plan (ICC Docket No. 12-0544, 2013 Electricity Procurement Plan Conforming to the Commission's December 19, 2012 Order at 84) included imputed prices for the five subsequent Plan Years 2013-17.

[8] Illinois Power Agency, ICC Docket No. 09-373, Supplemental Filing (Nov. 9, 2010).

The electricity procured from conventional sources listed in the following tables and in Appendix B only includes procurements conducted by the IPA. Through 2013, the portfolio that served ComEd and Ameren eligible retail customers also included financial swap contracts that were part of the 2007 settlement that created the IPA. Because the IPA did not procure those swap contracts, they are not listed here, but it should be noted that they proved to be significantly above the market price of electricity. This price disparity can be considered as one of the main drivers of a large load migration away from the utilities' bundled rate offerings in 2012 and 2013, which in turn triggered the curtailment of deliveries under the LTPPAs discussed in this Report. A summary of the IPA's historical procurements of renewable energy resources is presented in Appendix A.

1. ComEd

Table III-1 shows a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to ComEd in the 2014-15 delivery year. Table B-1through Table B-5 in Appendix B show comparisons of the cost of RECs relative to the cost of electricity delivered to ComEd for each of the previous five delivery years.

Cost of RECs and Electricity Under Contract for Delivery to ComEd in the 2014-15 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[9]	1,261,725	RECs	$18.38	$23,190,506
REC Purchases, 2012 Rate Stability	623,577	RECs	$1.65	$1,027,243
Total RECs	1,885,302	RECs	$12.85	$24,217,749
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[10]	1,261,725,	MWh	$39.03	$49,244,208
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2014 Spring Block Energy Procurement	5,914,000	MWh	$38.18	$225,770,460
2014 September Energy Procurement	3,663,400	MWh	$36.39	$133,304,668
2012 Block Energy Procurement, Rate Stability	3,942,000	MWh	$33.39	$131,623,380
2012 Block Energy Procurement, Procurement Plan	367,600	MWh	$43.11	$15,846,432
Total Conventional Energy Resources	13,887,000	MWh	$36.48	$506,544,940

Table III-1: Relative Cost Comparison of RECs and Electricity under Contract to ComEd in the 2014-15 Delivery Year

[9] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and not quantities of RECs delivered to date in the 2014-15 delivery year. There were 34,106 Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

[10] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and not volumes of energy associated with RECs delivered to date in the 2014-15 delivery year. There were 34,106 MWh of energy associated with Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

2. Ameren

Table III-2 shows a comparison of the cost of RECs relative to the cost of electricity under contract for delivery to Ameren in the 2014-15 delivery year. Table B-6 through Table B-10 in Appendix B show comparisons of the cost of RECs relative to the cost of electricity delivered to Ameren for the previous five delivery years.

Cost of RECs and Electricity Under Contract for Delivery to Ameren in the 2014-15 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[11]	600,000	RECs	$13.59	$8,154,000
REC Purchases, 2012 Rate Stability	425,366	RECs	$2.38	$1,012,540
Total RECs	1,025,366	RECs	$8.94	$9,166,540
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements[12]	600,000	MWh	$38.89	$23,332,666
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2014 Spring Block Energy Procurement	364,800	MWh	$46.06	$16,801,980
2014 September Energy Procurement	311,400	MWh	$42.57	$13,256,186
SB1652 Rate Stability 2012 Block Energy Procurement	5,694,000	MWh	$31.44	$179,019,360
Total Conventional Energy Resources	6,370,200	MWh	$32.82	$209,077,526

Table III-2: Relative Cost Comparison of RECs and Electricity under Contract to Ameren in the 2014-15 Delivery Year

[11] This represents the Annual Contract Quantity Commitment of RECs specified in the contract and not quantities of RECs delivered to date in the 2014-15 delivery year. There were 17,978 Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

[12] This represents the energy associated with the Annual Contract Quantity Commitment of RECs specified in the contract and not volumes of energy associated with RECs delivered to date in the 2014-15 delivery year. There were 17,978 MWh of energy associated with Carry-Over RECs delivered in the 2013-14 delivery year that will be applied toward the 2014-15 delivery year Annual Contract Quantity Commitment.

3. Costs of intermittency

According to statistics published by the U.S. Energy Information Administration, in 2014 Illinois' electric power sector ranked sixth among U.S. states in wind production (Table III-3), dropping one spot from 2013's fifth rank, although Illinois ranks fifth in the country for overall installed wind capacity as of December 31, 2014 according to the American Wind Energy Association (AWEA),[13] with over 3.5 GW installed. Wind and solar power are dependent on uncertain and unpredictable energy sources – the wind and sun. There is some concern that as the fraction of electricity supplied by intermittent generators grows, additional resources and/or more complex control systems will be needed to maintain the stability and reliability of the power system.

	State	2014 Generation from Wind (GWh)	2013 Generation from Wind (GWh)	2013 Rank
1	Texas	39,371	35,937	1
2	Iowa	16,295	15,571	2
3	California	13,776	13,230	3
4	Oklahoma	11,862	10,881	4
5	Kansas	10,844	9,430	6
6	**Illinois**	**10,077**	**9,607**	**5**
7	Minnesota	9,060	8,065	7
8	Oregon	7,580	7,452	8
9	Colorado	7,351	7,382	9
10	Washington	7,264	7,008	10

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, March 2015 and February 2014*

Table III-3: Top Ten Wind Generating States, 2014 vs. 2013

The IPA's *2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts* ("2013 Report") contains a complete description of the Agency's review of existing studies on the costs of intermittency. The main findings from the studies that were judged to be relevant to the MISO and PJM areas were:

- Integration cost estimates range from less than \$1/MWh to \$12/MWh,
- An EPRI study[14] states that most power systems can reliably accommodate up to 10% wind penetration (as a percentage of annual energy load) with minor cost and operating impacts
- Benefits due to reduced CO_2 emissions and fossil fuel usage from the development of wind and solar generation are significant,
- The primary challenge associated with intermittency is the magnitude and timing of ramping requirements.

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[13] American Wind Energy Association, "U.S. Wind Industry Fourth Quarter 2014 Market Report," January 28, 2015, at http://awea.files.cms-plus.com/4Q2014 AWEA Market Report Public Version.pdf, pp. 5 and 7.

[14] The EPRI Impacts of Wind Generation Integration study reviewed for the 2013 Report.

Although Illinois produced a large amount of wind energy in an absolute sense, this was still a small fraction (5.0%) of its total 2014 production. The penetration rate of wind generation in Illinois has increased slightly over the past three years from 4.0% in 2012 and 4.8% in 2013 to 5.0% in 2014 (Table III-4). In order for intermittent generation to have a noticeable operational impact on the power system, it should represent a sizable fraction of total generation. The low renewable penetration should imply that intermittent generation is not a large enough part of the total in Illinois to impact system operations. However, it is worth considering that Illinois is interconnected with its neighboring states. Illinois utilities are part of the PJM and MISO RTOs, whose member states include Iowa and Minnesota that rank first and seventh in renewable energy penetration respectively.[15]

	State	2014 Intermittent Generation (GWh)	2014 Net Generation (GWh)	Penetration (Ratio)
1	Iowa	16,295	57,123	28.5%
2	South Dakota	2,916	11,530	25.3%
3	Kansas	10,844	50,043	21.7%
4	Idaho	2,778	15,176	18.3%
5	North Dakota	6,349	36,113	17.6%
6	Oklahoma	11,862	70,299	16.9%
7	Minnesota	9,060	56,825	15.9%
8	Colorado	7,619	54,001	14.1%
9	Oregon	7,610	59,719	12.7%
10	California	23,667	197,705	12.0%
11	Texas	39675	437,236	9.1%
12	Wyoming	4,420	49,458	8.9%
13	New Mexico	2,806	32,125	8.7%
14	Maine	1,095	13,154	8.3%
15	Nebraska	2,736	39,610	6.9%
16	Montana	1,966	30,243	6.5%
17	Hawaii	633	9,998	6.3%
18	Washington	7265	115,363	6.3%
19	**Illinois**	**10,137**	**202,352**	**5.0%**
20	Vermont	335	6,997	4.8%

*Source: U.S. Energy Information Administration, **Electric Power Monthly**, March 2015*

Table III-4: Top Twenty States by Intermittent Penetration (Ratio of Intermittent to Net Generation), 2014

Many commentators expect energy storage resources to be important in controlling and mitigating the impacts of increasing penetration of wind and solar power. Energy storage is addressed in more detail in chapter IV of this report.

[15] If Illinois were to be considered together with Wisconsin, Iowa, and Minnesota, for instance, the resulting renewable penetration rate rises to 9.8%.

B. Cost/Benefit Comparison

"[T]he Agency shall prepare a public report … that shall include … a comparison of the costs associated with the Agency's procurement of renewable energy resources to … (2) the benefits associated with the Agency's procurement of renewable energy resources."[16]

A comparison of costs and benefits is of necessity a combination of a quantitative and qualitative analysis. The costs are described in Section III.A above, and the benefits are described below.

1. Environmental Benefits

The environmental benefits of renewable energy resources are mainly associated with the benefits of avoiding the use of traditional generation sources that emit regulated pollutants. For example, the United States Environmental Protection Agency ("EPA") has found that emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (NO_2), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[17] Traditional generation from power plants include air emissions responsible for approximately one-third of nitrogen oxide emissions, two-thirds of sulfur dioxide emissions, and one-third of carbon dioxide emissions nationally, emissions associated with lung diseases such as asthma and chronic obstructive pulmonary disorder.[18] Renewable energy sources can avoid or reduce these air emissions, as well as reduce water consumption, thermal pollution, waste, noise, and adverse land-use impacts.[19]

Environmental benefits can be measured in terms of annual emission benefits, that is, the benefits of not using traditional generation sources such as coal or natural gas fired power plants that emit restricted pollutants.

In the 2012 Report, the IPA estimated the emissions reductions impact of all renewable generation in Illinois, not just the generation attributable to IPA procurements. This model used a simulation of the entire regional electric grid and therefore did not single out the impacts of individual generation facilities or the specific procurements conducted by the IPA.

2. Economic Benefits

Various categories of economic benefits are attributed to renewable energy, including electricity price reductions, economic development, and local economies. Those benefits are detailed in the subsections below. By counterpoint, critics of renewable energy point to factors that may offset some of its purported benefits, including government subsidization of the industry, reduced land values, wear and tear on local roads during the construction of turbines, future decommissioning costs, stranding of coal-fired and nuclear generation assets, and increasing spinning reserve requirements.

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[16] 20 ILCS 3855/1-75(c)(5)(A).

[17] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

[18] Air Emissions Fact Sheet, U.S. Environmental Protection Agency http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html (accessed March 2012).

[19] Breath Taking: Premature Mortality due to Particulate Air Pollution in 239 American Cities, National Resources Defense Council, at 1 (May 1996).

a) *Impact on Electricity Prices*

General Price Impacts

Illinois State University's Center for Renewable Energy concluded that because wind is both an inexhaustible energy source and is free from fuel price volatility, it can contribute to the nation's energy security.[20] Wind power and other forms of renewable energy can also lead to more stable electricity prices by diversifying supply portfolios and softening impacts from fuel price volatility. The U.S. Department of Energy characterizes renewable energy as a resource for hedging against risks posed by electricity price volatility, particularly through the purchase of long-term, fixed-price supply contracts for renewable energy resources directly with developers or generators.[21] Using renewable energy can also reduce the risk of disruptions in fuel supplies, like natural gas, resulting from transportation difficulties or international conflict.[22] Likewise, wind, solar, and certain other forms of renewable energy are not subject to the uncertainty surrounding future carbon taxes, unlike fossil fuel-fired power plants.[23]

Impacts on Locational Marginal Prices

Electricity purchased for either utilities or ARES in Illinois is sourced in competitive regional wholesale markets. Power that flows through the transmission grid and wholesale market is coordinated by PJM for ComEd customers and MISO for Ameren customers. PJM and MISO are two of the seven Regional Transmission Organizations (RTOs) responsible for reliable flows of energy. The RTOs ensure that the electrical system is always perfectly balanced between supply and demand, by dispatching generation (and load reduction under some circumstances) to meet the fluctuating load. Which power plants will be used at any time to serve load is generally determined through operation of wholesale electricity markets by the RTOs.

Wholesale electric energy prices are set for hourly periods based on bidding by available generators into the regional markets. Most analyses of the impact of renewable generation on electricity prices address these real-time Locational Marginal Prices (LMPs) and assume generator bids reflect variable costs. However, the IPA purchases power through block contracts in forward markets. Prices in those markets do not immediately incorporate changes in LMP fundamentals. Energy supply also requires the purchase of capacity credits, which guarantee the availability of power plants to reliably serve load under all circumstances. Because of their variable output, which is dependent on weather conditions, wind and solar resources have less impact on capacity prices than do dispatchable power plants. In PJM, the average capacity factor used to evaluate new wind projects in the forward capacity market has been set at 13%, and solar is set at 38%.[24]

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[20] *Economic Impact: Wind Energy Development in Illinois*, Center for Renewable Energy, Illinois State University (June 2012) at 10.

[21] *Guide to Purchasing Green Power*, United States Department of Energy Office of Renewable Energy and Energy Efficiency, at 5. (March 2010).

[22] Id.

[23] Economic Impact: Wind Energy Development in Illinois at 10.

[24] PJM System Planning Department, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, Revision 11, March 5, 2014, p. 19.

Increases in capacity bids from other generators would probably more than counteract any reduction in system capacity prices attributable to new wind plants. The fact that both wind and solar generators can offer their energy into wholesale electricity markets at a relatively low price has resulted in some concern that they might undercut and offset electricity offered into the markets by coal-fired and nuclear generators. Coal-fired and nuclear plants would then demand higher capacity prices to continue operation.

In both PJM and MISO, over the past seven years, electric energy produced by coal-fired plants has accounted for a lower percentage of the total electricity generated, while nuclear generation has remained stable. The decrease in generation by coal-fired generation in MISO is particularly pronounced given the amount of coal-fired capacity has increased between 2008 and 2014[25]. In both markets the drop in coal-fired generation is largely attributable to lower natural gas prices. The most efficient gas-fired generation is becoming increasingly cost-competitive with the less efficient coal-fired generators. As shown in Figure III-1 and Figure III-2, the drop in coal-fired generation is more pronounced in PJM, as there is more gas-fired generation installed there.[26]

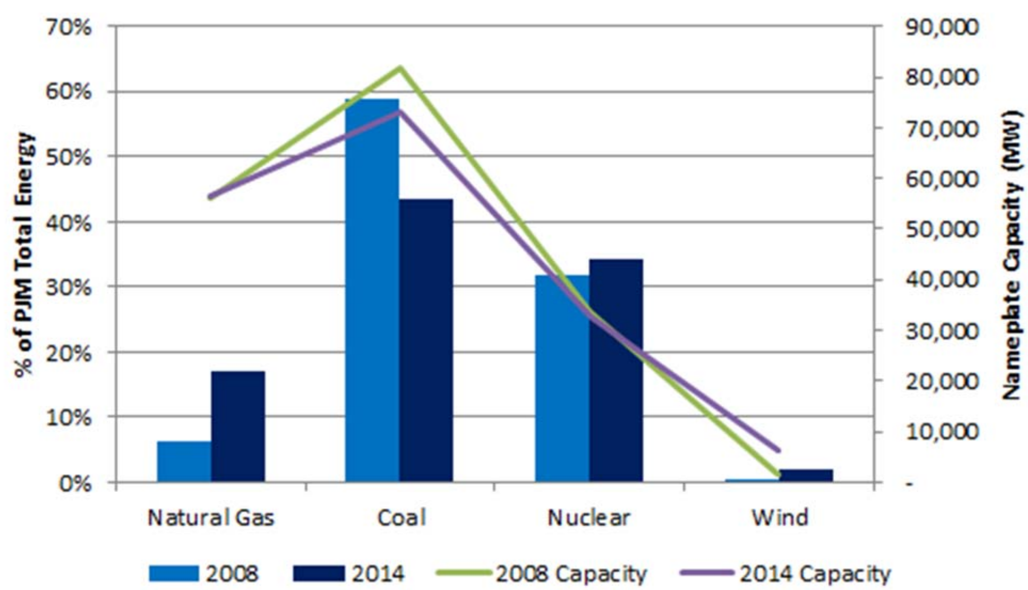

Figure III-1: 2008 and 2014 PJM Energy and Capacity by Fuel Type[27]

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[25] The increase in natural gas, coal and nuclear capacity in MISO between 2008 and 2014 includes generation that joined the market when Entergy Gulf Coast joined MISO in December 2013.

[26] PJM experienced a 8,684 MW decrease in coal-fired generation between 2008 and 2014 and this decrease would have been even greater if not for the addition of 4,657 MW of coal-fired generating capacity when Duke Energy Ohio and Duke Energy Kentucky moved from MISO to PJM on January 1, 2012.

[27] Data Source: PJM State of the Market – 2014 (Tables 3-8 and 5-3).

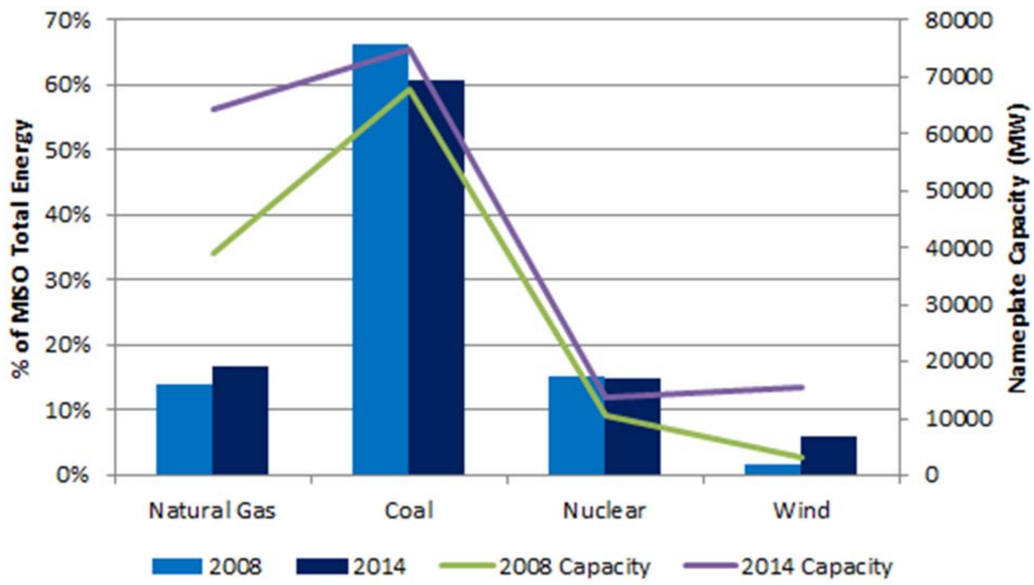

Figure III-2: 2008 and 2014 MISO Energy and Capacity by Fuel Type[28]

To date, the impact of electricity supplied to the PJM market by wind generators has been somewhat negligible, as it only accounted for 2% of the total market generation in 2014. In MISO, wind generation reached 6% of total production in 2014.[29] The higher proportion of wind production in MISO is largely attributable to the fact that wind capacity represents a larger fraction of installed capacity in MISO than in PJM.[30] Some of the increase in MISO wind generation is also due to the implementation of the Dispatchable Intermittent Resources designation that allows registered wind resources to participate in the real-time energy market.[31] Overall, increased wind generation has offset 97% of the decrease in MISO coal generation over the past seven years.[32]

Conceivably, additional low-variable-cost renewable generation could put additional downward pressure on market electric prices. While ratepayers do see immediate benefits from reduced market prices, reduced prices are not indefinitely persistent. If other plants were unable to achieve additional revenues from capacity prices to counteract the downward pressure on electricity prices, they could be forced to retire. The reduction in supply would lead to an eventual increase in wholesale prices.

The market price effects of renewable resources added to the interconnected electric system can be estimated using market-modeling software. The IPA's previous procurement planning consultant, Adica,

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[28] Data Source: MISO 2008 Summer Resource Assessment (2008 capacity data) and Energy Velocity (2014 capacity data and energy data).

[29] Source: Energy Velocity reporting EIA 923 data.

[30] Wind generation would have accounted for an even greater proportion of MISO total generation in 2014 if not for the addition of Entergy Gulf Coast, which has limited wind resources located in its territory, on December 19, 2013.

[31] MISO 2012 Winter Assessment Report.

[32] Source: Energy Velocity.

employed a proprietary market model[33] capable of modeling the entire Eastern Interconnection[34] using data at the nodal level for both load and generation. For the 2012 edition of this Report,[35] the IPA commissioned the consultant to run the model with and without Illinois renewable generation in order to test the effect on overall LMPs for calendar year 2011. The model results indicated a reduction of several percent in average LMPs, based on the impact of all Illinois wind generation (not just the amount under contract to IPA). As noted above, LMP reductions at the wholesale level are not necessarily directly or immediately reflected in the prices the IPA pays for energy that are then translated into the retail rates customers actually pay. Therefore, while that analysis was indicative of the impact added renewable generation has on energy markets, it was of less value in quantifying the direct benefit to eligible retail customers in Illinois.

b) Economic Development

Illinois State University's Center for Renewable Energy modeled the economic impact of wind energy upon Illinois' economy by entering project specific information into the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) model to estimate the income, economic activity, and number of job opportunities accruing to the state from the project.[36] The report estimated that the development of the 23 largest Illinois wind farms installed at the time of the analysis, accounting for 3,335 MW of nameplate capacity, was responsible for 19,047 full-time equivalent (FTE) jobs in Illinois during construction and 814 permanent jobs, and will generate a total economic benefit of $5.98 billion[37] during the construction and 25-year operational lives of the projects.

The report found that wind power leads to the creation of temporary and permanent jobs requiring highly skilled workers in the fields of construction, management, and engineering.[38] Construction phase jobs typically last anywhere from 6 months to over a year, while operational jobs, including operations and maintenance positions, last the life of the wind farm, typically 20-30 years.[39]

The jobs and economic benefit estimated in the report included "turbine and supply chain impacts" or "indirect impacts."[40] Indirect impacts occurred both in the construction and the operation of wind turbines, and included construction spending on materials and wind farm equipment and other purchases of goods and offsite services and "expenditures related to on-site labor, materials, and services needed to operate the wind farms (e.g., vehicles, site maintenance, fees, permits, licenses, utilities, insurance, fuel, tools and supplies, replacement parts/equipment); the supply chain of inputs required to produce these goods and services; and project revenues that flow to the local economy in the form of land lease revenue, property tax revenue, and

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[33] MarSi is a software tool developed by Global Energy Market Systems, Inc. ("GEMS") for electricity market simulations that uses generator data, transmission network data, and hourly load data to model the effects of changes in fuel prices, carbon costs, wind and solar penetration, load growth and load growth rate, and addition/decommissioning/planned outages of generating units and transmission lines.

[34] The Eastern Interconnection includes MISO and PJM.

[35] Available at http://www2.illinois.gov/ipa/Pages/IPA_Reports.aspx.

[36] Economic Impact: Wind Energy Development in Illinois at 20.

[37] Economic Impact: Wind Energy Development in Illinois at 7.

[38] Economic Impact: Wind Energy Development in Illinois at 26.

[39] Id.

[40] Economic Impact: Wind Energy Development in Illinois at 21.

revenue to equity investors."[41] The estimate also included local spending by employees working directly or indirectly on the wind farm project who receive their paychecks and then spend money in the community.[42]

The analysis also concluded that local wind turbines raise the property tax base of a county, which can create "a new revenue source for education, fire departments, and other local government services,"[43] since local governments can receive significant amounts of revenue from permitting fees.[44] Benefits to landowners identified included revenue from leasing their land, which the report found was "usually greater than that from ranching or farming and it does not require any work from the landowners."[45] There may be some local concerns such as wear and tear on roads during construction, unfunded decommissioning cost liability, and possibly lowered land values that should be considered when evaluating any specific project's impacts.

Other parties have published related statistics. According to the AWEA, wind power supports 6,001-7,000 jobs in Illinois.[46] This apparently includes manufacturing jobs, which may be supported by wind generation located outside Illinois. The Clean Energy Trust ("CET") in partnership with Environmental Entrepreneurs ("E2"), the Environmental Law and Policy Center ("ELPC") and the Natural Resources Defense Council ("NRDC") in a 2014 report states that 20,123 Illinois workers are in the renewable energy sector.[47]

c) Impact of Economic Incentives for Renewable Energy

In the last few years, the economics of renewable energy have been influenced by state and federal tax credits and other taxpayer supported incentives. It is unknown whether these incentives will be modified or will remain available. The following state tax incentives impact the benefits derived from renewable energy resources:

- An Investment Tax Credit entitles Illinois developers to a 0.5% income tax credit for investments in qualified property, which may include building, structures, and other tangible property.[48]
- A Jobs Tax Credit entitles Illinois employers to a $500 tax credit for hiring individuals certified as economically disadvantaged.
- A Sales-and-Use Tax Exemption for Building Materials grants Illinois businesses full exemption from sales-and-use tax without having to apply for enterprise zone status.[49]

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[41] *Id*. at 22.

[42] *Id*. at 23.

[43] *Id*. at 11.

[44] *Id*. at 18.

[45] *Id*. at 18.

[46] State Wind Energy Statistics: Illinois.

[47] Clean Energy Trust, *Clean Jobs Illinois: An In-Depth Look at Clean Energy Employment in Illinois*, March, 2014, at 11 and 15.

[48] Economic Impact: Wind Energy Development in Illinois at 15.

[49] Pub. Act 96-0028 (eff. July 1, 2009) amended the Illinois Enterprise Zone Act, to provide that businesses that intend to establish a new wind power facility in Illinois may be considered "high impact businesses" allowing them to claim a

- Property Tax Valuation of Wind Turbines: The wind energy property assessment division of the Illinois Property Tax Code specifies wind energy devices larger than 500 kilowatts (kW) that produce power for commercial sale be valued at $360,000 per megawatt (MW) of capacity and annually adjusted for inflation according to the United States Consumer Price Index.[50] The depreciation allowance may not exceed 70%. Current law allows this valuation methodology to be used until the end of 2016. This provides greater certainty for all stakeholders in wind energy developments.[51]

At the federal level, the American Taxpayer Relief Act of 2012 modified and extended tax credits and other incentives for wind energy and other forms renewable energy (including geothermal energy, biomass, and landfill gas). The production tax credit (PTC), created under the Energy Policy Act of 1992, provides an income tax credit for generation from eligible renewable technologies, including 2.3 cents per kilowatt-hour for the production of electricity from utility-scale wind turbines for the first 10 years of electricity production. The PTC, which was previously renewed by the American Recovery and Reinvestment Act of 2009 (ARRA), expired at the end of 2013 and has not yet been extended. Since its inception, the PTC has been allowed to lapse four times: in 2000, 2002, 2004, and 2013. Although in the first three cases the credit was extended retroactively, the uncertainty in the market resulted in decreases in new capacity additions ranging from 73% to 93%[52] of the previous year’s installed capacity.

The American Taxpayer Relief Act of 2012 (ATRA) extended "bonus depreciation" for both wind and solar generation projects first established by the Economic Stimulus Act of 2008. Prior to the inception of bonus depreciation, wind and solar project developers were allowed to recover investments through depreciation deductions over a five-year period. Under the bonus depreciation guidelines, the first-year deduction for property acquired and placed in service between September 8, 2010 and the end of 2011 is 100% of the adjusted basis, and for property placed in service in 2012 and 2013 the allowable first-year deductions is 50% of the adjusted basis with the remaining 50% depreciated over the ordinary MACRS depreciation schedule.

The investment tax credit (ITC) for renewable energy, which allows certain generation facilities to take a one-time credit in the year in which they are placed in service, was first introduced in 1978 and has been modified and extended multiple times since the mid-80s. Solar energy technology has qualified for the ITC throughout the history of the program, and in 1992, the 10% ITC was made permanent for solar. In 2005, legislation temporarily increased the solar ITC to 30% and subsequent legislation extended the 30% rate through the end of 2016, at which time it will revert to 10%.

Through Section 1603 of the ARRA, wind project developers were given the option of choosing to receive a 30% ITC in lieu of the PTC for new developments placed in service prior to the end of 2012. The

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full exemption from sales-and-use tax without having to apply for enterprise zone status. *See* Economic Impact: Wind Energy Development in Illinois at 16.

[50] 35 ILCS 200/10-605.

[51] Economic Impact: Wind Energy Development in Illinois at 16.

[52] Production Tax Credit Fact Sheet, American Wind Energy Association (April 2011).

ATRA extended this option through the end of 2013 and modified it such that wind projects only need to have started construction to qualify.

C. Rate Impacts on Eligible Retail Customers

> ***"[T]he Agency shall prepare a public report … that shall include … an analysis of the rate impacts associated with the … Agency's procurement of renewable resources, including … any long-term contracts, on the eligible retail customers of electric utilities. The analysis shall include the Agency's estimate of the total dollar impact that the Agency's procurement of renewable resources had has on the annual electricity bills of the customer classes that comprise each eligible retail customer class."*** [53]

The IPA asked Ameren and ComEd to provide breakouts, for each customer class and delivery year, of the additional amounts reflected in the supply charge attributable to renewable resource delivery. These breakouts provide the rate impact associated with the Agency's procurement of renewable resources. When multiplied by the overall billing determinants, the values also provide the total dollar impact on the annual electricity bills of each customer class. Results for each electric utility and corresponding customer class are presented for ComEd in Table III-5 and Table III-6 and for Ameren in Table III-7 and Table III-8. Note that these rate impacts are only for eligible retail customers who are the customers who take energy supply service from the utility. Customers who buy their electricity from an Alternative Retail Electric Supplier are not included in these spreadsheets.

[53] 20 ILCS 3855/1-75(c)(5).

1. ComEd

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year	2014 Plan Year (Through January 2015)
Single Family No Electric Space Heat	Revenue/kWh	$0.118	$0.132	$0.132	$0.128	$0.108	$0.138
	REC/kWh	$0.000768	$0.000258	$0.000064	$0.001152	$0.001800	$0.001900
	Ratio (REC/Revenue)[54]	0.65%	0.20%	0.05%	0.90%	1.67%	1.38%
Multi Family No Electric Space Heat	Revenue/kWh	$0.134	$0.148	$0.145	$0.141	$0.122	$0.156
	REC/kWh	$0.000768	$0.000258	$0.000063	$0.001151	$0.001800	$0.001900
	Ratio (REC/Revenue)	0.57%	0.17%	0.04%	0.81%	1.47%	1.22%
Single Family With Electric Space Heat	Revenue/kWh	$0.081	$0.090	$0.085	$0.093	$0.085	$0.108
	REC/kWh	$0.000498	$0.000170	$0.000042	$0.000554	$0.001900	$0.002100
	Ratio (REC/Revenue)	0.61%	0.19%	0.05%	0.59%	2.25%	1.94%
Multi Family With Electric Space Heat	Revenue/kWh	$0.089	$0.099	$0.093	$0.100	$0.091	$0.117
	REC/kWh	$0.000499	$0.000170	$0.000043	$0.000552	$0.001900	$0.002000
	Ratio (REC/Revenue)	0.56%	0.17%	0.05%	0.55%	2.09%	1.71%
Watt-hour	Revenue/kWh	$0.132	$0.145	$0.150	$0.151	$0.134	$0.166
	REC/kWh	$0.000780	$0.000270	$0.000060	$0.001240	$0.002000	$0.001900
	Ratio (REC/Revenue)	0.59%	0.19%	0.04%	0.82%	1.49%	1.15%
Small Load (< 100 kW)	Revenue/kWh	$0.101	$0.114	$0.113	$0.112	$0.095	$0.116
	REC/kWh	$0.000770	$0.000270	$0.000060	$0.001210	$0.002000	$0.001900
	Ratio (REC/Revenue)	0.76%	0.24%	0.05%	1.08%	2.11%	1.64%

Table III-5: ComEd Rate Impact - Calculated Bill Impacts by RECs[55]

[54] This value represents the amount that RECs cost each customer of that delivery year class as a percentage of the amount paid for total "annual electricity bills," including taxes. Thus, a Rate Impact of 0.69% means that 0.69% of the total electricity bill of a customer of that class in that delivery year was spent on contracts for renewable energy resources and credits.

[55] Overall bill (e.g. Revenue/kWh) includes fixed supply charges, PJM services charges, delivery services charges (customer charge, standard metering service charges, distribution facilities charges, and Illinois Electricity Distribution

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year	2014 Plan Year (Through January 2015)
Single Family No Electric Space Heat	Usage (kWh)	24,195,356,771	25,557,124,031	19,465,098,302	12,843,203,500	6,345,420,910	4,909,593,033
	Dollar Impact	$18,582,034	$6,593,738	$1,245,766	$14,795,370	$11,421,758	$9,328,227
Multi Family No Electric Space Heat	Usage (kWh)	4,837,665,365	5,384,174,419	4,178,671,736	3,041,118,982	1,218,371,654	937,442,860
	Dollar Impact	$3,715,327	$1,389,117	$263,256	$3,500,328	$2,193,069	$1,781,141
Single Family With Electric Space Heat	Usage (kWh)	881,222,892	506,129,412	645,304,684	546,220,195	407,285,628	210,560,008
	Dollar Impact	$438,849	$86,042	$27,103	$302,606	$773,843	$442,176
Multi Family With Electric Space Heat	Usage (kWh)	1,860,212,425	984,758,824	1,361,870,329	991,185,128	623,631,143	359,324,226
	Dollar Impact	$928,246	$167,409	$58,560	$547,134	$1,184,899	$718,648
Watt-hour	Usage (kWh)	588,208,974	578,444,444	392,413,102	210,947,790	99,782,219	67,504,390
	Dollar Impact	$458,803	$156,180	$23,545	$261,575	$199,564	$128,258
Small Load (< 100 kW)	Usage (kWh)	9,766,981,818	8,912,892,593	6,005,560,303	4,701,423,060	4,015,484,746	2,713,118,085
	Dollar Impact	$7,520,576	$2,406,481	$360,334	$5,688,722	$8,030,969	$5,154,924

Table III-6: ComEd Total Dollar Impact[56]

Tax charge), other environmental cost recovery and energy efficiency & demand adjustments, franchise cost additions, and municipal and state taxes.

[56] For Plan Years 2011 and 2012, the Usage values are from the "switching statistics" reported by the Illinois Commerce Commission (http://www.icc.illinois.gov/electricity/switchingstatistics.aspx), excluding the usage of customers taking supply service from a Retail Electric Supplier (RES). For Plan Years 2013 and 2014, Usage values were reported by ComEd. Dollar Impact values for Plan Years 2011, 2012, 2013 and 2014 were calculated by multiplying the Usage by the REC/kWh reported in Table III-5. For Plan Years 2009 and 2010, the "switching statistics" did not provide this amount of customer class detail; Dollar Impacts values for those years in Table III-6 are taken from Figure 28 in the 2012 Report and Usage was calculated by dividing the reported Dollar Impact by the REC/kWh reported in Table III-5.

2. Ameren

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year	2014 Plan Year (Through January 2015)
Residential Service	Revenue/kWh	$0.104	$0.107	$0.108	$0.104	$0.087	$0.083
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466	$0.0016811
	Ratio (REC/Revenue)[57]	0.62%	0.20%	0.05%	0.65%	1.68%	2.02%
Small General Service	Revenue/kWh	$0.111	$0.108	$0.107	$0.102	$0.085	$0.080
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466	$0.0016811
	Ratio (REC/Revenue)	0.58%	0.20%	0.05%	0.66%	1.72%	2.10%
General Service[58]	Revenue/kWh	$0.086	$0.084	$0.083	$0.075	$0.065	N/A
	REC/kWh	$0.000645	$0.000211	$0.000058	$0.000669	$0.001466	$0.0016811
	Ratio (REC/Revenue)	0.75%	0.25%	0.07%	0.89%	2.26%	N/A

Table III-7: Ameren Rate Impacts[59]

Customer Class	Description	2009 Plan Year	2010 Plan Year	2011 Plan Year	2012 Plan Year	2013 Plan Year	2014 Plan Year (Through January 2015)
Residential Service	Usage (kWh)	11,113,952,386	12,099,965,649	11,038,029,446	8,263,759,490	4,499,952,187	3,148,441,666
	Dollar Impact	$7,168,499	$2,553,093	$644,621	$5,525,976	$6,597,380	$5,292,845
Small General Service	Usage (kWh)	3,615,924,697	3,026,300,756	2,544,215,445	2,063,439,107	1,817,935,154	1,238,644,951
	Dollar Impact	$2,332,271	$638,549	$148,582	$1,379,822	$2,665,275	$2,082,286
General Service[60]	Usage (kWh)	1,240,657,248	623,518,977	443,840,561	304,704,282	232,672,832	N/A
	Dollar Impact	$800,224	$131,563	$25,920	$203,756	$341,122	N/A

Table III-8: Ameren Total Dollar Impact

[57] This value equals the REC/kWh value for the delivery year class divided by the total revenue per kilowatt-hour of the corresponding delivery year class. The REC/kWh value is equal to the cost of renewable resources in the delivery year, calculated based on the ACP computed by the ICC, divided by the forecasted load of eligible customers during the same period. *See* 220 ILCS 5/16 115D(d)(1). Thus, a Rate Impact of 0.70% means that 0.7% of the forecasted revenue from that class in the given delivery year was spent on contracts for renewable energy resources and credits.

[58] General Service (DS-3) was declared competitive in 2014and Basic Generation Service is no longer a supply option for those customers. Therefore, Revenue and Ratio (REC/Revenue) are reported as N/A in 2015.

[59] A single company-wide rate is reported for Ameren.

[60] General Service (DS-3) was declared competitive in 2014and Basic Generation Service is no longer a supply option for those customers. Therefore, Usage and Dollar Impact are reported as N/A in 2015.

D. Rate Impacts on Customers of Alternative Retail Electric Suppliers

"The Agency's report shall … analyze how the operation of the alternative compliance payment mechanism, any long-term contracts, or other aspects of the applicable renewable portfolio standards impacts the rates of customers of alternative retail electric suppliers."[61]

An ARES may satisfy its RPS requirement entirely through Alternative Compliance Payments (ACP) or through a combination of an ACP payment and procurement of renewable resources. An ARES must meet at least 50% of its RPS requirement using the ACP mechanism.[62] The law allows ARES to meet 100% of the RPS with the ACP mechanism, though it appears that most ARES currently choose to use the ACP for the minimum 50% of the required RPS. This behavior is to be expected as long as market prices for REC products which satisfy the RPS requirement for an ARES produce a lower cost alternative to using ACP for 100% of the RPS compliance.[63] This Report has estimated the ACP payment based on the actual published ACP rate and the estimated load of ARES customers.

Delivery Year	ComEd Usage Forecast[64] (kWh)	ComEd ACP Rate (¢/kWh)	Ameren Usage Forecast (kWh)	Ameren ACP Rate (¢/kWh)
June 2009 - May 2010	39,469,952,000	0.0764	17,700,274,000	0.0645
June 2010 - May 2011	35,993,039,000	0.0256	16,525,235,000	0.0211
June 2011 - May 2012	35,335,934,000	0.00568	15,065,960,000	0.00584
June 2012 - May 2013	19,695,906,000	0.09724	11,125,884,000	0.06687
June 2013 - May 2014	10,557,106,000	0.15923	5,405,499,000	0.14661
June 2014 - May 2015[65]	12,003,838,000	0.18917 (estimated)	5,453,214,000	0.18054 (estimated)

Table III-9: ACP Rates[66]

[61] 20 ILCS 3855/1-75(c)(5).

[62] 220 ILCS 5/16-115D(d).

[63] ARES are required to procure renewable energy or credits equal to at least 9% of total sales. The estimated ACP Rate for ComEd for the June 2014 through May 2015 delivery period is 0.18917 cents/kWh sold, which is equivalent to the cost of buying RECs equal to 9% of sales (the 2014-15 RPS requirement) for 2.10 cents/kWh. The estimated ACP rate for Ameren is 0.16811cents/kWh, which similarly translates to a REC cost of 1.87 cents/kWh. Those price targets significantly exceed the market price of RECs, based on both the IPA's own procurement (see Table III-1 and Table III-2); note that 1c/kWh is the same as $10/MWh) and estimates published by the US Department of Energy (http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5).

[64] "Usage" in this table is the forecasted usage of utility supply customers only (excludes ARES customers).

[65] Because the delivery year has not yet been completed, an actual ACP rate cannot be provided and instead the estimated ACP rate for delivery year 2014 - 2015- provided in the Illinois Commerce Commission Notice Concerning Alternative Compliance Payments on 5/6/2014- has been used.

Assuming an ARES uses the ACP to meet half its RPS requirement and passes through the costs of the ACP to all its volume sold, the estimated rate impact on ARES customers would be half the values shown in Table III-9 above. That is, for an ARES customer in Ameren territory, the ARES rate impact in delivery year June 2013 to May 2014 would be 0.073305 cents per kilowatt-hour for the ACP portion of that ARES's compliance.

Because ACPs are based on the utilities' average cost of REC procurement, if ARES were to pay approximately the same amount for renewable resources they directly procure as the IPA, the bill impact of renewable procurement on ARES and utility customers would be similar in dollar amount. The percentage impact on an ARES is shown in Table III-10. However, if ARES procure different or cheaper products (for instance, only purchasing short-term RECs rather than entering into long-term PPAs), ARES costs are likely to be less in the short run.

Utility Territory	ACP Rate (¢/kWh) (estimated) – From Table III-9	Representative ARES Price (¢/kWh)[67]	Maximum Rate Impact on ARES Customers Assuming 100% ACP (estimated)
ComEd	0.18917	7.88	2.40%
Ameren (Zone 1)	0.18054	5.95	3.04%
Ameren (Zone 2)	0.18054	5.94	3.04%
Ameren (Zone 3)	0.18054	5.95	3.04%

Table III-10: RPS Compliance - Comparative Rate Impact on ARES Customers

The ICC's estimated ACP Rates for the June 2014 through May 2015 Plan Year are shown in Table III-9 above. These estimates include the effect of the 2010 LTPPAs. The rate impact is a high-end estimate

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[66] Sources are as follows: Illinois Commerce Commission:

Delivery Years 2009 through 2012: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - ACP Rate History as of 2013-05-13.pdf.

Delivery Year 2012/13: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - Notice of 2012-2013 Actual ACP Rate as of 2013-07-01.pdf.

Delivery Year 2013/14: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - Notice of 2013-2014 Actual ACP Rate as of 2014-06-09.pdf.

Delivery Year 2014/15: http://www.icc.illinois.gov/electricity/rpscompliancepaymentnotices.aspx - Notice of 2014-2015 Estimated ACP Rate as of 2014-05-06.pdf.

[67] Representative ARES prices are based on offers found on the Plug in Illinois website for 12-month fixed price non-green energy contracts as of 3/15/15. Any monthly fees included with the offers were converted to cents/kWh based on a usage rate of 1000 kWh/month. http://www.pluginillinois.org/OffersBegin.aspx. Note that some plans may contain early terminations fees that are not included in the calculation of representative prices.

that assumes that an ARES complied with the RPS through 100% ACP payments rather than the minimum 50% payment and purchases of RECs that appears to be more typical of most ARES. Price information on ARES direct purchases of RECs is not publically available so an exact calculation of typical or average rate impacts on ARES customers is not possible.

IV. Energy Storage

A. Introduction

As Illinois continues to modernize its electric system, the IPA is reviewing how and what types of energy storage technologies could potentially be applied to help better meet the needs of Illinois electric customers. In particular, the IPA continues to review how energy storage technologies can further support the development, operation and integration of renewable generation resources in Illinois that will promote both a cleaner electricity system and increase job opportunities within the state.

While increasing renewable generating resources within the state would reduce Illinois' dependence on fossil fuels, renewable generation places unique challenges on the operation of electric grids. Most of these operational challenges stem from the fact that renewable resources are "intermittent" in nature. That is, electric generating technologies like solar and wind generation have variable and uncertain electrical output due to the second-by-second changes in environmental factors outside of a generator's control. For example, constantly changing cloud cover varies the output of solar generation, while fluctuations in wind speeds vary the output in wind generation. These variances in outputs places stress on the electricity system by requiring additional resources (often fossil fuel) to continually modify their output to make sure electric supply is in lock-step with demand. This continual load following decreases the efficiency and increases the maintenance costs of these load following resources. These intermittency challenges do not apply to most conventional resources that provide a relatively steady and largely predicable output based on the amount and type of fuel consumed.

Energy storage technologies provide an opportunity to improve the integration of renewable generation by complementing clean, intermittent technologies with the services they need to operate in a more stable manner. For example, energy storage technologies can help control moment-to-moment variances in power flow by providing fully synchronized energy reserves that do not consume fuel. In addition, energy storage can be used to shift renewable generation from times of high abundance or low price to times of peak demand or higher cost. Energy storage is often paired with wind generation for this purpose. In general, the peak production of wind generation is typically during the night when overall system costs and demand tends to be low. Storage of energy for nighttime wind can shift cheaper, clean power to times when peak demand is high during the day when fossil fuel peaking facilities are typically used.

More innovative uses of energy storage for renewable integration include off-grid, micro storage, and smart distribution grid applications. Off-grid energy storage can be paired with renewable generation to allow Illinois consumers to improve their reliability when, for example, extreme weather threatens the performance of the grid. Similarly, micro storage, when paired with distributed solar PV, can help maximize local consumption of distributed generation, time shift the energy to period of high cost, and help ensure local reliability. Energy storage can also be used in smart distribution applications. For example, when a substation operates near peak capacity upgrades are often considered, particularly when intermittent generation may threaten reliability. Strategically placed energy storage can help integrate additional renewables by deferring or eliminating the need for major capital expenditures in transmission and distribution.

Different types of energy storage technologies surpass others at meeting different types of operational challenges. As such, the procurement of energy storage requires an understanding of its intended use. For example, large scale pumped hydro has proven to be an effective technology for load shifting (i.e. consuming electricity for storage when it is of lower cost and then converting storage to electricity during periods of higher cost). In contrast, the quick response times of flywheels have proven the technology extremely adept at providing frequency regulation and maintaining operating reserves.

This chapter reviews current energy storage technologies, summarizes how these technologies are used in practice, and explores how other states are approaching the procurement of storage with a focus on renewable integration. The chapter is not prescriptive. Rather, the purpose is to review the current state of energy storage technologies and procurements to begin to understand (1) what commercially viable energy storage technologies might be applicable to the integration of renewables for Illinois, and (2) how other states and utilities have approached the procurement of energy storage to serve electric customers need for clean, affordable and reliable energy. More specifically, the chapter:

- Clarifies how energy storage is measured.
- Provides an overview of commercially viable energy storage technologies.
- Discusses the capabilities of these technologies.
- Discusses the various applications of these technologies, including renewable integration.
- Reviews the current landscape of installed energy storage in the United States and in Illinois.
- Discusses energy storage policy at the federal-level and regional level.
- Discusses state-level policies and recent request for proposals (RFPs) and request for offers (RFOs) for energy storage in New York, Texas, Hawaii, and California—four geographically diverse states that have demonstrated considerable progress in procuring energy storage and renewable generation.

B. Defining Energy Storage

At its most basic, energy storage is the procurement of energy for use at a later time. The technologies to store energy can broadly be classified as electrochemical (e.g. batteries), mechanical (e.g. pumped storage), chemical (e.g. fuel cells), thermal (e.g. heat), and electrical (e.g. ultra capacitors). Additionally, energy storage can be classified by application such as energy supply (e.g. load following), transmission and distribution (e.g. investment deferral), and consumer energy management (e.g. customer demand shifting). Storage facilities that are interconnected to electricity grids are typically defined by six major attributes:

Storage Capacity: How much energy can be usably stored by the facility (measured in kilowatt-hours or megawatt-hours).

Discharge Capacity: The maximum rate of storage that can be discharged at any point in time by the facility (measured in kilowatts or megawatts).

Duration: The length of time over which the energy can be discharged from the facility (duration = storage capacity ÷ discharge capacity).

Depth of discharge: The amount of energy that may usably be stored by a facility (under normal conditions, and available by discharge at the rate represented by the discharge capacity) divided by the maximum energy storage by the facility (which may all be dischargeable under emergency conditions).

Efficiency: The ratio of stored energy available divided by the amount of energy that must be consumed to charge the facility, both under normal (non-emergency) operation.

Duty Cycle: The number of times the facility can charge and discharge during any defined time period.

C. Applications for Energy Storage

Energy storage systems provide an opportunity to convert electricity into an alternative form of energy and then reconvert the energy into electricity when needed. This means that a storage asset is generally made up of two components, the energy conversion system that converts electricity to and from the alternative energy form, and the reservoir(s) that store the energy in its alternative form. Energy storage systems can be deployed to support generation, transmission, distribution, substations, and the consumer. Table IV-1 provides a list of power system applications that can be supported through the deployment of storage systems, with their key requirements. This section provides a brief description of each application. The section overviews key applications in regard to supporting renewable integration and additional benefits that storage can provide in addition to renewable applications.

Application	Storage Range (MW)	Discharge Duration (Hours)	Usage (Cycles/Year)
Energy Supply			
Energy Time Shifting	1 – 500	<1	250+
Customer Load Following	10 – 40	0.25 – 1	250 - 10,000
Renewable Load Following	1 – 100	0.25 – 1	NA
Supply Capacity	1 – 500	2 – 6	5 - 100
Operational Reserves	10 – 100	0.25 – 1	20 -30
Black Start	5 – 50	0.25 – 1	10 - 20
Transmission and Distribution			
Congestion Relief	1 – 100	1 – 4	50 -100
Transmission Upgrade Deferral	10 – 100	2 - 8	10 - 50
Distribution Upgrade Deferral	0.5 – 10	1 - 4	50 - 100
Voltage Support	1 – 10 (MVAR)	NA	NA
Stability	10 – 100	0.008(5 sec) - 2	20 -100
Customer Energy Management			
Customer Energy Time Shift	0.001 – 1	1 - 6	50 – 250
Demand Charge Management	0.05 – 10	1 - 4	50 -500
Power Quality	0.1 – 10	0.016(10sec) – 0.25	10 – 200

Table IV-1: Energy Storage System Technical Considerations[68]

1. Firming and Shaping Renewable Generation

Renewable generation is by its nature intermittent. It delivers energy to the grid when its fuel source (wind or solar) is available. This provides challenges to the grid operator. For the generation owner, it limits energy revenues to real time prices. By installing energy storage systems behind the generator's revenue meter, the output can be firmed and shaped. This would make the renewable generation act more like conventional generation and provide an opportunity to access the forward capacity and energy markets.

[68] Source: DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA, July 2013

a) Short-Duration Renewable Firming

Short-term intermittency extends from seconds to minutes. For solar generation short-term intermittency can be caused by terrain shadowing but is most likely the result of cloud cover. Intermittency in wind generation is the result of wind gusts. In both cases, the intermittency results in varying amount of output volatility. For PV systems, scattered clouds can produce a small but volatile change in output, while heavy clouds can produce a steadier but greater reduction in output. Similar volatility and output reduction can impact wind generation depending on whether the wind gusts are light or intense.

Short-term renewable firming requirements are similar to regulation needs, but are geographically concentrated in areas of high renewable production. Those areas can be remote from load (especially when the renewables of concern are wind generators) so there is value to having the firming energy source close to the generators. Energy storage systems that directly respond to renewable generation output changes could manage short-term renewable generation volatility. In addition to rapid response, the storage system would need to charge and discharge frequently throughout the day.

b) Diurnal Renewable Shaping

Diurnal intermittency is a predictable change in output that occurs over multiple hour periods on a daily basis. For PV generation, this intermittency is related to the pattern of insolation throughout the day. In the morning and evening hours, the reduced angle of the sun hitting the solar panels reduces electricity conversion efficiency. The temperature of the panels can also affect efficiency. For wind generation, diurnal intermittency is driven by the local wind patterns. In many regions, the wind is weak overnight and in the early mornings. It picks up at daybreak and is strongest in late afternoon into evening.

For diurnal intermittency, rapid response energy storage is not as important as duration of output, that is, storage (energy) as well as discharge (power) capacity. When the storage is associated with specific renewable generators it allows renewable generation to be able to declare more firm capacity, whereas renewable capacity is often "derated" when used for reliability purposes. Storage suited for following demand can be utilized to firm renewable capacity. Diurnal shaping may be required for blocks of several hours.

c) Renewable Energy Time Shifting

Some renewable energy generation resources produce a significant portion of their energy output during periods when the market value is low (i.e., at night or during early mornings). The energy is more valuable during on-peak periods and especially during hot summer afternoons. At other times, renewable generation may produce during periods when baseload generators must run at minimum loading to remain committed, requiring the grid operator to request curtailment of output. An energy storage system can be charged during periods of either low market value or to avoid curtailment. The energy can then be discharged when prices are more favorable. The energy storage system will need to be able to discharge energy for four to six hours. This is a "shaping" application because it functions to change or move the temporal shape of renewable output.

d) Reliability of the Grid Connection

Most distributed generators require the grid to operate. A storage system can effectively cover for a total loss of power from the source utility. An energy storage system can provide sufficient energy to bridge an outage, to provide time for orderly shutdown or to avoid the generator tripping offline. When large numbers of distributed renewables trip simultaneously it can be a difficult and time-consuming process to bring the grid back; this has been observed in Germany.

2. Renewable Integration Applications

a) Regulation

Regulating resources manage the moment-to-moment variations in demand and maintain grid frequency during normal operation and disturbance as required by NERC. Response speed is the key difference between regulation and load following. Regulation generation responds to rapid load fluctuations, the order of a minute or less. Load following response to slower load changes, in the order of five to thirty minutes. Regulation is similar to short-duration renewable firming, except that it operates at a system rather than local level. Regulation services require generation to be online and under grid control. Operation is such that its output may not be at its most efficient levels and the varying output increases wear and tear.

Energy storage is also well suited for regulation because rapid response storage systems can respond quickly to demand changes. In addition, most types of storage can operate at partial discharge levels without significant loss of efficiency. Regulation is a particularly appropriate role for storage technologies that can easily switch for charging to discharging, even if they have limited duration, because the cumulative impact of truly random demand variations should return to zero over relatively short periods. At least one ISO (New York) has special rules to facilitate provision of regulation by such "limited energy storage resources". Regulation is a critical service to help address the moment-to-moment fluctuations common amongst intermittent renewable resources.

b) Operating Reserve Capacity

The grid operator procures reserve capacity that can be called when scheduled supply resources are unavailable, such as when a generator goes offline or a transmission line trips. Three types of reserves are procured and differ by response time.

- **Spinning reserve** capacity must respond within 10 seconds. It must be on-line with sufficient unloaded capacity to meets its obligation. It is the first to be called with a shortfall occurs.
- **Non-spinning** reserve capacity may or may not be operating at the time of need but must be available within 10 minutes.
- **Supplemental** reserve capacity does not need to be online and connected to the grid at the time of need but must be available within 30 minutes.

Energy storage is well suited for providing reserve capacity. One advantage of storage is that, unlike some generators, it does not need to be online, partially loaded, consuming fuel. Reserve provision also allows the resource to preserve some of its energy and extract greater value from each stored MWh. Operating reserves can help enhance the reliability of renewable resources, by providing necessary reserve capacity to address sudden downward ramps in renewable energy production.

c) Voltage Support

To maintain system stability in the transmission and distribution (T&D) network, the grid operator must maintain system voltages with in safe limits. To meet the challenge requires management of reactance, a phenomenon that occurs in power system equipment and customer motors. Traditionally, generation resources and T&D substation devices produce reactive power (VAR) to offset reactance in the grid.

To provide voltage support, energy storage technologies must be able to produce reactance as well as energy. For example, batteries would have to be paired with a converter that can provide reactance. The random and often rapid fluctuations in internment renewable supply requires additional voltage support when compared with conventional electric generators.

d) *Transmission Congestion Relief*

Transmission congestion occurs during periods of high demand when energy cannot be delivered because transmission facilities are not adequate. During periods, the need for transmission capacity increases. Transmission congestion may also lead to increased congestion costs.

Electricity storage can be used to avoid congestion-related costs and charges. Storage systems would be installed at locations that are electrically downstream from the congested transmission link. Energy would be stored when there is no transmission congestion, and then discharged to avoid congestion. Energy storage can provide relief to congestion caused by the integration of renewable resources, particularly when intermittent resources are generating near max output.

e) *Transmission and Distribution Upgrade Deferral*

When a transmission or distribution system's peak electric load approaches its design rating, investments are necessary to maintain adequate capacity to serve all load requirements. The upgrade could be a replacement of an aging or over-stressed transformer at a substation or replacing existing conductor wire with heavier wire. In cases where the demand exceeds resources for at most a few hours on any given day, installing energy storage downstream from the overload node may defer the need for an upgrade. As distributed renewable resources are integrated to the grid, this use of energy storage has the potential to reduce overall system costs.

3. Additional Energy Supply Applications

a) *Energy Time Shifting*

Energy time-shift activities involve taking advantage of the varying cost of electricity over time. Energy storage systems have the ability to store energy during periods of low energy prices and then discharge the energy during periods of high demand when the price is higher. The frequency of discharge is driven by the spread between the buy-low-sell-high prices and the cost of storage and delivery. Energy storage systems with the capability to discharge energy over two to six hours are well suited for time shifting.

b) *Supply Capacity*

In many areas, system peak energy demand occurs for only a few hours year and only in specific seasons of the year. Traditionally, grid operators had the option to purchase additional energy from the wholesale market, install central station generation capacity with low initial utilization, install high-cost - low-utilization peaking capacity, or develop demand response programs to meet this short term demand. Energy storage can be used to defer new generation installation by supplying capacity.

c) *Load Following*

Grid operators provide load following services to meet expected increases and decreases in demand across the day. Energy is added to the grid in increments to accommodate increasing load through the morning hours. Energy is incrementally removed to accommodate decreasing load, especially during evening hours. Load following energy is offered on an hourly basis and is dispatched by the grid operator at intervals of five to 30 minutes. Storage is well suited to provide load following services because it can respond quickly to dispatch instructions and can operate with modest performance penalties at partial output levels.

d) Black Start

A disturbance that results in the loss of all generation will require a self-starting generator to begin the black start restoration process. Self-starting hydroelectric or fossil fuelled generators are presently used for black start. A self-starting energy storage system can also be utilized.

4. Additional Transmission and Distribution Applications

a) Transmission Support

Transmission and distribution (T&D) systems are subject to voltage sag, unstable voltage, sub-synchronous resonance as a result of electrical anomalies and disturbances. Applications for energy storage systems include increasing load carrying capabilities through dampening oscillations and sub-synchronous resonance. They also manage voltage fluctuations and prevent under-frequency load shedding. For use in transmission support, storage systems must be capable of sub-second response and many charge-discharge cycles.

b) Substation On-site Power

Battery storage systems are used at utility substations to provide power to communication systems and switching components when grid energy is lost. Most of these batteries are either lead-acid or NiCad. Energy storage systems that required less maintenance, better reliability and longer battery life may be an alternative.

c) Distribution Resiliency

Circuit reliability can be improved with the addition of a secondary energy source. A storage system can effectively support customer loads when there is a total loss of power from the grid. An energy storage system can provide sufficient energy to bridge an outage, to provide time to orderly shutdown non-efficient load, or to transfer to a back-up generation resource.

5. Customer Energy Management

a) Customer Time-of-Use Rate Management

In many regions, retail customers, especially commercial and industrial customers, are served on rates that change across the day. These time-of-use (TOU) rate tariffs are higher during high demand periods and are design to provide incentives to shift consumption to non-peak hours of the day. Energy storage can be used to reduce the overall cost of energy by charging during low cost periods and discharging during high cost periods. For customers with distributed renewable resources, energy storage has the potential to help better manage TOUs rate tariffs. In Illinois, customers have the option of real-time pricing which is an hourly energy price based upon wholesale market prices and is a type of TOU rate.

b) Demand Charge Management

Under a demand charge rate tariff, part of the customer's bill is determined by its maximum instantaneous consumption during the billing period. To avoid penalties, customers must reduce demand during specified periods. Energy storage can be used to avoid penalty by charging during low demand periods and supplying energy when the customer's consumption peaks. With a demand charge, the difference between peak demand and hourly average demand can become quite significant. Short-duration storage can capture that differential by smoothing demand within the hour.

c) Electric Service Power Quality

Poor power quality can be the result of short-duration variations in voltage and frequency levels, system harmonics, and load interruptions. Motors, data processing equipment, and certain industrial processes are sensitive to fluctuations in power quality. Energy storage systems that are of high quality with rapid response rates on the order of a few seconds to a minute are required.

6. Application Synergies and Micro-Grids

An energy storage system can be utilized for more than one application. Energy storage used to help aid the integration of renewable resources can serve additional purposes on the gird. Large, fast response systems designed for load shifting can be utilized to supply capacity, defer T&D upgrades, relieve transmission congestion, and provide operating reserves. Storage systems that include adjustable power factor power converters for local voltage support can be used for customer service support and power quality.

Micro-grid deployment is an excellent opportunity for energy storage systems. A micro-grid is a stand-alone distribution network usually embedded in a power system. It is designed to be energy self-sufficient. Energy storage can provide load shifting and firming support if renewable energy is the primary generator. In addition, storage can provide frequency and voltage stability, power quality, backup power and black start support.

D. Technologies

This section and Appendix C provides a summary of available and emerging electric storage technologies. These technologies can be considered for providing services for the range of applications described above. Table IV-2 summaries the features and cost estimates of several technologies. These are based on a vendor survey reported in a DOE/EPRI report. The survey covered several different storage applications and multiple technologies. Only utility applications are reported here (as opposed to end-user applications). For lead acid and lithium ion technologies, there were enough data points that costs and characteristics could be reported for individual applications; for other technologies the ranges given include all utility applications (bulk storage, wind integration and T&D support). In all but two cases ranges are based on three or more data points, and cost ranges are shown to two significant figures.

Cost is given in two different metrics, $/kW and $/kWh. The size of a storage installation can be measured in two different ways: the (instantaneous) discharge capacity, measured in units of power such as Watts, kilowatts (kW) or megawatts (MW); and the storage capacity or total amount of usable energy that can be extracted over time when fully charged, measured in units of energy such as Watt-hours (W-h), kilowatt-hours (kW-h) or megawatt-hours (MW-h). The use of the hyphen (e.g., kW-h instead of kWh) emphasizes that the energy is only available ratably over the dispatch duration, which is the ratio of the energy storage capacity to instantaneous discharge capacity. The distinction between discharge and storage is clearest in the case of pumped hydro, CAES or flow batteries, where there is a physical storage reservoir or tank separate from the equipment that converts stored energy to electricity.

Technology	Capacity (MW)	Duration (Hrs)	% Efficiency	Total Installed Cost[a]	
				$/kW	$/kW-h
Lead Acid Battery – Bulk Storage	20 - 100	4 - 6	85 - 90	1,700 – 5,900	340 – 1,100
Lead Acid Battery – Frequency Regulation	1 - 100	0.25 - 1	90	1,100 – 2,500	2,400 – 4,800
Lead Acid Battery– T&D Grid Support	1 - 100	1 - 10	87 - 90	2,400 – 5,900	500 – 2,500
Lithium Ion Battery – Frequency Regulation and Renewable Integration	1 - 3	0.25 – 1.35	80 - 92	1,000 – 2,600	1,300 – 4,400
Lithium Ion Battery– T&D Grid Support	1 - 10	1 - 5	90 - 94	1,300 – 5,000	990 – 2,200
Sodium-Sulphur Battery	1 - 100	6 - 7	80	3,000 – 3,500	430 – 520
Sodium-Nickel-Chloride Battery	0.03 - 53	2 - 5	80 - 85	1,800 – 5,700	560 – 1,700
Vanadium Flow Battery	10 - 50	4 - 5[b]	72 - 75	3,300 – 3,800	740 – 840
Zinc Bromine Flow Battery	1 - 100	1 - 5[b]	60 - 65	1,400 – 3,000	320 – 1,500
Zinc-Air Battery[c]	1 - 50	6	80	1,400 – 1,900	230 – 310
Iron-Chromium Battery	1 - 100	4 - 10	75	840 – 2,100	200 – 380
Pumped Hydro	280 – 1,300	8 – 16	81	1,800 – 2,700	130 – 340
CAES (below ground)	50 - 441	8[b]	–N/A	650 – 1,300	80 – 160
CAES (above ground)	50	5[b]	–N/A	1,700 – 2,000	350 – 390
Flywheel[d]	20	0.25	85	2,159	8,638

[a] Does not including financing costs, operations and maintenance costs, or the periodic replacement of degraded battery modules
[b] Storage duration for CAES systems and flow batteries can be expanded rather cheaply by building larger caverns or tanks
[c] Based on two samples
[d] Based on one sample

Table IV-2: Energy Storage Features and Cost Estimates[69]

Appendix C provides a high level overview of the technologies listed above and select other relevant technologies.

E. The Status of Storage in the United States

Energy storage technology in the U.S. has a long history of helping to meet peak demand. The Rocky River pumped hydro facility on the Housatonic River in Connecticut, completed in 1928, was the United States' first major large-scale pumped hydro project with an operating capacity of 24 MW. Today, the use of storage in the US has grown considerably. According to the U.S. Department of Energy's Global Energy Storage Database, the US has just over 21 GW of operational storage capacity (263,000 MWh) with approximately 5.5 GW of additional storage capacity under development (65,000 MWh). On a capacity basis, over 95% of the storage technology that currently operates in the US is pumped hydro (97% on a megawatt-hour basis). PJM has over 5 GW (33,000 MWh) of energy storage and MISO has over 2 GW (18,500 MWh) with over 99% of energy storage in both markets being pumped hydro. The disproportionate use of pumped storage versus other technologies is consistent with world trends. There is an estimated 145

[69] DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA, Sandia National Laboratories, February 2015.

GW of storage capacity operating worldwide, with only 3.5 GW (approximately 2.5%) of that total being non-hydro energy storage. Five countries—U.S., UK, Germany, Spain and Japan—account for 92% of the 3.5 GW of hydro energy storage.

Energy storage is being increasingly used to provide a range of other services beyond load shifting, such as helping stabilize the grid through ancillary services and offer revenue opportunities. This is largely due to the growth of alternative storage technologies. For example, batteries and flywheels are increasingly used to provide frequency response and other ancillary services. Economics and various regulatory hurdles have previously limited these technologies. However, installation costs are declining rapidly and regulatory developments are improving opportunities. In fact, battery installations operating on US power grids have increased nearly 700% since 2010. Figure IV-1 shows the breakdown of installed battery capacity. Approximately 48% of installed battery technologies in the US are lithium-ion, with lead-acid (30%) and nickel-based (11%) batteries making up the majority of the remainder.

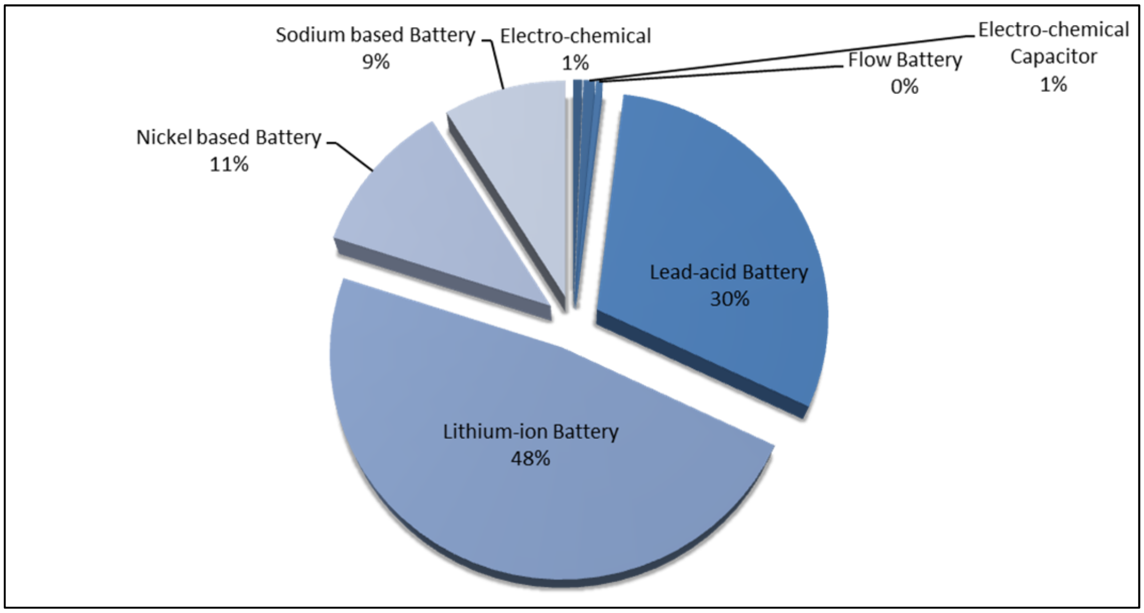

Figure IV-1: **Installed Capacity of Battery Storage Technologies in the US (MW)**[70]

Some commercially viable technologies, like pumped hydro and compressed air storage, are geographically limited. For example, PowerSouth Energy Cooperative's 110 MW (2,800 MWh) McIntosh Compressed Air Energy Storage facility in Alabama is the United States' first and largest operational compressed air facility. Compressed Air Storage generally requires a large geologic repository, such as an underground salt cavern, limiting where such facilities can be installed. Similarly, pumped hydro storage requires the appropriate geography such as a large body of water or significant variation in height.

[70] U.S. Department of Energy's Global Energy Storage Database, http://www.energystorageexchange.org/projects

Technology	First commercial use	U.S. Installed Capacity (MW)	Primary Use
Pumped Hydro	1928	~19,000	Peak shaving
Compressed Air	1991	~110	Peak shaving
Battery	2001	~140	Ancillary services, peak shaving, renewable integration
Flywheel	2008	~30	Ancillary services E.g., regulation up/down, frequency regulation

Table IV-3: **Overview of U.S. Installed Storage Technologies**

1. Federal Support of Energy Storage

There have been several policies and regulations enacted by the federal government. In 2011, the Federal Energy and Regulatory Commission (FERC) issued Order 755, which mandated that wholesale markets must develop compensation mechanisms for the provision of frequency regulation. This order ensures that all eligible resources, including energy storage, providing frequency regulation within existing RTO or ISO frequency regulation markets, are compensated at just and reasonable rates.

The Department of Energy (DOE) has developed several programs explicitly directed at the development of energy storage. For example, the DOE's Energy Storage Technology Advancement Partnership is a cooperative funding and information-sharing partnership between the DOE and interested states. The purpose is to accelerate the commercialization and deployment of energy storage technologies in the United States via joint funding and coordination. Similarly, the Smart Grid Investment Grant Program and the Smart Grid Demonstration Program seek to help fund and demonstrate the viability of a broad range of technologies that can help modernize the U.S. electric grid by transitioning to a smarter, stronger, more efficient and reliable electric system—including the use of innovative storage technologies.

2. Energy Storage in MISO

With the exception of FERC Order 755 implementation procedures, MISO has enacted few policy measures that directly affect energy storage. In compliance with FERC Order 755, MISO developed a compensation mechanism for frequency regulation services, which includes energy storage resources operating in both its day-ahead and real-time markets. MISO's mechanism, approved in December 2012, is a two-part compensation offer: one for the amount of capacity reserved for providing the service, and one for the amount of movement, or mileage, a resource makes in response to deployment signals. Beyond MISO's FERC Order 755 procedures, there have been no substantive energy storage polices enacted.

3. Energy Storage in PJM

PJM has recently developed two policies impacting energy storage. The first is its implementation plan for FERC Order 755, and the second is proposed changes to its capacity market.

In compliance with FERC Order 755, PJM developed requirements for frequency regulation resources to submit a two-part offer, composed of both a "capability" offer and a performance offer. PJM regulations require that certain adjustments be made to each of these when calculating the total Regulation Market Clearing Price. Specifically, PJM intended to adjust each capability and performance offer by a benefits factor, or, a system of converting megawatts of fast regulation into the units of slow regulation. The intent is to allow PJM to procure both unit types in a single market with a single clearing price. The requirements were approved in October 2012.

More recently, on December 12, 2014, PJM filed proposed rule changes with FERC (which have yet to be approved) that would fundamentally change PJM's forward capacity market. The proposed changes, referred to as the Capacity Performance Proposal, were largely driven by power generator outages during the 'Polar Vortex' of January/February 2014. This proposal is modeled after ISO New England's "Pay for Performance" rules, and is designed to introduce the appropriate incentives into PJM's RPM capacity auctions to improve reliability during summer/winter peak electricity demand periods. Related to storage, the proposal would allow energy storage to participate as a capacity resource. Under the current capacity auction rules, it is challenging for energy storage to qualify as a capacity resource.

4. Storage in Illinois

The mix of storage technologies operating or currently under development in Illinois' differs from the overall picture of the United States. The majority of energy storage facilities in Illinois are thermal and electro-chemical storage, with limited electro-mechanical. The applications of storage technologies in Illinois include electric bill management, load shifting, on-site power, electric supply capacity, and frequency regulation. A list of non-thermal storage installations and their application is provided in Table IV-4.

Project Name	Technology Type	Rated Power (kW)	Application
Follett VYCON Flywheel	Flywheel	300	• Operating Reserve Capacity • Resiliency
Invenergy Grand Ridge Wind Project BESS	Lithium Ion Titanate Battery	1,500	• Regulation • Renewable Energy Time Shifting
Elwood Energy Storage Center: RES Americas	Lithium Iron Phosphate Battery	19,800	• Regulation
Jake Energy Storage Center: RES Americas	Lithium Iron Phosphate Battery	19,800	• Regulation
AllCell Chicago EV Charging Station	Lithium-ion Battery	40	• Electric Service Power Quality
EnerDel Mobile Hybrid Power System	Lithium-ion Battery	15	• Electric Service Power Quality • Renewable Energy Time Shifting • Microgrid Deployment
Grand Ridge Energy Storage 31.5 MW	Lithium-ion Battery	31,500	• Operating Reserve Capacity
NextEra Lee/DeKalb 20 MW Illinois	Lithium-ion Battery	20,000	• Frequency Regulation • Short-Duration Renewable Firming • Transmission Support
S&C CES: Chicago/PJM Frequency Regulation	Lithium-ion Battery	150	• Regulation
Illinois Institute of Technology RDSI Perfect Power Demonstration	Zinc Bromine Flow Battery	250	• Black Start

Table IV-4: Energy Storage Systems in Illinois[71]

[71] DOE Global Energy Storage Database (http://www.energystorageexchange.org/projects)

a) Thermal Storage in Illinois

There are several examples of commercialized applications of thermal storage currently being deployed in the state of Illinois.   Some examples of installations are summarized below.

- Underwriters Laboratories (UL) installed a thermal-ice energy storage system at its facility in Northbrook, IL. The system is a peak shifting system designed to reduce UL's cooling costs in the summer months. The system uses lower cost power during the off-peak period at night to operate two 800-ton chillers to cool the system during ice production. The facility is able to provide approximately 17.5 MWh of energy storage capacity.
- Ice Energy installed three smaller thermal storage systems in Evanston, Naperville, and St. Charles totaling approximately 30 kW (0.06 MWh). Similar to the UL installation, these three facilities are load shifting/energy management systems that shift air conditioning electrical power demand to off-peak hours.
- Thermal storage provides air conditioning and emergency backup cooling for computers at the Harold Washington Social Security Center in Chicago. Four (4) 8,400 gallon existing water tanks were converted to ice thermal storage. The retrofitted system is capable of providing 1,960 ton hours of storage capacity as compared to 400 ton hours possible from chilled water storage. Ice is produced during off-peak night hours. The system has resulted in reduced maintenance costs of $4,000 per year while maintaining the cooling redundancy required by the government.
- Enwave Chicago's district cooling system in downtown Chicago is an integrated network of five (5) power plants providing over 100,000 tons of cooling capacity. The peak demand load shift to ice thermal energy storage reduces peak demand by 30 MW and requires less space than traditional chilled water storage plant. The system provides redundancy for any building attached to the network.
- The Center for Neighborhood Technology (CNT) located on the Northwest side of Chicago renovated its offices and installed a thermal storage unit as a part of the LEED Platinum certificated renovation. A Cryogel Ice Ball system was installed beneath the side yard to use as form of ice storage to shift air conditioning load to off-peak times.
- University of Illinois at Urbana-Champaign built a Thermal Energy Storage tank for the campus chilled water system. The tank is 6.5 million gallons and was to help meet 7000 tons of additional cooling requirements for five (5) building projects, all of which are completed with one exception. The goal was to meet the cooling needs for these buildings without increasing the number of chillers.

b) Battery Storage in Illinois

The use of battery storage in Illinois is increasing. Representative projects include:

- RES Americas announced two major battery projects in November 2014 with estimated commercial online dates of August 2015. The projects are the Elwood Energy Storage Center in West Chicago and the Jake Energy Storage Center in Joliet. Both facilities are planned to have approximately 7.8 MWh of energy storage capacity utilizing lithium-ion batteries. These projects are intended to provide real-time frequency regulation service to the PJM ancillary services market and are interconnected to the ComEd electric grid.
- Invenergy and Xtreme Power through a joint venture installed a 1.5 MW lithium-ion battery system at Invenergy's Grand Ridge Wind facility in La Salle County. The primary purpose of

this installation is frequency regulation. Additionally, Invenergy is working with Blue Oak Energy at this site to build a 23 MW solar farm. This project will consist of twenty individual 1 MW solar inverters and over 155,000 photovoltaic modules.

- S&C Electric Company has installed a 150 kW lithium-ion battery system at its headquarters in Chicago, intended to participate in PJM's frequency response market.
- AllCell, as part of its solar-EV charging station in Chicago, has installed a 40 KWh lithium-ion battery to help regulate uneven power demands of EV charging and provide enough capacity to charge two vehicles in case of a power outage.

c) Other technologies in Illinois

Follett Higher Education Group installed a 300 kW (0.002 MWh) VYCON flywheel system at its distribution center in Aurora. The system is primarily intended to serve as back-up on-site power in the event of an outage.

F. The Procurement of Storage in the United States

The integration of storage technologies for grid applications is increasingly deemed necessary throughout the United States. Several states have recently made or proposed regulatory changes that improve the commercial environment for energy storage technologies. Additionally, several utilities have issued request for proposals (RFPs) or request for offers (RFOs) to procure innovative storage technologies. This section highlights the recent regulatory and procurement advances in four states (New York, Texas, Hawaii and California). These four geographically diverse states provide an indicative view of how regions across the US are thinking about modernizing their electric grids through the integration of storage technologies.

1. New York

a) Regulatory Overview

Changing market conditions and industry-wide challenges; such as aging infrastructure, increases in distributed resources, and increasingly destructive storms; have motivated New York to take a proactive role in changing the way it produces and consumes energy. In April 2014, the New York Public Service Commission (NYPSC) launched a proposal called Reforming the Energy Vision (REV). REV is an ambitious initiative focused on restructuring the state's energy industry and regulatory practices towards a customer-focused system. The goal is to create a system that takes advantage of advanced and emerging energy technologies. Overall, REV envisions re-purposing the electrical distribution system to enable Distributed System Platform Providers (DSPPs) to provide advanced electricity products and services to customers. REV promotes increased adoption of distributed technologies such as micro grids, on-site power supplies and energy storage.

The specific details regarding REV, including the specific products and services that would be enabled by DSPPs, are still being refined. However, in February 2015, the New York Public Service Commission issued the first major order related to REV. This order identifies a process for adopting a policy framework around electric industry reform. Though in its infancy, REV is poised to alter the ways in which New York manages its energy, including the wider integration of energy storage.

New York has taken several steps to encourage the development of energy storage beyond REV. In April 2014, Governor Andrew M. Cuomo announced the opening of the Battery and Energy Storage Testing and Commercialization Center in Rochester, New York. The Center is a collaboration between NY Battery and Energy Storage Technology Consortium (NY-BEST) and DNV GL, an international energy testing and advisory firm. The purpose of the center is to facilitate technological growth and catalyze the storage industry in New York. The facility offers testing, product development and validation services necessary to drive technological advancements in energy storage technology—particularly battery storage.

In response to the potential retirement of New York's Indian Point Energy Center nuclear plant, the New York State Energy Research and Development Authority (NYSERDA) partnered with Consolidated Edison and the New York Power Authority to create a Demand Management Program ("DMP"). The program seeks a 125MW reduction in peak demand through the incorporation of various demand response resources, such as Combined Heat and Power (CHP) and energy storage. The DMP offers financial incentives to customers who are able to achieve a combined peak demand reduction of 50kW or greater between the hours of 2pm-6pm, Monday through Friday, from June 1st through September 30th. Thermal storage solution incentives are capped at $2,600/kW and battery storage solution incentives at $2,100/kW.

b) Recent Procurements

1) Long Island New Generation, Energy Storage and Demand Response Resources

In 2013, the Long Island Power Authority (LIPA) issued an RFP to replace some of its aging and inefficient peaker fleet by May 2019. Rather than restoring existing plants or building new ones that rely on conventional generation resources, LIPA planned to replace its infrastructure with a combination of more efficient, modern, and cleaner peaking systems. These new systems would feature distributed generation, demand response, and energy storage. One of the RFP's goals was to install up to 150 MW of energy storage resources that would assist black start operations and help regulate planned increases in renewable resources. In December 2014, LIPA announced that it has decided not to move forward with any of the applicants. However, LIPA issued an explanation recognizing the need for these types of resources throughout the electric system, and stated that they expect more RFPs to be issued in the future. The future RFP's will be in coordination with PSEG Long Island's Integrated Resource Plan, PSEG Long Island's Utility 2.0 Long Range Plan, and the New York Public Service Commission's Reforming the Energy Vision.

2) PSEG Long Island– Utility 2.0 Long Range Plan

While peak demand has grown in the Long Island jurisdiction, round-the-clock energy use has remained relatively constant. This has driven the need for increased capacity during a select number of hours. In July of 2014, PSEG LI, which operates LIPA, submitted the Utility 2.0 Long Range Plan to help address this challenge of decreasing load factor. The Utility 2.0 Plan seeks to invest in more customer-oriented solutions that reduce peak demand for electricity, and thereby improve the efficiency and resiliency of the grid at an affordable cost. The plan features the need for increased energy storage, and has called for the development of an energy storage system that would operate as part of a microgrid pilot program. The microgrid pilot program would operate within the framework of a larger South Fork infrastructure deferment plan. Under the plan, PSEG LI would develop, own and operate a 5MW/25MWh battery storage system. The utility expects the $15 million system to:

- Facilitate significant additions of renewables.
- Enhance power quality.
- Enhance grid reliability and resilience across the vulnerable grid areas.
- Be coupled with one or more large solar arrays.

- Develop a successful demonstration of storage that could be applied elsewhere.

PSEG LI had previously issued an RFP for New Generation, Energy Storage and Demand Response Resources, on which the bidding closed in March 2014. In December 2014 PSEG announced that it was no longer pursuing any of the proposals it had received under that RFP but that it would be issuing new RFPs under the Utility 2.0 Long Range Plan.[72]

2. Texas

a) Regulatory Overview

In 2011 Texas enacted SB 943, which specifically recognized storage as a potential generation resource in Texas' wholesale energy and ancillary markets. Prior to this legislation's passage, Texas' power markets did not explicitly specify if storage was able to participate. Per SB 943, energy storage equipment or facilities that operate in the wholesale market must register as a Power Generation Company with the Public Utility Commission of Texas (PUCT). The legislation additionally clarifies that energy storage is afforded all the same interconnection rights as any other generation asset. However, the legislation does not speak to the use of energy storage as a transmission asset.

Since the passage of SB 943, the PUCT has taken several steps to improve the integration of energy storage to the Texas grid. In late-2011, the PUCT provided clarity to interconnection of energy storage by explicitly developing rules to include electric energy storage equipment or facilities under the definition of a power generation company per SB 943 (project number 39657). Given the dual nature of storage[73], it was unclear how storage should be treated. In March 2012, the PUCT clarified the operation of energy storage. It determined that energy storage equipment or facilities will be settled at the node when charging, and these transactions will be considered wholesale and will generally not be subject to ancillary costs (Project Number 39917)[74]. To improve the integration of energy storage in Texas, the PUCT in 2012 granted the Electric Reliability Council of Texas[75] (ERCOT) the authority to conduct pilot projects and grant temporary exceptions to ERCOT rules for the pilot projects. The purpose of this rule change is to allow ERCOT to develop better knowledge, understanding and experience with novel technologies and services.

b) Recent Procurements

With the majority of Texas falling under ERCOT's fully competitive, energy-only market, there have been limited RFPs related to the procurement of storage. However, in November 2014, Texas' largest transmission and distribution provider, Oncor, announced a proposal to install up to 5,000 MW of energy storage on the ERCOT power grid at an approximate cost of $5 billion.

Oncor's proposal highlights a principal challenge for energy storage providers in competitive energy markets. In an energy competitive market, such as ERCOT, transmission and distribution utilities are

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[72] PSEG Long Island press release, December 3, 2014, at http://www.longisland.com/news/12-03-14/lipa-statement-on-gsdr-rfp.html.

[73] Storage acts as a consumer when charging and a generator when discharging.

[74] In the ERCOT wholesale market, load generally is charged a zonal price whereas generation is typically settled at the node.

[75] Operates the electric grid and manages the energy market.

typically prohibited from owning generation to prevent the utilities from exerting inappropriate market power. Given that SB 943 defines energy storage as a power generation resource, Oncor is currently unable to own and operate storage technologies. However, as discussed in Section IV.C.4 of this report, energy storage technologies can be used by transmission and distribution providers for services outside of wholesale energy and ancillary markets, such as the deferment of investment in new transmission and distribution lines, reduction in congestion, and providing voltage support. In other words, storage cannot just improve the efficiency of wholesale markets, but also the operation of transmission and distribution.

As such, Oncor seeks to change current market rules that define energy storage as a power generation resource. Oncor commissioned The Brattle Group to study and develop a proposal for storage in ERCOT. The proposal suggests that for storage to be cost competitive on the transmission and distribution side, energy storage technologies should be able to receive compensation for providing benefit to both the wholesale energy market and the transmission and distribution utilities. In particular, The Brattle Group's proposal would modify the current law to allow transmission and distribution utilities to auction off the wholesale generation portion of utility-owned storage resources to independent generators. The independent generators would then be able to sell the generation directly into the ERCOT wholesale markets, and thereby mitigate market power concerns.

3. Hawaii

a) Regulatory Overview

Hawaii has experienced significant growth in renewable generation, both at the grid-level and behind-the-meter. While Hawaiian electric utilities continue to integrate high-capacity renewable projects, distributed rooftop solar is the fastest growing share of renewable generation each year. These projects have reduced reliance on imported oil, created thousands of jobs, and put Hawaii on track to exceed its 2015 Renewable Portfolio Standard goal. Despite these advances, Hawaii has recognized that continued penetration of distributed resources will require a more advanced, modern grid to successfully accommodate new technology. Hawaii understands it must address issues and concerns such as renewable variability and reliability. Additionally, Hawaii has found that new legislation is necessary to ensure that utilities are fairly compensated for new services provided to customers, and that customers are fairly compensated for services provided to the utility via distributed generation.

In 2014, Hawaii passed HB 1943, which established five guiding principles and a timeline for Hawaii to address the modernization of its electric infrastructure. Among those principles, Hawaii intends to:

- Diversify the state's portfolio of renewable resources.
- Expand customer options for energy management.
- Establish just rules, orders, and tariffs.
- Determine fair compensation for grid services (customer or utility).
- Maintain or enhance grid reliability and safety.

Additionally, the Act explicitly states that energy storage and demand response will be a critical component to Hawaii's future electricity grid.

b) Recent Procurements

1) Kaua'i Island Utility Cooperative

In March 2014, Kaua'i Island Utility Cooperative ("KIUC") issued the Energy Storage/Dispatchable Renewable Energy RFP. KIUC's request is broad in its requirements, but articulates a number of needs that should be addressed. The first requirement is to store over-generation during the midday hours in order to avoid curtailment of low-cost renewable energy. The second is to be able to release stored energy back onto the grid to assist its conventional peak resources afternoon load ramps that can result in increases of 40MW during a four hour period.[76] The final requirement focuses on evening peak shaving, which is currently the utility's highest cost period for power generation.

Although the utility deliberately allows for a range of different solicitations, KIUC offers a list of requirements including:

- The range of sizes and flexibility of energy storage solutions
- An explanation of the levelized cost of storage in $/MWh; initial capital and ongoing O&M costs, as well as proven round-trip efficiency
- The desired financing structure desired by vendor (i.e. energy only PPA, performance contract, purchase contract, etc.)
- An explanation of the size profile and time period availability of energy storage (i.e., 40 MWh available in a 8MW by 5 hour time frame, starting any time after 4:00pm daily)
- A proven track record of bidder or system provider in bringing similar projects online; a list of references.

While KIUC has not yet procured storage as part of this RFP, KIUC recently won approval from the Hawaii Board of Land and Natural Resources for to conduct site-specific feasibility studies for the development of a 25 MW pumped hydro system.

2) Hawaii Electric Company

In April of 2014, Hawaiian Electric issued an RFP for the engineering, procurement and construction of 60 to 200 megawatts of energy storage. The system will be installed on the island of Oahu. It is intended to provide frequency regulation, minute-to-minute load following, peak shaving, and load shifting services to further facilitate the integration of renewable resources across the island's electric grid.

As renewable energy penetration has rapidly increased, Oahu has experienced a variety of issues largely associated with the intermittent nature of wind and solar. This has resulted in an over-reliance and inefficient utilization of the grid's thermal generation resources, and an increasing need for voltage support and frequency regulation. Hawaiian Electric expects that energy storage systems will address these challenges and further enable the utility to successfully integrate its renewable resources.

The proposals for the RFP include lead-acid batteries, several forms of lithium-ion batteries, flow batteries, pumped-storage hydroelectric, and mechanical flywheels. Hawaiian Electric has selected three finalists. All three proposed battery storage technologies. The utility is in the process of negotiating energy storage agreements with these finalists and is targeting filing the agreements with regulators in 2015.

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[76] Peak load is approximately 80 MW on Kauai.

4. California

a) Regulatory Overview

California has taken several steps to increase the procurement of storage on its grid. In September 2010, California enacted AB 2514. This legislation requires the California Public Utilities Commission ("CPUC") to establish appropriate energy storage targets for regional utilities. The bill requires investor-owned utilities[77] (IOUs) to meet energy storage system procurement and installation targets, set by the CPUC, by 2015 and 2020 respectively. The storage targets are to be integrated into the IOUs renewable energy procurement plans. Additionally, AB 2514 requires publicly owned utilities to set their own targets for the procurement and installation of energy storage and meet those targets by 2016 and 2021 respectively.

In December 2010, the CPUC opened a rulemaking proceeding (R.10-12-007), leading to the issuance of ruling D. 13-10-040 "Decision Adopting Energy Storage Procurement Framework", in October 2013. This Decision set a combined IOU energy storage target of 1,325 megawatts (MW) by 2020. The target must be completed with required installations by the end of 2024. Additionally, the Decision establishes a target for other CPUC jurisdictional electric service providers[78] to procure energy storage equal to one percent of their annual 2020 peak load by 2020 with installation no later than 2024.

The plan outlines three guiding principles for the integration for storage by the utilities:

- The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments,,
- The integration of renewable energy
- The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California goals.

California currently has the largest energy storage target in the United States, and has led to several recent RFPs (discussed further below).

In addition to the storage target rule making process, California has implemented several other regulatory changes favorable to storage. Two such changes are to the CPUC's Self-Generation Incentive Program ("SGIP"). The SGIP was established in 2001, through AB 790, as a peak-load reduction tool in response to California's 2000-2001 energy crisis. The program was originally intended to incentivize both renewable and non-renewable distributed generation technologies. In 2009, the program was modified by SB 412 to change the primary goal of the program to greenhouse gas emission reductions. In September 2011, California approved AB 1150, which further modified the SGIP by authorizing the eligibility of energy storage in the program. The program covers standalone energy storage as well as storage coupled with PV.

b) Recent Procurements

1) Southern California Edison

Southern California Edison (SCE) issued two recent storage related RFOs, geared towards addressing different types of system challenges.

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[77] Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.

[78] California allows communities (municipalities) energy aggregation and third party sales to some retail customers.

The first RFO was part of SCE's Local Capacity Requirements procurement for the West LA Basin and Moorpark Sub-Areas. The RFO, issued on September 12, 2013, solicited a range of resources including gas-fired generation, combined heat and power, demand response, energy efficiency, energy storage, renewable, resource adequacy, and distribution generation. On November 21, 2014, SCE announced the list of successful projects, which included 264 MW of storage-related contracts. Of that, 100 MW is a grid-connected lithium ion battery storage system, 29 MW is behind-the-meter thermal storage, and 235 MW is behind-the-meter battery storage.[79] The total exceeded the minimum energy storage procurement authorized by the CPUC (50 MW). In this solicitation, energy storage was competing with a range of conventional resource types.

The second RFO was exclusively for the procurement energy storage resources. In December 2014, SCE announced released an RFO for 16.3 MW of energy storage under California's energy storage targets. Under the FRO, energy storage must be at least 1 MW and must be a fully-deliverable transmission or distribution connected market resources. Additionally, proposed energy storage must qualify as eligible storage under the CPUC's energy storage target requirements. SCE is soliciting under two different structures. The first would procure energy storage power purchase agreements for resource adequacy. The second would procure all deliverable benefits of the energy storage facility including capacity and ancillary services. The deadline for indicative offers is April 1, 2015.

2) Pacific Gas & Electric

In December 2014, Pacific Gas & Electric (PG&E) issued an RFO for 74 megawatts of eligible energy storage resources connected to PG&E's transmission or distribution systems. As part of this RFO, PG&E seeks to purchase energy storage resources, either on a turnkey basis, or by entering into agreements, that minimally meet the following requirements:

- Are 1 MW or larger and connected to PG&E's distribution system
- Are 10 MW or larger and connected to the CAISO transmission system[80]
- Have a minimum of 15-minute discharge duration.

Projects must be capable of providing energy, capacity, or ancillary services for use by the CAISO, and must serve one of the three guiding purposes outlined in the CPUC Decision. The RFO submittal deadline was February 17, 2015. PG&E is currently reviewing offers and plans to notify shortlisted participants on April 24, 2015.

3) San Diego Gas & Electric

San Diego Gas & Electric (SDG&E) has issued two recent storage solicitations, geared towards addressing different types of system challenges.

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[79] Public Testimony of Southern California Edison Company in California Public Utilities Commission Docket A14-11-012, November 21, 2014, at http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/46ABDD2208E5CFC288257D980006196D/$FILE/A.14-11-XXX - SCE-1 PUBLIC Testimony of SCE on LCR RFO in LA Basin.pdf, pp. 71-77.

[80] Pumped hydro may not be larger than 50 MW.

The first storage solicitation was issued in September 2014, as part of SDG&E's ongoing 2014 All-Source RFO for Local Capacity Requirements. This RFO is partially in response to the closure of the San Onofre Nuclear Generation Station, as the closure created a deficit in local resource adequacy. This RFO seeks to procure between 25 MW and 800 MW of energy storage for capacity purposes. The procurement is intended to help fill the current projected capacity shortfall and SDG&E's 2015 energy storage target, under the CPUC's storage framework. Offers were due on January 5, 2015, and are currently under review.

The second solicitation is an RFP issued in December 2014 for a distribution level 4MW/12MWh utility-owned Energy Storage System ("ESS") in lieu of traditional circuit upgrades. The ESS will not participate in the California wholesale market. Offers are due on March 31, 2015.

4) Southern California Public Power Authority

Southern California Public Power Authority[81] (SCPPA) issued a renewable energy and energy storage RFP in February 2014. The RFP seeks to find the best combination of projects or products to store energy, with an emphasis of integrating Renewable Portfolio Standards (RPS)-compliant intermittent renewable energy into SCPPA's system. The RFP is largely open-ended on the technical requirements for energy storage developers, including guidance on the size of the proposed storage facilities. The deadline for proposals was December 31, 2014. However, SCPPA reissued the RFP on January 1, 2015 with a new response deadline of December 31, 2015.

5) Imperial Irrigation District

In January 2014, the Imperial Irrigation District[82] (IID) issued a Request for Qualifications (RFQ) for the design, engineering, procurement and construction of 20-40 MW of utility scale battery storage. Although not bound by the CPUC's storage targets, the IID agreed to construct a storage facility as part of a settlement with Federal Energy Regulatory Commission (FERC) after a blackout in 2011[83].

IID's RFQ was broad, requesting that projects be able to address the following operational characteristics:

- Spin/non-spin reserves.
- Automatic ramping.
- Frequency regulation.
- Capacity (20-40 MW).
- Support intermittent renewable integration.
- Peak shift energy.
- Black start capability.
- Ancillary service capacity.
- Smooth intermittent resource output.
- Improve short-duration performance.
- Improve system reliability.

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[81] A joint power authority formed to generation and transmission resources. The members include one irrigation district and eleven municipal utilities.

[82] A community-owned provider of irrigation water and electric power.

[83] This blackout left nearly 3 million customers without power on a day when temperatures reached nearly 115 degrees.

- Improve power quality.
- Integrate intermittent distributed generation.
- Provide uninterruptible power supply.

This RFQ resulted in nine vendors being selected for the second phase of the solicitation, which are still currently under consideration.

G. Summary

There is growing interest nationally in energy storage. One key driver of this interest is the perceived need for additional tools to integrate renewable energy; but there are a number of other potential storage applications under consideration. Storage assets have the ability to meet multiple requirements, which adds to their value but forces planners to take care to avoid double-counting benefits, or double-counting capacity (e.g., by assuming the same storage capacity can be simultaneously producing energy and reserves).

A variety of storage technologies are available, based on a number of physical and chemical processes. These technologies are at various stages of development and commercial availability. While storage is expensive, the cost is expected to come down.

Energy storage policy and procurement continue to evolve across the United States. Several states have developed policies to aid the integration of energy storage technologies into their electric grids. Each state is pursuing policy directed at meeting both local operational needs and broader state policy goals. Of the procurement processes reviewed, the majority are still in process. To aid in the understanding of how energy storage technologies could help meet the needs of Illinois customers, Illinois should continue to monitor the developments in other states and the results of these solicitations.

V. Alternative Compliance Payment Mechanism Fund Report

"[T]he Illinois Power Agency shall submit an annual report to the General Assembly, the Commission, and alternative retail electric suppliers that shall include …

> ***(A) the total amount of alternative compliance payments received in aggregate from alternative retail electric suppliers by planning year for all previous planning years in which the alternative compliance payment was in effect;***
>
> ***(B) the total amount of those payments utilized to purchased [sic] renewable energy credits itemized by the date of each procurement in which the payments were utilized; and***
>
> ***(C) the unused and remaining balance in the Agency Renewable Energy Resources Fund attributable to those payments."***[84]

Whether through self-procurement or alternative compliance payments ("ACPs"), each ARES is responsible for procuring the same proportion of cost-effective renewable energy resources as each electric utility, measured as a percentage of prior year load and with costs calculated on a per kilowatt hour basis.[85]

Up to, but no more than half of that procurement obligation may be met through self-procurement of renewable energy resources. An ARES must meet at least 50% of its renewable resource requirements by making ACPs, and may meet the entirety of its renewable resource obligation through ACPs.[86] As of this report date, most ARES have chosen to meet only the minimum amount of the RPS requirement (50%) using the ACP mechanism. ACPs related to ARES' compliance for load served in the energy delivery year beginning June 1, 2015 must be made by September 1, 2016.[87]

To the extent the ARES complies by procuring renewable resources, at least 60% of the renewable energy resources procured by an ARES must be from wind generation. Starting June 1, 2015, at least 6% of the renewable energy resources procured must be from solar photovoltaics.[88] If an ARES does not purchase at least the technology-specific sub target levels of specified renewable energy resources (wind, photovoltaics), then it is required to make additional ACPs.

All ACPs are placed into the Agency's Renewable Energy Resources Fund ("RERF") that is intended to be used to purchase RECs.[89]

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[84] 220 ILCS 5/16-115D(d)(4).

[85] 220 ILCS 5/16-115D(a).

[86] 220 ILCS 5/16-115D(b).

[87] 220 ILCS 5/16-115D(d)(2).

[88] 220 ILCS 5/16-115D(a)(3) (the 60% statutory wind energy minimum for ARES is lower than the 75% wind standard for utilities).

[89] 20 ILCS 3855/1-56.

A. Total Amount of ACPs Received

This report must provide the total amount of alternative compliance payments received in aggregate from alternative retail electric suppliers for each planning year in which the alternative compliance payment was in effect.90 Under the PUA, a "planning year" begins on June 1st of each calendar year.91 The ACP mechanism was "in effect" by September 1, 2010 to require payments by ARES for the period of June 1, 2009 to May 1, 2010.92 Therefore, this report must provide the aggregate total amount of ACPs for planning years 2009-10, 2010-11, 2011-12, 2012-13 and 2013-14. Table V-1 shows the total ACPs for each year.

Planning Year	Funds Received	Total ACPs
June 2009 – May 2010	2010 – Quarters 3 and 4	$7,148,261.61
June 2010 – May 2011	2011 – Quarter 3 and 4	$5,606,245.18
June 2011 – May 2012	2012 – Quarter 3 and 4	$2,156,777.61
June 2012 – May 2013	2013 – Quarter 3 and 4	$38,382,345.57
June 2013 – May 2014	2014 – Quarter 3 and 4	$77,145,921.09
Aggregate Total		**$130,439,551.06**

Table V-1: Total ACPs Received[93]

B. Amount of ACPs used to purchase RECs

1. Purchases Made

May 2013 marked the first time the IPA utilized RERF funds to purchase RECs. The IPA was granted a legislative appropriation to spend $8 million from the RERF in the 2013 fiscal year. For the 2014 fiscal year $51 million was appropriated and $1,719,141.52 was spent. For the 2015 fiscal year the IPA was appropriated $50 million. In addition, the IPA was granted legislative approval to commit up to $30 million from the RERF towards the purchase of RECs from PV resources. As discussed further below, the first procurement for that $30 million commitment is scheduled for June 2015.

In 2013, the IPA and ComEd offered to purchase an amount of curtailed RECs which corresponds to the amount by which REC deliveries under the 2010 LTPPAs were curtailed for the participating LTPPA-

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[90] 220 ILCS 5/16-115D(d)(4)(A).

[91] *See e.g.* 220 ILCS 5/16-111.5(b).

[92] Pub. Act 96-0033 (eff. 7/10/2009); 220 ILCS 5/16-115D(d)(2).

[93] Total ACPs Received does not account for expenditures from the RERF and, therefore, the Aggregate Total reported in this figure will differ from the RERF balance reported in Table V-2.

holders based on the budget cap and the imputed price of those RECs.[94] In May 2013, the IPA entered into contracts to purchase RECs associated with ComEd's curtailed long-term contracts that were not otherwise purchased by ComEd using the hourly ACP payments.[95] These purchase contracts were for the delivery year June 1, 2013 through May 31, 2014, and were for up to 121,620 RECs with no minimum delivery levels with a total value of $2.24 million. The contracts did not require delivery of RECs and, due to improved market prices for RECs elsewhere, not all contract holders exercised their rights to deliver RECs. A total of 74,402 RECs were delivered by suppliers in the June 1, 2013 through May 31, 2014 delivery year under these contracts at a total cost of $1,719,141.52. There is no direct rate impact of these contracts because they utilize funds already collected from customers of Alternative Retail Electric Suppliers as part of those suppliers' compliance with the Renewable Portfolio Standard. As approved in ICC Docket No. 12-0544, ComEd also used hourly ACP funds to purchase 79,674 RECs from suppliers under the LTPPAs in the June 1, 2013 through May 31, 2014 delivery year at a total cost of $1,647,596.

On June 28, 2014, Illinois Governor Pat Quinn signed Illinois House Bill 2427 into law as Public Act 98-0672, creating new section 1-56(i) of the Illinois Power Agency Act. Section 1-56(i) calls on the Illinois Power Agency to "develop a one-time supplemental procurement plan limited to the procurement of renewable energy credits, if available, from new or existing photovoltaics, including, but not limited to, distributed photovoltaic generation" through "using up to $30,000,000" from the RERF. Additional discussion of this plan is included in Section D below.

Prior to May 2013 the only disbursements from the RERF were temporary transfers of funds to the State's General Revenue Fund pursuant to 30 ILCS 105/5h(a). Of the $7,148,261.61 in total ACPs received for the 2009-10 planning year, the State of Illinois transferred $2,000,000 on September 20, 2010 and $4,710,000 on October 15, 2010.[96] The remaining $438,261.61 was not used to purchase RECs and remained in the RERF. The State was required to repay the funds within 18 months of borrowing, and it repaid $2,000,000 to the RERF in March 2012 and the remaining $4,710,000 was repaid in April 2012. Because the funds were transferred from a non-interest earning account, no interest was paid.

2. Agency Challenges in Spending RERF

To date the IPA has only spent a small portion of the funds available in the RERF. As the IPA explained in ICC Docket 12-0544 (approval of the 2013 Procurement Plan), Sections 1-56(c) and (d) of the IPA Act prevent the IPA from procuring renewable resources when bundled customers are at or above the rate cap from Section 1-75(c)(2)(E) or the Commission otherwise does not order a renewable procurement. This is because Sections 1-56(c) and (d) tie RERF procurements to utility procurements, including using utility procurements as a price cap for products procured from the RERF. Although the IPA has plans for spending the RERF in the manner outlined in Section 1-56(b) and in newly enacted Section 1-56(i) of the IPA Act, the IPA believes that absent legislative changes, any procurements using the RERF without an

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[94] Illinois Power Agency, *2013 Annual Report*, December 1, 2013, at 5. This document, which is available at http://www2.illinois.gov/ipa/Pages/IPA_Reports.aspx#AnnualReports, should not be confused with the *2013 Annual Report on the Costs and Benefits of Renewable Resource Procurement in Illinois*.

[95] Of the eight LTPPA-holders, seven elected to enter into contracts.

[96] 30 ILCS 105/5h(a).

associated utility procurement (other than the specifically authorized procurement plan developed in adherence to Section 1-56(i) of the IPA Act) would risk subsequent legal challenges at significant cost to the IPA and counterparties. The IPA remains actively involved in discussions with stakeholders about what legislative changes would be necessary to allow the RERF to be spent as intended by the General Assembly.

C. Balance in RERF attributable to ACPs

As of April 1, 2015, the RERF balance equals $30,550,341.21. Table V-2 shows the current IPA RERF balance sheet. The reported balance is significantly different from that reported in the 2014 Annual Report for several reasons. First, the ACPs received for the 2013-14 delivery year in the fall of 2014 totaled $77,145,921.09. These payments, in the aggregate, are significantly higher than prior year payments and is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

Second, Public Act 99-0002, which was signed into law by Governor Rauner on March 26, 2015, authorized the transfer of $98,000,000 from the RERF to the State's General Revenue Fund. That transfer occurred on April 1, 2015. Sufficient funds will remain in the RERF to allow the IPA to continue with the supplemental PV procurement required by Section 1-56(i) of the IPA Act.

Date	Transaction	Amount	Cumulative balance
Fall 2010	ACPs received	$7,148,261.61	$7,148,261.61
9/2010	Transfer out pursuant to 30 ILCS 105/5h(a)	($2,000,000.00)	$5,148,261.61
10/2010	Transfer out pursuant to 30 ILCS 105/5h(a)	($4,710,000.00)	$438,261.61
Fall 2011	ACPs received	$5,606,245.18	$6,044,506.79
3/2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$2,000,000.00	$8,044,506.79
4/2012	Transfer in pursuant to 30 ILCS 105/5h(a)	$4,710,000.00	$12,754,506.79
Fall 2012	ACPs received	$2,156,777.61	$14,911,284.40
Fall 2013	ACPs received	$38,382,345.57	$53,293,629.97
Winter/Spring 2014	RECs purchased per May 2013 Contracts	($1,719,141.52)	$51,574,488.45
Fall 2014	ACPs received	$77,145,921.09	$128,720,409.54
Fall 2015	Fall 2015 Supplemental PV Procurement Expenses	($170,068.33)	$128,550,341.21
Spring 2015	Transfer pursuant to Public Act 99-0002	($98,000,000)	$30,550,341.21

Table V-2. IPA RERF Balance Sheet

D. Future Use of the ACP-Funded RERF

As noted above, Section 1-56(i) of the IPA Act directed the Agency to “develop a one-time supplemental procurement plan limited to the procurement of renewable energy credits, if available, from new or existing photovoltaics, including, but not limited to, distributed photovoltaic generation” through “using up to $30,000,000” from the RERF. While the ICC has held that it does not have jurisdiction over the RERF, and as a result the IPA has not sought approval for procurement using the RERF in the approved 2015 Procurement Plan, enactment of Section 1-56(i) called for the ICC to approve the supplemental PV procurement plan[97] and the results of procurements stemming from that supplemental PV procurement.

On January 21, 20015 the ICC approved that plan which includes three procurement events to seek these RECs:

- June 2015 ($5,000,000 budget)
- November 2015 ($10,000,000 budget)
- March 2016 ($15,000,000 budget),

As noted in Section V.C above, the balance of the RERF declined significantly due to the transfer of funds from the RERF to the General Revenue Fund. While $30 million for the supplemental PV procurement was left in the RERF, the IPA is hesitant to speculate on other future potential expenditures from the RERF. The risk of the fund being subject to further transfer would create risks to any additional contracts the IPA may seek to enter into.

[97] See https://www.icc.illinois.gov/downloads/public/edocket/398633.pdf for the Final Approved Plan complying with the ICC’s order in Docket No. 14-0651.

Appendix A. Summary of IPA's Historical Renewable Energy Procurements

The ICC has approved the IPA's procurement of RECs to comply with the entirety of the utilities' RPS-mandated volumes except where the those purchases would increase rates above the cap specified in Section 1-75(c)(2)(E) of the IPA Act. A summary of the ICC's decisions authorizing those procurements is below:

- For the 2009 procurement, the ICC approved the IPA's plan to purchase RECs for delivery from June 2009 – May 2010 to fulfill the RPS mandate for that period and stated: "the IPA is not permitted to undertake the acquisition of multi-year or long-term renewable resources."[98]
- For the 2010 procurement, the ICC agreed with the IPA's proposal to procure RECs on a short-term basis, for delivery from June 2010 – May 2011.[99] The ICC additionally found that the 2010 LTPPAs "will supplement the short-term REC acquisition," and approved the IPA's revised plan to enter into LTPPAs for renewable energy supplies "outside of the RPS."[100]
- For the 2011 procurement, the ICC found that "a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy," and approved the IPA's plan to procure unbundled one-year RECs for delivery from June 2011-May 2012.[101]
- For the 2012 procurement, the ICC agreed with the IPA's proposal to include one-year RECs and to procure the minimum unbundled RECs required under the solar and wind REC carve-outs, taking into account LTPPA volumes for delivery from June 2012 – May 2013.[102]
- No REC procurements were conducted during 2013. The ICC approved[103] the IPA recommendation that there should be no new Ameren or ComEd REC procurement event in the 2013 Procurement Plan taking into account June 2012 – May 2013 REC volumes from the 2012 Rate Stability Procurement and anticipated LTPPA deliveries.[104]
- As part of the approval of the IPA's 2013 Procurement Plan, the ICC also approved a "curtailment" of the LTPPAs. The curtailment was the trigger of a contract term that allowed the ICC to order Ameren and ComEd to only take enough from the LTPPAs so that the rate cap in Section 1-75(c)(2)(E) of the IPA Act was not exceeded. The LTPPA holders accepted a temporary (annually reviewed) curtailment, but also had the contractual option to permanently curtail the contracts or to terminate the LTPPAs. The ICC authorized supplemental payments to the LTPPA-holders out of a non-bundled customer fund, and

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[98] ICC Docket No. 08-0519, Final Order at 45 (Jan. 7, 2009).

[99] ICC Docket No. 09-0373, Final Order at 127 (Dec. 28, 2009).

[100] ICC Docket No. 09-0373, Final Order at 126, 115, 43 (Dec. 28, 2009).

[101] ICC Docket No. 10-0563, Final Order at 83 (Dec. 21, 2010).

[102] ICC Docket No. 11-0660, Final Order at 84 (Dec. 21, 2011); IPA 2012 Power Procurement Plan (Updated) at 53 (Feb. 17, 2012).

[103] ICC Docket No. 12-0544, Final Order (Dec. 19, 2012).

[104] IPA 2013 Electricity Procurement Plan at 83-84 (Sept. 28, 2012).

the IPA used RERF funds to offer to purchase curtailed RECs. Based upon updated forecasts provided in March 2013, REC deliveries from the ComEd LTPPAs were curtailed but there was no curtailment of Ameren LTPPAs.

- No REC procurements were conducted during 2014. The ICC approved[105] the 2014 Procurement Plan without modifying the IPA's recommendation that there should be no new Ameren or ComEd REC procurement event in the 2014 Procurement Plan.[106] The basis for the IPA's recommendation was that the rate cap from Section 1-75(c)(2)(E) of the IPA Act was projected to be exceeded again in the 2014-15 delivery-year. The IPA further recommended that the utilities update their load forecasts in March 2014, and that a decision on LTPPA curtailment would be made on the basis of those forecasts. Based upon those updated forecasts, the ComEd LTPPAs were curtailed; ComEd then purchased the curtailed RECs using alternative compliance payment funds collected from its hourly customers pursuant to Section 1-75(c)(5) of the IPA Act.
- In its 2015 Procurement Plan, the IPA recommended that as the target total renewables and wind requirements are forecasted to be met in the 2015-16 delivery year, no additional wind or generic renewable resources should be procured on behalf of Ameren or ComEd. The IPA did, however, note that the photovoltaic ("PV") and distributed generation ("DG") requirements for both utilities are not forecasted to be met and recommended that a Spring 2015 procurement of Solar Renewable Energy Credits and a September 2015 procurement of DG RECs (using already collected hourly ACP funds) be conducted to meet each utility's PV and DG requirements for the 2015-16 delivery year[107]. The ICC accepted these recommendations.[108] The Commission also separately approved the supplemental procurement of RECs from new distributed PV systems, authorized by Public Act 98-0672, using $30,000,000 from the IPA's Renewable Energy Resources Fund.[109]

[105] ICC Docket No. 13-0546, Final Order (Dec. 8, 2013).
[106] IPA 2014 Electricity Procurement Plan at 102 (Sept. 30, 2013).
[107] IPA 2015 Electricity Procurement Plan at 100, 102, and 107 (Sept. 29, 2014).
[108] ICC Docket No. 13-0588, Final Order (Dec. 17, 2014).
[109] ICC Docket No. 14-0651, Order (Jan. 21, 2015).

Appendix B. Historical Cost Comparison

Cost of RECs and Electricity Delivered to ComEd for the 2013-14 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity[110]**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[111]	900,087	RECs	$18.29	$16,464,933
REC Purchases, 2012 Rate Stability	1,339,909	RECs	$1.28	$1,714,615
Total RECs	2,239,996	RECs	$8.12	$18,179,202
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	900,080	MWh	$38.58	$34,728,798
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement, Rate Stability	3,942,000	MWh	$32.57	$128,390,940
2011 Block Energy Procurement	12,555,600	MWh	$37.51	$470,917,380
Total Conventional Energy Resources	16,497,600	MWh	$36.33	$599,308,320

Table B-1. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2013-14 Delivery Year

110 According to ComEd, "small differences between REC amounts and Energy amounts [associated with the 2010 Long-Term Purchase Agreements] are due to rounding since RECs delivered each month are in whole integers and Energy is calculated out to .001 MWhs."

111 RECs delivered may include Carry-Over and Short-Fall RECs that reflect year to year delivery fluctuations.

Cost of RECs and Electricity Delivered to ComEd for the 2012-13 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity[112]**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[113]	1,205,267	RECs	$17.30	$20,848,772
REC Purchases, 2012 Procurement Plan	1,335,673	RECs	$0.88	$1,175,392
Total RECs	2,540,940	RECs	$8.67	$22,024,164
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	1,205,266	MWh	$38.04	$45,844,618
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement	411,600	MWh	$30.58	$12,587,388
2011 Block Energy Procurement	1,486,400	MWh	$44.55	$66,216,080
Total Conventional Energy Resources	1,898,000	MWh	$41.52	$78,803,468

Table B-2. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2012-13 Delivery Year

Cost of RECs and Electricity Delivered to ComEd in the 2011-12 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Procurement Plan RECs	2,117,054	RECs	$0.95	$2,011,202
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Block Energy Procurement	9,119,600	MWh	$36.84	$335,946,584
2010 Block Energy Procurement	2,529,200	MWh	$42.69	$107,982,124
Total Conventional Energy Resources	11,648,800	MWh	$38.11	443,928,708

Table B-3. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2011-12 Delivery Year

[112] See note 110.

[113] See note111.

Cost of RECs and Electricity Delivered to ComEd in the 2010-11 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Procurement Plan RECs	1,887,014	RECs	$4.88	$9,207,447
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Block Energy Procurement	9,866,800	MWh	$34.43	$339,703,232
2009 Block Energy Procurement	3,430,400	MWh	$41.47	$142,256,832
Total Conventional Energy Resources	13,297,200	MWh	$36.25	$481,960,064

Table B-4. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2010-11 Delivery Year

Cost of RECs and Electricity Delivered to ComEd in the 2009-10 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Procurement Plan RECs	1,564,360	RECs	$19.27	$30,145,217
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Block Energy Procurement	13,364,000	MWh	$33.17	$443,264,460

Table B-5. Relative Cost Comparison of RECs and Electricity Delivered to ComEd in the 2009-10 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2013-14 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[114]	482,581	RECs	$13.24	$6,391,185
REC Purchases, 2012 Rate Stability	536,020	RECs	$3.43	$1,836,736
Total RECs	1,018,601	RECs	8.08	$8,227,921
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	482,581	MWh	$38.43	$18,546,157
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement, Rate Stability	5,694,000	MWh	$29.51	$168,029,940
2011 Block Energy Procurement	5,466,800	MWh	$34.83	$190,426,316
Total Conventional Energy Resources	11,160,800	MWh	$32.12	$358,456,256

Table B-6. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2013-14 Delivery Year

[114] RECs delivered may include Carry-Over and Short-Fall RECs that reflect year to year delivery fluctuations.

Cost of RECs and Electricity Delivered to Ameren in the 2012-13 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
REC Purchases, 2010 Long-Term Purchase Agreements[115]	513,940	RECs	$12.29	$6,316,618
REC Purchases, 2012 Procurement Plan	523,376	RECs	$1.15	$600,269
Total RECs	1,037,316	RECs	$6.67	$6,916,887
Long-Term Renewable Energy, 2010 Long-Term Purchase Agreements	513,940	MWh	$37.92	$19,489,407
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2012 Block Energy Procurement	612,000	MWh	$27.78	$17,003,992
2011 Block Energy Procurement	3,448,400	MWh	$35.79	$123,421,404
2010 Block Energy Procurement	2,292,400	MWh	$35.06	$80,371,656
Total Conventional Energy Resources	6,352,800	MWh	$34.76	$220,797,052

Table B-7. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2012-13 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2011-12 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Procurement Plan RECs	952,145	RECs	$0.92	$878,354
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2011 Block Energy Procurement	3,856,800	MWh	$32.28	$124,506,944
2010 Block Energy Procurement	3,424,400	MWh	$35.69	$122,209,912
Total Conventional Energy Resources	7,281,200	MWh	$33.88	$246,716,856

Table B-8. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2011-12 Delivery Year

[115] See note 114.

Cost of RECs and Electricity Delivered to Ameren in the 2010-11 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Procurement Plan RECs	860,860	RECs	$4.05	$3,482,964
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2010 Block Energy Procurement	4,888,000	MWh	$31.31	$153,039,096
2009 Block Energy Procurement	4,139,200	MWh	$39.68	$164,239,360
Total Conventional Energy Resources	9,027,200	MWh	$35.15	$317,278,456

Table B-9. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2010-11 Delivery Year

Cost of RECs and Electricity Delivered to Ameren in the 2009-10 Delivery Year				
Procurements from Renewable Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Procurement Plan RECs	720,000	RECs	$15.86	$11,419,200
Electricity Procured from Conventional Energy Resources	**Delivered Quantity**		**Average Unit Price**	**Amount Spent**
2009 Block Energy Procurement	6,109,600	MWh	$33.04	$201,840,356

Table B-10. Relative Cost Comparison of RECs and Electricity Delivered to Ameren in the 2009-10 Delivery Year

Appendix C. Summary of Relevant Energy Storage Technologies

1. Electrochemical or Batteries

Electrochemical, or battery, technology is well suited for firming renewable resource output. Batteries are efficient and can respond quickly to rapid changes in renewable output. Capacity can be scaled by adding additional modules. Utilization times range from under an hour to almost eight hours. Battery technologies for grid utilization range from very mature, for lead-acid, to demonstration stage, for zinc-air. In normal operation, batteries are environmentally friendly. But because of the chemicals used, care should be taken during operation and decommission.

a) Lead-Acid Batteries

Lead-Acid batteries are the oldest form of rechargeable battery. They are present in a variety of commercial applications, resulting in good reliability and a wide variety of designs to choose from. They function by passing charge via acid-base chemistry. Contained in the battery are one lead-dioxide positive electrode (cathode) and one metallic lead negative electrode (anode). These are submerged in sulfuric acid, which allows charge to flow easily from one electrode to the other. There are two types of commonly used lead-acid batteries: lead-acid carbon and advanced lead-acid.

Lead-acid carbon batteries replace the negative electrode with an assembly of electrodes in separated cells. This increases efficiency and maximizes power storage. This results in faster recharge times, significantly longer life cycles, and minimal maintenance as compared to classic lead-acid batteries.

Advanced lead-acid batteries improve function by adding carbon to one or both electrodes in the battery. This limits "sulfation", or buildup of sulfur crystals, inside of the battery. These batteries have been successfully integrated in renewables systems such as wind and solar energy.

Both of these types of lead-acid battery are specifically designed for energy applications. They can also deliver high impulses of power if needed.

b) Lithium-Ion Batteries

Lithium-Ion is the fastest growing stationary energy storage technology. This mature technology is used in a number of commercial and consumer electronic applications. Lithium-Ion batteries are comprised of one negative carbon electrode and one positive metal-oxide electrode both submerged in an electrolyte bath with free floating lithium ions. A polymer electrolyte barrier conducts ions from one electrode and passes them to the other. Electrons cannot be transferred through the electrolyte barrier. In order to balance charge, they seek transfer through the external circuit, providing power through the external nodes of the battery.

Lithium-Ion storage for grid applications is available and in use in the United States. Commercial demand and popularity have driven down production costs. A large number of batteries are required to support grid scale operations. The metal oxide electrode is thermally unstable, so lithium-ion units are not recommended for processes requiring full discharge.

Lithium-Ion batteries have a high life cycle, high efficiency, and low standby energy loss. They also have high energy density; meaning less battery units are required to provide the same amount of energy support, saving on both installation cost and space. They are most commonly used in conjunction with renewable energy sources such as solar and wind power.

c) Sodium Based Batteries

Sodium-Sulfur Batteries are a commercialized and fast-maturing system currently employed globally. They have high discharge life cycle, high efficiency, and high energy density. However, high operating temperatures of 300-350ºC present a challenge to cost and overall efficiency.

The batteries are comprised of molten sodium negative electrode and a molten sulfur positive electrode, separated by solid beta alumina. This is submerged into positively charged molten sulfur where sodium ions pass through the beta alumina interface into the molten sulfur bath. The charge difference causes energy to be discharged.

Sodium-Sulfur batteries are best suited for large-scale grid applications due to long discharge times and rapid response. High power density allows for a smaller footprint, though infrastructure for temperature maintenance could require extra space. Cost estimates for manufacture and installation are still high due to the newness of this technology.

Sodium-Nickel-Chloride Batteries, like sodium-sulfur batteries, are kept at 270-350°C due to the use of molten sodium. The cell contains a positive nickel chloride electrode submerged in a bath of sodium tetrachloroaluminate all encased in a beta alumina tube, and a negative molten sodium electrode. Energy is chemically stored as sodium chloride and nickel are reacted into nickel chloride and molten sodium. The reaction is reversed upon discharge, releasing energy to the external circuit.

Compared to sodium-sulfur batteries, sodium-nickel-chloride batteries have higher over-charge and over-discharge tolerance, higher cell voltage, and better safety characteristics. These batteries have high reliability, high efficiency, and promising safety.

d) Flow Batteries

Vanadium Redox Flow Batteries have been demonstrated in large-scale field trials, but are not as mature as other battery types. They are comprised of two cells of aqueous acidic vanadium solutions. Electricity is chemically stored in these cells. Reduction takes place in one cell with a negative electrode. Oxidation takes place in the other cell with a positive electrode. A proton exchange membrane between the two cells allows charge to pass between them. Energy is discharged when the reduction cell undergoes an oxidation reaction, and the oxidation cell undergoes a reduction reaction. The discharge is released through the external circuit.

Vanadium electrolyte solutions are stored in separate tanks and must be pumped into the batteries as needed. Reaction occurs within milliseconds of electrolyte exposure. When in the discharged state, the two electrolytes are chemically the same, which simplifies the storage. Temperature control systems are a necessary to keep stored electrolytes within an appropriate temperature range.

These batteries are useful in utility applications such as load shifting, renewables time shifting, mitigating transmission curtailment, spinning reserve, power quality (especially long duration), voltage support, and frequency excursion suppression. They have a high tolerance for over-charge and over-discharge and can be used easily in utility-scale applications.

Iron-Chromium Redox Flow Batteries have reached the demonstration stage of development. They are projected to have a low cost structure making them a potential source of grid storage. Like the Vanadium battery, the Iron Chromium system suspends the electrolytes in liquids stored in separate tanks. They are pumped into the battery as needed. The difference is that both iron and chromium are abundant, relatively low-cost materials.

Zinc-Bromine Batteries are another type of flow battery early in their practical application. They are comprised of a positive bromine electrode and a negative zinc electrode separated into two cells by a micro-porous membrane. These are submerged in an aqueous bath of catholytic (positively charged) and anolytic (negatively charged) zinc bromine. Each of these electrolytes must be pumped into each cell with two separate flow streams. These streams can be co-current or counter-current depending on the battery design.

While charging, elemental zinc is plated onto the negative electrode, and solid bromine forms on the positive electrode. When discharged, the reaction reverses and both the elemental zinc and solid bromine are dissolved back into the electrolyte bath. Energy is released to the external circuit.

These batteries have long lifetimes, long charge and discharge life cycles, and average efficiency. Module sizes can vary greatly.

e) Zinc-Air Batteries

Zinc-Air Battery technology is being tested at several utilities. The battery consists of an electropositive metal, such as zinc, aluminum, magnesium, or lithium, and an electrochemical couple. These work with oxygen from the air acting as a second electrode. Current is produced when the air electrode is discharged with the help of a catalyst, leaving hydroxyl ions in the electrolyte bath. This oxidizes the metal electrode and creates a current. When the battery is recharged, the process is reversed, and oxygen is released into the air electrode. Zinc-air batteries are susceptible to changes such as humidity and air pollutant contamination.

Because each battery only requires one electrode, energy densities can be very high. This is expected to result in low-cost, high-efficiency systems. Fewer batteries would be required per module, resulting in a smaller footprint. Unlike other batteries, zinc-air batteries do not produce environmentally dangerous components when being disposed and are highly recyclable.

2. Mechanical

a) Pumped Hydro

Pumped hydro is a very mature energy storage system that uses gravitational potential. Two water reservoirs are constructed at different heights with a pump to move the water to the upper reservoir and a generator to create electricity as the water flows to the lower reservoir. Water is pumped to the upper reservoir when energy is in excess, usually during non-peak hours. It is then allowed to flow from the upper to the lower reservoir during peak hours where it passes through turbine generators to produce energy.

Its capacity and location are limited by terrain and ecological protections. The site requires hydraulic head, so it must include an elevation change such as a large hill or mountain. While the facility is running, factors such as noise, ground vibration, watershed effects, and outgoing water temperature may affect wildlife.

Pumped storage facilities are a popular and well-established power technology. They have a long lifespan, and can be sized to high capacity. They are built for long discharge times and frequent use.

b) Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) uses a large air compressor to pump compressed air into either above ground storage containers or belowground caverns. The air is pumped into these containers during off-peak hours. During peak hours, the compressed air is heated to create higher pressure. Then this pressurized air is released through expansion turbine generators, producing electricity.

CAES can be built in a variety of environments. With the use of underground storage, a cavern or other underground reservoir is necessary. This encourages the re-use of old caves and mines. Above ground storage requires the construction a number of storage vessels.

Second generation CAES use a natural gas combustion turbine to heat the compressed air before it is released to the expansion turbines. Effectively, a storage loop is inserted between the compressor and the turboexpander, occupying a position similar to that of the intercooler in an automotive turbocharger. CAES has relatively long discharge times.

Three primary types of expansion technologies are used in CAES systems. Diabatic systems harness the heat added during expansion when the air is released to increase power capacity. Adiabatic systems capture heat from the compression process and recycle it to heat up the air during expansion. Near-isothermal systems compress and expand the air slowly so that there is no need to reheat the air. This saves on fossil fuels that would normally be used to reheat the air. The different technologies result in varying efficiency estimates and utilization times.

c) Flywheels

Flywheel energy storage is a mature system that is regarded as both reliable and environmentally safe. It uses the angular momentum of a rotor to store kinetic energy. When power is needed, a power conversion system is used to turn this kinetic energy into AC power.

Flywheel energy storage is heavily dependent on its containment vessel, both for efficiency and safety. The vessel is usually made of thick steel that encases the rotor and other moving parts of the flywheel. Creating a vacuum in the vessel or filling it with a low-friction inert gas can increase performance and efficiency. The containment vessel also provides a safety barrier from the high-velocity parts of the flywheel. Because the system is so contained, there is little to no environmental impact.

Flywheels are efficient and have quick recharge and discharge times. Their compact design allows for a large number of units. This is necessary since each unit has a low power capacity. Flywheel storage systems have short energy duration times and are not designed for grid support services involving time scales longer than regulation. They have excellent life cycles compared to other energy storage systems.

3. Chemical

a) Regenerative Hydrogen Fuel Cells

Except for fuel cells, hydrogen energy storage systems are in the early stages of development. Value and cost have yet to be accurately assessed, but current costs are not competitive with available battery technology. It is proposed that grid systems in the future can be supported by generation from components such as fuel cells, electrolyzes, or turbine-and-storage combinations with either above ground or underground storage. Environmental and safety risks for this type of storage would be highly dependent on generation method used. Hydrogen storage provides low efficiency, around 40%, but that would be balanced out by long storage times.

Hydrogen fuel cells are the most advanced form of hydrogen energy storage. These cells convert the chemical energy of hydrogen gas to electricity through an electrochemical reaction. A bipolar chemical environment is separated from a hydrogen rich environment with an electrolyte plate. Hydrogen ions pass through the plate to react with the bipolar substance creating current and voltage across the cell. This cell can then be used for the same applications as a battery. Regenerative hydrogen fuels cells electrolyze water to create hydrogen.

4. Thermal

Thermal energy storage is an emerging technology promising enormous energy density anywhere from 5 to 20 times greater than conventional storage. It uses reversible processes to store heating or cooling capacity in a compound. Significant research is being focused on this energy storage method.

a) Molten Salt Thermal Storage

Molten Salt Thermal storage is comprised of a two-tank system where a receiver reflects concentrated sunlight into a heating chamber. Fluid is heated in a heating chamber and then transferred to a heated fluid storage tank. When needed, the heated fluid is used to create steam to power a generator or turbine. This storage system can improve efficiency and reduce heat loss. Cost varies greatly depending on the method of storage.

b) Ice Energy Storage

Ice Storage is a form of thermal energy storage. It works by harnessing the cheaper off-peak nighttime hours to freeze water or other substances. These chilled substances are used during on-peak periods to reduce cooling costs.

5. Electrical

a) Electrochemical Capacitors

Electrochemical Capacitors (a.k.a. double capacitors, super capacitors, ultra capacitors) are a mature technology known for providing high energy density. They are comprised of two porous carbon electrodes and a separator immersed in an electrolyte chemical bath. Each electrode is connected to a current collector similar to external battery connectors. While batteries store energy chemically, electrochemical capacitors store energy statically.

There are two main types of electrochemical capacitors: symmetric with identical electrodes, and asymmetric with non-identical electrodes. Symmetric capacitors have lower energy density but higher power performance. Asymmetric capacitors have very high energy density but lower power performance. Both types of capacitors have cells that are highly dependent on one another and are susceptible to a “domino effect” during cell failure. This necessitates the use of strict maximum voltage to increase life expectancy.

Electrochemical Capacitors have a high cycle life and a low incidence of self-discharge. However, there are many safety and environmental concerns. Most capacitors pose electrical and chemical hazards similar to batteries.

b) *Superconducting Magnet*

Superconducting Magnet Energy Storage (SMES) systems are currently commercially available. They are comprised of a super cooled coil which generates a magnetic field that can store and release energy. They are best known for “permanent” storage where there is no standby loss. SMES has the highest efficiency of any storage technology at around 95%. A lack of moving parts makes for high reliability. It has a long life cycle independent of charge-discharge duty cycle. Charging and discharging of magnetic storage is much faster than mechanical or chemical storage.

Disadvantages include the cost of refrigeration and the presence of strong magnetic fields. The cost of equipment and cooling makes this the most expensive energy storage system. The presence of magnetic fields may interfere with other machinery or medical devices.