Appendix A

2014

ILLINOIS
POWER AGENCY

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[ELECTRICITY PROCUREMENT PLAN]

Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts

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Illinois Power Agency
2014 Electricity Procurement Plan

Prepared in accordance with the

Illinois Power Agency and Illinois Public Utilities Act

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Illinois Power Agency
2014 Electricity Procurement Plan

1 Executive Summary

This is the sixth electricity and renewable resource procurement plan (the "Plan", "2014 Procurement Plan") prepared by the Illinois Power Agency ("IPA" or "Agency") under the authority granted to it under the Illinois Power Agency Act ("IPA Act") and as further regulated by the Illinois Public Utilities Act ("PUA"). Section 2.1 of this plan describes the specific legislative authority and requirements to be included in any such plan including from previous orders of the Illinois Commerce Commission ("Commission" or "ICC").

The Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren Illinois Company ("Ameren") and Commonwealth Edison ("ComEd") as defined in Section 16-111.5(a) of the PUA, who generally are residential and small commercial fixed price customers who have not chosen service from an alternate supplier. The Plan considers a 5-year planning horizon that begins with the 2014-2015 delivery year and lasts through the 2018-2019 delivery year.

The fifth plan developed by the IPA, and approved by the Commission in ICC Docket No. 12-0544, was the first plan that recommended no procurement of electricity or renewable resources for the utilities. It was also the first plan that included incremental energy efficiency programs as mandated by Section 16-111.5B of the PUA. The decision not to conduct any procurement of electricity in calendar year 2013 was a reflection of the monumental changes in the Illinois electricity markets brought about by the rapid increase in customer switching due to retail competition and municipal aggregation.

Although switching led the portfolio considered in last year's plan to be long and thus without procurement needs, this plan recommends a return to electricity procurements to address supply shortfalls and switching risk (Chapter 7). This conclusion is based on the IPA's analysis of the load forecast scenarios (Chapter 3), the expiration of existing supply contracts (Chapter 4), and the IPA's analysis of the risks associated with serving electric load and the various factors of power procurement (Chapter 6). The Plan continues to recommend no procurement of renewable resources for the utilities because current targets are being exceeded and the statutory rate caps preclude any additional procurement and the Plan also continues to recommend no sale of renewable resources for existing quantities in excess of targets (Chapter 8) The accelerated switching of load to competitive supply associated with governmental aggregation (which led to no procurement in 2013) is unlikely to continue at the same accelerated pace as has been seen since roughly 2011. Market saturation coupled with decreased headroom for competitive suppliers will drive any slowing or reversal of municipal aggregation gains. Most, though not all, of the large blocks of load that could switch have now done so and any likely additional load switching will come from ongoing retail marketing. The available headroom has diminished as a consequence of the utilities' current supply portfolio's lower price relative to market; it is now significantly closer to market price. As a consequence of these factors, the supply strategy presented in this plan takes the cautious view that expiring municipal aggregation contracts provide switching risk that the IPA must account for when considering what procurements to propose for eligible retail customers. To mitigate that risk, the IPA proposes a second procurement event to be held in September 2014 unless ComEd's load drops significantly below current projections and other factors determine that a second procurement is not cost-effective. In the event a second procurement is held, the parties shall rely on the same contracts and letter of credit forms used for the initial procurement in April 2014.

1.1 Power Procurement Plan

This Procurement Plan proposes to continue using the procurement strategy that the IPA has historically utilized (hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach). While the IPA investigated alternative strategies such as full requirement contracts or use of options, the IPA believes the continuation of the IPA's past strategy at this time to be the most prudent and the most likely to produce its statutorily mandated objective to, "[d]evelop electricity procurement plans to

ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[1]

As described in detail in Chapter 7, based on the analysis of the costs of procurement in Chapter 6 and supply shortfalls identified in Chapter 4, the Plan makes several recommendations for procurements for delivery year 2014-2015. The Plan recommends decreasing the size of procurement blocks from 50MW to 25MW. The hedging strategy is revised to bifurcate the first delivery year into two periods with different hedging levels. The summer would be "fully hedged" at the time of the April procurement and the balance of the year 75% hedged. The IPA recommends the Commission pre-approve a supplemental September procurement, which would bring the hedging level for the rest of the first delivery year to the "fully hedged" level. Approval would be based on factors intended to ensure that the benefits of the September procurement outweigh the costs of running the procurement. The strategy for years two (delivery year 2015-2016) and three (delivery year 2016-2017) reflects lower forward hedging strategies when compared to prior Plans. The proposed overall strategy is designed to manage the risk of load uncertainty resulting from the possibility of large blocks of load returning to the utilities because of municipalities choosing not to continue their aggregation programs.

The IPA continues to recommend that capacity, ancillary services, load balancing services, and transmission services be purchased, as they are now, by Ameren from the MISO marketplace and by ComEd from PJM.

1.2 Renewable Energy Resources

The load forecasts supplied by the utilities on July 15, 2013 indicate that existing renewable energy resources under contract exceed the Renewable Portfolio Standard obligations for eligible retail customers. Separately, the statutorily mandated rate caps also lead the IPA to recommend that the Commission approve a curtailment of the long-term power purchase agreements that were entered into as part of the 2010 procurement plan based on utility load forecast updates in Spring 2014. This is essentially the same as was adopted in last year's plan. To mitigate the impact of those curtailments the IPA also recommends the use of Alternative Compliance Payments collected from customers on hourly pricing to purchase some or all of the curtailed Renewable Energy Credits ("RECs"). While not subject to ICC jurisdiction, the IPA will also plan to use funds from the RERF to purchase any remaining curtailed RECs.

The following tables summarize the IPA's proposed hedging strategy and the IPA's proposed 2014 procurements:

Table 1-1 Summary of 2014 Illinois Agency Hedging Strategy

Mid-April 2014 Procurement			Mid-Sept 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**November 2014-May 2015**
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

[1] 20 ILCS 3855/1-20(a)(1).

Table 1-2 Summary of 2014 Illinois Power Agency Procurement Plan Recommendations based on July 15, 2013 Utility Load Forecasts:

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	2014-15	Up to 175MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except solar and DG), budget cap exceeded	Will be purchased from MISO
	2015-16	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2016-17	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2017-18	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2018-19	No energy procurement required	Direct purchase from MISO capacity market	Shortage of 10GWh but budget cap exceeded: no RPS procurement	Will be purchased from MISO
	Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
COMED	2014-15	Up to 1,175MW forecasted requirement (April Procurement) Up to 350MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	Shortage of 116GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM
	2015-16	Up to 375MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2016-17	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2017-18	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2018-19	No energy procurement required	Direct purchase from PJM capacity market	Shortage of 178GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

1.3 Incremental Energy Efficiency

This plan is the second year of inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. The IPA recommends inclusion of the programs submitted by the utilities that have passed the Total Resource Cost Test. The IPA further suggests consideration be given to issues relating to other third party programs that the utilities did not include in their savings goals but that the IPA believes should be presented by the IPA to the Commission.

Finally the IPA recommends that the Commission adopt the recommended policies laid out by the IPA in Section 7.1 to address open questions involving incremental energy efficiency procurement, including adoption of certain consensus items from recent workshops relevant to the Section 16-111.5B procurement process.

1.4 The Action Plan

In this plan, the IPA recommends the following items for ICC action:

1. Approve the base case load forecasts of ComEd and Ameren as submitted in July 2013.
2. Require the utilities to provide an updated March 2014 forecast which will be pre-approved by the ICC in this docket subject to the March 2014 consensus of each utility, the IPA, ICC Staff, the Procurement Administrator(s) and the Procurement Monitor.
3. Approve two energy procurements. The first in April 2014, the second in September 2014. The September procurement will be held subject to a July 2014 forecast indicating a hedging shortfall exists for the prompt year, a determination that the estimated hedging benefit exceeds the cost of the procurement, and other conditions as specified by the Commission.
4. Require the utilities to expand the July 2014 forecast to include the November 2014 to May 2015 period. The addition of the November 2014 through May 2015 forecast will be used solely in determining the quantity of energy to be solicited, if applicable, in the September 2014 procurement event and will have no bearing on the renewable curtailment.
5. Approve continued procurement by ComEd and Ameren of capacity, network transmission service and ancillary services from their respective RTO for the 2014-2015 delivery year.
6. Approve pro-rata curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy, subject to the updated March 2014 forecast. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the ~~aforementioned~~ parties identified in Item 2 above. Otherwise, the July 2013 forecast will form the basis for curtailment.
7. Approve the use of hourly ACP funds to buy curtailed RECs.
8. Approve the Section 16-111.5B incremental energy efficiency programs submitted by the utilities. The IPA also identified additional energy efficiency programs which were not included in the savings goal for the ICC to consider and approve as appropriate.
9. Approve and adopt the solutions to open Section 16-111.5B energy efficiency procurement issues recommended by the IPA, or as modified in response to stakeholder input. These recommendations include which programs the IPA must provide to the Commission, and then which programs the Commission may or should not approve.

The Illinois Power Agency respectfully submits this Procurement Plan, which the IPA believes is compliant with all applicable laws, to the Illinois Commerce Commission for review and approval.

2 Legislative/Regulatory Requirements of the Plan

This section of the 2014 Procurement Plan describes the legislative and regulatory requirements applicable to this Procurement Plan. This includes compliance with previous Commission Orders; a Regulatory Compliance Index, Appendix A, provides a complete cross-index of regulatory/legislative requirements and the specific sections of this plan that address each requirement identified.

2.1 IPA Authority

The Illinois Power Agency ("IPA", or "Agency") was established in 2007 by Public Act 95-0481 in order to ensure that customers, particularly customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[2] benefit from retail and wholesale competition. This objective of the Act was to improve the process to procure electricity for those customers.[3] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability."[4] The General Assembly also stated "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" as additional goals.[5]

Each year, the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in the final procurement plan, as approved pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[6] The purpose of the power procurement plan is to secure the electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren").[7] The Illinois Power Agency Act ("IPA Act") directs that the procurement plan be developed and the competitive procurement process be conducted by "experts or expert consulting firms," respectively known as the "Procurement Planning Consultant" and "Procurement Administrator."[8] The Illinois Commerce Commission ("Commission" or "ICC") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[9]

2.2 Procurement Plan Development and Approval Process

Although the procurement planning process is ongoing and incorporates party input and lessons from past proceedings, the statutory timeline for this 2014 Procurement Plan began on July 15, 2013. On that date, each Illinois utility that procures electricity through the IPA submitted load forecasts. These forecasts – which form the backbone of the Procurement Plan and which are covered in Sections 3.2 and 3.3 in greater detail – cover the five-year planning period for the next procurement plan. The forecasts include hourly data representing high, low and expected scenarios for the load of the eligible retail customers.

Next, the IPA prepared a draft Procurement Plan and on August 15 made it available for public comment. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA released the plan. Because the 30th day was on a Saturday, the comment period closed on Monday, September 16, 2013. During the thirty-day comment period, the IPA held one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan; those public hearings were on September 4

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[2] 220 ILCS 5/16-111.5(a).
[3] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).
[4] 20 ILCS 3855/1-5(1).
[5] 20 ILCS 3855/1-5(4).
[6] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).
[7] ICC Docket 11-0660, Final Order of December 21, 2011 at 1. Although the IPA must create a procurement plan for ComEd and Ameren, the IPA must also create a procurement plan for MidAmerican Energy Company ("MidAm") if MidAm elects to opt into the IPA procurement process. (*See* 20 ILCS 3855/1-20(a)(1).) MidAm has not made such an election at this time.
[8] 20 ILCS 3855/1-75(a)(1), 3855/1-75(a)(2).
[9] 220 ILCS 5/16-111.5(b), (c)(2).

and 10, 2013 in Chicago and Springfield, respectively. Fourteen days following the end of the 30-day review period (*i.e.*, September 30, 2013), the IPA filed this revised Procurement Plan with the Commission for approval. Objections must be filed with the Commission within five days after the filing of the Plan;[10] typically the Administrative Law Judge sets the dates for Responses and Replies to Objections by Ruling after the docket opens. The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA, which this year will be Sunday, December 29, 2013 (leading to a Monday, December 30, 2013 deadline). The current ICC calendar indicates the last scheduled meeting prior to that deadline is on Wednesday, December 18, 2013.

The Commission approves the Plan, including the load forecast used in the procurement plan, if the Commission determines that it meets the requirements of the PUA.

2.3 Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers, (2) the supply currently under contract, and (3) what type and how much supply must be procured to meet load requirements and all other legal requirements (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class.[11] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency programs, both current and projected.[12] Based on that hourly load analysis, the Procurement Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through preexisting contracts,[13] and in doing so must:

- Define the different Illinois retail customer classes for which supply is being purchased, and include monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period.[14]
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts.[15] Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[16]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms, time frames for security products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment.[17] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.

[10] 220 ILCS 5/16-111.5(d)(3).
[11] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).
[12] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).
[13] 220 ILCS 5/16-111.5(b)(3).
[14] 220 ILCS 5/16-111.5(b)(i), 220 ILCS 5/16-111.5(b)(iii).
[15] 220 ILCS 5/16-111.5(b)(3)(iv).
[16] 220 ILCS 5/16-111.5(b)(3)(v).
[17] 220 ILCS 5/16-111.5(b)(3)(vi).

- For load requirements included in the Plan, the Plan should include the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. [18]
- Include renewable resource and demand-response products, as discussed below.

2.4 Standard Product Procurement and Load-Following Products

As noted in Section 2.3, the IPA Act provides examples of "standard products."[19] Reading Subsection 16-111.5(b)(3)(vi) in conjunction with Subsection 16-111.5(e) and reviewing past IPA practice, the IPA believes that the definition of "standard product" may be broad enough to include wholesale load-following products (including full requirements or partial requirements) as long as the procurement is standardized such that bids may be judged solely on price.[20] The IPA understands that the legal question of the IPA's authority to procure full requirements products was litigated in ICC Docket No. 11-0660, but the Commission did not reach the legal issue in that docket.[21] The IPA anticipates that the question will be re-litigated in this docket to the extent that ICEA's proposal for a full requirements procurement is litigated as well.

2.5 Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[22] "Renewable energy resources" is defined in the Illinois Power Agency Act, and means (1) energy and its associated renewable energy credit or (2) credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and panels, biodiesel, and others as identified in the IPA Act.[23] A minimum percentage of each utility's total supply to serve the load of eligible retail customers shall be generated from cost-effective renewable energy resources; by June 1, 2014, at least 9% of each utility's total supply should be generated from renewable energy resources.[24] For the current (2014) Procurement Plan, to the extent cost-effective resources are available, the IPA is directed to procure at least 75% of the renewable energy resources from wind generation, 3% from photovoltaics, and 0.75% from distributed renewable energy generation devices.[25] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[26] In other words, if the IPA procures 0.75% distributed renewable energy that is solar-generated, that 0.75% counts against the 3% solar guideline, leaving 2.25% solar to be procured from other sources.

The IPA Act defines "cost effective" in two ways: first, for different renewable resources the Procurement Administrator creates a "market benchmark" against which all bids are measured. Second, and in addition to the market benchmarks, the total cost of renewable energy resources procured for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources to no more than the greater of:

- 2.015% of the amount paid per kilowatt-hour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatt-hour paid for these resources in 2011.[27]

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[18] 220 ILCS 5/16-111.5(b)(4).
[19] 220 ILCS 5/16-111.5(b)(3)(vi).
[20] *See, e.g.*, 220 ILCS 5/16-111.5(e)(2) (requiring development of standardized "contract forms and credit terms" for a procurement); 16-111.5(e)(3)-(4) (creation of a price-based benchmark and selection of bids "on the basis of price"); ICC Docket No. 09-0373, Final Order dated December 28, 2009 at 115-116 (Commission approval of long-term renewable resource PPA project selection based on price alone).
[21] *See* ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 174.
[22] 20 ILCS 3855/1-5(5), 3855/1-5(6).
[23] 20 ILCS 3855/1-10.
[24] 20 ILCS 3855/1-75(c)(1).
[25] Id.
[26] 20 ILCS 3866/1-75(c)(1).
[27] 20 ILCS 3855/1-75(c)(2)(E).

These values are now fixed, and the greater of the two is 0.18054 ¢/kWh for Ameren and 0.18917 ¢/kWh for ComEd.

Cost-effective renewable energy resources are subject to geographic restrictions: the IPA must first procure from resources located in Illinois or in states that adjoin Illinois.[28] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must instead seek cost-effective renewable energy resources from "elsewhere."[29]

In addition to the funds available from eligible retail customers, the alternative compliance payments collected by the utility from the utility's customers taking service under the utility's hourly pricing tariff "increase [IPA] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year."[30] In the IPA's 2013 Procurement Plan approval docket, the Commission authorized these funds to be spent on RECs from long-term renewable PPA holders that could not be purchased by eligible retail customers due to Commission-authorized curtailments.[31]

Also in the IPA's 2013 Procurement Plan, the Commission pre-authorized a curtailment of long-term renewable PPAs, pursuant to the language of the contract. The Commission ordered that if a March, 2013 load forecast (not yet drafted at the time of the Commission's Final Order) showed that the eligible retail customer rate cap would be exceeded under the expected load forecast, the long-term renewable PPAs would be curtailed *pro rata* in order to reduce volumes to a level that would not exceed the rate cap under the expected load forecast.[32]

2.6 Distributed Generation Resources Standard

Effective beginning in the 2013 Procurement Plan, a distributed generation resource requirement was added by the General Assembly. Procurement of renewable energy resources from distributed renewable energy generation devices is to be conducted on an annual basis through multi-year contracts of no less than five years, and shall consist solely of renewable energy credits.[33]

A generation source is considered a "distributed renewable energy generation device" under the IPA Act if it is:

- Powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[34]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25kW in nameplate capacity.[35]

In the Commission proceeding to approve the 2012 Electricity Procurement Plan, the Illinois Power Agency committed to holding workshops in the spring of 2012 to assist with the development of a future distributed generation renewable resource procurement plan (at this time no such procurement is planned).[36] The IPA

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[28] 20 ILCS 3855/1-75(c)(3).
[29] *Id.*
[30] 20 ILCS 3855/1-75(c)(5).
[31] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 111; *see also id.* at 114-115 (discussing mechanics of application of hourly ACP payments to curtailed RECs).
[32] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 67-69, 110.
[33] 20 ILCS 3855/1-75(c)(1).
[34] 20 ILCS 3855/1-10.
[35] Id.
[36] ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 117.

discussed best practices for meeting the obligations of the distributed generation portfolio requirement with stakeholders on February 24th and April 2nd 2012. Meeting materials are available on the IPA website.[37]

Further development of a distributed generation purchase program also impacts the IPA's use of the Renewable Energy Resources Fund. Although not subject to Commission jurisdiction,[38] the Renewable Energy Resources Fund may be used to procure distributed renewable energy resources, and the IPA believes it would be desirable to have a uniform purchasing program, especially if Renewable Energy Resources Fund procurements are held "in conjunction with" eligible retail customer procurements.[39]

2.7 Energy Efficiency Resources

Section 16-111.5B of the PUA, as amended by PA 97-0824 effective July 18, 2012, outlines the requirements for the consideration of energy efficiency in the Procurement Plan. The Procurement Plan must include the impact of energy efficiency building codes or appliance standards, both current and projected, and an assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered by the utilities' Commission-approved energy efficiency plans or to implement additional cost-effective energy efficiency programs or measures. To assist in this effort, the utilities are required to provide, along with their load forecasts, an assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan. Both Ameren and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. This information includes an analysis of new or expanded programs that demonstrates their cost-effectiveness as defined in the PUA, and information sufficient to demonstrate the impacts of the assessed incremental programs on the overall cost to the utility of providing electric service, including how the cost of procuring these measures compares over the life of the measures to the prevailing costs of comparable supply, along with estimated supply quantity reductions should the IPA recommend to include them in the proposed resource portfolio. Programs come from two sources: expansion of existing utility programs authorized by the Commission pursuant to Section 8-103 of the Public Utilities Act, or new programs bid pursuant to a request for proposals undertaken annually by the utilities.

The PUA requires the Agency to include in its Procurement Plan energy efficiency programs and measures that it determines are cost-effective; the utilities are directed to factor in the associated energy savings to the load forecast. If the Commission approves the procurement of this additional efficiency, it shall reduce the amount of power to be procured under the procurement plan and shall direct the utility to undertake the procurement of the efficiency resources. For purposes of meeting this statutory requirement, cost-effective means that the assessed measures pass the total resource cost test as defined in the IPA Act:

> *"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.*[40]

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[37] http://www2.illinois.gov/ipa/Pages/CurrentEvents.aspx.
[38] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 112-113.
[39] *See* 20 ILCS 3855/1-56(c) (current law requiring purchases "in conjunction with" utility procurement).
[40] 20 ILCS 3855/1-10.

Since the 2013 Procurement Plan, the IPA has engaged in significant discussions with stakeholders, including in Commission Staff-led workshops that have taken place since the Final Order in ICC Docket No. 12-0544.[41] These workshops have resulted in several "consensus" points regarding the utility-led efficiency portfolio standard required under Section 16-111.5B of the PUA. However, the IPA notes that the workshop process, while helpful, did not result in a formal agreement and therefore may not represent the formal opinions of participating parties. Further, the parties sought to, and at times did, reach consensus based on then-current, prevailing information and policy at that time of the discussions. Parties' positions were therefore subject to change based on changes in information and policy.

A list of "consensus items" is available as part of an ICC Staff report,[42] but the IPA respectfully requests that the Commission address those consensus items below that pertain directly to the Plan: [43]

1. Both new and expanded programs may be approved for up to three-year increments.
2. DCEO may bid programs into the utility-run RFPs and should pass the TRC test as indicated in the legislation.
3. Any utility savings goals pursuant to Section 8-103 and contractor performance "goals" pursuant to Section 16-111.5B are separate and non-transferrable. Budgets should also be kept separate.
4. Utilities should provide the IPA with all bids to the RFP (on a confidential basis) so the IPA may independently evaluate the bids.
5. The IPA also believes that parties should work collaboratively on contract principles for successful bidders, which may include pay-for-performance language and grant the utility "flexibility" to reward successful programs while minimizing resources spent on unsuccessful programs.

The IPA further notes that parties may advocate additional items beyond the scope of the consensus items listed in the Staff Report. In that vein, the IPA raises and addresses four additional issues specific to the Procurement Plan in Section 7.1.3:

- Feedback mechanisms between the utility potential study and programs proposed (Section 7.1.3.1);
- How to undertake expansion of Section 8-103 efficiency programs in a year where the utilities' Section 8-103 efficiency plan is up for approval (Section 7.1.3.2);
- How DCEO may or should participate in the process (Section 7.1.3.3), given the consensus that DCEO programs should be considered under Section 16-111.5B; and
- How and at what stage in the process to eliminate third-party bids that are duplicative of or in competition with utility energy efficiency programs (Section 7.1.3.4).

The IPA has provided its take on addressing these issues in the subsections cited above, and looks forward to stakeholder input on the IPA's proposed resolutions.

The IPA wishes to elaborate on one item on which consensus was not achieved in the workshop but which will be relevant in this proceeding: which programs *must* be proposed (as opposed to permissively may be proposed).[44] According to statute, the Procurement Plan "shall include . . . energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal included in the annual solicitation process and assessment [of new and expanded plans by the utilities]."[45] Meanwhile, the Commission "shall also approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential

[41] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 271 (directing Staff to convene workshops and requesting the IPA and other interested parties participate).
[42] *See* http://www.icc.illinois.gov/downloads/public/ICC Staff Report Summary of Section 16-111.5B EE Workshops 2013-08-02.pdf.
[43] Several additional consensus items touch on items relevant to execution of the 16-111.5B-approved programs, highlighted by evaluation of the programs, but those items are not directly relevant to approval of the programs in this proceeding.
[44] The IPA views the issues in Section 7.1.3.4 as a subset of this more general issue.
[45] 220 ILCS 5/16-111.5B(a)(4).

for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act."[46]

While the IPA shall include in the Procurement Plan energy efficiency programs and measures "it determines are cost-effective" that were submitted by the utilities, the IPA or other stakeholders may point out reasons that the utilities and Commission may consider rejecting a particular cost-effective program and the utilities and Commission may consider those reasons in its submission and approval process. Some examples include:

1. If a bid appears to be from a grossly undercapitalized and understaffed bidder that the IPA, or the utilities, concludes will be unable to execute the program, the IPA believes that the IPA, utilities and Commission should consider rejecting the affected program. Such information would help determine whether the proposed savings are "achievable cost-effective savings." The IPA, as described in Section 7.1.3.4 does not believe there should be a "bright-line" test with these, or other factors, but rather a multi-factor analysis.
2. In the event similar or duplicative cost-effective programs are bid, the TRC is calculated with the assumption that the program is not being implemented simultaneously with such similar or duplicative programs and thus if both programs were implemented simultaneously both programs may be cost-ineffective.
3. To the extent that the standard in Section 16-111.5(d)(4) is applied directly to Section 16-111.5B energy efficiency procurements, the Commission has broader discretion to consider a variety of factors, including "lowest total cost over time," "price stability" and the inclusion of savings "to the extent practicable."[47] The IPA appreciated comments and looks forward to stakeholder discussion as part of the approval docket.

2.8 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[48] Under the PUA, cost-effective, demand-response measures may be procured whenever the cost is lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[49] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;
- The products must at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements[50];
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations.[51]; and
- Demand-response measures included in the plan shall meet the same credit requirements as apply to suppliers of capacity in the applicable regional transmission organization market.[52]

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[46] 220 ILCS 5/16-111.5B(a)(5).
[47] 220 ILCS 5/16-111.5(d)(4); *see, e.g.*, ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 234-235 (applying 16-111.5(d)(4) to Procurement Plan as a whole, not individual components of the plan such as FutureGen).
[48] 220 ILCS 5/16-111.5(b)(3)(ii).
[49] 220 ILCS 5/16-111.5(b)(3)(ii).
[50] 16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).
[51] *Id.* at 16-111.5(b)(3)(ii)(C); 16-111.5(b)(3)(ii)(D).
[52] *Id.* at 16-111.5(b)(3)(ii)(E).

Public Act 97-0616, the Energy Infrastructure Modernization Act (EIMA), requires ComEd and Ameren to file tariffs instituting an opt-in market-based peak time rebate (PTR) program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[53] ComEd's PTR program was provisionally approved in ICC Docket No. 12-0484 and Ameren's PTR program is pending approval in ICC Docket No. 13-0105; both programs have operational and implementation issues being discussed at Staff-led workshops.[54] These programs are discussed further in Section 7.5, where demand response resource choices are examined.

2.9 Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.[55] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[56] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[57], Section 1-75(d) describes two special cases: the "initial clean coal facility"[58] and "electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities ("retrofit clean coal facility").[59] Currently, there is no facility meeting the definition of an "initial clean coal facility", that the IPA is aware of, that has announced plans to begin operations within the next five years. In ICC Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a clean coal resource starting in the 2017 delivery year.[60] The IPA is not aware of any additional retrofit clean coal facilities seeking inclusion in the Procurement Plan. Aside from a pending appeal of the Commission's Final Order in ICC Docket No. 12-0544 regarding inclusion of FutureGen, the IPA is not aware of any change in status since approval of the 2013 Procurement Plan to FutureGen's ability to deliver clean coal electricity as anticipated.

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[53] 220 ILCS 5-16-108.6(g).
[54] *See, e.g.,* ICC Docket No. 12-0484, Interim Order dated February 21, 2013 at 32.
[55] 20 ILCS 3855/1-75(d).
[56] 20 ILCS 3855/1-75(d)(1).
[57] 20 ILCS 3855/1-10.
[58] Id.
[59] 20 ILCS 3855/1-75(d)(5).
[60] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; *see also* ICC Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in ICC Docket No. 12-0544).

3 Load Forecasts

3.1 Statutory Requirements

Under Illinois law, a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois."[61] The plan has to include a load forecast based on an analysis of hourly loads. The statute requires the analysis to include:

- Multi-year historical analysis of hourly loads;
- Switching trends and competitive retail market analysis;
- Known or projected changes to future loads; and
- Growth forecasts by customer class.[62]

The statute also defines the process by which the procurement plan is developed. The load forecasts themselves are developed by the utilities as stated in the statute:

> *"Each utility shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios.*[63]

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Illinois Power Agency. The Illinois Commerce Commission is required to approve the plan, including the forecasts on which it is based. Therefore, the Agency must review and evaluate the load forecasts to ensure they are sufficient for the purpose of procurement planning. In doing so the Agency first reviewed the forecasts from July 2012, to determine if the form and content of those forecasts support the analyses the Agency plans to undertake this year. The Agency and its consultant put a series of questions to the utilities. A similar process was then applied to the July 2013 forecasts.

This chapter contains a summary of the load forecasts for Ameren and ComEd, the Agency's evaluation of the load forecasts, and a recommendation on the forecasts that the Commission should approve for procurement planning.

Note: Throughout this report, except where noted, the retail load is taken to include an allowance for losses. In other words, it represents the volume of energy that each utility must schedule to meet the load of its eligible retail customers at the RTO level (MISO for Ameren and PJM for ComEd).

3.2 Summary of Information Provided by Ameren

In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, Ameren provided the IPA the following documents for use in preparation of this plan:

- Ameren Illinois Company ("AIC") Load Forecast for the period June 1, 2014 – May 31, 2019 (See Appendix B)
- Electric Energy Efficiency Compliance With 220 ILCS 5/16-111.5B. This document also contained seven Appendices. (See Appendix B. Note, Ameren Appendix 6 [Third Party Bids] and 7 [Detailed Analysis] were marked confidential and are not included in Appendix B.)

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[61] 220 ILCS 5/16-111.5(a).
[62] 220 ILCS 5/16-111.5(b)(1).
[63] 220 ILCS 5/16-111.5(d)(1).

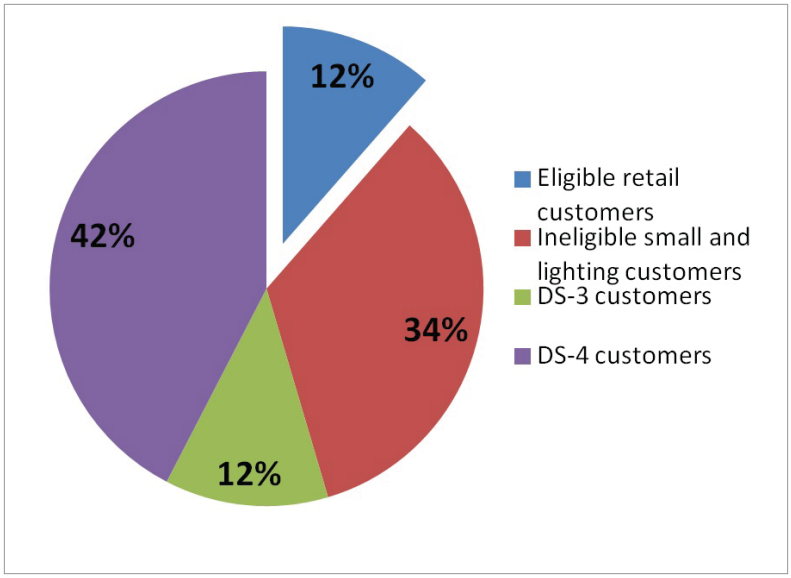
- Spreadsheets of the expected, high, and low forecasts. Supplemental spreadsheets detailed the renewable portfolio standard targets and budgets under each scenario, capacity needs under each scenario, and the impact on the expected load forecast of incremental energy efficiency programs. (Summarized in Appendix D)

Ameren uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A Statistically Adjusted End-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability to identify historic trends and project future trends with the end-use model's ability to identify factors driving customer energy use.

Industrial and public authority classes are modeled using a traditional econometric approach that correlates monthly sales, weather, seasonal variables, and economic conditions. The Lighting load class is modeled using either exponential smoothing or econometric models.

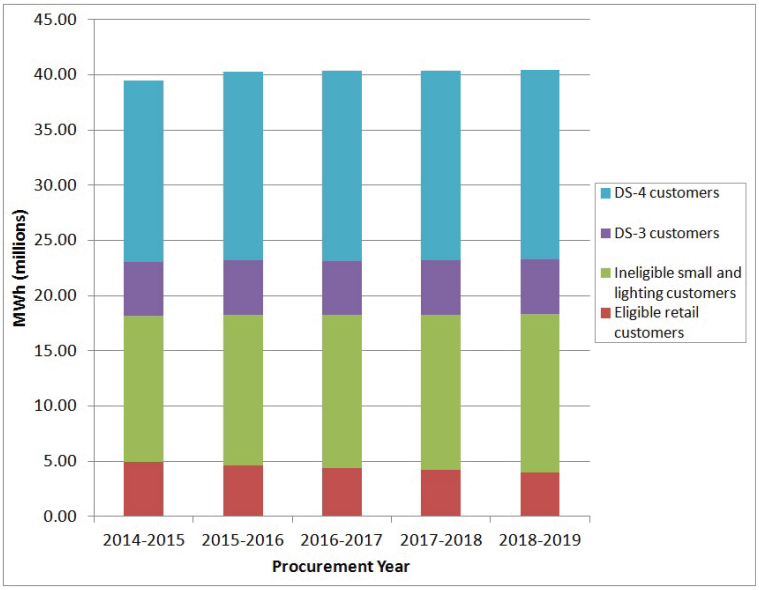
Figure 3-1 shows the annual breakdown of usage by customer class, and separates out the eligible from ineligible small and lighting customers.

Figure 3-1 Ameren Load Breakdown, Procurement Year 2014-2015



Ameren forecasts are performed on the total Ameren delivery service load using a regression model applied to historical load and weather data. A separate analysis is performed for each customer class to account for the differing impacts of weather on the different customer classes. Figure 3-2 shows the Ameren 5-year forecast by customer group.

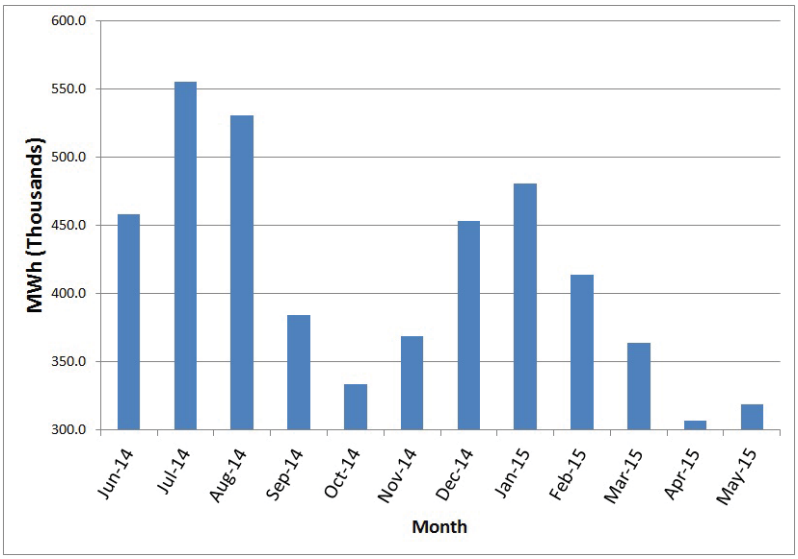
Figure 3-2 Ameren Load by Procurement Year



Ameren applies assumed "switching rates" to the total system load forecast to remove the load to be served by bundled hourly pricing (Power Smart Pricing or rider HSS), municipal aggregation, or other Alternative Retail Electric Suppliers ("ARES"). Ameren establishes the current customer switching trend line utilizing actual switching data by customer class. Qualitative judgment is used to make adjustments. The portion of the forecast load attributed to rider HSS, municipal aggregation, and other ARES customers is subtracted from the total system load forecast. The result is the forecasted load to be supplied by Ameren.

Figure 3-3 provides a monthly breakdown of the expected or base-case forecast of Ameren's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this procurement plan.

Figure 3-3 Ameren Eligible Retail Load* by Month, Procurement Year 2014-2015



*Total load, prior to netting QF supply

Ameren provides a base case and two complete excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties that simultaneously move in the same direction: macroeconomics, weather and switching. This means, for example, that a high load case should represent the combination of stronger-than-expected economic growth (which increases load), extreme weather (which increases load) and a reduced level of switching (which increases the "eligible" fraction of retail load, that is,

the fraction for which the utility retains the supply obligation). Similarly, a low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increase level of switching.

3.2.1 Macroeconomics

The Ameren base case load forecast is based on a Statistically Adjusted End-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). Ameren did not define "high" and "low" cases by varying the econometric (or other) variables. Instead Ameren looked at the statistics of the residual from the model fit; the high case is somewhere between the 90% and 95% confidence level and the low case is between the 5% and 10% confidence level.

Ameren's "high" and "low" forecasts are uniform modifications of the expected case, excluding incremental energy efficiency, by rate class.[64] Specifically, in each case, a single multiplier is defined for each of the five delivery service rate classes, and the "before switching" load forecast for every hour is multiplied by the rate class multiplier.

Table 3-1 Load Multipliers in Ameren Excursion Cases

Rate Class	Low Case	High Case
DS1	0.935	1.060
DS2	0.900	1.100
DS3	0.900	1.100
DS4	0.930	1.070
DS5	0.930	1.070

Because the excursion cases are based on the statistics of the residuals, they reflect the influence of unmodeled variables. The forecasting model appears to be dominated by technological and weather effects. The econometric variables are related to short-term decision making. Uncertainty around long-term economic growth will appear in the residuals.

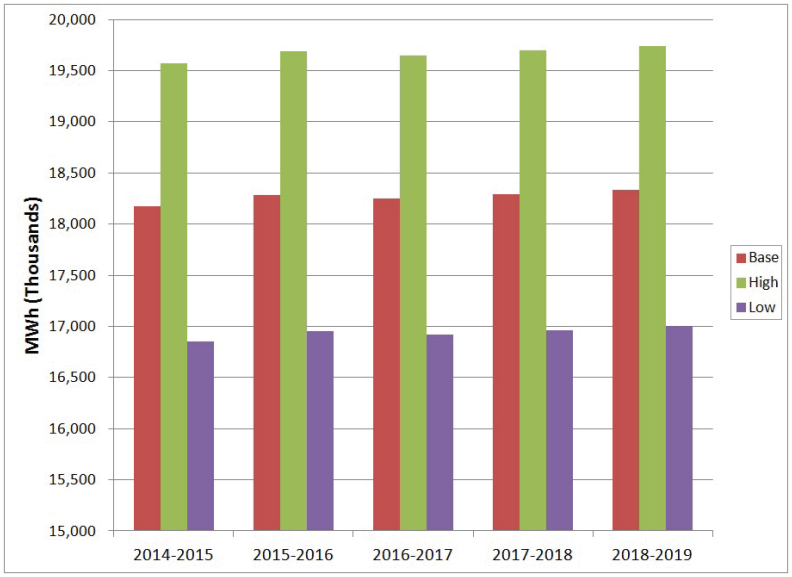
3.2.2 Weather

Ameren includes "high weather" and "low weather" in its characterization of the high and low cases. Ameren did not re-compute its load forecasting models with different values for the weather variables. The high and low scenarios only account for an averaged impact of weather, as well as macroeconomics, which is proportionally the same in each hour.

Figure 3-4 shows the base, high, and low case forecasts of Ameren's total delivery service load, assuming no switching, for the non-competitive classes DS1, DS2, and DS5. The difference between the high, low and base cases show the variation Ameren attributes to macroeconomics and weather. It is about +/-9%.

[64] Ameren provided four forecast cases: an expected case, a high case, a low case, and a version of expected case that also included incremental energy efficiency not yet approved (cf. Section 7.1). While the IPA's analysis has in general been based on this fourth case, the high and low cases were computed without incremental energy efficiency.

Figure 3-4 Ameren Annual Load by Procurement Year



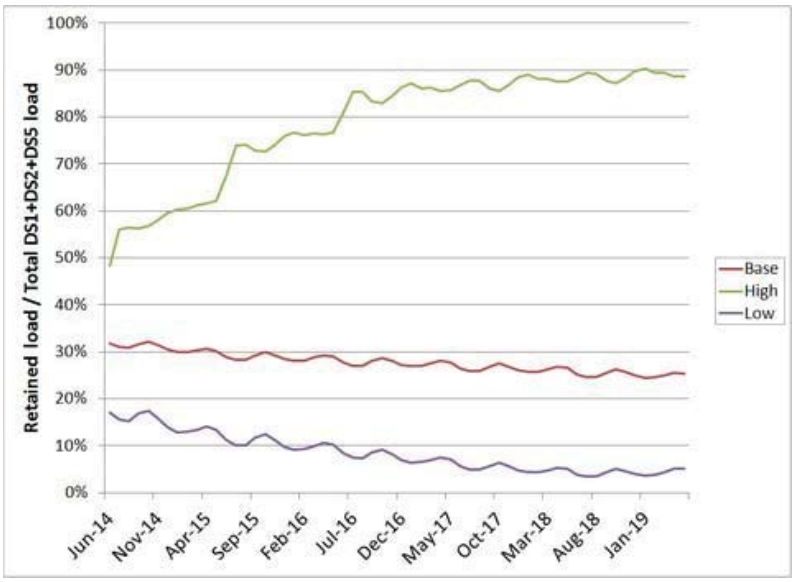
3.2.3 Switching

According to Ameren, switching, in particular municipal aggregation, is the greatest driver of load uncertainty. A wave of switching is expected in the summer and early autumn of 2013, driving the switched load to about 65-70% of residential and small commercial load. A low-load scenario would involve a higher level of switching, possibly a fourth wave of referenda leading to 95% or higher switching, so that Ameren would retain only 5% or less of the residential and small commercial customers by the end of the Plan horizon.

On the other hand, a large portion of the initial set of municipal aggregation contracts will be expiring in mid-2014. The price for utility energy supply lags the market price of energy, because the IPA's portfolios are laddered (bought over a period of several years). As the market price fell, the utility price lagged and was above market; but if the market price of energy rises, new aggregation contracts could appear more expensive than utility supply. Rising market prices could motivate a significant return to utility service beginning with the 2014-2015 procurement year.

The difference in the amount of switching among the three cases is significant. Figure 3-5 shows the retention, that is, the fraction of delivery load in classes DS1, DS2 and DS5 that remains on utility service, for the base, high and low cases.

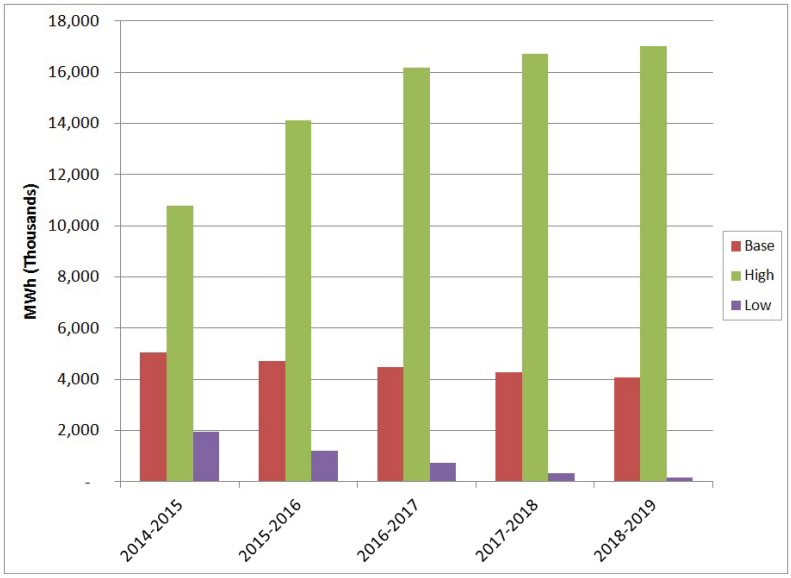
Figure 3-5 Utility Load Retention in Ameren Forecasts



As the figure shows, the difference in switching rates among the scenarios grows through the projection horizon. The difference in switching rates is the most significant factor driving the differences among the scenarios.

The load to be met by Ameren is the retained load, minus the expected supply under legacy PURPA qualifying facility (QF) contracts. Late in the forecast horizon, the hourly retained load in the low case is projected to be less than the QF deliveries, for a minority of hours implying that the utility's supply obligation could be negative in a worst case scenario. This is an indication of the extreme nature of the switching scenarios. Figure 3-6 shows the forecasted Ameren supply obligation in each case.

Figure 3-6 Utility Supply Obligation by Procurement Year in Ameren Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-7 and Figure 3-8 display the hourly profile of Ameren's supply obligation in each case (relative to the daily maximum load). Figure 3-7 illustrates a summer day and Figure 3-8 a low-load spring day. In these figures the curves are normalized so that the highest value in each is 1. There is little difference between the

profiles of the high and base cases, although the high case is a bit peakier. One calls a load shape "peaky" if there is a lot of variation in it – for example, if there is a large difference between the lowest and highest load values or, in these normalized curves, if the lowest point is well below 1. A load shape that is not peaky is one in which the load is nearly constant. The low-load case is definitely less peaky than the base case, especially on the lower-load day.

Figure 3-7 Sample Daily Load Shape, Summer 2014 in Ameren Forecasts

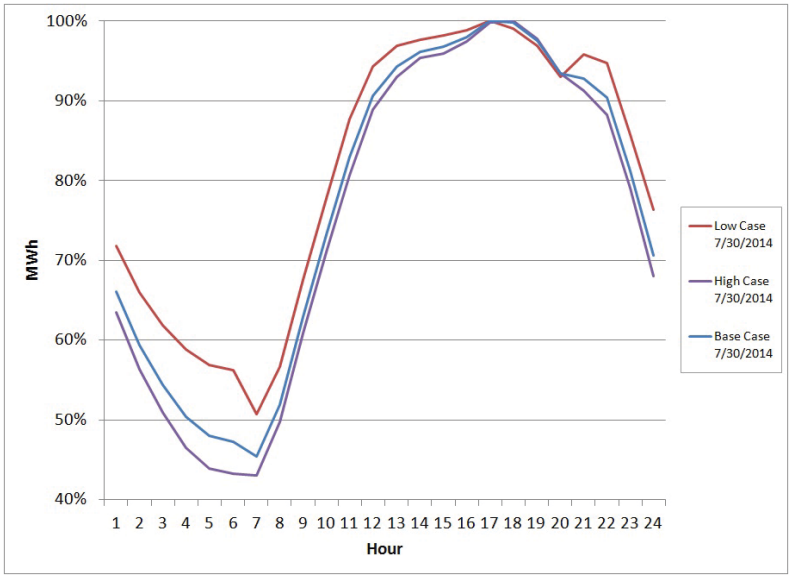
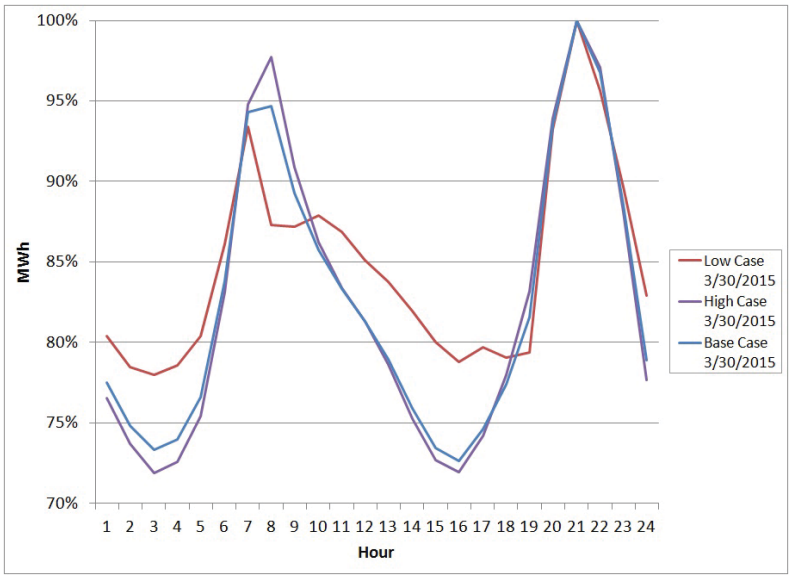


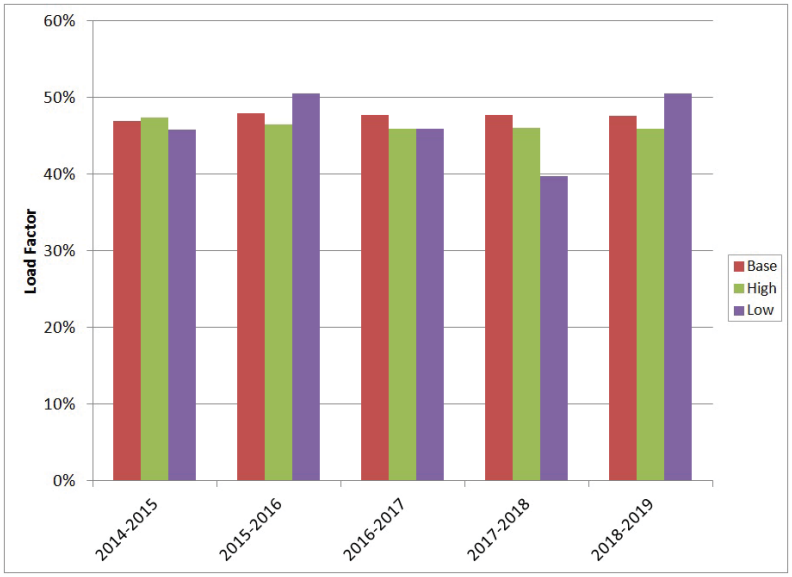
Figure 3-8 Sample Daily Load Shape, Spring 2015 in Ameren Forecasts



The peakiness of a case is usually borne out by the load factors. The load factor in any time period, such as a year, is the ratio of the average load to the maximum load. Peaky load curves have low load factors.

However, the comparison of Figure 3-9 with Figure 3-7 and Figure 3-8 does not reflect this trend: in 2014-2015 the low case is less peaky than the other cases while it has the lowest load factors. This may reflect a difference in weather assumptions between the low case and the other two cases.

Figure 3-9 Utility Load Factor by Procurement Year in Ameren Forecasts



3.3 Summary of Information Provided by ComEd

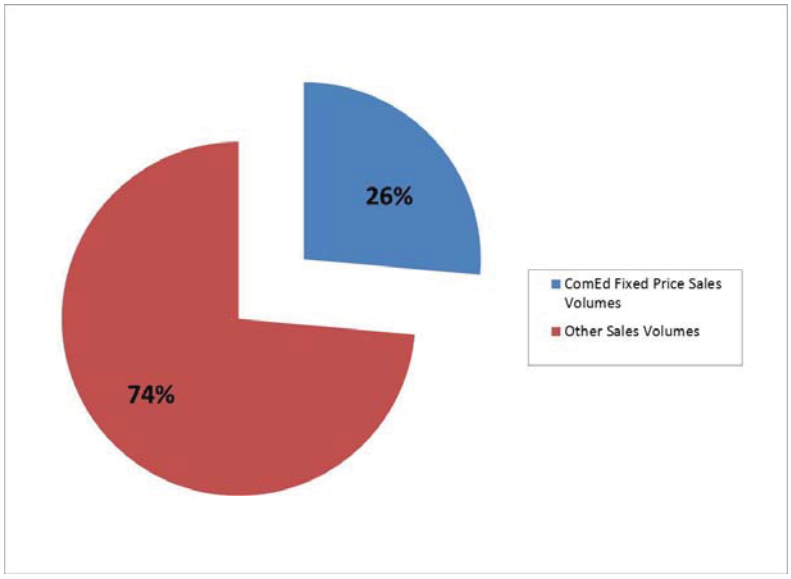
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2014 – May 2019.* This document also contained Appendices A-D. Four of the Appendices are included in the main document, while one (ComEd Appendix C) with supplemental information on Section 16-111.B incremental programs was included as four additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *2013 Third Party Efficiency Program Summary of Vendor Scoring Process* which was marked confidential and is not included in Appendix C.)
- Spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix E)

ComEd forecasts load by applying hourly load profiles for each of the major customer groups to the total service territory annual load forecast and subtracting loads projected to be served by hourly pricing, ARES and municipal aggregation. Hourly load profiles are developed based on statistically significant samples from ComEd's residential, non-residential watt-hour, and 0 to 100 kW delivery customer classes. The profiles show clear and stable weather-related usage patterns. Using the profiles and actual customer usage data, ComEd develops hourly load models that determine the average percentage of monthly usage that each customer group uses in each hour of the month.

ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who therefore cannot be eligible retail customers. Figure 3-10 shows the annual breakdown of usage by eligible and ineligible small and lighting load.

Figure 3-10 ComEd Composition of Eligible Customers Weather Normal Sales Volumes, Procurement Year 2014-2015



As noted above, ComEd provides a forecast of total usage for the entire service territory and allocates the usage to various customer classes using the models specific to each class. A suite of econometric models, adjusted for other considerations such as customer switching, is used to produce monthly usage forecasts. The hourly customer load models are applied to create hourly forecasts by customer class.

In determining the expected load requirements for which standard wholesale products will be procured, the ComEd forecast must be adjusted for the volume served by municipal aggregation and other ARES. The ComEd 5-year annual load forecast, shown in Figure 3-11, is based on the rate of customer switching in the past, expected increases in residential ARES service, and the anticipated additional migration of 0 to 100 kW customers to ARES and municipal aggregation. The figure decomposes the total forecast of residential and small commercial customer load, in the same way as Figure 3-10 does for a single year.

Figure 3-11 ComEd Composition of Eligible Customers Weather Normal Sales Volumes by Procurement Year

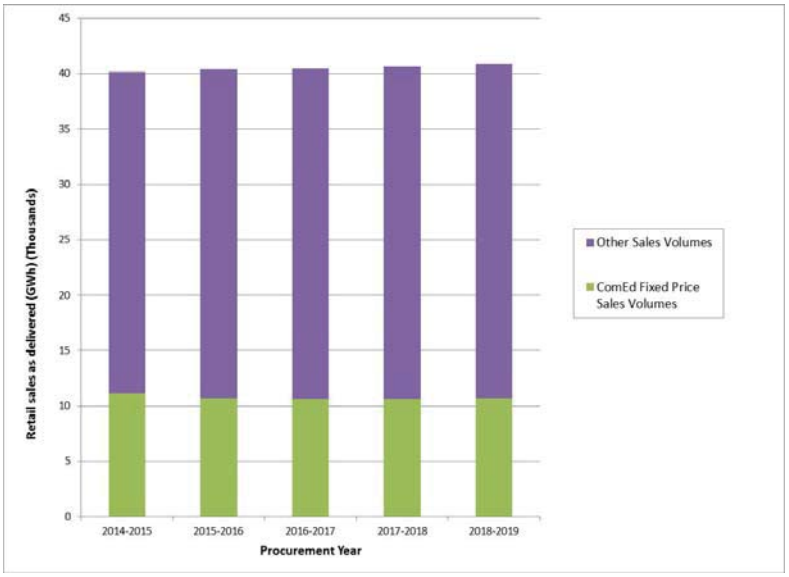
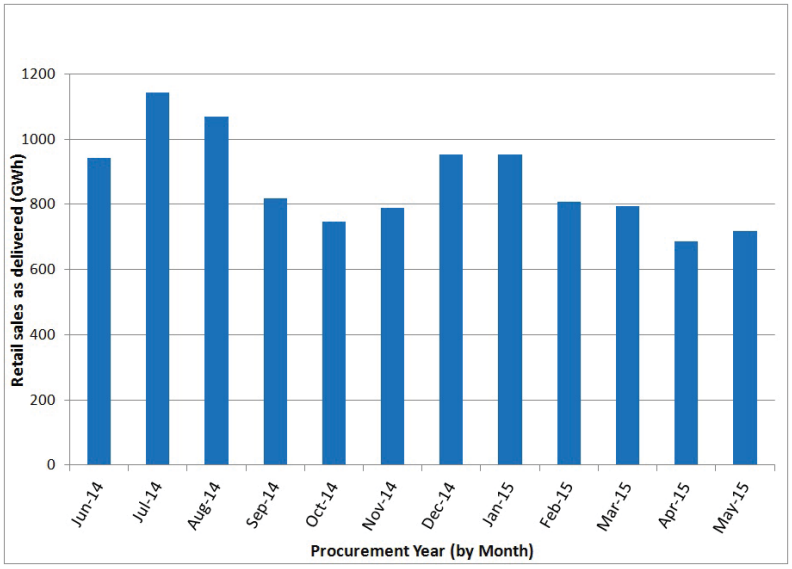


Figure 3-12 provides a monthly breakdown of the expected or base-case forecast of ComEd's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this procurement plan.

Figure 3-12 ComEd Eligible Load by Month, Procurement Year 2014-2015



ComEd provides a base case and two excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather and switching.

3.3.1 Macroeconomics

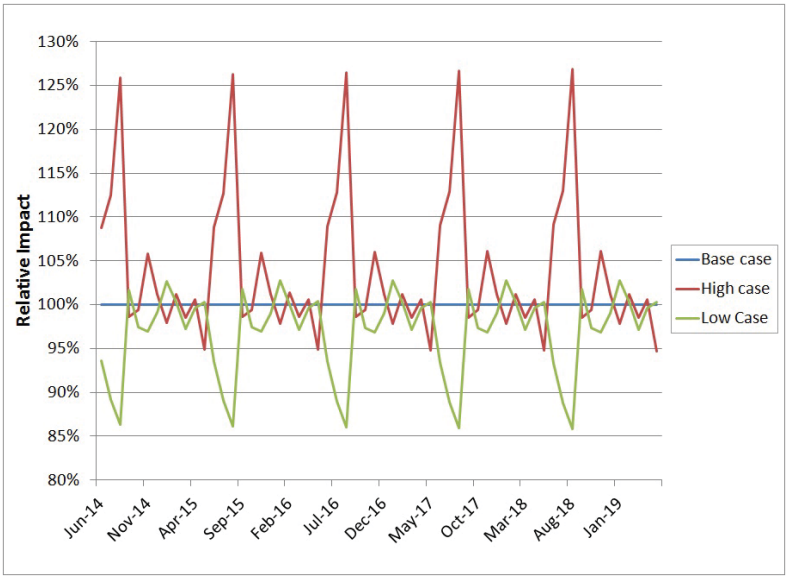
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and Rockford, household income) and demographics (household counts). ComEd did not use this model to define "high" and "low" cases. ComEd modified the service area load growth rates, increasing them by 2% in the high case and reducing them by 2% in the low load (because the growth rate in the expected case is below 2%, presumably this implies negative load growth in the low case throughout the projection horizon). ComEd has informed the Agency that, in its assessment, the high load case is near the bottom of the top quartile of the load growth distribution (75th to 80th percentile) and the low load case is conversely near the top of the lowest quartile of the load growth distribution (20th to 25th percentile).

3.3.2 Weather

ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. The high weather case is based on observed temperatures in 1995, and the low weather case on observed temperatures in 2004. These years represent the 90th to 95th percentile and 5th to 10th percentile of weather impacts on load respectively.

ComEd has not provided the specific impacts of the load growth assumption (load forecasts in the absence of switching). ComEd did provide the impacts of the weather case on residential and small commercial load, relative to the base case forecast. They are provided as percentages that summarize the hourly impacts of a finer-scale model of the effect of temperature on load. Figure 3-13 shows the impact of weather on load by month. The high and low years are not high and low in every month. There are some months, for example, where the impact of the "high weather" year is less than 1.

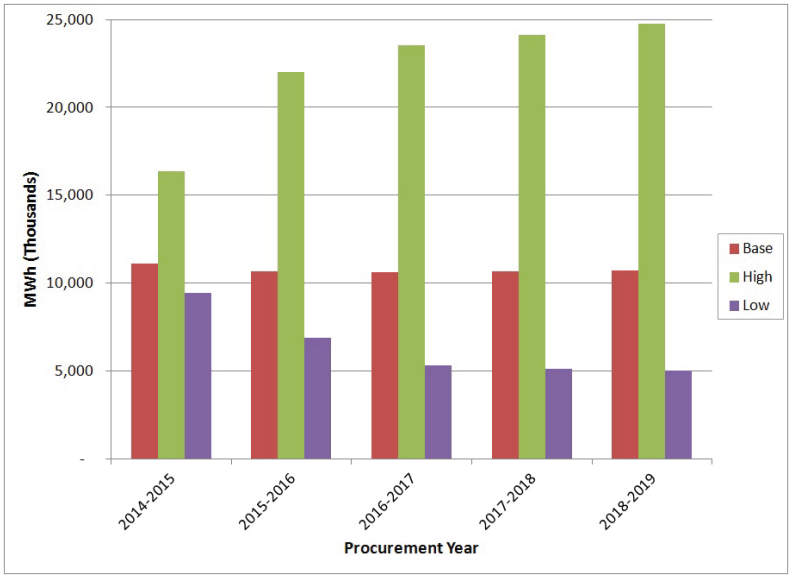
Figure 3-13 Weather Impacts in ComEd Forecasts



3.3.3 Switching

ComEd's high and low switching cases are not as extreme as Ameren's, and are based on specific event-related assumptions. The high switching (low load) case assumes an additional round of municipal aggregation referenda resulting in the departure of an additional 10% of load, and additional switching to ARES. Figure 3-14 shows the forecasted utility supply obligation in each case.

Figure 3-14 Utility Supply Obligation in ComEd Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-15 and Figure 3-16 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-15 illustrates a summer day, and Figure 3-16 a low-load spring day. The high case is definitely peakier on a summer day than the base case, and the low case is flatter. ComEd has not explicitly indicated QF supply in its forecast.

There is not a great deal of difference between the profiles of the high and base cases, although the high case is a bit less peaky. The low-load case is definitely peakier than the base case, especially on the lower-load day.

Figure 3-15 Sample Daily Load Shape, Summer 2014 in ComEd Forecasts

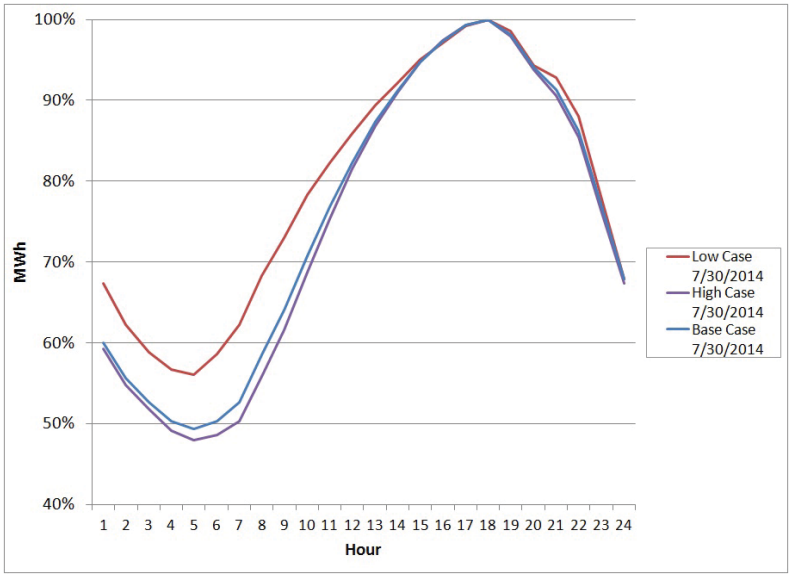
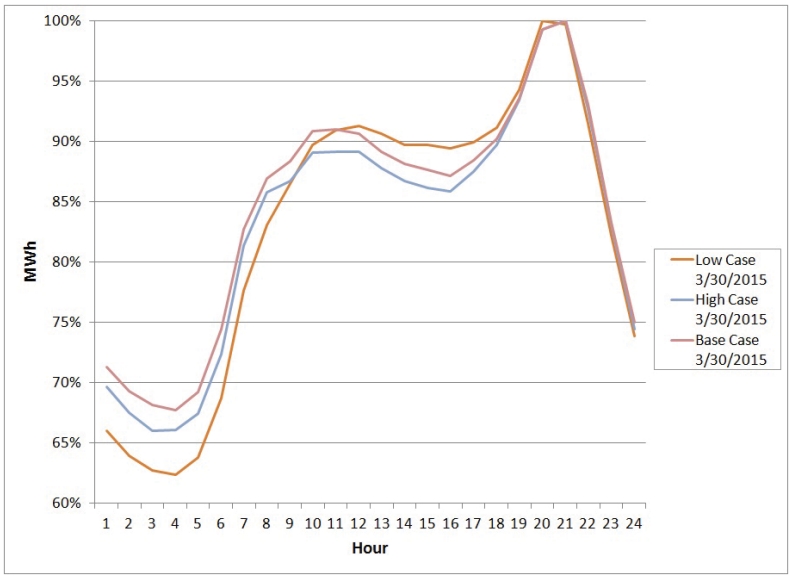


Figure 3-16 Sample Daily Load Forecast, Spring 2015 in ComEd Forecasts



The annual load factors are shown in Figure 3-17. As expected, the high load case has a lower load factor than the base case. Unexpectedly, the base case load factor is much higher than both the high-case and low-case load factors. This may indicate that the base forecast was based on an over-averaged temperature pattern (normal every day).