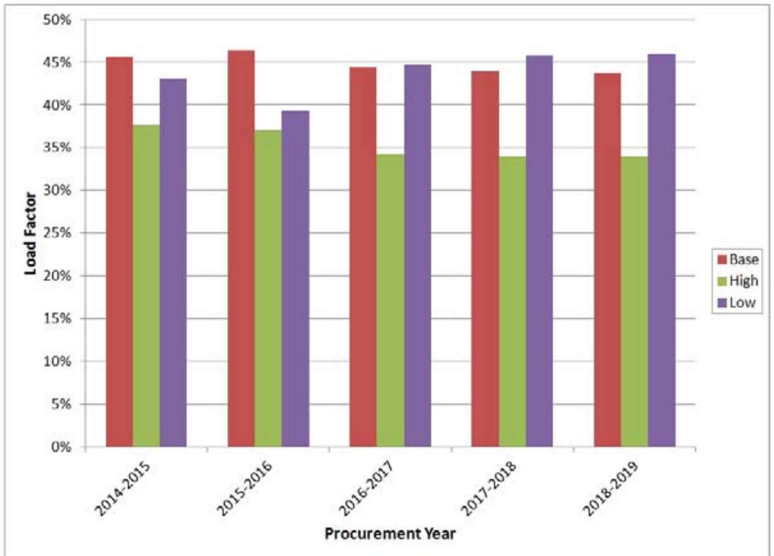
Figure 3-17 Utility Load Factor in ComEd



3.4 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured or hedged power for the utilities to meet a forecast of the average hourly load in each of the on-peak and off-peak periods. The Agency has addressed the volatility in power prices by "laddering" its purchases: hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the delivery year. Even if pricing two years ahead were extremely advantageous, the Agency should not purchase its entire forecast that far ahead because the forecast is itself uncertain. It is therefore important to understand the sources of uncertainty in the forecasts.

Furthermore, even if the Agency could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. Load varies from hour to hour. Energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. A perfect hedge would cover differing amounts of load in different hours, and would have to be based on a forecast of the different hourly loads. The "expected hourly load" is not an accurate forecast of each hour's load (see Section 3.4.3). This is not an issue of uncertainty: it would be true even if the expected hourly load were a perfect forecast of the average load, and the hourly profile (the ratio of each hour's load to the average) were known with certainty. So it is treated here together with the other uncertainties.

3.4.1 Overall Load Growth

Both utilities construct their load forecasts by forecasting load for their entire delivery service area, then forecasting the load for each customer class or rate class within the service territory, and then applying multipliers to eliminate load that has switched to municipal aggregation or other ARES service. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely, as the utilities have no supply or planning obligation for them.

Ameren does not explicitly address uncertainty in load growth. In other words, they do not define "load growth scenarios" and examine the consequences of high or low load growth. They address both load and weather uncertainty by defining high and low scenarios at particular confidence levels of the model fit, that is, of the residuals of their econometric model. The high and low cases, which represent the combined and correlated impact of weather and load growth uncertainties, represent a variation of only ±9% in service area load. However, Ameren's high and low cases also include extreme customer migration uncertainty.

ComEd defines high and low load growth scenarios as 2% above or below the load growth in their base or expected case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios so it is hard to determine how they relate to economic uncertainty. Given the stability of utility loads in recent years, differences of +/-2% in load growth should represent a good range of uncertainty.

3.4.2 Weather

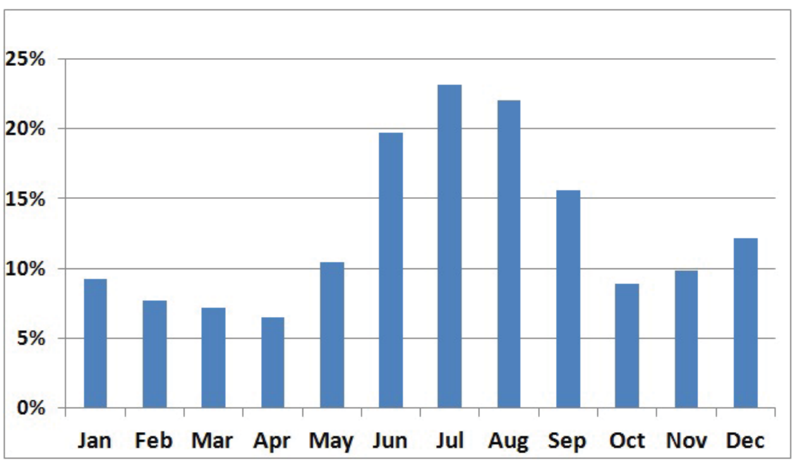
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios, Sections 3.2.2 and 3.3.2, notes the way that Ameren and ComEd have incorporated weather variation into their high and low load forecasts. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. Much of the impact of weather is on load variability within the year.

3.4.3 Load Profiles

As noted above, the "average hour" load forecast is not an accurate forecast of each hour's load. Within the sixteen-hour daily peak period, mid-afternoon hours would be expected to have higher loads than average, and early morning or evening hours lower loads. More important, multiplying the average hourly load by the cost of a "strip" contract (equal delivery in each hour of the period) gives an inaccurate forecast of the cost of energy, because hourly energy prices are correlated with hourly loads (energy costs more when demand is high). Technically this is referred to as a "biased" forecast, because the expected cost will predictably differ from the product of expected hourly load and expected hourly cost.

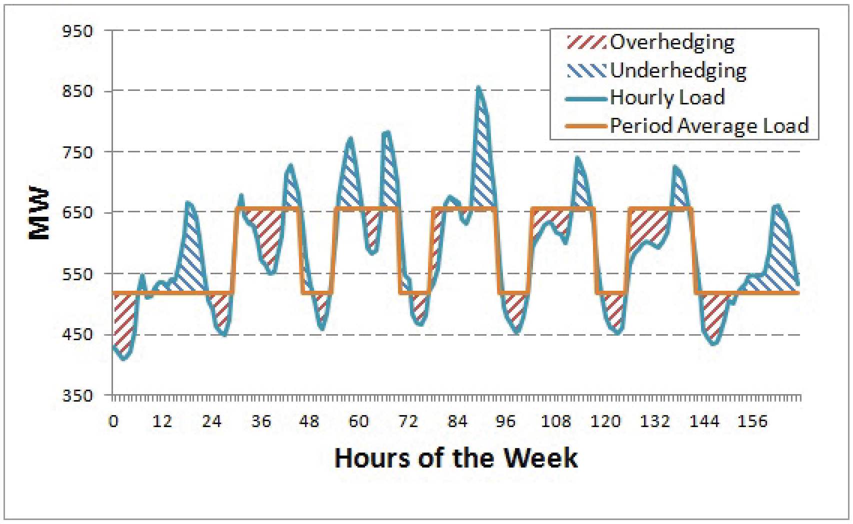
Figure 3-18 illustrates this by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. It is based on historical ComEd loads from June 2002 through 2011, normalized to the monthly base case forecasts in the first procurement year. The variances of loads within each day's peak period are averaged to get an expected daily variance. That variance is scaled to load by first taking the square root and then dividing by the average peak-period hourly load forecasted for the month. As the figure shows, there is significant load variation during the day in the high-priced summer months.

Figure 3-18 Coefficient of Variation of Daily Peak-Period Loads



Because of this variation, if the average peak and off-peak monthly load is perfectly hedged the actual hourly load will still be imperfectly hedged. In other words, if the Agency were to buy peak and off-peak hedges whose volumes equaled respectively the average peak period load and average off-peak period load, there would still be unhedged load because the actual load is usually greater or less than the average. This is illustrated in Figure 3-19 below:

Figure 3-19 Example of Over- and Under-Hedging of Hourly Load



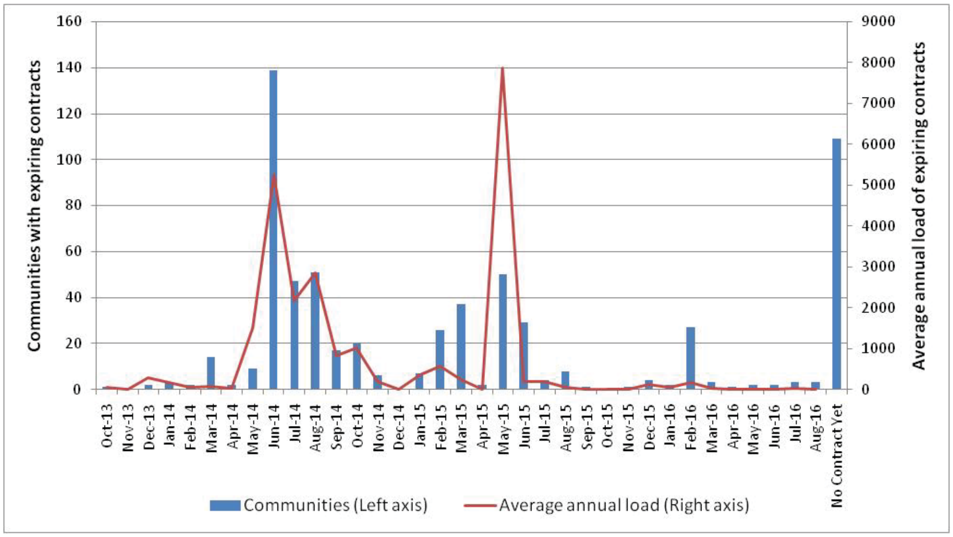
3.4.4 Municipal Aggregation

In their base cases, Ameren projects 73.0% switching by eligible retail customers by the end of the 2014-5 procurement year and ComEd projects about 74.7%. This may be approaching a saturation level; switching levels are so high that there is not much "headroom" for upwards uncertainty, and www.pluginillinois.org/MunicipalAggregationList.aspx does not, as of the date of this document, list any aggregation referenda scheduled for November 2013.

At this point the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase from return to service or opt-out. In July 2012, ComEd assumed a 4% opt-out rate but later in the year, based on experience, they raised their assumption to 8% for single-family residential customers and 12% for multi-family customers (still 4% for non-residential customers). Ameren assumed a 10% opt-out rate in their load forecast computations.

As shown in Figure 3-20 over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. It is a possibility that many of the renewal offers made by the suppliers to municipal aggregations may be out of the money relative to utility bundled supply prices, so there may be a considerable amount of return to utility service. This is especially true if market prices rise between now and the expiration of municipal aggregation contracts. On the other hand, switching could be higher than expected resulting in an over-hedged position. Expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. Both Ameren and ComEd have assumed a wide range of switching fractions in their low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time). The IPA notes that some multi-year municipal aggregation contracts may have early termination clauses if the supplier cannot match or beat the utility-offered supply price.

Figure 3-20 Distribution of Municipal Aggregation Contract Expirations



3.4.5 Impact of Wholesale Pricing and Market Arrangements on Switching Behavior

Customer migration behavior is particularly important because of its linkage with market prices. Utility retail tariff prices tend to lag prices in the power market for two reasons.

1. First, the IPA's procurement strategy has been to buy power in a "laddered" fashion. A large fraction of the power consumed by retail customers would have been bought forward one to two years earlier. In a period of rising prices, those forward purchases would have been priced below the current spot price (and below the current forward price), and therefore the blended price of IPA supply would be less than the current price of a new contract, e.g., a renewed municipal aggregation contract.

   The reverse is true in a period of falling power prices, as has been experienced over the last several years: the blended price of IPA supply would be higher than the contemporary price of power, or the price of new contracts. That would motivate rational consumers to depart from utility service for the price of a new contract either with an ARES or through municipal aggregation. If the market is moving into an environment of rising power prices it is equally true that consumers would be motivated to return to utility service. The forward contracts in the utilities' portfolios for 2014-2015 are currently above the forward curve (out of market).

2. Second, there are regulatory lags involved in utility rate setting. Even if the IPA supply were purchased entirely at the spot price, the monthly retail price would have been set in advance and reconciled after the fact. In a rising market the tariffs will be below the actual supply cost. Customers do eventually pay those higher prices, through a delayed balancing account mechanism. Price caps, such as the ceiling on ComEd's Purchased Energy Adjustment, introduce further delays. A customer who aggressively exercises his or her switching options would leave utility service when spot prices begin to fall, to obtain a more immediate benefit from the price reduction, and return to utility service when prices begin to rise, since he or she would be insulated from that rise for at least several months. Of course, customers may not be so aggressive in switching, and that aggressiveness may also be mitigated by regulatory and legal barriers, such as the prospect that they may have to stay on utility service for 12 months if they do not select a new supplier within two billings periods of returning to utility service.

Although it is not yet clear how governments running municipal aggregation programs and individual customers who may opt out or leave a program will act, it is likely that customers would return to utility service in periods of rising prices.[65] The Agency and the utilities would have to arrange for additional supply to cover the returning load, at a price higher than was paid for the originally forecasted load and higher than would be built into utility tariffs. Therefore, load whose return is correlated with high prices (and whose departure is correlated with low prices) represents not only load uncertainty but also an absolute price risk.

Finally, independent of market pricing, there may be other market arrangements that motivate customers to switch from or return to utility service. Some customers, or customers in some locations, may be inherently less expensive to serve and will see a benefit from moving to a retailer that can provide them a differentiated price. Others, who may find they are more expensive to serve, will be motivated to return to the uniform tariff. Customers may not have realized these differences when the initial municipal aggregation referenda were held; the costs may actually be utility delivery charges that only become visible when customers leave bundled service. For example, ComEd's current practice uses four different PLCs – one for each of the four sub-classes of residential customers. Each of these constant PLCs is the same for all customers within the sub-class, regardless of other measures of the customer's "size." Low-usage customers or aggregation groups dominated by low-usage customers will find that they are disadvantaged by ARES or municipal aggregation service, relative to bundled service. The IPA is interested in stakeholder feedback on the effect and magnitude of non-market price factors leading to government and individual decision-making.[66]

3.4.6 Individual Switching

Although switching from the utility to ARES by individual customers has some impact, Ameren and ComEd switching forecasts have been dominated by municipal aggregation. The most desirable customers to ARES would be medium and large commercial and industrial customers. Since their load has been declared competitive they are not eligible for IPA-procured default rate service. Although the IPA recognizes that many ARES do focus on individual residential switching, the IPA is not aware of a way to model or predict how many customers will leave default service for a non-municipal aggregation ARES. In the absence of such a model, it is reasonable to assume that switching behavior by individual customers will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation.

3.4.7 Hourly Billed Customers

Customers who could have elected bundled utility service but take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers". Therefore, these hourly rate customers are not part of the utilities' supply obligation and the IPA does not have to procure energy for them. Ameren and ComEd did not include customers on hourly pricing in their load forecasts; they appropriately considered these customers to have switched. The amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts.

3.4.8 Energy Efficiency

Public Act 95-0481 also created a requirement for ComEd and Ameren to offer cost-effective energy efficiency and demand response measures to all customers.[67] Both Ameren and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with this Procurement Plan. Section 7.1 of this plan discusses the proposed incremental energy efficiency programs that have been submitted pursuant to Section 16-111.5B. These programs are reflected in the load forecasts.

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[65] The necessary timeframe or magnitude of rising prices (or, more accurately, the spread between the bundled utility rate and the best price a municipal aggregation supplier will offer) for customers to engage in this behavior is unknown, and the IPA is interested in feedback from stakeholders as to expected quantitative or qualitative parameters.
[66] The IPA believes that any proposed changes to PLCs are outside the scope of this proceeding; the IPA is simply interested in the effect of current PLCs on switching decisions.
[67] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).

3.4.9 Demand Response

As noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources. Section 7.5 of this Procurement Plan contains the IPA's discussion and recommendations for demand response resources.

3.4.10 Emerging Technologies

A number of emerging technologies were described in the 2013 procurement plan. That material will not be repeated here. This plan will comment on the likely effect of two technologies on load forecast uncertainty during the projection horizon, and particularly in the first half of the projection horizon.

3.4.10.1 Advanced Metering Infrastructure

Many of the most effective emerging technologies and rate options depend on the installation of "smart meters." When the 2013 Procurement Plan was produced, the ICC had not yet approved the AMI deployment plans for Ameren and ComEd. The ICC approved a revised deployment plan for Ameren in December 2012 in which 15% of its meters will be upgraded to AMI by the end of 2015[68] and a revised AMI deployment plan for ComEd in June 2013 in which 900,000 AMI meters (out of 4.03 million, about 22%) will be installed by the end of 2015.[69] Given the necessary lag between the time that meters are installed and the point at which customers are able to make use of them with new technologies or rates, it is likely that less than 22% of ComEd customers, and less than 15% of Ameren customers, will be able to make use of smart meters by the end of the 2015-2016 procurement year. The load uncertainty associated with AMI meters and related technologies should be low for the first half of the projection horizon.

3.4.10.2 Electric Vehicles

Electric vehicles (EVs) have the potential to significantly impact electricity demand. However, while their prices have been declining, they remain expensive, and of limited range. One promising spur to adoption was battery-swapping technology. The main proponent of that technology, Better Place, went bankrupt in 2013, but the market leader in electric vehicles, Tesla Motors, subsequently demonstrated its own battery-swapping. Still, optimism about EVs must be tempered by the price of EVs, the difficulties that have faced some manufacturers (such as Fisker) and supply limitations (Tesla Motors is currently producing at a rate of only 20,000 cars per year).

The 2013 procurement plan included estimates from Ameren and ComEd totaling no more than 536,000 EVs on the road in Illinois by 2020 (the projection horizon for this plan extends to 2019) and a second estimate of 300,000 MWh of additional load per 100,000 electric vehicles. The plan forecasted an increase of 1.6 TWh of annual load by a year after the end of the projection horizon. Actual EV load will probably be much lower. This figure should be compared with the total residential and small commercial load in Ameren and ComEd service territory, which is forecasted to be over 82 TWh in the 2018 procurement year. Although EVs are a promising technology they do not appear to significantly contribute to load forecast uncertainty during the projection horizon of this procurement plan.

3.5 Recommended Load Forecasts

3.5.1 Base Cases

The IPA recommends adoption of the Ameren and ComEd base case load forecasts, both of which include incremental energy efficiency programs. The IPA's recommendation that the Commission approve the incremental energy efficiency is presented in Section 7.1.4.

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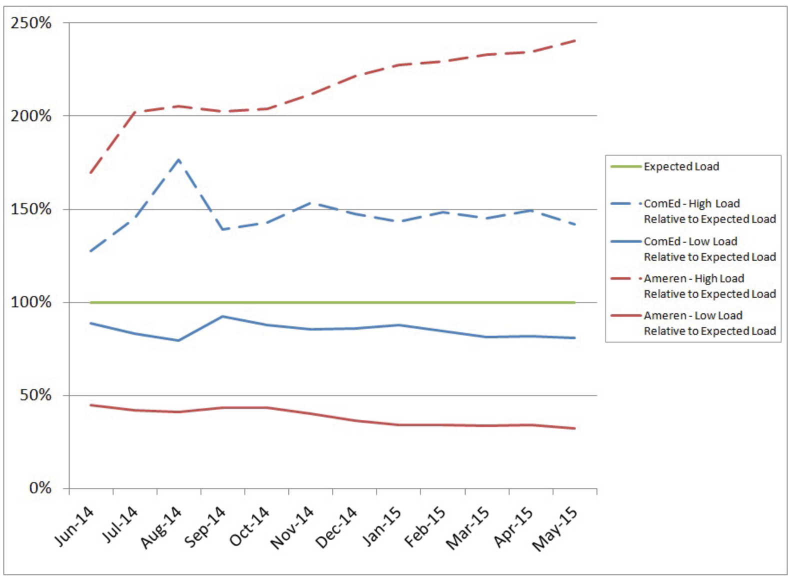
[68] Illinois Commerce Commission Order on Rehearing in docket 12-0244, December 5, 2012; also Ameren Illinois Advanced Metering Infrastructure Plan filed as Exhibit 2.1RH attached to the Corrected Petition for Rehearing in ICC Docket No. 12-0244, June 28, 2012.
[69] Illinois Commerce Commission Final Order in Docket No. 13-0285, June 26, 2013.

3.5.2 High and Low Excursion Cases

The high and low cases represent useful examples of the extent to which load can vary. Although they are primarily driven by variation in switching, Ameren correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren's high and low forecasts, is extreme and thus these may be characterized as "stress cases." The Agency's procurement strategy to date has been built on hedging the average hourly load in each of the peak and off-peak sub-periods, and the high and load cases represent significant variation in those averages.

As illustrated in Figure 3-21, Ameren low and high load forecasts are on average 63% lower and 117% higher during the 2014-2015 Delivery Year relative to the expected, base forecast. Comparatively, ComEd low and high load forecasts are 15% lower and 47% higher than the expected, base forecast. This reflects the differences in switching assumptions used by the two utilities.

Figure 3-21 Comparison of Ameren and ComEd High and Low Forecasts for Delivery Year 2014 - 2015



Another use of the high and low cases will be to estimate the risks of different supply strategies. A key driver of that risk is the cost of meeting unhedged load on the spot market. One of the main reasons load is unhedged is that one attempts to hedge a variable or shaped load with a product whose delivery is constant. The spot price at which the unhedged volumes are covered is positively correlated with load. The high and low cases are less suitable for such a risk analysis.

The high load factor of the ComEd base case forecast implies that the hourly profile of that case is not representative of a typical year. This means that the base case hourly forecast would understate the amount by which hourly loads vary from the average hourly loads in the peak and off-peak sub-periods. Using that hourly profile for a risk analysis could lead to underestimating the cost of unhedged supply.

The Ameren load scenarios have identical monthly load shapes (differing by uniform scaling factors). These shapes will not provide much information about the cost of meeting fluctuating loads, except for the information contained in the expected load shape. The expected load shape may have an overstated load factor like that of ComEd, and no other forecast case is available for comparison.

The extreme nature of Ameren's low and high load forecasts can influence the results of a probabilistic risk analysis. With almost any assignment of weights to the Ameren cases, load uncertainty will dominate price uncertainty. This does not apply to ComEd, which must be taken into account when evaluating any simulation of procurement risk.

ComEd informed the IPA that they assessed the variation in delivery service load (before considering switching) in the high and low cases as representing the 75th to 80th percentile and 20th to 25th percentile, respectively. In its probabilistic analysis the IPA treated ComEd's high and low forecasts of retained load as representing the 95th and 5th percentile points of an underlying load distribution. Ameren had described the high and low delivery service forecasts as being the 80th to 90th and 10th to 20th percentiles respectively, and the associated switching forecasts were also more extreme, so the IPA treated Ameren's high and low forecasts of retained load as the 97.5th and 2.5th percentiles of an underlying distribution.[70]

[70] As a technical note, the "percentiles" are not the same as the probabilities one would assign in constructing a discrete distribution for probabilistic analyses. For example, if one were to construct a discrete distribution using the mean and the 10th and 90th percentile points of a normal distribution, and assign probabilities in such a way as to match the mean and variance of the (original) normal distribution, then the probability weight on the mean would be 39.1% and the weights on the extremes would each be 30.45%.

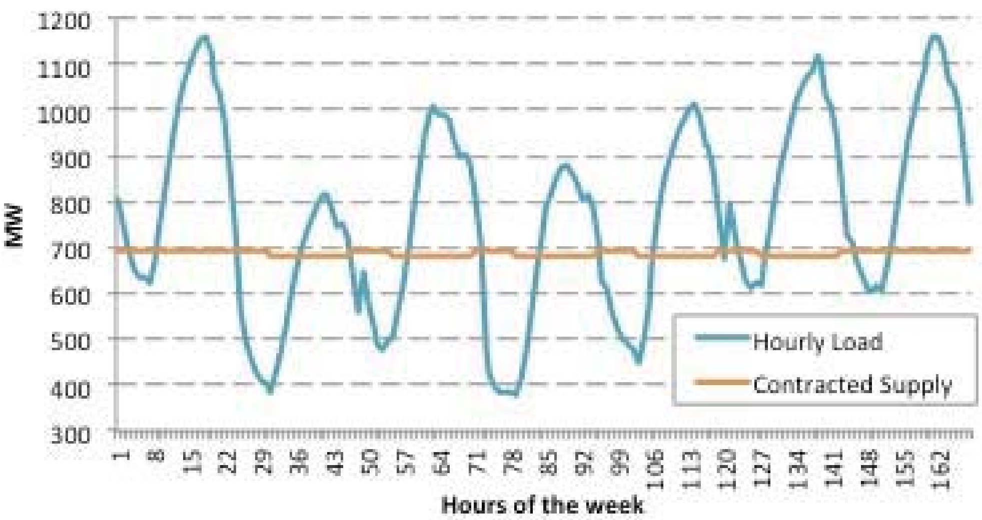
4 Existing Resource Portfolio and Supply Gap

The IPA has historically purchased supply in standard 50MW on-peak, off-peak, and around-the-clock blocks. The history of the IPA energy purchases is available on the IPA website[71].

These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process. This procurement process is administered and monitored for the Commission by independent third parties.

In addition to purchasing block contracts, Ameren and ComEd rely on the operation of their RTOs (MISO and PJM respectively) to balance their loads and consequently incur additional costs. During on-peak hours, purchased energy blocks may not fully cover the load therefore triggering the need for spot energy purchases from the RTO. Similarly, during off-peak hours over-supply may occur, prompting the utilities to sell their excess-energy to the RTOs at a low off-peak hour price. This is illustrated in Figure 4-1 where Ameren's hourly load oscillates between 377MW (minimum off-peak hour load) and 1162MW (maximum peak hour load) for the first full week of August 2014 while the hedge portfolio varies only between 682MW and 698MW. Note that ComEd is currently under hedged in every hour of the June 2014 to May 2019 period relative to the expected forecast and (absent additional purchases) would be expected to rely on the operation of PJM in every hour to meet its load.

Figure 4-1 Ameren Hourly Supply Gap - First Full Week of August 2014



The IPA procurement plans are based on a supply strategy designed, among other things, to manage price risk and cost. The underlying principle of this supply strategy is to procure energy products that will cover all or most of the near-term load requirements and then gradually decrease the amount of energy purchased relative to load for the following years.

Prior to the 2013 Procurement Plan, the first year of the 3-year procurement plan was hedged at 100% (meaning that energy contracts would fully cover the demand) while the second and third years would only be hedged at 70% and 35% respectively. As part of the 2013 Procurement Plan and based on suggestions from the Commission staff, the IPA considered a revision to this strategy (for the energy products only[72]) to account for declining market prices and accelerating customer switching. This proposal was the first year

[71] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.
[72] In the 2013 Procurement Plan, the IPA recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction.

would be hedged at 75% while the second and third year would be hedged at 50% and 25% respectively. However, because no procurement was required, the IPA recommended that the hedging strategy be revisited in future Plans.

Because of the lack of visibility and liquidity of the energy markets and to limit the ratepayers' exposure to unnecessary price risk and cost, the IPA has not purchased any energy beyond a 3-year term horizon, except for long-term procurements which were mandated by the Legislature. These include:

- A 20-year bundled REC and energy purchase, starting in June 2012, made by Ameren and ComEd in December 2010.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017; there were also associated REC procurements but they do not impact the (energy) resource portfolio.

Due to the reductions in rate revenue attributable to customer switching, ComEd has been obliged to curtail its existing long-term renewable contracts in order to keep the cost of renewable energy resource under the statutory cap for the 2013-2014 delivery year (i.e., the year commencing June 1, 2013 and ending May 31, 2014). Possible curtailment for the 2014-2015 delivery year for both ComEd and Ameren is addressed in Section 8.2 of this plan.

The discussion below explores in more detail the supply gap between the updated utility load projections described in Chapter 3 and the supply already under contract for the planning horizon. The IPA's approach to address these gaps is described in Chapter 7.

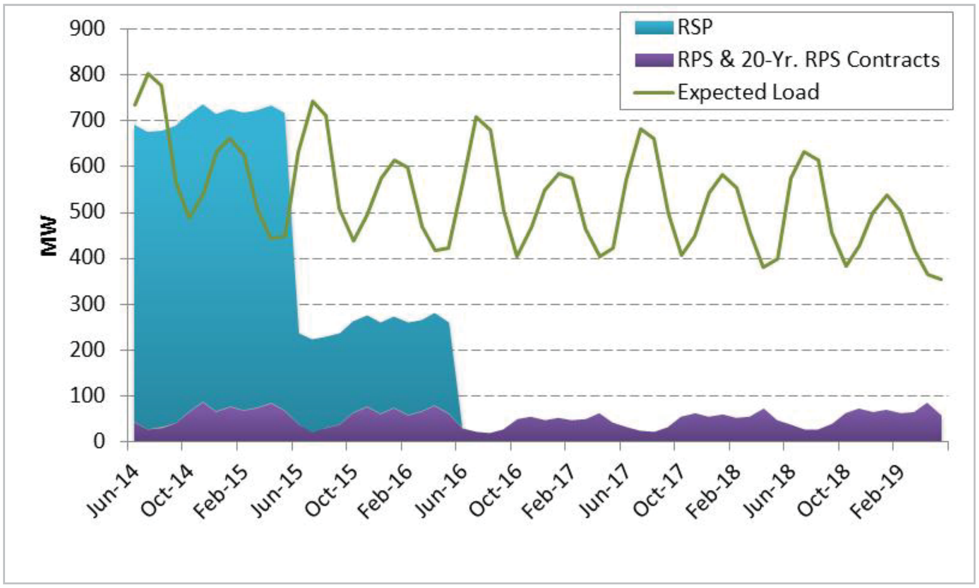
4.1 Ameren Resource Portfolio

Figure 4-2, Figure 4-3, and Figure 4-4 show the current gap in the Ameren supply portfolio for the June 2014-May 2019 planning period, using the average, high and low load on-peak forecast described in Section 3.2.

The Rate Stability Procurements (RSP) mandated by SB1652, and Ameren's existing contract portfolio, including long-term renewable resource contracts (assuming no curtailments), should cover the projected load for the 2014-2015 delivery period, with the exception of the months of June, July and August. However, additional energy will be required in 2015-2016 and beyond.

Quantities shown are average peak period MW for both loads and historic purchases.

Figure 4-2 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - Expected Load Forecast, No Curtailment of Renewable PPAs



Under the high load forecast scenario, Ameren will be consistently short starting as early as June 2014. The average supply gap for peak hours of the 2014-2015 delivery period is estimated to be 586MW.

Under the low load forecast scenario, Ameren would not require any additional energy procurement until June 2016 and Ameren's supply portfolio would actually be in excess during the peak hours of the 2016-2017 period in average by 11MW (shortfalls would only occur during the summer of 2016).

Figure 4-3 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - High Load Forecast, No Curtailment of Renewable PPAs

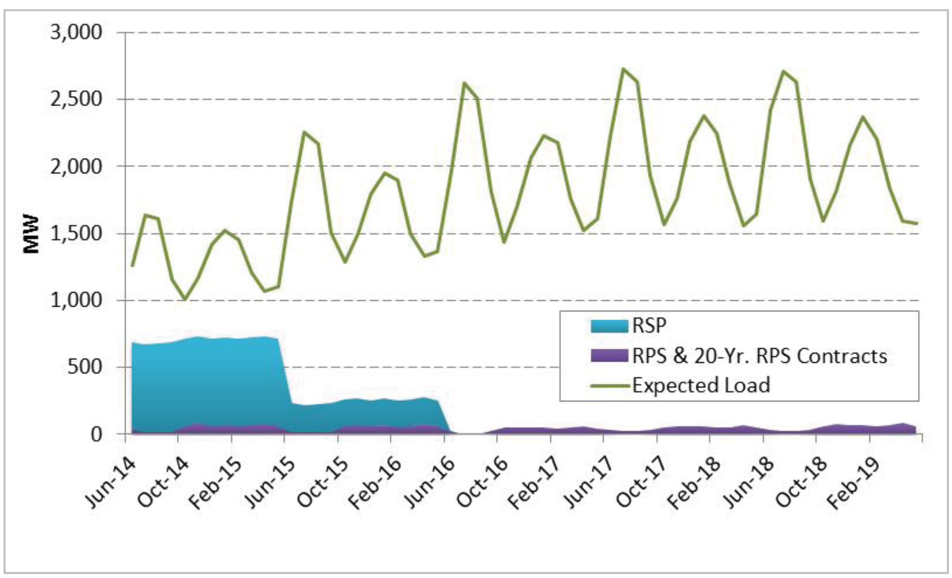
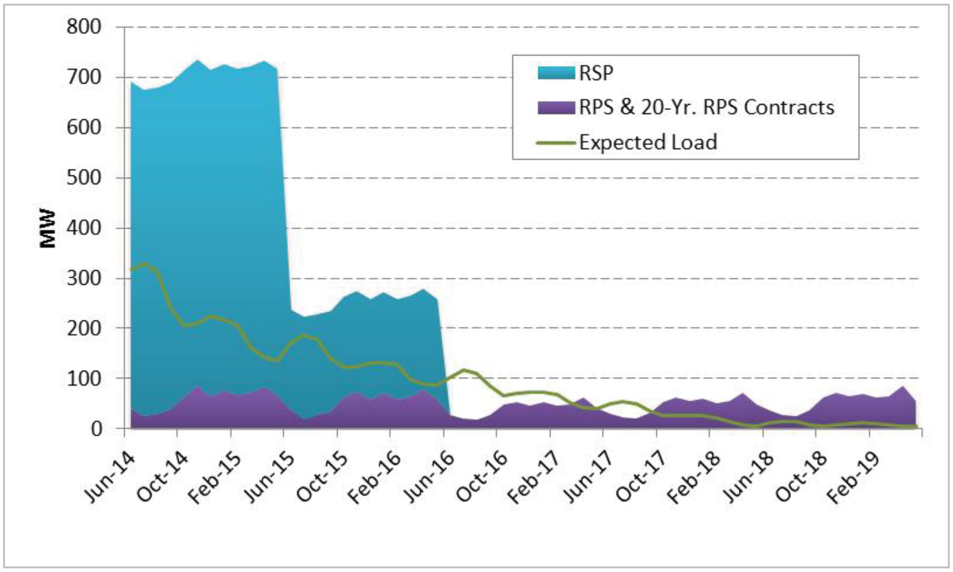


Figure 4-4 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - Low Load Forecast, No Curtailment of Renewable PPAs

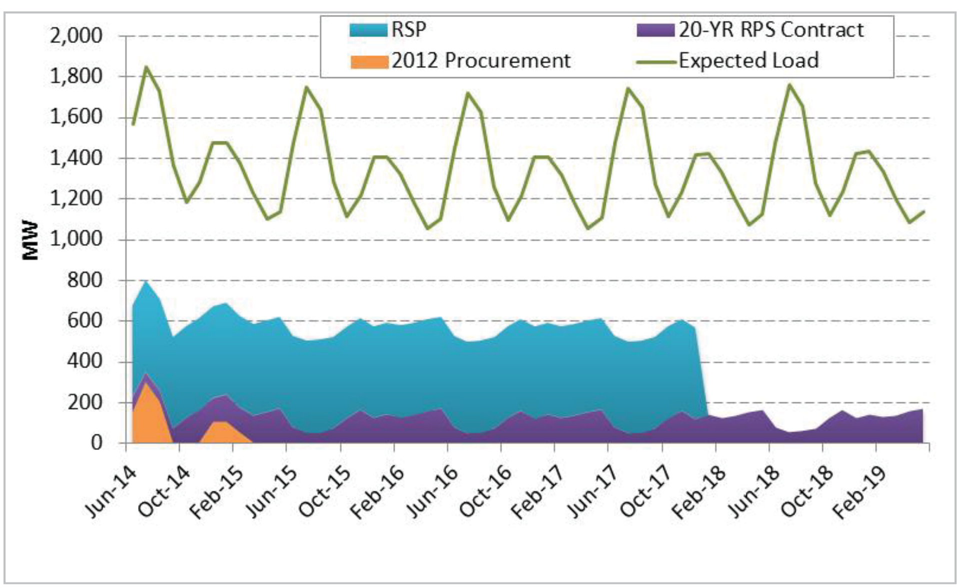


4.2 ComEd Resource Portfolio

Figure 4-5, Figure 4-6, and Figure 4-7, show the current gap in the ComEd supply portfolio for the June 2014-May 2019 planning period, using the average, high and low load on-peak forecast described in Section 3.3.

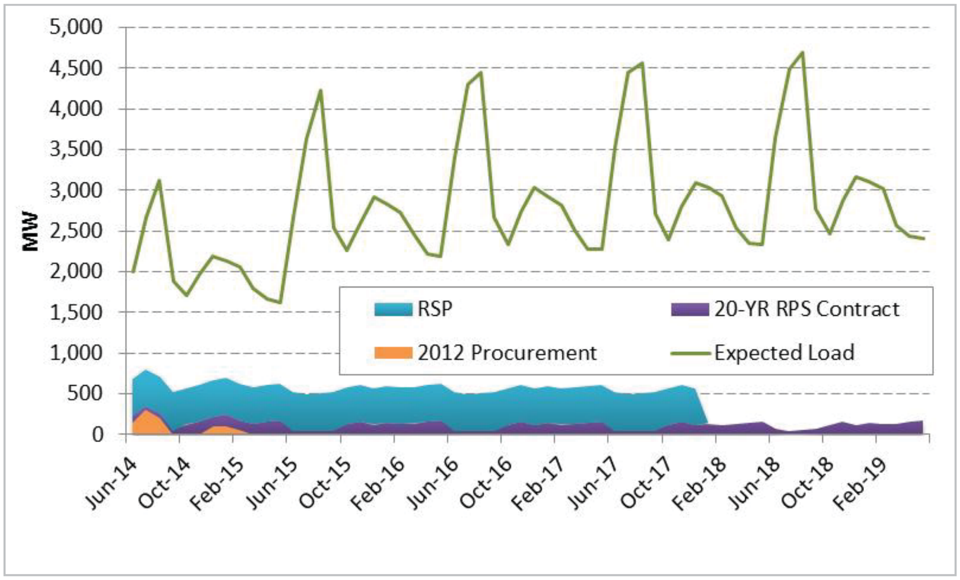
ComEd's current energy resources will not cover load starting in June 2014. The average supply gap during peak hours for the 2014-2015 delivery year is estimated to be 771MW. The 2013 Procurement Plan explicitly stated a change in the hedging plan, so that only 50% of expected 2014/2015 load would be hedged a year ahead. This gap is expected to remain relatively constant until the Rate Stability Procurement (RSP) contracts terminate in January 2018.

Figure 4-5 ComEd's On-Peak Supply Gap - June 2014-May 2019 period - Expected Load Forecast, No Curtailment of Renewable PPAs



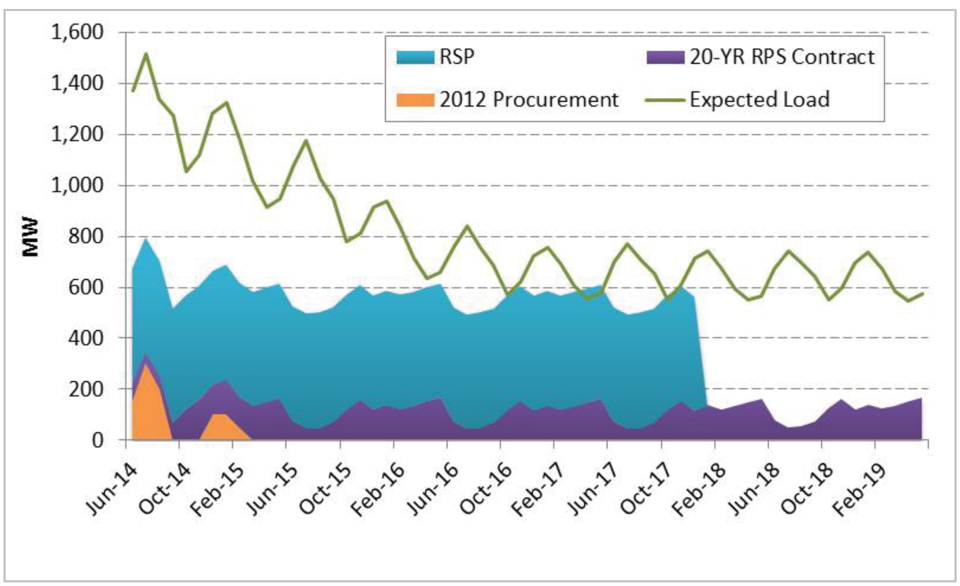
Under the high load forecast scenario, ComEd will be consistently short during the whole study period. The average supply gap for peak hours of the 2014-2015 delivery period is estimated at 1429MW.

Figure 4-6 ComEd's On-Peak Supply Gap - June 2014-May 2019 Period - High Load Forecast, No Curtailment of Renewable PPAs



Under the low load forecast scenario, ComEd will also be consistently short during the study period except for the months of April, May and October 2017.

Figure 4-7 ComEd's On-Peak Supply Gap - June 2014-May 2019 Period - Low Load Forecast, No Curtailment of Renewable PPAs



5 MISO and PJM Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, resource adequacy (the load/resource balance) can be viewed as a function of determining what level of resources to purchase from which markets over time. However, in order for the Illinois market to properly function, the overall RTO markets (e.g. MISO and PJM) must provide sufficient resources to satisfy the load of all customers. This section reviews the likely load/resource outcomes over the planning horizon to determine if the current system is highly likely to provide the necessary resources such that customers will be served with adequate and reliable power.

In reviewing the load/resource outcomes over the planning horizon, this section analyzes several outside studies of resource adequacy that are publicly available from different planning and reliability entities. These include:

- North American Electric Reliability Corporation ("NERC"), the entity certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midcontinent ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois.
- PJM Interconnection ("PJM"), which operates the transmission grid in Northern Illinois.

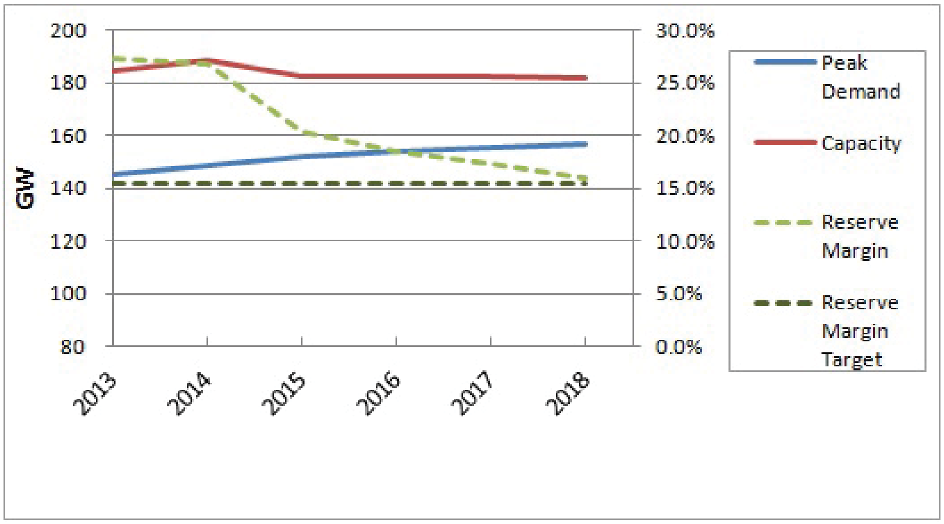
From review of these entities' most recent documentation, it is clear that over the planning horizon both PJM and MISO will maintain adequate resources to meet the collective needs of customers in those regions.

5.1 Resource Adequacy Projections

In PJM, capacity is largely procured through PJM's capacity market, Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. RPM is a forward capacity auction through which generation offers capacity to serve the obligations of load-serving entities. The primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May, three years prior to the commitment period. The commitment period is also referred to as a delivery year ("DY").[73] In addition to the BRAs, up to three incremental auctions are held, at intervals 23, 13, and 3 months prior to the DY.[74] As outlined in Figure 5-1, PJM is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with projected reserve margins averaging over 20% during this time frame. This is approximately 5% above the 15.6% reserve margin requirement.

[73] A DY is June 1 through May 31 of the following year.
[74] To the extent the 1st and 3rd incremental auctions are not needed, they may be cancelled by PJM. The 2nd incremental auction is held to procure capacity to meet the deferred short-term resource procurement.

Figure 5-1 PJM NERC Projected Supply and Demand



MISO's capacity market construct, Module E-1, creates a framework for electric utilities and capacity resources to enter into bilateral agreements for capacity. Specifically, Module E-1 is a resource adequacy program that requires the region's load-serving entities to procure sufficient capacity resources to meet their peak load plus target reserve margin.[75] Under Module E-1, a load-serving entity can procure resources to meet its resource adequacy requirements by offering or self-scheduling resources in the annual auction or by submitting a Fixed Resource Adequacy Plan ("FRAP") to demonstrate sufficient resources have already been procured. As outlined in Figure 5-2, MISO is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with reserve margins averaging over 22% during this time. This is approximately 5% above the 17.5% reserve margin requirement.

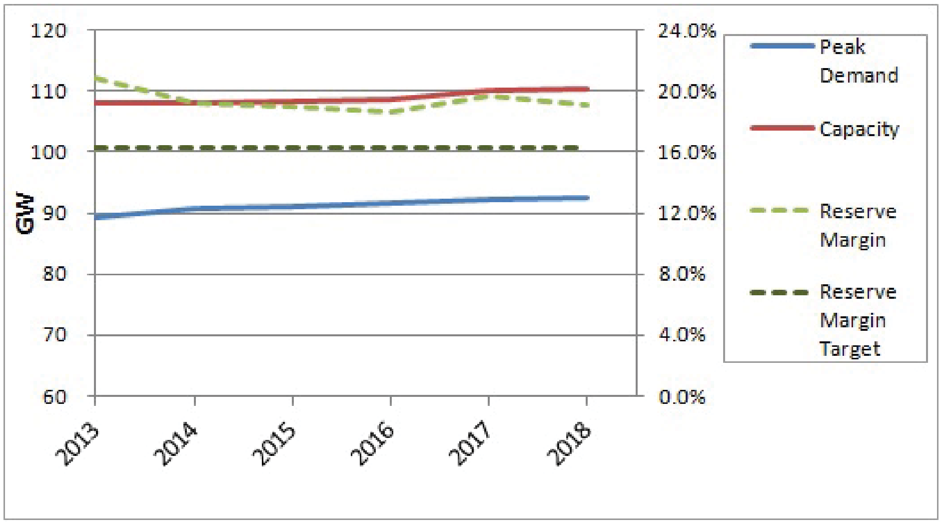
5.2 Locational Resource Adequacy Needs

The RTO-based reliability assessments examined above are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. While changes are projected to occur in the RTOs, as outlined below, the IPA concludes that it does not need to include any extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.

The integration of Entergy into MISO, which will create the MISO Southern Region and is planned for December 2013, will provide more generation to be dispatched and bid into the MISO markets (the load/resource balance associated with the Southern Region is not reflected in Figure 5-2 as it has yet to be incorporated in NERC projections).

[75] An LSE's reliability requirement is based on either planning reserve margins (PRM) determined by MISO, based on a loss of load expectation of one day in ten years, or state-specific standards.

Figure 5-2 MISO NERC Projected Supply and Demand



An increase in capacity resources exporting into PJM (7,500 MW in total representing an incremental 4,000 MW from the previous year's auction) is reported in the 2016/17 Base Residual Auction.[76] This substantial increase in imports for PJM is a positive development with respect to PJM's capacity market, but may also indicate less confidence in MISO's Module E-1 anticipated pricing and/or liquidity to the extent imports are coming from this region.

5.3 Operational Adequacy

MISO has discussed setting requirements for upward and downward ramping capacity. The concept is that at least a specified fraction of the resource adequacy would have to be met by capacity capable of meeting a flexible ramping standard. To date, no such requirement has been incorporated into Module E-1.

[76] Of the 7,500 MW of total net imports, approximately 4,800 had firm transmission service into PJM. The remaining 2,700 have submitted requests for firm transmission service, but have yet to receive it. This situation adds some uncertainty regarding the ability of those capacity resources without firm transmission rights into PJM to meet their capacity obligations for the 2016/17 delivery year.

6 Managing Supply Risks

The Illinois Power Agency Act lists the priorities applicable to the IPA's portfolio design, which are "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."[77]

At the same time, the Legislature recognized that achievement of these priorities requires a careful balancing of risks and costs, when it required that the Procurement Plan include:

> *an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.*[78]

This chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating them. Developing a strategy requires knowledge of the risk factors associated with energy procurement and delivery and of the tools available to manage those risks. The first section describes the risk factors themselves. These include some risk factors identified in the previous sections. The balance of the chapter identifies and analyzes the tools available to manage those risk factors. Section 6.2 describes types of contracts and hedges that can be used to manage supply risk. Those products may be thought of as being used to build a supply portfolio. Section 6.3 addresses the complementary issue of reducing or re-balancing the supply portfolio when needed.

Sections 6.4 through 6.7 address the cost and uncertainty impacts of these risk factors. Risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois is based on estimates and cost differences are trued up after the fact through the Purchased Energy Adjustment (PEA). Section 6.4 provides a historical summary of PEA rates as a guide to the historical impact of risk factors. Section 6.5 includes estimates of the cost impacts of risk factors based on a Monte Carlo simulation model, and compares several forward hedging strategies. Section 6.7 focuses on full requirements tranche contracts. Tranche contracts can eliminate the uncertainty in supply cost, and the Monte Carlo model is used to estimate the associated price premium.

Finally, Section 6.8 addresses demand management.

6.1 Risks

Procurement risk factors can be divided into three broad categories: volume, price, and hedging imperfections. Volume risk deals with risk factors associated with identifying the volume and timing of energy delivery to meet demand requirements. Price risk covers not only the uncertainty in the cost of the energy but also the costs associated with energy delivery in real time. Hedging imperfections are the result of mismatches between the types of available hedge products and the nature of customer demand.

6.1.1 Volume Risk

The accuracy of load forecasts directly impact volume risk. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. Sections 3.2 and 3.3 describe the load forecasting processes undertaken by Ameren and ComEd respectively. This section discusses the risk factors associated with those forecasts.

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[77] 20 ILCS 3855/1-20(a)(1).

[78] 220 ILCS 5/16-111.5(b)(3)(vi).

6.1.1.1 Load Profiles

The load forecasts of both utilities start by developing a system-wide forecast. Multipliers are applied to eliminate load that has switched to ARES service or municipal aggregation. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely. The use of a multiplier assumes the profile of non-switched load and switched load are equivalent. If the switched loads have different load shapes from the retained loads then the profiles that are the basis for the forecast do not represent actual load shapes.

6.1.1.2 Load Growth Projections

Ameren does not explicitly separate uncertainty in load growth from customer migration and weather uncertainty, all three of which are combined in the definition of high and low scenarios. The high and low cases represent a variation of ±9% in service area load.

ComEd defines high and low load growth scenarios as 2% above or below the load growth in their base or expected case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios.

6.1.1.3 Weather Forecast

On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. Ameren and ComEd have incorporated weather variation into their high and low load forecasts. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's high and low forecasts are built around two sample years and the historical weather affects impacting forecasted load variability within the year.

6.1.1.4 Technology Impacts

The deployment of smart meters can provide customers with a better understanding of the relationship between consumption and pricing. This knowledge may lead to changes in consumption patterns. It also may allow ARES to target specific customers. For example, ARES may be able to identify and target customers with flatter or more predictable loads.

Energy efficiency programs and the introduction of customer generation can also impact consumption patterns. Weatherization and efficient appliances will reduce the total volume of energy required. The intermittent character of small-scale wind and roof-top solar will impact both the total volume and load shape.

6.1.1.5 Customer Switching

Ameren and ComEd forecast the load to be served by subtracting from the retail load, in classes that have not been declared competitive, the fraction of load expected to be served by ARES directly or through municipal aggregation.

In their base cases, Ameren projects 73.0% switching among eligible retail customers by the end of the 2014-2015 delivery year; ComEd projects about 74.7%. No additional municipal aggregation activities are forecast. At these high migration values, switching may be approaching saturation.

The uncertainty around customer switching appears to be more related to the chance that utility load will increase from return to service. Over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. If ARES and municipal renewal offers are more expensive relative to utility bundled supply prices, there may be a considerable amount of return to utility service. On the other hand, switching could be higher than expected resulting in an over-hedged position. Expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates.

6.1.2 Price Risk

The price the Ameren and ComEd supply customer pays for electricity consists primarily of the price of energy procured in the forward and spot markets (Sections 6.1.2.1 and 6.1.2.2 as well as 6.1.2.7) the cost of capacity to meet resource adequacy requirements (Section 6.1.2.3), and the cost of delivery (Sections 6.1.2.4 through 6.1.2.6), plus additional charges related to RPS compliance.

6.1.2.1 Energy

Spot market electricity prices are volatile. Purchasing electricity in forward markets can reduce price risk. On-peak, off-peak, and around-the clock products are offered for various time periods from next day through several years. The price of the hedges to be bought in each subsequent year is unknown because the future price cannot be known in the present.

6.1.2.2 Real-Time Balancing

Forward contracts are based on the procurement of a block of energy over multiple hours. Customer consumption changes hourly. For example, the portion of an energy block that is not consumed during the hour starting at 10 AM cannot be moved to the hour starting 2 PM when consumption is greater than the energy block. The day ahead forecast excess energy for the hour starting at 10 AM is sold first into the RTO's day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. Likewise the shortfall of energy required for the hour starting at 2 PM is purchased from the day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. The volume and price sold at 10 AM do not necessarily match the volume and price purchased at 2 PM.

6.1.2.3 Capacity

ComEd is a member of PJM. PJM holds annual auctions to procure capacity through its Base Residual Auction (which occurs three years and one month prior to the delivery period) and all subsequent Incremental Auctions. The clearing price for the capacity purchased through these auctions is the Final Zonal Capacity Price that PJM uses to price ComEd's Daily Unforced Capacity (UCAP) Obligation. ComEd, like nearly all PJM Load Serving Entities, fulfills its capacity obligation through relatively passive participation in the PJM Reliability Pricing Model as a price taker. Specifically, ComEd pays PJM the resulting Final Zonal Capacity Price times ComEd's daily UCAP Obligation.

Ameren is a member of MISO. MISO also has a capacity requirement and has instituted its own Planning Resource Auction (PRA). The PRA covers the prompt year. The 2013-14 delivery year was the first year in which Ameren fulfilled its Planning Reserve Margin Requirement (PRMR) by participating in the auction. Although the bulk of Ameren's Zonal Resource Credits (ZRCs) were purchased in the 2012 procurement event, Ameren participated in the auction by offering to sell into the PRA all ZRCs acquired by Ameren through previous IPA procurement events as a price taker and receive the auction clearing price. Ameren will pay the same auction clearing price for its entire PRMR, which is updated on a daily basis to take into account retail switching.

6.1.2.4 Ancillary Services

Ancillary services consist of regulation to correct short-term load changes, and energy reserves to protect services from unexpected shortages. They support reliable delivery of energy. A load serving entity's (LSE's) obligation for these services can be met by self-provision, by contracting with another party, or through the RTO's reserve market. Bilateral contracting for ancillary services is not very liquid; therefore most LSEs are exposed to the RTO's ancillary service pricing.

6.1.2.5 Transmission

The delivery of procured energy resources requires the reservation of adequate transmission capacity to transport the energy to customer locations. LSEs generally use network transmission service. Transmission service is purchased on a first-come first-serve basis. Energy contracts that call for delivery at the customer location shift transmission price risk to the seller. The pricing of transmission service is FERC regulated and tends to be transparent.

6.1.2.6 Congestion

Transmission congestion occurs when the desired flow of power on a transmission path exceeds the path's capacity. The RTO runs a day-ahead market to identify and reschedule flows. The cost of this service is charged to entities scheduling delivery into a congested load zone. Financial Transmission Rights (FTRs) are hedging instruments used to mitigate congestion risk and Auction Revenue Rights (ARRs) allocate to transmission customers (both firm and network) the revenues resulting from the auction of FTRs. LSEs can use these revenues to offset congestion charges.

6.1.2.7 Correlation Between Volume and Price Risk Factors

Customer switching decisions may be influenced by the difference between utility and third party provider pricing. Customer switching behavior impacts volume risk. Variability in utility customer volume impacts price risk.

IPA's historic procurement strategy has been to buy power in a "laddered" fashion. A large fraction of the power consumed by retail customers was bought forward one to two years earlier. In a period of rising prices, those forward purchases may be priced below market. Therefore the blended price of utility supply may be less than the current price of an ARES or municipal aggregation offer. This price difference may result in increased migration back to the utility. The reverse is also true: higher utility supply costs may increase switching away from the utilities.

These trends may be intensified if there is a lag in reflecting the utility's energy costs in customer rates. Slowly rising rates will increase switching to the utility. Slowly dropping rates may increase migration from the utility.

Volume changes resulting from these pricing differences may result in additional price risks.

6.1.3 Hedging Imperfections

6.1.3.1 Procurement Supply Shape

The standard on-peak and off-peak block energy products do not reflect each hour's load. These products provide a constant volume and hourly price across a fixed number of hours. Hourly energy prices vary across the day and within each of the peak and off-peak periods. Load also varies within those periods and a great deal of that variation is predictable. Energy costs more when demand is high and less when low. Therefore, fixed volume and price purchases by themselves give an inaccurate forecast of the cost of energy to serve load and provide only a partial price hedge.

Because of this variation, if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. Residual risk will still exist because the actual load is usually greater or less than the average.

6.1.3.2 Procurement Location versus Customer Location

Hedge contracts for energy located remotely from the load location have transmission access and congestion risks. This is unlikely to be a problem with hedge contracts that deliver to the LSE's load zone, as is the case with existing hedges for which the IPA has procured.

6.1.3.3 Renewable Energy

Renewable energy procurement requirements met through the purchase of generation output are subject to intermittency. The cost to cover this intermittency may not be hedgeable, because the IPA procures renewable products (such as RECs or energy on an as-generated, rather than as pre-scheduled, basis) that are not comparable to standard block energy products. This risk factor was discussed at length in the Agency's 2013 report on the cost and benefits of renewables.[79]

6.2 Tools for Managing Supply Risk

Traditionally a utility's electricity supply plan includes physical supply and financial hedges. Physical supply includes the power plants that the utility owns or controls, as well as transactions for physical delivery of electricity. Financial hedges are additional hedging instruments used to manage residual price risk and other risks, such as weather risk.

ComEd and Ameren divested their generating plants to unregulated affiliates or third parties. They have no contracts for unit-specific physical delivery, other than certain QF (Qualifying Facilities under the Public Utilities Regulatory Practices Act (PURPA)) contracts. Their long-term renewables PPAs (Power Purchase Agreements) are structured as Contracts for Differences. The utilities do not purchase and take title to electricity. The utilities' supply positions, other than RTO spot energy, are price hedges.

Physical electricity supply and load balancing for ComEd and Ameren are coordinated by the respective RTOs (PJM and MISO respectively). ComEd and Ameren are considered Load Serving Entities (LSE) by the RTOs. Each RTO provides day-ahead and real-time electricity "spot pricing". That is, generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. The RTO ensures the physical delivery of power. The cost of managing this delivery, including the cost of managing reliability risks is passed on to the LSEs financially. The risks faced by LSEs in supplying energy to customers are mostly financial. The LSE still needs to manage certain operational risks such as scheduling and settlement. There are other, non-financial risks associated with electricity retailing, such as customer billing or accounts payable risks; but those are not associated with the supply portfolio.

Each RTO charges a uniform day-ahead price for all energy scheduled in a given hour and delivery zone. To the extent that real-time demand differs from the day-ahead schedule, load is balanced by the RTO at a real-time price; if demand exceeds the day-ahead schedule then the LSE pays the real-time price, and if demand is less than the day-ahead schedule the LSE is credited the real-time price. Both the day-ahead and the real-time prices are referred to as Locational Marginal Prices (LMPs) because they depend on the delivery location or zone.

6.2.1 Types of Supply Hedges

An important category of energy supply hedges is a unit-specific supply contract. Other supply hedges are forward contracts, futures contracts, and options.

6.2.1.1 Unit-Specific Hedges

Unit-specific hedges are contracts for the output of a specific generator. Contractually they are sometimes structured as financially-settled swaps. The selling counterparty (i.e., generator) pays the hourly spot LMP to the buyer (i.e., LSE), and receives from the buyer either a fixed payment per MWh or a payment computed from a floating index (as in the case of a contract indexed to the price of fuel). The amount of the payment for each hour is the difference between these two $/MWh values and a notional energy quantity, which equals the volume of energy dispatched by a specific generating unit or a fixed fraction of the dispatched volume. Unit-specific hedges may be categorized based on the control that the buyer has over the unit's dispatch.

- <u>As-available.</u> In this case the buyer cannot instruct the unit to generate, although in some cases the buyer has a limited right to curtail the generation. As-available hedges usually involve intermittent renewable generators that have an uncontrollable energy source, or which depend on the availability of energy as a byproduct of an economically independent industrial process (e.g., cogenerators that

[79] Illinois Power Agency, 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, March 29, 2013.

are QFs). In an as-available hedge the payment received by the generator is usually a fixed amount per MWh. The 20-year renewables contracts entered into by ComEd and Ameren in 2010 are examples of unit-specific, as-available energy hedges. Actually they are unit-specific as-available combinations of energy hedges and REC supply contracts.

- Baseload. In this case the generator is assumed to operate around the clock except for outages. There can be notice provisions or performance standards that are intended to limit the impact of forced outages and provide certainty around the timing of maintenance outages. The payment received by the generator may be a fixed amount per MWh or an amount indexed to a fuel price.
- Dispatchable. In a dispatchable contract the buyer has the right to schedule the generator's operation, except for outages. They are like options exercised each hour, subject to physical constraints on the unit's ability to modify its generation level. The payment received by a dispatchable generator will often be indexed to a fuel price, in which case the dispatchable contract is similar to a physical tolling contract. There is usually an initial cost to the buyer to enter into a dispatchable contract, equivalent to an option premium. As-available or baseload contracts often have no initial cost or option value.

6.2.1.2 Unit-Independent Hedges.

Other available hedges do not depend on the production of any generating unit or combination or units. From the standpoint of a generation owner selling such a hedge it is "portfolio-based" rather than unit-specific because it depends on the owner's entire portfolio.

- Standard forward hedges. A forward contract for energy is a contract for the delivery of energy at a future date, or over a fixed period of time in the future, at a predetermined fixed price. A financial forward hedge is a fixed-for-floating swap where the selling counterparty receives a fixed payment for energy in each hour, and pays the RTO LMP to the buyer. A notional hourly energy volume multiplier is used to determine the payments. The period of time and the notional volume are defined in the contract. Standard wholesale forward contracts cover one or more months. A typical contract sold in the winter for summer delivery would cover July and August, or the third calendar quarter. While in May, one would be more likely to find separate contracts for the following July and August. A "7x24" contract has a constant notional amount in each hour. A "5x16 peak" contract has a constant notional amount in each hour from the hour ending ("HE") 7 AM to HE 10 PM (prevailing time) on weekdays except for holidays,[80] and zero in other hours. An "off-peak" contract has a constant notional amount in the hours in which a peak contract has a zero notional amount.
- Shaped forward hedges. A shaped forward hedge is similar to a standard forward hedge except that the notional volume can vary across the hours of the delivery period. For example, the notional volume could be proportional to the average expected customer load in each hour, to hedge against the correlation of price risk with load. Alternatively a shaped forward hedge could be based on a different time period. For example, there could be a fixed notional volume only in weekday afternoon hours, or on weekends and holidays from HE 7 AM to HE 10 PM but not other off-peak hours. Trading in shaped hedges is much less liquid than trading in standard forward hedges. So one could expect shaped hedges to be priced at a premium to expected LMP prices, or, at a higher premium than standard forwards.
- Futures contracts. Futures contracts are purely financial instruments that are not subject to delivery requirements such as day-ahead scheduling with the RTOs. They are otherwise similar to forward contracts except for collateral and margining requirements. Futures contracts generally require both parties to deposit cash with an exchange, and as the contract price moves each day this "margin" is moved between the parties' accounts to reflect their gains and losses. In this way, futures contracts are settled incrementally up to the expiration date (end of the delivery period). Forward contracts

[80] A standard set of holidays is defined by NERC: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

are settled entirely on the expiration date, or monthly if the term is longer than one month. Instead of margin, forward hedges often require parties to post collateral with each other as a guarantee of settlement. Both the NYMEX and the Intercontinental Exchange ("ICE") list futures contracts corresponding to the standard forward hedges described above, at both the PJM Northern Illinois Hub (ComEd) and the MISO Illinois Hub (Ameren).

- Options. A call option gives the buyer the right, but not the obligation, to buy a specific contract. A put option gives the buyer the right, but not the obligation, to sell a specific contract. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. A price decrease is a risk to the utilities, passed through to their customers, if it is accompanied by increases in municipal aggregation or other forms of switching that leave the utility expensive hedges it no longer needs. Options on forward or futures contracts are much less expensive than the contract themselves, because they only convey the right to spend the money to buy the contract.
- Swing options. A swing option is a forward hedge that gives the buyer the right, but not the obligation to change the volume in some subset of hours. Generally, the buyer can either zero out the volume in hours in which it was previously nonzero (curtail), or increase the volume from zero to the full notional volume (dispatch). A contract can include multiple "swings", that is, multiple points at which the decision can be made. A dispatchable option is essentially the same as a swing option with one swing each hour, and unit-contingent volumes. Swing option contracts are generally customized. An exception is a unit-specific dispatchable contract, which is a standard concept.
- Full requirements hedges. A full-requirements or "tranche" contract covers a fixed fraction of an LSE's load, rather than a fixed volume. For example, a 1% one-month tranche contract is a swap contract under which the selling counterparty receives an amount for each hour in the month equal to a fixed price per MWh multiplied by 1% of the LSE's total supply requirement for that hour (load plus losses), and would pay to the LSE an amount equal to the LMP multiplied by 1% of the LSE's total supply requirement for that hour. All these hourly amounts are netted for the entire month. One hundred such tranche contracts will fully hedge the LSE's energy supply for the month, at a fixed price.

  Full requirements hedge contracts differ significantly from the other examples above. Forward hedges and futures require specification of the notional energy volumes. This makes them convenient for suppliers, who can for example sell a forward contract to achieve a precise effect on their portfolio. For example they can be used to take a short position, flatten the portfolio, reduce overall risk, etc. They are not as convenient for an LSE with a varying and uncertain load, who may wish to have a perfectly hedged portfolio. Forward block hedges cannot perfectly cover a load that is 1,900 MW in HE 10 AM and 2,900 MW in HE 4 PM. And, forward hedges cannot perfectly cover a load at HE 4PM that can be either 2,900 MW or 2,000 MW, depending on the weather. Full requirements hedges are useful in addressing load-related risks. Full requirements hedges can also be used in combination with other standard products in a supply portfolio to reduce, but not completely eliminate price risk.

  Full requirements hedges have been used in other states to provide the utility its entire supply requirement at a known fixed price for a specific term. They are not traded products and had to be specifically defined (standardized) for the purpose, through regulatory processes. Auctions were defined in which the utilities would procure them. Information sharing and multiple workshops were needed to ensure that the auctions would attract significant supplier participation and produce competitive prices.

  Section 6.7.1 includes a summary of other states' experience with full requirements hedges and Section 6.7.2 provides an estimate of the cost premium associated with them.

6.2.2 Suitability of Supply Hedges

Not all of the types of hedges described in Section 6.2.1 are suitable for use in this procurement plan and all may not be readily available in electricity markets. Illinois requires that "any procurement occurring in accordance with this plan shall be competitively bid through a request for proposals process," provides a set of requirements that process must satisfy, and mandates that the results be accepted by the ICC.[81] Among the specific requirements, the procurement administrator must be able to create a market price benchmark for the process; the bidding must be competitive; and the procurement administrator is required to report on bidder behavior. The most natural evidence of competitiveness will be breadth of participation, although other evidence may be possible as well.

Hedges most suitable for use by the Agency would be those standardized products that are well-understood, and preferably widely traded. If a product has liquid trading markets, or is similar to other product with liquid markets, a bidder can control its own risk exposure. Availability of information on current prices and the price history of similar products help bidders provide more competitive pricing, and help the procurement administrator produce a realistic benchmark. In its previous procurement plans the IPA has generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The Agency's recommended plans have been stated in terms of monthly contracts although procurement events have met some of these needs with multi-month contracts.

The IPA has in the past purchased energy products that are not typically traded, such as the long-term PPAs with new build renewable generation that were authorized in the 2010 Procurement Plan. As noted in Chapter 2, these products still must be standardized in such a way that the winning bidders may be selected based on price alone, and the price is subject to a market-based benchmark. As a result, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could end up litigated in this proceeding. For any discussion about authority and policy regarding full requirements purchases, the IPA notes that the markets will likely not be as transparent, which in turn results in challenges for the benchmarking and approval process that are central to the IPA's procurement structure.

Futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub are traded in reasonably deep liquid markets, making such contracts easier to benchmark. The markets for long-dated (*i.e.* further in the future) contracts are less liquid, however. The Agency ought to be able to obtain competitive pricing on such contracts if it were to want to incorporate them in its portfolio. However, it may be difficult or impossible to conduct the statutory RFP process for futures contracts; for example, it is unclear how the margin requirements would fit within the current regulatory framework.

Even if the utilities cannot procure futures contracts directly, the IPA does take account of them in the development of its procurement strategy. For example, in the past the Agency has procured forward contracts in 50 MW increments. NYMEX futures are 5 MW contracts. This means that both price discovery and supplier hedging are available for smaller quantities. The Agency should be able to conduct its procurements in smaller units too, such as 25 MW blocks.

6.3 Tools for Managing Surpluses and Portfolio Rebalancing

Chapter 4 illustrated that under its expected and low load scenarios. Ameren will be overhedged and will have forward contracts in excess of expected load for most or all of the 2014-2015 delivery year. ComEd appears not to be overhedged in 2014-2015, but under a low load growth, high switching scenario will be overhedged later in the projection horizon. Furthermore, if the Agency continues to use a "laddering approach" it is quite possible that in future years one or both utilities will find that it over-procured in the early years of the ladder and became overhedged.

[81] 220 ILCS 5/16-111.5(b), (e), (f).

The Illinois Power Agency Act specified that the procurement plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[82] Such re-balancing may be necessary this year, in the case of Ameren. It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the Agency, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

1. To date the only rebalancing of hedge portfolios prior to the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a mandated rate cap. Since these contracts provide renewable energy (energy plus RECs), curtailing them has reduced ComEd's forward position. Still, this is a small effect compared to the potential re-balancing need, especially for Ameren. Ameren has not previously curtailed renewable contracts but expects to beginning with the 2014-2015 delivery year.
2. For the last few years the utilities have rebalanced their portfolios in the RTOs' day-ahead markets. This has been the dominant mode of portfolio rebalancing. Revenues from the sale of excess energy in the day-ahead market helps to offset the overall cost of the hedges already procured.
3. As an alternative form of rebalancing, the Agency could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency would have to verify that these kind of events fall within its authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2) and that the utilities whose contracts are to be sold or who would be selling an offsetting position are amenable. The utilities' amenability will probably flow from ICC approval of a procurement plan including such reverse RFPs. Finally the risk associated with the volume to be re-balanced would have to be large enough to justify the expense of a procurement event.
4. Assuming the Agency had the requisite authority, it could also issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid contractual difficulties associated with selling forward hedge contracts, if those contracts are not freely assignable. However, this approach will require the utilities to ensure they had regulatory approval to exercise the options after purchasing them.

6.4 Comparison to the Purchased Electricity Adjustment

The Purchased Electricity Adjustment ("PEA") functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked, and the PEA adjusted, for each customer group.

The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from the estimate – in other words, the impact of risk. Figure 6-1 shows how the PEAs have changed over the last three years. While Ameren's PEAs have been generally negative, ComEd's have been more often than not positive, but quite volatile. ComEd has voluntarily limited its PEA to move between 0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits. In July 2013 the absolute value of Ameren PEAs increased significantly. The IPA understands this decrease to be temporary in nature as Ameren approaches the final months of transitioning to a uniform PEA applicable to all zones, and that the Ameren PEA is likely to return to a smaller adjustment in coming months.

[82] 220 ILCS 5/16-111.5(b)(4).