Natural Resources Defense Council

Comments on 2015 Draft Energy Procurement Plan
September 15, 2014

Anthony Star, Director
Illinois Power Agency
160 North LaSalle Street
Suite C-504
Chicago, Illinois 60601

Dear Mr. Star:

Thank you for this opportunity to comment on the Illinois Power Agency's (IPA) Draft Electricity Procurement Plan (Draft Plan). Over the past two years, it has been heartening to have witnessed the successful launch and growth of Incremental Energy Efficiency programs as part of the IPA Procurement Plan. By the end of 2016-2017 year, NRDC estimates that energy programs implemented under section 16-111.5B will have resulted in net saving of nearly $1 billion for Illinois residents and arrested the emission of a 12 million tons of carbon-based pollution. This year's procurement is particularly gratifying in that it includes a major increase in funding for programs serving multi-family residential buildings. Ameren's Multi-Family Program will go a long way toward ensuring that hard-to-reach customers are served by efficiency programs. NRDC is grateful for the hard work of the IPA and all stakeholders that have made these programs an indisputable success and looks forward to continuing to work toward the expansion of energy efficiency as a core component of the IPA's procurement strategy.

Incremental Energy Efficiency

I. THIRD PARTY BID REVIEW

In preparation for its submittal to the IPA, Commonwealth Edison (ComEd) engaged stakeholders by means of a collaborative bid review process, as it has done every year since the inception of this policy. As a result, ComEd was able to reach consensus with stakeholders as to whether third party programs met basic requirements, were cost-effective, and/or were duplicative of existing programs. NRDC agrees with the IPA that the greater input and expertise brought to bear on the third party bids through ComEd's collaborative review process "yield[ed] better evaluations and [left] fewer issues unresolved at the time of the plan's filing."[1] In addition to better evaluations, a collaborative process also saves resources that would otherwise be spent litigating issues that could be settled through direct communication.

NRDC is mindful of the IPA's reluctance to mandate a "rigid decision-making model" ordaining a preliminary form of collaboration.[2] However, in view of the evident benefits derived from third party bid review, the Illinois Commerce Commission (ICC) should expressly encourage utilities to engage in a collaborative process similar to the one established by ComEd in preparation for submittal of future procurement plans. Moreover, the procurement plans of those utilities that do not avail themselves of the opportunity to collaborate with stakeholders should be subject to enhanced scrutiny by the IPA, especially with regard to total resource cost test (TRC) calculations. In view of the fact that an energy efficiency program's inclusion in the procurement plan turns upon its cost-effectiveness under the TRC, it is critical to ensure that the calculations of a non-collaborating utility are accurate.

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[1] IPA Draft Plan at 72.
[2] *Id.* at 73.

II. TRC STANDARDS

Because the TRC is tied so inextricably to the success of energy efficiency policy under both sections 16-111.5B and 8-103, the ICC must establish guidelines to ensure the TRC is accurately applied by utilities. NRDC requests that the IPA establish guidelines directing that, at a minimum, the following be made part of the TRC calculation:

1) demand reduction induced price effects (DRIPE);
2) marginal line losses; and
3) a non-energy benefits adder.

First, NRDC requests that the ICC establish through guidelines that utilities use DRIPE when calculating TRC. DRIPE, it is a widely recognized and quantifiable benefit of improved energy efficiency.[3] In September of 2014, Resource Insight, Inc. produced a study demonstrating that the DRIPE benefit significantly reduced rates paid by Illinois electricity consumers.[4] Specifically, this study demonstrates that the DRIPE benefit is about 20% - 40% of avoided energy costs for a measure with a 15-year life and higher percentages for measures with shorter lives.[5] Attached, please find the Resources Insight, Inc. Memorandum for your review.

Illinois law requires that "other quantifiable societal benefits" be included as part of any TRC cost-benefit calculation under both sections 16-111.5B and 8-103.[6] As a "quantifiable societal benefit," the law necessitates that DRIPE be included in the TRC calculation. Indeed, the IPA has acknowledged the benefit of DRIPE in the instant Draft Plan. In footnote 104, the

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[3] *See* Memo: Paul Chernick & Ben Griffiths, *Analysis of Electric Energy DRIPE in Illinois*, Resources Insight Inc. (Sept. 2014).
[4] *See Id.*
[5] *Id.* at 2.
[6] 20 ILCS 3855/1-10.

IPA has stated, "…to the extent quantifiable, the value of any reduction in wholesale LMPs should be considered."[7]

Secondly, NRDC requests that the ICC establish through guidelines that utilities should use marginal line loss rather than system average line loss. Calculating the marginal line loss avoided, as opposed to average line loss, provides a far more accurate estimation of actual capacity savings.[8] Line losses grow exponentially with load and are most pronounced during peak hours.[9] Marginal line loss calculations, unlike those for average loss, are able to account for line losses as a square of the load.[10] Consequently, an energy efficiency program's savings calculated using marginal line loss is on average 1.5 times greater than average losses.[11]

Finally, NRDC requests that the ICC establish through guidelines that non-energy benefits, those benefits that reach beyond direct savings, are considered in calculating the TRC. Non-energy benefits, especially for low-income customers, can be dramatic in their capacity to improve the lives, safety, health, and comfort of customers - often having more value than the associated reductions in energy costs. Ameren has made it a practice to include a 10% non-benefits adder. NRDC regards this as conservative. The ICC should direct that utilities engage in an analytical process to properly quantify non-energy benefits and identify an appropriate adder to be included in TRC calculations.

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[7] *Supra* n. 1 at 64, fn. 104.
[8] *See* Jim Lazar & Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, Regulatory Assistance Project (Aug. 2011), *available at* http://www.raponline.org/document/download/id/4537.
[9] *Id.* at 4, 5.
[10] *Id.* at 4.
[11] *Id*. at 5.

III. AMEREN'S TOTAL RESOURCE COST TEST CALCULATIONS

NRDC is concerned that Ameren's application of the TRC significantly overstated costs and understated benefits of their third party bids. Specifically, Ameren used average line losses as opposed to marginal line losses to calculate a program's capacity savings. Moreover, NRDC is concerned that Ameren included unnecessarily high assumptions about the costs of the programs. These costs may have mistakenly resulted in multiple third-party bids having a TRC of less than one and, accordingly, having prematurely been removed from consideration. Therefore, NRDC formally requests that the IPA thoroughly review Ameren's TRC calculations before finalizing a procurement plan.

The IPA has statutory authority to independently review Ameren's TRC calculations. Pursuant to section 16-111.5B(a)(4), the IPA "shall include in the procurement plan…energy efficiency programs and measures ***it*** determines are cost-effective" (italics added).[12] In the Draft Plan, the IPA has stated that it understands "cost-effective" to mean "a program has met basic utility RFP requirements… and passes the total resource cost test."[13] Drawing these principles together, the IPA should not merely defer to Ameren's TRC results, but "shall" perform its own, independent calculation as to each program. Failure on the part of the IPA to independently verify Ameren's TRC results would not only contravene the IPA's clear statutory mandate, but may very well result in the exclusion of energy efficiency programs that are legally required to be included.

A review of Ameren's TRC calculations is vital, especially since their procurement plan, unlike that of Com Ed, has not been subjected to the collaborative process of evaluation and approval by stakeholders prior to IPA submission.

[12] *Supra* n. 6 § 6/16-111.5B(a)(4).
[13] *Supra* n. 1 at 73.

IV. QUALITATIVE CONSIDERATIONS

The IPA has also asked stakeholders to consider whether the standard for Commission approval, which differs from the standard for inclusion in the IPA's plan, grants the IPA latitude to evaluate programs based on qualitative criteria in addition to cost-effectiveness. The answer is no. First, the Commission's more elaborate standard, directing the Commission to include not only all programs that are "cost-effective," but only those programs "***to the extent practicable***,"(italics added)[14] cannot fairly be read to justify the IPA reading into its statute the authority to consider qualitative factors. The term "practicable" is not synonymous with pragmatic, "sensible," or "promising." Rather, "practicable" is defined by Merriam-Webster Dictionary as "capable of being put into practice or of being done or accomplished."[15] Section 16-111.5B(a)(5), therefore, does not permit an open and discretionary process by which the Commission forms a decisive opinion on the quality of an energy efficiency program. Rather, "to the extent practicable" is a failsafe measure that merely requires that the ICC make a *prima facie* finding that the program is capable of being put into practice and/or not disqualified because of some basic, irreparable deficiency that would render implementation impossible.

Second, it would not be prudent policy to allow the ICC to consider qualitative factors in determining whether to include energy efficiency programs. NRDC concurs with the IPA that under a qualitative bid review framework, newer and more innovative programs may be at a disadvantage.[16] Moreover, the evaluation of qualitative factors is necessarily value-based and permitting their inclusion would unduly inject ideology into the decision-making process. Such an approach is not only incautious in that it may empower less politically independent chairmen to undermine the legislative purpose of expanding the use of cost-effective energy efficiency

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[14] *Supra* n. 6 at § 16-111.5B(a)(5).
[15] "practicable." Merriam-Webster Online Dictionary (2004). http://www.merriam-webster.com.
[16] *See supra n. 1* at 73.

measures in Illinois, but has not been shown to be necessary. As observed by the IPA, the pay-for performance contracting already effectively mitigates against the risk of poorly designed programs or incompetent program teams.[17]

Rather, as was done by the IPA when selecting between the Home Energy Reports and Behavioral Energy Efficiency programs in the Draft Plan,[18] qualitative factors should only be considered after the IPA has properly determined that two or more programs are "duplicative" or "competing" and when deciding which program(s) should be excluded.

Energy Efficiency as a Supply Side Resource

NRDC supports the IPA's efforts to create a new avenue for allowing "energy efficiency as a supply side resource" (EEAASR) programs to compete as a lower cost alternative to traditional supply. NRDC looks forward to continuing to work with the IPA to further adjust and develop the EEAASR proposal before its implementation.

The IPA has stated that it would prefer to avoid overlap between EEAASR procurement and the procurement of energy savings through sections 8-103 and 16-111.5B, and for procurement through EEAASR to be limited to the development of new resources. It notes that some parties have suggested an alternative in which savings during the 260 super peak hours could be "backed out" of total annual savings from measures installed through 8-103 and/or 16-111.5B, "allowing for dual participation without savings overlap."[19]

NRDC suggests that the ideal solution to this issue would be to allow the utilities who acquire savings through 8-103, and both utilities and third parties who generate savings through 16-111.5B, to bid those savings into EEAASR. In essence, this would make EEAASR an

[17] *Id.*
[18] *Id.* at 76.
[19] *Supra* n. 1 at 66.

additional funding mechanism for such savings. Put another way, there would not be a need to ensure that EEAASR savings are separate from 8-103 or 16-111.5B savings. It is worth noting that this is exactly what happens today with the PJM capacity market. ComEd bids savings generated by its 8-103 and 16-111.5B programs into PJM's market. It then takes the revenue it receives from the market – on the order of $5 million in PY6 – and uses it to supplement its 8-103 budget, allowing it to set and meet or exceed higher goals.

If the IPA chooses instead to require savings procured under EEAASR to be totally separate from those acquired and used to meet goals under 8-103 and/or 16-111.5B (i.e. if the IPA rejects NRDC's preferred solution described above), then it would be preferable to require savings to come solely from "new" efficiency programs and projects. The alternative of separating savings into two "buckets" – one for the 260 super peak hours and another for the other 8500 hours of the year – will impose administrative costs on the utilities, consumers and other parties. There will also be additional complexity and confusion imposed on consumers. Finally, the IPA would be setting up competition for the savings that the utilities are trying to acquire to meet their 8-103 goals as well as for what the utilities and third parties are trying to acquire to meet 16-111.5B commitments. The initial instinct of some may be to suggest that competition is a good thing – that it leads to lower prices. However, it is important to distinguish between lower "prices" to those consumers selling efficiency resources (i.e. those the utilities and third parties would be competing to acquire) and the impact on "prices" to rate-payers who will be paying the bill. For example, an industrial customer will get a better "price" – i.e. a higher financial incentive which leads to a lower net acquisition cost for the customer – for efficiency savings it can provide. But that higher incentive will be paid by ratepayers. While the savings over the 260 peak hours would represent only a relatively modest portion of the utilities' and third parties' claimed savings, it would nevertheless be an erosion of what they were planning to acquire, forcing them to compete with third parties interested in EEAASR to acquire the savings and/or to acquire the "lost" savings from other measures and projects (likely at higher cost).

Regardless of decisions on the options discussed above, the IPA will need to put in place a processes for: 1) establishing and any party bidding to provide efficiency resources under EEAASR owns those resources; 2) ensuring that the same resources are not being bid by different parties (i.e. that there is no double-counting of EEAASR resources); and 3) ensuring that interactive effects between different resources (i.e. efficiency and load-shifting) have been addressed so that there is no over-counting of super peak hour savings. It is worth noting that this is not an issue unique to the IPA's proposed EEAASR procurement. Both PJM and the New England ISO already address this issue through their administration of their respective capacity markets. Parties who bid into those markets have also adapted. For example, Efficiency Vermont now has language on all its rebate forms that make clear that a condition of accepting its financial incentives is agreeing that Efficiency Vermont "holds the sole rights to any electric system capacity credits and environmental credits associated with the energy efficiency measures for which incentives have been received."[20]

Second, the IPA should provide further clarification as to whether the "expected total customer costs" and "expected total cost to ratepayers, inclusive administrative costs" standards are equivalent as is seemingly suggested by the IPA.[21] The language, however, appears to refer to two distinct standards. Specifically, the "customer costs" standard seems to correspond to the

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[20] *See attached* Commercial Lighting Rebate Form (2014), p 8.
[21] *See Supra* n 1at 63-4.

TRC whereas the “cost to ratepayers” standard seems to correspond to the utility cost test. NRDC requests clarification as to the correct interpretation.

Fourth, the IPA should clarify the meaning of its statement that “procured demand side resources should be delivered within the service territory for which they are being procured (even if not situated within the service territory itself).”[22] It is unclear how energy efficiency / demand side resources could be physically delivered to a service territory where they are not “situated.”

Fifth, the proposed duration of delivery contracts, a maximum of three years, is too short and will limit the inclusion of measures that require significant capital investment. Many worthwhile and effective capacity generating energy efficiency measures must remain in operation for five to ten years in order to recoup upfront costs. The exclusionary effect of these unnecessarily short delivery contracts will be especially pronounced if energy efficiency resource providers cannot be rebid in a future procurement when the contract expires. Should the IPA maintain the maximum three year duration of delivery contracts, the IPA should permit energy efficiency resource providers to rebid in future procurements.

Sixth, the optionality provisions as currently expressed may negatively affect participation levels. Under the optionality provision, the IPA has nearly limitless discretion in canceling planned EEAASR procurement. So as not to discourage participation in this novel program, the ICC should revise its optionality provisions to include specific, demonstrable criteria for cancelation that dramatically diminishes IPA discretion.

Seventh, while NRDC agrees that the ISO-New England *Manual for Measurement and Verification of Demand Reduction Value from Demand Resources* (ISO-New England) could be a helpful starting point for developing qualification protocols, the Illinois Technical Reference

[22] *Id.*

Manual ("TRM") should be the basis for verification procedures. Any conflict between ISO-New England and the TRM should be resolved in favor of the TRM.

Respectfully submitted,

Patrick Kenneally
Staff Attorney
Natural Resources Defense Council
20 N. Wacker Drive, Suite 1600
Chicago, IL 60606
312-651-7917
pkenneally@nrdc.org

Rebecca Stanfield
Deputy Director for Policy, Midwest Program
Natural Resources Defense Council
20 N. Wacker Drive, Suite 1600
Chicago, IL 60606
312-651-7910
rstanfield@nrdc.org

Resource Insight Inc.

MEMORANDUM

To: Chris Neme
Rebecca Stanfield
David Farnsworth

From: Paul Chernick
Ben Griffiths

Date: September 3, 2014

Subject: Analysis of Electric Energy DRIPE in Illinois

Introduction and Summary

Market energy prices are driven in large part by load levels; that is why on-peak energy prices are higher than off-peak energy prices. Thus, reducing Illinois electric loads would be expected to reduce market prices, which will flow through to reductions in generation rates paid by electricity consumers.

Based on our analysis of loads and prices in PJM's ComEd zone, in MISO's Central zone (which includes Ameren Illinois) and other portions of MISO, we reach the following conclusions:

- A 1% reduction in load over a wide area (Illinois and a large part of MISO) would reduce Illinois market energy prices by about 2%. Reducing load 1% just in Illinois, or in part of Illinois, will have a smaller effect on Illinois prices.
- While reduction in load by one MWh would have a miniscule effect on price, the reduction would apply to a large amount of energy, producing a significant price-reduction benefit for Illinois customers per MWh saved.
- A reduction in load just in the ComEd territory would reduce ComEd generation bills by about 36%–70% of the ComEd avoided energy cost, and reduce Ameren bills by about 17%–30% of the Ameren avoided energy cost. Thus, if the avoided energy cost is $50/MWh in both the ComEd and Ameren areas, the price benefit of ComEd energy-efficiency improvements is somewhere between $26/MWh and $50/MWh.
- Similarly, a reduction in load just in the Ameren territory would reduce Ameren generation bills by about 36%–70% of the Ameren avoided energy cost, and reduce ComEd bills by about 17%–30% of the ComEd avoided energy cost.

- Those effects are mitigated in the short run by existing contracts which lock in some consumer prices for a couple years.
- The DRIPE is also eroded over time due to price-induced demand increases; acceleration of retirements and delay of capacity additions; and a shift toward more peaking and less baseload generation (e.g., retirement of more coal and construction of less gas combined-cycle capacity).
- After accounting for reasonable estimates of the effects of existing contracts and decay, the levelized DRIPE benefit would be about 20%–40% of avoided energy costs for a measure with a 15-year life and higher percentages for measures with shorter lives..

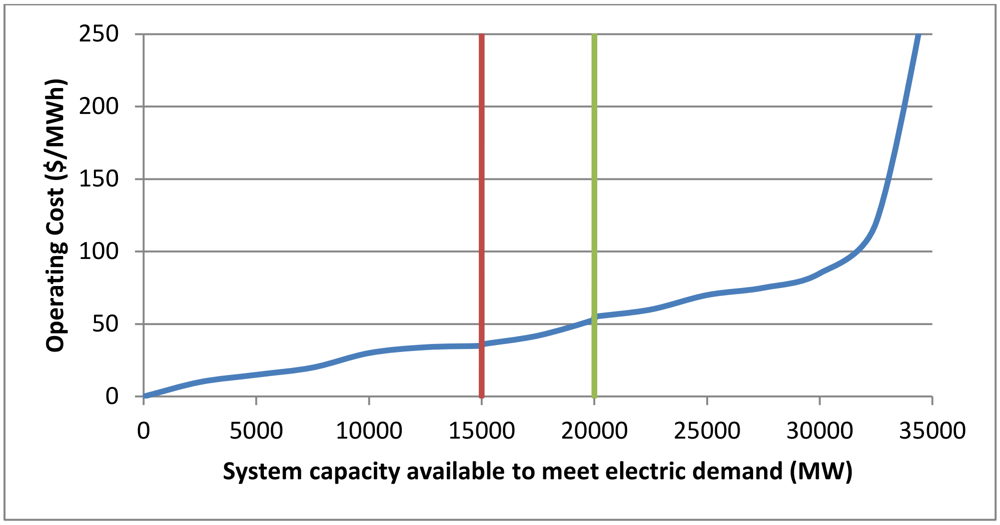
Effect of Load on Market Energy Prices

The cost of energy avoided by energy-efficiency programs in Illinois is determined by prices in the competitive electric energy markets administered by the PJM independent system operator for Commonwealth Edison (ComEd) and by the Midcontinent Independent System Operator (MISO) for the remainder of the state, primarily served by Ameren. In each of these markets, the price of electricity is estimated for each hour on a day-ahead basis and revised in real time.

In a centrally-dispatched electric generation market system, the market price in any hour is the result of the intersection of the demand curve (a nearly vertical line, given the limited short-term response of load to market price) and the supply curve composed of prices bid by owners of generation and other resources. Every resource (mostly generators in the ISO, but also some imports and demand response) offering energy into the market at or below the market-clearing price is paid the market-clearing price for that hour.[1] As illustrated in Figure 1, the supply curve rises as required output rises, and usually becomes steeper as output rises. In this example, reducing load from 20,000 MW to 15,000 MW reduces the market price from about $52/MWh to $40/MWh.

[1] The price-setting process is slightly more complicated than this simplified description, since unit dispatch is constrained by unit start-up time, ramp rate, minimum up time and down time, limited daily and weekly water supply for storage hydro facilities, and similar factors.

Figure 1: Illustration of Electric Energy Supply Curve and Effect of Load Reduction



In traditional vertically-integrated utilities, with cost-of-service regulation of generation prices, consumers pay for the fixed costs and the actual operating costs of the utility's generation resources, including wholesale purchases and sales. But for restructured utilities, the price of generation services is set by the market-clearing price.

Some electric customers pay the hourly energy prices directly, through the utilities' hourly generation-service rates or through retail electric suppliers. Most electric customers pay for generation services through rates that are fixed for months or years in advance, through the utility's Basic Generation Service or through a rate offering from a retail electric supplier. Those longer-term rates are based on suppliers' expectations regarding the hourly market prices, which determine the price at which suppliers will commit resources to contracts with the utilities and retail electric suppliers.

Reducing demand reduces the market-clearing price and hence the price paid by all load that has not hedged its prices for that period. This effect is referred to as "price suppression" in the general economic literature. More recently, the reduction in prices in the wholesale markets for electric and gas capacity and energy resulting from the reduction in required supply due to the impact of efficiency programs (and sometimes other reductions in load on the electric system) has been referred to as Demand Reduction Induced Price Effect (DRIPE) in the utility literature.[2] Various utilities, regulators and analysts have treated DRIPE as benefit to retail customers.

In general, DRIPE effects are very small when expressed in terms of the impact of each MWh of energy conservation on market prices ($/MWh price reduction per MWh saved). Even a significant annual energy-efficiency portfolio may reduce prices by a fraction of a percent. However, even very small impacts on market prices, when applied to all the market purchases in a utility service territory, state or region, can produce large absolute dollar savings to consumers, which can be comparable to the directly avoided market prices.

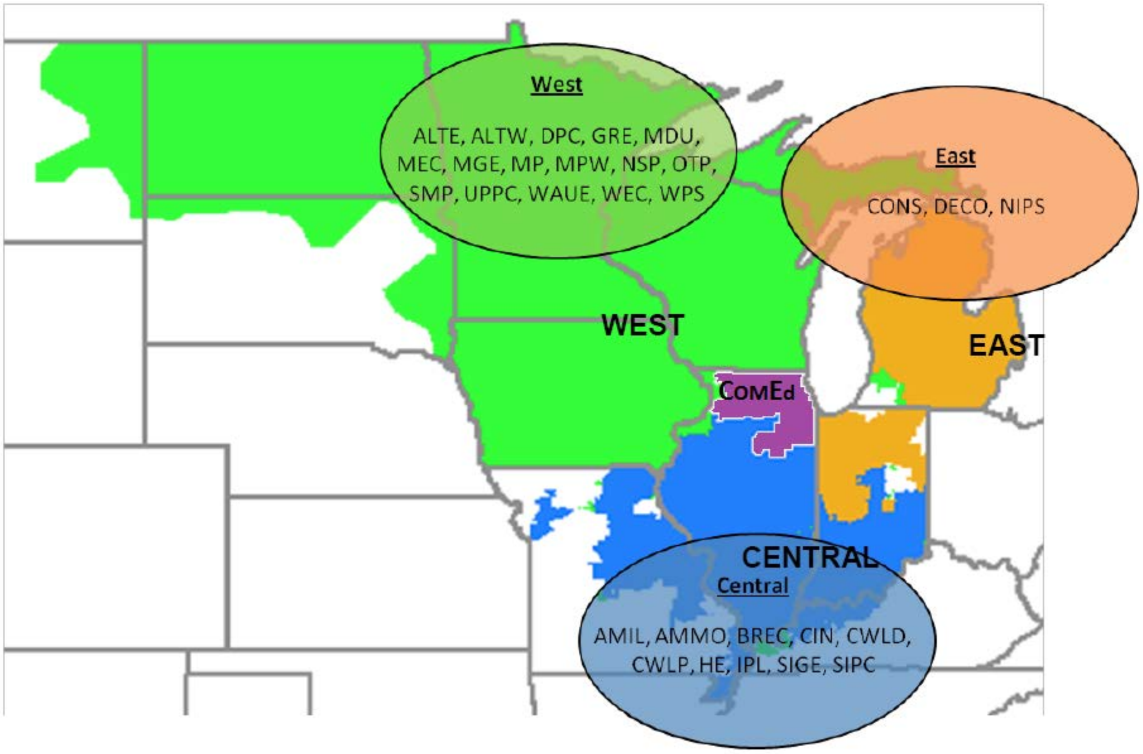
Energy DRIPE in ComEd and Ameren-IL

We estimated the DRIPE coefficients (the effect of a change in demand on the market-clearing prices) from regression analyses of hourly locational market prices (LMP) as a function of hourly loads in one or more regions. From the web sites of the two ISOs, we obtained day-ahead LMPs for the PJM ComEd zone and for the MISO Illinois hub (which is mostly Ameren), and loads for the PJM ComEd zone, as well as day-ahead loads for the ComEd zone and three MISO regions, as illustrated in the Figure 2. All these data were available for July 2009 through December 2012.[3]

[2] See, e.g., Avoided Energy Supply Costs in New England Final Report, Avoided-Energy-Supply-Component (AESC) Study Group, December 23, 2005 (updated and expanded in 2007, 2009, 2011 and 2013); Costs and Benefits of Electric Utility Energy Efficiency in MA, Northeast Energy Efficiency Council, Aug 2008; Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies, Final Report, February 2011, New York State Energy Research and Development Authority, No. 11-23; Ten Pitfalls of Potential Studies, Chris Kramer and Glenn Reed, Regulatory Assistance Project, November 2012; Summary of Progress to Date on Goal to Reduce Electricity Consumption by 15% by 2015 and Recommendations for Next Steps, Maryland Energy Administration, March 2013.

[3] The July 2009 start date was determined by the availability of MISO load data, which starts July 6, 2009.

Figure 2: MISO Load Regions and PJM ComEd Zone



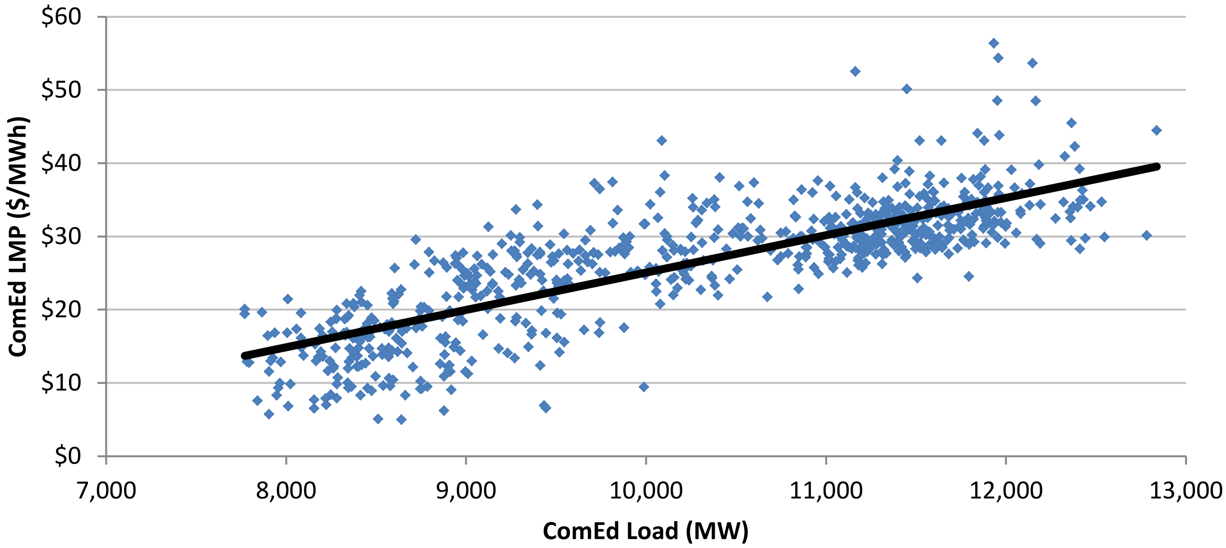
While load data were available for PJM zones to the east of MISO, we do not expect those loads to affect prices in Illinois as much as those in Figure 2. In particular, loads in the westernmost non-Illinois portions of PJM (especially Ohio and Kentucky) probably have some effect on Illinois prices (transmission gets constrained further east), but loads in parts of MISO (such as Michigan, Minnesota and the Dakotas) would have relatively modest effects on Illinois prices. Hence, a regression of Illinois prices on total MISO load would ignore some load that has some effect on Illinois price and overstate the effects of other load.[4]

We expected that the slope of the supply curve would be steeper in the on-peak period than in off-peak periods, so we conducted separate regressions for the peak hours (16 hours per day, Monday through Friday) and the off-peak hours.

Figure 3 shows a simple regression of hourly ComEd LMP as a function of ComEd load. In this example, LMP rises about 0.61¢/MWh for every MWh of increased energy requirements in the hour.

[4] The correlation of loads gets weaker as for areas further away from Illinois, due to differences in sun position, weather, and time zone; even Michigan and most of Indiana are in the Eastern time zone.

Figure 3: ComEd LMP as a Function of ComEd Load, October 2012



A number of factors other than load change over time, including fuel prices, installed capacity and capacity unavailable due to maintenance and forced outages. To eliminate the effect of the non-load-related changes from one month to the next, we normalized the data for each month, by:

- Computing the average price in each Illinois pricing zone (ComEd and MISO Illinois) for each period (on- and off-peak) in each of the 45 months, for a total of 2 × 2 × 45 = 180 average prices.
- For each hour, dividing the hourly price by the average price in that zone/period/month combination. For example, the ComEd price in each on-peak hour in July 2012 was divided by the July 2012 ComEd on-peak average.
- For each period (on and off) in each of the 45 months, computing the average load in each load zone (ComEd and MISO Central, East and West) as well as various combinations of those zonal loads:
    - the sum of ComEd and MISO loads,
    - the sum of ComEd and MISO Central loads, and
    - the sum of ComEd and MISO Central and East loads.
- For each hour, dividing the hourly load by the average load in that zone/period/month combination.

We then conducted a series of linear regressions for each period for each of the two prices zones of interest, using the normalized data. Each regression had over

20,000 observations. We regressed each of these dependent variables against various combinations of normalized loads. The coefficients in each regression are essentially the percent change in zonal LMP as a function of a percent change in load.

The regressions with highly-correlated multiple independent variables generally produced implausible results, such as negative coefficients (indicating that higher load in some regions would decrease prices in Illinois) or implying that a MWh load reduction downstate would reduce ComEd prices more than a MWh reduction in Chicago. We therefore dropped those specifications from further consideration

The results of these regressions are summarized in Table 1, which shows the results of regressing ComEd hourly price as a function of various combinations of loads, and Table 3, which does the same for modeling MISO Illinois price as a function of various loads.

In each of these tables, the first column describes the regression, listing the explanatory variables used. Where zones are aggregated into a single variable, the Tables joins them with a "+" (e.g., ComEd+MISO).

For example, in the on-peak section of Table 1, line 1 reports the results of regressing the ComEd price (the dependent variable for all the regressions summarized in Table 1) as a function of only ComEd load. Line 1 should thus be read as reporting that "ComEd price increases by 1.979% for each 1% increase in ComEd load."

The next three lines show comparable results for the effect on ComEd price of changes in total load in (line 2) ComEd plus all of MISO, (line 3) in ComEd plus Central MISO, or (line 4) ComEd plus MISO Central plus MISO East. Line 2 of the on-peak section of Table 1 reports that "ComEd price increases by 2.228% for each 1% increase in the combined load of ComEd plus MISO."

Table 1: Regression results for ComEd LMP as a Function of Load

	Load Coefficients				
On-Peak regressions against load of	**ComEd Load**	**ComEd + MISO**	**ComEd + Central MISO**	**ComEd + Central MISO + East MISO**	**Adjusted R^2**
1. ComEd	1.979				0.48
2. ComEd + MISO		2.228			0.59
3. ComEd + Central MISO			1.989		0.57
4. ComEd + Central MISO + East MISO				2.080	0.46
Off-Peak regressions against load of					
1. ComEd	1.519				0.37
2. ComEd + MISO		2.155			0.44
3. ComEd + Central MISO			1.824		0.43
4. ComEd + Central MISO + East MISO				2.151	0.59

All of these results indicate that a 1% change in loads would change the Illinois LMPs by about 2%. The co-efficient t-statistics were quite impressive, ranging from 7 to over 100. As we would expect (given that fuel prices, power-plant availability and the load and supply from neighboring regions can change considerably, even within a month), the R^2 values are not impressive.

These coefficients (2.0 to 2.2 on peak and 1.5 to 2.2 off-peak) are consistent with the effects observed in other areas.

- For New England, the comparable ratios are about 2.2 on peak and 1.1 to 1.2 off-peak.[5]
- Using a production-costing model, Exeter Associates estimated early-year price effects of 0.5 to 2.4 times the percentage reduction in total PJM load, depending on the location of the load reduction and the pricing zone.[6] The load reduction in this analysis was a flat block, which would tend to understate the price effect. In addition, production-cost models are not reliable for small load changes, since random effects in the model (maintenance scheduling, stochastic outages) can produce greater differences between runs than the modeled input change.

[5] AESC 2013, op cit., Exhibit 7-5. These results have been fairly consistent throughout the biennial updates of the AESC studies, from 2007 through 2013.

[6] Avoided Energy Costs in Maryland: Assessment of the Costs Avoided through Energy Efficiency and Conservation Measures in Maryland, Final Report, for Power Plant Research Program Maryland Department of Natural Resources, April 2014, pp. 33–35.

- PJM found that changes in load produce two to three times as large a percentage change in market energy prices, depending on gas prices and CO_2 prices.[7]
- Using a production-cost model, the IPA estimated that wind generation in MISO and PJM reduced Illinois's 2011 LMP by $1.30/MWh from a base of $36.40/MWh, or about 3.6%.[8] In 2011, wind provided 2.3% of MISO's energy,[9] and 1.5% of PJM's energy.[10] Depending on the relative importance of the MISO and PJM wind in IPA's modeling, and the amount of wind generation IPA actually included, roughly 2%–2.2% of energy from wind reduced prices 3.6%, for a ratio of 1.6 to 1.8. Since wind has a lower-value shape than DSM, with a lot of energy delivered at very low loads off-peak, when the price is low and the supply curve is quite flat. Hence, it is not surprising that the ratio is somewhat lower for wind energy than for average load reductions.

Because of the correlation in load among zones, it is difficult to determine how large an area significantly affects the ComEd LMP. The conservative end of the range of possibilities (i.e., understating the DRIPE effect of Illinois load reductions) would be represented by regression 2, which represents ComEd price as a function of the combined ComEd and MISO load. This computation assumes that load anywhere in MISO, from North Dakota to Michigan, has the same effect on ComEd prices, so it likely understates the effects of load reductions in Illinois on ComEd prices.[11]

We did not investigate the extent to which the price response per unit of load reduction increases at very high load levels, such as the summer peaks. Due to

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[7] Potential Effects of Proposed Climate Change Policies on PJM's Energy Market, 1/23/2009.

[8] Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts, Illinois Power Agency, 3/29/2013, Figure 12.

[9] MISO Historical Regional Forecast and Actual Load and MISO Historical Hourly Wind Data pages for 2011.

[10] 2011 State of the Market Report for PJM, Monitoring Analytics, 3/15/2012, Table 2-2. IPA may not have included all the PJM wind energy, since the IPA report says that wind "only accounted for 1% of the total market generation in 2012" for PJM (IPA Report, p. 29).

[11] On the other hand, this regression does not account for any correlated effect of load in western PJM on Illinois load, which might slightly increase the coefficient on total MISO load.

generation and transmission outages, the highest market prices may not coincide with the highest loads, but the energy DRIPE effect from heavily on-peak loads (such as air conditioning) may well be higher than our estimates.

Converting the coefficients in Table 1 into DRIPE values in terms of price benefits to all Illinois customers for a one-MWh load reduction requires some information about the relative size of the various energy markets. Table 2 provides those data, from the MISO web site for the MISO zones, from the PJM web site for the ComEd zone load, and from EIA for the ComEd and Ameren sales.[12]

Table 2: Relative Energy Use by Region

	Zonal Load			EIA Sales	
	MISO Central	**MISO Total**	**Com Ed**	**ComEd**	**Ameren**
GWh	174,106	504,593	101,996	89,977	37,642
ComEd Energy as %					
Zone					239%
Zone+ ComEd	37%	17%			
Ameren Energy as %					
Zone				42%	
Zone+ ComEd	15%	7.0%			

The on-peak regression coefficient of about 2.2 in regression 2 represents the percentage reduction in ComEd price as a function of the percentage load reduction in the combined ComEd-MISO region. Since ComEd represents about 17% of the combined load of ComEd and MISO, a 1% reduction in ComEd load would reduce energy bills in the ComEd zone by about 1% × 0.17 × 2.2 = 0.37%. So if the market energy cost (and hence roughly the avoided energy cost) for ComEd is \$*C*/MWh and the ComEd load is L_C, a 1% reduction in ComEd load ($0.01 \times L_C$) would reduce the energy bill for all ComEd customers by $0.37\% \times C \times L_C$. The DRIPE benefit per MWh saved would be

$$[0.37\% \times \mathrm{C} \times L_C] \div [1\% \times L_C] = 0.37 \times C$$

If the ComEd market price is \$50/MWh, the DRIPE effect would be about 37% × \$50 = \$18.5/MWh.

While regression 2 defines the area affecting ComEd prices too widely, regression 3 defines it too narrowly, assuming that only ComEd and Central MISO loads

[12] ftp://misoftp.midwestiso.org/rfal_HIST/, www.pjm.com/markets-and-operations/energy/real-time/loadhryr.aspx, EIA-861 Survey for 2012. Since the zonal load includes losses and other energy not counted as retail sales, the ComEd zone load is about 13% higher than the ComEd sales. For the comparison to the MISO zones, we increased the Ameren sales by that 13% ratio.

affect ComEd prices. Following the computation from the discussion of regression 2, above, the ComEd DRIPE benefit from a reduction in ComEd load is

$$\{\text{ComEd share of ComEd+MISO Central}\} \times \{\text{regression 3 coefficient}\} \times C$$
$$= 0.37 \times 1.989 \times C$$
$$= 0.70 \times C$$

Hence, every dollar of direct on-peak energy avoided costs saved would result in 37¢ to 70¢ of DRIPE benefit in the ComEd territory, or at a $50/MWh avoided cost, $18.5 to $35/MWh.

Table 3 provides similar information for regressions of the MISO Illinois price on various combinations of load.

Table 3: Regression results for MISO Illinois LMP as a Function of Load

	Load Coefficients		
	ComEd + MISO	ComEd + Central MISO	Adjusted R^2
On-Peak regressions against load of			
1. ComEd+MISO	2.430		0.49
2. ComEd+Central MISO		2.051	0.48
Off-Peak regressions against load of			
1. ComEd+MISO	2.359		0.59
2. ComEd+Central MISO		2.103	0.57

Again, the regressions of MISO Illinois price as a function of the combined ComEd and MISO load (regression 1) are the more conservative estimates of the DRIPE effects, because the area is probably too broad, while the combination of ComEd and Central MISO load (regression 2) is probably too restrictive.

In addition to reducing prices in the ComEd zone, load reduction in ComEd's territory would reduce prices for Ameren. MISO Illinois on-peak regression 1 indicates that a 1% reduction of ComEd and MISO load would reduce the Illinois Hub price by 2.43%. As discussed above, ComEd load is about 17% of the combined load, so a 1% reduction in ComEd load would reduce the Illinois Hub price by about 2.43% × 17% = 0.41%. A 1% reduction in ComEd load would reduce the MISO Illinois bill by 0.41% times the Illinois Hub price ($A/MWh) times the Ameren Illinois load. Since Ameren load is about 42% of ComEd load, the value of Ameren DRIPE per MWh of ComEd load reduction with regression 1 would be

$$[0.41\% \times A \times 42\% \times L_C] \div [1\% \times L_C] = 0.17 \times A$$

Using on-peak regression 2, 1% reduction in ComEd load would reduce the Illinois Hub price by about 2.05% × 37% = 0.73%, and the value of Ameren DRIPE per MWh of ComEd load reduction would be

$$[0.73\% \times A \times 42\% \times L_C] \div [1\% \times L_C] = 0.32 \times A$$

If the Ameren market price is $50/MWh, the DRIPE effect of ComEd load reductions on Ameren prices would be about 17% × $50 = $8.5/MWh to 32% × $50 = $16/MWh. Combined with the DRIPE effect in reducing ComEd's own load, this would bring the total Illinois energy DRIPE from savings in the ComEd zone to about $27 to $53/MWh.

Rather than describe in text all the additional combinations of broad and narrow regions, on- and off-peak, and the effect of ComEd and Ameren load reductions on ComEd and Ameren prices, Table 4 summarizes the computations for energy savings in the ComEd territory and Table 5 summarizes the computations for energy savings in the Ameren territory.

Table 4: Benefits of ComEd Energy Savings, via Market Price Reduction

		Benefits in ComEd			Benefits in Ameren				
						Load Ratio			
Period	MISO Regions Modeled	%Δprice ÷ %Δload	ComEd load as % Region	DRIPE as % AvCost	%Δprice ÷ %Δload	ComEd: Region	Ameren: ComEd	DRIPE as % AvCost	Total DRIPE/MWh if Av Cost = $50/MWh
On	All	2.228	17%	37%	2.430	17%	42%	17%	$27.3
	Central	1.989	37%	73%	2.051	37%	42%	32%	$52.6
Off	All	2.155	17%	36%	2.359	17%	42%	17%	$26.4
	Central	1.824	37%	67%	2.103	37%	42%	33%	$49.9

Table 5: Benefits of Ameren Energy Savings, via Market Price Reduction

		Benefits in Ameren			Benefits in ComEd				
						Load Ratio			
Period	MISO Region Modeled	%Δprice ÷ %Δload	Ameren load as % Region	DRIPE as % AvCost	%Δprice ÷ %Δload	Ameren: Region	ComEd: Ameren	DRIPE as % AvCost	Total DRIPE/MWh if Av Cost = $50/MWh
On	All	2.430	7%	17%	2.228	7%	239%	37%	$27.3
	Central	2.051	15%	32%	1.989	15%	239%	73%	$52.6
Off	All	2.359	7%	17%	2.155	7%	239%	36%	$26.4
	Central	2.103	15%	33%	1.824	15%	239%	67%	$49.9

If the direct avoided energy costs per MWh are similar for ComEd and Ameren, the DRIPE effect is potentially worth somewhere between 50% and 100% of the direct avoided costs. As explained in the next section, not all of these price reductions flow through to consumers.

Reduction for Hedged Supply

Not all energy purchased for retail load will be affected by reductions in market prices in the short term, due to (1) existing energy-purchase contracts for the utility generation services (procured through the Illinois Power Agency) and (2) contracts between customers and retail electric suppliers.

From the Illinois Power Agency 2013 Electricity Procurement Plan, it appears that Ameren's fixed-price service is hedged

- fully through 2014/15,
- 53% on-peak and 64% off-peak for 2015/16,
- 14% on-peak and 18% off-peak for 2016/17 and after;

Furthermore, ComEd's fixed-price service is hedged

- fully through 2014/15,
- 45% on-peak and 54% off-peak for 2015/16,
- 45% on-peak and 55% off-peak for 2016/17,
- 30% on-peak and 37% off-peak for 2017/18, and
- 8% on-peak and 11% off-peak after 2017/18.[13]

The current procurement plan targets are to hedge 75% of energy in the current year, 50% for the next year, and 25% for the second year into the future. (Plan, p. 57) In addition, as of the June 2013 Switching Reports, about 6% of Illinois load (nearly 30% of load on utility service) is on utility hourly pricing service, and hence not hedged at all.

Some data are available on the duration of the competitively-bid supply contracts for municipal aggregators of residential and small-commercial load. Table 6 reproduces contract duration data from a 2013 study.[14]

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[13] Sections 4.1 and 4.2. In the 2011 Annual Report, IPA indicated that Ameren was about 45% hedged and ComEd was a remarkable 125% hedged for 2012/13. As a result, Figure 13 of the Report shows ComEd customers paying higher prices with more wind; IPA appears to have eliminated this over-hedging.

[14] From "Municipal Aggregation in the State of Illinois: An Examination of the Supply or Energy Component of Electric Service," Alexander Echele, University of Illinois, September 2013, Table 6, irps.illinoisstate.edu/downloads/Echele%20ECO%20300%20Paper%20090513.pdf.

Table 6: Municipal Aggregator Supply Contract Duration

Contract Duration	Ameren Illinois	Commonwealth Edison	Combined	Percentage
<12 Months	0	5	5	2.5%
12 Months	3	20	23	11.6%
13 to 23 months	12	7	19	9.6%
24 Months	23	107	130	65.7%
36 Months	6	15	21	10.6%
Total	44	154	198	

At any particular point in time, the remaining time on the contracts in Table 6 would average about half the full duration, averaging about 11 months.

Table 7 summarizes the distribution of remaining contract duration, as of July 31, 2014.[15]

Table 7: Remaining Contract Duration, Municipal Aggregations

Remaining Duration	Number of Municipalities	Percent of Municipalities
≤6 months	132	22%
6–12 months	206	35%
12–24 months	185	31%
24–37 months	73	12%

Many of the municipalities whose contracts have less than six months remaining would have selected suppliers for the next contract period of one to three years. The effecting remaining contract duration, and hence the period before market price changes can flow to customers, would be something like 5% for less than six months, 40% for 6–12 months, 40% for one to two years, and 15% for two to three years.

Determining how long prices are fixed for customers served by retail electric suppliers (RESs) is more difficult. Various suppliers offer residential customers fixed rates for one to 24 months, sometimes with cancelation penalties, sometimes without. Business customers are offered fixed-price and indexed products; little pubic information is available on the details of those offers. No public information appears to be available on the distribution of the RES contracts by duration.

Since about 80% of the Illinois energy requirement is served by retail electric suppliers, the lack of additional data is a significant limitation in any analysis of

[15] From www.pluginillinois.org/MunicipalAggregationList.aspx.

the extent to which Illinois customers' energy supply is hedged. In any given year, a fraction of customers will be faced with rate options based on current market prices, either because their rates vary monthly or because their contracts expire during the year.

Overall, it seems reasonable to assume that the overall supply will be about 60% hedged for the first year, 40% in the second year, 20% in the third year, and perhaps 2% in subsequent years.

Market Responses to Lower Loads and Prices

Renewable Portfolio Standard

For each MWh conserved, the utility or RES must supply a fraction of a MWh worth of renewable energy or renewable energy credits. The target fraction grows over time, as shown in Table 6. Depending on the cost increment for renewable energy, the actual requirement may be capped by rate-effect limits. Utility RPS obligations are computed at a percentage of sales two years earlier, while RES obligations are computed at the same percentage of current sales. Of the total renewable energy requirement, 6% must be from solar from 2015 on (and 3% for utility supply in 2014) and wind must be 75% of the utility supply and 60% of the RES supply.[16] Distributed renewable generation must meet 0.75% of load in 2014/15 and 1% thereafter. The remainder of the RPS can be met from existing resources, including old hydro-electric plants, in Illinois and adjacent states.

Table 8: Illinois Renewable Portfolio Standard Requirement

Year Beginning May	Renewable Generation Requirement	Utility Energy Use in Year Beginning May
2014	9.0%	2012
2015	10.0%	2013
2016	11.5%	2014
2017	13.0%	2015
2018	14.5%	2016
2019	16.0%	2017
2020	17.5%	2018
2021	19.0%	2019
2022	20.5%	2020
2023	22.0%	2021
2024	23.5%	2022
2025	25.0%	2023

[16] The RESs must secure at least half their renewable supply by making alternative compliance payments (ACPs) to the Illinois Power Authority, which then purchases RECs.

If the supply of renewable energy is constrained by the inability of new renewable energy projects to secure contracts for their output and/or RECs, reduced load would reduce the development of renewable projects. Since those renewables generally operate as price-takers, the net effect of a MWh of energy savings would be to reduce the load on the thermal generation system by $1 - r$ MWh, where r is the renewable requirement percentage.

However, if there is a surplus of renewable energy or if new renewable projects can be developed with little or no incremental REC payment, the effect of energy-efficiency programs will not change the demand for renewables.

The 2012 procurement of RECs for 2012/13 yielded prices under $1/MWh for wind and miscellaneous renewables, indicating that these resources are not dependent on REC revenues, at least in the short term.[17] In renewable-short New England, by comparison, REC prices are in the $50–$60/MWh range.

The average 2012/13 solar REC price was about $80/MWh, indicating that the supply of those facilities is constrained, and that decreased load is likely to result in reduced development of photovoltaic facilities. The same is probably true of the more expensive distributed renewable generation. The combined effect of the solar and distributed generation RPS components would rise from 1% of load in 2014/15 to 2.5% in 2025/26. This offset to DRIPE would be very small.

If wind and other renewables remain inexpensive and flexible, the RPS will not have a significant effect on DRIPE.

Price Elasticity

To some extent, the lower energy prices resulting from DRIPE would tend to result in increased energy usage and that increased energy usage will tend to push energy price back up. The magnitude of the effect depends on the elasticity of electric energy demand with respect to price.

While ComEd's load forecast (Appendix A-2 in Appendix II to the Procurement Plan) is not very clear about the functional form of its models, ComEd appears to estimate short- and long-term price elasticities of –0.031 and –0.047 for the residential class and –0.024 and –0.042 for the small commercial class. Ameren Illinois's load forecast (Appendix I to the Procurement Plan) mentions the

[17] Public Notice of Winning Bidders and Average Prices, Ameren Illinois Company and Commonwealth Edison Company Spring 2012 Procurement of Renewable Energy Credits, May 16, 2012.

inclusion of price in various composite indices, but it is difficult to determine the implicit elasticities from the results in the forecast report.

Generation energy costs are only a little more than half of total residential electricity bills, and about two thirds of commercial electricity bills. A 1% reduction in generation energy prices might thus increase both residential and small commercial load by about 0.015% in the first year and 0.025% in the long terms.

Depending on the elasticities assumed for large commercial and industrial load, as well as for Ameren, price elasticity might offset 1.5% or 2% of energy DRIPE in the short term, rising to 2% or 3% over ten years or so.

Resource Retirements and Additions

Potentially the largest offset to energy DRIPE would result from changes in installed thermal generation (fossil and nuclear). Low prices may result in owners of existing generating capacity

- Allowing their energy-producing assets to become less efficient and reliable, leading to more outages and higher market-clearing prices.
- Retiring plants rather than upgrading them to meet new environmental requirements. This phenomenon is particularly important recently for coal plants, but has also resulted in retirement of some oil- and gas-fired plants. A number of coal plants remain at the edge of profitability and may be pushed into retirement by lower prices.
- Retiring plants that cannot cover their operating costs with the lower revenues. The retirement of the Kewaunee nuclear plant is a recent example of this effect of low prices.

In addition, lower loads would tend to delay the construction of new resources, and when new capacity is required, lower energy prices would tend to shift the mix of new resources toward peakers and away from baseload resources that would otherwise have reduced energy prices. The timing of new resources will be determined in large part by the amount of capacity retired. MISO does not project any capacity shortfall until 2022 with “anticipated” resources (NERC 2012 Long-Term Reliability Assessment, p. 101).[18]

These effects are difficult to model, and are probably weaker for the vertically-integrated utilities that dominate the rest of MISO system (and recover their costs

[18] If supply tightens faster than MISO anticipates, DRIPE may decay more rapidly, but both avoided energy and avoided capacity costs should increase due to the loss of resources.

through retail rates) than for Illinois's merchant generators (which are more immediately dependent on market energy prices).[19] While there are many uncertainties, it may be reasonable to assume that responses in existing and new generation resources decays DRIPE slowly in the first five years, at about 5% annually, and more rapidly thereafter. A 10% linear annual decay from year six onward would result in the extinguishing of DRIPE in year 13.

DRIPE Decay Summary

Table 7 summarizes the three factors discussed above that would tend to decrease the DRIPE effect: hedging through fixed contract prices, price elasticity, and effects of lower prices on decisions regarding generation maintenance, retirement and additions. It also shows the total DRIPE offset and the share of DRIPE remaining, and multiplies that net DRIPE share by the potential DRIPE factors (low and high for on- and off-peak), assuming that the ComEd and Ameren avoided energy costs are very similar and that the direct avoided costs are constant in nominal terms. For a 15-year measure, DRIPE would be somewhere between 20% and 40% of the direct avoided energy cost.

Table 9: DRIPE Decay Summary

						DRIPE as % Direct AvCost			
						On Peak		Off Peak	
Year	Hedged	Price Elasticity	Effects on Resource Decisions	Total DRIPE Offset	Net DRIPE Share	55%	100%	53%	95%
	a	b	c	d	e	f	g	h	i
1	0.6	0.015	0.05	0.63	0.37	20%	38%	20%	36%
2	0.4	0.017	0.10	0.47	0.53	29%	53%	28%	51%
3	0.2	0.019	0.15	0.33	0.67	36%	67%	35%	64%
4	0.02	0.021	0.20	0.23	0.77	42%	77%	41%	73%
5	0.02	0.023	0.25	0.28	0.72	39%	72%	38%	69%
6	0.02	0.024	0.35	0.38	0.62	34%	62%	33%	59%
7	0.02	0.025	0.45	0.47	0.53	29%	53%	28%	50%
8	0.02	0.026	0.55	0.57	0.43	23%	43%	23%	41%
9	0.02	0.027	0.65	0.67	0.33	18%	34%	18%	32%
10	0.02	0.028	0.75	0.76	0.24	13%	24%	13%	23%
11	0.02	0.029	0.85	0.86	0.14	8%	14%	8%	14%
12	0.02	0.030	0.95	0.95	0.05	3%	5%	3%	5%
Levelized at 6% real over Years 1–5					0.60	33%	60%	32%	57%

[19] For example, while Dominion retired its merchant Kewaunee nuclear plant in 2013, and Entergy announced the retirement of Vermont Yankee for 2014, it has been decades since a vertically-integrated utility has retired a nuclear unit, unless it faced repairs (as was the case for San Onofre and Crystal River).

Years 1–10	0.53	29%	53%	28%	51%
Years 1–15	0.41	23%	41%	22%	39%
Years 1–20	0.35	19%	35%	19%	33%

Notes: d = 1 – (1 – a) × (1 – b) × (1 – c)
e = 1 – d
f, g, h, i = e × potential DRIPE (top row)

Other Potential DRIPE Effects

In addition to electric energy DRIPE, reduction of electric loads will generally result in some reduction in electric capacity prices and in natural gas prices (to the extent that gas is the marginal fuel avoided by efficiency). Reduced gas prices benefit end-use gas customers and also reduce market electric energy prices. We have not estimated any of these additional DRIPE effects, which would be incremental to the effects quantified above.

Rebate Form Valid July 1 – December 31, 2014

Commercial Lighting

LIMITED TIME BONUS
20% bonus on select fixtures + controls.
See following pages for details.

Efficiency Vermont

888-921-5990 • www.efficiencyvermont.com

Steps to Getting Your Rebate:

1. Confirm that equipment is eligible.
2. Purchase and install new eligible equipment.
3. Sign and submit completed rebate form and invoice.

Submit completed form and invoice to:

Mail: Efficiency Vermont
c/o Rebate Coordinator
128 Lakeside Ave., Suite 401
Burlington, VT 05401

Fax: 802-658-1643

E-mail: rebatecoordinator@efficiencyvermont.com

For Burlington projects, submit form to:
Burlington Electric Department
c/o Energy Services Area
585 Pine St., Burlington, VT 05401

Need-to-Know Info:

- Customer is responsible for the proper disposal/recycling, including all associated costs, of any waste generated as a result of this project. All fluorescent lamps contain mercury and pre-1979 ballasts contain PCBs. For a list of licensed lamp recycling and ballast disposal companies, visit **www.mercvt.org**.
- For more information or to confirm eligibility, visit **www.efficiencyvermont.com/businesslighting** or call **888-921-5990**.
- Prefer to submit online? Visit **https://efficiencyvermont.com/lighting-rebates**.
- **Limited Time—20% Bonus on LED fixtures plus Controls!** Customers can obtain a 20% rebate bonus when they purchase qualifying LED troffer, highbay, and exterior pole mount fixtures with fixture-mounted occupancy and/or daylight controls. The bonus is applied to both the fixture and control rebate. See sections 1, 2 and 3 for qualifying products.
- Burlington Electric Department (BED) administers efficiency programs for the City of Burlington, including the rebates listed on this form. For more information, call 802-865-7342.

CUSTOMER INFORMATION & AGREEMENT

Business Name | Contact Name/Title

Address (of installation location) | City/Town | State | Zip

Mailing Address (if different) | City/Town | State | Zip

Telephone # | E-mail Address

Electric Utility Company | Electric Utility Account # (of installation location)

Is equipment installed in a new construction building? ○ Yes ○ No
If yes, provide building sq. ft. ____________ If over 10,000 sq. ft., call 888-921-5990 (see Terms & Conditions).

I certify that all equipment for which I am requesting a rebate has been installed, that I meet the eligibility requirements of this rebate program, and that all information submitted as part of this application, including proof of purchase, is correct to the best of my knowledge. I agree to the terms and conditions listed on the back of this form.

CUSTOMER SIGNATURE (required even if rebate is going to vendor) | Date

PAYEE INFORMATION

Rebate check payable to (must match EIN/TIN or SSN below): ____________

Payee's Federal Tax ID Number (TIN) – **check one and provide EIN/TIN or SSN below:**

○ Corporation (provide TIN)
○ Tax-Exempt Organization (provide TIN)
○ City, County, or State Dept., Govt. or Agency (provide TIN)
○ Other (provide EIN/TIN or SSN)

Employer Identification Number | or | Social Security Number

Contact Name (leave blank if same as customer contact information above)

Mailing Address | City/Town

State | Zip

For Internal Use

Project # ____________

See requirements and rebate amounts on pages 4-7 and then fill in form below.

SECTIONS 1-2: LED LIGHTING

Code (see pages 4-5)	Installation Date	# of Hours Lights are on per Week	Manufacturer	Model #	Corresponding Lighting Control Code (if bonus applies)	A= Quantity (or Total Fixture Length) of Products	B = Rebate (see pages 4-5)	A x B = Total Rebate Amount
							Total Rebate Sections 1-2	$

SECTION 3: LIGHTING CONTROLS

Code (see page 6)	Installation Date	# of Hours Lights are on per Week (before controls)	A= Quantity of Controls Products	Corresponding LED Lighting Code (if bonus applies)	B = Rebate per Control (see page 6)	A x B = Total Rebate Amount

*Efficiency Vermont will calculate final bonus amount on eligible fixtures and lighting controls. In the event of a discrepancy between the final amount and the expected amount, you will be contacted by the Rebate Coordinator.

Expected Bonus Amount for Qualifying LED Lighting & Controls* $

Total Rebate Section 3 $

SECTION 4: FLUORESCENT LIGHTING

Code (see page 7)	Installation Date	# of Hours Lights are on per Week	# of Lamps per Fixture	A= Quantity of Lighting Products	B = Rebate (see page 7)	A x B = Total Rebate Amount
					Total Rebate Section 4	$

REBATE FORM TOTAL Sections 1-4 $ ____________________

1 INTERIOR LED LIGHTING

Eligibility Requirements

- Products must be qualified by ENERGY STAR® or DesignLights Consortium® (DLC).
- For qualifying products, visit **www.efficiencyvermont.com/ledproducts**.
- Rebates cannot be combined with any other offer, including LED instant coupons available at some lighting retailers.
- Rebates do not apply when products are used in exterior applications, or when application is not appropriate for lighting category.

Code	Type	DLC or ENERGY STAR Category	Specification	Rebate	Eligible for Bonus*
n/a	Screw- or Pin-based LED Replacement Lamps	n/a	Instant off rebates available through SMARTLIGHT. For information, visit **www.efficiencyvermont.com/smartlight**.	n/a	
1.1	**DOWNLIGHT** Fixtures	**ENERGY STAR** - Downlight Pendant, Downlight Surface Mount, Downlight Recessed, Downlight Solid State Retrofit	• Includes recessed, pendant, surface mount and retrofit kits. • Can be used in exterior applications if damp-location rated.	$35	
1.2	**TRACK** Lighting Fixtures	**DLC** - Track or Mono-Point Directional Luminaires	• Excludes screw- and pin-based products.	$50 per head	
1.3	**UNDER CABINET** Shelf-Mounted Task Fixtures	**ENERGY STAR** - Under Cabinet, Under Cabinet Shelf-Mounted Task Light		$15 per foot	
1.4	**REFRIGERATED CASE** Fixtures	**DLC** - Vertical Refrigerated Case Luminaires, Horizontal Refrigerated Case Luminaires	• Horizontal or vertical.	$15 per foot	
1.5	**FREEZER CASE** Fixtures	**DLC** - Vertical Refrigerated Case Luminaires, Horizontal Refrigerated Case Luminaires	• Horizontal or vertical.	$15 per foot	
1.6	**DISPLAY CASE** Fixtures	**DLC** - Display Case Luminaires		$15 per foot	
1.7	**SURFACE** and **SUSPENDED LINEAR** Fixtures	**DLC** - Linear Ambient Luminaires: Indirect, Indirect/Direct, Direct/Indirect, Direct	• Any combination of Indirect/Direct. • Includes linear strips.	$10 per foot	
1.8	**2' x 2' TROFFER** Fixtures	**DLC** - 2x2 Luminaires for Ambient Lighting of Interior Commercial Spaces	• Includes recessed, surface mount, and retrofit kits.	$50	√
1.9	**2' x 4' TROFFER** Fixtures	**DLC** - 2x4 Luminaires for Ambient Lighting of Interior Commercial Spaces	• Includes recessed, surface mount, and retrofit kits. • For 4' LED replacement lamps, see 1.11.	$60	√
1.10	**1' x 4' TROFFER** Fixtures	**DLC** - 1x4 Luminaires for Ambient Lighting of Interior Commercial Spaces	• Includes recessed, surface mount, and retrofit kits. • For 4' LED replacement lamps, see 1.11.	$50	√
1.11	**4' REPLACEMENT LAMPS** (Tubes)	**DLC** - Four-Foot Linear Replacement Lamps	• Electrical modification to existing fixture may be required; consult with an electrician. • Not for use on T12 magnetic ballasts.	$5 per lamp	
1.12	**HIGH- & LOW-BAY** Fixtures	**DLC** - High-Bay Luminaires for Commercial and Industrial Buildings, Low-Bay Luminaires for Commercial and Industrial Buildings, High-Bay Aisle Luminaires	• Includes retrofit kits.	$125	√

*Eligible for additional 20% of rebate amount when combined with a control specified in Section 3. Each fixture must be combined with one control.

2 EXTERIOR LED LIGHTING

Eligibility Requirements

- Products must be qualified by DesignLights Consortium® (DLC) for Rebates.
- For qualifying products, visit **www.efficiencyvermont.com/ledproducts**.
- Rebates do not apply when products are used in interior applications, or when application is not appropriate for lighting category.
- Fixtures leased from an electric utility company are not eligible.

Code	Type	DLC Category	Specification	Rebate	Eligible for Bonus*
2.1	Outdoor **POLE-MOUNTED** Area Fixtures and **RETROFIT** Kits	**DLC** - Outdoor Pole/Arm-Mounted Area and Roadway Luminaires	< 30 input watts	$100	
			≥ 30 input watts or ≥ 2,000 lumens	$200	√
			≥ 75 input watts or ≥ 5,000 lumens	$300	√
2.2	Outdoor **DECORATIVE AREA** or **POST-TOP** Area Fixtures and **RETROFIT** Kits	**DLC** - Outdoor Pole/Arm-Mounted Decorative Luminaires	< 30 input watts	$100	
			≥ 30 input watts or ≥ 2,000 lumens	$200	
			≥ 75 input watts or ≥ 5,000 lumens	$300	
2.3	**PARKING GARAGE** or **CANOPY** Fixtures and **RETROFIT** Kits	**DLC** - Parking Garage Luminaires, Fuel Pump Canopy Luminaires	< 30 input watts	$100	
			≥ 30 input watts or ≥ 2,000 lumens	$200	
			≥ 75 input watts or ≥ 5,000 lumens	$300	
2.4	Outdoor **WALL-MOUNT** Fixtures (including Wall Packs) and **RETROFIT** Kits	**DLC** - Outdoor Wall-Mounted Area Luminaires	< 30 input watts	$100	
			≥ 30 input watts or ≥ 2,000 lumens	$150	
			≥ 75 input watts or ≥ 5,000 lumens	$200	
2.5	**BOLLARD** Fixtures	**DLC** - Bollards	< 30 input watts	$100	
			≥ 30 input watts or ≥ 2000 lumens	$175	
2.6	Outdoor **FLOOD** Light Fixtures	**DLC** - Landscape/Accent Flood and Spot Luminaires, Architectural Flood and Spot Luminaires	Accent: < 1000 lumens	$50	
			Architectural: 1000 – 4000 lumens	$100	
			Architectural: > 4000 lumens	$150	

*Eligible for an additional 20% of rebate amount when combined with a control specified in Section 3. Each fixture must be combined with one control.

3 LIGHTING CONTROLS

3.1 Interior Dual Occupancy and Daylight Controls

Eligibility Requirements

- For use on interior LED or fluorescent equipment.

Code	Type	Specification	Rebate per Sensor	Eligible for Bonus*
3.1a	Fixture Mounted Dual Sensor	• Minimum 30 watts controlled.	$40	√

3.2 Interior Occupancy Controls

Eligibility Requirements

- For use on interior LED or fluorescent equipment.
- When used on fluorescent equipment, program start ballasts are recommended.
- Companion switches for wireless sensors are not eligible for rebates.

Code	Type	Specification	Rebate per Sensor	Eligible for Bonus*
3.2a	Ceiling or Wall Remote Mounted Sensor	• Hard-wired or wireless. • Minimum 150 watts controlled.	$75	
3.2b	Switch Mounted Sensor	• Minimum 60 watts controlled.	$30	
3.2c	Fixture Mounted Sensor	• Minimum 30 watts controlled.	$30	√
3.2d	Refrigerated Case Sensor	• Minimum 3 doors per sensor.	$40	
3.2e	Freezer Case Sensor	• Minimum 3 doors per sensor.	$40	

3.3 Interior Daylight Controls

Eligibility Requirements

- For use on interior LED or fluorescent equipment.
- To realize full energy savings potential, commissioning is recommended for daylight controls.

Code	Type	Specification	Rebate per Sensor	Eligible for Bonus*
3.3a	Ceiling or Wall Remote Mounted	• Minimum 150 watts controlled.	$60	
3.3b	Switch or Fixture Mounted	• Minimum 30 watts controlled.	$30	√

3.4 Exterior Lighting Controls

Eligibility Requirements

- For use on exterior LED or induction equipment.
- Lights must be turned off or reduced by at least 50% during unoccupied times.
- Additional controls are required to prevent daytime operation.

Code	Type	Specification	Rebate per Sensor	Eligible for Bonus**
3.4a	Exterior Occupancy Sensor	• Minimum 45 watts controlled.	$40	√

*Eligible for an additional 20% of rebate amount when combined with an interior fixture specified in Section 1. Each fixture must be combined with one control.
**Eligible for an additional 20% of rebate amount when combined with an exterior fixture specified in Section 2. Each fixture must be combined with one control.

4 FLUORESCENT LIGHTING

4.1 High-Performance T8 (HPT8) Linear Fluorescent Systems

Eligibility Requirements

- HPT8 system = high-lumen or reduced-wattage lamp(s) + **low ballast factor (BF) ballast**.
- Lamp and ballast combinations must be listed on the Consortium for Energy Efficiency's (CEE) Qualifying Products List available at **www.efficiencyvermont.com/HPT8products**.

Code	Type	Specification	Rebate per Fixture	Rebate per fixture with Bi-level/ Dimming Ballast
4.1a	Relamp/Reballast to HPT8	• Must use **low ballast factor**. • Must be an upgrade of an existing T8 or T12 system.	$10	$20
4.1b	New HPT8 Fixture	• Must use **low ballast factor**. • Includes any HPT8 fixture type.	$10	$20
4.1c	New or Retrofit 2 Lamp HPT8 High Efficiency Troffer Fixture	• Must use **low ballast factor**. • Fixture efficiency must be 80% or greater. • 2 lamp fixtures only.	$30	$40
4.1d	New HPT8 High-Bay Fixture	• Must use **high ballast factor**. • Fixture efficiency must be 85% or greater. • 4, 6, or 8 lamps only; call to inquire about other lamps.	$50	$60

4.2 T5 Linear Fluorescent Systems

Eligibility Requirements

- Fixture must utilize a T5 lamp/ballast system.

Code	Type	Specification	Rebate per Fixture	Rebate per fixture with Bi-level/ Dimming Ballast
4.2a	New T5 Fixture	• Includes any T5 fixture type.	$10	$20
4.2b	New or Retrofit 2 Lamp T5 High Efficiency Troffer Fixture	• Fixture efficiency must be 85% or greater.	$30	$40
4.2c	New T5HO High-Bay Fixture	• Fixture efficiency must be 90% or greater. • 3, 4, or 6 lamps only; call to inquire about other lamp combinations.	$50	$60

Induction Lighting

Efficiency Vermont or BED incentives may be available for exterior projects utilizing induction lighting technology. Projects must be enrolled with Efficiency Vermont or BED before purchase and installation, and incentives will be determined on a case-by-case basis. For more information, visit **www.efficiencyvermont.com/induction** or call **888-921-5990**. For BED projects, please call 865-7342.

TERMS & CONDITIONS

REBATE is for new equipment purchased and installed between July 1, 2014 and December 31, 2014 by customers of Vermont electric utilities. Equipment must be installed within the state of Vermont. Rebate forms must be postmarked or received by January 31, 2015. Rebate offer is subject to change without notice and may not be combined with any other offer. **LIMITATIONS:** This form cannot be used for any project involving more than 250 items for which rebates are sought; for information on such projects, please call Efficiency Vermont (or Burlington Electric Department for projects within the City of Burlington). This form also cannot be used for any project involving new construction within the City of Burlington, or for any project outside the City of Burlington involving new construction of greater than 10,000 sq. ft.; please call Burlington Electric Department or Efficiency Vermont, respectively, for information on such projects. **PROOF OF PURCHASE:** Invoice(s) must include the quantity, size, type, manufacturer, model or part number, purchase date, and vendor of the efficient equipment. All sales transactions and installations are subject to verification and inspection. The customer agrees to allow Efficiency Vermont (or, within the City of Burlington, Burlington Electric Department) access to the equipment for purposes of verification and inspection. **LIMITATION OF LIABILITY:** Performance of installed equipment is not guaranteed expressly or implicitly. **ENDORSEMENT:** No particular manufacturers, products, or system designs are endorsed through this program. **PAYMENT:** Allow 60 days for delivery of payment. Incomplete or missing information will delay processing of rebate form and payment. **MAXIMUM PAYMENT** will not exceed 100% of the equipment purchase price. Customer is responsible for all costs associated with sales tax, installation, and disposal/recycling. Customer is responsible for any tax liability associated with rebate payment. **CAPACITY CREDITS/ENVIRONMENTAL CREDITS:** In accepting these financial incentives, the customer agrees that Efficiency Vermont (or, for customers within its service territory, Burlington Electric Department) holds the sole rights to any electric system capacity credits and environmental credits associated with the energy efficiency measures for which incentives have been received. These credits will be used for the benefit of Vermont ratepayers.

Efficiency Vermont

128 Lakeside Ave., Suite 401 • Burlington, VT 05401 • 888-921-5990 • **www.efficiencyvermont.com**

EV-1897-0714-RNEX

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

Principal authors
Jim Lazar and Xavier Baldwin

August 2011

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

by Jim Lazar, RAP Senior Advisor
Xavier Baldwin, P.E., Principal Electrical Engineer, Burbank Water and Power[1]

Introduction

Utilities and their regulators have become familiar, comfortable, and sometimes enthusiastic about the energy savings that energy efficiency measures provide. These savings reduce fuel usage, reduce air pollution, and reduce consumer bills.

Energy efficiency measures also provide very valuable peak capacity benefits in the form of marginal reductions to line losses that are often overlooked in the program design and measure screening. On-peak energy efficiency can produce twice as much ratepayer value as the average value of the energy savings alone, once the generation, transmission, and distribution capacity, line loss, and reserves benefits are accounted for. Geographically or seasonally targeted measures can further increase value.

This paper is one of two that the Regulatory Assistance Project (RAP) is publishing on this topic; the second looks in a more detailed fashion at the transmission and distribution system benefits of energy efficiency.[2]

Principal Conclusions

The line losses avoided by energy efficiency measures are generally underestimated. Most analysts who consider line losses at all use the system-average line losses, not the marginal line losses that are actually avoided when energy efficiency measures are installed. Generally this is because average line losses are a measured and published figure, while determining marginal line losses requires more information and more detailed calculations.

Because losses grow exponentially with load, the marginal losses avoided are much greater than the average losses on a utility distribution system. As calculated in Figure 4, marginal line losses at the time of the system peak of 20% are entirely consistent with average line losses of 7% on a utility distribution system.

Because energy efficiency measures reduce loads at the customer premises, they also avoid the associated marginal line losses. As a result, the utility avoids the need for as much as 120% of the generating capacity needed to serve the avoided load.

1 This paper builds on work originally presented to the Northwest Power and Conservation Council's Regional Technical Forum (RTF); it has benefited greatly from the contribution of Charlie Grist of the Council staff and Adam Hadley, P.E., a consultant to the RTF. See: http://www.nwcouncil.org/energy/rtf/meetings/2008/09/Marginal%20Distribution%20System%20Losses%203.ppt http://www.nwcouncil.org/energy/rtf/meetings/2008/09/Marginal%20Distribution%20System%20Losses%20Illustration%20v.xls

2 *US Experience with Efficiency as a Transmission and Distribution System Resource,* Chris Neme, Regulatory Assistance Project, November 2011. http://www.raponline.org/docs/

Utilities maintain generating reserves so that when one generating unit goes out of service, customers continue to receive service. Because energy efficiency reliably reduces energy loads and avoids marginal line losses, thus achieving reliable reductions in loads to be served at the generation level, the utility avoids the need for expensive reserves to assure reliable service. When compounded with the avoided marginal line losses, energy efficiency measures can save about 1.4 times as much capacity at the generation level as is measured at the customer's meter. While the energy benefit of line loss avoidance by investment in energy efficiency is relatively well-understood, the capacity benefit is a separate and additional benefit that is seldom quantified by efficiency analysts.

Efficiency Has a Favorable Daily and Seasonal Resource Shape

Most electric utilities have loads that rise during the day and decline at night. They also have seasonal increases in the summer, winter, or both, compared with the spring and autumn seasons. This variation is caused by people waking up and turning on appliances, going to work and turning on lights and office equipment, and using air conditioners following the heat of the afternoon.

A typical utility will have an on-peak demand during the peak season that is twice as high as the average demand over the year. The ratio of average demand to peak demand is called the *system load factor,* and in this example, would be 50%. Figure 1 shows a typical utility daily load shape.

Because investments in energy efficiency reduce the very loads that cause the overall system load, they generally have about the same load shape as the loads themselves – rising at peak hours and declining at night. Therefore, efficiency measures generally contribute more to the reduction of peak demands than they do on average. They have a better "load shape" than baseload power plants, and the savings are consequently more valuable.

This load shape is not uniform from measure to measure. Some types of efficiency, such as Energy Star air conditioners, provide very large peak demand savings relative to the energy savings. Others, like more efficient street lights, may only reduce demand during shoulder or off-peak hours.

Analysis is required to determine the peak demand of various efficiency measures. This is measured by the typical *load factor* of the individual measure (ratio of average to peak demand reduction) and the *coincidence factor* of the measure (the portion of the demand reduction of the individual measure that will occur at the time of the system peak demand). Measures that provide most of their savings during the high-load hours are said to have a favorable load shape. All three of these measures are important to valuing the energy savings from efficiency measures.

The peaking capacity value of different measures varies by region of the country, depending both on climate and on whether the local utility system is summer-peaking or winter-peaking. A summer-peaking region, like Texas or Florida, will value the capacity benefits of air conditioning savings, but will derive much less capacity value from electric space-heating savings. Winter-peaking regions will have the opposite perspective. Utilities with dual peaks will generally assign a greater value to measures other than space conditioning (i.e., that reduce peak demand in both seasons) compared to regions with a strong peak demand in one season or the other.

Figure 1:

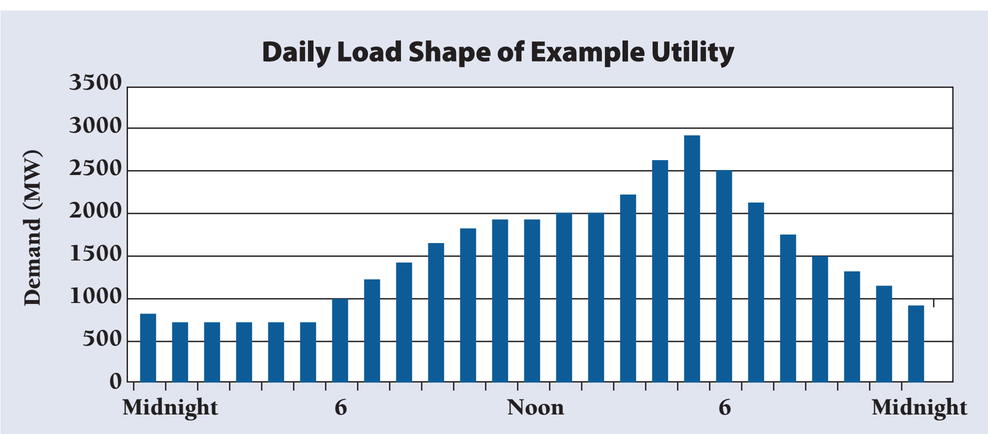


Figure 2 shows the relative on-peak summer and winter savings of some typical energy efficiency measures as evaluated in the Pacific Northwest, a winter-peaking region.

Figure 2

Ratio of Coincident Peak Savings to Average Annual Energy Savings [3]

Measure	Summer Peak	Winter Peak
Residential Lighting	0.90	1.37
Residential Water Heat	0.94	2.63
Residential Space Heat	0.28	4.00
Residential Air Conditioning	1.72	0.08
Residential Refrigerators	1.11	0.87
Commercial Lighting	2.17	2.00
Commercial Air Conditioning	2.86	0.08

As is evident in a winter-peaking region like the Pacific Northwest, investments in space heating conservation (floor, ceiling, and wall insulation) will provide very large peak demand benefits, whereas in summer-peaking regions, it is natural that air conditioning measures are most valuable. One of the more interesting findings of this particular analysis, however, was the relatively high winter-peak coincidence factor of residential water heating consumption.[4] This might be very different on a summer-peaking system.

Energy Efficiency Provides Significant Distribution and Transmission Loss Savings at the Time of Critical System Peak Demands

Because energy efficiency reduces loads at the customer premises, the utility does not have to supply these avoided demands with generating facilities. Generating facilities are often located at great distances from customers and require step-up transformers to get the power onto the transmission system, long transmission lines, transmission substations, step-down transformers to distribution voltages, distribution lines, and distribution line transformers.

Losses occur at each of these steps of the transmission and distribution system. Typical utility-wide average annual losses from generating plants to meters ranges from 6% to 11%, depending on the transmission distances, system density, distribution voltages, and the characteristics of transmission and distribution system components.[5]

Energy efficiency is often credited with avoiding these average losses when regulators and utilities value efficiency investments and set the program cost-effectiveness thresholds based on avoided cost. However, the losses on utility transmission and distribution systems are not uniform through the day and the year, and the peak capacity savings from energy efficiency are typically much greater than the average savings.

Line Losses on a Distribution System

Many utility conservation programs credit efficiency measures with line loss reduction, but most of these calculations are based on the *average* losses, not the *marginal* losses avoided by efficiency measures.

There are two types of losses on the transmission and distribution system. The first are *no-load* losses, or the losses that are incurred just to *energize* the system – to create a voltage available to serve a load. Nearly all of these occur in step-up and step-down transformers. The second are *resistive* losses, which are caused by friction released as heat as electrons move on increasingly crowded lines and transformers. Typically, about 25% of the average

3 Northwest Power and Conservation Council Regional Technical Forum, 2001; see: http://www.nwcouncil.org/energy/rtf/measures/support/procost/MC_AND_LOADSHAPE_6P.XLS

4 Water heat usage is concentrated in the early morning and early evening hours, when households are beginning and ending their day. System peaks typically occur when residential and commercial loads overlap – in the morning around 8 a.m. and the evening around 5 p.m.; therefore electric water heat usage is highly peak-coincident at least for a winter-peaking system. By contrast, while gas water heat usage occurs in the same hours, water heat is a very high load factor usage on gas systems, because in the natural gas industry, peak demand is measured on a daily basis, not an hourly (or sub-hourly) basis as is the standard for the electricity sector. Prior to the 1960s, timers were common on electric water heaters to keep them from contributing to peak demand; with the advent of smart grid resources, electric water heaters are now being looked to for demand response and to complement intermittent generation from wind.

5 Page 401a of the FERC Form 1 shows system losses and system retail sales, and generally fall in this range for vertically integrated utilities. Line losses attributable to wholesale sales and wholesale purchases are typically reported in part by the seller and in part by the buyer – and therefore the losses reported in the Form 1 may not reflect all losses attributable to retail sales by the reporting utility.

annual losses are no-load or core losses, and about 75% are resistive losses. Utility loss studies generally separate the core losses from the resistive losses.[6]

Losses increase significantly during peak periods. The mathematical formula for the resistive losses is I^2R, where “I” is the amperage (current) on any particular transformer or distribution line, and “R” is the resistance of the wires through which that current flows. While the “R” is generally constant through the year, since utilities use the same wires and transformers all year long, the “I” is directly a function of the demand that customers place on the utility. Thus, resistive losses increase with the square of the current, meaning losses increase as load increases.

Let’s start with a very simple calculation: the load (current times voltage) of a utility during the highest on-peak hours is two times the average load for the year, a system load factor of 50%. Because the voltage is constant, losses are a function of the square of the load, and that load is two times as high on-peak as the average, the total resistive losses are *four times* as great during the summer afternoon peak as they average over the year. It’s a bit more complicated than that, but this example gives a general idea.

Depending on the load shape of the utility (how sharp the “needle peak” is), the percentage of generation that is “lost” before it reaches loads are typically at least twice as high as the average annual losses on the system. During the highest critical peak hours (perhaps 5-25 hours per year) when the system is under stress, the losses may be four to six times as high as the average.

There are many tools available to utilities for line loss reduction, including voltage upgrades, reconductoring, and improved transformers. While these are valuable and may often be cost-effective, the focus of this paper is on the avoidable marginal losses as a result of load reductions from implementation of energy efficiency measures.

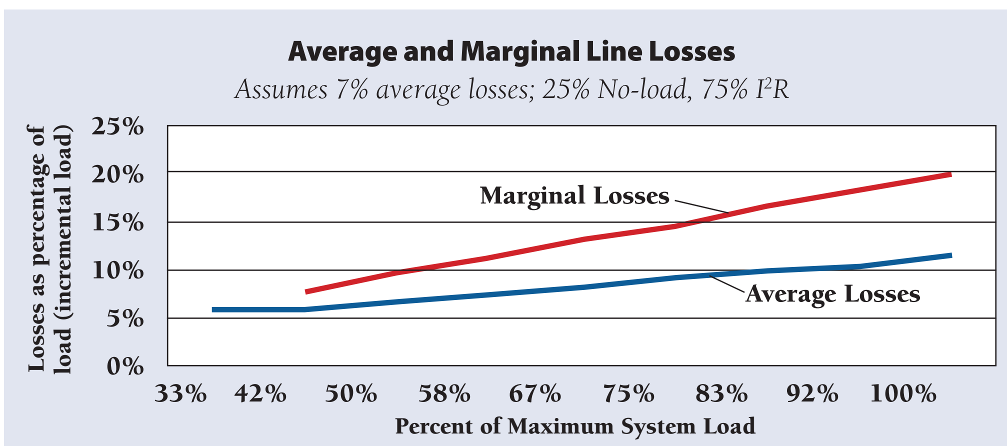
Marginal Losses Are Greater Than Average Losses

Important to valuing any investment is how much the *incremental* cost of the measure is, and what the incremental savings are.[7] Because the average losses increase with the square of the load, the marginal line losses at any point are significantly higher than the average losses at that same point on the load curve. It turns out that the incremental system losses during the peak hours are *much* greater than the average losses during these hours. As noted above, this is due to the total losses growing with the square (I^2R) of the load in response to linear growth in the loads, and the incremental losses (the change in losses with respect to the change in loads) are therefore more than exponential.

The graph below shows the average losses at various load levels for a hypothetical small utility with an average annual resistive loss of 7% on its system. It also shows the incremental losses sustained as load increased from the minimum level of about 100 megawatts to the system record peak demand of nearly 300 megawatts for this utility.

This utility’s average resistive losses on their distribution system are only about 7% over the course of the year. At their system extreme peak, the estimated total losses

Figure 3



6 In preparing this paper, the authors reviewed line loss studies for several utilities; they indicated no-load losses ranging from 18.5% to 30% of total annual losses. A mean figure of 25% is used for simplicity in illustrating the principle of marginal line loss calculation.

7` The most comprehensive and most commonly accepted cost-effectiveness test is the Total Resource Cost (TRC) test, which, when properly applied, measures both energy and non-energy benefits; but the principles in this analysis apply equally to the Program Administrator Cost (PAC) test used by some utilities and regulators to value energy efficiency investments.

Figure 4:

Calculation of Average and Marginal Line Losses

Load Level	No-Load Losses MW	Resistive Losses MW	Square of Load	Loss %	Total Loss MW	Incremental Load	Incremental Loss	Marginal Loss %
100	2.625	3.5	10,000	6.1%	6.1			
125	2.625	5.5	15,625	6.5%	8.1	25	2.0	8%
150	2.625	7.9	22,500	7.0%	10.5	25	2.4	10%
175	2.625	10.7	30,625	7.6%	13.3	25	2.8	11%
200	2.625	14.0	40,000	8.3%	16.6	25	3.3	13%
225	2.625	17.7	50,625	9.0%	20.3	25	3.7	15%
250	2.625	21.9	62,500	9.8%	24.5	25	4.2	17%
275	2.625	26.5	75,625	10.6%	29.1	25	4.6	18%
300	2.625	31.5	90,000	11.4%	34.1	25	5.0	20%

reached about *11%,* one and one-half times the average losses for the year. At that extreme peak, however, the *marginal* resistive losses – those that would be avoided if load had been a little bit lower if an efficiency measure were installed – were *20%.*

The graphic in Figure 3 is derived from the calculations above in Figure 4.

Few utilities or regulators have studied the marginal losses that can be avoided with incremental investment in efficiency measures that provide savings at the time of extreme peak demands. This type of analysis suggests a very significant benefit from measures that reduce peak demand, including energy efficiency, demand response, and use of emergency generators located at customer premises.

Mathematically, the formula I^2R reduces the marginal resistive loses to a calculation. At any point on the load duration curve, marginal resistive loses are two-times the average resistive losses at that same point on the load duration curve. During off-peak hours, when average resistive losses may be only 3%, the marginal losses are 6%. During the highest peak hours, when average resistive losses may be 10%, the marginal losses are 20%.

However, because part of the overall losses at every hour are (no-load) losses, the marginal losses are not two times the total losses – only two times the resistive losses. The no-load losses are not reduced by energy efficiency measures. A variety of utility loss studies indicate that 20%-30% of total losses are no-load losses, meaning that about 75% are resistive losses. Therefore this paper uses a rule of thumb that marginal losses are about 1.5 times average losses (it's actually a bit lower at low loads, and a bit higher at high loads where the no-load losses are a smaller part of total losses.)

This means that a conservation measure that saved 1 kilowatt at the time of the system peak measured at the customer's meter would save about 1.25 kilowatts measured at the generation level.[8] The critical peak-period marginal line-loss savings of energy efficiency therefore adds another 25% to the value of the load reduction itself, in determining the amount of generating capacity required to meet critical peak period demand. If the utility has 1.25 kW of generating capacity, and loses at the margin 20% of this capacity during the highest peak hours, it has 1 kW available to serve the load.

The hypothetical analysis may not be universally applicable, but the principles are universal: losses increase with the square of the demand, and incremental losses during the critical peak period are much larger than the average losses over the year.

Avoidable Transmission and Distribution Capacity Costs Are Significant

In addition to the avoided losses and the reduced need for generating capacity that can be achieved through

8 [1.25 – (.20 x 1.25) = 1.0]; If the utility must serve a 1 kW incremental load on-peak, it needs 1.25 kW of additional generating capacity to feed the transmission and distribution system.

energy efficiency investment at the distribution level, the peak load reduction from energy efficiency investment also reduces transmission and distribution capacity costs. Recognizing this value may be especially important for those jurisdictions that actually review T& D investments against targeted energy efficiency program opportunities.[9]

Transmission and distribution systems must be designed to carry extreme peak demands. The costs of oversizing systems for these demands are quite significant. In states where marginal cost of service studies are used to set rates, utilities regularly examine the cost of adding capacity to their transmission and distribution grids. The results of these studies vary widely, in part due to regional conditions and in part due to a lack of standardized methodologies.

The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt, and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt.[10] Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution. There are also marginal operations and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs.

In valuing energy efficiency investments, it is important to consider the avoided energy and capacity not only at the generation level, but also at the transmission and distribution levels. Inclusion of these values, particularly considering the marginal capacity benefits from incremental efficiency investments, can greatly increase the value of these measures, and therefore the level of financial assistance or incentives that utilities may offer to encourage implementation.

Another important benefit of increased energy efficiency at the distribution/customer level is the significant extension in useful life of distribution system components and the resulting deferral of capital expenditures for upgrade or replacement of electrical equipment, including conductors, transformers, etc. In effect, energy efficiency allows the system to absorb additional load growth without the need to upgrade system components as soon. This capital deferral translates more or less directly into avoided distribution-capital investment costs for capacity expansion. A prudent assumption is that the avoided capacity benefits are at least one-half of the utility's estimated marginal transmission and distribution capacity costs, based on their most recent cost-of-service analysis.[11]

Another benefit of reducing marginal losses is lower loss of service life due to a reduction in winding and insulation temperatures in distribution transformers, which are normally operated at up to 200% of their nameplate rating during peak load periods, a condition that causes accelerated aging of these components.

Efficiency Reduces System Generating Reserve Requirements

Utilities must provide *reserves* of generating facilities in order to ensure that service is not interrupted if (and when) generating units fail to operate as planned. Generating reserve requirements in the United States range from as low as 7% on hydro-rich utilities to as much as 25% for isolated small utilities in Alaska and Hawaii. Ten to fifteen percent is typical for large thermal-based systems.[12]

Efficiency investments reduce loads at the customer's meter, and, as we have seen, provide even larger reductions at the generation level during system peak periods when losses skyrocket and capacity/reserve requirements are greatest.

Since the reserve requirement is tied to the amount of generation required to serve load, efficiency reduces the reserve requirement not only by a percentage of the

9 Id footnote 2.

10 These wide ranges reflect the wide possible range of outcomes for distance, topography, real estate costs, and construction costs that may be incurred.

11 The capacity benefit may not be monetized immediately, due to temporary excess capacity; but over the life of a distribution circuit, eventually components will need to be replaced due to age or upsized due to growth. Using one-half of marginal cost implies that, on average, the capacity benefits will be realized within a half-lifetime of the circuit components.

12 The level of required reserves is a function of the size of the total system, the size of the largest single generating units, and the reliability of the various generating units. Because hydro units are generally relatively small and extremely reliable, utilities that rely on hydro for reserves have the lowest reserve requirements. Small island systems, like those in Hawaii, with a few relatively large generating units typically have the highest reserve requirements.

savings that customers enjoy, but also by a percentage of the incremental peak losses on the transmission and distribution system that reduce the utility's generation requirements. The reserve requirement is measured against the amount of generation needed – *including that needed to cover line losses.* Therefore, the avoided reserves resulting from efficiency investments are increased in value by the avoided marginal line losses.

The table below looks at the capacity savings during an off-peak period and an on-peak period for two hypothetical resources, one with a low coincidence factor relative to the system peak (efficient lighting), and one with a high coincidence factor, efficient air conditioning. The table shows that after considering the coincidence of different loads to the system peak, the marginal line losses, and the avoided reserve requirement, the capacity benefit of energy efficiency measures increases significantly from that measured at the customer's meter.

As is evident, the total capacity benefit of each of these measures is 1.44 times the capacity savings at the customer's meter, because of the value of the marginal line losses and avoided reserves during peak periods (line 8 divided by line 3). Thus the generation capital cost savings are significantly higher than if only average line losses were used and if the reserves benefits were not included.

Efficiency Is The Most Reliable Resource

Energy efficiency is the most reliable resource in which a utility can invest. Unlike any type of generating unit, efficiency investments are composed of hundreds or thousands of small, distributed units, each of which saves anywhere from a few watts (e.g., a compact fluorescent lamp) to a few kilowatts (e.g., a high-efficiency commercial air conditioning unit).

It has long been recognized that a utility network made up of a large number of small generating units provides a more reliable system simply because they will not all fail simultaneously. The same principle applies to energy efficiency investments, which are a large number of small energy-saving devices. But these go beyond this mathematical advantage in at least two ways:

First, the individual units (efficient light bulbs, refrigerators, and air conditioners) are, as a population, extremely reliable, far more so than any type of generating plant.[13] Energy Star windows, attic insulation, or variable speed drive in a commercial HVAC system are almost certainly not going to "fail" during a heat wave. Conversely, generating plants, transmission lines, and even distribution transformers are most susceptible to failure when under stress. Even the most reliable type of generating units (hydro turbines) have higher "forced outage rates" than energy savings devices.

Second, if one energy efficient unit does fail, such a "failure" often actually reduces electric demand (i.e., when a high-efficiency air conditioner breaks, the customer may be entirely without air conditioning – uncomfortable, but using less energy). The utility loses an "efficient" load, but nonetheless, the load goes down when the unit fails, generally reducing the load-related stress and threats to reliability on the system. When a generating plant or transmission line fails, it leaves the utility with the same load, and less ability to serve that load and with increased risk of a system outage affecting hundreds, thousands, or even millions of consumers.

Figure 5:

Peak Capacity Savings from Energy Efficiency Investments

Line		Lighting	Air Conditioning
1	kW Savings at Customer Meter	10	10
2	Coincidence Factor	0.25	0.75
3	kW Savings at Customer Meter at Peak (1 X 2)	2.5	7.5
4	Marginal Line Losses At Peak @ 20% (3 / (1 - 20%) -3)	0.625	1.875
5	kW Savings at Busbar (3 + 4)	3.125	9.375
6	Reserve Margin Requirement	15%	15%
7	Avoided Reserve Capacity (@ 15%)	0.47	1.41
8	kW Savings At Generation Level (5 + 7)	3.59	10.78

13 The most reliable peaking units have on-peak availability of about 95%, and forced outage rates of about 5%.

How the Smart Grid Can Enhance the Application of Energy Efficiency Measures

At the time of the system peak demand, line losses are highest and marginal line losses may be 20% or higher. For this reason, actions that reduce load at the time of the system peak are extremely valuable. As utilities invest in smart grid assets and learn to deploy them, avoidance of expensive peak load related costs becomes more feasible. The application of smart grid technology will enhance the application of energy efficiency measures by:

- **Accurately measuring conditions on the distribution system before and after the application of load management tools, so that the value can be accurately known.**
  For the first time utilities will be able to accurately measure voltage, load, and reactive power at the distribution level down to individual customers. Data will be available to determine the level of losses occurring on a circuit and what control actions are needed. For example, the data will show when and how to optimally adjust circuit voltage level to reduce demand or save energy.
- **Providing the ability to control or shift demand at peak times**
  Customer load can be reduced or shifted by application of smart thermostats, pool pump controls, water heater controls, appliance controls, etc. This is most valuable during peak load events when the combination of energy savings and peak capacity savings is at its highest.
- **Providing the ability to utilize/control distributed generation (i.e. fuel cells, batteries, solar arrays, PHEV's etc.) as needed.**
  Customers may invest in distributed resources and energy storage to reduce their peak demand as measured by their electric meters, which typically measure non-coincident peak demand. With smart grid tools, the energy control center can interface with distributed generation to provide additional capacity at the utility's peak time or store renewable energy during off-peak periods, both of which benefit the system, but might not be apparent to the individual customer.

These types of control may enable the utility to avoid load during the needle peak hours – when marginal line losses may exceed 20%, and when generation reserves are stretched thin at a much lower cost than building additional generation, transmission, and distribution capacity. This will have a small effect on the value of energy conservation measures, such as those described here, which provide savings for thousands of hours per year. However, it may provide significant cost relief to the utility and its consumers in avoiding the cost of seldom-used capacity, thereby adding great value to the types of measures that provide savings concentrated at the time of the system peak demand.

The measures mentioned above are part of the emerging *demand response* capability of smart grid, which promises to provide a verifiable *virtual* reserve of reliable capacity directly equivalent to a *spinning reserve* but at a much lower cost.

Summary: The Avoided Line Losses and Avoided Reserves Benefits of Energy Efficiency Are Very Important

This paper has attempted to highlight two often-overlooked attributes of energy efficiency investments.

First, energy efficiency measures typically provide significant savings at the time of the system peak demand, and that time occurs when the line losses are highest. The avoided line losses can add as much as 20% to the capacity value measured at the customer meter.

Second, because they are reducing loads, including marginal line losses, energy efficiency measures also reduce the level of required generating reserves.

Each of these benefits increases the economic savings provided by energy efficiency investments. The compounding of a 20% marginal line loss savings and a 15% reserves savings can produce a 44% total generating capacity benefit, over and above the peak load reduction measured at the customer's meter.

For peak-oriented loads like air conditioning, the annual capacity cost of generation, transmission, and distribution *capacity* needed to assure reliable service can equal or exceed the cost of the *energy* used during the year.

Add it all together, and the total capacity value of energy efficiency investments in peak-oriented loads like space conditioning can be as valuable as the energy savings are.

Marginal line loss calculations and avoided reserve requirements should be an integral part of any evaluation of the benefits of energy efficiency measures.

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability and the fair allocation of system benefits among consumers. We have worked extensively in the US since 1992 and in China since 1999. We added programs and offices in the European Union in 2009 and plan to offer similar services in India in the near future.
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RAP

Home Office
50 State Street, Suite 3
Montpelier, Vermont 05602
802-223-8199
www.raponline.org