BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: RESOLUTION REGARDING PROPOSED RULEMAKING TO ESTABLISH INTEGRATED RESOURCE PLANNING COMPONENTS AND REPORTING REQUIREMENTS FOR ENTERGY NEW ORLEANS, INC.	**DOCKET NO. UD-08-02**

Building Science Innovators Comments on Entergy New Orleans' 2015 Draft Integrated Resource Plan

Building Science Innovators [BSI][1] submits these comments[2] regarding the Entergy New Orleans' [ENO] 2015 Draft Integrated Resource Plan [IRP]. Following the 1) *Executive Summary* and a *Concise List of BSI's Recommendations*, justifications are found in 2) a *Critique of the Assertions by ENO and Various Intervenors Presented during the IRP Meetings*, as well as, 3) *Elaborated Recommendations* designed to enhance both the IRP results and IRP process.

EXECUTIVE SUMMARY

BSI is especially interested and applauds the actions of the New Orleans City Council [Council] to direct ENO to regularly engage in a quality IRP process. This is because of i) BSI participation and leadership within the New Orleans Energy Policy Task Force which recommended this *NOVEL* course of action in 2007, and ii) BSI's "Inverted Demand Compliant Construction — a Key to a Renewable Energy Future" [IDCC][3] 2014 original research and leadership at the nexus between building science and utility policy design which established consumer-installed battery systems as cost-effective and suggested that universal adoption may be a necessary step for a sustainable planet.

ENO's Draft IRP has fatal flaws and ENO should be directed to revise its IRP to address them.

However, the Draft IRP produced by ENO is fatally flawed and should be rejected by the Council. The Draft IRP is rift with flawed assumptions, modeling errors, and unsubstantiated conclusions. Four of the most egregious errors derive from the serious deficiencies in the way ENO utilized the IRP modelling software. ENO's four most serious modelling errors (among others) were: 1) failing to include batteries in the model despite the fact that batteries were already price competitive at the beginning of the IRP process and have dramatically declined in price in the past year; 2) failing to perform an industry-standard risk analysis; 3) failing to fully take into account the impact of EPA's Clean Power Plan, which has been in an open development process for several years although it was formally mandated earlier this month; and 4) failing to consider zero-capital-cost customer-owned solar power plants. A fifth fatal flaw is the "black box" data used by ENO for utility-scale solar. A sixth fatal flaw is that ENO's demand-side management (DSM) program success is paltry compared to what is already working at other utilities and a robust DSM program can more quickly close the gap between supply and demand than investment in a new, fossil-fueled electricity-generating plant.

With regard to the first error, installing batteries has been known to be more cost-effective than building peaking plants since before the beginning of the current IRP process. With only a few changes in regulatory policy, consumer-installed battery installations were already cost-effective two years ago, prior to the initiation of the current IRP process. Grid-connected battery installations have been recognized by a wide range of experts to have become cost-effective since late-2014, i.e., in the middle of the IRP planning process. The dramatic drop in battery prices during the last year is a game-changing event which goes to the core of ENO's assumptions and resulting conclusions. Despite all of this, ENO discounted battery storage early on, and this technology was never reconsidered.

With regard to the second error, an industry-standard risk analysis is the result when an extended list of optional solutions and an extended list of variable assumptions and their probability distributions are considered against each other in an automated fashion against various goals including the goal to minimize costs. Without performing an industry-standard risk analysis, ENO concludes that, a 300 MW combustion turbine [CT] is the best choice based upon risk despite the fact that the CT option did not "win" the competition in any scenario. In fact, nothing presented by ENO during the IRP meetings demonstrated that the "do nothing" option is more expensive than building anything, much less a new CT generating plant. The deficiencies in ENO's risk analysis are well highlighted when ENO's IRP is compared to the robust risk analyses performed by other utilities utilizing the same or similar IRP-modelling software.

With regard to the third error, ENO's Draft IRP, published as it was before the recent EPA Clean Power Plan announcement, could only conjecture that the Generation Shift option was a viable scenario. However, following the Clean Power Plan announcement, economic biases against CO_2

production are much more likely and substantial, and will more surely encourage more PV generation. Consequently, this watershed event means that the hypothetical "generation shift" scenario described in ENO's IRP may now be the most likely scenario. If that were the case, according to ENO's IRP, the best plan is build a 1.2 GW solar plant, not a 300 MW CT.

Compounding the failure to adequately price CO_2 projection is ENO's fourth error of only considered a utility-owned solar plant instead of customer-owned solar plants. ENO considered a solar plant within its IRP's alternative generator choices but determined that the solar option only "wins" the competition for best choice in the scenario that assumes very high CO_2 emission prices; this only happens because of the solar plant's very high capital costs. However, because customer solar power does not have any capital costs borne by the utility, the solar option should "win" in every scenario.

A fifth fatal flaw is ENO's use of "black-box" data to develop cost assumptions for utility solar. Instead of utilizing a public report on such cost assumptions, ENO commissioned a "proprietary" report which hides these cost assumptions in a black box which cannot be examined by the other parties or the public.[4] Such black-box data should never be used in an IRP, particularly on a fundamental core issue – the cost of power generation.

A sixth error is to fundamentally ignore the fact that ENO's demand-side management (DSM) program success is paltry compared to what is already working at other utilities. BSI explains how multiple DSM pathways can be easily employed to fill the projected 300 MW gap between supply and demand fast enough and much more cheaply than building a fossil-fuel-powered generator.

BSI submits that any one of the six preceding errors is a fatal flaw which makes ENO's conclusion that the best plan is to build a 300 MW CT without credibility. Accordingly, BSI submits that the Draft IRP should be rejected and that ENO should be directed to perform a new IRP utilizing a robust risk analysis similar to that performed by other utilities which takes into account:

1. one alternative resource option is "build nothing"
2. CO_2 emission price in light of the recent EPA Clean Power Plan announcement;
3. economics of battery storage when grid installed vs consumer installed;
4. economics of PV when utility owned vs consumer owned; and
5. economics of DSM in all four of its various forms:
    I. Energy-Efficiency,
    II. Demand Response,
    III. PV installations, and
    IV. Battery installations.

Furthermore, ENO should be directed not to utilize "proprietary" data prepared by outside parties which cannot be examined by other parties or the public.

The Draft IRP fails to adequately discuss how the closure of the Michoud power plant may affect ENO's planning reserve margins and ENO's membership in MISO.

A seventh major error is ENO's failure to adequately discuss how the closure of the Michoud power plant may affect ENO's planning reserve margins and ENO's membership in the Midcontinental Independent System Operator [MISO] wholesale electricity marketplace. ENO has often used this market to supply itself with power or sell ENO's power when prices were favorable. MISO often has a gross excess supply of power between midnight and 6 AM.

MISO has a membership requirement for a load center like ENO, namely, that ENO's "Planning Reserve Margin" of capacity must exceed its annual peak demand by at least 12% or 14% and this requirement will grow in the future to over 17% in twenty years. Therefore, shutting down Michoud could jeopardize ENO's membership in MISO. Because there is over 8,000 MW of capacity in excess of the demand needs within MISO, it is not in ENO's customers' best interest for ENO to close itself off from this rich buyer's market selling power. ENO's hidden agenda may be to close Michoud down in order to create a shortage in its planning reserve margin requirements so that ENO can claim that because no zonal resource credits (ZRCs)[5] are available to ENO, the only way to remain in MISO is to purchase a portion of another Entergy power plant. BSI urges in the strongest terms possible that the Council must require ENO to have a long-term agreement for the option to buy adequate ZRCs from Entergy in place prior to closing Michoud.

ENO's IRP's Main Argument

1. ENO's peak demand is and will be over 300 MW higher than can be economically furnished using its existing generators,
2. ENO's DSM's success is too slow to ever close the supply / demand gap, and
3. The best plan is build a 300 MW combustion turbine [CT] because this option minimizes risk.

BSI's Response

1. BSI agrees with ENO's first assertion but challenges what ENO assumes is a done deal: that ENO will soon shut down all of the Michoud power station. As noted above, Michoud should not be closed unless ENO can prove that this loss of generation will not adversely affect ENO's membership in MISO.
2. BSI challenges the nuanced implication which ENO has associated to its second assumption that *DSM cannot close the gap in a few years*.
3. Even if the supply / demand gap cannot be closed soon enough with various forms of DSM, BSI submits that ENO presented no credible evidence that the best option is building a 300 MW CT.

BSI recommends revisions in rate structure in order to stimulate DSM which will work together, help finance each other and close the supply/demand gap within a few years.

BSI submits that ENO's DSM is performing poorly for more than a dozen reasons. This is in sharp contrast to the success of Tucson Electric Power's[6] (TEP is about 2.5 times as large as ENO) DSM which is projected to continue to experience—twenty times as much as ENO's DSM's annual success each year for the next six years. Moreover, TEP's DSM program lowers peak demand at half of the cost (in $/W) of ENO's DSM program.

BSI also notes that there is an artificial distinction between various ways to use utility funds to "induce" drops in peak demand, a.k.a., DSM. Traditionally, the term "DSM" has not included any but the first of these ways to reduce demand:

a. Subsidizing energy-efficiency retrofits in buildings,
b. Using price signals to temporarily lower demand, (known as demand response (DR))
c. Subsidizing renewable energy installations, and
d. Subsidizing battery installations.

BSI submits that this distinction has been hampering ENO's DSM program design, grossly slowing down DSM's success and increasing its costs.

Therefore, BSI recommends that the Council should:

- Not pick the winner, or allocate or segregate resources among these four ways to reduce peak demand, but instead should create a *carrot and stick* approach that applies graduated charge increases and rebates to engage and transform the marketplace.

- Replace decreasing block rates with increasing block rates for residential customers and increases in the peak demand charges for other customers, as well as a menu of targeted, performance-based rebates. The cost of the rebate program need not exceed 5% of what ENO projected to spend for the proposed solar option. This will empower the marketplace to close the gap. BSI submits that the marketplace will do it faster and cheaper than ENO's proposal.

- Use the extra income from these rate increases to first completely fund the rebates and then lower the cost of energy for consumers whose consumption is limited to the first block within the rates.

The details of these recommendations are presented in summary form in the next section and in an elaboration of recommendations section at the end of the document.

Recommendations to improve the IRP process.

BSI's recommendations are not limited to how to close the demand/supply gap. The following recommendations are also given to improve the IRP process. The order of these recommendations reflects BSI's opinion about their importance.

- Compensate intervenors when their contribution to a regulatory decision saves money.
- Mandate that the IRP process has complete transparency.
- Mandate that the IRP is dynamically responsive to changes in fact.
- Mandate that the IRP conforms to industry standards in IRP quality including, but not limited to risk analysis.
- Mandate that an independent third party produces the analysis, run the meetings, and collect and publishes information.
- Provide for a minimum test for passing or failing the IRP process.

BSI also notes that similar tests should be instituted for other regulatory processes like the design of the DSM program and ENO's rate design.

BSI Supports Decoupling by which ENO can earn a profit without investing in new power plants.

ENO has an economic incentive to bias its IRP towards investing in new generation plants. The contract between ENO, ENO's ratepayers and the City of New Orleans is conventional and provides two stipulations: i) all cost of electricity is passed through to the customer with no profit, except that ii) the IOU is allowed to make a "fair" profit on capital improvements. There is currently a docket where ENO, the Council and intervenors are working on "Decoupling", i.e., finding an agreed upon alternative mechanism where the utility can make increasing profits without adding new capital investments. Although BSI is not an intervenor in that docket, BSI supports that process. BSI wants ENO to earn more profit without adding new generating equipment.

Accordingly, BSI recommends:

- ENO should not be allowed to own new generating plants; instead
- ENO should be rewarded for facilitating a future where the ratepayers of New Orleans have lower electricity bills, enjoy improved electricity outlet reliability, and use less fossil-fuel generated electricity.

CONCISE LIST OF BSI'S RECOMMENDATIONS

How should the Council engage City of New Orleans [CNO] ratepayers and the construction industry to rapidly and economically reduce peak demand in sufficient size and speed?

BSI believes any one the following three methods *CAN* displace 300 MW of peak demand in 5 years.

1. Incentivize much more robust, extensive, and cost-effective energy-efficiency retrofits (a.k.a., demand-side management [DSM]) by utilizing many of the means described in the Elaborated Recommendations section at the end of this document.[7]
2. Incentivize the installation of battery energy storage systems [BESS] in every building.
3. Incentivize and provide legislative support for Community Solar in two ways:
   - Promote 75kW to 3 MW solar farms at distressed property found all around the city.
   - Promote a system of small, 50 to 100 KW solar farms with 150 to 300 kWh of integral battery storage on many "key lots" of the city.

BSI considers all of the above, as well as Demand Response, forms of DSM.[8,9]

The Council should not pick the winner, allocate or segregate resources among these ways to reduce peak demand, but instead create *carrot and stick* mechanisms of graduated charge increases and rebates to engage and transform the marketplace.

A. Install smart meters throughout the ENO building stock. Each smart meter should have the ability to report consumption every 5 minutes. Residential customers should be the last to get them because they are the smallest users per building. In order to be eligible for rebates, discounts or power quality sales, customers must have smart meters.[10]
B. Change the rate structure from declining blocks to inclining blocks.[11]
C. Change the *demand charge* found in all except residential customers bills to a *utility peak demand charge* from what the customer had been paying as a demand charge by equal steps each year for five years until $20/KW/month. *Utility Peak Demand* for a building is the maximum measured KW consumption rate during any consecutive 15-minute period within the utility's 3 to 6 hour peak demand time of any day for a month of readings.[12]
D. Customers earn a 50% demand charge discount if they buy into a solar farm or install a rooftop system sufficiently large to displace at least 30% of their annual consumption.[13]
E. Rule that kWh's generated at a solar farm cannot be banked for future use; energy not consumed in a five-minute generation period is used to discount bills for low-income ratepayers.[14] Even better, set 10% as the preset amount allocated to low income.
F. Facilitate solar farms on key lots and/or economically distressed real estate.

G. Institute a rebate schedule to incentivize reduction in peak demand. Define "↓peak watt for 10 years" as the 10-year average demand drop during utility peak hours.
    a. Provide a \$1.50/"↓peak watt for ten years" rebate for an energy efficiency retrofit that reduces the annual bill of a particular consumer by at least 10%; accept RESNET certified, Home Energy Raters as 3rd party verifiers;[15] CNO retains ownership of associated White Certificates [WC].[16,17,18,19]
    b. Provide a \$0.75/"↓peak watt for ten years" rebate for purchasing part of a PV system. The utility retains ownership of the ZRC for the purposes of MISO but not an equity interest in PV systems partially financed this way. The CNO retains ownership of the associated Renewable Energy Credits [REC].[20,21]
    c. Provide a \$0.50/"↓peak watt for ten years" rebate for any purchase of part of a BESS. The utility retains ownership of the ZRC for the purposes of MISO but not an equity interest in battery systems partially financed this way.[22]
    d. Provide a \$0.20/"↓peak watt for ten years" rebate for any other kind of retrofit.[23]

H. Provide a mechanism whereby any ENO customer can sell power quality services, i.e., spinning reserve and/or frequency regulation, to ENO or MISO at competitive rates.[24]

I. Mandate that Real Estate Multi-listing services publicize energy ratings if available.[25]

J. Invite input by educational institutions, other industries or NGO's to propose regulatory changes or rebates that can invite their services or further lower ENO's DSM costs.

What should ENO do while waiting for these peak demand programs to have their full effect?

1. ENO should continue to satisfy unmet peaking energy needs with power from MISO.[26]
2. ENO should stop adding generation resources to the rate-base now and for the foreseeable future.[27]
3. The Council should terminate the existing regulatory paradigm by which ENO makes more profit only by building more generators and replace it with a new decoupling paradigm which rewards ENO for efficiency in delivering energy services.[28]
4. The Council should remove DSM from ENO's control and place it under the control of a third party administrator.[29]

What should the Council do to ensure that this IRP process and future IRP processes find optimal results?

Compensate intervenors when their contribution to a regulatory decision saves money.

TABLE OF CONTENTS

4. CRITIQUE OF THE KEY ASSUMPTIONS AND CONCLUSIONS OF ENO'S 2015 IRP

BSI's critiques (in italics) follow each item of the IRP's core assumptions and conclusions (in bold).

4.1 ENO states that shutting down Michoud is a pre-condition of the Draft IRP.

The Council should prohibit ENO from shutting down Michoud IF ENO's membership in MISO is jeopardized without Michoud.

BSI is opposed to decommissioning Michoud — at least in the short term — if without Michoud's capacity, ENO would be precluded from meeting MISO's Primary Reserve Margin [PRM] and then lose access to the cheap non-peaking power available within MISO as well as necessary, expensive peaking power as well.

MISO's minimum required PRM is currently 14.9% and rises to 17.3% by 2023.

"Planning reserve margin (PRM) requirement, based on MISO's Planning Year 2014 Loss of Load Expectation (LOLE) Study Report (November 2013). Table 9.1 shows the MISO System PRM from 2015 through 2023. The long-range PRM was assumed to continue at 17.3% through the remainder of the planning horizon. Table 9.1 MISO System Planning Reserve Margins 2015 through 2023 Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources. The chart shows the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP energy efficiency and demand response. The system capacity includes the capacity benefit of the RES Compliance portfolio."[30]

Table 9.1 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM Installed Capacity	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

If Michoud is shut down, ENO must obtain an equivalent amount of zonal resource credits [ZRC] to satisfy its PRM requirements.[31] *See Appendix A.*

Zonal Resource Credits are defined as follows:

"Zonal Resource Credit (ZRC) is a credit for owning resources that count towards MISO resource adequacy requirements. By selling ZRC's from capacity, an entity does not give up any transmission, ARR, or energy production rights, other than being required to meet the MISO Must-Offer requirement. ZRC's replace PRC (Planning Reserve Credits), which are part of the existing construct, and will be granted to resource owners in the same way that PRCs are currently granted. Under the current construct, resource credits (PRCs) can be applied anywhere in the footprint. Under the new construct, resource credits (ZRCs) are zone specific."[32]

This probably means that ENO can only stay in MISO if some other part of Entergy is willing to sell it ZRC's. Although it is clear that MISO in general has a large over capacity situation[33], it may be that most if not all of this overcapacity is north of St Louis. Zonal may mean that New Orleans cannot buy a ZRC from a supplier north of St Louis, and all of members of MISO south of St Louis are parts of Entergy.

Thus, ENO can only stay in MISO at minimal increase in capital cost repayment obligations, if Entergy outside of New Orleans agrees to sell it ZRCs to ENO.

ENO's hidden agenda may be to close Michoud down in order to create a shortage in its planning reserve margin requirements and claim that because no ZRCs are available to ENO that the only way to remain in MISO is to purchase a portion of another Entergy power plant. BSI urges in the strongest terms possible, that the Council must require ENO to have a long-term agreement for ZRCs in place prior to closing Michoud.

4.2 ENO reviewed grid-side battery installations in their preliminary review of competing supply side resources and concluded that battery storage was not sufficiently cost-effective to make it into the set of alternative resource options used in the comparison studies used later in the IRP process.

BSI never recommended grid-side battery installations; at every public meeting BSI recommended consumer-installed batteries. This is the case because BSI presented a full, 20-year internal rate of return analysis[34] that showed that this could have been an economical purchase from the customer's point of view in 2013. Among the consequences of this decision:

- *Each home with such a system and used as recommended would*
- *Contribute nothing to ENO's peaking load*
- *Contribute nothing to ENO's load-following load*
- *Contribute peaking power to ENO to allow ENO to somewhat offset its need for expensive miso power*
- *Contribute frequency regulation services to lower the cost of that service to ENO*
- *Shift the burden of electricity reliability away from ENO, and*
- *All of this with no capital costs shifted to ENO and no costs shifted to the non-participant.*

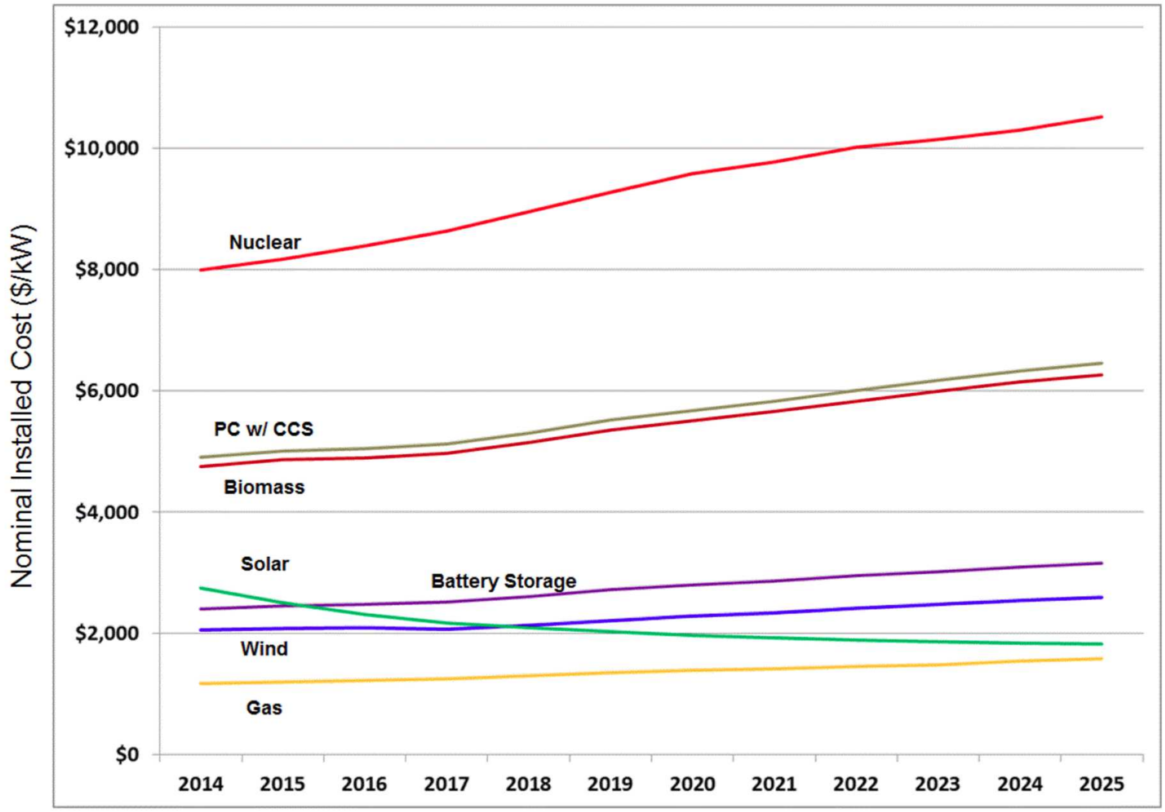
The battery system BSI studied is actually installed within a home in New Orleans and was deemed a prudent investment by all residents of the home simply because of the added resiliency against future power outages like those created by hurricanes. Its components were purchased in 2013 and include the highest quality batteries commonly used for off-grid homes in the US at that time: AGM lead-acid.

The system performance BSI assumes is complete inversion of demand, i.e., deep cycling of the batteries every day via charging between midnight and 6 am to provide sufficient energy and power for the home to be effectively off-grid the rest of the day. By considering the economic value of resilience against expected power outages as well as access to selling frequency regulation to ENO or miso, the battery backup system pays for itself faster than a similar PV system. That analysis assumed either no PV or battery subsidies or equal subsidies to get the same result.

However, BSI is happy to discuss grid-side battery installations because, during the one-year IRP planning process, li-ion battery prices have dropped so much and so rapidly that a bevy of top-notch industry experts agree that grid-connected battery systems more cost-effective than gas-fired peaking plants in 2015.

WHY NOT BATTERIES? ENO "EXPLAINS" THEIR RATIONALE FOR THIS CONCLUSION BY REFERENCE TO THE FOLLOWING GRAPH FOUND ON PAGE 8 OF ENO'S IRP.

Figure 2: Projected Installed Cost of Supply-Side Resource Alternatives



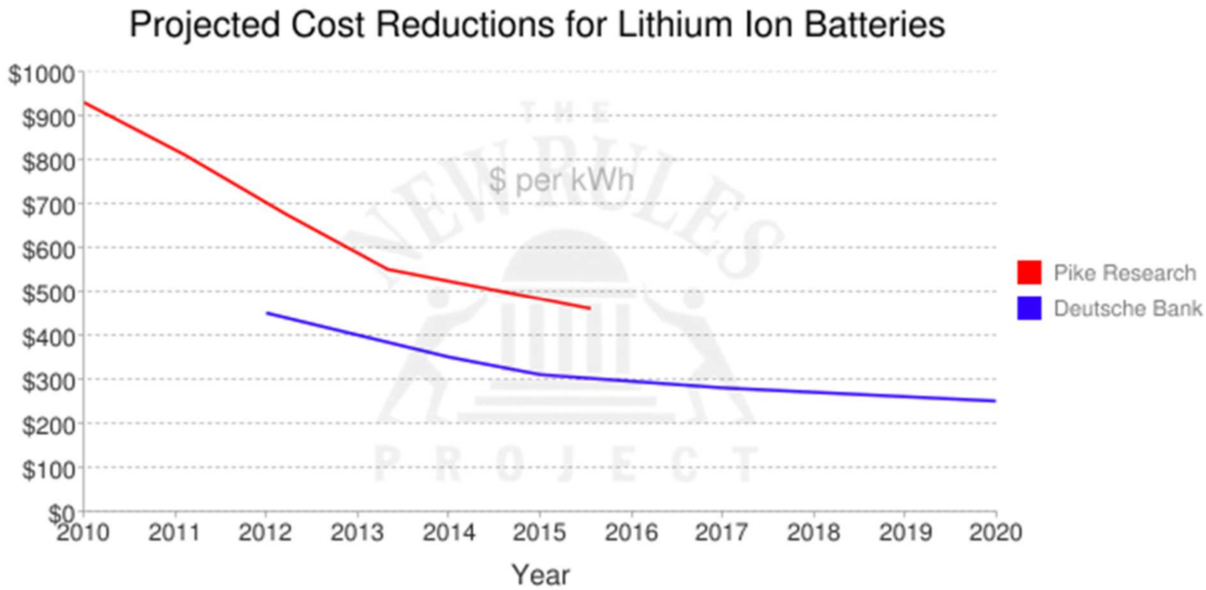
BSI submits that, except for the 2014 point on the violet, "battery storage" curve, the rest of the graph for battery storage is completely wrong.

Although ENO's initial, 2014 data point for battery storage is approximately correct, BSI's corrected curve has a declining slope that is lower than the slope shown for solar — instead of ENO's projected, slow 40% increase over the next 20 years.

The battery storage system described in detail within the IDCC talk [reference and page number], purchased before 2014[35] translates to a value of $2300/KW, just above the first data point on the purple curve. However, this system used lead-acid battery technology.

Although, lithium-ion batteries have greater first costs than lead-acid, they are rated to have about 7 times as many cycles at 40% depth of discharge. Assuming, one 40% discharge cycle per day, one set of AGM batteries will last 1500 days or just over 4 years; while one set of li ion batteries would last almost 7 times as long—or about 28 years. (See appendix B.)

So, what do li-ion batteries cost and what are they expected to cost? The following graphic was published in September, 2011—more than 2 years before the start of this IRP process. [36]



Note that when that graph was published, li-ion batteries cost $800/kWh and that deutsche bank predicted what actually happened; tesla motors released its tesla wall in the spring of 2015 selling for $300/kWh for residential use and $250/kWh for grid scale batteries. [37]

However, if we use the pike research prediction from 2011 for a 2014 battery purchase, the predicted price would have been $500/kWh. If you use this figure and plug it into the economics just explained for the previously discussed battery system, [38] *that system would have cost a total $16,000 for an 8 KW system or $2000/KW. This number is about 90% the value of the first point (2014) on ENO's graph.*

However, it turns out that the average real price of li-ion batteries in 2014 was lower than $200/kWh. That is explained in the next quotation, published in October, 2014; because that is the price tesla paid to another supplier for fully formed batteries, not the price tesla used to sell these batteries to the general public. In that case, the previous figures change from $4000 for 8 KW of inverters and $4800 for 24 kWh of batteries. Then the cost changes to $8400 / 8 KW or $1050/KW.

In an article published October 13th, 2014, Sam gaffe of Navigant research noted that grid-battery storage systems that employ li-ion batteries are cost-competitive compared to natural gas-fired peaking plants at the prices of that date. (See appendix c.)

BSI asserts:

- *The commonly sold price for li-ion batteries in 2014, was around $400 to $500/kWh making the price of a grid competent battery system to be around $2000/KW.*

- *2015 price of batteries for sale for grid application by tesla motors today, is $250/kWh. When used with an 8 KW inverter system, $4000 for the inverters and $6000 for 24 kWh of batteries allows the recalculation that today's grid price is $1250/KW.*

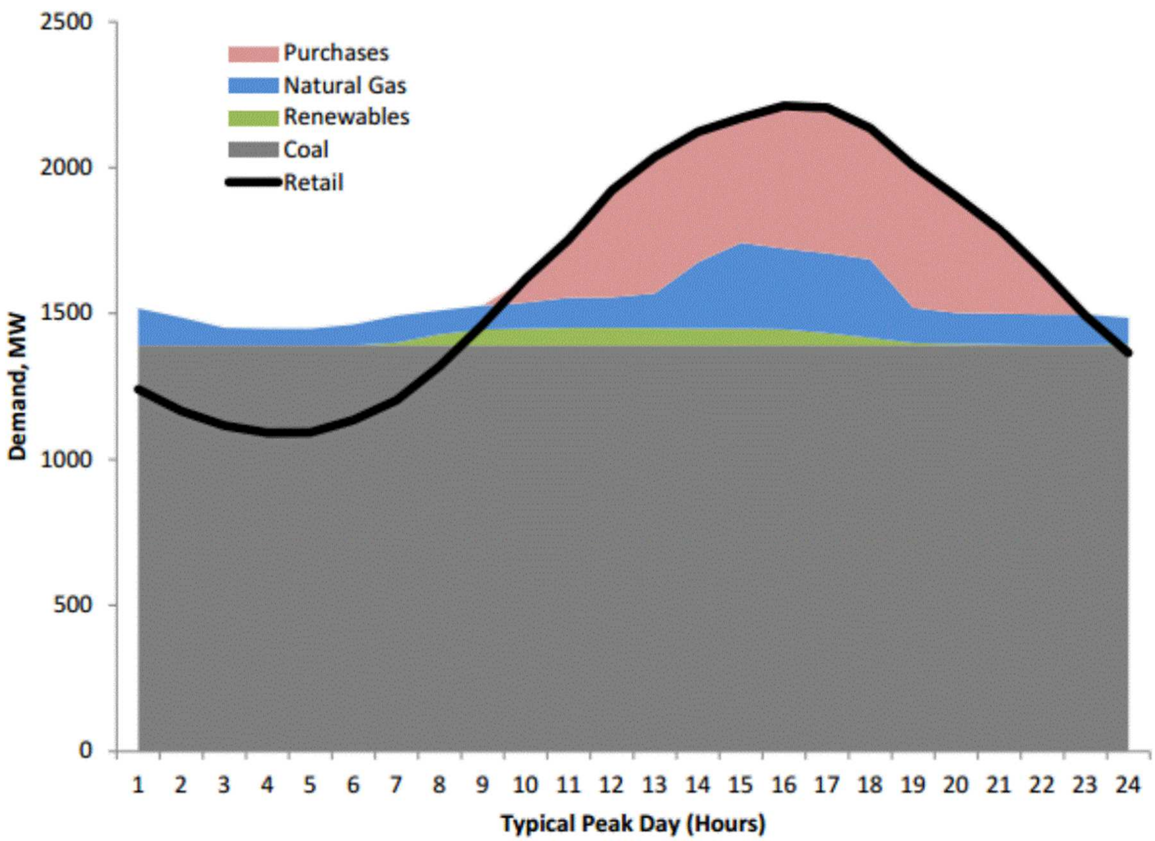
Conclusion. Although the first (2014) point on ENO's graph was not too far off, the slope of the curve was dramatically wrong. ENO's curve shows slow growth to 140% of the first data point over 20 years; whereas during the year that the IRP was produced, 2014 – 2015, the price of battery storage decreased to 5/8 or 62% of the price it had during 2014. This shows that not only was the price of batteries dropping instead of rising, but it is actually dropping much faster than solar PV.

Is battery storage sufficiently cheap to be cost-effective on the grid? *It would seem that this question was already answered above, but in fact the previous answer belies the fact that batteries have many uses besides price arbitrage, i.e., buying when energy is cheap for later use when energy is expensive.*

The previous quotation from Navigant Research says that at prices of $230/kwh batteries favorably compete with conventional generation and that comparison is simply based upon price arbitrage.

The next graphic comes from Tucson electric power's 2014 IRP, it shows the typical summer day demand (black curve) and supply (colored blocks). Notice that the base loaded coal plant produces more power than the demand from midnight until 8 am! This is excess energy that the utility cannot sell to anyone. Price arbitrage picks up this cheap energy and moves it to later in the day.

Chart 17 – 2013 Example Summer Day Dispatch



The right question is at what li-ion battery price do the full set of benefits of grid-side battery storage outweigh the costs?

There are other services of batteries that sweeten the economics for batteries… these will be discussed at length in the elaboration of recommendations section of the document. In fact, many of the most lucrative of these other benefits were already mentioned four pages back in this document—where the benefits of consumer-installed battery systems are highlighted. The following quote discusses the economics of grid-battery storage by considering a much broader array of battery benefits than price arbitrage.

"… Texas utility Oncor commissioned a [Brattle] study [entitled] [the value of distributed electricity storage in Texas [39]] of whether it would be cost-effective to deploy [grid-side] storage throughout the Texas grid (called ERCOT), placing the energy storage at the 'edge' of the grid, close to consumers.

The conclusion was an overwhelming yes. The study authors concluded that, at a capital cost of $350 / kWh for lithium-ion batteries (which they expected by 2020, but which tesla has already beaten), it made sense across the ERCOT region to deploy at least 15,000 MWh of battery storage. (That would be 15 million kWh, or the equivalent battery capacity of nearly 160,000 tesla model 85ds.)

The study's authors concluded that this additional battery storage would slightly lower consumer electrical bills, reduce outages, reduce the need to build added capacity (by shifting the peak, much as a home battery would), and similarly reduce the need to build additional transmission and distribution lines."[40]

It should be noted that the referred to assertion by brattle, assumes:

- *A very conservative estimate of the value of reliability to customers*
- *The batteries are not installed in the home or commercial building*
- *The [current, limited] opportunities within RECOT for energy arbitrage.*

All of these assertions compromise the benefits, although the 2nd assumption also lowers the cost of the batteries.

In particular, Brattle's estimate of the benefit value of electricity-reliability provided to customers is less than half of what Pepco reported.[41] By putting batteries within buildings, the user can switch to a different mode when there is power outage: from maintaining full services, to some kind of emergency mode, and thereby extend the benefits.

4.3 ENO employed the AURORAxmp® software to model its current and future economic operating conditions. Although created by a third party, the software's input and conclusions were handled and presented to the IRP meetings by ENO personnel.

- *BSI studied this software.[42] Following review of some published IRPs of other utilities[43] and an extensive conversation with Aurora's technical support,[44] BSI learned that risk analysis is a mature and significant feature (albeit slightly restricted for some clients[45]) of the Aurora software. After application of modest computer skills, battery storage can be modelled within AURORAxmp®.*

- *ENO's methodology has a number of serious errors which lead to erroneous conclusions.*
  - *Batteries were not included; (perhaps this happened because ENO announced that they "knew" batteries would not be economical).*
  - *An industry standard risk analysis was not performed.*
  - *ENO assumed a new PV system could not go not on-line until 4 years after approval,[46]*
  - *ENO assigned zero value to off-peak PV produced energy,*
  - *ENO did not model* the do nothing different that current actions *option, and*
  - *ENO combined the Combustion Turbine [CT] option with three mixes of renewable energy; but did not do the same for the Combined Cycle Gas Turbines [CCGT].*

- *BSI also notes that ENO's Draft IRP, published as it was before the recent EPA Clean Power Plan announcement, could only conjecture that the Generation Shift option was a viable scenario. However, following the Clean Power Plan announcement economic biases against* CO_2 *production are much more likely and will more surely encourage more PV generation in this and future IRPs.*

  The real upshot of this can be appreciated by comparing two paragraphs, the first from page 24 of ENO's IRP and the second from a May, 2015 report from Synapse Energy,

  ENO's estimate for the price of CO_2 *is roughly ¼ of that estimated by Synapse Energy.[47] Synapse Energy's top side forecast is even lower than Puget Sound's Forecast in their 2013 IRP.[48]*

  In particular, this means that the hypothetical "generation shift" scenario described in ENO's IRP may now be the most likely scenario. And that means, according to ENO's IRP, the best plan is build a 1.2 GW solar plant.

CO_2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether national CO_2 legislation will eventually be enacted, and if it is enacted, when it would become effective, or what form it would take. In order to consider the effects of this uncertainty on resource choice and portfolio design, the IRP process evaluated the effect of CO2 regulation by analyzing a range of projected CO_2 cost outcomes. The reference case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The mid case assumes that a cap and trade program starts in 2023 with an emission allowance cost of $7.54/U.S. ton and a 2015-2034 levelized cost in 2014$ of $6.83/U.S. ton.[16] The high case assumes that a cap and trade program starts in 2023 at $22.84/U.S. ton with a 2015-2034 levelized cost in 2014$ of $14.61/U.S. ton. By evaluating a range of potential outcomes, the IRP is better informed regarding the impact that the extent and timing of CO_2 regulation can have on the optimal mix of resources.

The following Table 5 is found on page 26 of ENO's IRP:

Table 5: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
Electricity CAGR (Energy GWh)[19]	~1.0%	~1.0%	~0.40%	~0.80%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Price ($/MMBtu)	Reference Case ($4.87 levelized 2014$)	Low Case ($3.84 levelized 2014$)	Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
CO_2 Price ($/U.S. ton)	Low Case: None	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $14.61 levelized 2014$

1.3. Synapse's 2015 CO_2 Price Forecast

Based on analyses of the sources described in this report, and relying on our own judgment and experience, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2015 to 2050. In these forecasts, the proposed Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2014 dollars per short ton of CO_2.

- The **Low case** forecasts a CO_2 price that begins in 2020 at $15 per ton, and increases to $25 in 2030 and $45 in 2050, representing a $26 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which the final version of the Clean Power Plan is relatively lenient and readily achieved, and a similar level of stringency is assumed after 2030.
- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton, and increases to $35 in 2030 and $85 in 2050, representing a $41 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals. The stated goals of the Clean Power Plan are achieved and science-based climate targets are enacted mandating at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.
- The **High case** forecasts a CO_2 price that begins in 2020 at $25 per ton, and increases to approximately $53 in 2030 and $120 in 2050, representing a $52 per ton levelized price over the period 2020-2050. This forecast is consistent, in the short term, with a more stringent version of the Clean Power Plan, as well as a recognition that achieving science-based emissions goals by 2050 requires significant near-term reductions. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2025. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

4.4 ENO believes that the Michoud power plant should be shut-down very soon; this will create a 300 MW shortfall of peaking power and has concluded that this problem will be most economically resolved by building a new generating station.

- *Unless ENO needs the Michoud plant to complete its minimum Planning Reserve Margin to stay within MISO, BSI agrees with the decision to shut down the Michoud Gas Powered Plant.*
- *BSI did not observe a presentation by ENO within the IRP which demonstrated that building new generating stations is more economical than doing what ENO is already doing: that is, buying energy from MISO.*

i) ENO has been purchasing power from MISO whenever it was cheaper.

BSI points out that, in the recent past, ENO has often purchased peaking power from MISO that Michoud could have provided, because MISO's power was more economical to do so.

ii) ENO did not "prove" its assertion that building a plant is cheaper than buying from MISO. The IRP presenters did not dispute the fact that MISO power would be available and sufficient to meet ENO's needs, but argued that this option would be more expensive than building its own generator.

This contention was not proven because

i) The "build nothing" option was not directly compared to the three, "build something" options and,

ii) Batteries were not included in the modeling.

4.5 ENO used the modeling software to consider six generation options—each chosen to provide 300 MW of peaking power and come on line in 2019: four options utilized a Combustion Turbine [CT], where three of these utilized a smaller turbine and had various mixes of renewable energy; one option was a Combined Cycle Gas Turbine [CCGT]; and one option was a much larger solar plant.

Although ENO evaluated six sets of generation options to meet the 300 MW shortfall (however based on the unrealistic generation capability of wind in or near New Orleans and the other two options that contain hybrid pairing with CT), ENO's IRP calculation results indicate that three options stand out as most realistic.

Option A. 300 MW Combustion Turbine [CT], to run on natural gas
Option B. 300 MW Combined-Cycle Gas Turbines set [CCGT], to run on natural gas
Option C. 1,200 MW Solar System, which did not include batteries

BSI points out that two options are glaringly missing:

Option D. Keep doing business just like ENO has been doing before decommissioning Michoud, i.e., build nothing new and continue buying peaking power from MISO as needed.

Option E. Build battery bank(s) sufficient to buy off-peak power from MISO to store electricity for later use and place power onto ENO's grid during peak times.

- *Without modelling Option D with its software, ENO has no right to assert a key idea within Assertion 2, that building ANYTHING will be cheaper than not building something.*
- *Without modelling Option E, ENO cannot argue that a generator will lower costs more than a battery.*
- *BSI also points out that with the large number of utilities being required to conform to a Renewable Energy Portfolio standard and additionally, in light of the recent EPA, Clean Power Plan addendum to the federal Clean Air Act, more and more renewable energy will be entering the grid. This means that beyond the excess capacity already present within MISO between midnight and six AM,*[49] *the above two driving effects encourage BSI to believe that there will be more of such cheap non-peak wholesale power available for purchase into the future. BSI doubts that ENO modelled this excess and growing renewable energy available within MISO.*

4.6 Because ENO did not consider using batteries at all—despite the fact that batteries are often employed on both sides of the meter to store cheaper, non-peaking energy to provide power during peaking hours. It is no coincidence that ENO assigned energy produced by the PV system during off-peak hours to have zero value. ENO personnel pointed out that the solar option was somewhat more undesirable than options A and B partly because the excess off-peak energy it would produce could not be reliably sold (at all, much less) at a profit through MISO.

BSI submits that the last sentence of 4.6 which states that excess off-peak solar energy could not be reliably sold at a profit through MISO and statement 4.4.ii (that MISO's power is more expensive than building its own generator) are somewhat in contradiction because statement 4.ii asserts that MISO's power is too expensive for ENO to buy, and statement 4.6 asserts that MISO's off-peak prices will be too low (to help justify the building of a solar power plant). This apparent contradiction can only be explained by recognizing that the wholesale price of power is highly time-dependent. Given that fact, it is even more significant and perplexing that ENO refused to consider batteries in the IRP because batteries can potentially eliminate the problem of time-dependent variations in energy cost.

BSI is not alone in its contention that batteries alone can supply peaking energy; no peaking plants are needed. In fact, that is an opinion shared by other utility executives and expressed at a conference held before the beginning of the IRP planning process.

> *"Utilities and energy project developers are now considering batteries as alternatives to traditional grid infrastructure, such as substation upgrades and natural gas-fired "peaker" power plants that only run a few days a year, according to industry executives who spoke at the Utility of the Future conference in Washington D.C. last week. Once the price of energy storage goes below US $300 per kilowatt-hour, batteries could transform how power is delivered, they said."*[50]

- *At the first IRP meeting, ENO's conclusion, that batteries are too expensive, can be excused because the above quote was from a very recent conference and may not have been known to them at that time; however after repeated messaging on this point by BSI at most of the IRP public meetings, ENO may not be as easily excused.*
- *The quoted assertion only assumes the economics of batteries when installed on the utility side of the meter; however a late summer 2014 presentation by BSI shows that if installed on the consumer side, the economics of batteries greatly improves — sufficiently to allow $400/kWh batteries — which were commonly available over two years ago.*[51]
- *Moreover, Tesla came out with the Tesla Wall in spring 2015, which sells for $300/kWh if under 100 kWh, and even cheaper if larger.*

4.7 In the past few years, ENO's Demand-Side Management [DSM] program has displaced around 2 MW of peak demand per year. ENO's IRP projects further peak demand reductions by another 40 MW in the next 20 years at a cost near $1/W.[52] DSM's success at reducing the demand of its customers has been linear with ENO investment; that is, more demand reduction in the future can be expected to pay back at no better or poorer than the same $/W as previous investments. Thus, ENO contends that <u>into the future, its DSM activity cannot displace a 300 MW generation shortfall fast enough to substantially alleviate the need for installing more generating capacity. That is, ENO does not believe that it can reduce the demand of its customers sufficiently or fast enough to avoid building a power plant.</u>

BSI contends that ENO's conclusion is incorrect because:

- *Compared to some DSM programs, ENO's DSM has produced exceptionally poor results — for example see Tucson Electric Power's 2014 IRP.[53]*
- *ENO's DSM's success is also outrageously poor because of its design—it is not even trying to exploit many, much less, most opportunities to lower demand; more than a dozen ways are overlooked. These are briefly listed below; however, examples and better explanation of these categories are provided in great detail in the Elaborated Recommendations section.*

<u>*Perhaps the biggest problem is the fact that ENO controls the DSM done on its behalf.[54]*</u>

<u>*Perhaps the second biggest problem is that the DSM plan was designed and is administered by out-of-state consultants.*</u>

In addition to these two, ENO's DSM program

1) *underpays the consumer for energy-efficiency retrofits,*

2) *does not exploit the full range of cost-effective retrofits,*

3) *only awards success by "deemed savings" and provides no award for performance-assured savings — which can be much greater and have a lower cost per W of reduced peak demand,*

4) *only promotes energy-efficiency by direct and shared investment in a building: this is too restrictive and impedes invention and market transformation,*

5) *fails to address any of the 3, major, split-incentive problems, e.g., the tenant-landlord problem,*

6) *ignores retrofits in existing buildings that save much energy by focusing upon much more economically-significant problems like moisture control or worker productivity,*

7) *takes no steps to repair or circumvent broken building codes; faulty DOE, EPA or FEMA decisions; short-sighted manufacturers' activities or industry standards that impede energy-efficiency,*

8) *fails to employ highly cost-effective retrofits that lower peak demand and raise kWh use,*

9) *fails to employ time-of-use pricing or any other kind of Demand Response (DR) which cause retail rates to reflect wholesale prices—these can be cheaper in $/W than standard DSM programs,*

10) *restricts customers from selling the spinning reserve service to ENO or MISO,*

11) *restricts customers from selling the frequency regulation service to ENO or MISO,*

12) *restricts customers from selling electricity at near wholesale prices during peak times,*

13) *sets the demand charges on commercial and industrial customers far too low,*

14) *provides no mechanism to facilitate PV installations, and*

15) *provides no incentive to help customer's buildings have more reliable electricity by purchasing their own battery back-up power supply; moving toward such a situation will lower the need for utility reserve margins and placing more batteries in the system facilitates all of the above means of lowering demand and the costs of the utility.*

4.8 At the last two IRP public meetings, BSI publicly pointed out that, although called a Demand Side Management program, ENO's DSM (like most DSM programs in the United States) should be more accurately called an "Energy Efficiency" Program, because all it really does is "buy" reduced kWh consumption instead of more directly buying reduced demand, i.e., measured in W.

Nevertheless, such DSM programs are typically substantial and cost-effective from both the customer's and utility's points of view, even though load reduction only occurs as a by-product of pursuing energy efficiency. However, as is explained above in number 3, ENO's DSM does this at $1/W, the best value as measured in dollars/W for money administered by ENO presented anywhere in the IRP.

4.9 BSI agrees and extends a comment made by the Alliance for Affordable Energy that: unlike the poorly named DSM program reviewed in the IRP process, ENO actually has a demand response [DR] program which is more accurately a *pure* demand-side management method. Although ENO refused to discuss it in the IRP, use it or expand it; it can reduce demand at lower $/W costs.

BSI believes that unlike ENO's DSM plan, a process focused upon demand response [DR] will reduce demand at significantly less than $1/W, i.e., lower than ENO's current process. DR is growing in popularity and effectiveness among utilities in the United States. DR can be done with a variety of tools. One of which, real-time pricing, is so popular in New York that customers actually pay ComEd to get access to it.

To compare the cost-effectiveness of DR to typical energy efficiency programs note:

- *"Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized. • Price-based demand response such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high. • Incentive-based demand response programs pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices."*[55]

- *"Despite barriers to widespread participation in demand response programs, the FERC's 2012 State of the Markets Report notes a substantial increase in capacity enrolled in demand response programs, rising from 3 gigawatts (GW) of capacity in 2007 to 12 GW in 2012. The report states that demand response programs are becoming an increasingly important resource for grid operators during periods of system stress."*[56]

4.10 BSI submits that rooftop solar installed in New Orleans has displaced 9 MW of demand, i.e., more than half of that effected by ENO's DSM process and did this at no cost to ENO or to any its rate-payers except those few who voluntarily installed their own rooftop solar systems. Moreover, both the number of installations and the effect of each installation on peak demand can be very cost-effectively and significantly enhanced. Therefore a distributed system of solar systems can do the job of Option C at zero cost to ENO and need not be nearly as big as ENO contends.

Although an ENO presenter said New Orleans has 30 MW of PV, "Shining Cities 2015" reported 36 MW.[57] 9 MW is used because ENO assigns a 25% CF to PV.

BSI submits that the 36 MW of PV installations realized in New Orleans occurred despite the fact that about 90% of New Orleans buildings' owners and occupants consider themselves ineligible.[58] There would have been more residential solar if there were no solar siting issues associated with

- *i) shading trees,*
- *ii) inappropriate roofs,*
- *iii) aesthetic concerns,*
- *iv) the Central Business District—where electricity may not run backwards,*
- *v) tenant-landlord situations, or*
- *vi) Capital accumulation which was hampered because of recovery from Katrina, the BP oil spill and the 2008-2009 recession.*

BSI notes that 36 MW implies that rooftop solar sits on 2%-4% of New Orleans residences. If we can avoid these barriers, New Orleans can easily have ten times as much installed PV.

Moreover, the actual amount of peak power displaced by a PV system depends upon how batteries are integrated into these systems—as is shown in the Solar City graphic within the comments regarding the 15th assertion. Thus the peaking power displaced can be larger than the 25% demand reduction ENO assigns to a PV system without batteries!

Solar farms and other creative solutions to these problems have, by-in-large, not been significantly explored in New Orleans. However, looking to other cities and states — many solutions have been employed—such programs are described in the Shining Cities 2015 reference.

However, even the Shining Cities 2015 Report ignores a higher solar penetration potential into the marketplace given a push for PV that can be generated from higher demand charges. Commercial customers would be much more interested in installing PV integrated with batteries if the demand charge was much closer to the real cost of new peaking plants, i.e., which should be around $25 kW/month [59]— instead of the paltry demand charge of $6/KW/month currently set within some ENO commercial rates. In fact, one reason Solar City does not do business in our marketplace is precisely because of Entergy's unrealistically low demand charges. Moreover, in the current utility paradigm, the utility has nothing to gain to help solve these problems. However, BSI has come up with additional solutions for these problems as well.

4.11 ENO modelled the 1.2 GW solar plant as an appropriate "competitor" for the 300 MW available from either Option A or B by presuming a 25% capacity factor [CF]. ENO's IRP modelling assumptions included that any power or energy produced by the 1.2 GW solar plant in excess of the 300 MW during peaking power or produced outside of peaking times would have negligible value.

Because solar power is a non-dispatchable electricity producer, it cannot be throttled like a gas plant and therefore will not, on average, produce power at times only coincident with the times of near peak demand even though a large percentage of its output occurs at such times. ENO assigned this 25% CF in order to account for this problem so that Option A and Option B can be effectively compared to Option C. Because solar energy does not always make power at peak times or reliably make power at any time, such power cannot participate in the daily power auctions held within MISO.

A substantial part of the remaining 75% of the time, the solar plant can be expected to produce energy and power; however, ENO claims that this power has negligible economic value to ENO. BSI challenges this claim; see critique of assertion 6.

This means that ENO personnel may have biased the calculation against the solar option by discounting the value of its off-peak power production.

Moreover, the recent EPA rule 111d – Clean Power Plan *provides the opportunity to trade pollution credits between utilities. This trade is not based upon kW of generator size but instead upon kWh of production. Therefore a PV plant's off-peak production could be very valuable indeed.*[60]

4.12 Options A, B and C were compared in four feasible economic scenarios: Industrial Renaissance, Business Boom, Distributed Disruption, and Generation Shift.[61]

Table 5: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
Electricity CAGR (Energy GWh)[19]	~1.0%	~1.0%	~0.40%	~0.80%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Price ($/MMBtu)	Reference Case ($4.87 levelized 2014$)	Low Case ($3.84 levelized 2014$)	Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
CO_2 Price ($/U.S. ton)	Low Case: None	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $14.61 levelized 2014$

4.13 ENO's IRP analysis found the CCGT to be the most favorable in every scenario except the Generation Shift scenario—where higher prices for natural gas and new carbon taxes are imposed—in that scenario, Solar was calculated to be most favorable.

BSI finds fault with the timing of when these plants could be brought on line and begin generating electricity. In the model, none of the three options begin contributing energy until 2019. It can be presumed that a 300 MW plant (either CT or CCGT) could take as long as three years to complete construction. However, a solar plant, such as that in option C (particularly if built in phases), could be installed and brought on line much sooner and begin reducing the 300 MW power gap far faster than options A or B.

4.14 In every scenario, each of the power supply options were further analyzed by component costs: e.g., construction costs, fuel costs, etc. The solar option, i.e., Option C, had the lowest costs in every category except for construction within every scenario where it showed the highest cost. This means that if the solar option had substantially lower capital costs it would have been recognized as the best option for every scenario.

ENO calls capital costs for new investments: "Non-Fuel Fixed Costs of Incremental Additions" on page 14 of the Modeling Overview Section. It shows that the solar plant is projected to cost around $1.6B or $1.25/W. Because ENO projects that only 25% of this capacity is really useful, the "real cost"/W is four times $1.25, or $5/W.

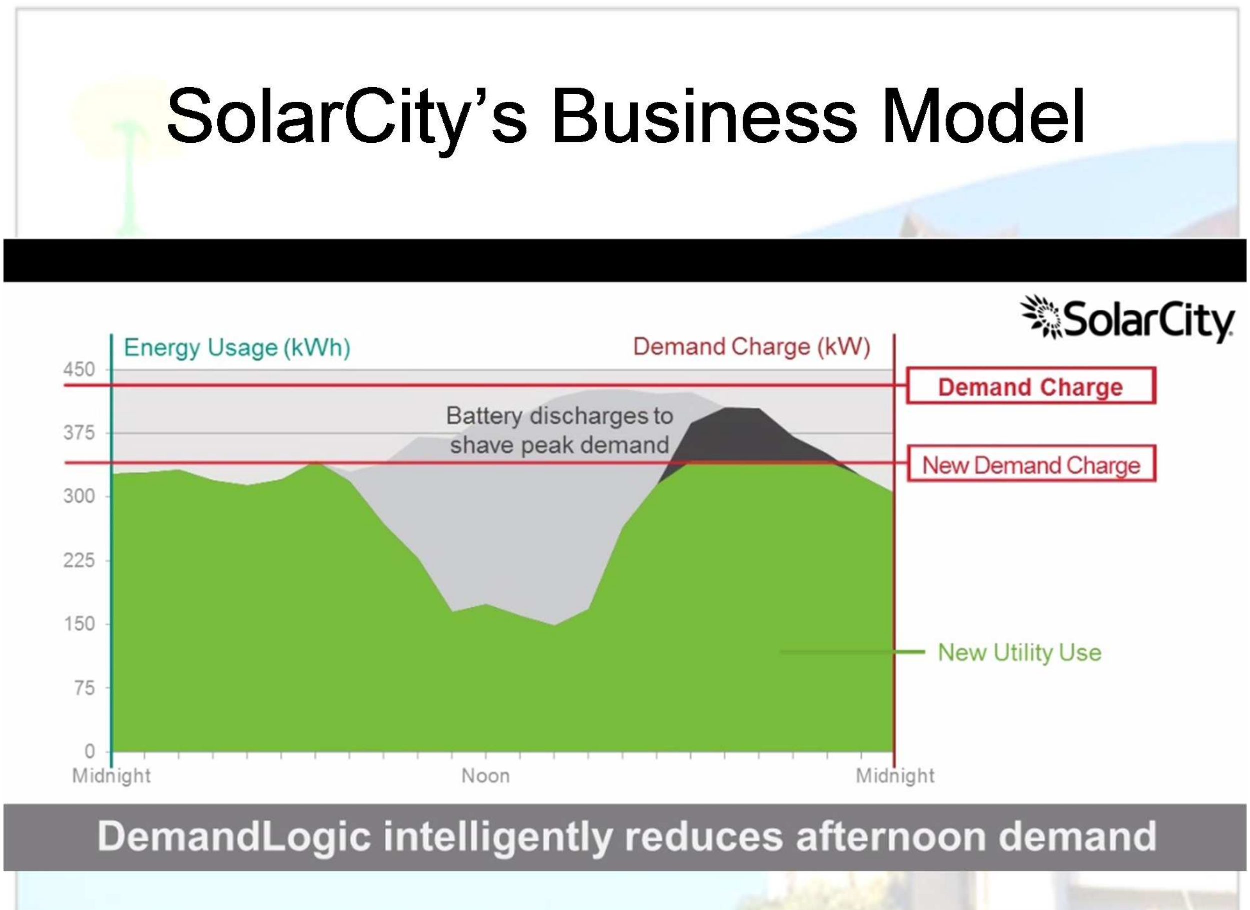
Although given out of order, this assertion supports the first of BSI's asserted deficiencies of ENO's DSM plan. Given that solar power generation costs around $5/W (according to ENO's figures), why is ENO only willing to buy DSM at $1/W?

Note that assertion 4.10 above points out that with a robust combination of community solar and rooftop solar, all of the needed solar capacity can be built at zero capital cost to the utility (and its ratepayers). This is because the full capital cost is completely borne by the owners of these solar farms.

Thus, empowering solar farms may be all that is needed to take the IRP's advice for a way to close the gap between supply and demand.

4.15 A few months before the end of the 2015 IRP process, ENO announced the construction of a 1 MW solar plant which will integrate batteries.

However ENO's own IRP ignores batteries. The efficacy of batteries is made abundantly clear by the adjacent image taken from Solar City's website where it points out that a commercial building can economically avoid much of its demand charges by installing both solar and batteries because the combination allows battery charging in the late morning in order to offset the need for higher demand in the afternoon.



4.16 Without performing an industry standard risk analysis, ENO concludes that a 300 MW CT is the best choice based upon risk. ENO was publicly informed regarding BSI's stated concern about the lack of a calculated risk analysis at the last two public IRP meetings.

The IRPs already referenced, namely those from Puget Electric Power and Tucson Electric Power, each do stochastic, automated analyses on a wide range of solutions and variable assumptions.

What is an "industry standard" risk analysis? Here are two somewhat equivalent definitions:

> "Using our power market planning and dispatch tools, Pace Global developed alternative portfolios for consideration and subjected the alternatives to rigorous uncertainty analysis around fuel prices, energy demand, capital costs for new units, and environmental policy outcomes."[62]

From the following example we can observe what one utility and its regulator considers an industry standard risk analysis:

> *An industry standard risk analysis is the result when an extended list of alternative resource plans and an extended list of variable assumptions and their probability distributions are considered against each other in an automated fashion against various goals including the goal to minimize costs.*

"Ameren Missouri's modeling and risk analysis consisted of a number of major steps:

1. Identification of alternative resource plan attributes. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and existing supply side resource options such as retirement, conversion and environmental retrofits.
2. Development of the baseline capacity position, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Pre-analysis was used to determine certain key base elements for alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility.
4. Development of planning objectives to guide the development of alternative resource plans.
5. Development of the alternative resource plans. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, the results of the pre-analysis conducted in step 3, and the planning objectives identified in step 4.
6. Identification and screening of candidate uncertain factors, which are key variables that can influence the performance of alternative resource plans. Ameren Missouri 9. Integrated Resource Plan and Risk Analysis Page 2 2014 Integrated Resource Plan Renewable Portfolios - Missouri Renewable Energy Standard (RES) - Balanced

7. Sensitivity analysis and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.
8. Risk analysis of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 7. This chapter describes these various steps and the results and conclusions of our integration and risk analysis."[63]

In the quoted example, 19 "Alternative Resource Plans" (which correspond to the "3 Options" in ENO's model) were reviewed against the results of a sensitivity analysis of 19 "Uncertain Factors" (which correspond to ENO's 4 economic scenarios) to create an optimization over 1215 branches of the resulting probability tree (which correspond to 12 branches on ENO's tree and ENO presented no discussion describing the probabilities of the branches). [See page 27 of the last cited reference.]

Missing in ENO's risk modelling are: 1) an <u>extended</u> list of "alternative resource plans" and 2) an <u>extended</u> list of "uncertain factors", and in an "automated sense", the 3) <u>Sensitivity Analysis</u> and 4) <u>Risk Analysis</u>, i.e., the last two steps should be done via an automated and stochastic inquiry into possible best and worst cases.

Neither of the two automated steps were done in ENO's IRP and the IRP used quite abbreviated lists of "alternative resource plans" and "uncertain factors".

ENO, as a part of Entergy, has a special responsibility to do an industry standard risk analysis as much as or more than any utility in the US. This is the case because in the late 1970's and early 1980's Middle South Utilities (the former name of Entergy) was severely economically thwarted during the construction of the Waterford III nuclear powered electricity generator. Cost overruns effected a many-fold underestimate of the eventual price of construction of Waterford III. Among the unforeseen and not considered risks were rising cost of capital and interest rates and great construction delays from increased regulation following the 3-Mile Island Disaster. Although these two planning issue oversights may have been forgivable and deemed outside of normal business practice, the mere question about whether it is more prudent to build a small number of large plants instead of a large number of small plants was never questioned. Literature on the last issue had been published before the mid 1970's. That literature asserted that the added reliability from a large number of small plants, shorter transmission lines, greater confidence that demand will rise to meet supply, and less need for extra power to meet a smaller reserve margin, provide more than enough ameliorating effects to balance the lower marginal cost of generation typically found in larger plants. Thus, it is inexcusable for ENO to prepare an IRP without doing a robust, automated risk analysis. Furthermore, it is grossly inappropriate for ENO to not do a risk analysis AND blithely assert that some unperformed risk analysis would pick option A despite the fact that the Aurora software never finds A the best choice for any scenario.

4.17 Implicitly, ENO and the New Orleans City council assert that the rate structure of ENO is as good as it should be in order to appropriately discourage increased demand at peak times, and the current equipment for metering electricity consumption cannot be cost-effectively improved.

BSI contends that ENO's commercial demand charge is unreasonably too low — which therefore shifts costs onto other customers. Because the largest set of customers are the residents, it is highly likely that the low commercial demand charge causes residential customers to subsidize commercial customers.

ENO's demand charges for commercial customers are as low as $6/KW/month. Compare that to what is common in California; there it ranges from $10 to $23/KW/month. The lower value is only available to customers with a renewable energy system.[64]

Although some may think that California's commercial rates are unreasonably high, Steven Fenrick of Power Systems Engineering contends that $25/KW/month is a very good approximation of the true cost of peak power that should be allocated to commercial customers.[65]

As stated below regarding process, the California Public Utilities Commission not only accepts public comments but pays intervenors for quality contributions to the rate-making process, and CPUC has been doing this for decades. Thus, it is highly likely that the CPUC has developed equitable rates, that is, rates that do not unfairly burden other rate classes.

Demand charges should be converted to <u>Utility</u> Peak Demand Charges. Utility Peak Demand for a building is the maximum measured KW consumption rate during any consecutive 15-minute period within the utility's 3 to 6 hour peak demand time of any day for a month of readings. This is only possible with smart meters.

One might think that this change will raise all commercial buildings' demand charges but there are some uses like churches that can find their demand charge actually drop.

BSI submits that a very effective and no cost way to lower peak demand is to replace declining block rates with inclining block rates. This was confirmed by an analysis done by Ameren Missouri.[66]

<u>*BSI submits that the cash flow generated by these two APPROPRIATE AND FAIR rate increases can both allow rate decreases for customers who should have been better rewarded in the past for their frugality and, more importantly, completely fund the rebates proposed in the Concise List of Recommendations section.*</u>

BSI contends that ENO should be distributing smart meters to its customers and in particular, these meters should be able to measure electricity flows in both directions and report them at least once every five minutes.

Smart meters that make measurements every five minutes allow the utility and the customer to accurately track retail electricity consumption or sales of power produced by the customer with the needed temporal resolution sufficient to allow tracking of the time-varying price of wholesale electricity. MISO sells electricity within the wholesale marketplace with prices that vary every 5 minutes; this is called the 5-minute real-time price.

Over 50 million smart meters have been deployed in the US. The cost of purchase and installation of each smart meter is less than $500.

Only by the use of smart meters can the City Council of New Orleans expect to meter "peak power" demand and consumption in a manner that is responsive to wholesale electricity price. ENO can only provide rates and subsidies explicitly focused upon Utility Peak demand side management, i.e., actually focused upon avoiding the utility's peak demand.

4.18 ENO contends that community solar cannot be executed without placing an undue burden upon non-participants and, most particularly, on the low-income, non-participants.

BSI submits that for almost all practical purposes and ways of perceiving this problem, ENO is wrong. However, assuming that this potentially real but very minor problem is deemed to be significant, a mechanism has already been implemented to overcompensate for this concern.

The following quote from a May 2015 publication implicitly defines Community Solar, presents arguments for it and outlines how it is financed and administered:

> *"Since 2010, residential solar installations have added more than 2,500 megawatts of clean energy - Enough to power more than two million homes for a year. Yet nearly 75% of residential rooftop space is prohibited from participating in individual programs such as net metering due to structural constraints or ownership issues. Community solar aims to resolve this impediment, providing restricted residents access to solar in a virtual fashion. An administrating entity will cover the cost of installing a large solar array and recoup these costs by allowing co-investors to buy into the project. Co-investing participants then receive the benefits from their share's solar energy production. "* [67]

This same report points out that I) there are Community Solar [CS] programs in 19 states including Washington, D.C. and ii) D.C.'s CS regulation requires that instantaneous excess generation is not "stored for future use" by the owners of the CS, but instead is given to the low-income community. These last two sentences are significant because they concern decisions made by utility regulators based upon due consideration for the passing the non-participant test.[68] *The first statement indirectly asserts that in over 18 jurisdictions, the regulator determined that the costs thrown onto non-participants either did not exist or was negligible. The second statement (ii) observes that in DC, whether or not negligible, DC's regulators decided to provide a consideration for low-income people that would defeat this argument. For the average net-metering customer, less than 10% of the energy generated by a PV system goes to the grid. This 10% gift to the low-income community is small enough to keep from spoiling the economics for ratepayers who will buy into a CS system in order to gain virtual net-metering.*

Although the Shining Cities Report is focused upon Utility-Sponsored, Community Solar, the Utility does not end up owning the solar plant; i.e., the solar plant does not end up in the rate base, it is owned by the tens to hundreds of individual residents who finance their shares. Neither does the original sponsorship have to be a utility; the economics of CS is well enough explained to outline a plan for a private investor to sponsor and own the whole project. Moreover, since CS programs described in this report go all the way back to 2005, most of the currently existing CS projects have significantly higher capital costs than a new CS system owner would have to pay today; namely, about $2.5/W was the stated capital cost in the example given in the guide whereas ENO's IRP predicts that they could build their utility-scale PV power plants at half that price.

4.19 ENO's IRP is a far too limited treatment of the IRP decision-making process.

BSI believes that the City of New Orleans will much better served by an IRP that is more similar in content to other utilities. BSI has referenced three IRP's published in the last two years by other utilities: Puget Sound Electric, Tucson Electric Power and Ameren Missouri. BSI thinks it is worthwhile to make some comparisons.

	ENO	TEP	PSE	AM
Number of Customers	*171,000*	*414,000*	*1,100,000*	*1,200,000*
Holding Company	*Entergy Corp*	*Fortis*	*Puget Holdings LLC*	*Ameren*
Retail Sales/year (GWh)	*5.1*	*12*	*23*	*36*
Generating Capacity (MW)	*645 + Michoud*	*2,300*	*6,000*	*10,300*
Last IRP	*2015*	*2014*	*2013*	*2014*
IRP modeling Software	*AURORAxmp*	*AURORAxmp*	*AURORAxmp*	*MIDAS*
ISO	*MISO*	*WECC*	*WECC*	*MISO*
Pages in IRP	*66*	*387*	*300+*	*Over 480*
Alternative Resource Plans	*6 (but really 3)*	*5*	*1200+*	*19*
Uncertain Factors	*?*	*> 20*	*14*	*19*
# of scenarios	*4*	*100*	*140*	*15*
Sensitivity Analysis	*partial*	*yes*	*yes*	*Yes*
Stochastic Risk study	*no*	*yes*	*yes*	*Yes*
IRP website	*http://www.entergy-neworleans.com/content/IRP/ENO_2015_IRP_Portfolio_Composition_and_Results.pdf*	*https://www.tep.com/doc/planning/2014-TEP-IRP.pdf*	*http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf*	***https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp***
LCOE for all load reduction and generation options	*No*	*yes*	*no*	*yes*
cost of every individual program or generation option in $/peak Watt	*No*	*yes*	*no*	*partial*
$/W for Energy Efficiency	*1*	*0.50*	*no*	*0.93*
$/W for Demand Response	*no*	*0.30*	*no*	*?*

In particular, note the gross deficiency in number of cases and scenarios in ENO's IRP compared to three other utilities. Based upon this data, BSI concludes that ENO's IRP does not contain an industry-standard risk analysis.

4.20 BSI contends that the IRP process was far from collaborative, did not follow its own guidelines for decision making, and seemed to be more like a performance played out over as many acts as there were public meetings but the content in each act seemed to be almost completely unaffected by comments or criticisms brought during previous meetings.

CASE IN POINT: ENO's IRP displays the adjacent IRP Milestones which pretty clearly asserts that all inputs to the IRP will be decided on June 27 unless they are about DSM. On that day, BSI asked in the open meeting about the lack of batteries in the study and argued that ENO had the facts wrong. But this decision was never reviewed by ENO.

However, ENO's preliminary supply side study (found on page 8 of ENO's IRP see next graph) lists battery storage as a supply side option and not part of DSM.

A very similar story plays out regarding the need to do an industry-standard risk analysis. That deficiency was discussed at the second-to-last meeting which was more than a month before the last meeting. But the IRP modelling was not upgraded between meetings. At that meeting ENO contended that the CT option was the best even though it was not chosen to be better than all of the other alternatives in any scenario.

When challenged on what basis can the CT be deemed best? ENO's response was because of risk—despite the fact that no risk analysis was ever done and the CT option did not "win" the competition for best in any scenario.

Figure 1: IRP Milestones

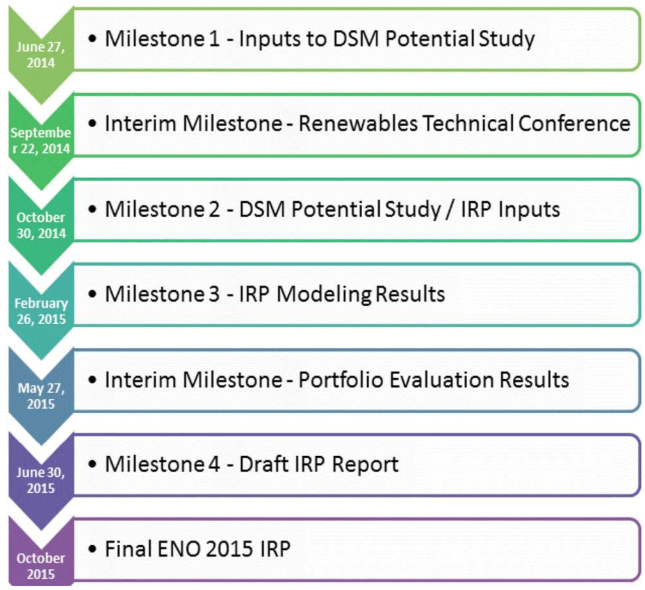
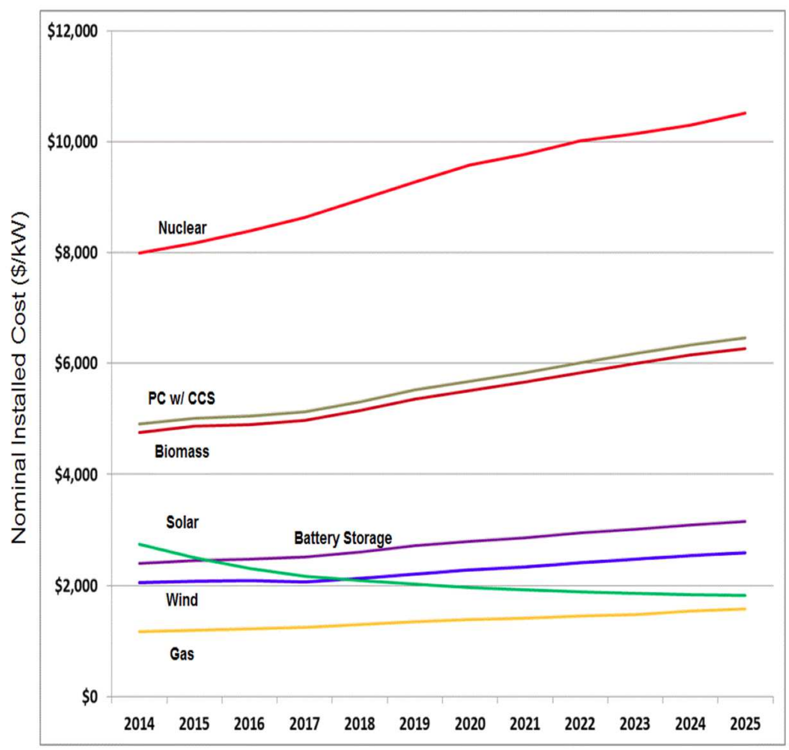


Figure 2: Projected Installed Cost of Supply-Side Resource Alternatives



5. ELABORATED RECOMMENDATIONS

Overview of Recommendations

Recommendations to Make Supply Cost-effectively Match Demand

- If shutting down Michoud jeopardizes ENO's membership in MISO, do not allow this.
- ENO should continue to satisfy unmet economical peaking needs with power from MISO.
- Do not add utility-owned generators to the rate-base now and for the foreseeable future.
- Replace ENO's access to profit from building more generators to a new decoupling paradigm which rewards ENO for better energy delivery.
- Remove DSM from ENO's control.
- Incentivize robust demand-side management [DSM] by utilizing more than a dozen means overlooked in ENO's DSM approach.
- Incentivize the installation of battery energy storage systems [BESS] in every building.
- Incentivize and provide legislative support for Community Solar in two ways:
    - Promote 75 KW to 2 MW solar farms at distressed property found all around the city.
    - Promote a system of small, 50 to 100 KW solar farms with 150 to 300 kWh of integral battery storage on many "key lots" of the city.

Recommendations to Improve the IRP Process

- Improve public confidence, input, input effectiveness, collaborative process and result finding.
- Publicize how, when and where key assumptions are made and how they can be changed.
- Publicize examples of effective input by the public.
- Compensate intervenors for effectively contributions to a regulatory decision that saves money.
- Fund the Center for Excellence in the Built Environment [CEBE] by paying intervenors. (Part of the CEBE's stated job is to intervene into an IRP.)
- Vet third-party consultants to assure that motivations are not compromised by self-interest or on-going relationships with any utility, business, industry, or government policy purveyor.
- Pay a third-party consultant to choose and implement the IRP modelling software employed.

The Detailed Specific Recommendations are found in the

Concise List of BSI's Recommendations

Section right after the Executive Summary and are not repeated here.

5.1: Recommendations to Make Supply Cost-Effectively Match Demand

5.1.1 Cause robust DSM by using most of the means overlooked in ENO's DSM program design.

The following show examples to help explain each of the deficiency categories of ENO's DSM.

5.1.1.1. ENO's DSM underpays for energy-efficiency.

The current average price ENO pays is $1/"peak demand W" even though it considers a solar system that costs $5/"peak demand W" a good candidate for an alternative to a combustion turbine. This means that ENO should at least be paying $1.5/"peak demand W" on average for its DSM program.

5.1.1.2. Fully exploit a broader range of cost-effective, energy-efficiency retrofit options.

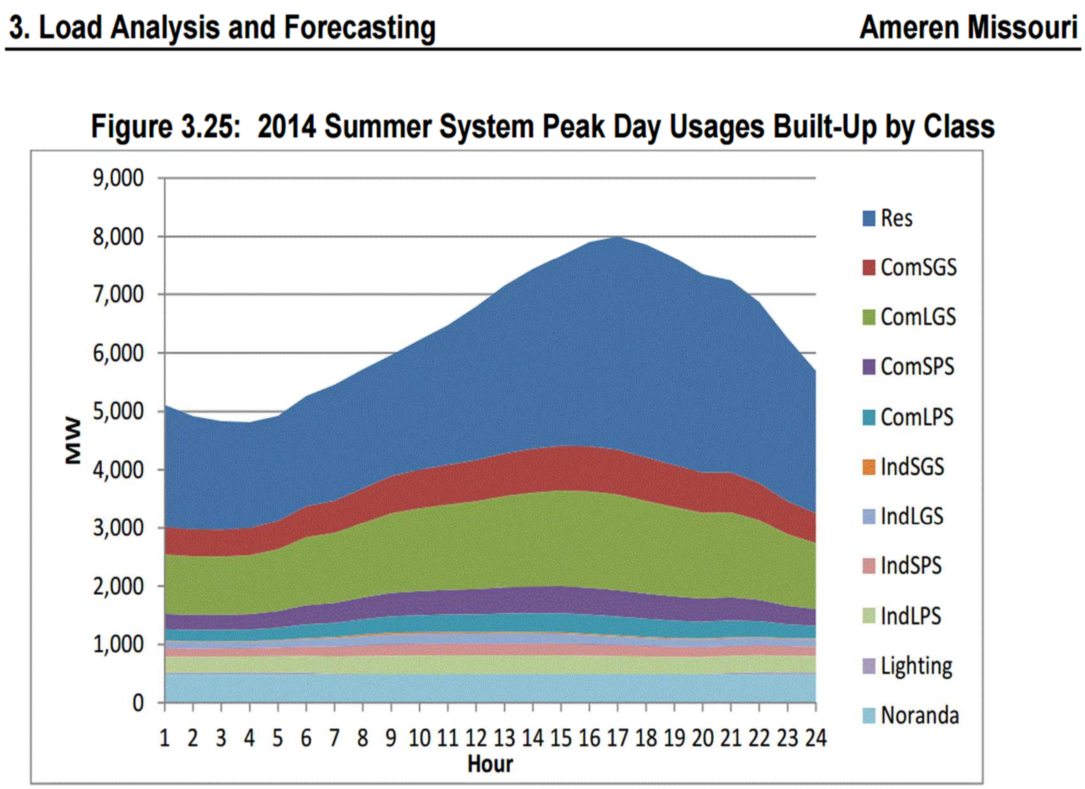
a) The Geyser heat pump water heater made by Nyle industries, is more efficient, less expensive and cheaper to install that those on ENO's short list of approved water heaters.
b) Almost all ductless AC's save more energy by the aggregated effects of: a) avoided distribution energy losses, b) zoning, and c) dehumidification and cost much less to a) purchase, b) install or c) test than almost all ducted systems even though some ductless AC are nominally rated to have lower energy-efficiency than many ducted systems.
c) Converting an open to a closed crawl spaces saves a considerable amount of energy, is an inexpensive retrofit and avoids more expensive, serious and very common moisture problems.
d) Properly focus on the primary problem of high peak demand: residential cooling.

5.1.1.3. The DSM plan should reward performance-assured savings.

Reducing infiltration and duct leakage are highly cost-effective retrofits but cannot be adequately appraised with deemed savings because there are gross differences from home to home in the extent of the previous conditions of the home and from contractor to contractor in the quality of the retrofits. A highly skilled and experienced, 3rd party, home performance expert will easily find more cost-effective retrofits than can be found on ENO's DSM list but the success must be verified with a before and after energy audit — nothing else can confirm energy savings. This strong opinion is an embodiment of the *modus operandi* of Louisiana's highly successful HERO program which operated for almost 20 years.

The performance of some equipment is highly dependent upon how and where it is installed: e.g., duct testing must be done to assure ducted AC performance, and the placement of a heat pump water heater can easily change its efficiency by 50%.

The next two graphs help make this point. Note that Residential load is the biggest problem.

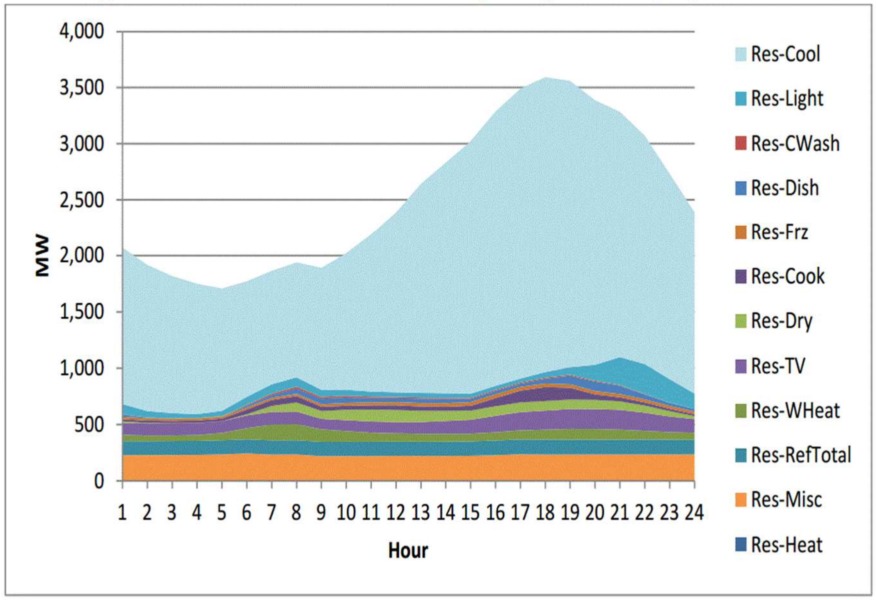


Then notice that within Residential customer class, the biggest problem, by far, is cooling.

By review of the money actually allocated for this problem in both ENO and Ameren Missouri [AM] one notes a few things: There are only a few ways to treat this problem and the utility-sponsored subsidy is around \$1/4/W for HVAC energy efficiency retrofit compared to the average subsidy of \$1/W. Why under incentivize the biggest problem? Moreover, this problem can be addressed in only a few ways on the list like: a Freon pressurization, fixing duct leakage, or a general HVAC upgrade to higher SEER equipment. It is often the case that more cost-effective retrofits are infiltration repairs, installing ductless equipment and shading of windows. However, window shading cannot be classified as a deemed saving, and infiltration's deemed saving effect is highly dependent upon the efficiency of the HVAC and its installation, and ductless equipment's saving is highly dependent upon the existence and placement of interior doors and the number of floors in the home. These last few measures are highly customized effects that are better served by a home energy auditor who can identify them instead of working from an abbreviated list.

Ameren Missouri **3. Load Analysis and Forecasting**

Figure 3.24: Residential Summer Day Usage Built-Up by End Use



The following quote points out that Ameren Missouri [AM] already utilizes "evaluators" for broad overview purposes; why not expand this team and its responsibilities it to a more granular system with home energy audits like those employed within TEP?

"8.4 Evaluation Measurement and Verification (EM&V)
8.4.1 Existing EM&V Model Separate evaluators are currently under contract for the Residential and Business portfolios. The consultants provide an annual independent review of the gross and net program impacts. They also provide process evaluations including reviews of databases and marketing materials, conduct implementer interviews, and measure customer satisfaction with programs. The Commission has hired a State Auditor to audit and report on work of Ameren Missouri's independent EM&V contractors. The Auditor a) monitors EM&V planning, implementation, and analysis of the EM&V contractors, (b) provides on-going feedback to the Energy Efficiency Regulatory Stakeholder Advisory Team (EERSAT) on EM&V issues and (c) provides EERSAT with a copy of their final report in a timely manner.20 The evaluators submit their draft annual process and impact evaluation reports to EERSAT and the State Auditor for review and comment 45 days after the completion of each program year and their final annual process and impact evaluation reports 135 days after the completion of each program year."[69]

5.1.1.4 Allow market transformations and indirect or unshared investment in each building.

Indirect investments can save energy at low $ / "↓peak demand W"; for example, consider education.

"… The most significant improvement to the planning process, however, may very well be Ameren Missouri's acquisition of new, state-of-the art software to both develop and periodically update a secure, online Technical Reference Manual (TRM) database capable of capturing, organizing, and tracking the comprehensive set of Ameren Missouri's energy efficiency measures, their corresponding data elements and values, along with accompanying documentation. The TRM software will also support Ameren Missouri in the calculation of its 2013-2015 ex-post actual annual kWh. Ameren 43 EO-2012-0142 14 8. Demand-Side Resources NP Ameren Missouri 2014 Integrated Resource Plan Page 35 Missouri, the Commission, stakeholders and ultimately customers will realize the following benefits of the system:
"The MEEIA Cycle 2016 - 2018 TRM is an online technical reference database containing measure-level data, including savings, savings estimation protocols, and source documentation for all measures in the existing Ameren Missouri TRM. Customers, Ameren Missouri, the Commission, and stakeholders will realize the following benefits of the state-of-the art TRM system:

- Consolidation and organization of efficiency measures, measure attributes, and supporting data, including all savings values, costs, assumptions, equations, savings estimation protocols and source documentation. An easy-to-use, web-based interface to facilitate access to measure parameters, savings calculation algorithms, effective useful life, and incremental measure costs.
- Automated version control, including logging, retention, and archiving of all measure versions, including interim measure updates. Greater transparency into measure assumptions due to the fact that source documentation can be directly linked to a measure and the relevant attributes and parameters.
- Ability to create customized measure specific reports and/or export files in various file formats; this can be used to develop customized files for program reporting.
- Maintenance of accurate records of TRM savings based on versions for tracking and reporting using the online TRM tool." [70] [71]

By using an approved list of retrofits, manufacturers will raise their prices to match the subsidy and thereby undermine the economic potential for future retrofits. It is better to approve a generic list instead and if necessary, reject bad models; even better is let installer claim and garner the benefit after installation and inspection by 3rd party verifier. Even better: use performance-based rebates.

Control is a means of energy conservation that is purposely ignored in homes by RESNET; but this need not be the case in ENO's DSM by design.

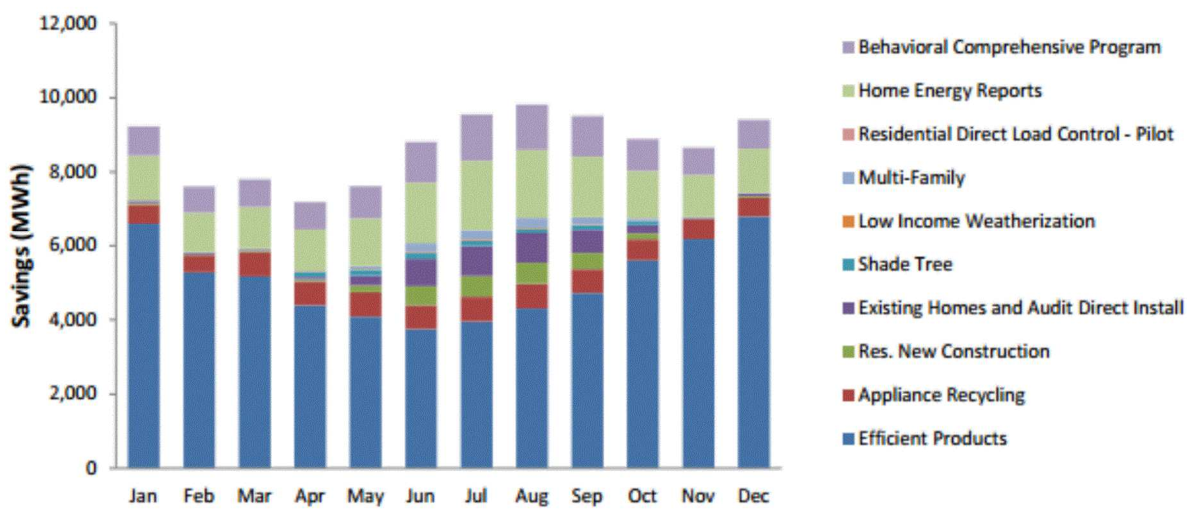
“Behavioral Energy Efficiency programs are designed to affect habitual behaviors like turning off lights or adjusting the thermostat, purchasing behaviors such as buying efficient lights and appliances, and the behavior of participating in utility DSM programs. More specifically, the types of behaviors to be influenced include: • Habitual Behaviors » Adjust thermostat setting » Turn off unnecessary lights • Small Purchasing and Maintenance Behaviors » Purchase and install faucet aerators and low flow shower heads » Purchase and install compact fluorescent light bulbs » HVAC maintenance • Larger Purchasing Decisions » Purchase an ENERGY STAR appliance » Purchase higher EE heating and cooling system through participation in a TEP DSM program TEP proposes to continue our K-12 Education and Community Education for the 2014 program year portfolio,”[72]

To this BSI would add providing information about how focusing upon improved energy-efficiency is not always the best way to decrease energy consumption while maintaining or improving lifestyle choices. For example, ductless HVAC equipment can provide more energy savings even though such equipment often has lower efficiency ratings.

73

Mandate that energy ratings of homes to be posted in all local listings by the real estate industry whenever they are available and publicize the improvement in selling price caused by an energy rating.

Figure 25 - 2012 Residential & Behavioral DSM Programs



The previous graph comes from Ameren Missouri's 2014 IRP.[74] It points out that there are a number of ways to decrease consumption that cannot be classified as energy efficiency. Moreover, their cumulative effect is about the same as energy efficiency when it really matters, i.e., at the height of the summer.

BSI likes the following, suggested electric vehicles idea but would amend the idea to make sure the utility provided, car charging equipment can only be used between midnight and 6 AM. ENO should not subsidize equipment that can be used to increase peak demand.

"8.13.7 Electric Vehicles
Ameren Missouri is considering the development of a program in which residential electric vehicle charging stations are incented to promote the adoption of electric vehicles (EVs).
As defined by MEEIA a: (F)

Demand-side program means any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load;

This is a unique program in that most energy efficiency programs apply a measure to replace or upgrade an existing piece of equipment, while a program of this nature involves the shift of "fuel type" from one industry to another in the interest of reducing CO_2 emissions (i.e., the Oil Industry to the Electric Industry).

The internal combustion engine (ICE) has powered motor vehicles for years and dominated the market. Auto manufacturers, in an effort to comply with federal regulation and to attract customers, have tried to increase the fuel economy of their fleet. Many automakers are switching some of the product offerings to EVs, but one of the hindrances to their adoption is the need for charging stations.

Ameren Missouri is considering a potential energy efficiency program to incent the full cost and installation of a residential charger for customers who purchase an EV. A supply chain analysis (of Ameren Missouri generation); comparing a vehicle with an ICE averaging 30 mpg and an electric vehicle with a 16.5 kWh battery results in the electric vehicle emitting almost 3 tons less CO_2 into the atmosphere than the ICE vehicle. If the overall environmental goal is to reduce carbon and mitigate climate change influences from the transportation sector then this is a segment of the market that should be considered alongside other energy efficiency initiatives. The difference in carbon emissions between ICE and EVs is expected to increase going forward as Ameren Missouri adds more renewable energy resources to its portfolio.

<u>Energy Savings Calculations</u>

Since the traditional way of calculating incremental energy savings (kWh) doesn't apply to a program of this nature Ameren Missouri developed a methodology to convert the carbon savings from CO_2 to kWh. The supply chain energy for both ICEs and EVs was converted to a common unit (BTUs) and then the difference was converted to kWh. In the case of comparing one vehicle powered by an ICE and another by electricity, the resulting savings is 26.44 mmBTU or 7,750 kWh per year per automobile. An illustrative example of the carbon reduction potential from an EV program - if Ameren incents 100 residential charging stations each year (2016 – 2018), the estimated reduction in CO_2 Emissions is shown below. The first graph shows the emissions saved at the wheel and the second graph includes the source emissions saved."[75]

5.1.1.5. Forthrightly ameliorate the three major split-incentive problems of the utility and utility consumer.

Use the following method to solve the tenant-landlord, split-incentive problem.

Using third-party financed, EE retrofits can provide payback sufficient to pay all of the following four cash flows

i) the investment's capital cost via small monthly payments over 5 years,
ii) substantial net discount on tenants' monthly energy bills and, as well,
iii) a smaller but non-trivial monthly payment to the landlord, and
iv) a much smaller income for the 3rd party investor and/or administrator of the program.

After 5 years, all energy retrofit capital costs are paid and three of these cash flows are eliminated. Thereafter all kWh savings from this retrofit will go exclusively to lower tenants' bills.[76]

BSI was informed that tenants comprise 45% of New Orleans residents.[77] Clearly a program focused upon this segment can have tremendous effects on peak demand.

The other two major split-incentive problems are:

- The problem of the new homeowner who only plans to live in the home for 5 years or less.

- The problem of the poorly coupled incentive of the utility which only makes a profit by owning capital investments but makes no profit by lowering its consumer's bills.

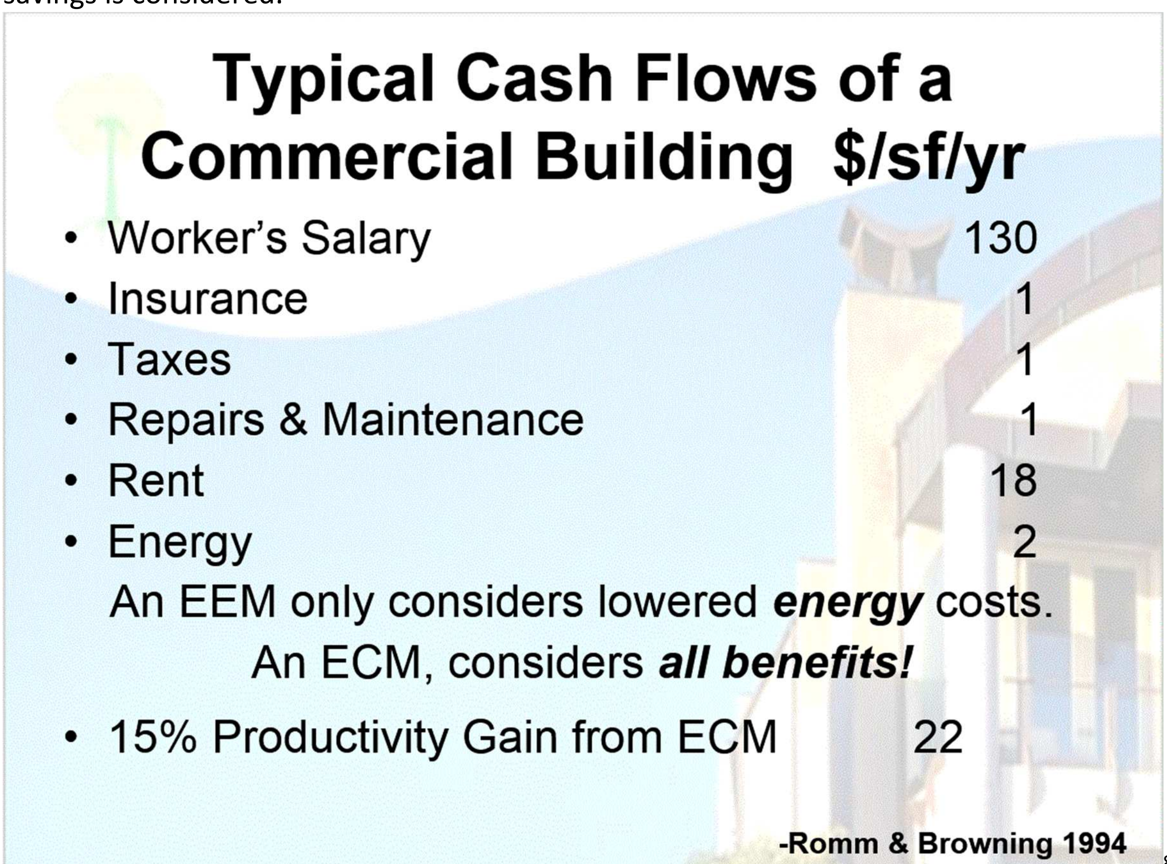
BSI considers this split-incentive problem perhaps the biggest problem facing ENO and thus, indirectly, the biggest problem facing any successful IRP or intervention that addresses an IRP. Solving it is called decoupling. There are many, many ways to solve this problem and BSI is firmly on the side of ENO that they should have a means toward making a profit when building generation can no longer be counted upon to a substantial profit center. However, BSI is not going to propose a solution to this problem seeing that this problem was already "solved" in 30 states, over 4 years ago.

> "Currently, some form of decoupling has been adopted for at least one electric or natural gas utility in 30 states and is under consideration in another 12 states. As a result, a great number of stakeholders are in need, or are going to be in need, of a basic reference guide on how to design and administer a decoupling mechanism. This guide is for them." June 2011 [78]

5.1.1.6. More fully exploit the gold mine of retrofits of existing buildings that solve much more economically significant problems like moisture control or worker productivity which create prodigious energy-efficiency and decreased demand as minor ancillary by-products, and conversely.

Insulating a building shell by placing pre-cast foam boards onto the exterior side of stud walls can solve two major moisture problems: stopping rain intrusion as well as controlling vapor flows — neither of these are positively affected by putting any kind of insulation between studs. Moreover, this system is far and away better than any alternative to retard heat flows; a homeowner would not tend to choose this if the benefit is measured in energy savings alone because of its installation cost, but when durability and health are considered, this retrofit is an easy sell.

Because worker productivity easily has 50 times the economic value compared to utility bill savings to a commercial building's tenant[79], a lighting retrofit that allows individualized control of lighting levels or prodigious natural lighting can be sold based upon improved productivity — the same retrofit will likely not meet have the cost / benefit ratio if only energy savings is considered.



[80]

However, the converse problem also exists: some energy retrofits can actually create much more economically significant moisture problems or degrade worker productivity.

Well known examples are:

- Vinyl wallpaper placed on the interior side of exterior walls.
- Installing over-sized AC equipment or equipment with poor dehumidification ability.
- Over-lighting offices or hallways or providing limited control of location or level.

Less well known examples are:

- Using exhaust fans to dry or cool a crawl space or attic.
- Place a radiant barrier in a vented attic that contains a ducted AC system.
- Putting fiber or foam insulation between studs behind a stucco-coated exterior.
- Cooling a home below the monthly average outside dew point.

5.1.1.7. Engage in efforts with others to fix broken building codes, reverse faulty DOE, FEMA, MISO or EPA decisions, reform manufacturers' activities that impede energy-efficiency and redirect the energy design industry.

During the last few decades the building codes have changed regarding where and how to insulate the top of a residential attic, crawl space, as well as on the floor of a drop-ceiling of a one-story commercial building. Some of these moved in the wrong direction and some of these changes took far too long to happen. For example: cathedralized or unvented attics took too long to become code-compliant and insulation over drop ceilings has recently become non-compliant; both of these are wrong and have wasted or will waste retrofit opportunities, raise energy consumption, and increase demand that will happen whether or not ENO gets involved.

The EPA has rated many appliances with a national perspective without getting into the granularity of climate-zone specific considerations. For this reason, although heat pump water heaters can be more than twice as efficient when installed in a southern basement as a northern basement, they nevertheless get only one efficiency rating. Similarly, FEMA has insisted that homes in flood plains, must have vented crawl spaces — big mistake.

"It is estimated that 70% of the summer distribution system peak demand, or approximately 5,400 MW, is served by substations with voltage control capability. Although higher levels of voltage reduction are possible, this study assumed voltage reduction would be limited to 2.5%. Based on Ameren Missouri experience, load decreases by approximately 0.84% for every 1% reduction in voltage. Furthermore, experience indicates not all LTC equipment responds when signaled to reduce voltage. It is assumed that 90% of the equipment will respond properly. On this basis, Ameren Missouri can achieve approximately 100MW of demand reduction via voltage control at the time of system peak. However, Ameren Missouri has determined that voltage reduction should not be included in its capacity position since there are no provisions in MISO tariff for a load serving entity to include voltage reduction to modify its coincident peak demand or to register it as a demand response resource."[81]

Manufacturers of fiberglass batts clearly state that the paper backing should be down when installed in an attic — which may be a good recommendation for homes north of Missouri, but in our climate, such insulation should be installed with the paper backing above. In fact, the best choice would be fully air-tight, thin-plastic encased insulation, without which both the energy and moisture flows are grossly adversely affected. In fact, studies indicate that fiber-batt or loose fill insulation installed on the floor of an attic without a covering air-flow barrier can expect the insulation to perform at 1/30 of the insulation's rating.[82]

The home energy design industry has purposely ignored energy control in the design of new homes or retrofits of existing homes. For this reason, homes are frequently fitted with single-hung windows which cannot accept full height screens and cannot be opened at the top. This is a gross design error.

5.1.1.8. Utilize highly cost-effective retrofits that lower peak demand even though they may RAISE kWh use.

There are certain retrofits that can significantly reduce utility peak demand and the wholesale cost of energy, but may actually raise kWh use. For example, a timer connected to an electric water heater that keeps the device off and thus the electricity consumption zero between 6 AM and midnight can be expected to increase kWh use but decrease the wholesale cost of energy needed to heat water because it recharges the water heater during off-peak periods. At the same time, the KW consumption at peak times goes to zero for this appliance. For the same reasons, an AC that makes ice at night may raise kWh use, but it can drastically lower peak demand. (Although these retrofits may raise kWh use, they are more likely to reduce CO_2 emissions because a significant portion of the energy used would come from underutilized off-peak wind power.)

5.1.1.9. Fully exploit time-of-use pricing, interruptible rates, or any other kind of Demand Response means of having retail rates better reflect wholesale prices.

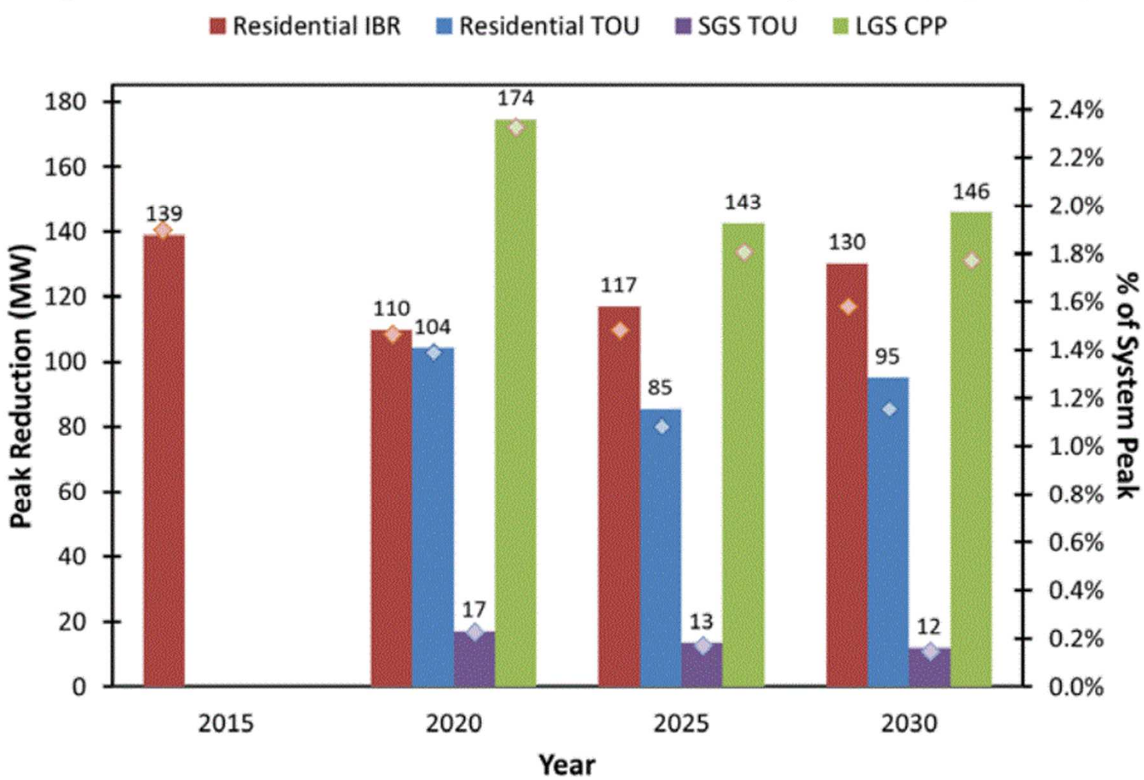
The ComEd example shows that people will pay to get access to real time pricing. This example may be showing that a drop in demand need not have any cost to the utility.

Ameren Missouri has researched a variety of "demand response" alternative "sticks" to encourage reduced consumption at peak demand times.[83]

"The analysis of demand-side rates in the study indicate that inclining block rates (IBR) and time-of-use (TOU) rates have the potential to reduce customers' energy consumption. If offered as a customer opt-out option, demand-side rates have significant customer energy usage reduction potential. However, if they are offered as a customer opt-in option, the potential diminishes to relatively modest levels."[84]

The most effective for residential was inclining block rates or [IBR]. The most effective for industrial was critical peak pricing [CCP]. Less effective but substantial was time of use pricing [TOU]. But when time-of-use is applied to commercial [SGS TOU] much less savings are to be expected.

Figure 8.18: Peak Demand Reductions by Year (Opt-Out)[74]



5.1.1.10. Allow customers to participate in selling the *spinning reserve*, a.k.a. *voltage support,* service to ENO or MISO.

Estimates of the cost-effectiveness of selling spinning reserve[85], show that it has about the same value to a utility as Frequency Regulation, i.e., around $5/month per residential-sized battery backup power supply (as explained in number 11). Moreover, it can be simple and even less expensive than frequency regulation to implement because it may be as simple as requiring PV inverters to provide reactive power.[86]

Although the direct effect of selling spinning reserve has little effect on the cost of peak power, this step can have major consequences on reducing peak demand because it helps finance battery installations which actually do the heavy lifting. This same statement applies to selling frequency regulation described just below.

5.1.1.11. Allow customers to participate in selling the *frequency regulation* [FR] service to ENO or MISO.

In the IDCC talk referenced earlier, the V2G experiment showed that the FR cash-flow provided by a home-sized battery back-up power supply can be expected to generate about $5 a day. Note that $5/day is about $150 a month and more than 50% greater than the average residential energy bill.

5.1.1.12. Allow customers to sell electricity at near wholesale prices to the utility during peak times.

Moving low priced energy purchased in the early AM for delivery to the grid in the late afternoon can change the value of that energy by a factor of 2 to 20. For confirmation, see MISO graphics within the IDCC document.[87]

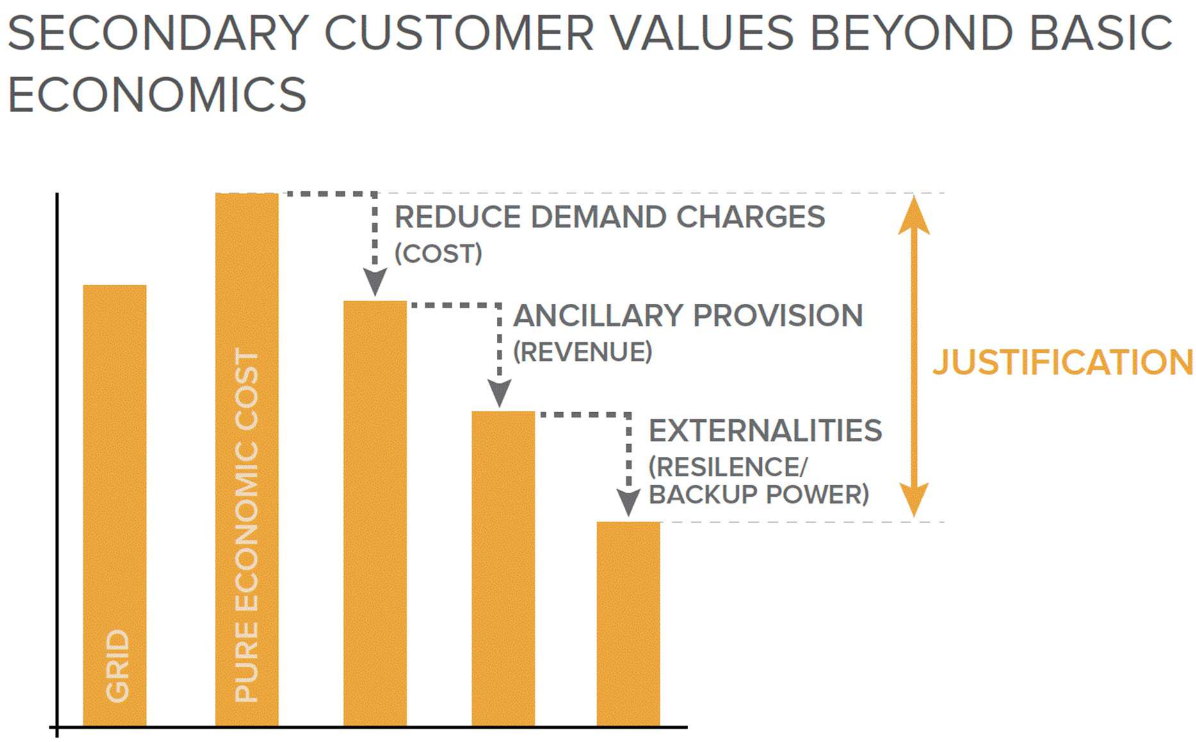
5.1.1.13. Raise demand charges on commercial and industrial customer to $20 /kW-month.

Commercial Demand rates within ENO and Entergy Louisiana in general are currently around $6/ kW-month. This is less than 1/4 of the fair price and 40% of the average rates found in CA, FL and NY. This depressed price may help encourage the relocation of businesses to our region but at a price which unduly burdens residential customers. Switching to this higher figure has multiple benefits:

a) Stops the unfair situation where residential customers are subsidizing commercial.
b) Creates, in the short term, a cash flow which can be used to support new rebates, and
c) Provides a normal marketplace sufficient to entice national companies like Solar City.

5.1.1.14. Facilitate the purchasing of battery back-up power supplies in all buildings.

Moving toward such a situation will lower the need for larger utility reserve margins and help place more batteries in the system to facilitate all of the above means of lowering demand and the costs of the utility.



The previous graph shows that a consumer-installed battery provides three services: decreased demand, ability to sell spinning reserve or frequency regulation, and added resiliency because of the backup power.[88]

This same set of benefits were more precisely exploited within BSI's IDCC talk and explain why consumer-installed battery systems have been cost effective for years. The IDCC reported that Pepco found (before it went out of business)[89] that the average cost of unreliable electricity to its residential and commercial customers exceeded $500 / year and $2000/ year, respectively. This cash flow is not a cost to be borne by the utility but provides an economic incentive for the average customer to purchase back-up power. Customers in the more affluent parts of this city are already investing in natural gas powered back-up systems for more capital cost but such equipment provides no ability to facilitate any of the above DSM benefits. Why not make a wedding with mutual benefits?

5.1.2. Incentivize the installation of battery energy storage systems [BESS] in every building by allowing the batteries to earn money by providing valuable utility services and inverting demand from traditional peak times to other times of the day.

Besides for the homes adjacent to solar farms on key lots, battery energy storage systems [BESS] can provide services to each and every building and to the utility whether or not that building has its own PV system at the building or even in a virtual sense as in community solar. As explained in the IDCC talk, BESS without PV is more economical than PV with BESS or PV without BESS, for a variety of reasons, that is, as long as the utility regulator allows one of these easily available cash-flows to inure to the benefit of the owner of BESS:

- Enact time-of-day or some other rate mechanism that pays consumers to use more electricity when wholesale electricity prices are cheap and less when it is expensive.
- Pay customers for assured drops in peak demand.
- Pay customers for supplying power during peak demand times at above retail prices.
- Allow a BESS owner to sell Frequency Regulation
- Allow a BESS owner to sell Spinning Reserve.

Note that the two measures in iv) and v) above do not directly affect drops in peak demand, but they greatly help to finance the batteries that can then participate in major drops in peak demand via i), ii) or iii).

Note that, because of the more than 25% drop in the price of Li-ion batteries, BESS is at least 25% more economical today that it was more than a year ago when IDCC was first conceived. This results from the difference in price and longevity of batteries available a year ago and those available today. Thus if BESS were cost-effective then, it is still cost-effective and costs 25% less today.

BSI reiterates and emphasizes that the economics of BESS is far greater on the consumer side of the meter than on the utility side of the meter. As is explained in the IDCC talk, this is the case because of the extra reliability batteries provide to their buildings; half of the first costs of a BESS can be paid off in less than 5 years by this cash-flow. Moreover, via batteries, the responsibility for electricity reliability can gradually shift from the utility to the building's BESS. As it does, consumer-installed BESS takes great economic burdens off of the utility; this benefits the building with BESS as well as lowering the cost of electricity for buildings without BESS.

5.1.3. Incentivize and provide legislative support for Community Solar by promoting the construction 75 KW to 2 MW Solar Farms at distressed properties found throughout the city.[90]

The following quote from *Design Decisions for Utility-Sponsored Community Solar*, a May 2015 report, implicitly defines Community Solar, presents arguments for it and outlines how it is financed and administered.

> "Since 2010, residential solar installations have added more than 2,500 megawatts of clean energy—enough to power more than two million homes for a year. Yet nearly 75% of residential rooftop space is prohibited from participating in individual programs such as net metering due to structural constraints or ownership issues. Community solar aims to resolve this impediment, providing restricted residents access to solar in a virtual fashion. An administrating entity will cover the cost of installing a large solar array and recoup these costs by allowing co-investors to buy into the project. Co-investing participants then receive the benefits from their share's solar energy production. " [91]

This same just quoted report points out that i) there are Community Solar [CS] programs in 19 states including Washington, D.C. and ii) D.C.'s CS regulation requires that instantaneous excess generation is not "stored for future use" by the owners of the CS, but instead is given to the low-income community. These last two clauses are decisions made by utility regulators based upon due consideration of the passing the non-participant test. The first indirectly asserts that in over 18 jurisdictions, the regulator decided that the cost thrown onto non-participants either didn't exist or was negligible compared to benefits. The second sentence states that in DC, the regulators decided that whether or not negligible, DC's regulators decided to provide a consideration for low-income people that would defeat any argument against CS. For the average net-metering customer, less than 10% of the energy generated by a PV system goes to the grid. This 10% gift to the low-income community is small enough to keep from spoiling the economics for the residents who will buy into the CS array in order to gain virtual net-metering.
Although the report is focused upon <u>Utility-Sponsored</u>, Community Solar, the Utility does not wind up owning the solar plant; i.e., its capital cost does not wind up in the utility's rate base, it is completely owned by the tens to hundreds of individual residents who finance their shares. Neither does the original sponsorship have to be a utility; the economics of CS is well enough explained to outline a plan for a private investor to sponsor and own the whole project. Moreover, since CS programs described in this report go all the way back to 2005, most of the currently existing CS projects have significantly higher capital costs than a new CS system owner would have to pay today; namely, about $2.5 / W was the stated capital cost in the example given in the guide while ENO's IRP says they could build their PV power plants at half that price.

The range of solar farms sizes, i.e., from 75 KW to 2 MW, conform to BSI's estimate of the size of a solar farm that would largely fill a single 30' by 100' lot and a solar farm the size of an entire city block, respectively. One such empty lot is a former Superfund site located at the corner *of* Lowerline St and Earhart Blvd. Although completely empty city blocks are rare, there are over 35,000 lots awaiting reuse in Orleans Parish.[92] At the scale of 1 or MW's the installed cost should be nearly as low as ENO"s projection $1.25/W. However, even at 75KW at a time, the price should probably go below $2/W.

5.1.4. Incentivize and provide legislative support for Community Solar by promoting a system of 50 to 100 KW solar farms with 150 to 300 kWh of integral battery storage on many "key lots" of the city. [93]

> *The following (solar farms on key lots), is an important example of how to do solar farms and has the advantage that it garners the most subsidy: 30% from IRS and 50% from state, as well as an accelerated depreciation credit if privately owned—which totals more than 100%!*

Many to most "city blocks" have what is a called a "key lot". This lot is usually located near the center of the block and relatively far from any of the four bounding streets. This lot may be "L" shaped, longer than other lots or even have triangular regions. When it exists, it sits as the "odd-ball" lot within the block so that the other lots will have the more common dimensions like 30' wide and 120' long. This key lot is also distinguished in that it often has a boundary with most of the other lots. For these reasons, the key lot is a perfect place to put a variety of energy improvements that can enhance the energy services utilized for all of the homes on that block. Of course, at the time of this writing, the lot is privately owned and would not be automatically available for such improvements. To garner use to any part of the land, the owner should be paid the fair market value of the acquired land. The most expensive land in the city within residential neighborhoods probably costs around $25 / sq ft, but most of the rest of the land is far, far cheaper. [94]

The land needed for a solar farm big Enough to serve all of the homes on block is roughly 30' x 85'; this is roughly 2/3's the size of the smallest lot size commonly used in New Orleans. Because solar PV is currently nearly 20% efficient and 1 sq meter normally receives 1000 Watts of sunshine at sea level, a minimum of 5 x 50 sq meters is needed for a 50 KW solar farm. Because a sq meter is very nearly 10 sq feet, the minimum amount of land is around 2500 sq ft.

What can be done with such land?

- Site a Solar Farm
- Site a Ground Coupling array for Heat Pumps.
- Facilitate communication and control of Battery Banks installed within each home on that block

Because the solar farm is close enough to the home and not separated by an intervening street, the solar equipment installed there may qualify for both the La and Federal solar tax credits; this is because the solar system will be "AT" the home, even though the PV servicing that home is not on the same piece of real estate. In that case, the energy flows to and from these homes would qualify for energy–net-metering and be logically entitled to completely avoid all of the costs associated with each kWh consumed at the residence and generated by the solar system.

The Ground Coupling Loop can facilitate ground-coupled heat pumps as needed up to the limit of the size of the ground coupling array installed at the key lot and sufficiently large for those homes that can take advantage of them. Unlike the solar farm, the extent of the ground coupling need not be limited to the area of the surface of the ground because modern ground coupling can use diagonally-inserted ground loops and these can be made more efficient using copper coils containing Freon instead of the less expensive and more common methods which employ plastic pipes filled with water.

Ground-coupled heat-pump provide all of these advantages:

- Drastically lowers energy consumption and demand of AC equipment connected to it,
- Facilitates energy conservation by timing (on an annual basis which is even better than on a daily basis), and
- Helps to avoid heat islands.

The battery energy storage systems [BESS] of the Solar Farm should be installed within homes adjacent to the key lot.

Each of these equipment types, (i.e., PV, ground-coupling and BESS) greatly contribute to reducing electricity demand and the second kind of equipment even lowers the demand of other, conventional AC's operating nearby.

The energy equipment on the Key Lot will be a resource for all homes on the block to share. The equity interests of the various homeowners can be divided at the onset or redistributed like shares in a corporation as needed. Because of the economics of net metering, the highest value to any homeowner is limited by the amount of energy consumed, the resources will be shared and regularly redistributed according to the varying needs of the homes and the effects of newer energy efficiency retrofits employed. The resources can be shared in an ownership sense or leased out.

Another legal/economic mechanism for maintaining and distributing the value and energy assets of the solar farm could be a cooperative or condominium-type arrangement.

Notice that at 50 KW, it would take 6000 of these systems to displace the 300 MW of peak power ENO claims it needs. However, even that is an overestimate because the battery systems can be designed to move substantial power generated between 10 and 1 PM to peak hours, this can cause a 50 KW solar array to output like a 75KW array during the peak hours.

Notice that whether the solar farm is privately held or ENO fronts the cost of construction, the developer of the solar farm can lease all of the parts of the system and thereby generate a cash flow sufficient to pay all of the cost of amortizing the debt. If this is case, the cost of this system of solar farms to ENO will also be $0/"↓peak demand W".

The reason why the full capital cost can be amortized via leases is that the purely PV part of solar equipment can be expected to cost no more than $1.5/W, the battery back-up system no more than $400/kWh.[95] Assuming that on average, each home will want a 5 KW PV array and a 10 kWh battery back-up, for a block with 15 homes, the solar array will be 75 KW and the battery back-ups total 150 kWh. The costs can be estimated by $102,500 for the PV array and $60,000 for the Battery Back-up. Thus the total cost of the solar farm's electrical systems would be $162,600 to service 10 homes. However, people who can afford a natural-gas-fired electricity, back-up generator are already paying about the same as this $16,260 for their equipment but such a purchase provides no benefits from reduced energy bills or cash flow from selling spinning reserve or frequency regulation power quality services to ENO or MISO. The frequency regulation service alone can be expected to be worth more than $1000 a year. This means that the sale of a BESS to a homeowner shouldn't be even slightly too hard to do.

5.1.5. Stop adding generation resources to the rate-base now and for the foreseeable future. BSI points out that the 300 to 400 MW shortfall described in ENO's IRP presentation that will present itself in 2016 when Michoud is fully decommissioned does not create a speed bump or hill for ENO's ratepayers. This is because from the perspective of the cost of electricity, ENO has already been purchasing power from MISO instead of making it with Michoud because Michoud's efficiency is so poor.

No matter whether the generator is or is not fossil fueled, any generator is superfluous in MISO with adequate batteries and every generator becomes part of stranded investments in the future when solar farms and wind make everything else uneconomical.[96]

According to ENO's IRP, ratepayers of ENO will only begin to gain from a newly constructed generating plant in 2019 when either a CT or CCGT comes on line (given that ENO is successful in convincing its regulator both that building a new generator is the cheapest option and either of the fossil fuel plants should be built).

It is both clear now and every indication in the future, that MISO will have great and growing excess electricity generation at low prices for a long time even if ENO's consumers enjoy none of: growth in PV, increase in DSM or growth of BESS. This is because MISO's off peak electricity is being sold below production costs and the case for this is strongest within the wind farms. The price facts are explained in the IDCC talk.[97] The growth predictions for wind are explained here.[98]

The situation will tend to grow; because of EPA's Clean Power regulation and addendum to the federal Clean Air Act, more and more jurisdictions will be economically pushed to build new renewable energy generators. However, because wind only has a 14% capacity factor, and PV only has a 25% capacity factor (according to assertions by ENO representatives at IRP meetings) the overwhelming majority of the electricity they produce will be generated out of step with peak demand. Thus any wholesale purchaser of electricity who can buy now for later use will find himself in a grossly one-sided buyer's market. Because of the Clean Power regulation and Renewable Portfolio Standards, this situation will only become more and more of a buyer's marketplace for the foreseeable future.

Wind-powered electricity is commonly sold at night within MISO at less than $0.01 / kWh. Compare that to the Levelized cost of electricity for a new CT or CCGT which is nearly 7 times as high.[99]

5.1.6. Replace the existing regulatory paradigm where ENO makes more profit only by building more generators with a decoupling paradigm which rewards ENO for lower energy bills, etc.

- As long as ENO only makes more money by building new generators, the CEO and other top executives should expect to be fired by the board of directors it they cannot sell the need to build new generators to the regulator. As explained on the previous page, building new generators should not happen. If construction of new generators stops, what should be done to promote/allow profit making? The obvious answer is to decouple the profit calculation for an IOU (investor owned utility) from the amount of capital the IOU owns. If that is not the metric for profit, what should it be? BSI has no intention to weigh in with its own creative formula or choose among feasible choices, but BSI agrees that this is the right direction to go and will look to other intervenors' comments with an expectation to support them.
- However, if this incentive problem is not solved, what can you expect from ENO? It will be forced to argue that any DSM cannot displace the need for new generation. Thus ENO has a vested interest in making sure that every IRP shows that any DSM cannot be effective fast enough to displace the need for new generation. This motivation is obvious, thus the tendency to make sure that the IRP provides this assertion is literally mandated by ENO's profit situation.
- For the ratepayers of New Orleans to enjoy a healthy and significant amount of DSM, the only way it can happen is if ENO has nothing to do with controlling it, choosing the administrators, choosing the implementers, choosing the metrics or choosing the retrofits.

5.2 Recommendations to Improve the IRP Process

OVERVIEW

- Improve public confidence, input, input effectiveness, collaborative process and result finding.
- Publicize how, when and where key assumptions are made and how they can be changed.
- Publicize examples of effective input by the public and, thereby, facilitate it happening again.
- Compensate intervenors when they effectively contribute to a regulatory decision that saves money.
- Fund the Center for Excellence in the Built Environment (described as the 2nd most important recommendation of the Energy Hawk, the 2007 report of the New Orleans Energy Policy Task Force) by paying intervenors.
- Employ a third-party consultant to choose and implement the IRP modelling software employed.
- Select from among pre-certified IRP modelling software to confirm its competence to:
    - Fully handle demand, supply and storage options located on either side of the meter,
    - Perform automated, what-if analyses on the broadest range of issues — including risk,
    - Warn against classes of input errors and inappropriate interpretation of results.
- Vet third-party consultants to assure that motivations are not compromised by self-interest or on-going relationships with any utility, business, industry, or government policy purveyor.

- **Improve public confidence, input, input effectiveness, collaborative process and result finding.**
- **Publicize how, when and where key assumptions are made and how they can be changed.**
- **Publicize examples of effective input by the public and, thereby, facilitate it happening again.**

5.2.1 Compensate intervenors if their contribution to a regulatory decision saves money.

> Compensate intervenors whenever their contributions contribute to rulings that save more money for ratepayers than the fair consulting fees and costs of the intervenors. The California Public Utilities Commission has a mature process and has been paying intervenors for decades; similar laws exist in at least two other states. Also, after a decade of experience utilizing a public law requiring the payment for intervenor services in the California insurance industry, $100 Billion was saved at a rate of 400 times as much public benefit than was paid to intervenors. Paying intervenors is a well-established practice and New Orleans should join a number of other jurisdictions where this policy is the law.

BSI notes that the processes used for insuring public input is grossly deficient primarily because, besides for a few devotees who truly educate themselves about the process, jargon and technical information, comments from the public are almost always viewed as ancillary expressions of concern with little to no merit regarding the issues under current discussion. The field of utility regulation is very complex and thus precludes competent public comment from almost anyone who does not invest the needed time to understand the playing field, in general, and the details currently on the table, in particular. Thus public comments are, by and large, an exercise that allows public venting of frustration but does not contribute to the process in a meaningful way.

However, that general description of public comments does not apply to all parties. The exceptions are, most notably: the Alliance for Affordable Energy, and secondarily intervenors like: Green Coast Enterprises, and the Gulf States Renewable Energy Industries Association (GSREIA); BSI counts itself in this group.

During the time Myron Katz (the primary author of this document) has been watching, namely since the early 1980's, many, many groups of people and businesses have come forward and given many thousands of hours to help direct the fortunes of New Orleans's electricity rate payers. The most notable examples in my memory are:

- The effort leading up to the May 1983 and May 1985 *Get NOPSI Back* referenda where more activists were working on that project than were working on all other environmental issues in the State of Louisiana put together.

- The effort leading up to the release of the Energy Hawk, the report of the New Orleans Energy Policy Task Force; it benefitted from the work of hundreds of well-educated and well-informed volunteers.

These efforts were actions taken by private citizens in order to improve the governance of their utility. However, none of these people were ever paid by the City or its utility for their services. As a result, the level of participation of people with competent knowledge has deeply waned yet again. This is to the public's great detriment. What New Orleans needs is a process that will support public comments from competent sources. The only way to get that is to pay for it. California recognized this dilemma decades ago and created a "pay the intervenor" mechanism. New Orleans should do the same.

Ratepayers of ENO, i.e., citizens of New Orleans, have higher bills and contribute to more global warming because ENO is more poorly regulated than it would be if more privately funded or publicly funded business or non-profits could depend upon some income to compensate them for their efforts as intervenors.

BSI conjectures that if one of the groups just mentioned believed that a member of the public had an argument that could contribute to better governance of the utility and by presenting this argument more money would be garnered to support intervenor activities, it would be in the best interest of that intervenor to encourage a full expression of the concern so that that issue can be properly presented within an IRP. As it is now, the Alliance and other groups are grossly strapped for resources to promote the issues they already have on their plates.

5.2.2 Mandate that the IRP process has complete transparency.

BSI notes that ENO does not publicly publish its full IRP and the IRP that it communicates to the intervenors is not easily computer readable (the text appears as pictures where words cannot be selected individually). Both of these steps create barriers to full transparency and public discussion. BSI recommends that preliminary versions of the IRP should be published before and after each meeting with a special section that spells out in detail what changed as a result of each meeting and who suggested that change. BSI found that it was too often the case that nothing changed between meetings despite multiple polite statements by the public or intervenors asserting multiple deficiencies.

BSI notes that public concerns were also expressed about the mismatch between ENO's approved DSM retrofits and the needs of the public to find comfort at high humidity and low electric bills. However, this issue seemed to fall right onto the ground since ENO's personnel are not home energy consultants and could not speak to the issue. However, BSI can speak to the issue as energy and moisture consultants for New Orleans buildings. *BSI has already expressed the fact that ENO's DSM is significantly incompetent to recognize or specify home energy retrofits that cost-effectively control moisture. That discourse is found among the more than a dozen deficiencies of ENO's DSM plan presented earlier in this document.*

5.2.3 Mandate that the IRP is dynamically responsive to changes in fact.

Two important "facts" changed dramatically during the one-year long IRP planning process: grid-connected battery storage became well accepted and the EPA published the Clean Power Plan; however, ENO's IRP did not acknowledge, much less incorporate either of these changes of fact.

5.2.4 Mandate that the IRP conforms to industry standards in IRP quality.

Demonstrate that the extent of the content and the complexity of analysis is at least average in the industry. BSI notes that ENO's IRP is apparently lacking in both of these regards.

5.2.5 Require that a third party produces the analysis, runs the meetings and collects and publishes the information.

This goes for the Council's, ratepayers, and societal goals; providing a cooperative workshop process; and utilizing a stenographer or camera crew to create a complete record of all meetings. BSI found all of these deficiencies and points out that much of these concerns are resolved within the administrative hearing process of the Louisiana Public Service Commission.

- Pay a third-party consultant to choose and implement the IRP modelling software employed.
- Select from among pre-certified IRP modelling software to confirm its competence to:
    - Fully handle demand, supply and storage options located on either side of the meter,
    - Perform automated, what-if analyses on the broadest range of issues — including risk,
    - Warn against classes of input errors and inappropriate interpretation of results.
- Vet third-party consultants to assure that motivations are not compromised by self-interest or on-going relationships with any utility, business, industry, or government policy purveyor.

BSI believes that the 2014-2015 ENO IRP process was degraded by insufficiencies in all but perhaps the last of the above categories. However, since the software used was chosen by ENO and implemented by ENO personnel, the ratepayers of New Orleans should have little to no confidence that either the software was competent nor that the use of the software was optimal.

BSI's VP of Research is an expert in mathematical modelling and knows that either poor software or poorly handled software will grossly degrade the result of software use.

Even if the software were chosen by a third-party who was chosen by a vetting process that protected the public from compromised self-interest, it is clear from looking at the nascent field of distributed generation and battery sizing that it would be very difficult indeed to find software that could easily handle batteries and integrate their economics into a sufficiently robust model for Integrated Resource Planning.

5.2.6 Provide a minimum test for passing or failing the IRP process.

The test should address errors of omission, insinuating misunderstanding, understatement of important issues, errors of fact, errors associated with recognizing that facts can change between the beginning and end of the IRP process. BSI thinks that ENO's IRP process may have been plagued by all of these problems. BSI thinks that such a test should generate a failing grade for ENO's 2015 Draft IRP. The Council should confect a reward for passing or a punishment for failing this test.

5.2.7 BSI also notes that similar tests should be instituted for other regulatory processes like the design of the DSM program and ENO's rate design.

BSI would not approve ENO's DSM's design and has found strong evidence that ENO's rate structure may I) cause one rate class to subsidize another, ii) undermine market forces that can encourage energy saving, iii) decrease opportunities for private enterprise to help ameliorate ENO's gap between supply and demand and iv) provide inadequate support for reversing the causes of global warming.

BSI notes that many members of the public came to the last meeting and some of them urgently pointed out that Global Warming is on the line and ENO is not concerned. BSI found no evidence that ENO's IRP considers avoiding the causes of Global Warming a goal within the IRP planning process. After that meeting, BSI was told that Global Warming is of great concern to perhaps a majority of New Orleans's City Council. There seems to be disconnect here. BSI thinks that the right way to address global warming within an IRP is to create a market-based mechanism that entices people to act in their environmental best interest as an ancillary effect of pursuing their economic best interest. ENO's IRP shows no evidence that it shares this view.

5.2.8 Fund the Center for Excellence in the Built Environment [CEBE] by compensating intervenors.

The CEBE is described as the 2nd most important recommendation of the Energy Hawk, the 2007 report of the New Orleans Energy Policy Task Force [NOEPTF].

BSI was a key author of the Energy Hawk and helped to write this proposal and guide the CEBE resolution though the process of finding consensus for getting the resolution passed and placed near the top of the recommendations put in front of the City Council. Many of NOEPTF's recommendation were taken, including using an IRP process. The City Council actually voted and approved the CEBE and its functions in 2008 in every way described, except CCNO did not approve any funding. The CEBE idea need not be dead, it just needs a funding source. BSI thinks that paying intervenors is a good start for a funding source.

BSI's two principals are both senior citizens in age and expertise. We do not need major salaries to encourage us to participate in Utility Regulatory Interventions. Moreover, we would, because our senior statuses want to find alternative personnel to replace our expertise within a few years.

This could be a win-win for New Orleans.

Notice the synergy and overlap between the content of this document and the stated proposed functions of the CEBE.

Sincerely,

____

Myron Katz, PhD
VP for Research
Building Science Innovators, LLC

CERTIFICATE OF SERVICE

I hereby certify that a copy of these comments has been electronically transmitted to each person on the service list on this 31st day of August, 2015.

____

Myron Katz

Appendix A — Bill for Services Rendered

BSI knows that the City of New Orleans does not pay for the services of intervenors. However, that is not a good thing. In fact, California has been paying intervenors in utility rate cases for many decades. This bill is submitted to demonstrate the time and effort by one intervenor, BSI, in this process.

> http://www.cpuc.ca.gov/NR/rdonlyres/A0BD21F9-7644-477E-94F4-85B504D43F66/0/UpdatedIntervENOrCompensationProgramGuide.pdf

Because BSI normally charges $200/hour for consulting time for its clients and this project has taken over 250 hours, the normal billed cost of the report would be $50,000.

BSI hopes that the City of New Orleans will institute a process similar to the one utilized in California and make this invoice retroactively acceptable.

Of course, BSI would only be paid if it met the following requirements:

1) The decision the Council made was significantly swayed by BSI's arguments, and

2) The resulting decision saves the ratepayers more money than BSI's consulting fee.

BSI believes that it has special expertise and experience in the matter of Integrated Resource Planning, the historic and present condition of utility regulation, the building stock of New Orleans and the profession of Building Energy Performance Design and retrofit contracting. BSI has devoted a tremendous amount of time and effort to the preparation of this document, but in the future, if such efforts are not properly met with economic remuneration, BSI will not be able to afford to provide this help in the future. However, should BSI receive this economic help, it plans to hire researchers and authors to augment this work into the future.

BSI is not the only intervenor who should be paid for its historic efforts in utility regulation. The most notable example of an unpaid public servant is the Alliance for Affordable Energy. Its efforts have contributed to avoiding many hundreds of millions of dollars since 1985 when it was first formed. The Alliance is a public servant and deserves public funds according to the same California process BSI recommends to the City Council of New Orleans.

Respectfully submitted,
Myron Katz,
VP for Research,
Building Science Innovators, LLC
August 31, 2015

Appendix B — Can Shutting-down Michoud Adversely Affect ENO's Membership in MISO?

From: Bruce Froyum <bfroyum@misoenergy.org>
To: "myron.bernard.katz@gmail.com" <myron.bernard.katz@gmail.com>
Date: Mon, 24 Aug 2015 16:28:32 +0000
Subject: Explain the Planning Reserves Margin membership requirement

---

Good Afternoon Myron,
Your ***answers*** are supplied below. Have a great day.
Regards Bruce
ext. 8429
Client Relations Contact Information
(*1-866-296-6476 Option 1,*
E-mail: ClientRelations@misoenergy.org
IT Support 1-866-296-6476. Option 2

This e-mail message may contain legally privileged and/or confidential information. If you are not the intended recipient(s), or the employee or agent responsible for delivery of this message to the intended recipient(s), you are hereby notified that any dissemination, distribution or copying of this e-mail message is strictly prohibited. If you have received this message in error, please immediately notify the sender and delete this e-mail message from your computer.

From: Myron Katz [mailto:myron.bernard.katz@gmail.com]
Sent: Monday, August 24, 2015 10:52 AM
To: *Client Relations
Subject: Explain the Planning Reserves Margin membership requirement

Dear Sir,
Is it the case that a load center like an IOU for a city may not become or stay a member node of MISO... if IOUs supply capacity does not exceed the peak load by the minimum PRM? ***No (or from reviewing the questions below I believe I have supplied the answer.)***
For example, suppose an IOU member of MISO, which at first meets the PRM requirement but then shuts down a 500MW plant which then lowers capacity below demand; does this new situation automatically force the IOU to quit MISO? ***No*** What must/can be done to fix this? ***Replacement Resource*** Can the problem be fixed for a week, month or year and then be revisited periodically. . Or does the IOU have to buy into partial ownership in a long term PPA or power plant? ***No*** Of so, what is the minimum contract time for such a PPA or power plant ownership? ***PRMR is determined yearly, i.e. for the Current Planning Year Timeframe of June 1, 2015 thru May 31, 2016***
Home > Library > Business Practices Manuals (BPMs)
· **BPM 011 - Resource Adequacy**
Section 6 Performance Requirements (Sections 6.1-6.4)

§ **6.3 Replacement Resources 6-106**

6.3 Replacement Resources

Any Market Participant with a Planning Resource that either cleared in a Planning Resource Auction or was identified in a FRAP who plan to de-commit (retire, suspend", other) the Planning Resource during the Planning Year must be replaced with ZRCs from a Planning Resource located in the same Local Resource Zone as the Planning Resource that is being de-committed. Planning Resources that are used for replacement purposes should be done at least 7 days prior to effective date of replacement. Replacement of resources can be done only with ZRCs that have not cleared in an annual or Transitional PRA, included in a FRAP. The ZRCs can be from the Market Participant's own Planning Resources or from another Market Participant as long the Planning Resources are in the same LRZ and have not been used to meet Module E requirements. New resources can be used if registered, qualified and approved by MISO by the due dates for annual and Transitional PRAs.

For Planning Resources from a diversity contract, the Market Participant must replace the ZRCs by replacing them with an equivalent volume of ZRCs from Planning Resources located in the same LRZ.

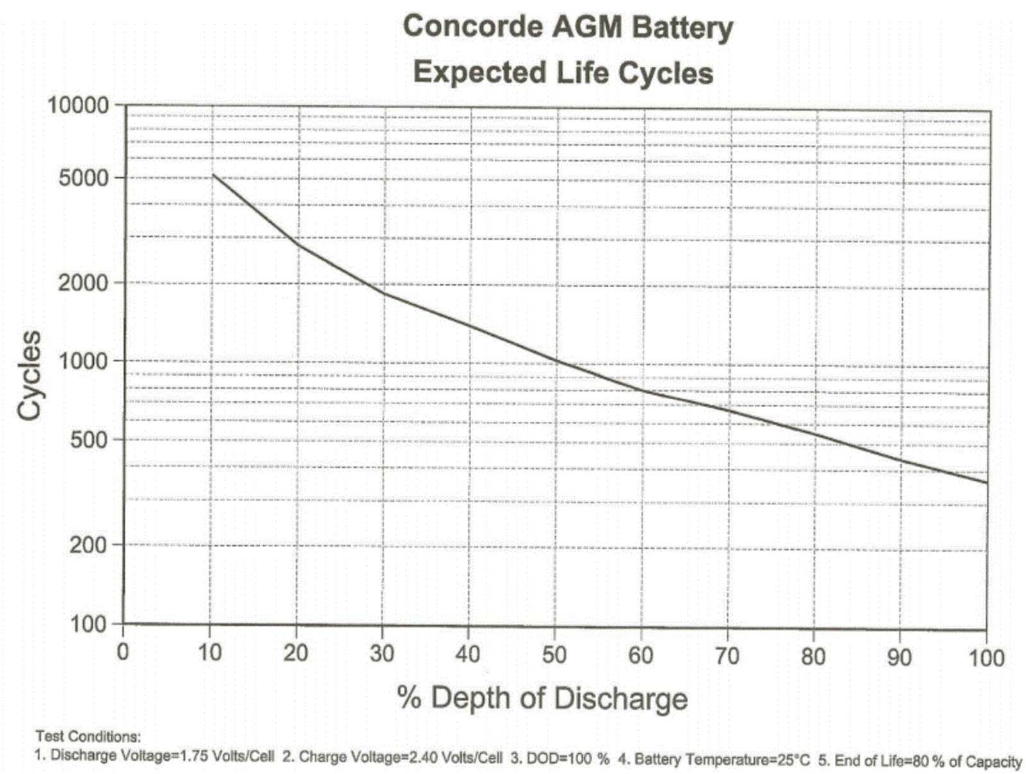
For External Resources that are diversity contracts, the Market Participant must replace the ZRCs by using the following methods:

- Replacing with an equivalent volume of ZRCs from a Planning Resource in the same LRZ; or
- Replacing with an equivalent volume of ZRCs from an External Resource that is a diversity contract that is at least as available for the same duration during the Planning Year as the resource that is being replaced.

APPENDIX C — LIFE CYCLE VS DEPTH OF CHARGE FOR LEAD ACID AND LI-ION BATTERIES

Although lithium-ion batteries have greater initial costs than lead-acid batteries, they are rated to have about 7 times as many cycles at 40% depth of discharge.

The adjacent graph is a publication from a particular manufacturer for its AGM lead acid batteries. At 40% depth of discharge, roughly 1500 cycles is predicted.



The adjacent graph from the DOE's Pacific Northwest National Laboratory report states that a Li-ion battery will last around 10,000 cycles at 40% discharge.

Assuming, one 40% discharge cycle per day, the AGM batteries will last 1500 days or just over 4 years; while one set of Li ion batteries would last almost 7 times as long—or about 28 years.

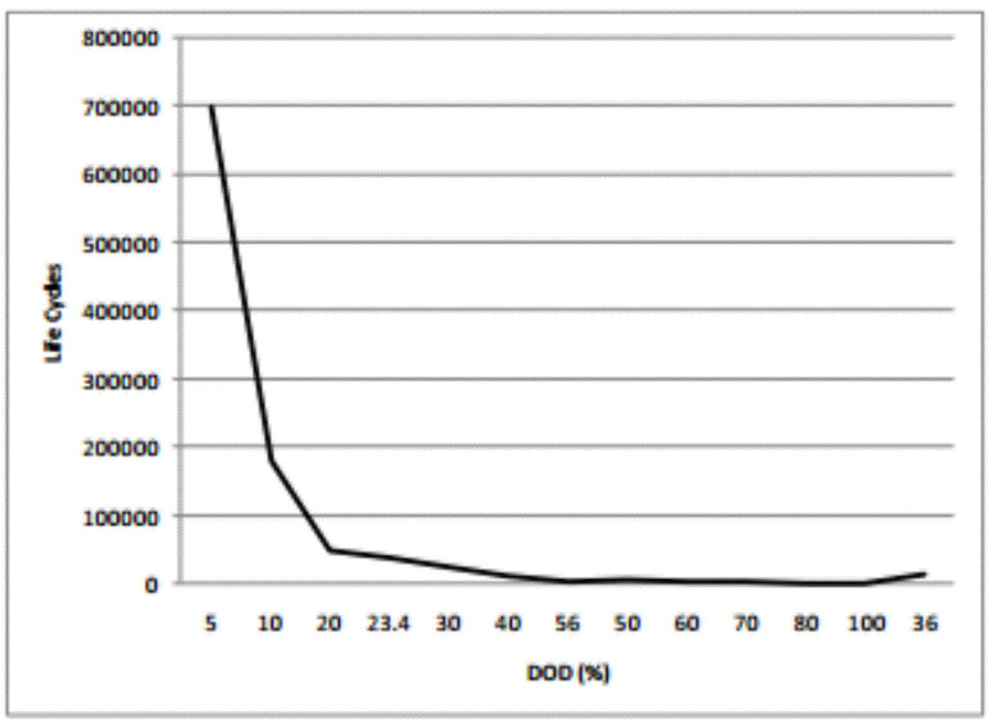


Figure 2.2. Li-Ion Battery Life-Cycle versus DOD Curve.

APPENDIX D — EXPERT OPINIONS ON COST-EFFECTIVENESS OF GRID-CONNECTED BATTERY STORAGE

October 13th, 2014 by **Giles Parkinson**
"**Renew Economy**.
(Note, all dollars are $US).
The flow of analysis about battery storage from big-end investment banks continues apace. Last week it was **HSBC** and **Citigroup** with ground-breaking reports – which we wrote about **here** and **here.** UBS also jumped in on the act too.
Why is this so? Well, according to UBS, interest from both investors and corporates has accelerated in recent months. That's because the big end of town is suddenly alive to the opportunities of a technology that will likely be even more disruptive than solar. And the key is in the forecast on costs.
Citigroup last week cited $230/kWh as the key mark where battery storage wins out over conventional generation and puts the fossil fuel incumbents into terminal decline.
UBS, in a report based around a discussion with Navigant Research, says the $230/kWh mark will be reached by the broader market within two to three years, and will likely fall to $100/kWh.
And it predicts that the market for battery storage will grow 50-fold by 2020, mostly in helping households and businesses consume more of their solar output, but also at grid scale and with electric vehicles.
So here are some highlights gleaned from the UBS discussion with Navigant:
Navigant estimates the cost of materials going into a battery at the Tesla Gigafactory on a processed chemical basis (not the raw ore) is $69/kWh [this metric is per kW per hour of operation].

The cost of the battery is only ~10-20% higher than the bill of materials – suggesting a potential long-term competitive price for lithium-ion batteries could approach ~$100 per kWh. Tesla currently pays Panasonic $180/kW for their batteries, although conventional systems are still selling for $500-700/kWh. But Navigant says that the broader marketplace will reach the levels Tesla is paying in the next two to three years.
A typical 'load shifting' 4-hour battery (designed to address the afternoon/evening peak) costs anywhere from ~$720-2,800/kWh, depending entirely on the scale of the lithium-ion battery employed and the size of order.

The average $500-700/kWh for a typical battery is probably closer to the $2,000-3,000/kW when including the balance of the system costs (around $400-500/kW), with a trend towards around $1,500/kW within the next 3 years. Navigant estimates the global market for batteries will grow from 400 MWh in 2013 (i.e. – 100 MW assuming 4-hour systems), to 20GWh (or around 5GW/yr) by 2020, globally.

UBS believes that the 'merchant' entry of batteries for wholesale purposes on the grid remains a few years off. Some above-market PPAs will be supported by utilities looking to use the technology to balance their grids but UBS believes commercialization of battery storage will remain biased towards 'short-usage' needs, and by businesses looking to clip their 'peak' usage charges.

Still, over the long run, the advantages of scale will mean that utility-scale storage will evolve much more rapidly compared to the residential product.

As for the market for batteries, UBS cites three sub-sectors:

Transportation: Low-cost, high-density, low-weight batteries. We emphasize this sector is likely to take a different direction from utility solutions.

Utility-scale: The main focus, with the primary consideration for these solutions being their ability to deploy quickly, into high-density populations without contributing to air or water permitting hassles.

Distributed resources: In commercial, industrial, and residential applications. "While many would point to the ability to move 'off the grid' entirely, we suspect the economics are unlikely palatable. Rather, the ability to clip 'peak' demand contributions by industrial customers is particularly notable. "

As for the question of which technology, Navigant expects lithium-ion to remain the market leader for grid as well as small-scale storage for the next ten years. The main risks remain the uncertainty on input costs for lithium, as well as cobalt and graphite, where Navigant thinks the greater "pinch points" await.

Other technologies being considered include flow batteries, such as advanced lead acid carbon, which are also functionally well suited for grid storage/long duration applications. Newer chemistries, such as the currently under research lithium sulfur and magnesium-Ion batteries may gain traction by early next decade.

Beyond batteries, pumped hydro faces the problem of limited favorable locations available, but fly wheels and compressed air storage (combined – and dispatched through gas turbines) may yet find their respective niches, although could well be excluded from ongoing state processes to kick-start the battery sector.

'In the end, lower prices are coming, but the technology is not yet clear,' UBS notes.

And, it quotes Navigant researcher Sam Jaffe in this clear point, that battery storage is coming now.

Jaffe said most of his ten years in the sector had been "sitting at conferences hearing the same presentations from the same people about the same hypothetical benefits of energy storage.

‘But I see a very important change in the last two years where most of the presentations at these conferences are now talking about actual deployment of storage. So what has a hypothetical concept been for so long is now becoming a real business.’

As Jaffe noted, the $180/kWh price paid by Tesla compares to about $1500/kWh even five years ago, maybe seven years ago when it was $1200 to $1500 per kilowatt-hour. ‘So $180 per kWh is the price of those batteries, not the manufacturing cost but the price that they’re paying for them,’ he said.

He also made this point about the comparison between battery storage and gas-fired peaking plant:

‘If you assume that we’re at around a $200 per kilowatt-hour price point today for high quality Lithium-Ion batteries that are going to last ten years under frequent cycling, and if you wanted to build a very large peaker plant with four hours of energy duration behind it, it would be about $1400 per kilowatt on those costs.’

‘Interestingly, that’s actually pretty comparable to the cost of building a natural gas-fired peaker plant. Keep in mind, you’re not buying fuel for batteries – you’re essentially just arbitraging low and high cost of daily electricity.’”[100]

Wisznia | Architecture

28 August 2015

To the New Orleans City Councilmembers engaged in the Entergy regulatory process:

Wisznia|Architecture+Development have reviewed BSI's intervenor submission regarding Entergy New Orleans-2015 Integrated Resource Plan. Our firm is particularly interested in supporting the expansion of PV in New Orleans and the means by which allowing community solar (a.k.a., virtual net metering) would facilitate the possibility for property owners and developers in the central business district (CBD) to incorporate renewable energy outside of Entergy's downtown grid. It is our understanding that Entergy does not permit net-metering in the CBD; even though utilities must facilitate net-metering as per State law.

wisznia

My company has developed almost 300 downtown residential units in New Orleans since Katrina. Despite our firm's inclination to be good global citizens, these developments have been blocked from using PV and electrical Net Metering because they all happen to be within the CBD. As you should know, Entergy New Orleans prohibits net-metering downtown because the majority of the CBD's electricity grid, by design, protects itself from reversed energy flows. Providing PV electricity for our downtown projects would become viable with community solar; and with lower utility bills, our tenants could better justify spending more of their money on improving their quality of life with additional dollars staying local, more fully supporting restaurants, merchants, and our City's numerous cultural events.

Based on the findings and assertions in the BSI Intervention Documents, it appears that there are no major obstacles in promoting community solar in New Orleans. Community Solar has been adopted by our Nation's Capital and in many other States; The New Orleans City Council should incorporate that opportunity into the Integrated Resource Plan because larger scale PV electric generation could play a significant role in eliminating the need for a new extremely expensive and environmentally adverse, fossil fuel generation plant.

Virtual net-metering, would also provide those home/business owners in New Orleans' many Historic Districts to more easily participate and benefit from renewable energy; in addition to home owners who have unique roofs or land that are blocked by our City's significant tree canopy. Community Solar resolves all of these inequities.

800 Common Street, Suite 200 New Orleans LA 70112 504.581.1948 tel 504.581.1954 fax wisznia.com

Wisznia | Architecture

New Orleans City Councilmembers
28 August 2015
Page 2

Wisznia|A+D would also like to see extra PV capacity going towards lowering the bills of low-income residents and to help those most in need. BSI's intervention explains that if the New Orleans City Council uses a variant of Washington D.C.'s community solar regulation, roughly 10% of the kWhs produced by community solar would go into a pool dedicated to lowering the bills of those of our least affluent citizens. This is a win-win-win opportunity; as such, Wisznia|Architecture+Development support those parts of BSI's plan referred to in this letter.

Sincerely,

New Orleans Offices of Wisznia | Architecture + Development

Marcel Wisznia, Architect, AIA
Principal

HRI PROPERTIES

August 31, 2015

We have reviewed BSI's Submission Regarding the 2015 Draft Integrated Resource Plan (Comments) prepared by Entergy New Orleans (ENO. Our firm is intrigued by the Recommendation of Virtual Net-Metering in the Comments (Recommendation). The Comments make reference to 19 jurisdictions that have adopted some form of this Recommendation. These jurisdictions should be investigated for their comparability to New Orleans. A way of adopting an appropriately confected New Orleans program should be explored. The Integrated Resource Plan should be able to incorporate this opportunity.

HRI Properties is a major developer of real estate in the New Orleans. I support the expansion of Solar Photovoltaics (PV) in New Orleans. The possibility of Ratepayers in the central business district (CBD) where we are being told that Net-Metering is not allowed or on properties unsuitable for solar installations especially those in our several historic districts and those under our wealth of live oaks being able to benefit from investing in PV would greatly improve the quality of life and spur economic growth in New Orleans. Commercial Ratepayers could have a more profitable energy use profile with their inclusion as well. Larger scale PV generation could play a significant role in eliminating the need for a new extremely expensive and environmentally adverse, fossil fuel generation plant.

This is a win-win-win opportunity.

Sincerely,

Pres Kabacoff
CEO HRI Properties

812 Gravier Street, Suite 200 • New Orleans, Louisiana 70112 • 504/566-0204 • fax 504/525-3932

Appendix G — Inverted Demand Compliant Construction — A Key to a Renewable Energy Future

[1] BSI, LLC, 302 Walnut St, New Orleans, La 70118, 504-343-1243, Myron.Katz@EnergyRater.com

[2] These comments were written by Myron Katz. By far, the biggest content and editorial help was provided by Thomas Milliner. Valuable review assistance was provided by Jaye Hakes, Eli Oppenheimer, Dan Weiner and Norman Witriol. Editorial assistance was also provided by Sharon Katz.

[3] This document references "Inverted Demand Compliant Construction, a Key to a Sustainable Energy Future," a presentation by BSI at EEBA's September 2014 national conference, "The Energy Hawk", published in 2007 by the New Orleans Energy Policy Task Force, as well as cited references.

[4] Email communication between Casey DeMoss and Timothy Cragin, August 26, 2015 and August 31, 2015.

[5] Zonal Reserve Credits are interests in otherwise under-committed generating capacity that can be purchased from other MISO entities to avoid this problem.

[6] https://www.tep.com/doc/planning/2014-TEP-IRP.pdf, page 197.

[7] https://www.tep.com/doc/planning/2014-TEP-IRP.pdf TEP's 2014 IRP predicts a 40 MW drop in peak demand from their energy efficiency program every year until 2020. Why? Because the state of Arizona mandated it.

[8] In a private communication on August 12, 2014, Joananne Bauchman, Business Development and Sales Manager of Vermont Energy Investment Corporation, expressed her opinion that classical DSM artificially separates — allowing rebates for in energy efficiency investments but not for solar or batteries; that is why DSM is renamed in NY.

[9] Demand response (also known as load response) is a temporary reduction to the electricity usage in response to power grid needs or shifting the electricity usage during periods of peak demand or other grid constraints.

[10] This helps to generate a desire for smart meters and a back-up means of quality control for rebates.

[11] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter8.pdf?la=en, page 75.

[12] This does not need to create an *increase* in demand charge because some buildings like churches will see a drop in this charge; conversely, some homes that operate like a commercial building should be required to pay this fee.

[13] California's utilities commonly have this discount. — Private communication, B Ward, Solar City executive, 8/15.

[14] Washington D.C.'s utility regulator applied this approach for solving the non-participant test for solar farms.

[15] Why reinvent the wheel? RESNET's rating providers are required by their industry to provide quality control.

[16] BSI believes that performance-based rebates can easily outperform price-based if there is good quality control.

[17] $1.5/W was chosen because the *BSI Critique* showed that ENO has been paying $1/W for DSM but is willing to pay $5/W for a plausible PV system in its IRP; the PV system was picked as most economical in one scenario.

[18] https://en.wikipedia.org/wiki/White_certificates; some regulators require their IOU's to buy and trade WC's.

[19] By demanding a minimum 10% reduction in consumption, *low-hanging fruit* cannot be the only fruits of success.

[20] This has highest priority; this one should be implemented yesterday, since most solar tax subsidies end in 2016.

[21] http://www.epa.gov/greenpower/gpmarket/rec.htm; EPA's recent *Clean Power Plan* will make this lucrative.

[22] BESS can be more cost-effective than PV and has a much greater ↓peak demand potential per dollar invested.

[23] E.g., putting timers on electric water heater that keep them off between 6 AM and midnight; this is too cheap.

[24] A BESS in a home, sized to provide emergency back-up power for a week, can earn $150/month with this tariff.

[25] This idea was already implemented in Gainesville, FL for their utility — zero cost and engages the marketplace.

[26] Currently, before Michoud is shut down, ENO buys power from MISO because it is cheaper than making electricity with the low efficiency generators within Michoud. ENO did not show in its IRP that a healthy contribution of DSM like proposed above could not decrease demand faster than ENO could build a new generator. No convincing evidence shows that ratepayers will be paying less for energy in 2019 (the earliest possible time that a new generator can come on line) with a new generator instead of more investment in DSM.

[27] ENO's IRP did not consider installing batteries to decrease the needed size of the alternative PV system by a factor of four; but it did show that if that PV system capital cost were one-fourth as much as modelled, it would have been deemed the lowest cost alternative in every scenario. BSI has shown that BESS storage without PV is more cost effective than PV without BESS and BESS added to PV can change the percentage of usable "on peak" output of a PV system from the 25% ENO assumed to two to six times that amount.

[28] Decoupling the incentive for the utility to only make a profit by building new generators is supported by BSI.

[29] As long as ENO runs the DSM it can be expected to discourage improvements in its effectiveness.
[30] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter9.pdf?la=en, page 3.
[31] Private Communication with Bruce Froyum of MISO, August 24, 2015; Section 6.3, Performance Requirements.
[32] http://archive.iamu.org/default%20page%20links/MISO/MISO%20Market%20Report%2010-12-12.pdf, page 6.
[33] "It is important to put context around the current value of capacity in the MISO market. MISO capacity market results for the 2013/2014 year cleared at $1.05/MW-day. MISO cleared with 8,100 MW of excess capacity not clearing and 96% of bids offered as price takers at a price of zero. UBS Investment Research, in a discussion of the MISO capacity markets on April 18, 2013 stated, 'Given substantial oversupply and the current market construct, we would expect prices to continue to clear at low prices going forward.'" Ameren Missouri, IRP, 2014.
[34] *http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf , slides 4 through 44.*
[35] The battery storage system cost $3000 for 20 kWh in batteries and $2000 for a 4 KW inverter and other electrical equipment. Using a 40% depth of discharge each day, the batteries are rated to last about 4 years before they need replacement. Assuming grid storage requires a 15-year battery life, 3 replacements would be needed; therefore, 4 x $3000 is needed for 15 years. Using a 3 to 1 ratio of kWhs to kW, as was assumed in http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf , that system can be "normalized" for the grid to have the two 4 KW inverters and 24 kWh of batteries. Thus the first cost of the "normalized" system would be $4000 + $3600 = $7600 and assuming a 0% discount rate, the cost to run for 15 years is $10,800 more. Thus the cost of a grid battery system should be roughly $18,400 for 8 kW. The grid value is thus $2300/KW.
[36] http://ilsr.org/graphics-from-the-report-democratizing-the-electricity-system/, Sept 2011.
[37] For more info on Tesla Energy, check out press kit. $250/kWh for utility scale is the real kicker http://www.teslamotors.com/presskit/teslaenergy?via=newsletter&source=CSAMedition …
[38] If you use $500/kWh and plug it into the economics just explained for previously discussed battery system, the cost of 8 KW of inverters is still $4000, but the cost of Li-ion batteries needed for 24 kWh that can operate for 15 years is 24 x $500 or $12,000.
[39] http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf
[40] http://rameznaam.com/2015/04/14/energy-storage-about-to-get-big-and-cheap/#Grid
[41] http://www.aoba-metro.org/uploads/docs/2011/MoCo%20PEPCO%20Work%20Group%20Report%204-21-11.pdf, page 92.
[42] One of BSI's principals holds a Ph.D. in mathematics from University of CA, Berkeley, is an expert in mathematical modeling, and is also a RESNET-Certified Energy Rater Trainer.
https://www.tep.com/doc/planning/2014-TEP-IRP.pdf Tucson Electric Power's 2014 IRP.
[44] Personal Communication with Bryan Mills, Market Research & Analysis, Lead, EPIS, Inc. 8/18/15.
[45] http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppK.pdf Puget Sound Electric 2013 IRP.
[46] http://www.entergy-louisiana.com/content/irp/2015_Louisiana_Draft_IRP.pdf.
[47] http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf
[48] http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf, page 4-3.
[49] [http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf slide 49.
[50] LaMonica, Martin. "Time to Swap Power Plants for Giant Batteries? Almost." *Spectrum.ieee.org*. IEEE, 10 June 2014. Web. 13 Aug. 2015. <http://spectrum.ieee.org/energywise/energy/the-smarter-grid/time-to-swap-power-plants-for-giant-batteries>.
[51] http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf, slides 4 through 44.
[52] Graphics on pages 8 and 14 of the 2015 IRP Modeling Overview section assert that over the next 20 years, the DSM program is estimated to reduce around 40 MW of demand at a cost of around $40 million.
[53] https://www.tep.com/doc/planning/2014-TEP-IRP.pdf

[54] https://www.veic.org ; Vermont Energy Investment Corporation has been controlling, designing and running DSM in that state for decades because the utility regulator found that this was most economical and effective.
[55] United States. Cong. House. U.S. Department of Energy. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*. 109th Cong. Washington: GPO, 2006. Print.
[56] "Best Practices: Demand Response." *Research Reports*. Energy Research Council, n.d. Web. 13 Aug. 2015. http://energyresearchcouncil.com/best-practices-demand-response.html .
[57] Burr, Judee, Lindsay Hallock, and Rob Sargent. *Shining Citys: Harnessing the Benefits of Solar Energy in America*. N.p.: Environment America, 2015. Print.
[58] Design Decisions for Utility-Sponsored Community Solar, http://innovation.luskin.ucla.edu/content/guide-design-decisions-utility-sponsored-community-solar, May, 2015. 75% is sited in this report, but New Orleans has two more, significant impediments not listed in their analysis.
[59] According to Steven Fenrick, chief economist at Power Systems Engineering; Personal communication 2014.
[60] http://www.epa.gov/airquality/cpp/fs-cpp-overview.pdf

[61] ENO's Draft IRP, page 26.
[62] http://www.paceglobal.com/RiskIntegratedResourcePlanningProcessDevelop.aspx
[63] https://www.ameren.com/-/media/Missouri-Site/Files/environment/renewables/irp/irp-chapter9.pdf?la=en.
[64] Personal Communication with Brian Ward, energy consultant working for Solar City — August, 2015.
[65] Personal Communication, Steven Fenrick, utility economist, Power Systems Engineering — March, 2014.
[66] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter8.pdf?la=en, page 7.
[67] Design Decisions for Utility-Sponsored Community Solar, http://innovation.luskin.ucla.edu/content/guide-design-decisions-utility-sponsored-community-solar, May, 2015.
[68] Ratepayer Impact Test (RIM). Originally known as the Non-Participant Test, RIM is also known as the "no losers test." The RIM tests from the viewpoint of a utility's customers as a whole, measuring distributional impacts of conservation programs. The test measures what happens to average price levels due to changes in utility revenues and operating costs caused by a program. A benefit/cost ratio less than 1.0 indicates the program will influence prices upward for all customers. For a program passing the TRC but failing the RIM, average prices will increase, resulting in higher energy service costs for customers not participating in the program. http://www.cadmusgroup.com/wp-content/uploads/2012/11/TRC_UCT-Paper_12DEC11.pdf; also see, https://beopt.nrel.gov/sites/beopt.nrel.gov/files/help/Ratepayer_Impact_Measure_Test.htm.
[69] IBID, page 27.
[70] IBID, Page 88.
[71] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter8.pdf?la=en, page 34.
[72] https://www.tep.com/doc/planning/2014-TEP-IRP.pdf, page 188.
[73] IDCC, page 121.
[74] https://www.tep.com/doc/planning/2014-TEP-IRP.pdf, page 193.
[75] IBID, page 100.
[76] www.academia.edu/2900824/Policy_Options_for_the_Split_Incentive_Increasing_Energy_Efficiency_for_Low-Income_Renters
[77] Personal communication, Casey DeMoss, August 27, 2015.
[78] file:///C:/Users/Myron/Downloads/RAP_RevenueRegulationandDecoupling_2011_04.pdf
[79] http://www.rmi.org/Knowledge-Center/Library/D94-27_GreeningBuildingBottomLine

[80] Greening the Building and the Bottom Line, Increasing Productivity through Energy-Efficient Design", Joseph J. Romm, U.S. Department Of Energy *And* William D. Browning, Rocky Mountain Institute 1994. http://www.rmi.org/Knowledge-Center/Library/D94-27_GreeningBuildingBottomLine

[81] https://qx5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter7.pdf?la=en, page 24.
[82] *Membranes Improve Insulation Efficiency*, Chris Bullock, 1986. Copies are available from BSI.

[83] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter8.pdf?la=en, page 75.
[84] https://q9u5x5a2.ssl.hwcdn.net/-/Media/Missouri-Site/Files/environment/renewables/irp/irp-chapter8.pdf?la=en, page 7.
[85] http://www.science.smith.edu/~jcardell/Courses/EGR325/Readings/Ancillary_Services_Kirby.pdf
[86] It has been pointed out by Thomas Bialek, an electrical engineer and prominent employee of San Diego Gas and Electricity, that such a change is a relatively minor improvement in standard inverters but may require such inverters to be connected to a relatively small battery. Bialek, Thomas, *Perspective on Solar and Energy Storage,* Presented at DOE's Sunshot Initiative: Integrated PV with Energy Storage Workshop, Jan 13, 2014.
[87] http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf slide 49.
[88] Rocky Mountain Institute; http://www.rmi.org/electricity_load_defection, page 20.
[89] PEPCO went out of business because the Maryland PUC was too displeased with its electricity reliability.
[90] There are at some 30,000 blighted properties in the City. http://www.fox8live.com/story/28278486/blighted-properties-up-for-auction-in-new-orleans. The City now seizes and sells them for liens and taxes. Maybe there is a way to sell the blighted properties at a discount to a community co-op or a for profit entity on the condition that community solar be installed.

[91] Design Decisions for Utility-Sponsored Community Solar, http://innovation.luskin.ucla.edu/content/guide-design-decisions-utility-sponsored-community-solar, May, 2015.
[92] http://www.nola.com/politics/index.ssf/2012/10/city_launches_weBSIte_to_track.html
[93] This idea need not utilize key lots, because there is much land in the city that can be otherwise made available, however, the use of land proximal to a home affords access to more and larger tax credits and allows fully, privately-funded solar farms to take full advantage of energy net metering—thereby providing more benefit for less net cost. However, the era of grossly subsidized PV is likely coming to an end because the price of installed solar has dropped by 80% since the Federal or State solar tax credits began. It is time to confect a tariff which correctly rewards owners of remotely placed solar farms without penalizing non-participating utility customers.
[94] http://nolaassessor.com
[95] The 20 kWh BESS described in detail at the September, 2014 EEBA conference costs $250/kWh, but that price does not include labor or profit; http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf; however it utilized the top-of-the-line Lead-Acid battery technology commonly used for off-grid homes at that time and a battery-type suitable for in-home installation. The 20 kWh battery bank costs $3000 and must be replaced every two years if fully cycled every day. The economics of a 20 year installation is provided in the talk assuming full cycling every day to completely avoid all electricity draws between 6 AM and midnight. Since then Tesla Motors released the Tesla Wall, a 10 kWh lithium-ion battery warranted for 10 years for $3000. This changes the cost for 10 years of batteries from $15,000 to $12,000.
[96] Rocky Mountain Institute; http://www.rmi.org/electricity_load_defection.
[97] http://www.eeba.org/Data/Sites/1/conference/2014/presentations/Katz-Inverted-Demand-Compliant-Construction.pdf; slide 49.
[98] http://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_2_final.pdf
[99] http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf
[100] http://cleantechnica.com/2014/10/13/battery-costs-may-drop-100kwh/, October 2014.