ALLIANCE FOR AFFORDABLE ENERGY EST. 1985 Energy Resilience in New Orleans

The Alliance for Affordable Energy continues to be disappointed with Entergy New Orleans Integrated Resource Planning efforts. We are frustrated that intervenor comments and suggestions have failed to be incorporated into the IRP. In the current draft IRP report, it is clear that ENO simply rejected all comments from intervenors and marched toward a pre-formed conclusion.

The Alliance believes that ENO will continue to fail to address the issues outlined in our current comments. Therefore, we implore the Council, staff, and Advisors to ensure that a final IRP report includes intervenor work that aims to safeguard New Orleans' energy future. The Alliance seeks a positive policy outcome that is a win-win for customers, the public, businesses, and ENO in New Orleans. We strongly urge ENO to seek out the win for their customers and not just their shareholders.

The Alliance's comments are structured as follows:

I. Executive Summary for Decision Makers
II. Seriously Flawed: What Went Wrong with the 2015 IRP
III. The Window for Resilience is Closing
IV. The Path Forward: Practical Steps to Optimize Clean, Affordable Energy
V. Conclusion

II. Seriously Flawed: What Went Wrong with the 2015 IRP

Entergy's draft IRP reflects an internal process that maximized bias while minimizing stakeholder and intervenor input. The draft IRP contains numerous biased assumptions and restrictions in modeling that in turn limited, rather than maximized, the amount of cost-effective energy efficiency, demand response, and renewable energy in their preferred portfolio. Further, ENO failed to comply with Council priorities to substantially increase the resiliency of the grid through investments in demand side management programs and renewable energy within the IRP docket.

Many of the issues that we raise now have already been communicated through this and previous IRP proceedings. We keep raising the same issues because ENO keeps failing to address them. There is little to indicate that ENO's response to these comments will be substantially different, unless additional action is taken by the Council now to enforce their expectations for a more resilient energy grid in this docket.

It is to this end that we make the following observations. We also note that our recommendations are based on successful steps taken in other relevant jurisdictions, including Arkansas, where Entergy Arkansas has easily achieved regulatory targets that are resisted in New Orleans.

Excessive Assumed Costs Bias the IRP Against DSM

One of the first essential points of comparison is the cost of implementing DSM measures, which ICF suggests are substantially more expensive than those found by the American Council for an Energy Efficient Economy in their national review of actual utility energy efficiency program costs in 20 states between 2009-2012. While ICF summarizes their findings with levelized cost per kWh ranging from $0.05 in the low scenario to $0.09 in the high scenario, ACEEE found average actual savings per kWh of $0.028 , with the least expensive programs having delivered efficiency savings at an average of $0.016 per kWh and the most expensive programs costing an average of $0.048 per kWh. While ICF partially explains their higher costs by pointing to a comprehensive portfolio including the cost of Low Income Weatherization programs at $0.14, this represents just 1% of the program savings in their study, suggesting that if excluded, the total average DSM cost would still be well in excess of those found in other jurisdictions.

More notable in the ICF study are the levelized costs for Small Business Solutions and Residential Home Audit & Retrofit at $0.09 per kWh. These account for 8% of total savings and raise the total average. Fifty-nine percent of savings come from measures that cost $0.05 per kWh including Commercial Prescriptive & Custom programs (50%), Home

Energy Use Benchmarking (1%), and Energy Star Air Conditioning (8%), which together accounts for the largest share of savings and are out of line with the costs found by ACEEE. Furthermore, when compared to the actual cost of energy saved reported in Entergy Arkansas' (EAI) 2014 energy efficiency report, ICF's assumed costs are far higher. EAI's Home Energy Solutions program would seem comparable to ICF's Residential Audit and Retrofit, which cost $0.09 / kWh while Arkansas program was just $0.04 / kWh. ICF's Small Business program was also $0.09 / kWh, more than four times what EAI spent on their Small Business program at just $0.022. These are just a few strong indications that the cost of energy used by ICF and ENO were substantially inflated, which in turn greatly reduced the selection of cost-effective DSM in the IRP.

Projected DSM Opportunity Declines Ignore Ongoing Innovation

ICF points to changing federal efficiency standards as a reason why New Orleans will be unable to achieve strong savings levels seen previously elsewhere. As example, ICF emphasizes that low cost lighting retrofit programs were a significant portion of savings in other jurisdictions, but that changes in federal standards will reduce the potential for similar savings from replacing incandescents with CFLs in the future. What this assertion overlooks however, is that technological innovation for energy efficiency continues to accelerate in countless areas such as lighting, thermostats, home energy benchmarking, building retrocommissioning, and countless other areas while costs for such technologies are steadily falling. Ultimately, there is no reason why we should not expect to see new energy saving opportunities in the future to replace those that have become common practice after innovation and economies of scale are realized. The implicit ICF assertion that we should view DSM savings potential as static and limited to today's technology and prices should be rejected. Fundamentally, these types of arguments by ICF and ENO simply seek to minimize cost effective DSM resources.

Comparing New Orleans DSM Targets Only to Southern States is Flawed

ICF takes a stand on comparing DSM in New Orleans only to Southern states, rather than looking elsewhere in the country, while focusing in on the years' 2010-2012. There are two serious flaws with this approach. First, the states selected by ICF for comparison rank at the bottom of the ACEEE annual scorecard for energy efficiency and therefore should in no way be seen as a model. Second, it is preposterous to think that by looking at extremely low performing states during a period of equally low political leadership on DSM that you would be able to get a snapshot into the achievable potential for a highly motivated jurisdiction like New Orleans. ENO and ICF have insisted on comparing their ability to improve savings to whole state programs, rather than peers in other cities, again, forcing the goal lower.

The poor energy efficiency performance of states selected by ICF for comparison in the 2010-2012 period is largely a reflection of the historic effectiveness of Southern utility resistance to DSM and a lack of political will by the majority of Southern regulators. Despite the fact that there are indeed weather and geography related differences between states in different regions, as ICF notes, it would be fundamentally wrong to suggest that it is our hot humid climate that explains lower energy efficiency performance in Southern states instead of acknowledging these political realities. In fact, there is strong reason to believe that such historic underinvestment means a greater level of low cost energy efficiency opportunities remain readily available in our region. Ultimately, one would hope and expect that the rest of the Southern states to pursue targets of their own, as Arkansas has done. Regardless of when and whether they do, New Orleans has the authority and stated intention of doing better than its regional peers have historically done. Therefore we differ strongly with ICF's assertion that a review of Southern state energy efficiency investments in the years 2010-2012 should serve as an appropriate benchmark against which to assess the efficiency savings potential for New Orleans over the next twenty years.

Entergy Has Demonstrated Ability to Easily Exceed ICF Proposed DSM Levels
For further illustration of how ICF has unduly restricted its basis of comparison, it is instructive to look at Arkansas, a state ICF included but chose to focus only on the years 2010-2012, rather than looking at more contemporary data. Following an initial quick start period, the Arkansas Public Service Commission established annual energy savings targets beginning in 2012. According to Entergy's recent IRP filings in Arkansas, in 2012 EAI achieved energy efficiency savings accounting for 0.51% of sales, 0.9% in 2013, 1.0% in 2014, and are now on track to reach 1.15% saving in 2015. Furthermore, Entergy indicates that they intend to achieve 1.27% annually for the period 2016-2018, which is 120% of the current APSC directed utility target. This is hard to reconcile with ICF's projected DSM savings potential of just 0.6% annually for the entire twenty year period of Entergy New Orleans IRP.

ICF certainly has access to Entergy's energy efficiency performance figures from Arkansas, so it is extremely difficult to understand why they felt it more appropriate to use figures from 2010-2012[1] as an appropriate basis for comparison in the New Orleans IRP.[2] This is just one reason of many why ICF's assertion that a restricted focus on Southern states for the period 2010-2012 should be rejected as the appropriate benchmark for comparison with potential ENO DSM savings in the IRP. As we have recommended in previous IRP cycles, we strongly recommend that the City Council reject attempts by ICF and ENO to avoid comparison to other jurisdictions and suggest using readily available contemporary

[1] It should be noted the 2012 figure ICF included for EAI in Appendix E conflicts with Entergy's own data filed with the APSC
[2] Aug_7_IRP_Stakeholder_Mtg.pdf, 37-44

energy efficiency data and approved policy targets for Arkansas and a broad cross-section of nationally recognized leaders when assessing how proactive New Orleans should be in setting their own DSM targets.

DSM Benefits Are Understated

At the 4th milestone technical conference it was noted that it is necessary to account for the full measure life of installed measures to accurately account for the net present value benefits of DSM investments, which is particularly important for those that are invested in the latter portion of the 20 year plan. To do otherwise is to inaccurately apply costs without accounting for the resulting benefits. This issue was raised during the last IRP cycle, but does not seem to have been addressed in the current IRP.

While it was decided following the previous IRP cycle that non-energy benefits would be identified and quantified to a reasonable level in future iterations, Entergy has not done so in the draft IRP. These benefits are important for the Council when considering a full range of policy issues and the differences between portfolio alternatives. While it is understood that the treatment of non-energy benefits will continue to evolve, it would be appropriate for the Final IRP to acknowledge differences in the non-energy benefits between the portfolios presented to the Council.

Restricted Participation Rates Severely Reduces DSM Adoption

Like the previous IRP, low assumed participation rates are unduly restricting the size of DSM programs in this IRP and unnecessarily extending the ramp up periods for highly cost effective energy efficiency investments. Because there are now several years of actual Energy Smart program activity, we can see that it is the restricted size of program budgets, and not a lack of customer willingness to participate, that is limited the deployment of cost-effective energy efficiency in New Orleans. Each year, Entergy has fully expended the allocated Energy Smart budget, for programs well before the year is over, resulting in interested customers being turned away. This is one more reason why the inaccurate market acceptance curves should not be allowed to restrict DSM in the early years of this IRP when program investments are most valuable.

Entergy's Modeling Minimizes, Rather than Maximizes DSM

There are several ways in which Entergy's approach to modeling in the IRP has restricted the amount of DSM selected, including: modeling against the MISO marketplace rather than head-to-head with proposed supply resources, incurring more free ridership costs by modeling high incentives without phasing, cream skimming, and lack of clear strategies for off system sales. By modeling DSM separately against MISO rather than head-to-head against proposed supply resources, Entergy has selected the minimum justifiable level -

rather than the maximum cost-effective energy efficiency investment for their preferred portfolio.

One consequence of this approach is that there is no way for Entergy, the Council, or other parties in this proceeding to see what supply investment savings could have been achieved through deeper investment in energy efficiency. This is particularly significant since Entergy's preferred portfolio is heavily focused on peak load, while many energy efficiency programs are known to be effective at reducing demand during times when energy use is highest. The use of high incentive levels for cost-effective energy efficiency programs is a way to increase total participation levels. However, without taking steps to incrementally raise the incentive level over time, the cost of free ridership is greater. This may be worthwhile if steps are being taken to aggressively expand DSM adoption for the purpose of directly offsetting the cost of more expensive imminent supply resource investments, which may in fact be appropriate for New Orleans at this time.

At the 4th milestone technical conference it was indicated that the high incentive level was used for all DSM programs. However, ENO's response to discovery AAE-37 suggests that different incentive levels were used for the various programs. In either event, greater nuance in phased deployment of increasingly higher DSM incentives (to a point) should enable all potential participants to benefit, while saving more money for program deployment. Commercial programs that expend their full budget prior to the end of a given year, for instance, would seem to suggest that either the program is spending too much on free riders. If, the energy savings impact is so great as to justify the cost of extra free ridership, then the budget should be increased to reflect it.

The process of skimming the most effective energy efficiency measures prior to modeling the others reduces the total DSM investment to a minimum level. Whereas adding additional measures until the full portfolio of programs has been brought up to the line of cost-effectiveness maximizes the amount of DSM investment. As noted above, when ramp-up rates are slowing the overall impact of DSM, this is one effective way to ensure a deeper level of impact earlier on. It has the additional benefit of supporting additional market development, which can in turn help to reduce costs. While the subject of off-system sales has been raised repeatedly in the current and previous IRP cycles, there is still no practical information provided in the Draft IRP to understand what impact varying levels of DSM investment would have on utility revenue requirements when sales of excess energy are factored in. Here once again, the heavy emphasis in this IRP on capacity without a balanced level of information on energy generation and off-system sales greatly limits our understanding of how DSM and renewable energy resources operate as alternatives to Entergy's recommended portfolio.

Policy Uncertainty
Numerous times throughout the Draft IRP, Entergy points to its own questions about policy certainty as a factor in how much energy efficiency belongs in the IRP. We believe this assertion reverses the purpose of the IRP, which is meant to find the most cost effective, reliable, and least risky plan for meeting customers' needs. Entergy is right to note that ongoing policy considerations related to DSM warrant continued attention, but wrong to suggest that limits should be placed on the analysis of cost effective available energy resources.

We believe that there are enough demonstrable biases against DSM and flaws in the IRP modeling process to warrant an additional technical conference on the subject. The Council should require that significant substantive changes be made in the IRP before the final report is submitted for their approval.

Bias Against Renewables
Despite consistently strong statements by the City Council, intervenors, and the community that renewable energy ought to play a significant part in how New Orleans meets its energy needs, Entergy's preferred portfolio includes no renewable energy resources for 20 years. Their principal argument against renewable energy are rooted in their own high installed cost assumptions, a range of unconventional and inconsistently applied charges, and unconventional capacity-related costs they imposed on wind and solar due to the intermittent nature of renewable energy generation.

Without providing citation or explanation, Entergy used installed and generated wind energy cost assumptions that are significantly higher than, and out of line with, contemporary market norms. There are at least three ways in which these costs have been inflated, thereby skewing the modeling against the selection of wind in favor of traditional fossil fuel resources:

1) Excessively high installed cost assumptions
2) Irregular "match ups" leading to inflated levelized cost of energy lifecycle resource costs
3) Adding non-standard, inconsistently applied or unexplained additional fees and charges to out of state wind contracts

Furthermore, by de-emphasizing energy generation in favor of capacity and obscuring the potential value of off-system sales, the natural advantages of wind energy have been further marginalized in the Draft IRP.

Excessively High Installed Cost Assumptions
Entergy's assumptions for installed and generated energy costs for wind are substantially

higher than those reported by the Department of Energy and Lawrence Berkeley National Laboratory. Over the past two decades, wind prices have trended downward to levels that now strongly compete with fossil fuel generation. Nevertheless, inflated costs in the utility's assumptions skew the modeling results away from wind in favor of fossil fuel generation.

Entergy's assumed cost of $2,050 per kW are far higher than the $900-$1,300 per kW range cited by LBNL in their 2013 Wind Technologies Market Report, and approximately 30% higher than the decade's *highest* single year average prices in 2008. (LBNL 2014, page 48)

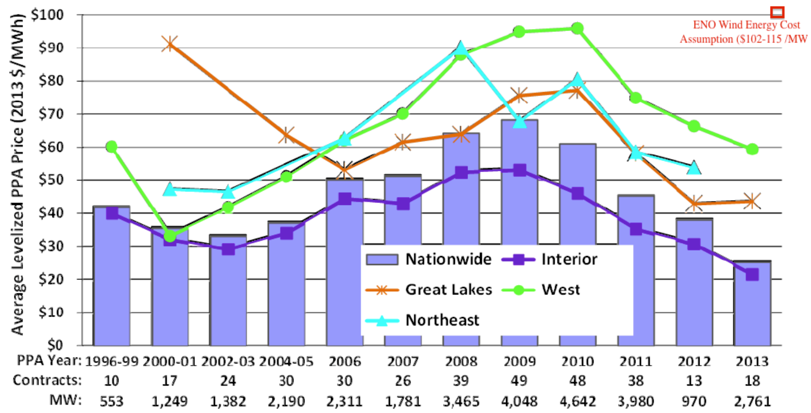
Inflated Levelized Costs for Wind Conflict with Reality

Like the inflated assumptions for installed costs above, the lifecycle resource costs Entergy uses for wind are similarly high, and also uncited and unexplained. In their 2013 wind report, the Lawrence Berkeley National Laboratory presents Levelized Cost of Energy (LCOE) figures for wind projects drawing on data from a total of 29,322 MW of wind installed in the U.S. since 1996. Once again, LBNL's data-backed research strongly conflicts with the LCOE figures used by Energy in their IRP assumptions. In contrast to Entergy's $102 - $115 / MWh assumptions (which will be discussed further in the next section), LBNL states the average LCOE for wind in 2013 was $25 / MWh, with the lowest-priced projects coming from the interior region of the country, with costs depending on resource location, production tax credit, availability, and other factors[3].

According to Lawrence Berkley National Laboratories' Annual Wind Technologies Market Report,[4] no region over the past 20 years has average power purchase agreement prices over $100/MWh. LBNL figures report contractually and legally binding prices, while figures given by Entergy are offered with no explanation or citation.

Generation-weighted Average Levelized Wind Power Purchase Agreement Prices by Execution Date and Region[5]

[3] The Southern Wind Energy Association (SWEA), April 1, 2015, Re: LPSC Docket: I-33014, Data Assumptions dated May 5, 2014.
[4] 2013 Wind Technologies Market Report, Lawrence Berkeley National Laboratory. [emp.lbl.gov/sites/all/files/lbnl-6809e.pdf]
[5] Ryan Wiser and Mark Bolinger (August 2014). 2013 Wind Technologies Market Report, Lawrence Berkeley National Laboratory. [emp.lbl.gov/sites/all/files/lbnl-6809e.pdf]



Source: Berkeley Lab

When this up-to-date and real-market data is compared to all other technologies shown in Entergy's chart, wind is the least cost resource. In fact, other utilities in Louisiana are including wind in their integrated resource planning as a result of lower costs as compared to CCGT or CT resources. Swepco includes a need of 1,700 MW of wind energy capacity over their 20 year study horizon.

Unconventional Match-Up Costs

Entergy has added a number of unconventional, selectively applied and unexplained costs when evaluating wind, beginning with what they call a "match-up cost." The problem with these figures begins with the fact that use of a match-up cost is not industry standard practice, is not used by Louisiana utilities (other than Entergy) in their respective IRPs, nor do we know of any example elsewhere that justifies these match-up charges as a suitable approach for assessment of wind in an IRP. It is inferred that this match-up cost is essentially paying for another generation resource whose cost is then being added to the LCOE for wind. While the intermittency of wind generation is to be acknowledged, it would not be proper to add the cost of a base load unit to a peaking plant in recognition of its limited run capabilities, nor is it therefore appropriate to add a match-up cost to wind as Entergy does when evaluating the cost of wind generation in this IRP.

As noted above, Entergy's lifecycle resource costs for wind are significantly higher than what is actually being seen in the market today. The only informative detail they offer for these high costs was a notation that during Technology Assessment screening a match-up cost of $47.88 was added due to wind's 14.1% capacity value in MISO[6]. Subsequently, in the Draft IRP the match-up cost was changed to $18.76 / MWh and the total cost for wind

[6] Supplement_2_ENO_IRP_Technology_Assessment, page 9

without PTC went from $115 / MWh to $109 / MWh.

While we disagree with the match-up cost concept entirely, Entergy has taken pains to state that they applied this charge to wind and solar resources only during the Technology Assessment screening[7], but that does not remove it as an issue in the IRP. This unconventional added charge is important in no small part because the only chart anywhere in the Draft IRP that shows a comparison of Levelized Cost of Energy for each resource alternative is Table 3 in the Draft IRP section entitled Assumptions, which includes the match-up cost.

To first appearances, the presence of match-up costs in this table itself counters the assertion that they were only for screening purposes, since a larger set of resources had already been screened for economic feasibility and market maturity to arrive at the 21 resource alternatives included in this table - and there is no indication that the table itself is actually being used to screen out resources.

Furthermore, since wind passed the original screening with the Technology Assessment in October 2014, there would seem to be no reason to reduce the match-up cost when presenting the same table in the Draft IRP. The practical effect of doing so, however, prevents a reviewer from taking the original $115 / MWh figure and subtracting $47.88 / MWh (match-up) to get an LCOE for wind of $67 / MWh - lower than the other energy resource in both the reference and high gas scenarios. While this is still far higher than the LBNL figures for LCOE using real wind contract data, the lower match-up fee in the Draft IRP would seem to imply that Entergy intends for a reviewer to instead figure the LCOE for wind by taking $109 / MWh and subtracting $18.76 / MWh (match-up) to get a LCOE for wind of $90 / MWh, no longer the least expensive in any of the scenarios.

The fact that the amount of the matchup-cost was changed between the Technology Assessment in October 2014 and the Draft IRP in June 2015 without any explanation or citation is odd. That the reduction of the match-up cost from $47.88 down to $18.76 / MWh resulted in a mere $6 / MWh reduction in the LCOE for wind from $115 / MWh down to $109 / MWh, and that there was inexplicably no change in the $102 / MWh figure used for wind with PTC, is even stranger. That these capacity match-up costs are being added to a table that is evaluating generation (MWh), rather than capacity (MW) makes the matter that much more unclear. Together, it raises serious concern that the wind cost figures used by the utility throughout the IRP process were arbitrary and without credible factual basis - despite the plethora of real contracted wind projects whose data is publicly available and could easily have been used for reference in this IRP.

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[7] ENO Draft IRP, page 19

It would have been better had the utility stuck to presenting the actual Lifecycle Resource Costs, as the title of the table indicated, rather than creating this unconventional charge to inflate and obscure the cost of renewables. The practical effect, however, is that wind and solar resources are represented as far more expensive than they actually are in the only part of the Draft IRP where an intervenor, Council member, or other stakeholder can compare and contrast the cost of energy produced for a given supply resource against the alternatives. This is a major problem for all interested parties, who should reasonably expect to make cost of energy comparisons a part of their evaluation when assessing the value and feasibility of resources beyond those that Entergy champions in their report.

Response to Stakeholders? - More Added Charges

The match-up cost is not the only unusual charge Entergy placed on wind resources. In their response to stakeholder questions, Entergy states that using their installed cost assumptions for Louisiana-based new wind development is sufficient for evaluation of wind resources in Aurora. But this is not the case when one considers how out of line their installed costs assumptions are and the reality that most wind resources are being acquired by utilities through PPAs, often outside the utility's geographic service territory.

With the incredibly low cost of wind energy being aggressively pursued by other utilities in the market today, it should be questioned whether Entergy is merely stacking the deck against renewable energy, or more generally clinging to the rate-based traditional generation model that typified their strategy as a vertically integrated monopoly from the last century. Purchasing out-of-region wind energy is now common for utilities in the Southeast. Some existing out-of-region wind energy purchases include Arkansas Electric Coop (201 MW), Alabama Power (404 MW), Georgia Power (250 MW), Southern Power (299 MW), Swepco (469 MW), and the Tennessee Valley Authority (1,542 MW). Gulf Power's (Florida) purchase of 180 MW of wind energy from Oklahoma highlights the feasibility of bringing low-cost energy into Louisiana from the mid-west.

Entergy's wind figures are approximately four times the contract price in 2013 and 50% higher than the *highest* prices of the decade (LPBN 2013, page 59). There are too many troubling issues with the way Entergy has evaluated wind. The lack of citation, explanation, and the seemingly arbitrary costs and match-up figures in the Draft IRP as well as the substantial difference between their assumptions and the actual costs cited by LBNL points to a strong bias against wind in the Draft IRP report that needs to be corrected.

Transparency

While the Alliance understands the use and value of proprietary information in modeling, without access to the inputs and information used in the modeling, it is impossible for intervenors to ascertain the validity of these numbers. Over the course of the IRP development year, in various technical conferences and in questions submitted to the company, intervenors have attempted to understand the values assigned to utility scale solar. Unfortunately because of the use of proprietary information from a 2013 report by IHS CERA, these numbers have been kept out of the record. We are concerned that these numbers do not reflect the current market rates available for utility scale solar projects. Indeed, Entergy New Orleans' sister company Entergy Arkansas, has announced the development of an 81 MW solar farm, and while the actual cost of this system is still confidential, the 20-year contract is in the range of 5-6 cents per kWh.

Carbon Assumptions

In a recent report released by Synapse Energy Economics, 79% of the IRPs released in 2014-2015 include a CO2 price in their reference case scenario.[8] Not only are most utilities more prepared for the likelihood of a carbon fee, other companies are planning for higher beginning costs (reference case beginning around $10) than ENO models and sooner (by 2020) than ENO models in their CO2 assumptions. Taking current Federal Carbon Price for Rulemakings (~$37 mm/ton), CPP studies, Utility IRP costs into account, Synapse offers a Low ($15), Mid ($20), and High ($25) beginning cost for CO2 forecast, beginning in 2020. The Alliance believes ENO is taking a risky bet by not including CO2 in their Reference Case.

The CO2 assumptions are not science-based and do not mitigate risk for customers or shareholders. We agree that it is difficult to predict when politicians will break from misinformation campaigns sponsored by the fossil fuel industry. But as responsible adults who live, work, and own property in one of the most vulnerable places on earth, we must address the issue. We will not be acting alone. The President has released a climate action plan that makes it very clear that the US is going to honor international agreements and global carbon reduction targets[9].

Including a cost of carbon also mitigates liability with their current and future shareholders as well as future generations suffering from the consequences of unlimited carbon pollution. Companies will NOT be able to say, "We didn't know". The Alliance predicts that lawsuits over climate damage will increase. It is important for the company to start planning for this.

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[8] Synapse Energy Economics, INC, May 2015, pg. 27 [http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf]

[9] The President's Climate Action Plan released June 2013. Accessed at https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf

Entergy should include a cost of carbon in its reference case. The staff of the Louisiana Public Service Commission in response to Entergy Louisiana's IRP stated "Recognizing that the finalization of EPA's Clean Power Plan will likely result in utilities having to plan for the potential impact of CO2 costs, Staff believes Entergy should explain why it chose to exclude CO2 costs from its Reference Case." This is just fundamental. Please use data collected by the well-respected firm CDP to follow a fact-based approach in setting the right carbon price[10].

Energy grid hardening and resilience is currently absent. Entergy companies presented to the LPSC after Hurricane Isaac and showed that the 5 most destructive and expensive hurricanes have hit Louisiana since 2005. This is a trend that is completely ignored in the resource planning but which will be of significant future cost to ratepayers if ignored.

Coal Asset Assumptions

The environmental costs of the coal plant assets were not included in the reports. Coal plants will be impacted by upcoming EPA rules including:

- Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR)
- Mercury and Air Toxics Standard (MATS) Rule
- Coal Combustion Residuals (CCR) Rule
- Clean Water Act "316(b)" Rule
- Effluent Limitation Guidelines and Standards (ELG)
- National Ambient Air Quality Standards (NAAQS)
- Carbon and GHG Regulations
- Regional Haze Rule

Natural Gas Assumptions

The Alliance is concerned about the long-term natural gas price forecast used in the modeling. While we understand the difficulty in projecting market assumptions along long time horizons, there are a number of demand pressures that will exert upward pressure on the market cost of natural gas in the mid/long term future. By investing solely in one fossil fuel over the time horizon, ENO directly ties consumer pocketbooks to a single, potentially volatile, fuel market.

Reasons for Concern:

[10] Climate change strategies and risk management - the perspective of companies and investors. (2015) Accessible at: https://www.cdp.net/CDPResults/CDP-CEE-100-Climate-Change-Report-2014.pdf

1) Current and future federal regulations, along with an aging fleet, will continue to force coal generation out of the market nationally. As a result of these decommissionings across the country, North America will likely build around 90 GW of natural gas generation over the next five years. This swift and immense investment in natural gas will put significant pressure on the cost of natural gas. Even while the shale gas "boom" continues, and reserves are at record highs, the demand for gas for electricity generation is evident. In July of this year, for the first time ever, electricity from natural gas surpassed that of coal. There is no doubt this trend will continue.

2) As a result of the aforementioned "boom" the so-called industrial renaissance in Louisiana is tied to other uses of natural gas, in both petro-chemical processes, and chemical manufacturing. Natural gas is now being used in processing for ethane, methanol, polyethylene, and ethylene.

3) Natural gas powered vehicles, especially for municipal transit, are adding to the national demand.

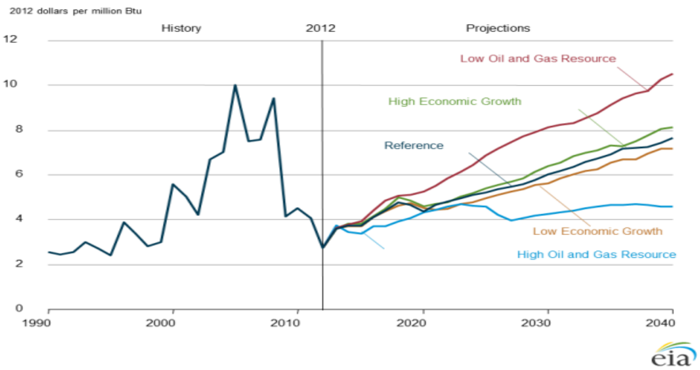
4) Exports of natural gas, including Liquified Natural Gas to be sold over-seas, and pipeline natural gas exported to Mexico, reduces American supplies.

5) Finally, even while natural gas is being touted as a cleaner burning energy "bridge," growing concern regarding the front end of the natural gas lifecycle, including more expensive and stringent rules on shale fracturing may have an added effect on the long-term cost of natural gas.

Analysts at Forbes support this position. Forbes predicts that natural gas demand growth will outpace supply growth[11] which will rebound U.S. natural gas prices sooner rather than later[12].

[11] According to Forbes, the number of natural gas drilling rigs has declined by 83%, peaking at 1,606 iSeptember 2008 and dropping to just 268 rigs as of March 6, 2016.
[12] To, Henry (2015) *A Bottom for U.S. Natural Gas Producers Is In Sight*. Forbes. March 10, 2015. 15.Accessed at: http://www.forbes.com/sites/greatspeculations/2015/03/10/a-bottom-for-u-s-natural-gas-producers-is-in-sight/

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040



Nuclear Assumptions

The company's current portfolio, and indeed the portfolio modeled over the planning horizon, includes a large percentage of nuclear generation, making assumptions that the nuclear assets currently available to New Orleans will continue as a foregone conclusion, with no additional costs. This assumption ignores the renewal process and costs and certainly should not have been left out of the planning report. According to the Nuclear Energy Industry, renewal of a reactor license is between $500 Million and $1.5 Billion[13]. These are not insignificant numbers and should have been included in the planning documents as Entergy's nuclear assets are scheduled for re-licensing during the planning horizon.

According to the U.S. Nuclear Regulatory Commission, the renewal process is approximately 30 months long and contingent on a hearing process. Based on current NRC renewal application information for Grand Gulf, the company began the process in 2011, and is 45 months into its application and is at least 12 months away from a final decision[14]. The reality of the costs and circumstances of Entergy's nuclear assets should not be excluded from the IRP.

Power Purchase Agreements

[13] Nuclear Energy Institute, "EPA's Clean Power Plan and Nuclear Energy." August, 2015. [http://www.nei.org/News-Media/Media-Room/Media-Briefings/EPA-s-Clean-Power-Plan-Nuclear-Energy]

[14] U.S. NRC, Grand Gulf Nuclear Station, License Renewal Application. [http://www.nrc.gov/reactors/operating/licensing/renewal/applications/gg1.html]

The Alliance recognizes that Entergy New Orleans' IRP presentations thus-far show fewer and fewer PPAs over the course of the study horizon. While this may be more appealing to the companies, as the opportunity to build new generation is attractive for increasing shareholder earning, the majority of generation options modeled include fuel costs that the consumer will be required to bear. We have noted that the company's planning includes a bearish outlook of natural gas prices over the coming 20 years, but as discussed above, history has shown much more volatile fuel costs. Because renewable energy generation provides a fixed cost energy resource, it provides a hedge against natural gas price fluctuations that consumers would pay through the FAC. It is always in the consumer's best interest to reduce the use of fuels that carry both economically and environmentally impactful price tags, and when Power Purchase Agreement prices for wind energy are markedly lower than the costs of a new gas plant built and operated by the company, the cost impact to the consumer is magnified.

Cherry-Picked CT

The company has made a very clear choice: building a gas-fired CT plant to address peak-load and capacity issues. The Alliance does not believe this was a choice made as a result of the IRP process. It is clear that Aurora did not choose the CT plant, as this technology did not rank as well as a CCGT plant. According to the Draft IRP, ENO chose the CT plant purely in response to the need for peaking and reserve resources. However, the difference between the CCGT and CT portfolios is roughly the same as the difference between the CT and the heavily biased portfolios with wind and / or solar.[15] The Alliance expects that the wind/solar portfolios will be much more competitive if the biases against DSM, solar and wind and those favoring natural gas are corrected.

After Union Power

Following the council's resolution to consider the purchase of 500 MW of Union Power Station in Arkansas, the planning reality for ENO has changed considerably. Almost immediately Entergy New Orleans has the opportunity to replace nearly all of the capacity lost in the decommissioning of Michoud units 2 and 3. This change, along with changes to ENO's options as a result of the dissolution of the Entergy System Agreement, materially affects the long-term planning modeled in this Draft IRP. As a result, this draft is an exercise produced, at considerable expense, in response to a council order, while actual resource planning is conducted outside the proceeding. Obviously, the company and city must make prudent decisions based on information available at the time, and must be flexible in order to best serve customers. However, the IRP is intended to capture costs that will be passed on to consumers. This IRP does not capture the real costs associated with the

[15] Draft IRP, Table 14, page 49

circumstances of the company, and does not meet the requirements set forth in the IRP order.

III. The Window for Resilience Is Closing

Timing is important. Entergy's preferred IRP represents a significant opportunity cost[16], that is Entergy recommends a course of action that precludes better alternatives for the foreseeable future. Further, Entergy takes the view that there are several mutually exclusive alternatives. If New Orleans were to follow Entergy's preferred portfolio, we would lock ourselves into a rigid course with little hope of changing direction. Entergy assumes that they cannot make the "best" choice because they cannot predict the future. But, the choices they make assume the worst about our future.

The opportunity to take advantage of federal tax incentives for wind is soon closing. The Tax Credit for wind is a 30% tax incentive that is available for wind developers until December 31, 2016. To qualify for the credit:

- System owner must be a tax-paying entity.
- Equipment must be new, though used equipment can potentially be treated as new depending on the amount of upgrades after the purchase.

Entergy Proposal Holds New Orleans Back

Entergy New Orleans' draft IRP lays out a future that would actually keep New Orleans firmly rooted in the energy past of the 20th century, rather than the energy future of the 21st. All new generation proposed is natural gas. These new investments marry New Orleans to dangerous fossil fuels for the next 30-50 years. Since the major expense of building or buying a power plant is the upfront purchase cost, ratepayers will be on the hook to pay off this debt for 30 years while being exposed to uncertain gas prices, federal regulation, and global climate change commitments and consequences.

This plan leaves little remaining power capacity to fill with clean or affordable alternatives like energy efficiency or renewable energy. With the exception of Michoud, Entergy plans to maintain their existing power generation including their nuclear power plants but, as mentioned above, does not include the cost of re-permiting the three different power plants.

The New Orleans City Council has made repeated statements regarding its priorities and commitment to energy efficiency and renewable energy, but these statements have fallen on deaf ears at Entergy. If New Orleans is to have clean energy, the time to act is now.

[16] James M. Buchanan (2008). "Opportunity cost". *The New Palgrave Dictionary of Economics Online* (Second ed.). Retrieved 2010-09-18.

Councilmember Guidry noted this is an opportunity to celebrate how far we have come in developing a strong, award-winning program. She stated her expectations for moving this work to the next level; for example, by fostering growth of demand-side management and establishing a percentage requirement for energy from renewables and conservation. She noted that now there are more community partners on this path and encouraged accommodating the partners' needs for documentation and data. She encouraged orderly program administration to make budgeting more manageable for partners providing services. Councilmember Brossett congratulated the Advisors and Entergy on the progress that has been made and noted the importance of tracking data and using benchmarks, as goals are met.

Council's Energy Vision Requires Council Action

The New Orleans City Council has demonstrated inspired leadership regarding progressive energy policy in the wake of unprecedented environmental and economic challenges. In 2006, electric rates were poised to double and the city used primarily polluting generation. Today, the City's ratepayers enjoy the opportunity to lower their energy bills and local pollution through our celebrated energy efficiency program and rooftop solar policy. The Council has indeed proven that good fiscal policy and clean energy work together for a healthier, more resilient community.

City Council members have made their policy priorities clear: continue the good work toward making New Orleans more resilient through better energy policy that promotes energy efficiency and renewable energy while keeping rates low. Since the only new investments proposed by Entergy are natural gas sourced, it is up to the Council to change the course of the IRP. Entergy's preferred portfolio contains no new investments in renewable energy, which is totally inconsistent with Council statements. In addition, Entergy's plan squeezes out the potential for investment in affordable energy efficiency, also in direct opposition to Council's stated support for growth of these programs.

The Clean power plan and lessons of Katrina

President Obama said in his recent visit to New Orleans, "We can build great levees. We can restore wetlands. But ultimately, what we also have to do is make sure that we don't continue to see ocean levels rise, oceans getting warmer, storms getting stronger." According to climate scientists, the next 10 years will determine whether humanity is able to keep planetary warming to 2ºC. As one of the most vulnerable cities to sea level rise, it is incumbent upon us to set the right example for the rest of the planet. The President said that a "clean energy revolution is helping to save this planet." If we do not prioritize clean energy alternatives, how can we expect others to? Entergy's draft IRP is not on the right side of history.

At the August Business and Executive meeting of the Louisiana Public Service Commission, Commissioner Holloway stated that all 3 Entergy Companies need to be one company and New Orleans should be under their jurisdiction. The LPSC has no understanding, nor sympathy for, the priorities or needs of New Orleans. It is critical that New Orleans' retains regulatory authority because we are the progressive policy leaders in the Southeast. The success of Council's programs, rates, and resiliency is a testament to this progressive leadership.

Now more that ever, the Council must show in its IRP that we are serious about resiliency. It is important to show the country and the world that we are serious about protecting our future. While the LPSC, the Governor and the Department of Environmental Quality fail to understand the value and importance of the Clean Power Plan, New Orleans should show the President and the EPA that we are serious about sea level rise.

Clean Power Plan:
• June 2015 Proposed Rule
• August 3, 2015 Final Rule issued along with:
• Final New Source Performance Standards
• Proposed Federal

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IV. **The Path Forward: Practical Steps to Optimize Energy Efficiency and Renewable Energy**

Peak Demand Management through DSM, Demand Response
Since peak capacity is the area of greatest need, we suggest investments in DSM instead of a CT plant as the more cost effective choice[17]. Peak load can be reduced and thereby managed more cost effectively through demand side management, using any number of DSM measures described ENO's potential study, including Dynamic Pricing. In fact, according to the Potential study, released in June 2015, Dynamic Pricing programs received some of the highest TRC scores, with "Non-Enabled Dynamic Pricing," receiving a TRC score of 139.0. This residential program is described as offering 11% peak demand savings, an extraordinary number. Residential Enabled Dynamic Pricing, with a TRC of 1.5, and defined as offering 27.5% Peak Demand Savings.

The Alliance appluads ENO's interest in upgrading to advanced meters. This technology would allow enabled-dynamic pricing and the potential for residential savings of 27.5% of peak demand. Dynamic pricing has proven to be effective and popular in other Louisiana

[17] LCOE of the various CT technologies modeled, with the reference cost of fuel range between $0.11/kWh to $0.24/kWh. Clearly, no CT LCOE is as low as the LCOE of the DSM programs modeled: averaging $0.05/kWh, according to ICF's October report.

service territories. Cleco has installed Advanced Metering across their territory and in 2014 offered customers a "Time Of Use" tariff. The program was so popular with customers in their second year, enrollment in the program increased 350% and Cleco reports a 9%[18] reduction in energy consumption during peak demand hours from participants in the program's first year.

Direct Load Control

Direct load control likewise received high scores in ENO's DSM final report from June 2015, and should be included in the Preferred Portfolio. In fact, Residential Direct Load Control received a TRC score of 4.1 for the reference case. According to Entergy New Orleans' Advanced Metering study beginning in June 2011, direct load control participant's demand reduction averaged 16.3% during load management events. Those customers who were offered Peak Time Rebates, or incentives for voluntarily reducing their use during peak events reduced demand by an average of 10.6%, and received a 96% approval rating from customers involved in the program. It is unclear why the company chose to exclude these DSM programs from their portfolio. DSM replaces the most expensive, least efficient power generation. We can only assume that the incentive for ENO to sell more energy is the reason for the exclusion of these valuable and popular DSM programs.

Commercial and Industrial Load Control was not included in the portfolio. This is confusing, as there is already an interruptible load tariff and customer, who continues to receive a benefit in rate, despite never being called upon to reduce their load. Further, as the company states, MISO values Load Modifying Resources on equal footing with generation resources, with the added benefit of reducing the associated reserve requirement. MISO acknowledges the value of using Load Modifying Resources to improve reliability[19], effectively and efficiently addressing the company's peaking and capacity concerns.

If peak demand is the greatest concern, there is incongruent logic in choosing DSM programs that do not address this issue, but rather, focus solely on energy use reduction.

Historic vs. Forecast Peak Demand

The Alliance is concerned that the forecast for demand is at odds with historic peak demand. According to ENO's historic reports, peak demand has stayed flat, if not incrementally decreased in the last three years, from a high in 2012 of 1,018 to 987 in 2014. We are encouraged that the reduction in peak suggests the success of the Energy

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[18] Cleco, (April 29, 2015). Time of Use report for Docket U-31393.
[http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=385f7451-0afd-40f1-b199-94d6232866f0]
[19] Organization of MISO States, "Useful Things to Know about Capacity Markets".
[http://www.misostates.org/files/WorkGroups/UsefulThingsToKnowAboutCapacityMarkets.pdf}

Smart Program. However, within ENO's forecasts, an actual peak of 1029 MW is not shown in 2015. In fact, a foot note, states: "Peak demand is a sum of individual (rate class) peaks. If classes peak at different hours, the coincident peak will be lower." It is unlikely that each of ENO's customer classes (residential, commercial, industrial, and government) peak coincidentally. This would explain the inconsistency between the Preferred Portfolio's Peak Load requirement, and the company's load forecast for the reference case. If peak load continues to remain stable, or even decreases as ENO's demand history shows, the capacity requirements suggested by the IRP is inaccurate.

Multi Family

According to the Aurora modeled DSM portfolio for multi-family, it appears the only program included for multi family programs are common area lighting and hot water management with faucet /showerhead aerators. This eliminates opportunities for families living in multi-family units from using the DSM programs offered. The Alliance believes there should be either more clarity about which measures are available for which residential customers. We understand this is outside the scope of the IRP, and falls within the Energy Smart Programming, however, these DSM programs are a piece of the reduction to total energy generated, it is important to include all residential customers.

Maximize DSM Now

The excess cost savings for some DSM measures should be applied to increase the number of additional DSM measures such that the size of the full DSM portfolio as a whole is maximized. Not only is this consistent with the Council's desire to substantially expand adoption of DSM, while targeting cost effective energy efficiency, it is a key method to increase DSM adoption early in the IRP cycle when the benefits can achieved in time to reduce other supply costs. Because it takes time to implement and achieve savings from DSM, expansion of DSM should not be put off to the end of the IRP.

While market penetration ceiling have been used by ICF to justify lower DSM investments at a time when greater DSM would produce greater benefits in direct energy and deferred supply cost savings, the fact that Entergy has successfully deployed their entire Energy Smart budget each year and in fact run out of incentives for some of the most successful programs should be clear enough evidence that the market ceiling figures used to suppress DSM in the IRP do not stand up to reality. (Not to mention other jurisdictions, like Entergy in Arkansas are already demonstrating higher penetrations. If potential program participants are being turned away at any time during the year (as is the case with Energy Smart in New Orleans), the limiting factor is not market penetration or cost effectiveness - it is inappropriately limited budgets. It is time to put DSM in place to maximize benefits for customers while there is still time to offset more expensive investments in fossil fuel generation. DSM budgets should be greatly expanded now.

One conflict between the manner in which DSM is being evaluated in the IRP and political / economic reality is that when electricity prices are comparatively low, as they are now, DSM resources are more intensively screened out. However, when electricity prices rise, it is less economically and politically feasible to deepen investments in energy efficiency (and the benefits will take to long to bring immediate financial relief). Therefore, it is appropriate that the council acknowledge that the time to deepen investments in energy efficiency is now, precisely because the cost of electricity is low - rather than the opposite as is happening with this IRP.

Resiliency Plan

The recently released Resilient New Orleans plan, calls for transforming New Orleans' energy use and generation, through energy efficiency and adoption of renewable energy. The Alliance sees this IRP as an opportunity to meet the challenges discussed in the plan, and offer new solutions, while continuing to serve New Orleans customers with reliable and affordable service. Resilience is a common goal for both Entergy and customers, and we believe the adoption of more sustainable generation and conservation will support these goals.

City Council's Instructions

In the New Orleans City Council Utility Committee Meeting on June 16, Council members Guidry, Head, and Williams made very clear their directions to the company: "We are ready." Ready to add more demand side management to reduce our use of fossil fuels. Ready to add more renewable energy to our fuel mix to reduce carbon dioxide emissions. Ready to take responsibility for the carbon we emit. Ready to make New Orleans a cleaner city, with sustainable energy portfolio. New Orleans' unusual regulatory position allows for forward looking planning that truly diversifies our generation, and continues to lead in clean energy in the gulf south. This current IRP draft is not ready.

Supplement or Replace Aurora

Aurora is biased toward capacity growth, which is why DSM, solar and wind do not perform as well in the modeling. The Alliance believes it would be fruitful to try a different modeling program for the next round to replace or enhance Aurora's results. There have been numerous improvements in modeling efforts to include non-traditional but expanding energy resources like energy efficiency, high-tech transmission, distributed solar, demand response, and other 21st century technologies and policies.[20],[21]

SWEPCO used Plexos® which "seeks to minimize the aggregate of the following capital and

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[20] Treatment of Solar Generation in Electric Utility Resource Planning (2013) http://www.nrel.gov/docs/fy14osti/60047.pdf

[21] Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments (2015) Available at: http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

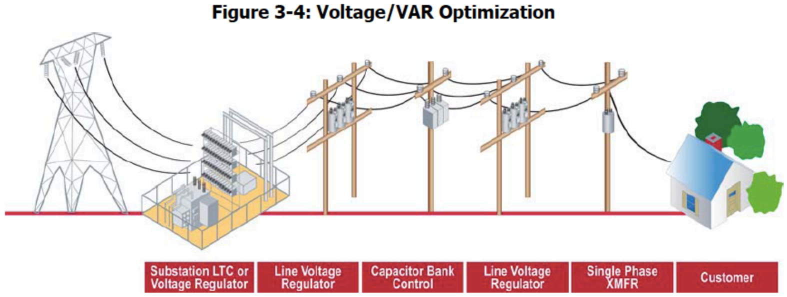
production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, i.e., carrying charges on incremental capacity additions (based on a SWEPCO-specific, weighted average cost of capital), and
- fixed O&M;
- Fixed costs of any capacity purchases;
- Program costs of (incremental) DSM alternatives;
- Variable costs associated with generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and/or carbon ‘tax,’ and variable O&M costs;
- Distributed, or customer-domiciled resources were effectively value at the equivalent of a full-retail “net metering” credit to those customers (i.e., a “utility” perspective); and
- A ‘netting’ of the production revenue made into the SPP power market from generation resource sales and the cost of energy – based on unique load shapes from SPP purchases necessary to meet load obligation.”

Energy Efficiency Upstream - Volt VAR Optimization (VVO)

VVO is a form of voltage control that allows the grid to operate more efficiently. VVO’s sensors and controllers monitor load flow characteristics to optimize power factor and voltage levels. The power factor optimization reduces line losses on the system. VVO also enables conservation voltage reduction (CVR). CVR allows the utility to systematically reduce voltages in its distribution network, resulting in a load reduction. While voltage optimization allows a reduction of system voltage, it still maintains minimum levels needed by customers. Customers use less without even knowing. SWEPCO states that early results from AEP operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for a 1% voltage reduction is possible. Especially as ENO now plans to bring the majority of the city’s energy in from out-of-state, and is making upgrades to transmission system in order to do so, planning for and use of technology like VVO can help the company reduce their load requirements.

Figure 3-4: Voltage/VAR Optimization



Distributed Generation

Solar is power that is added to the grid at no cost to ratepayers for the construction cost, debt financing, interest, taxes, fuel charges, or operating and maintenance. This is a

resource that should be planned *for* not against, as suggested by the title of Scenario 3 "Distributed Disruption". Currently, solar pv is treated as a load reduction but could be seen as a planned additions of new renewable energy.
From ENO's graph below, it is clear that solar could offset 25 MWs of new generation from the reference case by 2034. This is small but significant.

2015 Update Total Peak Forecast (MWs)	2015	2020	2025	2030	2034
Industrial Renaissance	1,029	1,070	1,105	1,143	1,176
Business Boom	1,052	1,101	1,137	1,178	1,212
Distributed Disruption	1,029	1,068	1,099	1,127	1,151
Generation Shift	1,027	1,067	1,104	1,141	1,173

In March 2015, the Department of Energy published *Wind Vision: A New Era for Wind Power in the United States*[22]. The report found that Louisiana could economically develop approximately 1,000 MW of in-state wind power by 2030 and at least 5,000 MW by 2050. Based on National Renewable Energy Lab-published data, Louisiana contains 110,000 MW of wind energy potential with 110-meter hub height wind turbines (current technology).[23] As the company is aware, several wind farm development firms are scouting projects in Louisiana. Wind from Louisiana is an option, and is a cost-effective option.

V. Conclusion

[22] United States Department of Energy (March 2015). Wind Vision: A New Era for Wind Power in the United States. [http://energy.gov/eere/wind/wind-vision]
[23]National Renewable Energy Laboratory (December 2014). Estimates of Land Area and Wind Energy Potential, by State, for areas >= 35% Capacity Factor at 80, 110, and 140m. http://apps2.eere.energy.gov/wind/windexchange/docs/wind_potential_80m_110m_140m_35percent.xlsx