ADVISORS REPORT

ENTERGY NEW ORLEANS, INC. & ENTERGY LOUISIANA, LLC
INTEGRATED RESOURCE PLAN FILINGS ON
OCTOBER 30, 2012 AND MARCH 11, 2013
COUNCIL DOCKET NO. UD-08-02

INTRODUCTION

Presented herein are the results of the Advisors' assessment of Entergy New Orleans, Inc., ("ENO") October 30, 2012 and Entergy Louisiana, LLP ("ELL") March 11 2013 Integrated Resource Plan Filings ("IRP Filings") (respectively referred to as "ENO IRP Filing" and "ELL-Algiers IRP Filing") pursuant to Council Resolution R-13-17 (collectively "IRP Filings"). This report provides the Council with the Advisors' evaluation and assessment of the IRP Filings, ENO's compliance with prior Council resolutions on Integrated Resource Planning ("IRP") matters, highlights of the important aspects of the evaluations conducted by the Advisors, and a listing of the recommendations based on the Advisors' evaluation of the IRP Filings, responsive comments of the Intervenors in the instant docket[1] and the public comments received by ENO and ELL at the ENO IRP Filing Public Presentation of February 20, 2013 and the Council at the Community Hearing that occurred on April 19, 2013.

SUMMARY OF ADVISORS' CONCLUSIONS AND RECOMMENDATIONS

1. The ENO IRP Filing complied with the Council's six components of its IRP Filing Requirements, however, the Advisors anticipate that the Council will make improvements to the IRP process in the future.[2] As noted hereinafter, the Advisors recommend that the Council adopt certain enhancements to the IRP process for the next IRP Triennial Filing of both ENO and ELL.[3]

2. ELL failed to file a 2012 IRP pursuant to Resolution R-10-142 and, further, failed to explain prior to the due date of the filing why it would not be making the filing as ordered. In its March 11, 2013 filing, ELL asserts, in part, that it would be impractical, uneconomical and unduly burdensome to create a standalone IRP for Algiers and that planning for Algiers must necessarily occur as part of the planning cycle for ELL as a whole. Further, ELL contends that because the Algiers DSM programs are expected to mirror the programs offered by ENO on the East bank of Orleans Parish, *"an IRP specific to Algiers is not necessary to develop general DSM budget and energy savings estimates."* The Advisors are of the view that ELL has put forth compelling arguments as to the necessity for coordinating planning for ELL-Algiers with planning for ELL as a

[1] Intervenors in IRP Docket No. UD-08-02 are the Alliance for Affordable Energy ("AAE"), Jacobs Technology, Inc., The Folgers Coffee Company, U.S. Gypsum, and The Sierra Club. In addition to the Advisors', ENO and ELL, participants in the IRP Technical Conferences were the AAE, Sierra Club, Gulf States Renewable Energy Industries Association ("GSREIA"), and Global Green; participants in the public meeting were the AAE, Green Grants, and Global Green. The American Council for an Energy Efficient Economy ("ACEEE") also provided comments.

[2] As defined in Resolution R-10-142 *"Electric Utility IRP Requirements of the Council of the City of New Orleans 2010."*

[3] Ibid.

whole and recommend that ELL be allowed to make its IRP Filing with the Council on or before May 20, 2015 contemporaneous with its integrated resource plan to be filed with the Louisiana Public Service Commission ("LPSC"). In fulfilling this obligation, ELL should be reminded that the Council will not accept an IRP designed to meet the LPSC requirements as a substitute for the Council's IRP Filing Requirements. To the extent ELL believes that planning for ELL-Algiers may require an exception to certain of the Council's IRP Requirements, ELL should be required to request relief from the Council well in advance of the May 20, 2015 filing date to ensure that any deviations from Council's requirements are pre-approved and any alternate requirements in turn are incorporated into the ELL IRP process in a timely manner. ELL should also be reminded that pursuant to the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans ("Charter"), the Council is authorized to enforce its orders by the imposition of such reasonable penalties as the Council may provide.

3. The Advisors participated in the IRP technical process and believe that the supply-side resource evaluation and integration method employed by the Companies was in compliance with the Council's IRP Requirements.

4. While in light of the IRP process many renewables were "*screened out*" during the technology assessment screening phase of the IRP, it is clear from the comments and questions at both the February 20, 2013 presentation of ENO's IRP Filing and the Community Hearing on April 19, 2013 that there is strong community interest in enhanced use of renewable technologies in the supply of energy in New Orleans (whether utility or consumer owned). In order to address this concern and not encumber and delay the ongoing matters in the instant docket, the Advisors recommend that the Council establish a separate utility docket to examine all issues associated with the implementation of more renewable energy technologies in the ENO and ELL-Algiers supply portfolios including individual consumer installed renewables and determine whether the establishment of a Renewable Portfolio Standard ("RPS"), when examined in concert with the Council's IRP Filing Requirements, is in the public interest and is reasonably expected to result in lower costs to New Orleans. Regardless of the outcome of the consideration of an RPS, renewable resources, including distributed generation and solar photovoltaic sources, should be considered in any future IRP, and ENO should be cognizant of the fact that the optimum level of renewable resources could exceed the amount set by any future RPS.

5. ENO's IRP Filing showed an effort to follow the guidelines of the IRP Requirements with respect to both the screening of resources and the comparison of supply-side and demand-side resources. The supply-side and demand-side resource integration methodology employed by ENO in the development of its IRP Filing is in compliance with the Councils IRP Requirements, however the Advisors anticipate that the IRP process will continue to be refined and improved during the development of subsequent IRP filings by the Companies by order of the Council in the instant docket

6. With respect to recommended levels of demand-side management ("DSM") achievable in New Orleans, corresponding spending levels and rate impacts, there are widely divergent views in the instant docket. ENO recommends a DSM level based upon the Council's IRP Filing Requirements and the IRP integration and optimization process as contained in its

IRP Filing. AAE recommends the Council adopt an Energy Efficiency Resource Standard ("EERS") in addition to IRP Requirements, which *"sets the expected program size based on total achievable energy efficiency."* Essentially, the difference in methodologies is a bottom up approach attempting to optimize all supply and demand resources available to ENO versus a top down, or goal setting approach, for energy efficiency without an attempt at optimization of all existing and new resources over a planning period. The following tables summarize the ENO IRP and AAE alternative approach to DSM and the respective estimated implementation cost impact on residential bills. Additionally the net impact on residential bills is shown for the ENO IRP results.

ENO IRP Filing and AAE's EER's Approach				
(Nominal Dollars)				
2014-2031	**ENO**		**AAE**	
Total Energy Savings (MWH)	4,256,080		11,377,366	
Total DSM Spending (Million Dollars)	74.34		423.04	
Levelized Annual Spending (Million Dollars)	4.01		21.73	
	Without Cap [1]	**With Cap**	**Without Cap**	**With Cap**
	($ per Bill)		**($ per Bill)**	
Levelized Monthly Average Residential Bill Impact	0.71	1.08	4.17	6.41
Levelized Net Benefit Average Residential Bill Impact [2]	(1.94)	(0.94)	See note [3]	

[1] The cap used is the same as established for Energy Smart Program ($100 for commercial customers, $200 for industrial customers).
[2] ($1.94) per Bill is calculated with 3.65% discount rate, for 30year Treasury Bonds at 7/9/13 (for Advisors calculation). The Discount rate in Table 3b is 9.25% , generic system return on rate base for ENO.
[3] Insufficient information was available to determine the comparable net impact on the residential bills for the AAE alternative approach.

ELL-Algiers and AAE's EER's Approach				
(Nominal Dollars)				
3 Years	**ELL-Algiers**		**AAE**	
Total Energy Savings (MWH)	6,207		35,186	
Total DSM Spending (Million Dollars)	1.66		7.58	
Levelized Annual Spending (Million Dollars)	0.57		2.62	
	Without Cap	**With Cap**	**Without Cap**	**With Cap**
	($ per Bill)		**($ per Bill)**	
Levelized Monthly Average Residential Bill Impact	0.89	1.35	0.98	1.49

[1] The cap used is the same as established for Energy Smart Program ($100 for commercial customers, $200 for industrial customers).

While the levels of DSM to be implemented in New Orleans and the corresponding spending levels and rate impacts are strictly a policy decision for the Council to make as the elected representatives in Orleans Parish charged with regulating the rates, terms and conditions of service in New Orleans, the Advisors would note that the adoption of an EERS for Orleans Parish would effectively render the Council's IRP Requirements moot to a large extent.

7. The Advisors recommend that the Council not adopt an EERS at this time. To be clear, the Advisors are recommending that the Council establish the levels of energy efficiency ENO should meet and that it require ENO to meet those levels. However, the Advisors recommend that this be done based upon the IRP process rather than through an EERS. The Advisors believe that the appropriate level of energy efficiency investment for New Orleans can be addressed in more detail and with greater flexibility through the current IRP process. The Advisors also believe that the Council can appropriately direct ENO and ELL regarding the level of energy efficiency to be achieved in New Orleans through the setting of targets as part of the incentive mechanisms it approves for the level of DSM implementation, and expenditures it authorizes. The Advisors believe that in light of this mechanism an additional EERS is not necessary. The Advisors' are particularly concerned that the proposal that an EERS require a certain level of investment in energy efficiency prior to investment in new generation resources may be inadvisable for New Orleans under the current circumstances. New Orleans faces a notable transmission constraint which limits its ability to purchase power from other areas, and increases the costs of those purchases. In addition, there has been at least one situation in the past where a major storm damaged the transmission system sufficiently to "island" New Orleans electrically from the rest of the nation. Therefore, having sufficient generation resources located within the transmission constrained region is of great importance to New Orleans. Within the region, certain generation sources are aging and as ENO notes, such a requirement could become an obstacle to the timely replacement of ENO's aging generation resources used for reliability purposes. The Advisors are concerned that a requirement that energy efficiency goals be met prior to any investment in new generation could cause delays in the effective procurement of the generation needed for reliability and reasonably priced electric service in New Orleans.

   Furthermore, the adoption of an EERS would result in implementing a higher level of spending than that which ENO alleges are the optimum levels determined in the IRP and, accordingly, would likely result in higher overall costs realized by New Orleans' ratepayers. The Advisors agree with ENO that given that the Council's jurisdiction extends only to ENO and ELL, it is not necessary to establish an EERS because the Council can address these issues in greater detail and in a more flexible manner through the IRP process.

8. Any subsequent ENO IRP Action Plan should address: (i) the continued evaluation of new supply-side resource alternatives including renewables, purchase power agreements and low cost, efficient gas-fired generation; (ii) the continued evaluation of local area reliability in coordination with efficient local generation resources, demand reduction, and transmission investment alternatives; (iii) short and long-term off system sales

opportunities created by DSM; (iv) approval of an implementation plan for the next phase of DSM in New Orleans; (v) monitoring and reporting on MISO's resource adequacy requirements and congestion management including impact on production costs; and (vi) integration of MISO's transmission expansion plan ("MTEP") into the IRP planning process. At a minimum the IRP Action Plan should also identify analyses (such as updated screening of renewables) to be included in the IRP Status Report required under Component 6 of the Council's IRP Requirements.

9. With the exception of the Behavioral Pilot Program and the level of spending proposed for the Evaluation, Measurement & Verification ("EM&V") program, the proposed set of DSM programs proposed by the Companies in their Supplemental Filings passed all of the Council's IRP Requirements' screening tests and are reasonable for consideration by the Council in the development of program implementation in New Orleans. The Advisors are troubled that the Companies chose in their Supplemental Filings of April 1, 2013 ("Supplemental Filings") to propose a set of programs different from those used to determine the DSM spending levels in their IRP Filings. The elimination of an interruptible rate for commercial & industrial customers and direct load control for residential customers is most disconcerting as the IRP clearly showed that these demand response programs represent the "*biggest bang for the buck*." However, we also recognize that demand response programs involving load control of customer appliances and time differentiated rates require further EM&V analysis to verify the cost and savings estimates assumed in the DSM potential study before including such programs for implementation at this time. The reality is that such programs will take time to develop. Therefore, the Council should require Entergy to implement these programs no later than its next Triennial IRP Filing. While we recognize ENO and ELL's pending integration in the Midcontinent Independent Transmission System ("MISO") presents a distinct learning curve, the Council should direct ENO and ELL to include an evaluation of the above as well as other demand response programs in their next Triennial IRP Filing. This evaluation should consider all programs available as a result of several MISO tariffs as discussed below.

   With respect to the addition of the Behavioral Program Pilot, the Advisors believe such funds could be better spent on an enhanced and more robust EM&V program to reduce future reliance on the deemed savings approach to measuring the effectiveness of any Council authorized DSM/EE programs, to provide for the calculation of any incentives awarded or penalties placed on the Companies, and to inform the Council in cost recovery matters. As such, the Advisors recommend that in any finally approved level of program costs, the Council should direct the Companies to include a budget of 6.5% for EM&V activities so as to further strengthen and create an enhanced EM&V program. Such actions would accelerate movement away from a deemed savings approach to measuring the results of the DSM programs in the specific New Orleans environment and the creation of much needed benchmarks for future DSM program considerations.

10. The kWh savings achieved and the educational and awareness benefits realized through Green Light New Orleans's ("GLNO") direct contact with customers supports the continuation of CFL Direct Install program. The Council should direct the Companies to continue for a one year transition period the use of GLNO direct Compact Fluorescent Light ("CFL") installations as part of the various DSM programs approved by the

Council. This transition period should be a minimum of one year, or until the first report regarding the DSM programs is provided to the Council which demonstrates that such program is no longer achieving its targeted goals and providing cost effective savings. Although LED lighting measures were evaluated in the DSM Potential Study[4] most of the TRC values for the measures were below 1.0, indicating that costs exceeded savings using the data available at the time of the study. Therefore no DSM programs for LED lighting were included in the current proposed programs. However, LED cost and technology improvements are anticipated, so the screening of LED measures should continue for all available residential and commercial measures in the next DSM Potential Study and IRP process.

11. Given the expiration of the Energy Smart Program by March 31, 2014 and to assure the continuation of DSM programs in Orleans Parish, the Council (upon its approval of the appropriate levels of DSM implementation and expenditures, and approval of a subsequent cost recovery and DSM implementation plans filed by the Companies), should direct the Companies to file with the Council for its subsequent approval an Energy Efficiency ("EE") Rider to be fully transparent and placed on customers' bills. Since it is highly unlikely that a general rate filing for ENO will be concluded by March 31, 2014, an EE Rider should be in effect to provide for the funding of the approved DSM programs at that time. Likewise, for ELL-Algiers, the rider will be required for funding by the conclusion of ELL-Algiers general rate filing by April 2014. The EE Rider should be designed to recover all costs related to the approved DSM programs including lost revenues and any Council approved utility incentives/crediting of penalties for non-performance (post achievement). Such Rider should be subject to an annual true up until such time as the Council approves new base rates for the Companies and evaluates the individual components therein attributable to the DSM programs. At such time, the Council can then evaluate all aspects of the DSM program cost recovery including incentives and penalties and evaluate the continuation or elimination of the EE Rider in favor of base rate considerations. Using current rates as an example, the Council has approved a Storm Reserve Rider to fund the storm reserve escrow account, with the additional advantage of transparency for ratepayers to identify that specific source of funding.

Furthermore, the Council should revisit the appropriate amount of "caps" to be applied to commercial and industrial customers in light of the allocation of program costs, lost revenues and incentives/penalties when measured by the benefits received among the various customer classes of any finally adopted DSM program levels.[5]

12. For the interim period of time from the Council's approval of the level of DSM expenditures and the Companies' DSM implementation plans through December 2014 (or such later date as determined by the Council in an order in the instant docket), the Council should continue allowing the Companies to recover Lost Contributions to Fixed

[4] Several residential LED lighting measures ranging from 8 watts to 15 watts, and several commercial LED lighting measures were evaluated as replace on burnout or retrofit, using referenced sources for measure life and annual savings to calculate the TRC for each measure

[5] The Council's prior Energy Smart Program employed a monthly bill cap amount of $200 on large industrial customers and $100 on commercial customers as the maximum monthly cost incurred by such customers for the Energy Smart Program.

Costs as part of the EE Rider. The Council should direct the Companies to file, within 120 days of the Council's approval of the Companies' DSM implementation plans, decoupling proposals that address all of the issues raised in The Regulatory Assistance Project's ("RAP") memorandum to the Council Utility Committee of June 26, 2013 for subsequent consideration by the Council in a new docket of all issues attendant to decoupling as a policy matter and future consideration in a redesign of rates for the Companies. To the extent that ENO files a general rate case sooner, it shall incorporate in such filing its proposed form of decoupling. ELL should be directed to make its filing in Council Docket UD-13-01 for consideration by the Council in said docket.

13. Rather than the continuation of the existing incentive approach as recommended by the Companies in their Supplemental Filings, the Council should adopt the incentives and penalties as recommended by RAP in its memorandum,[6] after the Council establishes appropriate and reasonable energy savings based upon the Council's determination in the instant docket of the appropriate level of DSM to be implemented in New Orleans.

In its consideration of such incentives and penalties, the Advisors recommend that the Council give strong consideration to a mechanism that awards incentives to the Companies not based upon the Companies' Supplemental Filings, but rather based upon the Companies achieving energy savings based upon, and related to, the optimal level of DSM as developed in the IRP preferred portfolio. In the establishment of penalties, the Council should consider implementation of penalties in the event the Companies' do not achieve the base level of DSM performance as ultimately approved by the Council.

14. The Council should take advantage of the NOLA-Wise Program and integrate its operations in a meaningful way into any approved DSM programs and spending levels it determines as a result of its evaluation of the IRP Filings. Furthermore, the potential exists to leverage the DSM spending levels in New Orleans by initiating a strategic alliance with Southeast Energy Efficiency Alliance ("SEEA") in the implementation of some of its existing (and future) DOE programs and further enhance the development of a tool and data base that can be employed to actually benchmark and track DSM program results and direct savings on consumer bills to further strengthen an enhanced EM&V program.

15. While the Advisors agree with the AAE that increased time for evaluation of each stage of the IRP and greater participation by stakeholders earlier in the process would be beneficial, the Advisors also note the need to maintain the IRP schedule to allow for the continuation of DSM programs in New Orleans without a lapse and mitigate increased regulatory costs due to an extended process. However, the Advisors believe that the IRP process could be improved through greater clarity in the process. To that end, the Advisors recommend that the Council adopt a procedural schedule for the next IRP that identifies discrete milestones in the IRP process and provides for opportunity for input from stakeholders at each milestone. Currently, the Council's IRP Requirements do not require input from stakeholders during the IRP process. The Advisors believe that stakeholders can provide valuable input into the process, however, the Advisors also believe that obtaining full agreement among all stakeholders at every milestone would be

[6] See Appendix D.

unduly burdensome. To that end, the Advisors recommend that in the next IRP process, the Council direct ENO to provide to the Council and stakeholders the relevant assumptions and work papers and hold a technical conference prior to each milestone. Subsequent to each technical conference and within a defined period, the Council and stakeholders will be provided the opportunity to provide comments to the Companies and the Companies will be given the opportunity to respond to any comments received. This will allow the Companies to address as appropriate, the concerns of the Council and stakeholders during the IRP process.

16. The Council's IRP Requirements are structured for a balanced utility resource portfolio with the primary objective: "(1) to optimize the integration of generation and transmission services with demand-side resource options to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost." Importantly, the Council's stated objective is framed in the perspective of all utility ratepayers, rather than the perspective of individual program participants. Paragraph 11 of Component 3 states: "If the Utility Preferred Resource Portfolio is not the least cost plan, the Utility shall provide the basis for rejecting the least cost plan and provide a schedule of costs showing the annual total demand related costs, energy related costs, and total supply costs associated with the least cost plan." Thus the Council used as its basis the utility's costs/revenue requirements borne by all ratepayers as the basis for an equitable comparison of supply and DSM costs. The utility costs/revenue requirements of DSM including low, reference, and high customer incentive levels with their corresponding kWh savings were used as the basis of comparison with supply costs by ENO. These costs were identified in the DSM potential study in computing the program administrator costs (PAC) test for each program. The remaining participant costs (that portion of DSM program incremental costs not reimbursed from the incentives) as well as benefits accruing specifically to the participant rather than to all electric ratepayers, were not compared to ENO's supply costs. However, Component 3 of the IRP requirements does require a TRC test, which estimates all customer benefits compared to all customer costs, for the initial screening of DSM programs, prior to the integration of the DSM programs with utility supply costs in the IRP analysis. The Advisors believe that ENO's application of the TRC and PAC tests is permissible under the IRP Requirements. The Advisors are also of the opinion that requiring ENO to perform the analysis again with a different application of the TRC and PAC tests would cause a significant additional delay in an IRP process that has already been substantially delayed. The Advisors recommend that if the Council wishes ENO to use a different application of the TRC and PAC tests in future IRP filings, it should clarify this point in its order.

17. The kWh savings from the DSM Potential Study were adjusted for line losses when configured as resource alternatives in the IRP. This adjustment provided by Entergy System Planning and Operations corresponded to total retail line losses of 7.29%, based on the utility's available data, and was used in preference to industry data non-specific to the utility. Practical time and resource constraints for the 2012 IRP process prevented a more extensive nodal analysis in the Aurora model to determine how marginal losses could be applied to the DSM load shapes. However, for the next IRP filing a marginal line loss analysis should be used with DSM programs having the kWh savings estimated or measured at the customer meter.

18. The Advisors agree with the AAE that avoided costs for the DSM analysis should be developed prior to conducting the DSM potential study. Such avoided costs could, at a minimum, include a detailed assessment of marginal transmission capacity costs, marginal distribution capacity costs, marginal line losses, and avoided reserves and ancillary services associated with deployment of energy efficiency resources. To that end, the Advisors recommend that the Council require ENO to file their proposed methodology for the development of avoided costs for use in the next IRP process with the Council within 120 days of a final order in the instant docket with annual updates and that the Council establish a procedural schedule allowing for comments from interveners and reply comments by ENO.

19. The Advisors agree with the AAE that, as part of any future IRP process, the Companies must provide information sufficient for verifiability of calculation outputs. The Advisors' are aware that some of this information may fall into the HSPM category, but such information nevertheless should be made available in a timely manner to parties that have properly executed a confidentiality agreement with the Companies. The Advisors recommend that the Council make clear to the Companies that this type of information should be shared with the Advisors and Interveners to the case through discovery, technical conferences and working group meetings, and that the HSPM designation apply only to information that meets the traditional threshold for this designation.

20. In its next Triennial IRP Filing ENO should be directed by the Council to file a gas EE potential study for consideration by the Council. In the development of such study ENO should be directed to follow the same guidelines as to process as discussed hereinabove.

21. The Council should adopt a future process in the docket as recommended herein so as to minimize any potential for a lapse in DSM program availability in Orleans Parish.

PROCEDURAL BACKGROUND AND COUNCIL OBJECTIVES

Background

The Council's objectives regarding resource planning have been clearly demonstrated over the recent 20 year period. On June 20, 1991 the Council adopted Ordinance No. 14629 M.C.S., which provided for least cost resource planning for the electric utilities within Orleans Parish. Chapter 158, Article V of the Code of the City of New Orleans ("LCIRP Ordinance") set forth 20 year least-cost resource plan biennial filing requirements applicable to both ENO and ELL (collectively "the Companies"). However, the Council's experience with the LCIRP Ordinance in the ensuing years showed the original structure and requirements to be costly, unduly burdensome and inefficient.[7]

Recent changes in the regulatory environment and the cost and availability of resources have

[7] Council Resolution R-96-303 suspended all proceedings in Docket Nos. UD-92A, UD-92B, UD-95-1, and all demand-side management programs that were then currently being implemented pursuant to the Council's order in Resolution R-94-373 (Substitute, As Amended).

rendered it critical that the Companies develop and routinely update a plan designed to optimize generation and transmission services and integrate demand-side resource options on an equal footing to provide New Orleans ratepayers with reliable electricity at the lowest reasonable cost. To that end, in Resolution R-08-295, the Council commenced a rulemaking proceeding to develop IRP components and IRP reporting requirements intended to integrate generation resources, purchased power and DSM, and incorporate into its planning process energy efficiency programs ("EE") developed at the direction of the Council. Resolution R-08-295 set forth a requirement for triennial filings, in which the Companies' IRP Filing shall incorporate the following components: (i) IRP objectives; (ii) demand and energy-use forecast; (iii) supply and demand-side resources; (iv) integration of delivery; (v) public presentation of their IRP Filing prior to filing of same with the Council; and (vi) reporting requirements.

Following IRP public hearings in November 2008 and January 2009, and comments submitted by the Energy Policy Task Force, AAE, and the Sierra Club regarding ENO's September 2008 IRP Status Report, the Council clarified and expanded upon the IRP framework, components, and reporting requirements in Resolution R-08-295.

In Resolution R-09-136 the Council approved funding, designed relevant cost benefit tests, adopted the implementation of a comprehensive demand-side program for ENO's customers ("Energy Smart Program") and provided that ENO have the opportunity to earn incentives based on its performance and implementation of the Energy Smart Program along with the collection of lost contributions to fixed costs. The Council funded such programs by the inclusion in rates of approximately $3.1 million per year over the three year period of 2009 through 2012 which funding terminated in June of 2012. Such programs commenced implementation in April of 2011 and are funded until on or about April 1, 2014 based upon the current program participation levels at which time the Energy Smart Program is expected to commence its second phase based on DSM programs appropriately screened under the IRP and approved by the Council.

On October 18, 2012 the Council approved the implementation of an Energy Smart Program in the ELL-Algiers jurisdiction which mirrored the success of the Council's Energy Smart Program on the East bank. The Energy Smart Program for Algiers was funded at a level of $939,000 for the period of October 2012 to March 2014 by ELL-Algiers' portion of the 2012 Rough Production Cost Equalization bandwidth remedy payment of $939,000.

Resolution R-10-142 adopted revised reporting requirements entitled *"Electric Utility IRP Requirements of the Council of the City of New Orleans 2010"* ("IRP Requirements") and on October 19, 2010 the Companies filed their first Triennial IRP plan, which purported to comply with the IRP Filing Requirements in Resolution R-10-142. On June 10, 2011, the Advisors submitted a Technical Advisors' Report in Docket UD-08-02 submitting their comments on the deficiencies of the October 19, 2010 IRP Filings, finding that the IRP Filings were supply-side plans that incorporated, but did not integrate, demand-side resources, or incorporate MISO transmission alternatives.

In Resolution R-11-301 the Council rejected the October 2010 Filings, and directed the Companies to make their next Triennial IRP Filing no later than October 30, 2012 noting "*The Council finds that ENO's IRP status report and the transmission report do not meet the IRP reporting requirements set for in Resolution R-08-295….ENO's proposed resource plan does not adequately integrate demand-side management programs into its supply plan and result in an*

IRP." The Council also directed that the Companies hold quarterly technical conferences with the Advisors and the Intervenors commencing in September 2011 (thereby accelerating a three year process into one), and that any future revisions to their DSM potential study should be performed in a transparent and open manner that allows for appropriate stakeholder review and comment.

In conjunction with these directives, in Resolution R-12-393 the Council assured the continuity of future funding and implementation of the demand side and EE programs contained in the IRP by directing ENO and ELL-Algiers to file supplemental implementation and cost recovery plans based on the optimal levels contained in their IRP Filings, or such other programs as directed by the Council, by March 31, 2013. Resolution R-13-17 set the procedural schedule for ENO technical conferences, provided for the filing of Supplemental Implementation and Cost Recovery recommendations by the Companies responsive filings by the Intervenors, and provided for the conduct of a community hearing by the Advisors and public comment periods. Resolution R-13-17 also directed ELL to make a filing by March 11, 2013 correcting any deficiencies in its October 2012 IRP Filing.

As a preamble to the Advisors' evaluation of the 2012 IRP in this report, there is insight to be gained by summarizing recent IRP's conducted in other jurisdictions. System Planning and Operations surveyed 15 recent IRP's from major utilities nationally to determine typically used techniques and best practices.[8] The following are noteworthy observations from the survey as a comparison to ENO's 2012 IRP:

- Most IRPs assess one or two alternative DSM levels.
- Two broad approaches are used (1) optimization modeling, and (2) judgment.
- Only half of the utilities surveyed varied DSM, even if modeling tools were available.
- Most IRPs evaluate how resource portfolios are affected by change in key variables (scenarios and model iterations).
- The focus is on a long term preferred portfolio, but not including a transmission planning process.
- The Aurora modeling system used in the IRP Filings is included among the optimization models utilized by the utilities.

Using this survey as an indication of the current state of IRP development in the industry, the Council should be commended with its comprehensive IRP Requirements and subsequent resolutions which recognized the inadequacy of previous IRPs and provided the guidance and structure resulting in the IRP Filings.

Objectives and Scope of Report

Pursuant to the objectives of the Council Resolutions summarized herein, the triennial Integrated Resource Plans are intended to integrate and optimize the planning of supply-side and demand-side resources rather than focus exclusively on either supply-side resources or demand-side resources. Specifically, the IRP Requirements stress the importance of the Integrated Resource

[8] *"IRP Tools and Techniques, Review of a Sample of Recent IRPs by US Utilities, Best Practices Supplement to the 2012 ENO IRP,"* Supplement to the ENO IRP Filing October 31, 2012.

Planning process as a whole and the interdependence of matters such as renewable energy, energy efficiency, distributed generation, transmission, regional developments, price stability, environmental and climate change legislation, rather than a discrete analysis of individual issues. Furthermore, the IRP Requirements direct the creation of a flexible resource plan that allows for uncertainty through a balancing of resource costs with the risk of achieving the projected benefits and permitting adjustment in response to changed circumstances. It should be noted that the IRP Requirements are intended to analyze and optimize the planning for utility resource projects, including renewables and DSM/EE programs approved by the Council. Customer owned renewables such as net-metered distributed generation including photovoltaic, wind and other customer renewable projects are not included in the optimization of supply and demand resources. Existing DSM/EE measures are incorporated in the demand and energy forecasts, while new DSM and EE successor programs are integrated into the IRP.[9]

The primary objectives of this report can be summarized as:

Compliance – Determine the compliance of the Companies' IRP Filing pursuant to the Council's IRP Filing Requirements in Resolution R-10-142 including the evaluation of the October 30, 2012 ENO IRP Filing and the March 11, 2013 ELL-Algiers Filing.

Directives of Resolution R-11-301 - Determine the compliance of the Companies with the directives of Resolution R-11-301, including the conduct of quarterly technical conferences and the Companies' obligations embodied in the Council's IRP resolutions.

Evaluation – Provide the Council with a high level evaluation of the IRP Filings, responses, and comments pursuant to the provisions of Resolutions R-12-393 and R-13-17; including definition and term of the Companies' IRP Action Plans, critique of proposed programs and level of spending in DSM/EE, potential funding mechanisms, RPS and EERS, decoupling, potential integration of NOLA-Wise, sustainability, utility incentives, cost recovery, transparency, and stakeholder involvement.

Recommendations – Provide the Council with a list of policy considerations, future schedules, and recommendations on the Companies' IRP Filings and the comments of Intervenors and interested stakeholders throughout the process.

COMPLIANCE ASSESSMENT OF ENO & ELL'S IRP FILINGS
RESOLUTION R-10-12 IRP FILING REQUIREMENTS

On October 30, 2012 ENO submitted its IRP Filing pursuant to Council Resolution R-10-142. The filing contained the following documents: (i) a document titled Entergy New Orleans Integrated Resource Plan; (ii) six Technical Supplements; and (iii) six Data Supplements,[10]

[9] As recommended herein, the Council may wish to consider the encouragement of customer renewable resources exclusive of ENO's IRP in a separate docket, such as net metering or other distributed generation, through a feed-in tariff or such pricing mechanisms which would promote the development of such non-utility resources.

[10] The Technical Supplements to the 2012 ENO IRP Filing include the 2012 Entergy System IRP, General Technical Supplement, Technology Assessment, DSM Technical Supplement, ICF Achievable DSM Potential Study, and Best Practices Supplement. The Data Supplements include the Customer Demand and Energy Forecasts, Macro Inputs, Total Supply Cost 2006-2031, Portfolio Design Analytics, Energy Supply by Resource Type, and Rate Effects (Data Supplements 1 – 6, respectively).

covering the period 2012 – 2031 referred to as the "*planning horizon*." The stated intention of the filing was to provide a relatively short summary of the overall eighteen month ENO IRP process, the main planning assumptions, and the process utilized. No separate documents were filed for ELL-Algiers.

The Advisors conducted an initial assessment of the ENO IRP Filing for compliance relative to each component of IRP Filing Requirements as required pursuant to Resolution R-10-142. The filing documents, including the technical supplements, data supplements, exhibits and work papers were examined to determine whether the requirements under each component were met. Based upon the Advisors review the following general observations are made.

Component 1 - IRP Objectives

The IRP Objectives were structured such that: (i) they developed a preferred portfolio that is purported to economically address the needs of the City of New Orleans; (ii) identified long-term DSM potential in New Orleans; (iii) evaluated the impact of Michoud deactivation on projected resource needs; and (iv) described the anticipated effects of the preferred portfolio on customer usage and rates.

Component 2 – Demand and Energy Use Forecast

A detailed demand and energy use forecast was provided by customer class, including the inputs and assumptions to those forecasts. Current EE programs were included in the forecast.

Component 3 – Supply- and Demand-Side Resources

Options were evaluated for the 20 year planning horizon, in terms of cost, system reliability, and risk to develop a preferred and alternate resource portfolio. The IRP also determined the approximate timing of the average annual changes in costs to ENO customers, as annual revenue requirements and corresponding rate effects. The IRP assumes that ENO, the other Entergy Operating Companies ("EOCs"), and all other load serving entities and independent power producers in close proximity to the EOCs join MISO effective January 1, 2014. The DSM Potential Study evaluated the extent to which DSM is achievable in New Orleans beyond the current goals established for the Council's Energy Smart Program, and the optimization of supply and demand side resources indicated the extent that DSM potential could be achieved in the current Integrated Resource Plan.

Component 4 – Integration of Delivery

The IRP incorporates the results of local area bulk generation and transmission planning for the Amite South and Downstream of Gypsy ("DSG") transmission constrained planning regions. In the IRP process, area planning considered the existing transmission network, as well as planned transmission investments, as an input into the evaluation of supply-side options.

Component 5 - Public Presentation of IRP

ENO conducted a public presentation of the IRP Filing on February 20, 2013 with the level of

Stakeholder input required in the Council's IRP Resolutions.[11] Furthermore, the Advisors conducted four quarterly Technical Conferences and eight DSM Working Group meetings which were hosted by ENO.

Component 6 - Reporting Requirements and Council Resolutions

The Companies have yet to file a fifteen month status report. In addition, ENO has incorporated substantial improvements in its modeling software and methodology since its 2010 IRP Filing.

Compliance Assessment of ELL-Algiers IRP Filing

ELL failed to file a 2012 IRP pursuant to Resolution R-10-142 and, further, failed to explain prior to the due date of the filing why it would not be making the filing as ordered. In Resolution R-13-17 the Council directed that ELL make an IRP Filing by March 11, 2013 consistent with the IRP Filing Requirements of Resolution R-10-142, and to provide in its filing compelling reasons for any deviation from the Council's IRP Filing Requirements.

In its March 11, 2013 IRP Filing, ELL asserts that: (i) the 2012 Entergy System IRP appended to the 2012 IRP filed by ENO is the most current planning information available for ELL; and (ii) ELL's resource planning process is done on an operating company-wide basis and there is no meaningful way to split out the Algiers customers and plan separately for their load. As such ELL argues that it would be impractical, uneconomic and unduly burdensome to estimate future load requirements, supply-side requirements or demand-side management potential for Algiers customers on a stand-alone basis.

ELL also argues that it is required by the LPSC to file an integrated resource plan by May 20, 2015 after ELL's transition to the MISO.

ELL further argues that it is working with ENO to make the April 1, 2013 Supplemental Filings required by the Council to assure continuity in the funding of the ENO and ELL's EE programs as well as the proposed energy savings goals, budgets and programs for implementation after March 31, 2014. According to ELL, because the Algiers DSM programs are expected to mirror the programs offered by ENO on the East bank of Orleans Parish, *"an IRP specific to Algiers is not necessary to develop general DSM budget and energy savings estimates."*

The Advisors are of the view that ELL has made a compelling argument to explain its failure to comply with the Council's directives to make an ELL-Algiers-specific IRP Filing on October 30, 2012. Nonetheless, the Advisors recommend that ELL be allowed to make its IRP Filing with the Council on or before May 20, 2015 contemporaneous with its Integrated Resource plan to be filed with the LPSC. This will allow ELL to prepare an Integrated Resource Plan on an operating company-wide basis but ELL should be required to comply with all the Council's IRP Filing Requirements and directives pertaining to ELL-Algiers.

In fulfilling this obligation, ELL should be reminded that the Council will not accept an IRP designed to meet the LPSC requirements as a substitute for the Council's IRP Filing Requirements. ELL should also be reminded that pursuant to the Constitution of the State of

[11] Resolution R-10-142, Resolution R-11-301, and Resolutions R-12-393 and R-13-17.

Louisiana and the Home Rule Charter of the City of New Orleans ("Charter"), the Council is authorized to enforce its orders by the imposition of such reasonable penalties as the Council may provide. Thus, ELL should be put on notice that its IRP Filing shall meet all Council regulatory requirements or ELL shall be subject to such reasonable penalties as may be determined appropriate pursuant to the Council's authority as the governmental body with the power of supervision, regulation and control over public utilities providing service within the City of New Orleans.

QUARTERLY TECHNICAL CONFERENCES, DSM MEETINGS AND COMMUNITY HEARING

The Advisors held four Quarterly Technical Conferences, beginning September 2011 which included the participation of several stakeholders.[12] The Advisors also moderated eight DSM Working Group meetings[13] since October 2011. The Technical Conferences focused on the development of working assumptions and data sets used in the IRP process and the Advisors provided the Council updates and status reports of the progress of the IRP process by the filing of summaries of the meetings in the instant docket.

The DSM working group meetings focused on the development of DSM potential, DSM inputs to the IRP process, and the optimization of DSM with supply side resources. ENO provided all requested deliverables assigned in the DSM Working group meetings, including data responses to frequent email requests for information. While there was not universal consensus on the results and findings of the DSM potential study,[14]the study was conducted in a transparent and open manner allowing for stakeholder review and comment pursuant to Resolution R-11-301.[15]

The summaries filed by the Advisors following each IRP Technical Conference and DSM Working Group meeting identified the information requests from the AAE and other participants, as well as the deliverables and discussions related to working assumptions, data sets, and updates.

As noted above, a Community Hearing was held on April 19, 2013 in order to receive public comments regarding the IRP Filings. Public comments were also received after ENO's IRP presentation on February 20, 2013. These public comments and those submitted in writing subsequent to the meeting included a broad consensus of support for the Council's IRP process and for enhanced Energy Smart Programs. The comments submitted by the public at the community hearing are generally summarized in Appendix C.

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[12] Attendees over the course of the four meetings included AAE, Sierra Club, GSREIA, and Global Green.

[13] Attendees over the course of the eight meetings included AAE, Council Staff and other interested parties from time to time.

[14] Later sections of the report discuss the participants' criticisms to the process, including the DSM Potential Study not as an end result, but rather as an input to the optimization process.

[15] Resolution R-11-301 directed the following stakeholder involvement: *"In the preparation of their next triennial IRP Filing, the Companies shall hold quarterly technical conferences with the Advisors' and the Intervenors in this Docket commencing in September 2011, the subject of which should be the Companies' plans for compliance with this Resolution, working assumptions and data sets for use in the next triennial IRP Filing, updates and status reports on the progress of their work efforts and such other matters as the Advisors' deem will facilitate compliance with this resolution. Within 15 days of such quarterly conferences, the Advisors' shall file comments on each such meeting into the Docket for monitoring by the Council."*

ADVISORS' EVALUATION

Supply Side Resources

To develop the supply-side resource technology alternatives the Companies began by surveying available generation technologies with the objective of identifying a wide a range of generation technologies that are reasonable to consider. The initial list of supply-side resource technology alternatives included eight different technology categories, with two to eight technologies included in each category for a total of 33 different technologies. The eight technology categories included were:

1. Pulverized Coal
2. Fluidized Bed
3. Integrated Gasification ("IGCC")
4. Combustion Turbine / Combined Cycle / Other Natural Gas
5. Fuel Cells
6. Nuclear
7. Entergy Storage
8. Renewable Technologies

The Companies then screened the technologies to identify those technologies that should be further considered in the resource portfolio optimization process. Details about the technology assessment and screening process were included in the technical supplements submitted with the IRP Filings. The following technologies were found appropriate for further detailed analysis:

- Pulverized Coal – Supercritical Pulverized Coal
- Pulverized Coal – Supercritical Pulverized Coal with carbon capture
    - Fluidized Bed – Atmospheric Fluidized Bed also known as "Circulating Fluidized bed" or ("CFB")
- Natural Gas Fired Technology
    - Simple-Cycle Combustion Turbines ("CT")
    - Combined-Cycle Gas Turbines ("CCGT")
    - Small Scale Aero-derivatives
- Nuclear – (Generation III Technology)
- Renewable Technologies
    - Biomass
    - On-shore Wind Power
    - Solar Photovoltaic ("PV")

For each of the technologies identified for further analyses, the Companies developed cost and performance assumptions including: unit size, development time, construction time, installed cost, heat rate, operation and maintenance costs, and emissions estimates. These technologies were then modeled over a range of fuel prices and operating assumptions to assess overall potential benefit and risk and to develop the supply-side reference technologies to be modeled in the production cost analyses in coordination with the demand-side alternatives. In addition to the new supply-side resources identified, ENO also considered the expected retirement of existing units and considered life extension alternatives for those units.

As part of the supply side analysis, ENO is modeled as a part of Entergy's six-Company System, which, in turn, is modeled as a part of the MISO RTO along with other parts of the market that interconnect with Entergy. The supply side analysis of the 2012 IRP also takes into consideration different configurations when Entergy Arkansas, Inc., and Entergy Mississippi, Inc., exit the Entergy System Agreement ("System Agreement") in December 2013 and November 2015, respectively.

The Advisors participated in the development of the IRP technical process and believe that the supply-side process employed by the Companies was in compliance with the Council's IRP Filing Requirements.

On February 20, 2013 ENO hosted a public meeting to review and discuss its IRP Filing. Of the questions submitted in response to the public meeting, thirty three out of the seventy three questions were related to supply-side issues. In general, these supply-side questions were with regard to the lack of renewable resources (e.g. wind, solar, biomass, etc.) in the utility preferred portfolio. While ENO adequately answered the questions in light of the IRP process and explained that many renewables were screened out during the technology assessment phase of the IRP, it is clear from the questions that there was a strong interest in renewable technologies. While the Companies' IRP process considers only large utility-scale renewable energy projects, there is a clear public perception that the IRP also analyzed smaller-scale customer renewable projects that are net metered. Similarly, in the public comments to the April 19, 2013 Community Hearing, the comments were overwhelmingly in favor of more reliance on renewable resources and EE measures. The AAE commented that ENO significantly underestimates renewable energy options for the IRP and encourages the Council to give consideration to pursuing a RPS.[16]

Demand Side Resources

The scope of DSM resources considered in the ENO IRP Filing included a comprehensive list of EE and demand response measures and bundled DSM programs that could be deployed to manage the level and timing of customers' energy use over the planning horizon. The identification of demand side resources included sufficient analytical support, though it could be improved in future filings. The comprehensive list of measures was evaluated with an initial cost-effectiveness screening, bundled into programs, and the market-achievable potential was assessed for the selected incremental utility-sponsored DSM programs. Twenty two DSM programs were modeled, including eleven EE programs based on current Energy Smart Program designs and six additional EE programs that expand the options for commercial and residential customers including those living in multifamily buildings. Six demand response programs were also modeled that provide customers with an opportunity to modify their energy usage patterns in response to price signals. ENO's IRP assumptions for the DSM program cost estimates as compared to the cost of supply-side alternatives are included in the DSM Technical Supplement to their IRP Filing. The evaluation of the DSM potential study including the comments of AAE, as well as the integration of the results of the DSM potential study into the IRP modeling, and the optimization of DSM with supply side resources, is discussed hereinafter.

IRP Scenarios and Scenario Assumptions

[16] AAE Comments at 31.

The IRP process included scenario planning to forecast future customer demand and sales. Four different macro-economic scenarios are modeled: (i) Reference Case which assumed reference load, reference gas price and no CO_2 cost; (ii) Economic Rebound Case which assumed the U.S. economy recovers and resumes expansion at a relatively high rates; (iii) Green Growth Case which assumed government policy and public interest drive government subsidies for renewable generation; regulatory support for energy efficiency and consumer acceptance of higher cost for "green" alternatives; and (iv) Austerity Reigns which assumed sustained poor conditions in the U.S. economy. The Economic Rebound and Green Growth scenarios also assume the occurrence of Carbon regulation in 2023 and in 2018 respectively. Estimated peak load and annual energy growth is modest even without additional ENO DSM due to federal efficiency standards and increasing customer awareness. In its Reference Case, ENO energy growth without new DSM is projected to be 1.1% annually through 2021 and 0.6% from 2022 to 2031. Average gas prices (in 2011 dollars) from 2012 to 2031 IRP study period are $5.29 in the reference case, $3.51 in the low gas price case and $7.20 in the high gas price case.

As of 2012, ENO owns a mix of nuclear, gas load-following and coal units to meet its firm load requirements. Currently, ELL is constructing the Ninemile 6 combined cycle unit, of which ENO will receive a 20% share by virtue of a purchased power agreement with ELL commencing in the 2014-2015 timeframe. Going forward, ENO's Michoud 2 and Michoud 3 units will have been in service sixty years, in 2022 and 2027, and both units would potentially be retired when they reach their sixty year service age. The preferred portfolio resulting from ENO IRP Filing reflects six perspectives: (i) input from stakeholders; (ii) optimal level of spending on demand-side management; (iii) preference for long-term resources, whether owned or contracted; (iv) existing base load units (coal, nuclear) remain in service; (v) investment in the existing Michoud Unit 3 facility to extend its service life due to cost savings and; (vi) new capacity from the Nine Mile 6 CCGT. The growth of total supply cost for ENO's preferred portfolio, expressed in 2012 dollars, is relatively small and is smaller than the forecasted increase of inflation.

Optimization of Supply and Demand Side Resources

The Energy Policy Act of 1992 defines Integrated Resource Planning as follows:

> *"The term 'integrated resource planning' means, in the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatch ability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis."* [17]

As in the Energy Policy Act definition, the key requirement in the Council's IRP Filing

[17] Energy Policy Act of 1992. §111(d)(19).

Requirements is the consideration of supply-side and demand-side resources in a fair, consistent, and integrated manner. In the June 13, 2011 Technical Advisors' Report in this docket, the failure to integrate DSM was one of the significant filing deficiencies identified with respect to the Companies' October 19, 2010 IRP Filing. Stepping back even further to ENO's September 2008 IRP Status Report and Council Resolution R-10-142 (the resolution adopting the Council's IRP Requirements), the Council agreed with the Energy Policy Task Force, AAE, and the Sierra Club that ENO's proposed resource plan did not adequately integrate demand-side management programs into its supply plan nor did it result in a truly Integrated Resource Plan.[18] Further, in the June 13, 2011 Technical Advisors' Report in this docket, the Advisors went on to comment that:

> *"The ICF Study conducted for all Entergy Operating Companies, while useful for screening demand-side measures and demand-side programs and providing a preliminary assessment of cost effectiveness, is simply the initial step in integrating demand-side resources in an IRP. Subsequently, the screening of demand-side resources must be integrated into the IRP process and evaluated using the modeling and assumptions applied in the selection of all resource options, whether Company-owned or customer-owned. The static approach employed by the Companies fails to recognize that the savings from implementing demand-side options are not simply the avoided costs of a peaking unit, as was utilized for screening, <u>but rather the overall change in production costs of two competing resource portfolios – resource portfolios that have a combination of supply-side resources, demand-side resources, and transmission projects</u>."*

In Resolution R-11-301, the Council adopted the findings of June 13, 2011 Technical Advisors' Report and initiated the process of quarterly technical conferences with the Companies and the Intervenors and required the IRP Filings currently at issue.

In the development of the IRP Filing, ENO did not superimpose the ICF DSM Study results on top of a supply-side resource plan an approach that they were chastised by the Council for in the past, rather they took cues from the Council's resolutions, the Advisor's Technical Report and the stakeholder process and developed a process by which they evaluated flights of demand-side management programs against competing supply-side alternatives. In part, the effort to consider demand-side resources and supply-side resources on a consistent and integrated basis resulted in the Companies replacing their existing Promod IV and PROSYM models with a new model, AURORAxmp Electric Market Module ("AURORA"). The AURORA model contains an optimization engine that can optimize both supply-side and demand-side resource alternatives and determine the optimal long-term resource portfolio under a range of varying potential future scenarios.

ENO's approach to optimizing supply-side and demand-side resources is well documented in its filing and in the materials presented in the quarterly stakeholder meetings and DSM Working Group meetings. Generally the approach included the following steps:

1. Cost-effective DSM programs resulting from the DSM Potential Study were combined into six bundles of programs based on program benefit/cost ratio. For each bundle, a low, reference and high level of program spending was developed. For each of the bundles

[18] Council Resolution R-10-142 at 16.

and spending levels, load-shapes and annual program costs were developed.

2. A "DSM Supply Curve," starting with the most cost-effective bundle and proceeding through the least cost-effective bundle, was developed from the eighteen hourly load-shapes.
3. Production cost modeling was conducted to identify the optimal level (lowest net present value of total cost of service) of DSM for ENO using the DSM Supply Curve. Production cost modeling was conducted with and without competing supply-side resources under each of the four IRP scenarios. The same level of DSM was found to be optimal for each scenario with or without including supply-side resources.
4. The optimal level of DSM for ENO in each of the IRP scenarios as identified in Step three was included in the capacity expansion module in AURORA to produce the optimum level of supply-side resources.

Appendix E provides additional information regarding the construction of the DSM "supply curve," as well as a table of DSM results for the four IRP scenarios.

The AAE criticizes ENO's supply-side and demand-side integration efforts and asserts that the Companies' methodology utilizes the Program Administrator Test ("PAC") test and not the Total Resource Cost ("TRC") test which results in a de-optimization of cost modeling with a bias against DSM.[19] ENO contends that it utilized the Council required TRC test to initially screen demand-side resources in the DSM Potential Study and that the use of the TRC test is consistent with the Council IRP Requirements.[20] Further ENO acknowledges that they utilized the PAC test basis for developing program bundles to be evaluated in the DSM optimization process of the IRP and that the PAC is an appropriate test for comparing supply-side and demand-side resources in a head-to-head manner.[21] In this manner, the Companies followed the guidelines of the IRP Filing Requirements with respect to both the screening of resources and the comparison of supply-side and demand-side measures in a fair and consistent manner.

The Council's IRP Requirements are structured for a balanced utility resource portfolio with the primary objective of optimizing the integration of generation and transmission services with demand-side resource options to provide all ratepayers (not just DSM program participants) with reliable electricity at the lowest practicable cost by minimizing revenue requirements. Although the initial screening tests for DSM measures are defined in the IRP Requirements, the methodology for optimization of the demand-side and supply-side measures is not specified. To the extent that the Council wishes to refine or clarify the IRP requirements as written, it should do so in its order in the instant docket with specific direction on how the cost-effectiveness of DSM should be determined in the optimization process.

The AAE indicates in its comments that the Companies' integration methodology resulted in a bias against DSM. In our evaluation of the Companies' integration methodology we did not find that the integration process resulted in the de-optimization by removing cost-effective resources previously identified. The DSM supply curve, which was constructed from DSM Potential

[19] AAE Comments at 10-14.

[20] ENO Reply Comments at 20. We would also note that RAP in its comments to the Council recommends the use of the TRC as one of the criteria to determine that an energy efficiency program is "reasonable." Also see Council Resolution R-10-142 at IRP Requirement page 5 component 4 part 7.

[21] ENO Reply Comments at 20, also refer to Appendix A for a discussion of the applicability of the PAC test.

Study results, was given equal treatment in the IRP's Aurora model. Furthermore, DSM was optimized with existing supply side resources before new supply additions were considered.

It would be nearly impossible and result in diminishing returns to evaluate in the production cost models all potential supply-side resources or demand-side resources no matter how costly or improbable the resource. Accordingly, as is customary practice, it is necessary to screen the resources prior to production cost modeling. Simply because some of the supply-side resources that made it through the screening process were ultimately not included in the optimal resource portfolio, does not mean that the planning process was de-optimized. Rather, it is supportive of the fact that the screening process, which is based on coarse static analyses, could not determine which resources would ultimately be selected as a result of the more rigorous and detailed production cost analyses. This applies in the same manner to the DSM measures that were screened for additional consideration in the production cost analyses, but not ultimately selected as part of the optimal resource plan. In fact, if the DSM screening process by itself could determine the optimal resource mix, there would be little need for Integrated Resource Planning and the Council's IRP Requirements.

There are two main drivers explaining why DSM implementation costs increase more in proportion to higher incentives and larger increases in MWh reduction, effectively constraining the amount of DSM reduction. First, MWh savings do not increase proportionally with increased participant incentives. Table 1a summarizes the ICF DSM Potential Study results by the annual program costs and MWh savings for high, reference, and low incentive levels (corresponding to 75%, 50%, and 25%, respectively, of the customer costs to implement a DSM program).

Table 1a

ICF DSM Potential Study Summary Results
(10 and 20 Year Estimates)

	Annual Program Costs ($ Millions)		**Cumulative Savings (MWh)**	
Scenario	**2021**	**2031**	**2021**	**2031**
Low	$7.6	$8.3	261,580	459,739
Reference	$20.4	$23.3	358,128	637,974
High	$ 35.1	$40.5	477,414	860,012

For the recommended set of DSM programs, the MWh savings does not increase proportionally with the increase in annual program cost. In fact, when the annual program cost at 2021 is increased from $7.6 million to $20.4 million (2.68 times), the corresponding MWh reduction is projected to increase from 261,580 MWh to 358,128 MWh (1.37 times). This results in a more expensive $/MWh cost of DSM reduction as incentives are increased from a low to reference level. The underlying reason for these results is the "law of diminishing return" evidenced from empirical studies[22,23] which confirm that increased participation levels for higher incentives is not linear.

The results summarized above can be converted to $/MWh savings for each level of incentives to demonstrate the average cost per reduction over the planning period for the total programs in the preferred DSM portfolio.

Table 1b

$/MWh Savings (10 and 20 Year Estimates)		
	10 Year Estimate	**20 Year Estimate**
	$/MWh Savings	**$/MWh Savings**
Low	$29.05	$18.05
Reference	$56.96	$36.52
High	$73.52	$47.09

The second driver is that the <u>DSM supply curve reflects the varying levels of program cost effectiveness</u>. As summarized in Step 1 in Appendix E, programs in the DSM preferred portfolio are grouped into six bundles, based on their cost effectiveness related to MWH savings. The DSM supply curve (relating DSM program cost to amounts of reduction) was constructed from the low, reference, and high incentive costs and corresponding reductions for each of the program bundles. The DSM supply curve ranged from the most cost effective program bundles and incentive levels to the least cost effective programs, clearly showing the diminishing reductions for increased levels of DSM and implementation costs. In other words, as more programs are included that are less cost-effective, and higher incentive levels are included that are also less cost-effective, the $/MWH cost of DSM becomes more expensive when compared with other supply cost options at the margin for each hourly load.

Figure 1 shows the levelized annual total supply cost is minimized, at $309 million, for the IRP optimal DSM level. Figure 1 also shows that the levelized annual ($/MWh) supply cost is highest with maximum DSM and least for Optimal DSM.

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[22] Direct Testimony of John Plunkett on behalf of the British Columbia Sustainable Energy Association and the Sierra Club in BCUC Project No. 3698592(April 17, 2012), stated that "*the cost of acquiring efficiency resources is subject to … diminishing marginal returns, …beyond a certain level of participation, fixed program costs per unit of saved energy are spread over more savings and tend to level off or decline gradually.*" Moreover, John Plunkett has testified that based on his experience, "*higher financial incentives are required to achieve participation rates in the 75 – 90 percent range, especially for more costly efficiency measures with deeper savings.*" Pg.15 – 16.

[23] Resource for the Future, "Cost-Effectiveness of Electricity Energy Efficiency Programs," November 2009. In investigating cost-effectiveness functions for Energy Efficiency Programs among large utilities throughout the nation, the study has shown that *"Harvesting additional savings tend to become increasingly challenging as the low-cost opportunites are used up. Thus, increased DSM spending has diminishing returns, which can occur due to both increasing the level of spending per participating customer, as well as increasing the number if customers participating in the programs."*

Figure 1: Levelized Annual Total Supply Cost and Levelized Annual $ per MWh

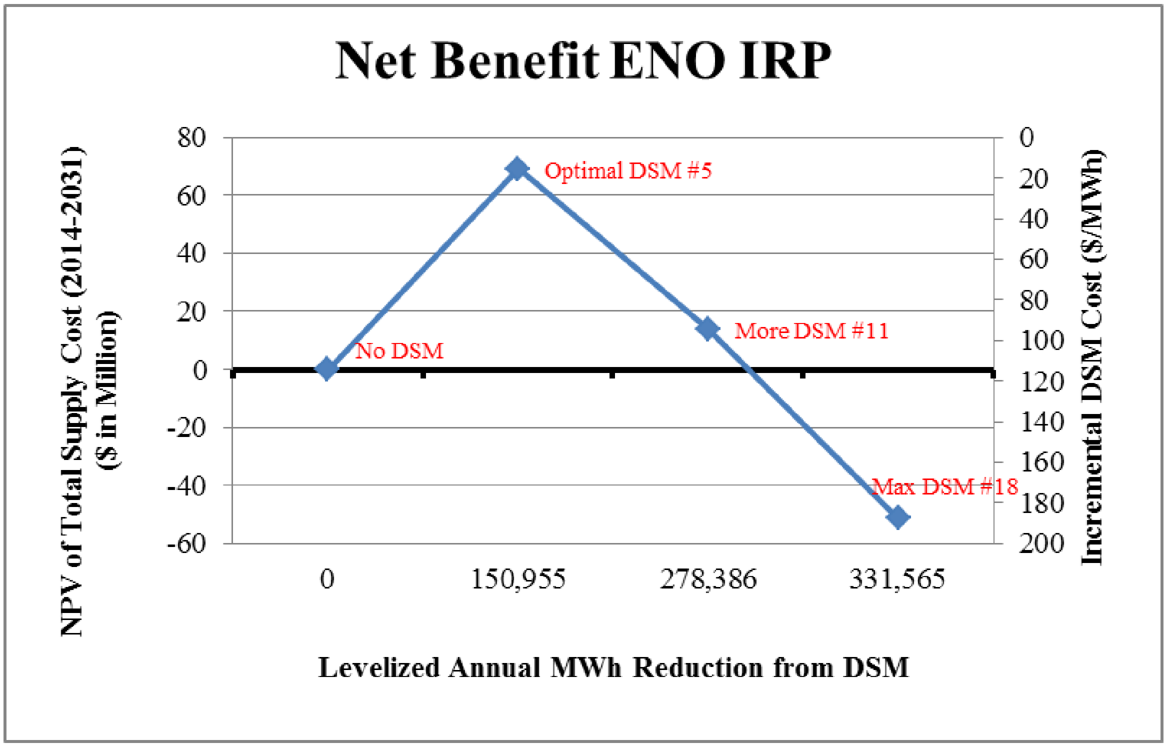
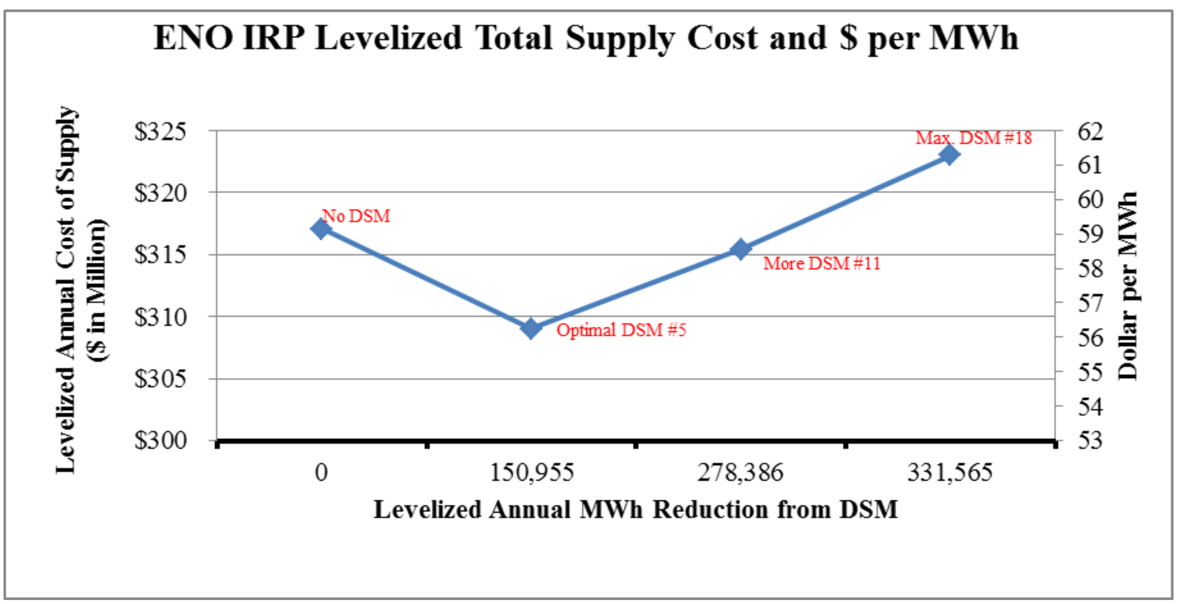


Figure 2 shows that the net benefit decreases for increasing DSM greater than the IRP optimal level. Figure 2 also shows the increasing incremental cost ($/MWh) for additional DSM beyond the optimum level determined in the IRP.

Figure 2: Net Benefit Comparison (With and Without DSM)



The AAE in its comments further contends that the optimization process was biased against DSM as it ignored opportunities to sell excess capacity off-system and the ability of ENO to shift costs to the other Operating Companies through the service schedules of the System Agreement. The primary service schedule of the System Agreement relating to credits for capacity is service schedule MSS-1. To be clear, the MSS-1 impacts and the capacity and load related impacts of other service schedules of the System Agreement are included in the average customer bill and customer rate analysis presented with the IRP, just not in the optimization phase of the IRP. With respect to the AAE contention of bias, the Advisors note that while the demand-side resources were not credited in the optimization process for MSS-1 capacity related credits, neither were the supply-side resources and, as such, the supply- and demand-side resources were treated in a similar fashion. With respect to including the ability of ENO to shift costs to the other Operating Companies as part of the optimization process, the Advisors believe that this would be inappropriate as long as the joint planning provisions of the System Agreement are in effect. In the event the System Agreement is either terminated or the joint planning and operating provisions of the System Agreement are eliminated in the future, the Advisors believe that the inclusion of capacity related credits in the optimization process would be appropriate on an individual Operating Company basis.

In discussing its concern regarding the inclusion of credits for excess capacity, the AAE questions the inclusion in ENO's preferred portfolio of a portion of a new CCGT in the Amite South planning region in the year 2020 at a time when ENO has sufficient excess capacity. As defined by Entergy in its Summer 2009 Request For Proposals (RFP) For Long-Term Supply-Side Resources, the Amite South planning region is:

> *"…the region of Louisiana south of the Amite Substation that is serviced by one or more of the Entergy Operating Companies and other utilities (generally from east of the Baton Rouge, Louisiana metropolitan area to the Mississippi state line and south to the Gulf of Mexico); the Southeast portion of the Amite South region is known as the Downstream of Gypsy (DSG) region and generally encompasses down river of the Little Gypsy plant including metropolitan New Orleans east to the Mississippi state line and south to the Gulf of Mexico and has unique planning requirements."*

In the Amite South planning region, the load is served by both generation within the region and imports to the region. To avoid potential transmission line loading problems during contingencies, imports into Amite South planning region are generally maintained below a certain load threshold.

In its comments, ENO acknowledges that the CCGT in 2020 was added to the IRP preferred portfolio to reflect aging generating resource infrastructure in Amite South and was not part of the DSM optimization process, nor the result of the AURORA capacity expansion modeling. Further, ENO comments that:

> *"The 2020 CCGT identified in the System and ENO IRP Preferred Portfolios serves as a placeholder. Ultimately, capacity could be met through one or a*

combination of resources (CCGT or otherwise) including capacity built by a third party, transmission upgrades, renewables, or DSM."

While the new CCGT was not identified as part of the Aurora capacity expansion modeling, the Advisors recognize the current import limitations into Amite South and understand the current need to maintain generation and load such that import limits to the region are not exceeded. Further, the Advisors recognize that the CCGT is a placeholder in the IRP and that ENO's share of that CCGT will be determined if an when the facility is authorized by the Council and other affected Operating Companies' regulators. Lastly, the Advisors note that the addition of this CCGT resource in the IRP did not change the optimal flight of demand-side resources identified by ENO in the IRP[24] and will be the subject of re-analysis in the next Triennial IRP Filing when more will be known regarding the System Agreement litigation now pending at Federal Energy Regulatory Commission ("FERC").

Accordingly, the Advisors find the supply-side and demand-side integration methodology employed by ENO in the development of its IRP Filing is consistent with the Council's IRP Requirements.

Comparison of Recommended Levels of DSM

In their comments AAE has put forth an alternative[25] to the Council's IRP Filing Requirements with respect to DSM. The Advisors recognize that AAE's alternative proposal may in some settings have specific policy benefits; but we also note the proposal is a departure from the Council ordered IRP process in this proceeding. Regarding levels of DSM, AAE's proposal that the Council adopt an EERS in addition to IRP Requirements, which "*sets the expected program size based on total achievable energy efficiency*",[26] is in conflict with the Council's IRP Requirements as enumerated in detail in Council Resolution R-10-142. Furthermore, AAE's recommendation appears to propose a combined implementation of the EERS and the IRP, two distinctly different approaches. As such, it would be difficult to determine how levels of DSM based on EERS would be implemented consistent with levels of DSM resulting from an IRP optimization of supply and demand resources.

AAE's recommended level of DSM refers to targeted levels of EE or kWh reductions, not including demand response. AAE's proposed level of EE incorporates the EERS concept of setting targets for annual levels of EE, expressed as a percent of total energy sales. Specifically, AAE proposes increasing the percent of EE for the first seven years of the planning period until a two percent (2%) level is reached, and then maintaining that 2% level to the end of the planning period (2031).[27] Under this approach, AAE's Filing shows that EE savings would reach 1092 GWH, or approximately 19% of the energy forecast, by 2031.[28] In comparison, ENO's IRP results show an optimized level of EE savings increasing over the planning period to a level of

[24] DSM was initially optimized with existing supply resources, and then re-optimized after supply additions were considered. The NPV of Revenue Requirements at the optimal level changed from $2,611million to $2,596 million.
[25] AAE Comments at page 22.
[26] Page 22, AAE April 30, 2013 Filing "*Comments of the Alliance for Affordable Energy*" Council Docket No. UD-08-02
[27] Energy Efficiency worksheet, Appendix A, of AAE Filing, April 30, 2013.
[28] Ibid.

393 GWH or 6.8 % by 2031.[29] Table 2 shows a comparison of the ENO IRP Filing and AAE levels of EE for the planning period, expressed also as a percent of forecasted total annual GWH.

IRP results for GWh reduction through DSM in column 2 of Table 2 reflect the projection that relatively smaller amount of GWh reduction will be achieved in the later years of the planning period due to lower energy growth and changes in the relative costs of resource options. These results also demonstrate that the IRP optimization of resources is a dynamic analysis.

This dramatic difference in the GWh reduction that can be achieved through DSM can be attributed to the constraints imposed in ENO's IRP Filing versus setting DSM targets independently.

Table 2

ENO IRP Filing and AAE's Savings Percentage					
Year	**Energy Forecast [1]**	**Cumulative Energy Efficiency Savings**		**Savings % of Forecast**	
		ENO IRP Filing [2]	**AAE [3]**	**ENO IRP**	**AAE**
	(GWh)				
2014	5,165	34	65	0.7%	1.3%
2015	5,233	55	115	1.0%	2.2%
2016	5,277	80	174	1.5%	3.3%
2017	5,308	107	241	2.0%	4.5%
2018	5,349	135	316	2.5%	5.9%

[29] Page 49, *2012 Integrated Resource Plan, Entergy New Orleans,* filed October 30, 2012.

2019	5,379	164	399	3.0%	7.4%
2020	5,411	191	487	3.5%	9.0%
2021	5,437	218	568	4.0%	10.4%
2022	5,466	245	644	4.5%	11.8%
2023	5,498	269	715	4.9%	13.0%
2024	5,534	290	781	5.2%	14.1%
2025	5,562	309	842	5.5%	15.1%
2026	5,594	325	899	5.8%	16.1%
2027	5,625	340	951	6.0%	16.9%
2028	5,662	354	994	6.3%	17.6%
2029	5,691	367	1,031	6.5%	18.1%
2030	5,727	380	1,063	6.6%	18.6%
2031	5,761	393	1,092	6.8%	19.0%

[1] ENO's IRP Filing 10/30/2012, Pg. 32, Considering 7.29% Average Line Loss.
[2] ENO's IRP Filing 10/30/2012, Pg. 49. Total 4,256,080,000 kWh saved over a period of 18 years.
[3] Appendix-A, AAE's Filing 4/30/2013. Total 11,377,366,000 kWh saved over a period of 18 years.

Comparison of Spending Levels, kWh Savings, and Rate Impacts

The spending levels proposed for EE programs differ significantly between ENO and the AAE. AAE's proposed level of EE spending incorporates the EERS concept of setting annual targets for EE independent of an IRP analysis of all resources, and then computing the costs of such targets based on an econometric model relating program costs to kWh reductions (savings). ENO's proposed DSM spending level is based on the IRP optimization process summarized above. Essentially the difference in methodologies is a bottom up approach optimizing all supply and demand resources available to ENO versus a top down or goal setting approach for EE without optimization of all existing and new resources over a planning period. AAE's econometric methodology is based on using national empirical data to determine DSM spending levels relative to kWh reduction. Several years of EE data from utilities located throughout the U. S. are evaluated in AAE's regression model, which estimates the cost of implementing EE programs per KWh saved based on the amount of kWh savings, EE portfolio maturity (years), type of customer, and U.S. location. The result of the econometric analysis[30] shows that program costs per kWh saved decreases up to a certain EE savings level (2.5% of total kWh), after which the program costs per kWh saved increases (similar to a "U-shaped" short run supply curve).[31] AAE then calculates the level of annual EE spending by applying the econometric relationship to the energy saving level based on EERS goals.

ENO's responsive comments in the docket state that the AAE's methodology to estimate EE spending levels using a regression relationship is flawed. ENO asserts that the AAE regression

[30] Page 25, AAE April 30, 2013 Filing "*Comments of the Alliance for Affordable Energy*" Council Docket No. UD-08-02 provides a graphic presentation of the results of the AAE econometric model.
[31] It should be noted that the AAE recommended targets of EE reduction exceed the 2.5% level (representing the EE level having the least program costs per kWh saved) for many of the years in the planning period.

analysis is a static analysis which includes an interdependence between the variables,[32] and that the relationship between program funding and kWh savings is not necessarily a linear relationship.[33] In other words, such analysis represents one of many possible DSM supply curves. In contrast, the IRP is a non-static process that dynamically integrates all resource options supply-side, demand-side, EE, and demand response, where changes in any resource will have an effect on the consideration of other resource options.

Table 3a shows the IRP spending levels of optimal EE as developed by ENO in its IRP Filing and corresponding kWh reduction compared to the AAE proposed spending levels and kWh reductions. AAE's recommendation is to spend an additional $348.7 million more than IRP results, equivalent to a significant increase over the spending level ENO determined to be cost-effective in the IRP over the 20-year planning horizon.

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[32] The result of multiplying the cost per kWh of savings by an annual savings target will not be as robust since cost per kWh of savings, as a result from the regression analysis, will be dependent upon the amount of energy saved. More specifically, when target energy savings change, the cost per kWh of savings also changes. Therefore, the product of such two variables will be a less than accurate estimate, resulting in a risk associated with the projected program costs.

[33] Pages 10-14, ENO Responsive Comments, filed April 30, 2013.

Table 3a

Comparison of ENO IRP Filing (Without Demand Response) and AAE Estimated DSM Annual Spending (in Nominal Dollars) [1]							
Year	**DSM Spending (Million Dollars)**			**Monthly Average Residential Bill Impact 1000kWh [4] ($ per Bill)**			
	ENO IRP Filing [2]	**ENO IRP Filing [2]**	**AAE Estimate [3]**	**ENO IRP**	**AAE**	**ENO IRP**	**AAE**
	With Demand Response	**Without Demand Response**		**w/o cap**		**w cap [5]**	
2014	$3.13	$2.41	$9.97	$0.44	$1.82	$0.66	$2.85
2015	$3.56	$2.74	$11.29	$0.49	$2.05	$0.75	$3.22
2016	$4.27	$3.27	$12.36	$0.59	$2.25	$0.89	$3.53
2017	$4.65	$3.65	$13.33	$0.65	$2.44	$0.99	$3.82
2018	$4.91	$3.90	$14.45	$0.70	$2.66	$1.06	$4.15
2019	$5.06	$4.06	$15.83	$0.72	$2.95	$1.09	$4.58
2020	$5.16	$4.16	$17.74	$0.74	$3.33	$1.12	$5.16
2021	$5.24	$4.23	$19.41	$0.75	$3.68	$1.14	$5.68
2022	$5.30	$4.30	$21.18	$0.76	$4.05	$1.16	$6.24
2023	$5.36	$4.36	$23.05	$0.77	$4.44	$1.17	$6.82
2024	$5.43	$4.42	$25.05	$0.78	$4.85	$1.19	$7.44
2025	$5.49	$4.49	$27.10	$0.79	$5.28	$1.20	$8.08
2026	$5.56	$4.55	$29.27	$0.80	$5.73	$1.22	$8.75
2027	$5.63	$4.62	$31.55	$0.81	$6.20	$1.23	$9.45
2028	$5.70	$4.69	$33.98	$0.82	$6.68	$1.24	$10.18
2029	$5.77	$4.76	$36.46	$0.83	$7.18	$1.26	$10.94
2030	$5.84	$4.83	$39.12	$0.84	$7.70	$1.27	$11.73
2031	$5.92	$4.91	$41.89	$0.85	$8.23	$1.29	$12.55
Total	**$91.98**	**$74.34**	**$423.04**				
Levelized Payment [6]	**$4.98**	**$4.01**	**$21.73**	**$0.71**	**$4.17**	**$1.08**	**$6.41**

[1] Comparison of ENO IRP Filing and AAE's Estimate for 20 Years.
[2] 2012 ENO IRP DSM Optimization_HSPM Data Supplement.
[3] 2013AAE Filing 4/30/2013, Pg. 27.
[4] Residential Bill Impact at 1000 kWh.
[5] Cap used is same as established for Energy Smart Program ($100 for commercial customers, $200 for industrial customers).
[6] At Discount Rate of 30 Year Treasury Bonds at 7/9/13 of 3.65%

Table 3b shows both the cost and the benefit to all ratepayers for the optimum DSM level of the IRP, providing the details regarding net benefit from DSM (including the net incremental supply fixed cost, the net variable production cost and the DSM implementation cost). The levelized monthly bill is reduced by $2.93, which includes the DSM implementation costs shown in Table 3a (without cap). The benefits include the impact of MSS-1 until 2031. However, it is important to note that there is considerable uncertainty regarding the Entergy System Agreement, and its applicability throughout the planning period through 2031. As an indication of the uncertainty, the Public Utility Commission of Texas has given approval for Entergy Texas Inc. ("ETI") to join MISO with the condition that ETI take all reasonable action to exit the Entergy System Agreement Termination as soon as feasible. Demand response benefits and other capacity credits through MISO were not included in the IRP analysis or work papers, since that specific information regarding MISO was considered to be tentative at the time the analysis for the 2012 IRP was initiated. Recovery of the lost contribution to fixed costs is not reflected in the net benefits shown in Table 3b. Including this additional cost impact is estimated to result in a levelized monthly bill reduction of approximately $0.17 for the optimal level of DSM indicated by the IRP.

Table 3b

Net Benefit DSM for ENO IRP [1] (Nominal Dollars) ($ in Millions)								
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Year	Variable Production Cost		Net Benefit Variable Cost	Incremental Supply Fixed Cost (Incl. MSS-1) [2]		Net Benefit Incr. Supply Fixed Cost	Net Benefit Fixed and Variable Cost	Total Bill Impact $ per Bill [3] [4]
			(a) - (b)			(d) - (e)	(c) + (f)	
	No DSM	With DSM	With DSM	No DSM	With DSM	With DSM	With DSM	With DSM
2014	193	190	(2.69)	(0.16)	1.93	2.09	(0.61)	(0.12)
2015	198	196	(1.80)	(1.86)	(0.24)	1.62	(0.17)	(0.03)
2016	210	207	(3.03)	0.45	1.80	1.35	(1.68)	(0.31)
2017	235	231	(4.25)	(0.41)	(0.15)	0.26	(3.99)	(0.73)
2018	261	255	(6.10)	(1.18)	(2.15)	(0.97)	(7.07)	(1.28)
2019	274	265	(8.20)	(1.55)	(4.09)	(2.55)	(10.74)	(1.93)
2020	288	278	(9.51)	38.28	34.23	(4.04)	(13.55)	(2.44)
2021	300	289	(11.94)	36.35	30.69	(5.66)	(17.60)	(3.16)
2022	316	302	(14.25)	34.50	27.52	(6.97)	(21.22)	(3.80)
2023	333	317	(16.44)	30.05	20.03	(10.02)	(26.46)	(4.73)
2024	346	329	(17.44)	26.76	14.67	(12.09)	(29.53)	(5.28)
2025	362	342	(19.56)	26.71	13.39	(13.32)	(32.88)	(5.87)
2026	382	359	(22.46)	24.69	9.87	(14.82)	(37.28)	(6.64)
2027	398	375	(23.71)	51.20	35.34	(15.87)	(39.57)	(7.03)
2028	419	393	(26.52)	47.87	31.57	(16.30)	(42.82)	(7.59)
2029	440	412	(28.43)	46.34	29.77	(16.57)	(45.00)	(7.94)
2030	461	430	(30.56)	45.59	28.12	(17.47)	(48.03)	(8.45)
2031	473	440	(33.40)	45.12	26.61	(18.51)	(51.91)	(9.09)
Total	**$5,889.88**	**$5,609.61**	**($280.27)**	**$448.77**	**$298.92**	**($149.85)**	**($430.12)**	**($76.41)**
Levelized Payment	**$289.07**	**$277.79**	**($11.27)**	**$17.24**	**$12.09**	**($5.15)**	**($16.42)**	**($2.93)**

[1] DSM on Incremental Supply Fixed Cost and Variable Production Cost.
[2] MSS-1 Assumed Through 2031.
[3] Bill Impact at 1000kWh.
[4] Total Energy Forecast Includes Reduction.
[5] 9.25% Generic System Return on Rate Base for ENO.

The AAE used an empirical model it developed from its sample of actual and planned energy---efficiency program spending and savings throughout the U.S. and Canada, then applied values of avoided electric energy and capacity costs to project the benefits of the electricity savings produced by each of three alternative scenarios.[34] In its comments following ENO's Supplemental Implementation and Cost Recovery Filing, AAE stated: "*This [AAE] analysis demonstrates that the ACEEE and Alliance alternatives to the ENO proposed energy efficiency investment plan are clearly economically superior*."[35]

In its responsive comments, ENO argues that AAE's conclusions and recommendations (1) are not properly supported, (2) do not recognize the time and expense of pursuing additional precision in the analysis that may not yield additional accuracy, (3) present concerns at such a level of detail that they are highly uncertain and difficult to predict, and (4) would result in such high and aggressive levels of DSM spending that it risks exposing customers to potentially cost-ineffective programs without a reasonable ramp-up and customer education/adoption period.[36]

Table 4 shows a comparison of AAE's cost estimates with program cost estimates and bill impacts corresponding to AAE's proposed target EE levels. The ENO IRP cost estimates were developed from the cost and kWh reduction data of the DSM programs at the optimum level in the IRP preferred portfolio. It is noted that AAE's cost estimates corresponding to their EE targets could be understated, based on data developed in the DSM Potential Study. Specifically, by 2031, program costs to meet AAE's EE targets could be at least \$64.63 million rather than the \$41.89 million estimated by AAE, expressed in nominal dollars.

[34] Page 23 AAE Comments Filed April 30, 2013.
[35] Ibid.
[36] Page 2 ENO Reply Comments filed May 30, 2013.

Table 4

Comparison of Cost Estimate and Bill Impact for AAE's Target EE and IRP DSM EE (in Nominal Dollars)				
Year	Cost Estimate (Million Dollars)		Monthly Average Residential Bill Impact 1000kWh [3] ($ per Bill)	
	For AAE Target EE [1]	Based on IRP DSM Data [2]	For AAE Target EE [1]	Based on IRP DSM Data [2]
2014	$9.97	$18.44	$2.85	$5.67
2015	$11.29	$22.68	$3.22	$6.96
2016	$12.36	$26.91	$3.53	$8.29
2017	$13.33	$29.84	$3.82	$9.32
2018	$14.45	$33.19	$4.15	$10.46
2019	$15.83	$36.74	$4.58	$11.72
2020	$17.74	$40.48	$5.16	$13.06
2021	$19.41	$43.42	$5.68	$14.05
2022	$21.18	$46.09	$6.24	$14.95
2023	$23.05	$48.69	$6.82	$15.82
2024	$25.05	$51.39	$7.44	$16.71
2025	$27.10	$54.23	$8.08	$17.66
2026	$29.27	$57.02	$8.75	$18.58
2027	$31.55	$59.61	$9.45	$19.42
2028	$33.98	$61.51	$10.18	$20.01
2029	$36.46	$62.95	$10.94	$20.48
2030	$39.12	$63.91	$11.73	$20.75
2031	$41.89	$64.63	$12.55	$20.94
Total	**$423.04**	**$821.72**	**-**	**-**
Levelized Payment [4]	**$21.73**	**$42.96**	**$6.41**	**$13.81**

[1] 2013 AAE's Filing 4/30/2013, Pg. 24.
[2] Calculated For Increased Estimates Based on IRP DSM Data for AAE's Target, 2012 IRP DSM Optimization.
[3] Residential Bill Impact at 1000 kWh.
[4] At Discount Rate of 30 Year Treasury Bonds at 7/9/13 of 3.65%

The Advisors believe that ENO complied with the Councils IRP Requirements in developing the IRP. The Advisors expect that the implementing the DSM programs identified as a result of the IRP and included in ENO's Supplemental Filing will, in a timely manner, put into effect DSM programs that should provide a solid base for DSM in New Orleans and provide valuable participation and savings information for the future evaluation of DSM and the potential expansion of the DSM measures. Additionally, the Advisors recognize that the Council may be interested in a more aggressive approach to DSM outside of the IRP, such as that which the AAE has put forth in its comments. The differences in potential costs and impacts of the approaches can be summarized below:

1. ENO's recommended spending levels through the IRP planning period are approximately 5 to 10 times lower than the spending levels recommend by AAE.

2. The savings from DSM identified in the IRP represent approximately seven percent (7%) of ENO's energy requirements by 2031; AAE's recommended kWh savings levels represent approximately nineteen percent (19%) of ENO's energy requirements by 2031.

3. There is a large disparity between ENO's and AAE cost estimates for similar levels of savings. ENO's IRP data would suggest that it would require in excess of $64.63 million to achieve kWh savings similar to the kWh savings AAE estimates would be achieved at a spending level of $41.89 million by 2031.

4. Considering the cost of implementing DSM for the three year period beginning April 2014, the ratepayer impact of the ENO's recommended spending level for DSM translates to an approximate $0.50 on a typical residential monthly bill. AAE's recommended spending level for DSM translates to an approximate $2.04 on a typical residential monthly bill.

5. The results of the DSM Potential Study can be used to estimate the benefits of DSM through the IRP analysis; however the DSM Potential Study results do not support a benefit estimate at the significantly higher level of DSM proposed by the AAE.

6. Given the triennial nature of the Council's IRP requirements, and that subsequent IRPs will utilize the EM&V obtained from implementing Council approved DSM programs to inform decisions regarding future supply-side and demand-side resources, Table 5 presents the near term impacts of the ENO and AAE DSM spending levels. Table 5 shows ENO's proposed program budget and estimated monthly bill impact for the three-year period 2014-2016 when compared to AAE's proposal for the same three year period. ENO's proposal in their Supplemental Filing uses DSM spending levels approximate to those determined through the IRP process.[37] Table 5 also shows the proposed program budget and estimated bill impact for ELL-Algiers for the three year period 2014-2016

[37] The proposed program budget proposed by ENO is $16.1 million for 3 years (2014-2016) or $5.37 million per year, as shown on page 2 of ENO's April 1, 2013 Supplemental Filing. In comparison, the IRP optimal spending level for DSM averages $5.24 million per year (in 2013 $), as shown on page 49 of the 2012 ENO IRP Filing.

Table 5

Comparison of ENO Proposed and AAE's Estimated DSM Annual Spending (in Nominal Dollars)						
Year	**DSM Spending (Million Dollars)**		**Monthly Average Residential Bill Impact [3] ($ per Bill)**			
	ENO Proposed[1]	**AAE Estimated[2]**	**ENO**	**AAE**	**ENO**	**AAE**
			without cap		**with cap [4]**	
2014	$5.65	$9.97	$1.02	$1.82	$1.55	$2.85
2015	$5.14	$11.29	$0.92	$2.05	$1.39	$3.22
2016	$5.33	$12.36	$0.94	$2.25	$1.43	$3.53
Total	**$16.12**	**$33.63**	**-**	**-**	**-**	**-**
Levelized Payment [5]	**$5.38**	**$11.18**	**$0.96**	**$2.04**	**$1.46**	**$3.19**

Proposed DSM Annual Spending for ELL-Algiers (in Nominal Dollars)			
Year	**DSM Spending (Million Dollars)**	**Monthly Average Residential Bill Impact [3] ($ per Bill)**	
		without cap	**with cap [4]**
Total for 3 Years	$1.66	$2.58	$3.91
Levelized Payment [5]	**$0.57**	**$0.89**	**$1.35**

[1] ENO's IRP Filing 04/01/2013.
[2] 2013 AAE Filing 4/30/2013, Pg. 24.
[3] Residential Bill Impact at 1000 kWh.
[4] Cap used is same as established for Energy Smart Program ($100 for commercial customers, $200 for industrial customers).
[5] At Discount Rate of 30 Year Treasury Bonds at 7/9/13 of 3.65%.

IRP Action Plan

As part of the continuing IRP planning process, an IRP Action Plan is necessary to identify activities that continue movement that supports implementation of the preferred portfolio and ensures improvements in the next IRP Triennial Filing. ENO's IRP Filing proposed an IRP Action Plan focused on the areas of supply side alternatives, demand side alternatives, MISO transition and area planning.[38]

Specifically, the IRP Action Plan should include: (i) the continued evaluation of new supply-side resource alternatives including renewables, purchase power agreements and low cost, efficient gas-fired generation; (ii) the continued evaluation of local area reliability in coordination with efficient local generation resources, demand reduction, and transmission investment alternatives; (iii) short and long-term off system sales opportunities created by DSM; (iv) approval of an implementation plan for the next phase of DSM in New Orleans; (v) monitoring and reporting on MISO's resource adequacy requirements and congestion management including impact on production costs; and (vi) integration of MISO's transmission expansion plan ("MTEP") into the IRP planning process. At a minimum the IRP Action Plan should also identify analyses (such as updated screening of renewables) to be included in the IRP Status Report required under Component 6 of the Council's IRP Requirements.

Proposed Energy Efficiency Programs Filing

ENO's Supplemental Filing proposed a set of programs different from those used by ENO to determine the optimum DSM spending levels in its IRP. The differences include exceptions to cost-effectiveness, such as the behavioral pilot program. Table 6 shows a comparison of the DSM programs used in ENO's IRP Filing with those proposed in ENO's Supplemental Filing.

[38] Page 53 of ENO's IRP Filing of October 30, 2012.

Table 6

Comparison of DSM Programs	
IRP Filing Program Recommendation	**DSM Proposed in Supplemental Filing**
Industrial Program Commercial Building Energy Management Commercial New Construction Large Commercial Energy Solutions	(Added) (Added) (Added) Large Commercial & Industrial (Energy Smart)
Small Commercial Energy Solutions Commercial New Construction	Small Commercial & Industrial (Energy Smart) (Added)
ENERGY STAR Air Conditioning	Residential Heating & Cooling (Includes an AC Tune-up Component)
Residential Lighting and Appliances	Consumer Products
Energy Smart New Homes	Home Performance and Energy Star
N.A.	Behavioral Program Pilot
N.A.	Low Income Audit & Weatherization
N.A.	School Kits & Education
N.A.	Multi-Family Weatherization
Interruptible Rate	Not Included
Direct Load Control	Not Included

As presented in Table 7, the proposed DSM programs in ENO's Supplemental Filing do not include two demand response programs from the IRP preferred portfolio, an interruptible rate for commercial & industrial customers and direct load control for residential customers, yet the IRP optimization clearly showed that these demand response programs represent the "biggest bang for the buck" and produced significant cost effective energy savings. Moreover, MISO has several tariffs related to demand response: (i) demand response resources ("DRR") which can be controlled "on-off," such as residential central air conditioners and water heaters; (ii) DRR loads which are capable of supplying a range of energy, such as commercial and industrial loads which can be curtailed; and (iii) load modifying resources which would not be monetized in the energy and ancillary services market, but which could help to satisfy the planning reserve margin requirement through MISO's Planning Resource Credits which have value in the capacity auctions. The Advisors have estimated that the annual demand response monetary savings could be approximately $550,000 for residential and $125,000 for non-residential, or a total of approximately $675,000.[39] These funds received from the MISO tariff are benefits realized in the near term rather than well into the planning period, and represent a credit offset to the funding required for the DSM programs. Although ENO did not explain in detail why the interruptible rate, direct load control or pricing measures were excluded in the portfolio, it briefly commented in the Supplemental Filing that "*A residential Direct Load Control program is not included in the portfolio at this time, pending the review of the programs related to the recently completed DOE AMI pilot.*"[40] The analysis of results and statistical analysis of the AMI pilot data were still in progress as of November 2012,[41] but should be completed by the fourth quarter of 2013. Notwithstanding the application of AMI results, these demand response programs

[39] Refer to page 26 of the Direct Testimony of Victor Prep in Council Docket No. UD-11-01.
[40] Page 11, ENO's April 1, 2013 Supplemental Filing.
[41] Refer to November 2012 monthly report to DOE, for the AMI Low Income Pilot Program.

should have been given more current evaluation and a proposed timetable for implementation. It is noted that the demand response estimates for the planning period in the IRP assume full deployment of AMI (approximately 167,000 AMI meters) by 2017 to support the projections of MW reduction due to demand response. In fact, ENO's proposed program budget for 2014-2016 is based on IRP DSM levels which include approximately $1 million annually for demand response programs. Instead, ENO proposed four additional programs which were not from its IRP Filing preferred portfolio. ENO explains that "*[t]hese programs were selected because of their market relevance and concurrent likelihood for cost-effective, successful, long-term energy savings within the territory.*"[42]

A summary of ENO's proposed programs and budget for 2014- 2016 is shown in Table 7, including the budget for each program, kWh savings, and anticipated participation.

Table 7

ENO's Three Year Proposed DSM Programs			
Program Name	**3-Year Budget**	**3-Year Savings (gross kWh)**	**3-Year Participation**
Home Performance with Energy Star	$1,907,722	3,561,286	2,400
Consumer Products	$1,471,700	5,434,460	10,000
Multi Family Weatherization	$1,134,577	1,661,840	4,488
Low Income Audit & Weatherization	$1,180,099	1,077,255	300
School Kits & Education	$590,840	3,934,980	1,550
Residential Heating & Cooling	$1,118,376	3,124,648	3,945
Total Residential	**$7,403,314**	**18,794,469**	**32,683**
Small Commercial Solutions	$2,213,417	9,638,184	294
Large Commercial Solutions	$5,124,284	27,853,606	64
Total Non-Residential	**$7,355,701**	**37,491,790**	**358**
Sub-Total Portfolio	**$14,759,015**	**56,286,259**	**33,041**
EM&V	$240,000		
Behavioral Program	$1,125,000		
Total Program Spending	**$16,124,015**		

Table 8 shows ELL-Algiers' proposed programs and budget for 2014 – 2016, including the budget and estimated kWh savings for each program.

[42] Ibid.

Table 8

ELL-Algiers' Three Year Proposed DSM Programs		
Program Name	**3-Year Budget**	**3-Year Savings (gross kWh)**
Home Performance with Energy Star	$140, 890	393,007
Consumer Products	$165,092	600,224
Multi Family Weatherization	$126,767	183,262
Low Income Audit & Weatherization	$131,124	118,805
School Kits & Education	$65,803	433,967
Residential Heating & Cooling	$125,346	344,911
Total Residential	**$755,022**	**2,074,176**
Small Commercial Solutions	$244,219	1,064,183
Large Commercial Solutions	$544,543	3,068,424
Total Non-Residential	**$768,762**	**4,132,607**
Sub-Total Portfolio	**$1,523,784**	**6,206,783**
EM&V	$24,750	
Behavioral Program	$116,150	
Total Program Spending	**$1,664,684**	

The Advisors are troubled that ENO chose to propose a set of programs different from those it used to determine the optimum DSM spending levels in its IRP Filing. The elimination of an interruptible rate for commercial & industrial customers and direct load control for residential customers is most disconcerting when the IRP optimization clearly showed that these demand response programs represent the "*biggest bang for the buck.*" However, we also recognize that demand response programs involving load control of customer appliances and time differentiated rates require further EM&V analysis to verify the cost and savings estimates assumed in the DSM potential study before including such programs for implementation at this time. The reality is that such programs will take time to develop.
While we recognize ENO and ELL's pending integration into MISO presents a distinct learning curve, in their next Triennial Filing the Council should direct that ENO and ELL include in their evaluation of demand response programs not only those forgone in the present IRP Filings, but those available as a result of several MISO tariffs as discussed herein.

With respect to the addition of the Behavioral Program Pilot, the Advisors believe such funds could be better spent on enhanced EM&V activities as discussed hereinafter.

All proposed programs, with the exception of EM&V and the behavioral pilot program, were screened for cost-effectiveness using the Total Resource Cost (TRC) screening test, the Program Administrator Cost Test (PACT), and Participant Test.[43] The results were provided in the Supplemental Filing.[44]

[43] Refer to Appendix 1 for a description and applicability of each of the cost-effectiveness screening tests.
[44] April 1, 2013 Supplemental Filing.

Table 9

Supplemental Filing Screening Test Results			
Program	**TRC**	**PACT**	**Participant Test**
Home Performance with Energy Star	1.18	1.63	2.71
Consumer Product Program	1.58	1.74	3.95
Multi-Family Weatherization	1.31	1.27	3.93
Low Income Audit and Weatherization	1.15	1.09	3.37
School Energy Education	1.45	1.00	13.48
Residential Heating and Cooling	1.12	1.45	3.31
Small Commercial Program	2.19	2.65	6.20
Large Commercial Program	1.30	1.83	3.42

Evaluation, Measurement and Verification

A robust EM&V program is required to accurately determine how many kWhs are actually saved from each DSM measure. Stakeholders can disagree about the effectiveness and accomplishments of a DSM program if the kWh reduction is estimated from deemed savings based on data from national sources or other jurisdictions. The best information is local; reflecting the climate and demographics of Orleans Parish. While some DSM measures are prescriptive with respect to estimating kWh reduction, such as conversion of incandescent bulbs to CFLs, a significant portion of the DSM portfolio's estimated savings require EM&V.[45] The EM&V program should be designed with the long term objective of minimizing the uncertainty of the kWh reduction calculations and elimination of the use of "deemed savings" in determining the performance of the DSM programs in New Orleans. As such, an effective EM&V program must be adequately funded.

The funding directive of the California Public Utility Commission ("CPUC") for EM&V projects adopted in 2006 and carried through 2011[46] was 8% of the total EE portfolio budget. Carryover funds for EM&V were available from those program years, so the CPUC re-evaluated EM&V budgets and adjusted funding directives to a 4% level of the total EE portfolio budget.[47] Additionally, Avitas Utility of Washington has reported, in its *"2013 Energy Efficiency Evaluation, Measurement and Verification Annual Plan,"* that EM&V expenditures would be 6.13% of the total DSM budget. Compared to the above EM&V allocation levels, only 1.5% of

[45] In the "*Advisors' Report on the Filing of the Energy Smart Annual Report for the First Program Year Pursuant to Resolution R-12-280",* September 21, 2012, the Advisor's concurred with the recommendations of the Independent Evaluator, Optimal Energy, regarding confirmation of specific changes to deemed savings calculations using EM&V. Specifically, the Advisors' recommended to focus evaluation resources on specific areas which represent significant savings but involve some uncertainty, such as: (i) evaluation of net savings, as opposed to gross savings; (ii) on-site verification to ensure that projects are being installed to the correct specification; (iii) on-site logging to ensure that the hours of operation used in the deemed savings approach reflect actual hours of operation; (iv) an evaluation looking at how to improve program processes and procedures; and (v) a review of specific parameters in the deemed savings document that have a high perceived uncertainty.

[46] Decisions 05-04-051 and 07-10-032, the California Public Utility Commission

[47] Decision 09-09-047, the California Public Utility Commission

the Companies' proposed DSM program spending is allocated to EM&V.[48] Furthermore, an increase in EM&V received strong support from public comments, and from the comments of RAP. If the appropriate level of EM&V is accepted to be in the range of 6.5% of the total budget, the EM&V budget should be approximately $975,000 for ENO's proposed three year DSM program, and approximately $100,000 for ELL-Algiers' proposed three year DSM program. Any Council approved DSM budget should be revised to provide increased EM&V, to include some NOLA Wise components, and to postpone of the Behavioral Pilot Program.

Compact Fluorescent Lighting Direct Install Program

Energy Smart featured a cost effective lighting program that has achieved significant levels of energy savings. The CFL Direct Install Program partnered with GLNO and provided incentives for the installation of energy efficient CFLs in customers' homes at no cost. In addition to incentives, the program provided marketing support to GLNO guaranteeing a steady stream of participants. In Year 1, the program achieved 108.8% of its electric kWh savings goal of 3,424,013 kWh.[49] However in Year 2, the program only achieved 58.2% of its 4,565,349 kWh target with an actual energy savings of 2,654,751 kWh.[50] Cumulatively, the CFL Direct Install Program achieved 79.9% of its combined Year 1 and Year 2 energy savings goals and expended 162% of its budgeted incentive allocation. ENO and CLEAResult cite federal lighting standards for the diminished savings per CFL.[51]

Since 2009 when the program was designed, the cost of CFLs increased significantly as a result of a shortage of phosphorus worldwide.[52] In an effort to continue its positive momentum, funding was moved in program years 1 and 2 from other underperforming programs to the CFL program.[53] Also faced with a shortage of volunteers, GLNO began soliciting gift cards from local businesses in the last quarter of Year 2 to defray program costs.[54] In program Year 3, GLNO is continuing to install CFLs at no cost to New Orleans residents. In an effort to improve the efficiency of the program, GLNO is experimenting with installing small base and candelabra style bulbs. Although these bulbs are more expensive than regular base CFLs, ENO and CLEAResult acknowledge the importance of these efforts to drive as much energy savings as possible. GLNO and Energy Smart intend to pursue donations of CFLs from charities and

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[48] For ENO's proposed 3-year DSM budget, EM&V is budgeted at $240,000 of the total DSM budget of $16,124,015. ELL-Algiers' proposed an EM&V budget of $24,750 of the proposed 3 year DSM budget of $1,664,684.

[49] Energy Smart Year 1 Annual Report April 1, 2011 to March 31, 2012 at page 12.

[50] Energy Smart Year 2 Annual Report April 2012 to March 2013 at page 14.

[51] *Id.* at page 14. In an effort to encourage energy-efficient lighting alternatives, the U.S. passed measures to phase out traditional incandescent light bulbs over three years beginning January 1, 2012. Federal energy efficiency standards now require light bulbs to use 25% less energy. Traditional 100W incandescent bulbs were no longer available in stores after January 1, 2012. On January 1, 2013, traditional 75W incandescent light bulbs were phased out. Finally, traditional 40W and 60W incandescent light bulbs will be phased out after January 1, 2014. "*New Lighting Standards Begin in 2012*." *Energy.gov*. 2012. July 1, 2013. <http://energy.gov/energysaver/articles/new-lighting-standards-begin-2012>.

[52] Year 1 Annual Report at page 30.

[53] In Year 1, $30,000 from the New Homes Program and $50,000 from the Energy Star A/C Program were reallocated to the CFL Program. Year 1 Annual Report at page 32. In Year 2, $5,000 from the New Homes Program, $42,787 from the A/C Tune-Up Program, and $5,093 from the Home Performance Program were reallocated to the CFL Program. Year 2 Annual Report at page 48.

[54] These gift cards were used to entice volunteers to assist in the light bulb installation. Energy Smart provided a matching sum of up to $10 per gift card to help cover the cost. *Id*. at page 15.

corporations in order to reduce the growing costs of implementing the program.[55]

ENO's IRP Filing and its Supplemental Filing do not include a separate CFL Direct Install program. However, components of several proposed programs do provide for the direct installation of CFLs. For example, the proposed Home Performance with Energy Star Program, the Multi-Family Weatherization Program, and the Low Income Audit and Weatherization Program all include direct install components for CFLs.[56] In addition to the above three programs, the Consumer Products Program includes incentives (rebates or coupons) for residents to obtain savings in connection with the purchase of CFLs and LEDs from retailers.[57]

Under the CFL Direct Install Program, GLNO installs the CFLs thereby ensuring that the EE potential available for this program is achieved. However, because traditional, inefficient incandescent light bulbs are being phased out under federal efficiency standards by January 1 2014, traditional incandescent light bulbs will no longer be available for purchase. Consumers will have no choice but to replace their current lighting with energy-saving incandescent bulbs, CFLs, or LEDs.[58] For a limited period, there may be an opportunity for GLNO to reach more homes than those of customers' replacing bulbs with CFLs due to burnouts. In this circumstance, EE savings achieved from a cost-effective stand-alone direct installation program may achieve a marginal level of savings over programs that offer customer discounts and rebates for replacement or burnout.[59]

There are additional benefits associated with the CFL Direct Install Program that should be considered. GLNO reached over 8,000 households through Year 2 of the program. This provided GLNO an opportunity to educate customers about the benefits and savings available through other aspects of Energy Smart. However there is no information in the Year 2 Annual Report that attributes incremental EE savings to the general educational effort by GLNO.

The Council's Advisors support the use of direct CFL installations as part of the various DSM programs proposed by ENO during a transition period of implementing the DSM programs approved by the Council. This transition period can be a minimum one year or until the first report regarding the Council approved DSM programs is provided to the Council. The kWh savings achieved and the educational and awareness benefits realized through GLNO's direct contact with customers support the continuation of CFL Direct Install through such a transition period.

DSM Cost Recovery Mechanisms and Incentives

Cost Recovery

Funding for DSM programs for ENO and ELL-Algiers customers can be accomplished through

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[55] *Id.* at page 15.
[56] Entergy New Orleans, Inc. DSM Plan Dated March 20, 2013.
[57] *Id.* at pages 28-31.
[58] Under the new standards, newer bulbs will use 25% - 80% less energy. Energy-saving incandescent use approximately 25% less energy than traditional bulbs. CFLs typically use 75% less energy and LEDs result in a 75% or more reduction in energy consumption. *"Lighting Choices to Save You Money."* Energy.gov. 2012. July 2, 2013. <http://energy.gov/energysaver/articles/lighting-choices-save-you-money>.
[59] Discounts and rebates are valuable incentives for the consumer to purchase the products and complete the installation.

several options: base rates, rider, cap on particular rate schedules, and periodic true-up. Annual funding levels could be recovered through base rates established in a rate case, with regulatory accounting and reporting stipulations to monitor account balances, funding and expenditures. A rate filing for ELL-Algiers in currently being evaluated and should be concluded by March 2014. A base rate case for ENO is anticipated in late 2013 or early 2014. This option was used successfully for the Energy Smart Program, the third program year of which concludes in March 2014. Alternatively, DSM costs could be recovered contemporaneously through an EE rider on bills. An EE rider could also be used for interim recovery of costs that are incurred prior to the effective date of new base rates. Revenue requirements related to utility incentives, lost contributions to fixed costs, or other decoupling options require additional rate mechanisms for cost recovery. Periodic true-up, at least annually, would be required to reset revenue requirements and be revised due to utility incentives or decoupling options. The periodic true-up could be incorporated into either the base rate or EE rider options.

Decoupling

When engaging in energy efficiency, in which utilities are encouraged to sell less of their product, recovery of lost revenues becomes a concern. One widely-used method of addressing this issue is through decoupling. Decoupling mechanisms remove the link between kWh usage/sales and utility revenue requirements. Several methods for addressing lost revenues could be applied to assure the authorized revenues required to cover fixed costs, regardless of any factors which affect the authorized revenue level. The options for lost revenue recovery include: (i) revenue (fixed costs) per customer with a periodic review of allowed versus actual; (ii) straight fixed cost versus variable cost pricing; (iii) a customer class approach versus the total customer pool; ROE formula earnings test with possible adjustments for inflation, weather and pro-forma costs; and (iv) decoupling related to specific factors affecting sales volume. Decoupling is often applied specifically to enable fixed cost recovery with the impact of kWh reductions from EE and DSM programs. The Advisors recommend that ENO be required to file a decoupling proposal for consideration by the Council as further discussed herein.

In its Supplemental Filing ENO has proposed to continue using the lost revenue recovery mechanism of recovering lost contributions to fixed costs, which focuses explicitly on the effects of EE. Several concerns relate to decoupling methods: (i) the shift of business and economic risks from the utility to ratepayers; (ii) clear benefits to the utility unless the ROE is adjusted periodically; (iii) rate impacts for customers not participating in the EE/DSM programs; and (iv) effects on low income customers.

The major benefit of decoupling is removing the disincentive for ENO to engage in energy efficiency since it will be relatively assured of obtaining the level of revenues that the City Council has authorized. To the extent that ENO's revenues exceed those authorized by the City Council, this would result in a refund to customers. Another benefit of decoupling is that the utility is compensated based on a calculation of energy savings at the same time that the utility may be increasing its sales through new business growth.

For a recent example from this jurisdiction citing the Energy Smart Program years, the lost contributions to fixed costs has been applied as a revenue adjustment without any difficulty or criticism through the use of the Formula Rate Plan mechanism over the same concurrent period. The impact on customer bills from this specific method of decoupling is significant (adding

17.28% to program costs) as shown in Table 10, which is the bill impacts shown previously in Table 5, but with the additional recovery of the lost contributions to fixed costs.

Table 10

Comparison of ENO Proposed and AAE's Estimated DSM Annual Spending, With Lost Contribution (in Nominal Dollars)								
Year	**DSM Spending (Million Dollars)**				**Monthly Average Residential Bill Impact ($ per Bill)**			
	ENO Proposed[1]	**AAE Estimate[2]**	**ENO Proposed**	**AAE Estimate**	**ENO**	**AAE**	**ENO**	**AAE**
	Without Lost Contribution		**With Lost Contribution [3] [4]**		**Without Cap**		**With Cap [5]**	
2014	$5.65	$9.97	$6.58	$20.49	$1.19	$3.74	$1.81	$5.67
2015	$5.14	$11.29	$6.07	$25.27	$1.08	$4.59	$1.64	$6.96
2016	$5.33	$12.36	$6.26	$30.04	$1.11	$5.47	$1.68	$8.29
Total	**$16.12**	**$33.63**	**$18.91**	**$75.80**				
Levelized Payment [6]	**$5.38**	**$11.18**	**$6.31**	**$25.15**	**$1.13**	**$4.58**	**$1.71**	**$6.94**

Proposed DSM Annual Spending for ELL-Algiers With Lost Contribution (in Nominal Dollars)				
Year	**DSM Spending (Million Dollars)**		**Monthly Average Residential Bill Impact ($ per Bill)**	
	Without Lost Contribution	**With Lost Contribution [2**	**Without Cap**	**With Cap [5]**
Total for 3 Years	$1.66	$1.97	$3.10	$4.70
Levelized Payment [6]	**$0.57**	**$0.68**	**$1.07**	**$1.62**

[1] ENO's IRP Filing 04/01/2013.
[2] 2013 AAE's Filing Pg. 24 and Pg. 27.
[3] Calculated with Fixed Adjusted Cost Margin of $0.0495/kWh.
[4] Increase in ENO's Spending

	$18.91	with lost contribution
	$16.12	without lost contribution
	$2.79	total increase
	17.28%	% of additional total spending

[5] Cap used is same as established for Energy Smart Program ($100 for commercial customers, $200 for industrial customers).
[6] At Discount Rate of 30 Year Treasury Bonds at 7/9/13 of 3.65%.

Utility Incentives

ENO and ELL propose to continue the current method for calculating a return on equity ("ROE") incentive, as set forth in Attachment H of the now expired 2009 Electric Formula Rate Plan ("EFRP"). The utility incentives in Energy Smart have been based on performance and implementation of programs relative to annual targets established by the Council. Specifically, the current Energy Smart DSM/EE targets have been previously set based on funding levels and specific programs with deemed savings and estimated participants. However, additional factors should be recognized in considering the utility incentive: (i) three years of EE program experience and results, (ii) the incentive feature should be symmetrical with a penalty for performance below expectations, and (iii) the cost effectiveness differences among programs should be included in the metrics measuring performance, with more weight given to the performance of more cost effective programs.

An ROE-based incentive calculation could use cost-effectiveness test results as an additional metric to measure the incentive payment to the utility. If the annual program savings meets or exceeds the Council's established energy savings goals for the annual period, the utility incentive would be based on the combined results of the amount of energy savings achieved as well as a screening test metric (such as the composite TRC net benefits for the programs in the annual period). California has established a shareholder incentive mechanism (Performance Earnings Basis) that is based on two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result.

Regulatory Assistance Project Participation in Process

At the invitation of several members of the Council Utility Committee, the Regulatory Assistance Project ("RAP") agreed to provide its assistance to the Council and the Advisors in reviewing the IRP docket and offering policy guidance for the Council's consideration of the Companies' IRP Filings. During the course of the IRP process the Advisors provided RAP with copies of the following: ENO's Transmittal Letter & Public IRP Filing dated October 31, 2012; ENO's Supplemental Implementation and Cost Recovery Filing, dated April 1, 2013; the final set of public IRP Q&As which were posted as a pdf to the ENO IRP website and the information submitted by the public through the technical conference and web portal, including questions and comments; ELL's Algiers Compliance Filing, dated March 11, 2013; and AAE's IRP Comments, dated May 1, 2013. Members of the Advisors have had several conversations with RAP since the Companies' IRP Filings and on June 26, 2013 RAP submitted to members of the Council Utility Committee, the Director of Council Utilities and the Advisors a *"Memorandum on Regulatory Options for Advancing Energy Efficiency"* which addressed: (i) recovery of reasonable program costs associated with implementing EE; (ii) recovery of lost revenues resulting from reductions in energy sales which are needed by the utility to maintain sufficient revenues to operate its system and earn a reasonable return for its shareholders; and (iii) payment of an incentive to provide utilities with a stronger impetus to advance EE. RAP's memorandum is enclosed with this report as Appendix D.

The Advisors have reviewed RAP's memorandum and the recommendation contained therein and agree with a majority of its recommendations with slight variations on each.

Program Cost Recovery – Given the expiration of the Energy Smart Program by March 31, 2014 and the Council's desire to assure the continuation of DSM programs in Orleans Parish, the Council (upon its approval of the appropriate levels of DSM implementation and expenditures, and approval of a subsequent cost recovery and DSM implementation plans filed by the Companies), should direct the Companies to file with the Council for its subsequent approval an EE Rider to be placed on customer bills. The EE Rider should be designed to recover all costs related to the approved DSM programs including lost revenues and any Council approved utility incentives/crediting of penalties for non-performance (post achievement). Such Rider should be subject to an annual true up until such time as the Council approves new base rates for the Companies and evaluates the individual components therein attributable to the DSM programs. The Council can then evaluate all aspects of the DSM program cost recovery in the Company's next base rate case, including incentives and penalties and evaluate the continuation or elimination of the EE Rider in favor of base rate considerations.

Furthermore, the Council should revisit the appropriate amount of "caps" to be applied to commercial and industrial customers in light of the distribution of program costs, lost revenues and incentives/penalties when measured by the benefits received among the various customer classes of any finally adopted DSM program levels.

Lost Revenues – For the interim period of time from the Council's approval of the level of DSM expenditures and the Companies' DSM implementation plans through December 2014 (or such other date as determined by the Council in an order in the instant docket), the Council should continue allowing the Companies to recover Lost Contributions to fixed costs as part of the EE Rider. Within 120 days of the Council's approval of the Companies' DSM implementation plans, the Council should direct the Companies to file decoupling proposals that address all of the issues raised in RAP's memorandum for subsequent consideration by the Council in a new docket and all issues attendant to decoupling as a policy matter.

Utility Incentives – Rather than the existing incentive approach as recommended by the Companies in their Supplemental Filings, the Council should adopt the incentives and penalties as recommended by RAP in its memorandum, upon the establishment of the appropriate and reasonable targets based upon the Council's determination in the instant docket of the appropriate level of DSM programs to be implemented in New Orleans.

NOLA-Wise

In 2010 SEEA was awarded $20,000,000 from DOE's Better Building Competitive Energy Efficiency and Conservation Block Grant ("EECBG") program. At the time, under the Nagin Administration, John Moore was the Energy Advisor in the Mayor's Office. The Nagin Administration was able to secure a $1,000,000 grant from SEEA to create an Energy Efficiency Financing program for the City of New Orleans with the intention to create a city wide Property Assessed Clean Energy ("PACE") programs. In the 2010-2011 time frame, residential PACE programs were effectively outlawed by the regulators of Fannie Mae and Freddie Mac and the NOLA-Wise program had to be effectively redesigned.

In the Fall of 2010 SEEA released a request for proposals for a program administrator in New Orleans that could provide an EE program that provided financing, contractor training and quality assurance, and customer education and marketing. The DOE required that the program collect data from a measured energy assessment that predicted 15% energy savings in order for a project to qualify for the program and that the administrator monitor the utility bills for 12 months after the retrofit. For this reason, the program needed more management than a traditional loan program. SEEA selected a team led by Conservation Services Group ("CSG") including Global Green, Green Coast Enterprises, and Henry Consulting to administer the program. Liberty Bank was the intended financing partner to provide the loans. SEEA and CSG were unable to reach a contract because CSG's program administration cost proposal would have utilized almost all of the funding for making loans. In the same time frame, Liberty Bank withdrew its support to provide low interest loans.

In 2011 SEEA was on the verge of pulling the program from New Orleans when Global Green offered to administer the program directly through Global Green. Green Coast Enterprises was retained to provide contractor QA/QC and training, and Troy Henry was retained to secure another lender and in the ensuing ninety day period Global Green redesigned the programs. During the spring of 2011 the NOLA Wise contractor management portion launched - providing scholarships for BPI training while Global Green issued yet another RFP for a lender. From this process Fidelity Homestead Bank ("Fidelity") was identified and secured as a lender with a product that offered a 3.5% rate for a one year loan, a 5.5% rate for a three year loan and 7.5% rate for a five year loan for EE programs. In addition, Fidelity agreed to make this interest rate available regardless of credit score (though the person still was required to pass other qualifying indicators to receive a loan). This program was secured with a DOE grant of $750,000 in a loan loss reserve and Fidelity pledged to make up to $15,000,000 in loans. To date Fidelity has made about $200,000 in loans - due mostly to a protracted underwriting process and a lack of interest of most customers in financing their projects.

Since there was not significant demand for a loan product, SEEA ran into a challenge with the NOLA-Wise program as to how to drive demand to the NOLA Wise certified contractors. The NOLA-Wise program required the work scope to achieve a 15% savings, while the Council's Energy Smart Program was single measure. Global Green observed several of the clients they were educating were completing the single measure EE work scope for Energy Smart and not completing the 15% NOLA Wise work offerings. In the fall of 2012, SEEA released a pool of funding to allow NOLA Wise to offer a cash incentive to customers reaching 15%. Today, this incentive of $750 has significantly increased the volume of completed NOLA-Wise 15% retrofits. In the summer of 2012 the program was serving approximately 35 customers after two years and in 2013 the program has accelerated to approximately 150.

In January, Green Coast Enterprises approached SEEA about rolling out a program that would benchmark multifamily and commercial properties in New Orleans to help build SEEA's dataset about energy usage in the buildings and to provide a cash incentive to property owners to retrofit 300 units of multifamily housing (again with the requirement of reaching 15% energy savings). Green Coast Enterprises has completed the 300 multi-family units during the summer of 2013. Their projects are all serving local homeless housing providers including Volunteers of America, Unity, Project Lazarus, and United Way. Green Coast Enterprises and SEEA are presently waiting for a response to a grant application from DOE to continue funding the MD/Commercial program for the next three years.

Today NOLA-Wise is a full service EE advisor for single family, multifamily and commercial property owners Projects must achieve a 15% energy savings threshold to qualify for the cash incentive or the loan product, but they are available for support no matter the size of the project. NOLA-Wise has five approved contractors and do QA/QC for every job. The current DOE funding ends August 31st of this year for the support and QA/QC, though the loan product will still exist.

In May of this year the Council adopted Resolution (AS CORRECTED) R-13-160 which directed the Advisors to confer with ENO and to develop a plan for the continuation of NOLA Wise beyond its current funding expiration of August 2013 at a cost not to exceed $200,000.

NOLA-Wise has served the New Orleans consumer well as a community partner to Energy Smart in the auditing of homes and business, training of contractors, implementation of QA/QC on every project and assistance in obtaining incentives and loans. Further NOLA Wise has successfully implemented contractor training and well documented QA/QC programs to verify and benchmark energy savings on every project which enhances the EM&V of the DSM programs in New Orleans. The Council should take advantage the NOLA Wise Program and integrate its operations in a meaningful way into any approved DSM programs and spending levels it determines as a result of its evaluation of the IRP Filings. Furthermore, the potential exists to leverage the DSM spending levels in New Orleans by initiating a strategic alliance with SEEA in the implementation of some of its existing (and future) DOE programs and further enhance the development of a tool and data-base that can be employed to actually benchmark and track DSM program results and direct savings on a consumer's bill to further strengthen an enhanced EM&V program and, in the longer term, move away from a deemed savings approach to measuring the results of the DSM programs in New Orleans.

Renewable Portfolio Standards ("RPS") and EERS

The AAE states that ENO significantly underestimates renewable energy options for the IRP and includes no renewable power whatsoever.[60] The AAE also argues that in addition to utility-scale renewables, New Orleans would benefit from an expansion of rooftop solar PV and distributed generation.[61] The AAE states that such distributed generation could offset demand, particularly during peak load hours, and free ratepayers from the capital costs of constructing new generation that would otherwise be built into ENO's base rate and from the constraints of the transmission geography on the Entergy system.[62] To that end, the AAE recommends that distributed generation be included in the IRP and the Council consider pursuing a Renewable Portfolio Standard ("RPS").[63] The AAE also believes it would be constructive for the Council to look into creating a feed-in tariff for local solar energy, which would provide more stable and predictable rates for larger solar installations than will a net metering rate standing alone.

ENO points out in its Reply Comments that many (though not all) of the states where an RPS is currently in effect are located in areas with high electricity rates and/or where wind and solar economics are more attractive (e.g. due to their proximity to load centers).[64] ENO argues that in those states, an RPS allows for the increased possibility of cost-effective renewable resources to be incorporated into the portfolio, but there is also the possibility that an RPS can arbitrarily set

[60] AAE Comments at p. 31.
[61] Ibid.
[62] Ibid
[63] Ibid.
[64] ENO Reply Comments at p. 10.

the standard beyond the cost-effective potential within the region.[65] ENO cites to an article reporting that there is currently a push in 16 states to pare back, dilute or eliminate their RPS altogether, due to the fact that many are costing customers a significant amount of money.[66]

While in light of the IRP process many renewables were "screened out" during the technology assessment screening phase of the IRP, it is clear from the comments and questions at both the February 20, 2013 presentation of ENO's IRP Filing and the Community Hearing on April 19, 2013 that there is strong community interest in enhanced use of renewable technologies in the supply of energy in New Orleans (whether utility or consumer owned). In order to address this concern and not encumber and delay the ongoing matters in the instant docket, the Advisors recommend that the Council establish a separate utility docket to examine all issues associated with the implementation of more renewable energy technologies in the ENO and ELL-Algiers supply portfolios including individual consumer installed renewables and determine whether the establishment of a Renewable Portfolio Standard ("RPS"), when examined in concert with the Council's IRP Filing Requirements, is in the public interest and is reasonably expected to result in lower costs to New Orleans. Regardless of the outcome of the consideration of an RPS, renewable resources, including distributed generation and solar photovoltaic sources, should be considered in any future IRP, and ENO should be cognizant of the fact that the optimum level of renewable resources could exceed the amount set by an RPS.

The AAE recommends that the Council adopt an EERS, stating that it would be the single most beneficial improvement that can be made to the IRP at this time.[67] The AAE states that over 20 states have established an EERS in addition to an IRP,[68] and that ACEEE has completed an evaluation of 20 EERS programs in 2011 and found that 13 had met or exceeded their targets, while 4 others had achieved at least 80% of their target.[69] The AAE explains that an EERS typically requires the investment in EE before the expansion of other fuel sources for electricity and that such standards generally ramp up over a period of years until all cost-effective EE is being captured before the investment in new generation.[70] The AAE also explains that this type of resource standard sets the expected program size based on the total achievable EE as opposed to one based on a dollar cap on spending for the program and that the success of the programs and appropriateness of the goals set thereunder are typically reviewed every 3 to 6 years.[71]

In its reply comments, ENO argues that the IRP does not include or represent a dollar cap on the amount of EE spending,[72] but bases the program size on achievable cost-effective EE specifically

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65 Ibid.
66 Ibid.
67 AAE Comments at p.3.
68 AAE Comments at p. 22. However, the implication of an IRP being compatible with EERS is questionable. The Regulatory Assistant Project ("RAP") has reviewed in its study *"The Treatment of Energy Efficiency in Integrated Resource Plans.*" EE practices in six states across the US, most of which have implemented EERS in addition to a resource plan. The RAP report indicated that in states where utilities are required to meet the EE targets set by regulatory commissions, it is generally assumed that the targets will be met and hence the load forecast is reduced by said amount. Supply-side resources are subsequently used in a resource plan to meet the reduced demand and energy forecast.
69 AAE Comments at p. 23.
70 AAE Comments at p. 22.
71 AAE Comments at p. 22-23.
72 ENO's Reply Comment at p.8

for New Orleans.[73] It also states that the IRP does review the level of cost-effective DSM every three years, consistent with AAE's assessment of the frequency with which EERS's targets are typically reviewed.[74]

In its reply comments, ENO argues that AAE's comments do not account for the fact that the Council jurisdiction is specific to New Orleans, and as such does not need to set generic targets for renewable resources or EE through an RPS or an EERS typically put into place by state regulatory authorities that desire to establish certain minimum requirements for all utilities under their jurisdiction in lieu of studying specific resource potential available in each and every service territory.[75] ENO believes that in a jurisdiction such as New Orleans, with a single regulator overseeing a single utility, there is no need for an RPS or EES when cost-effective energy or renewables can be studied directly as was done with the DSM Potential Study and IRP DSM Optimization for New Orleans. ENO also states that it does not favor an RPS or special feed-in tariff requirements because they limit ENO's ability to seek the lowest reasonable cost supply-side resources for the benefit of its customers.[76] ENO states that its IRP implicitly anticipates the development of customer-supplied distributed generation, including rooftop solar installations, because their effects are reflected in ENO's load forecasts.[77] ENO states that the increase of solar is one of the reasons that the load forecasts reflect a lower electricity sales growth (before considering DSM) to gross domestic product growth ratio than has been historically observed.[78]

ENO also argues that the AAE fails to acknowledge that high levels of EE spending will not negate the need to plan for replacement of ENO's aging generating resources.[79] ENO also argues that the AAE is incorrect in asserting that ENO's analysis excluded tax credits available to utility scale wind and solar PV resources evaluated in the IRP.[80]

ENO also asserts that for those states that have either an RPS or an EERS, most have electricity costs significantly above those of ENO, which raises the bar for the amount of EE that can be shown to be cost effective and allows for a higher level of EE measures and renewables to be cost-effective in those states.[81] ENO's Reply Comments include a table demonstrating that states with an EERS had an average residential electric rate of 13.34 cents per kilowatt-hour in March of 2013 whereas states without an EERS had an average residential electric rate of 10.65 cents per kilowatt-hour.[82] ENO also argues that the results of its Implementation filing and actual program performance are in line with national performance.[83]

In a similar vein, ACEEE's report[84] recommends that the Council set specific, multiyear energy

[73] The cost effective energy efficiency for New Orleans was determined by the optimization of all resources in the IRP process, pursuant to the Council's IRP Requirements.
[74] ENO Reply Comments at p. 8.
[75] ENO Reply Comments at p. 4.
[76] ENO Reply Comments at p. 27.
[77] ENO Reply Comments at pp. 27-28.
[78] ENO Reply Comments at p. 28.
[79] ENO Reply Comments at p. 5.
[80] ENO Reply Comments at p. 5.
[81] ENO Reply Comments at p. 8.
[82] ENO Reply Comments at p. 9.
[83] ENO Reply Comments at pp. 9-10.
[84] *New Orleans Efficient Path to 2030, Leadership to Save Energy, Lower Bills and Create Jobs,* April 2013

savings targets.[85] It recommends that programs developed to meet these targets should be subject to cost-effectiveness criteria to ensure that they provide cost savings to participants and ratepayers as a whole, and they should not be limited by a prescriptive cap on spending, rather, ENO should be empowered to achieve as aggressive cost-effective savings as possible.[86] ACEEE states that EE targets have been established by 24 states and numerous public and cooperative utilities.[87] It also states that such targets range from less than 0.5% to more than 2% of retail sales.[88] While ACEEE's analysis of potential cost-effective savings from EE programs suggests that New Orleans could achieve incremental annual electricity savings of 1% by 2016 and higher savings in following years,[89] the report fails to address the amount of program costs or recovery of such costs. ACEEE suggests that the Council consider an electricity savings target that builds upon the existing Energy Smart Programs to ramp up to 1% over the first three years of the next program cycle, e.g., 0.5% in 2014, 0.75% in 2015, and 1% in 2016.[90] ACEEE states that this quick ramp-up should be feasible given that the Energy Smart Program is already achieving savings of over 0.3% annually. ACEEE's analysis finds that over the long term, New Orleans could ramp up to annual savings targets of between 1.5% and 2% for the years after 2020 and that the targets for the years 2025-2030 could then be determined based on results and lessons from previous years.[91] ACEEE does note that its analysis includes only EE opportunities available in the residential and commercial customer classes, but recommends that any targets adopted by the Council also incorporate savings from programs targeting the industrial sector.[92]

ACEEE suggests that the Council periodically evaluate the success of the programs (e.g. every three to six years) and set new targets based on updated analyses of EE potential and best practices in program design.[93] ACEEE also recommends that the Council establish robust cost-effectiveness criteria with appropriate consideration of the full benefits of efficiency to guide EE investments, rather than limit efficiency investments through a prescriptive spending cap but fails to provide specifics on such items for Council consideration.[94]

Finally, ACEEE recommends that the Council also adopt a natural gas savings target that gradually increases to 0.75% over seven years, e.g., 0.25% in 2014, 0.4% in 2016, 0.55% in 2018, and 0.75% in 2020.[95] ACEEE suggests that natural gas savings targets for the years 2021-2030 could then be determined based on the results and lessons learned from previous years, but ACEEE's analysis suggests that savings of around 1% annually could be achievable.[96]

The Advisors recommend that the Council not adopt an EERS at this time. The Advisors believe that the appropriate level of energy efficiency investment for New Orleans can be addressed in more detail and with greater flexibility through the current IRP process. As previously discussed, the Advisors recommend that the Council set specific EE targets as part of its

[85] ACEEE Report at p. 15.
[86] ACEEE Report at pp. 15-16.
[87] ACEEE Report at p. 16.
[88] ACEEE Report at p. 16.
[89] ACEEE Report at p. 16.
[90] ACEEE Report at p. 16.
[91] ACEEE Report at p. 16.
[92] ACEEE Report at p. 16, n. 1.
[93] ACEEE Report at pp. 16-17.
[94] ACEEE Report at p. 17.
[95] ACEEE Report at p. 17.
[96] ACEEE Report at p. 17.

establishment of financial incentives for meeting the Council's approved DSM levels and penalties for failing to do so, rather than adopting an EERS. The Advisors are particularly concerned that the proposal that an EERS require a certain amount of investment in energy efficiency prior to investment in new generation resources may be inadvisable for New Orleans under the current circumstances. New Orleans faces a notable transmission constraint which limits its ability to purchase power from other areas, and increases the costs of those purchases. In addition, there has been at least one situation in the past where a major storm damaged the transmission system sufficiently to "island" New Orleans electrically from the rest of the nation. Therefore, having sufficient generation resources located within the transmission constrained region is of great importance to New Orleans. Within the region, certain generation sources are aging and as ENO notes, such a requirement could become an obstacle to the timely replacement of ENO's aging generation resources. The Advisors are concerned that a requirement that energy efficiency goals be met prior to any investment in new generation could cause delays in the effective procurement of the generation needed for stable and reasonably priced electric service in New Orleans.

The Advisors agree with ENO that given that the Council's jurisdiction extends only to ENO and ELL, it is not necessary to establish an EERS because the Council can address these issues in greater detail and in a more flexible manner through the IRP process.

DSM Potential Study

The objective of a DSM Potential Study is to develop, at a high-level, a broad range of achievable DSM programs that can be inputs in the IRP modeling process for the optimization of supply and demand resource selection. The potential study used a bottoms-up approach that estimated ENO's DSM potential from a baseline evaluation of a wide range of DSM measures. Data and assumptions in the study were provided by Entergy System Inc.'s System Planning & Operations Group ("SPO"), which included: (i) utility assumptions, such as avoided costs, retail rates, utility discount rate, and sales forecast, and (ii) residential/commercial/industrial assumptions, which included market size, energy use, and customer class specific measures. Baseline customers' electricity use was established to analyze energy consumption pattern and identify potential savings. A total of 899 EE measures were evaluated for cost-effectiveness using the Total Resource Cost test ("TRC").[97] Only 438 cost-effective measures were included and the market size for each was assessed – some measures were modeled within current Energy Smart Programs, and other measures were bundled into newly modeled DSM/EE programs. For each program, the DSM Potential study evaluated program costs and estimated participation levels and calculated reference case achievable DSM potential estimates. Two additional scenarios, low incentive and high incentive, were analyzed to develop different levels of achievable DSM potential estimates around the reference case.

The AAE's April 30, 2013 Filing asserted that the DSM Potential Study was flawed. AAE's comments focused on two major issues: (i) the estimates for EE programs participation levels, and (ii) assumptions related to avoided costs. AAE asserts that the DSM Potential Study uses low ceilings on the program market acceptance rate, reduces participation based on payback years, elongates ramp-up periods, and assumes the same net-to-gross ratio for all participant

[97] Refer to Appendix A for a description of the TRC test and other cost-effectiveness screening tests and their applicability.

incentive levels. AAE also challenges the use of a single avoided energy price, states that ENO's estimates for transmission and distribution ("T&D") are too low, and questions the absence of benefits associated with reduced gas and water usage. As a result, AAE asserts that the cost-effective EE programs included in the DSM Potential Study and their associated net benefits are greatly understated.

ENO's May 30, 2013 Filing responded to AAE's assertions with regard to the DSM potential study. ENO supported the assumptions and methodology adopted by ICF, stated that the programs modeled and the participation rates were based on existing Energy Smart and industry best practices, and emphasized that AAE did not provide any basis for its denunciation of the low ceilings. ENO explained that the payback acceptance curves[98] are not simple data points, the residential curve was developed based on national survey of 407 respondents, and the non-residential curve was based on 783 commercial and industrial respondents in Arizona. With regard to AAE's critique on using the same net-to-gross ratio for all incentive levels, ENO clarified that the net-to-gross was estimated separately for each program analyzed in the potential study. And based on the premise that there are many factors that can drive program success other than incentives, ENO responded that it is not appropriate to adjust the net-to-gross levels up or down for all programs in the high incentive and low incentive scenarios. ENO also noted that AAE has reviewed ICF's net-to-gross assumptions during the public input process, but has neither commented nor provided alternatives until their April 30, 2013 Filing.

ENO contended further that it is reasonable to use average avoided energy cost to estimate the cost-effectiveness of the measures and programs. ICF has found that using average avoided energy cost at initial measure screening resulted in more measures being included for further analysis. Water savings were not included in ENO's analysis since it is not considered a source of energy in New Orleans area, but gas savings were accounted for wherever applicable.

Although ENO has not replied to AAE's comments regarding T&D costs, a more complete analysis of T&D costs and corresponding estimated savings from DSM should be included in the IRP status report. This requirement should be included in the IRP Action Plan as well.

The Advisors believe that the range of results presented in the DSM Potential Study results are generally applicable until the next Triennial IRP Filing, with the exception of applying the AMI Pilot results to the demand response programs. This update to the demand response programs in the DSM Potential Study should be provided within three months following the date on which the report of the results of the AMI Pilot is provided to the Council.

IRP Process

The AAE notes that previous ENO IRP filings have fallen short of final expectations, creating the need to start completely over again, but that the active involvement of Council Advisors and intervenors during this most recent IRP process has had a significant positive effect and represents an important step in the right direction.[99] Nonetheless, they note, there are many lessons that can be derived from the experience to improve the process in the future.[100] The

[98] Payback acceptance curves depict the relationship between the percentage of customers who accept payback and the payback period.
[99] AAE Comments at p. 33.
[100] AAE Comments at p. 33.

AAE states that a meaningful level of public engagement earlier in the process would provide additional valuable perspectives, increase confidence in the ultimate final recommendations, and likely increase the actual benefits achieved on behalf of ratepayers.[101] AAE also states that another key issue was that rushed timelines, inadequate disclosure of methods and assumptions, and the need for additional specialized expertise greatly limited the verifiability of important aspects of the analysis.[102]

The AAE recommends that all interested parties, not just interveners, should be engaged as early as possible in the potential study process.[103] AAE states that stakeholders should be integral and equal partners in the development of the Request for Proposal and subsequent scope of work plan detailing the specifics of the DSM potential study, and should also have the opportunity to provide input into the data assumptions and calculation methodologies that will inform the study.[104] In particular, the AAE requests that when moving from one phase to the next, whereby the outputs of one phase become the inputs of the next, stakeholders should be permitted a reasonable time to review the outputs, ask questions, and make recommendations before the next phase commences.[105]

AAE recommends that the IRP process be transparent and well documented.[106] The AAE argues that there is an enormous amount of detail embedded in each of the many steps to complete a potential study and that these details need to be clearly explained, documented, and agreed to by all parties in each step.[107]

Specifically, AAE recommends that ENO develop a detailed RFP scope of work and project work plan for the DSM Study that properly reflects the needs and objectives of the IRP process and that the final project work plan should reflect input from all participating parties to ensure that the end product of the potential study will have the support of the greatest number of stakeholders.[108] AAE also recommends that the technical and economic potential results be provided as interim deliverables against which to benchmark results.[109]

While the Advisors agree with AAE that increased time for evaluation of each stage of the IRP and greater participation by stakeholders earlier in the process would be beneficial, the Advisors also note the Council's implementation of an IRP schedule to allow for the continuation of DSM programs in New Orleans without a lapse and mitigate increased regulatory costs due to an extended process. However, the Advisors believe that the IRP process could be improved through greater clarity in the process. To that end, the Advisors recommend that the Council adopt a procedural schedule for the next IRP that identifies discrete milestones in the IRP process and provides for opportunity for input from stakeholders at each milestone. Currently, the Council's IRP Requirements do not require input from stakeholders during the IRP process. The Advisors believe that stakeholders can provide valuable input into the process; however, the Advisors also believe that obtaining full agreement among all stakeholders at every milestone

[101] AAE Comments at p. 34.
[102] AAE Comments at p. 34.
[103] AAE Comments at p. 35.
[104] AAE Comments at p. 35.
[105] AAE Comments at p. 35.
[106] AAE Comments at p. 36.
[107] AAE Comments at p. 36.
[108] AAE Comments at p. 35.
[109] AAE Comments at p. 37.

would be unduly burdensome. To that end, the Advisors recommend that in the next IRP process, the Council direct ENO to provide to the Council and stakeholders the relevant assumptions and work papers and hold a technical conference prior to each milestone. Subsequent to each technical conference and within a defined period, the Council and stakeholders will be provided the opportunity to provide comments to the Companies and the Companies will be given the opportunity to respond to comments. This will allow the Companies to address as appropriate, the concerns of the Council and stakeholders during the IRP process.

The AAE recommends that an appropriate avoided cost for the DSM analysis should be developed prior to conducting the DSM potential study.[110] AAE suggests that Entergy work directly with the Council's Advisors, the AAE, and other interested and knowledgeable parties to develop a consensus set of avoided costs for energy-efficiency screening.[111]

The Advisors agree with the AAE that avoided costs for the DSM analysis should be developed prior to conducting the DSM potential study. To that end, the Advisors recommend that the Council require ENO to file their proposed methodology for the development of avoided costs for use in the next IRP process with the Council contemporaneously with their upcoming base rate case, and that the Council establish a procedural schedule allowing for comments from interveners and reply comments by ENO.

AAE states that unless there is a strongly compelling reason, the highly sensitive protected material ("HSPM") designation should not be applied to information generated during the potential study process unless it meets the traditional threshold for this designation.[112]

The Advisors agree with the AAE that the Companies must provide information sufficient for verifiability of calculation outputs and access to the models to the extent practicable and as deemed necessary by the Advisors and intervenors. The Advisors are aware that some of this information may fall into the HSPM category, but such information nevertheless should be made available in a timely manner to parties that have properly executed a confidentiality agreement with the Companies. The Advisors recommend that the Council make clear to the Companies that this type of information should be shared with the Advisors and Intervenors to the case through discovery, technical conferences and working group meetings, and that the HSPM designation be applied only to information that meets the traditional threshold for this designation.
It is anticipated that the Council Resolution regarding the IRP will include the specific DSM programs and DSM levels, funding levels for each, a rider for funding until a complete examination can be included in next rate case, three year targets based on IRP results, and a utility incentive program based on RAP recommendations.

SUBSEQUENT PROCESS AND FUTURE SCHEDULE

With the pending expiration of the Council's existing Energy Smart Program on or about April 2014, it is important for the Council to implement an accelerated schedule in the instant docket in its determination of the appropriate level of DSM programs, reasonable target levels,

[110] AAE Comments at p. 37.
[111] AAE Comments at p. 37.
[112] AAE Comments at p. 36.

expenditures, and all other attendant matters related thereto so as to minimize the loss of momentum in DSM program implementation in New Orleans. As such, the Advisors recommend the Council consider implementing the following schedule upon an issuance of a final order in the instant docket.

1. Within 120 days of the Council's order in this docket, the Companies should be directed to file their detailed DSM Program Implementation Plans incorporating the results of the Council's order, and convene a technical conference.

   a. within 30 days of such filing by the Companies the Intervenors and any interested parties shall file comments with the Council on the Companies' filings.

   b. 15 days after the filing by the Intervenors of their comments the Companies shall have the opportunity to file responsive comments.

   c. 30 days after the receipt of the Companies' responsive comments the Advisors shall issue their report to the Council on any issues raised in the filings.

2. The Council's order in this docket should direct ENO to file, within 90 days of the order, its proposed form of Energy Efficiency Rider that complies with the Council's final order in the instant docket. To the extent that ENO files a general base rate case sooner, it shall incorporate in such filing its proposed form of Energy Efficiency Rider.

   a. Within 30 days of such filing by the Company, the Intervenors and any interested parties shall file comments with the Council on the Companies' filings.

   b. 30 days after the filing by the Intervenors of their comments the Company shall have the opportunity to file responsive comments.

   c. 30 days after the receipt of the Company's responsive comments the Advisors shall issue their report to the Council on the issues raised in the filings.

3. Within 120 days of the Council's order in this docket ENO should be directed to file its decoupling proposal as provided for in the Council's order. To the extent that ENO files a general base rate case sooner, it shall incorporate in such filing its proposed form of decoupling. ELL-Algiers should be directed to make its filing in Council Docket UD-13-01 for consideration by the Council in said docket.

   a. Within 30 days of ENO's filing, the Intervenors and any interested parties shall file comments with the Council on ENO's filing.

   b. 30 days after the filing by the Intervenors of their comments ENO shall have the opportunity to file responsive comments.

   c. 60 days after the receipt of the Companies' responsive comments the Advisors shall issue their report to the Council on the issues raised in ENO's filing.