

**Entergy New Orleans and Entergy Louisiana LLC - Algiers
Integrated Resource Planning
Public Q&A
Questions to be received from October 26-November10, 2010**

Questions Received October 26

1. Can you do a comparison of the all in-cost of new CCGT vs. Michoud and provide such information?

A. The fuel cost of Michoud is higher than the fuel cost of either a modern CCGT or the fuel cost of baseload generation. For example, as reported in the Forms 1, an audited report that each electric utility is required to file annually with the FERC, the average fuel cost for Michoud in 2009 was 4.9 ¢/kWh, versus 3.8 ¢/kWh for Ouachita, a modern CCGT unit owned by Entergy Gulf States Louisiana, L.L.C. and acquired in 2008; 2.0 ¢/kWh for the Independence coal plant; or less than 1 ¢/kWh for nuclear power. Entergy Gulf States Louisiana, L.L.C.'s Ouachita plant is provided as a meaningful point of comparison because it is a modern plant that was purchased at a market price. The cost of constructing a new facility would be higher and would vary according to its location.

On the other hand, the non-fuel costs for Michoud are substantially lower than these alternatives. This can be seen from comparing the non-fuel costs of Michoud to the non-fuel costs of other generating facilities. One point of reference to determine these costs is the rate that Operating Companies pay each other for resources purchased pursuant to the terms of Service Schedule MSS-4 of the System Agreement. MSS-4 is a FERC-approved, cost-based formula rate that is used when one Operating Company sells a portion of the capacity of a generating unit to another. The rate that the FERC approved is designed to fully cover, but only fully cover, the actual cost of owning and maintaining a generating plant, and is based on actual costs as recorded in each Operating Company's accounting records. ENO purchases a bundle of coal and nuclear capacity from EAI through an agreement known as the "EAI WBL," and pays EAI an average rate greater than \$20.00 per kW-month for that capacity. Likewise, the rate that EGSL receives for sales of a portion of the capacity of the Ouachita facility is \$5.32 per kW-month. ENO does not sell capacity from Michoud to other Operating Companies, but the data that would be used to calculate an MSS-4 rate can be ascertained from information available to ENO, and that rate is \$1.92 per kW-month – less than half the capacity cost of a new CCGT, and less than one sixth of the capacity cost of the EAI WBL.

Combining fuel and non-fuel costs for the three resources, at the current cost of natural gas, produces the results below, which reflect the current total cost of capacity and energy provided from each resource.

All-In Production Cost			
	Michoud	EAI WBL	Ouachita
\$/MWh	\$56.85	\$41.59	\$82.44

2. Your cost of combined cycle gas plants and renewables appear quite high. The costs I have seen in the industry are New Combined Cycle @ 85% capacity factor, \$70/mwh and \$5/MMBTU; Wind at 25% capacity factor at \$60-70/mwh without investment tax credits or renewable energy credits.

A. Care should be taken in comparing technology costs estimates from different sources as metrics that appear similar may be stated using different methods and assumptions. The cost estimates used in the SRP are intended to comprehend all costs that will ultimately affect the customer. Moreover, cost estimates in the SRP for each technology have been prepared using consistent methods and assumptions in order to facilitate comparison. With respect to intermittent renewable resources such as wind and solar, cost estimates used in the SRP reflect cost components arising from the intermittent nature of output including system integration cost and “match-up” capacity. Both components ultimately affect the cost borne by the customer when these resources are included in the portfolio. The later component is necessarily included to properly compare the cost of intermittent technologies that provide limited or no contribution to planning reserves to technologies that do provide these benefits. Finally, differences in values may exist if one is attempting to compare costs for a resource on a levelized basis, that is, the cost of the unit over its life, to annual revenue requirement costs, which necessarily are higher than the levelized cost during the earlier years that a resource operates.

3. Will you be putting your assumptions on DSM planning and the equations used on the web or in report form?

A. The DSM planning assumptions and equations are reflected in the SRP Documents filed under the 2010 IRP on October 19, 2010 and in the Energy Smart Filing documents filed July 2, 2009. Both sets of documents can be found at www.energy-neworleans.com/IRP.

4. How does SRP change if Entergy Louisiana were to join a RTO?

A. At this time, the Entergy System and the Entergy Operating Companies are evaluating the potential benefits of joining an RTO. The effect of RTO participation on long-term planning is one element of that evaluation. At this time, the results of that evaluation are not complete.

5. What does the IRP consider to be the useful life of a generator? What is this assumption based on?

A. In developing long-term planning assumptions regarding technology alternatives, including useful life, Entergy relies on information from external consultants and internal

technical experts. Assumptions used in the 2009 SRP Refresh (Sept 2010) for useful lives of technology alternatives included the following:

Combined Cycle Gas Turbine (CCGT)	30 Years
Gas Combustion Turbine (CT)	30 Years
Pulverized Coal	40 Years
CFB Coal	40 Years
IGCC Coal	30 Years
Wind	25 Years
Biomass	25 Years
Nuclear	40 Years (license renewal extends to 60 years)
Solar	25 Years
In Stream Hydro	25 Years
Geothermal	30 Years

6. What is the target for DSM in the IRP? (annual %)?

A. The IRP’s assumption for ENO’s DSM represents a 0.03% reduction to peak load in the 2010 initial year and increases to about 4% of peak load starting in 2020. Over the 20 year planning horizon, 36% of ENO’s 120 MW of peak load growth is offset by 43 MW of DSM.

7. Given how cost-effective DSM is, why is there not greater amounts chosen in the SRP?

A. All cost-effective and market-achievable DSM was incorporated into the SRP. As shown in the response to Question 6, 36% of forecasted peak growth is offset by DSM. That is not a trivial amount. As the drivers of DSM change (gas price, environmental regulations, avoided costs, energy efficiency standards, technology innovation), the potential of cost-effective and market-achievable DSM will be re-assessed.

8. How did the SRP take into account the opportunity to partner with the industrial customers in combined heat and power projects?

A. The Entergy System’s procurement processes, including Requests for Proposals (RFPs) for limited and long-term products, consider offers from industrial co-generation facilities and have included products designed in consideration of the operational requirements of such facilities. As a result of these efforts, the Entergy System presently has under contract over 1000 MW of capacity from co-generation facilities. It further should be noted that the Entergy System has the largest level of interconnected QF capability relative to the size of its electric system, and the System routinely accepts deliveries of 500 – 1500 MW, and higher, of QF energy.

9. How is the risk of natural gas price changes managed in the SRP?

A. The SRP considers the effect of long-term gas price uncertainty on portfolio design through a number of techniques including 1) sensitivity analysis to assess the implications of alternative gas prices on the relative economics of technology alternatives and 2) analysis of the effects of long-term gas price uncertainty on portfolio risk and cost. Further, ENO, as do other Energy Operating Companies, engages in a hedging program for the purchase of natural gas as a means to mitigate price volatility.

10. Why are you not considering distributed smaller combined cycle systems based on 100 LMS GE units?

A. The SRP seeks to consider all reasonable alternatives to address customer needs. The process includes technology assessments of potential alternatives including small scale aero-derivative technology such as the LMS 100 manufactured by General Electric. At this time, the results of the technology assessment indicate that small scale aero-derivative technologies generally are not as economic as larger scale gas-fired combined cycle combustion turbines and simple cycle combustion turbines for meeting the needs of the Entergy System, including those of Entergy New Orleans customers. However, aero-derivative technologies offer unique operating and size advantages that merit consideration for some applications. The evaluation of technology alternatives is an ongoing effort.

11. Why are you not expanding Entergy Thermal central chilling system?

A. Entergy Thermal is an independent operating subsidiary of Entergy Corporation operating in Orleans Parish. As such, Entergy New Orleans has no knowledge of the operating factors related to future expansion of their facilities.

12. What data have you developed that shows the regulators that your proposal represents the optimal amount of DSM from a cost comparison perspective (i.e. like the supply resource mix scenarios with renewable energy)?

A. Entergy New Orleans has developed and presented to the City Council of New Orleans extensive research supporting the development of the estimate of cost-effective and market-achievable DSM. At this point in time, all cost-effective and market-achievable DSM can be incorporated into the long term plan as a first step, and then decisions among supply-side alternatives can be made as a second step. In other words, all of the resource mix scenarios in the IRP include DSM.

13. How will the solar thermal program in the Energy Smart Program target participants? Is there a focus on particular fuel replacement-gas vs. electric?

A. ENO anticipates that participants in the Energy Smart program are will be targeted in several ways including advertising, through the web, and through the One Stop Shop. However, ENO anticipates that the Participating Local Contractors who offer the program to customers will be the most important and vital marketing tool to the program.

14. Have you correlated combined wind and solar with demand and determined a joint operating factor?

A. At this time, we have not.

15. Have you evaluated the findings of your DSM potential study in comparison to other studies across the country? If so, how do your findings compare...higher? lower? And why?

A. No, the Company has not correlated the findings of the potential study with other studies across the country. However, the potential study was performed by ICF International and ICF has performed similar studies globally. As with metrics describing technology costs, care should be taken in comparing DSM potential estimates from different sources as studies that appear similar may be based on very different methods and assumptions.

16. Was the ICF potential study performed solely for Entergy New Orleans or did ICF also perform studies for other Entergy companies?

A. ICF International was engaged to perform potential studies for each of the Entergy Utility Operating Companies.

17. In accessing the smart meter technology, have you considered using humidity and temperature data (internal and external) to assess the comfort level the customer is willing to endure?

A. No, we have not. While this is an interesting data point to collect and analyze, it was not built into the scope or budget for this project.

18. Is ENO aiming for DSM program performance that would compare to the nation's most recognized successful programs, and if not, why? If yes, what is your strategy?

A. Entergy New Orleans has worked with ICF International, local stakeholders and the City Council of New Orleans to strike the right balance of program results and program costs. The Vision statement of the Energy Smart Plan reflects ENO's aim: Programs that transform New Orleans by creating demand for energy efficiency products and services and stimulate the development of the workforce to meet this demand. Part of achieving this right balance of program results and costs requires that ENO consider the cost of alternative supply side resources. The overall strategy of ENO, together with the Entergy System, is to provide service to customers at the lowest reasonable cost, and ENO has sought to implement the Energy Smart program consistently with that goal.

19. It appears that your DSM forecasts are projected into the future based on Entergy energy efficiency programs in Texas, Arkansas and New Orleans. Have you compared the relative performance of your programs vs. those that have been most successful? In your estimation, how do your Entergy programs compare?

A. A systematic comparison of Entergy Operating Company programs has not been completed; however, the programs are successful in a number of dimensions. First, because the energy efficiency programs were developed through consensus workshops they reflect local interest. Second, the programs are administered efficiently. For example, in Texas, administrative costs are held below 10% of total program cost. Finally, and most importantly, the programs consistently meet or exceed goals for delivering energy savings to customers.

20. What does Entergy need from the regulators in order to truly embrace energy efficiency? Is there a policy we can work toward that will allow Entergy to please its shareholders but which will make ratepayers have more stable bills and comfortable home?

A. The City Council of New Orleans has embraced energy efficiency and supports those efforts to a very high degree. Over the past several years the Council has taken positive steps in adopting supporting resolutions on energy efficiency programs in New Orleans. One such effort is the adoption of the Energy Smart Program which will begin in the next few months. In order to continue to successfully implement energy efficiency programs, ENO requires reasonable certainty from its regulator with respect to the prudence of its programs, including timely cost recovery of both the program costs and the lost contribution to fixed costs that results from the declining sales produced by such programs and appropriate returns on its investment in DSM, energy efficiency, and related programs.

21. Has the SRP factored in long-term distributed energy on homes and multi-family (solar energy) and the rapid expansion of solar over the next several years? What is the projected impact based on current trends?

A. The SRP considered utility-scale centrally dispatched solar PV projects and found that they are presently the most expensive among renewable generation alternatives. The DSM Potential Study also considered certain solar measures, but they did not pass the initial measure-level cost effectiveness requirement. It is important to note that the DSM Potential study informs, but does not dictate the energy efficiency programs selected by the Entergy Utility Operating Companies. For example, the portfolio of Energy Smart programs in New Orleans includes a Solar Water Heater pilot program and a Solar PV Monitor pilot program.

22. Why did we not invest in combined cycle gas for New Orleans many years ago? Michoud is our only functioning plant and it was known in the late 1980's and all through the 1990's that it was a largely inefficient plant costing ratepayers a great deal more than needed at peak time.

A. As an initial matter, Michoud is not ENO's only functioning generating plant. Entergy New Orleans owns or controls a diverse portfolio of resources that includes a portion of the Grand Gulf, ANO 1, ANO 2, and River Bend Nuclear Stations, as well as a portion of the Independence and White Bluff coal units. Moreover, as discussed in the response to question 1 above, Michoud is not a "largely inefficient plant costing ratepayers a great deal more than needed." ENO has not determined, now or in the past, that the all-in cost of replacing Michoud is an economic choice for its customers. See the response to Question 1 above for additional information.

Questions Received October 29, 2010

23. Please forward any new information and schedules about the smart meter, smart view, IRP, ENO programs, as it becomes available. Thank you.

A. ENO's IRP related documents can be found at ENO's IRP web link (www.entergy-neworleans.com/irp). Documents related to smart meters, Smart View, AMI, and Energy Smart are provided in their applicable Council utility dockets.

Questions Received November 1, 2010

24. On pg. 28 of the SRP, you indicate that your cost assumptions for renewable resources do not include incentives or REC values. Isn't your assumption, therefore, inaccurate, since a significant portion of the costs of renewable generation can be recovered through incentives and REC sales?

A. The question incorrectly assumes that ENO did not include incentives or REC values. In fact, the analyses presented in the 2009 SRP and in the September 2010 Refresh of the 2009 SRP, evaluated the economics of renewable resources both with and without incentives and RECs.

Questions Received November 2, 2010

25. The information provided at the IRP meeting stated that the last day to post a question on the IRP website was November 2, 2010, however, the resolution states the last day is November 10, 2010. Which date is correct?

A. The last day to post a question on the IRP website is November 10, 2010.

26. Entergy's cost and risk analysis rules out solar and wind energy sources, but why can't other companies take on the risk and step in to fill this market gap? What is Entergy's view of power-purchasing agreements and how did they factor in the IRP formulation?

A. Although the SRP analysis concludes that renewables tend to be higher cost than other alternatives available to meet customers' needs, the SRP does not "rule out" solar or wind as potential energy sources. On-going planning and procurement efforts continue to assess the cost of supply alternatives and the results of those efforts will be reflected in resource planning and selection activities. If another company proposes to develop a wind or solar resource and sell the output of that resource to ENO, ENO would certainly consider that resource. However, the structure of a resource transaction (e.g., contract or ownership, self-supply or third-party developed) generally does not change the uncertainty relating to the economics of the underlying technology relative to alternatives.

The assumptions used in the analysis are consistent with the level of detail that is appropriate to use in a long-term screening study. Accordingly, the supply-side alternatives assessed in the analysis are generalized or generic representations of technology options. The analysis used to develop this plan makes no distinction between owned or long-term contracted resources. In other words, the SRP assumes that the cost is the same whether the resources are owned or contracted. With respect to the element of risk, the risk considered in the SRP relates to the relative economics and reliability of technologies compared with alternatives. The SRP assumes that this risk remains the same, whether the resource is owned or contracted.

27. What is Entergy's view of power-purchasing agreements and how did they factor in the IRP formulation?

A. The SRP presumes that reliability requirements are met largely from long-term resources, whether owned assets or long-term power purchase agreements. The term "long-term resources" refers to owned resources or long-term (over ten years) power purchase contracts. In general, no distinction is made between owned resources and long-term contracted resources for planning purposes. ENO utilizes both owned

resources and long term contracted power purchase agreements.

28. Would Entergy support decoupling efforts should the Utility Committee undertake them, and was decoupling considered when forming the IRP?

A. Decoupling is a rate making concept and regulatory tool designed to separate a utility's revenue from changes in energy sales. Under current rate-making practices, the utility's revenues are tied to its sales of electricity and/or natural gas. The purpose of electric decoupling is to remove the disincentive of the utility to reduce sales by promoting energy efficiency and other programs that result in reduced customer consumption.

ENO has and continues to pursue a form of revenue decoupling by recommending increases in the customer charge to gradually weaken the linkage of volume and sales. ENO has specific mechanisms, such as Riders and Formula Rate Plans (FRP), in place to remove any disincentive to pursue cost effective EE and other programs resulting from our IRP process. The Riders recover lost contribution to fixed costs resulting from implementation of DSM programs and the Formula Rate Plan (FRP) mechanisms adjust rates outside a rate case. Both the Riders and FRP's remove the disincentive related to DSM programs because it allows utilities to reflect sales changes in rates more quickly than through the traditional rate case process.

While Entergy does not have explicit electric decoupling mechanisms, it has and continues to take steps to promote conservation and energy efficiency. Entergy routinely utilizes varied communications channels to provide its customers with energy savings tips and has numerous programs that have an energy efficiency component such as low income weatherization. Entergy's rates, particularly the seasonal nature of its fuel adjustment clauses, tend to provide sufficient price signals to encourage conservation during peak periods and thus Entergy has observed demand response, or elasticity, in response to rising prices.

It should be noted that in many cases Entergy's tariffs already provide price signals that encourage consumers to conserve. For instance, with the exception of Entergy Arkansas and Entergy Texas, all of Entergy's operating companies have seasonal fuel factor adjustments that more timely reflect cost resulting in more accurate pricing signals to our customers. This feature of Entergy's residential rates is unusual. Most other states and jurisdictions have relatively flat rates throughout the year and thus customers are not given clear pricing signals which can lead to uniformed demand response. Meanwhile, the effect of rising prices, particularly due to rising fuel costs as reflected in the operating companies' fuel adjustment clauses, unquestionably results in elasticity of demand from Entergy's customers. As a result, action by customer to conserve in these peak pricing periods can result in significant savings to the customers.

Although Entergy has and will continue to monitor the issue of revenue decoupling within our utility companies, the IRP does not utilize rate recovery mechanisms as a variable in the analysis so the issue of decoupling is outside of the scope of the IRP.

29. What does Entergy see as the pros and cons of Community Choice Aggregations (CCAs)?

A. Entergy New Orleans has not conducted the referenced analysis.

30. Global Green would like to emphasize that it is imperative that the City Council and Entergy work together to make the Energy Smart program sustainable beyond the three years currently allotted. Energy Smart will serve the people of New Orleans much better if it is embraced as a permanent program for improving NOLA energy efficiency rather than a one-time market transformation tool.

A. Provisions of the resolution authorizing Energy Smart allow for the Council and Entergy to extend the programs beyond the initial three years allotted. In addition, the vision of Energy Smart Plan is to develop programs intended to transform the market by creating demand for energy efficiency products and services and stimulate the development of the workforce to meet this demand. In turn, this will help create a sustainable, long term energy efficiency market that creates energy savings for New Orleans residents.

Questions Received November 3, 2010

31. In relation to the proposed New Orleans IRP, how much is ENO contributing to the proposed Energy Smart demand-side Energy Efficiency Program, that they did not derive from 3rd parties?

The Energy Smart Programs are funded by \$3.1 million of ENO revenue annually, for a three-year period as directed by Council Resolution R-09-139 and the associated settlement agreement which approved funding for Energy Smart. The referenced Council resolution and associated settlement agreement required that the Energy Smart Energy Efficiency Program be developed through a process that included robust public input and culminated in the programs adopted by the Council.

32. In relation to the proposed New Orleans IRP, how much of the proposed Entergy Smart plan is being spent on the average large commercial and industrial customer? Of that total amount, how much is actually being awarded as an incentive?

A. To date, no funds have been spent on the proposed Energy Smart Plan programs or incentives. The selection process for the third party administrator is currently underway. The programs are expected to roll out in the first quarter of 2011. However, it is expected that between 44-48% of total funding will be used to fund commercial and

industrial programs. Of the funding allocated for commercial and industrial programs, approximately 50% is expected to be utilized for incentives. For a description of the anticipated incentives, please see the presentation on ENO Energy Efficiency Programs given at the October 26, 2010 IRP conference or Appendix 4 to the July 2, 2009 Energy Smart Filing.

33. In relation to the proposed New Orleans IRP, how much of the proposed Energy Smart plan is being spent on the average residential customer? Of that total amount, how much is actually being awarded as an incentive?

A. To date, no funds have been spent on the proposed Energy Smart Plan programs or incentives. The selection process for the third party administrator is currently underway. The programs are expected to roll out in the first quarter of 2011. However, it is expected that between 52-56% of total funding will be used to fund residential programs. Of the funding allocated for residential programs, approximately 50% is expected to be utilized for incentives. For a description of the anticipated incentives, please see the presentation on ENO Energy Efficiency Programs given at the October 26, 2010 IRP conference or Appendix 4 to the July 2, 2009 Energy Smart Filing.

34. In relation to the proposed New Orleans IRP, if the proposed Energy Smart Plan were extended indefinitely at the proposed funding levels, how long before every ENO residential customer would be directly served?

A. Because the proposed programs are voluntary, it is unlikely that all customers would ever be directly served from the programs. However, because the proposed Energy Smart programs will ultimately reduce overall energy consumption, all customers will indirectly benefit.

35. In the IRP analysis, why was supply-side avoided cost analysis used to evaluate demand-side Energy Efficiency (EE) improvements?

A. As discussed in the IRP meeting, the DSM assumption was determined by screening the amount of DSM that is technically available to identify the subset that is cost-effective and market-achievable. The purpose of the cost-effectiveness screen is to reflect the economic merits of ENO's choice between an investment in demand-side alternatives or supply-side alternatives. The costs of demand-side alternatives were compared to what would have been spent on supply-side alternatives if the DSM was not put in place. This included capacity-related costs for generation, transmission, and distribution as well as energy-related costs such as the market price of electricity, fuel, and emissions, including carbon. Costs related to hurricanes, litigation, bankruptcy, direct payments from governmental agencies for transmission or distribution infrastructure, or the successor system agreement are not incremental to either supply- or demand-side resources, and as such are not included in either the avoided costs or the costs of demand-side alternatives. Further explanation of the best practice regarding the use of avoided costs in the economic analysis of incorporating DSM into long term planning can be found in the documents developed for the National Action Plan for

Energy Efficiency. They are available on the U.S. Environmental Protection Agency's website at www.epa.gov/cleanenergy/energy-programs/suca/resources.html.

36. In the IRP analysis, what is the estimated total demand-side Energy Efficiency reductions that could be captured by the rate base if funding were available?

A. The question is confusing on what is meant with the term "by the rate base". However, the IRP analysis estimated total demand-side reductions to be approximately 43 MW over the 20 year planning horizon.

37. In the IRP analysis, why didn't the supply-side avoided cost analysis include, Hurricane Recovery Costs?

A. See the response to No. 14.

38. In the IRP analysis, why didn't the supply-side avoided cost analysis include, the costs to the rate base associated with settling lawsuits filed against ENO?

A. See the response to No. 14.

39. In the IRP analysis, why didn't the supply-side avoided cost analysis include, the costs to the rate base associated with the bankruptcy of ENO?

A. See the response to No. 14.

40. In the IRP analysis, why didn't the supply-side avoided cost analysis include, the costs to the rate base associated with \$200M direct payment to ENO from the City/State?

A. See the response to No. 14.

41. In the IRP analysis, why didn't the supply-side avoided cost analysis include, the costs to the rate base of future hurricane riders currently being paid by customers?

A. See the response to No. 14.

42. In the IRP analysis, why didn't the supply-side avoided cost analysis not include the costs associated with settling the systems agreement realignment?

A. See the response to No. 14.

43. How many current ENO customers actually pay more than the supply-side avoided cost used in the proposed IRP today?

A. The avoided costs used in the context of resource planning are not comparable to rates paid by retail ratepayers. The rates that ENO ratepayers currently pay reflect the historical embedded cost, less depreciation, for providing transmission, distribution, generation, and customer service functions, plus current fuel costs as approved by the Council of the City of New Orleans. Avoided costs are a planning construct that considers only the future incremental cost of the generation function. That point aside, the avoided costs used to evaluate DSM alternatives are lower than ENO's current average rates.

44. Why wasn't Residential Solar included in any of the Integrated Resource Planning (IRP) analysis? When you say yes it was; then what was the cost basis of the solar used in demand-side analysis? Did that include Federal, State, Carbon incentives available to the residential customer? How much solar incentives are included in the proposed IRP and what is there value?

A. Both solar PV and solar water heater failed the Total Resource Cost (TRC) measure test. Their TRC values were 0.32 and 0.23, respectively. The TRC measure benefits include avoided energy and capacity costs through the lifetime of the technology; TRC measure costs include full incremental costs, which in the case of solar equal the full cost of the system. State and federal incentives are accounted for at the program level and not considered in the TRC measure test since TRC is meant to reflect societal benefits. State and federal tax credits are considered costs borne by society and are not included as benefits in the TRC measure test. This is applied consistently across all measures eligible for any tax credits.

The reason for the measure level screening is to compare all technologies on an apples to apples basis and to prioritize energy efficiency investment to ensure that the most cost effective measures are implemented.

45. Whose idea was it to conduct an open public meeting, public comment review and analysis of a + 3-years IRP planning process undertaking, during the final week of a hotly contested Federal Election cycle?

A. The date of the public meeting was set by the Council of the City of New Orleans in its March 25, 2010 Resolution R-10-142.

46. In reference to "Questions Received Oct. 26" No. 7: Given how cost-effective DSM is..." Entergy responds that over the 20 year planning horizon, 36% of ENO's ...load growth will be offset by DSM (43MW total). How does this compare to the amount of DSM that Energy Smart is expected to deliver? And if the 43 MW is greater than that expected from Energy Smart, can it be assumed to be done by

Entergy New Orleans voluntarily, or will further energy efficiency programs need to be required by the City Council to ensure this 43 MW of DSM?

A. At the October 26 public meeting, ENO announced that the first year of “Quick Start” energy efficiency programs achieved 2.8 MW of peak load reduction. Additionally, current plans for Energy Smart programs could result in a cumulative 9.7 MW of peak load reduction over its current three year horizon. This is a good start towards, and is consistent with, the 43 MW DSM planning assumption. The level of DSM that ENO actually achieves depends on a number of uncertain factors including the amount and type of DSM that not only ENO, but also local stakeholders, and the City of New Orleans agree to deploy, the relative cost of DSM versus supply-side alternatives, the willingness of customers to participate in programs, and the development of a consistent and sustained regulatory framework for cost recovery.

Questions Received November 8, 2010

47. Page 9-9 of the IRP indicates that the market potential of energy efficiency is limited. Is this judgment based on the Potential Study completed by ICF International for the Entergy system in May 2008?

A. DSM has the potential to significantly contribute to ENO’s incremental resource needs, but it cannot be relied upon to meet all future resource needs. ENO’s current DSM planning assumption is 43 MW of peak demand reduction over the 20-year planning horizon. Over this same time period, ENO’s peak load is forecast to increase 120 MW. See the response to Question #48 below for additional information regarding market potential.

48. The reference case of the ICF Potential Study estimated that achievable ten year energy savings represented only 2.6% of ENOs retail sales of electricity. This contrasts with the more common potential estimates of 8% to 15% produced in many other jurisdictions and actual energy savings of greater than 1% per year for many utility DSM programs. Why are Entergys efficiency estimates so much lower?

A. The actual incremental energy savings per year in ENO’s potential study range from .2% in the early years to .4% of retail sales in the outer years. ENO’s potential study was a “market achievable” study based on a bottom up analysis utilizing ENO specific data to provide an analytical estimate of achievable incremental energy savings. There are a number of factors that influence both projected results from potential studies and actual results that may have been reported in other areas. Many studies and actual reported results do not include net-to-gross ratios (or the effects of free-riders). Other factors that make it difficult to extrapolate estimates in other states to ENO include:

- Differences in the number and types of measures considered in the study

- Differences in avoided costs, discount rates, and other assumptions that influence cost effectiveness of the measures
- Differences in baseline assumptions regarding construction characteristics
- Differences in regulatory guidance (e.g. cost-effectiveness tests; funding)

Note that many early studies of DSM potential do not reflect the upcoming phase out of incandescent lamps, as well as potential future changes in building codes and equipment standards. Note also that ENO's customer base exhibits less potential for DSM than those in many other states due to: a) the comparative lack of industrial and large commercial customers, b) the comparatively high proportion of renters versus homeowners, and c) the comparatively depressed economic conditions.

There were no actual references provided to support the results indicated in the question but note also that, depending upon the study being referenced, there may also be serious methodological flaws.

49. The ICF Study estimates reflect hundreds of underlying assumptions and forecasts in respect to future fossil fuel costs, the likely costs of building new power plants, the future level of customer participation in energy efficiency programs, the costs and savings of such equipment etc. Have these many underlying assumptions and forecasts been reviewed by the City Council, the Councils Advisors, stakeholders or other independent parties?

A. The ICF study has been made public and made available to the New Orleans City Council, its Advisors, and other third parties. The underlying assumptions are discussed within the context of the study. As to whether they have been reviewed by the parties is unknown.

50. Please identify any independent reviewers of the underlying assumptions and forecasts in the ICF Study.

A. See the Company's response to question # 49, above.

51. Has ENO performed any studies to find out whether its customers would be willing to pay more for renewable generation? Experience in other states has shown that even a small rate increase can pay for the addition of some utility-scale RE in the portfolio. (For example, ratepayers in Gainesville, FL experienced a \$.75 increase in their monthly bills after the introduction of a solar feed-in tariff.) Are there any plans to reintroduce a program like Geaux Green with a focus on solar or wind, as opposed to biomass generation?

A. ENO has not performed any specific studies with regards to customer willingness to pay more for renewable electric generation. Elsewhere in Louisiana, as noted in the question, Geaux Green was a program that made renewable energy available to

participating customers who voluntarily enrolled to purchase renewable energy at an additional cost from a specific biomass generation project. Enrollment interest was limited and never reached the levels which would allow for the program to be sustained; therefore the Louisiana Public Service Commission discontinued the program.

52. During the 2009 energy efficiency hearings in Arkansas Entergy indicated that the ICF potential study only represented a cost to EAI of less than \$50,000. What was the cost to Entergy New Orleans, a much smaller utility, for this study?

A. Less than \$25,000.

53. In 2009 the ICF Potential Study was reviewed in testimony in front of the Arkansas Public Service Commission. Has the APSC accepted the ICF energy savings estimates as a basis for appropriate levels of energy efficiency programming?

A. The ICF Potential Study was prepared to support EAI's Integrated Resource Plan ("IRP") filed in APSC Docket No. 07-016-U on October 30, 2009. The IRP is filed pursuant to the Apse's Resource Planning Guidelines, which do not contemplate specific APSC approval for the utility's IRP. In addition, the ICF Potential Study was provided in APSC Docket No. 07-085-TF, the proceeding to review EAI's 2010 Energy Efficiency Program Plan filed on July 1, 2009. EAI's energy savings goals included in its 2010 Program Plan were not based on the ICF Potential Study. Therefore, the APSC has not made any specific decisions regarding EAI's energy efficiency program savings estimates or made any ruling regarding the specific results of the ICF Potential Study.

54. Mr. Phil Rosenthal, a national expert on DSM potential studies, has conducted such studies for numerous states and utilities around the US as well as co-authoring a national study on the issue for the USDOE and USEPA. In 2009, in association with an energy efficiency docket in Arkansas, Mr. Rosenthal reviewed the results of the 2008 ICF study for Entergy Arkansas what was his conclusion about the methodology and estimates produced by the study?

A. Mr. Mosenthal was not a witness in APSC Docket No. 07-085-TF, the docket referenced in the question. However, Audubon Arkansas witness Hale Powell attached to his testimony a letter purported to be from Mr. Mosenthal, wherein Mr. Mosenthal expressed concern that the ICF Potential Study contained flaws that would bias the results primarily downward. However, in the letter itself, Mr. Mosenthal, admitted that he made these assertions based only on his review of the Executive Summary of the Study. He specifically noted that he did not review the underlying workpapers or

analysis. Due to the hearsay nature of Mr. Mosenthal's testimony, no cross-examination of him could be conducted by any party.

55. Figure 10-3 on page 10-9 of the SRP identifies the levelized costs of electricity for gas, coal and nuclear generation but neglects to mention the analogous cost of saving energy. For the purpose of completing figure 10-3, what is the average levelized cost of energy savings achieved through efficiency programs as reported by the National Action Plan for Energy Efficiency and other similar national organizations?

A. ENO has not conducted an analysis of the levelized cost of energy efficiency programs as may be reported in the National Action Plan for Energy Efficiency or similar organizations. However, at the October 26th public meeting to present the IRP, a presentation describing the characteristics of the programs that comprise the DSM assumption used for long term planning included a comparison of the levelized cost of each DSM program to the levelized cost of a comparable peaking or load-following supply-side alternative. This presentation is available on the ENO website containing IRP materials.

56. What are the levelized costs of saving energy in the DSM programs operated by Entergy Texas since 2002?

A. ENO does not have the requested data on Entergy Texas programs.

57. ENO's IRP identifies, accurately, the unprecedented volatility of fossil fuel prices, particularly that of natural gas. Ratepayer funded efficiency programs have operated in some areas of the US for nearly 30 years; what is the comparative volatility of the costs of saving energy through these programs?

A. ENO has not conducted an analysis of the volatility of the costs of energy efficiency programs. However, the DSM Potential study included both High Case and Low Case scenarios that considered alternative energy costs, program costs, and participation levels.

58. Does the cost effective screening of energy efficiency programs act as a limiting factor on the cost volatility of energy savings programs?

A. It is not certain what is meant by the "cost volatility of energy savings programs". However, cost effective screening is a process by which the most cost effective programs as compared to supply side options can be prioritized so that customers receive the maximum benefits from investment in energy efficiency programs.

59. ENO's IRP states that energy efficiency programs are not fully designed. Can you describe the planning process by which these programs are currently being designed?

A. ENO is in the process of selecting the Third Party Administrator for Energy Smart, as outlined in the Council resolution approving such programs. The Third Party Administrator will finalize the details for program design and those programs are expected to be available in 2011. Council Resolution R-09-136 goes into great detail about the planning process for the Energy Smart Programs.

In addition, ENO will be enrolling customers for its AMI Smart meter pilot programs over the coming months. That program will also begin in 2011.

60. What is the status of this ENOs energy efficiency planning process and are there any preliminary materials that can be released to the New Orleans public?

A. See the Company's response to question # 59, above. Preliminary materials for Energy Smart can be found at www.energy-neworleans.com/irp. Preliminary materials for the AMI pilot can be found in the City Council filings in that docket and in regular DOE filings.

61. Entergys IRP says that a reasonable level of DSM has been included in the Reference Planning Scenario. Was this judgment made on the basis of minimum benefit cost ratios, levelized costs or other similar criteria?

A. The DSM assumption used in the Reference Planning Scenario is based on the results of the ICF study that identified market-achievable and cost-effective DSM. As part of this analysis, cost-benefit ratios were determined for individual measures as an initial cost-effectiveness screen and then passing measures were grouped into programs and cost-benefit ratios were determined as a second cost-effectiveness screen. The results of the economic tests are included in the DSM Potential Study Summary document posted on ENO's website containing IRP materials.

62. Page 9-2 indicates that the IRP does not reflect on-going energy savings from DSM programs because such programs have not yet been fully designed. Is Entergy willing to work closely with stakeholders in 2011 to develop a comprehensive long term DSM program for New Orleans?

A. Council Resolution R-09-136 outlines the process by which the City's Energy Efficiency Plan, Energy Smart, was to be designed and implemented. This program includes a significant amount of stakeholder input. The programs will be available to customers in 2011 and the process provides for an annual review of the programs and program results by the Council and interested stakeholders.

63. Has Entergy run any planning scenarios that reflect the levels of energy savings achieved by aggressive DSM programs that are common in a number of states?

A. The Reference Planning Scenario was evaluated against peak load and annual energy growth both higher and lower than the Reference Case including the High Load Factor Case which represented a scenario driven by energy efficiency, including the widespread implementation of demand response programs that eliminate peak load growth. For additional information regarding comparisons to other states or programs, please see the response to Question # 48 above.

64. A number of utility DSM programs are achieving energy reductions of 1% of retail sales per year; has Entergy modeled how such DSM programs might reduce or defer the need for near or midterm capacity additions?

A. ENO has not conducted an analysis of DSM-related energy reductions equal to 1% of retail sales per year. However, as explained in the response to Question # 63, the Reference Planning Scenario in the 2009 SRP considered the impact of different levels of peak load and annual energy growth on resource needs.

65. A number of stakeholders would like to play a constructive role in the development of sustainable energy efficiency programs. How can stakeholders play such a role going forward?

A. See the Company's response to question # 62, above.

66. The IRP mentions the importance of smart metering and AMI in the enabling of energy efficiency programs. Do most DSM programs in the US rely on this technology to produce energy savings?

A. There are many existing traditional energy efficiency programs (such as those comprising the Energy Smart Plan) as well as DSM / Demand Response (DR) programs that do not require AMI for implementation. However there are a number of existing programs that can be enhanced and new programs that can be enabled through an AMI network with two-way communications. Traditional programs such as Time of Use and load control are examples of existing programs that are enhanced by an AMI network whereby customers are provided more options and near- real time information to make better decisions. Also new programs such as In-Home Devices (IHD), Peak Time Rebate (PTR), Pre-Pay, etc are enabled by an AMI network. ENO plans to continue to pursue cost effective DSM programs that do not require an AMI network, but will also continue to evaluate the cost and benefits of AMI enabled DSM programs through such activities as the Energy Smart IHD pilot program and the AMI / DR DOE pilot program targeted to customers who meet specific income criteria.

67. Will investments in AMI be required in order to have effective DSM programs?

A. No. The current Energy Smart Plan budget is targeted at traditional energy

efficiency programs that do not require any AMI investment. An AMI network has the potential to enhance some existing programs and enable other new DSM programs as explained in the response to question # 66, above.

68. How has DSM been evaluated with respect to reducing the amount of needed reserve capacity?

A. ENO's reserve requirement is impacted by three types of DSM considered in long term planning. Increased amounts of customer-sponsored DSM and existing utility-sponsored DSM reduce the retail sales forecast which is the basis for the Total Load Forecast. The Total Load Forecast is further reduced by the amount of Interruptible Load provided by participating customers. The resulting load forecast is referred to as the Firm Load Forecast and this is the basis for calculating reserve requirement.

69. How much DSM would be needed to reduce reserve requirements?

A. See the response to Question # 68, above. Any amount of customer-sponsored DSM, existing utility-sponsored DSM, and customer participation in interruptible load programs serves to reduce reserve requirements.

70. Has ENO integrated Energy Smart into its supply portfolio?

A. Existing-utility sponsored DSM programs are incorporated into the retail sales forecast. As ENO's DSM programs develop, the impact will be included in the retail sales forecast.

71. If market barriers were addressed, what would be the optimal amount of energy efficiency from the demand load and cost perspectives?

A. From a long-term planning perspective, ENO should pursue all market-achievable and cost-effective DSM. The City Council, ENO and local stakeholders have successfully reduced market barriers through the development of the Energy Smart programs. However, the long term success in overcoming barriers will impact the amount of DSM that the City will ultimately achieve.

72. How is DSM potential being evaluated from the perspective of different customer classes?

A. DSM potential was estimated for each customer segment. Residential, commercial and industrial customer counts and baseline energy consumption were assessed. A market characterization analysis was conducted to understand the building characteristics and energy consumption of the customer base in ENO's service territory. This analysis was also necessary to identify the target markets and DSM programs expected to provide needed savings from energy efficiency projects. Residential, commercial and industrial measures and programs were assessed for cost

effectiveness, using rates, equipment saturation, costs, growth rates, customer willingness to invest in DSM, and other factors unique to each customer class. Cost effective measures were passed along to programs designed to deliver efficiency measures and services to each sector. This process is described in detail in the Potential Study.

73. In which customer classes are market obstacles seen as most difficult?

A. Each customer class has difficult market barriers to energy efficiency. For any customer to choose the efficient product, the product has to be available in the marketplace, the customer has to be aware the efficient product exists and be able to make the necessary investments. These key market barriers: availability, awareness and affordability vary considerably by, and often within, customer class and product/market. Further, the barriers are often unique to the technology being promoted, as well as the program design being employed. While it is impossible to generalize regarding the obstacles in each market, it should be noted that the residential and small commercial markets are often believed to be most difficult to penetrate due to their fragmented nature, and due to high numbers (in ENO's case) of renters and low-income customers.

74. In which customer classes is DSM the most advantageous?

A. DSM provides benefits to both the customer and ENO across all customer classes. Historically many commercial and industrial programs have delivered more savings at an overall lower cost per kW and kWh but as long as all programs in each customer class pass the appropriate cost / benefit tests, all customer classes can and should have the opportunity to participate in DSM programs.

75. What changes in the current resource mix would provide the most opportunity for expanding DSM from: 1) a cost perspective; and 2) an impact perspective.

A. Entergy's resource mix already provides a level of flexible capability that can respond to expanding DSM resources. The 2009 SRP and 2009 SRP Refresh Supplement calls for CCGTs to provide the bulk of new supply side capacity and energy over the twenty year planning horizon. The CCGT offers the flexible capability needed to adjust to rising DSM levels.

76. In what ways does a change in the system agreement potentially reinforce the advantages of energy efficiency?

A. The current System Agreement, which was largely drafted in the early 1970s, does not include DSM as a resource for which participating Operating Companies receive capacity or energy credits. Under the current agreement, Companies benefit only to the extent that their reduced loads or energy needs require less energy to be served. A successor

arrangement, such as the draft Commitment, Operations, and Dispatch Agreement (CODA) filed with the Council in Docket UD-07-03 can explicitly recognize DSM as resources, and provide for a consideration of such resources on a level playing field.

77. What types for load are most effectively served by DSM?

A. One of the findings of the DSM Potential study is that DSM programs can, to varying degree, reduce load in all hours of the year. As such, DSM programs can reduce load served by base load, load-following, or peaking generation. At the October 26 public meeting to present the IRP, a presentation describing the characteristics of the programs that comprise the DSM assumption used for long term planning included a calculation of each DSM programs' load factor. In general, the higher the load factor, the better correlation to base load generation; the lower the load factor, the better correlation to peaking generation.

78. Which DSM measures correspond to which types of load?

A. See the response to Question # 77, above. The DSM programs that comprise the DSM assumption correspond to base, load following, and peaking load.

79. How much of ENOs power is standing generation vs. power purchase?

A. Entergy publishes this information in both its annual ENOI FERC Form 1 filing and the Entergy Statistical Report and Investor Guide. For example in 2009 as reported on page 47 of the Entergy Statistical Report and Investor Guide, ENOI's energy needs were met by 2,202 gigawatt hours of energy generated from its owned resources and 4,350 gigawatt hours of energy from purchased power of which 3,760 gigawatt hours of purchased power was from affiliated companies.

80. What assistance from stakeholders would you welcome to get more DSM?

A. See the Company's response to questions # 62 and # 65, above.

81. How do the Quick Start results compare to your projections for future energy efficiency programming?

A. Generally, the Quick Start results indicate that there is a willingness on the part of vendors and suppliers to support energy efficiency programs. The success of the Quick Start programs on the part of the participating customers is being taken into consideration with regards to projections for future energy efficiency initiatives.

82. Will you share the results of your evaluation on the Quick Start program at a level of detail that would allow for comparison to programs in other parts of the country

and Energy Smart?

A. No specific or detailed evaluation of the Quick Start program is being considered at this time. A breakdown of program results was included in the October 26, 2010 presentation made by the Company. The presentation can be found on the ENO website at www.energy-neworleans.com/irp.

83. The ICF study worked not with the data at the program level, but at the hourly level to compare to the load forecasts. What are the implications of this decision?

A. As part of the DSM Study, ICF provided hourly load data as a project deliverable. The implication is that SPO had increased options for incorporating the DSM assumption into various long term planning analyses than if only a more limited description of the programs was provided, for example peak load reduction and annual energy savings.

84. What was the selected timeframe for ROI on DSM? How does that timeframe compare to their use value and how does it compare to calculations for supply side?

A. Assuming the question is asking about the comparison of DSM alternatives to supply-side alternatives presented at the October 26 IRP public meeting, the analysis considered a 30-year time period, from 2009 to 2038. More generally, the ROI on supply side resources is assumed to occur over the useful life of the supply side resource. The 2009 SRP Refresh Supplement provides the most current estimate of useful lives for supply side resources. By technology these are:

Combined Cycle Gas Turbine (CCGT)	30 Years
Gas Combustion Turbine (CT)	30 Years
Pulverized Coal	40 Years
CFB Coal	40 Years
IGCC Coal	30 Years
Wind	25 Years
Biomass	25 Years
Nuclear	40 Years*
Solar	25 Years
In Stream Hydro	25 Years
Geothermal	30 Years

*License renewal permits life extension for an additional 20 years

85. In considering DSM potential, has ENO considered that many customers are not yet up to current code requirements and may not act without incentives?

A. Building Code compliance and incentive participation are variables that were considered in preparing the DSM potential study and the Energy Smart programs. The

Energy Smart programs are incentive based programs.

86. Has ENO considered alternate scenarios of combining various forms of energy efficiency and renewable energy? If so, which scenarios are most successful?

A. As part of the 2009 SRP development process, eight different portfolios were evaluated in the Portfolio Strategy Assessment (Chapter 11 of the 2009 Strategic Resource Plan documents). While the level of DSM was held constant in all of the portfolios, five of the portfolios had various levels of renewables combined with various levels of conventional supply side resources. The GreenGold portfolio which had 2,000 MW of renewables was judged to be the best portfolio at meeting the overall objectives of reliability, lowest cost and risk mitigation. The renewable assumptions in the GreenGold portfolio were the basis for the level of renewables in the Reference Planning Scenario.

Questions received November 10, 2010

- 87. One of the Integrated Resource Plan Status Report (Status Report) deficiencies identified in Council Resolution R-10-142 was that the Status Report did not integrate transmission and distribution planning into its portfolio Furthermore, Component 4 of the Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans require that the IRP explain how transmission is integrated into the overall resource planning process to optimize the utility's resource portfolio. One of the strategic recommendations of the integrated resource plans for ENO and ELL is to continue to develop long-term integrated planning efforts with Entergy Transmission to identify portfolio solutions that best balance planning objectives. Results of integrated supply and transmission planning efforts that are now allowed subsequent to FERC Order 717 may result in adjustments to the timing and location of resource needs. However, the October 19, 2010 filing fails to describe how transmission is integrated into the overall resource planning process to optimize the utility's resource portfolio. Accordingly,**
- a) Please describe how transmission is integrated into the overall resource planning process to optimize ENO's and ELL's resource portfolio.**
 - b) Were any transmission upgrades or projects considered as part of ENO's and/or ELL's integrated resource plans? If the answer is in the affirmative, please identify transmission upgrades or projects and the rational for acceptance or rejection as part of the UPRP.**
 - c) For each of the planned transmission upgrades, were any selected primarily on the basis of economic benefit rather than for reliability? If the answer is in the affirmative, please identify the upgrades and provide a cost/benefit analysis.**
 - d) In September 2010, Charles River Associates prepared a cost/benefit analysis of Entergy and Cleco Power joining the SPP RTO. If the Entergy Operating Companies were to join the SPP RTO, would that have any impact on the resources identified in the Reference Planning Scenario? Please explain.**

A. Chapter 2 of the SRP provides a description of FERC Order No. 717 and the implications for long-term integrated planning. In accordance with Order 717, System Planning & Operations (“SPO”) and Entergy Energy Delivery (Transmission Planning) have initiated efforts to develop integrated planning processes. The goal of these efforts is to produce more comprehensive integrated plans for the Entergy System that include, consistent with Order 717, consideration of all aspects of various transmission and supply alternatives. Efforts to date have included, but are not necessarily limited to, the following:

Resource Selection

The process of evaluating potential resource alternatives including the evaluation of proposals offered in the recent 2009 Summer RFP have reflected greater coordination between SPO and Transmission Planning personnel. These efforts have focused on identifying those resources that can meet customer needs for reliable power at the lowest reasonable cost. Selections made from the 2009 Summer RFP reflect these efforts.

Area Planning

The Area Planning process provides an opportunity for greater coordination in planning activities because: 1) the nature of area planning provides an appropriate context for consideration of integrated supply solutions; and 2) area planning considers a sufficiently long-term planning horizon to enable assessment of tradeoffs between transmission and generation alternatives. Efforts have focused on:

- Identifying locations for potential future generating capacity additions;
- Assessing alternatives for addressing local area reliability requirements;
- Developing improved modeling assumptions and constructs.

Strategic and Regional Studies

SPO and Transmission personnel are participating jointly in a number of studies that consider integrated supply issues, including:

- The Bulk Power Minimization Study sponsored by the Entergy Regional State Committee.
- The Eastern Interconnect Planning Collaborative
- The Cost Benefit Study sponsored by the Entergy Regional State Committee.
- ICT Economic Studies

88. Component 3, Item 10 of the Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010 requires: A schedule of costs showing the annual total demand related costs, energy related costs, and total supply costs associated with the UPRP. The October 19, 2010 filing appears to provide only one set of annual costs for 2009 to 2028 which appear to be 2009 SRP system costs under presumably the reference planning scenario and reference fuel price forecast. Were projected costs developed for individual Operating Companies such as ENO and ELL? If the answer is in the affirmative, please provide the costs projected to be incurred under the Reference Planning Scenario and the Expected Natural Gas Price Forecast for both ENO and ELL separately. If the answer is in the negative, why were these costs not developed?

A. This data was not prepared at an Operating Company level as long-term planning seeks to minimize system cost for the mutual benefit of all Operating Companies.

89. One of the Integrated Resource Plan Status Report (Status Report) deficiencies identified in Council Resolution R-10-142 was that the Status Report included .only the selected supply resource plan and limits the ability of the Council to assess the robustness of the selected supply resource plan in comparison with alternative resource plans that were determined by ENO to be less than optimal but may be preferable to the Council and ratepayers. Furthermore, Component 3, Item 16 of the Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010 requires: A discussion of each alternative planning scenario considered, including a schedule of costs showing the annual total demand related costs, energy related costs, and total supply costs associated with each alternative planning scenario. The October 19, 2010 filing appears to provide only one set of annual costs for 2009 to 2028 which appear to be Entergy System costs for the 2009 SRP under presumably the reference planning scenario and reference fuel price forecast.

a) Were system supply costs developed for each scenario identified in the filings such as: the New Nuclear Planning Scenario, the High Growth Planning Scenario, the Low Growth Planning Scenario, and High Load Factor Planning Scenario, Low Natural Gas Price Forecast, High Natural Gas Price Forecast, High Case for Carbon Cost Assumptions and Low Case for Carbon Cost Assumptions? If the answer is in the affirmative, please provide the projected costs and please explain why these costs were omitted from the filing. If the answer is in the negative, please explain why the Councils directives were disregarded.

b) For the alternative scenarios identified in the filing, were projected costs developed for individual Operating Companies such as ENO and ELL? If the answer is in the affirmative, please provide the projected costs under each alternative scenario for both ENO and ELL separately. If the answer is in the negative, why were these costs not developed?

A. Although the Alternative Planning Scenarios, described in Chapter 12 of the SRP provide some indication of the robustness of the Reference Planning Scenario, they were not intended primarily for that purpose. Instead, the Alternative Planning Scenarios were developed for the purpose of describing how the Reference Planning Scenario would be adjusted in the future to respond to specific contingencies. The Portfolio Strategy Assessment described in Chapter 11 provides a basis for assessing how various portfolio strategies would perform across a range of assumptions regarding the key uncertainties of gas and CO2 cost. The results of the Portfolio Strategy Assessment when coupled with the results of the analyses described throughout the SRP including especially the Technology Assessment of supply-side alternatives, provides a basis for establishing a strategic direction and developing long-term portfolio scenarios for the Entergy Operating Companies.

The above notwithstanding, Entergy Services, Inc. (“ESI”) does have System level cost

data from the 2009 SRP of the Alternative Portfolios considered in the Portfolio Section process. These costs will be provided to the ENO City Council Advisors on a highly sensitive protected material (“HSPM”) basis. This data was not prepared at an Operating Company level as long-term planning seeks to minimize system cost for the mutual benefit of all Operating companies.

90. Component 3, Item 15 of The Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010 requires a risk assessment of the UPRP. Has a risk assessment of the type described in the Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010 been performed for ENO and ELL? If the answer is in the affirmative, please provide the input assumptions, provide the results, and explain why it was not included with the filing. If the answer is in the negative, please explain why the Councils directives were disregarded.

A. The analyses described in Chapters 10 (Generation Technology Assessment) and 11 (Portfolio Strategy Assessment) provide a basis for assessing the risks associated with alternative portfolio strategies.

91. Council Resolution R-10-142 found that ENO’s proposed resource plan does not adequately integrate demand-side management programs into its supply plan and result in an IRP. Contributing to this finding was the fact that demand-side management was included on an assumed level based on an independent study rather than an integrated component of the resource planning process. In ESI's October 19, 2010 filing, it appears the same approach of simply taking the results from an independent study has been employed once again. Please explain why ENO and ELL believe this approach is appropriate and in compliance with Council Resolution R-10-142.

A. Chapter 9 (Demand-side Resources) of the 2009 SRP explains how various DSM alternatives are considered in the resource planning process. This includes the treatment of customer-sponsored energy efficiency or conservation activities not requiring utility participation, existing utility-sponsored DSM programs, interruptible load, and incremental utility-sponsored DSM programs. The question correctly states that an independent study formed the basis for the planning assumption for incremental utility-sponsored DSM; however, the question incorrectly limits ENO’s consideration of DSM alternatives to this one alternative.

92. Included in ESIs October 19, 2010 filing is an April 28, 2009 summary of a demand side management potential study for ENO prepared by ICF Resources, LLC (ICF). This appears to be a separate study with assumptions which may not be wholly consistent with assumptions utilized in the Entergy New Orleans, Inc. An Integrated Resource Plan (2009-2028).

a) Please explain in detail how the results from the demand side management potential study were incorporated into the integrated resource plan.

b) Did ENO and ELL compare each DSM measure directly against supply-side alternatives and transmission alternatives in developing the integrated resource

plans for ENO and ELL? If the answer is in the negative, please explain why ENO and ELL did not perform the comparison.

c) Were the results from the demand side management potential study revised by the updated capital cost and natural gas price assumptions in ENO's and ELL's integrated resource plan and then screened utilizing the TRC and RIM tests as required by Component 3, Item 7 of The Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010? If the answer is in the negative, please explain. If the answer is in the affirmative please provide the results of the RIM and TRC tests for each DSM measure.

A. Chapter 9 (Demand-side Resources) of the 2009 SRP explains how the results of the DSM potential study were incorporated into the integrated resource plan. As part of the DSM potential study, cost-benefit ratios described by the TRC and RIM test were determined for all individual measures and a second time for passing measures grouped into programs for both ENO and ELL. The "benefit" in the cost-benefit ratio included the avoided cost of capacity, energy, transmission, and distribution. In addition, the DSM potential study considered the cost-effectiveness of the programs under Low Case and High Case scenarios and cost-benefit ratios for TRC and RIM tests were calculated for these scenarios for both ENO and ELL as well. Because the DSM potential study and the 2009 SRP were completed sequentially, there is some difference in the assumptions for capital cost and natural gas price; however these differences are well bounded by the Low Case and High Case scenarios considered in the original work. In addition, they are very close to the Reference Case assumption. For example, the Reference Case of the DSM potential study used capital costs for a combustion turbine (CT) of \$680/kW (2007\$). The 2009 SRP used \$684/kW (2007\$) for a CT. For natural gas, the Reference Case of the DSM potential study used \$7.22/mmBtu (level zed 2008 to 2035, 2007\$) and the 2009 SRP used \$7.25/mmBtu (level zed 2008 to 2035, 2007\$)

93. Component 3, Item 7 of The Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans 2010 requires a description of each demand-side resource considered, the expected penetration levels by planning year, and the results of the appropriate cost benefit analyses and acceptance tests which are consistent with the planning assumptions utilized within the IRP planning process. This information does not appear to have been provided as part of the October 19, 2010 filing. Did ENO and ELL develop this information? If the answer is in the affirmative, please explain why it was not included the filing and provide the data required by the Council. If the answer is in the negative, please explain why this information was not developed.

A. As discussed in the response to Question 92, the DSM potential study and the 2009 SRP were completed sequentially so there are some differences in the assumptions. The document contained in Appendix 9 of the July 2, 2009 Energy Smart Proposal filing contains a detailed description of the DSM resources considered for ENO and a similar summary has been prepared for ELL. The ELL document has not been made public and

it was inadvertently not provided in the October 19 filing; however, it will be provided to the CNO.

94. At the October 19, 2010 CNO Council Utility Committee Meeting there was an expressed interest in expanding the use of renewable generation. The Reference Planning Scenarios for ENO and ELL include future renewable generation resource additions such as biomass, in-stream hydro, and off-system wind. However, it is unclear if these resources were selected on an economic basis or based on some alternative criteria. Please explain the criteria utilized in selecting renewable resources for the Reference Planning Scenarios for ENO and ELL. Please also identify what ENO and ELL believe are the primary barriers to implementing an increased level of renewable generation in the resource portfolios of ENO and ELL.

A. The levels of renewable generation included within the SRP reflect consideration of multiple factors (both quantitative and qualitative) including but not limited to:

- a. The relative economics of renewable resources compared with demand and supply-side alternatives;
- b. Assessment of the amount of renewable resources within the Entergy region;
- c. An estimate of the amount of resources that are reasonably deployable over time; and
- d. The amount of generation capacity needed by the Entergy Operating Companies and the ability of renewable resources to contribute to that need.

All of these factors contribute to an assessment of the amount of renewable resources that can be deployed practically and economically over the planning horizon. As with all assumptions reflected in the SRP, the assumptions regarding renewable resources are subject to continuing re-assessment through ongoing planning and procurement activities.

95. With regard to the uncertainty regarding the long-term viability of the White Bluff facility (IRP Supplement, p. 5), please provide Entergy's best estimate of the maximum investment in White Bluff that would be cost-effective to keep that plant in service.

A. This analysis has not been performed.

96. Please provide any information available to Entergy regarding the range of costs required to meet the emissions requirements that EPA might impose for White Bluff.

A. Typically, the EPA does not impose costs, but regulations or requirements that result in costs of compliance. Entergy cannot speculate as the range of actions the EPA might take in the future affecting White Bluff or any other unit.

97. Please provide any information available to Entergy regarding the range of costs required to meet the emissions requirements that EPA might impose for Lake

Catherine 4, and the maximum investment that would be cost-effective to keep that unit on line.

A. Typically, the EPA does not impose costs, but regulations or requirements that result in cost of compliance. Entergy cannot speculate as the range of actions the EPA might take in the future affecting Lake Catherine or any other unit.

98. Do any of the environmental issues facing White Bluff also potentially affect ISES? Why or why not?

A. At present the White Bluff facility is subject to requirements relating to the Environmental Protection Agency (“EPA”)’s Clean Air Visibility Rule passed in July 1999, as amended on June 15, 2005. Under this rule industrial facilities including power plants emitting air pollutants that reduce visibility by causing or contributing to regional haze must install controls that limit such emissions. The pollutants that reduce visibility include fine particulate matter (PM_{2.5}), and compounds which contribute to PM_{2.5} formation, such as nitrogen oxides (NO_x), sulfur dioxides (SO₂), and under certain conditions volatile organic compounds, and ammonia. The state of Arkansas is responsible for developing a state implementation plan (“SIP”) to meet this rule. At present the EPA has not approved the state of Arkansas’s proposed SIP, however, it is clear from communications received from both the state of Arkansas and EPA, that White Bluff will be part of the Arkansas SIP. Compliance under this rule is a function of a plant’s emissions and its physical location relative to a 156 designated federal area. Based on its location this requirement does not apply to ISES. Otherwise, White Bluff and ISES are similar units and accordingly can be anticipated to face similar environmental compliance requirements in the future.

99. Regarding The results of the LOLP calculations [that] indicate much higher reserve requirements for a 4-company System (ENO IRP, p. 4); do those calculations assume that the 4-company system, EAI and EMI would not provide capacity to one another in the event of an outage in one of the systems?

a. If so, please explain why.

b. If not, please explain why the required reserve would increase if the utilities continue to support one another?

A. The reserve margin requirements assume that the 4-Company System, EAI and EMI operate as three separate planning entities and each are responsible for carrying its own planning reserves.

100. Please define the area in which power plants can be located and serve ENO (Entergy territory, part of SPP, part of SERC?).

A. There is no specific geographic boundary defining which power plants can serve ENO. Resource evaluations and selections are based a specific proposed resources’ ability to reliably meet the power needs of the Entergy Operating Companies’ customers at the lowest reasonable cost considering risk.

101. Please list the combined-cycle power plants neither owned by utilities nor under long-term contract to utilities in the area identified in the answer to the previous question.

A. Please see the response to Question # 100.

102. Please list the combined-cycle plants in the Entergy, SPP and SERC areas that have been sold in the past three years, and where known, the price of each in dollars per kW.

A. Response – See table below:

Closed transactions since 2007 involving a CCGT.
Source: Vantage Velocity Suite - Intelligent Query Nov. 11, 2010

Plant Name	Plant NERC Sub Region Name	Plant State Abbrev	Asset Sale Description	Sale Status	Status Start Date	Total MW Sold	Total Cost \$ (millions)	Total Cost per \$/kW (US\$)
Acadia Power Station	Southwest Power Pool	LA	Acadia Power Partners LLC is selling ownership of 1 power plant to CLECO Power LLC	Closed	2/24/2010	580	304	524.14
Acadia Power Station	Southwest Power Pool	LA	Calpine Corp is selling ownership of 1 power plant to Cajun Gas Energy LLC	Closed	9/13/2007	688	189	274.71
Dogwood Energy Facility	Southwest Power Pool	MO	Calpine Corp is selling ownership of 1 power plant to Kelson Energy	Closed	7/1/2007	677	234	345.64
Green Country Energy LLC	Southwest Power Pool	OK	Cogenrix Energy Inc and General Electric Capital Corp are selling ownership of 1 power plant to J Power USA Generation LP	Closed	9/28/2007	795		
Mustang Station	Southwest Power Pool	TX	EIF Management LLC and UnionBanCal Equities Inc are selling ownership of 1 power plant to Great Point Power LLC	Closed	6/4/2010	261		
Ouachita Power LLC	Delta	LA	Ouachita Power LLC is selling ownership of 1 power plant to Entergy Arkansas Inc and Entergy Gulf States Louisiana LLC	Closed	9/30/2008	789	256	324.46
Plaquemine Cogeneration Plant	Delta	LA	American Electric Power Co Inc is selling ownership of 1 power plant to Dow Chemical Co	Closed	1/1/2007	880	64	72.73
Redbud Power Plant	Southwest Power Pool	OK	Kelson Energy is selling ownership of 1 power plant to Grand River Dam Authority, Oklahoma Gas & Electric Co and Oklahoma Municipal Power Authority	Closed	9/29/2008	1,538	852	636.17

103. Please provide the avoided costs that ENO uses and intends to use in screening energy-efficiency programs and measures, and the derivation of those avoided costs.

A. Two types of long-term avoided costs must be developed to evaluate potential DSM: avoided energy costs and avoided capacity costs. Avoided energy costs are the variable costs (largely fuel and purchased power costs) of the energy that is not consumed as a result of the implementation of DSM. Typically, it is assumed that DSM replaces the most expensive source of generation that is capable of being reduced. This is often called the “cost at the margin” and is appropriately represented by the expected market cost of energy and/or commodity price inputs associated with energy production at the margin. Similarly, avoided capacity costs reflect the cost of incremental infrastructure investments (such as the cost of generation, transmission and/or distribution facilities)

that can be avoided or deferred by DSM projects. Avoided energy costs are expressed in terms of \$/kWh, and avoided capacity costs in terms of \$/kW. The avoided cost that ENO used to screen DSM measures and programs are shown starting on page 2-14 of the summary report of the DSM potential study contained in Appendix 9 of the July 2, 2009 Energy Smart Proposal filing on the ENO website at www.entergy-neworleans.com/irp.

104. Please provide a breakdown of the WBL line in Figure ENOI-2, showing separately the capacity represented by ANO 1, ANO 2, Grand Gulf 1, Independence 1, White Bluff 1 and White Bluff 2

A. Response – See table below:

ENO Wholesale Baseload (WBL) based on Summer 2008 Capacity from Chart ENOI-2				
Unit	Supply Role	Fuel	Age	2008 Summer Capacity (MW)
ANO 1	Baseload	Nuclear	36	22.93
ANO 2	Baseload	Nuclear	30	26.99
Grand Gulf	Baseload	Nuclear	25	27.71
Independence 1	Baseload	Coal	25	7.16
White Bluff 1	Baseload	Coal	30	12.08
White Bluff 2	Baseload	Coal	29	13.50
Total				110.38

105. Please explain why Michoud is classified as Seasonal Load Following and not Core Load Following or Peaking in Figure ENOI-6.

A. For planning purposes, nuclear and coal fueled generating units are assigned to the Nuclear & Coal capability category, CCGT generating units are assigned to the CCGT capability category, lower heat rate gas fired steam generating units are assigned to the Seasonal Load Following capability category, and higher heat rate gas fired steam generating units, CT units, and hydro units are assigned to the Peaking/Reserve capability category. In general, based on the IRP, Nuclear & Coal capability is compared with base load requirements, CCGT capability is compared with base load and core load following requirements, Seasonal Load Following capability is compared with seasonal load following requirements, and Peaking/Reserve capability is compared with peaking and reserve requirements. Comparison of the existing portfolio of resources with the supply role requirements indicates potential opportunities to improve the resource mix and can be used to inform the design of the Reference Planning Scenario. In assessing the existing portfolio relative to these guidelines, each unit has been assigned within a specific supply role. In actuality, the distinction between supply roles is neither sharp nor static.

106. Would the classification of Michoud and similar units change, depending on the price of gas?

A. No, based on the criteria used to assign generating units to supply roles for the IRP, the classification of Michoud and similar units would not change depending on gas price. Please see the response to question # 105.

107. Please describe the transactions selected in the 2009 Summer RFP (2009 IRP Supplement, p. 4) and the status of each.

A. Entergy Services Inc. has disclosed the following information regarding selections from the Summer 2009 Request for Proposals (RFP) for Long-term Supply-Side Resources.

ESI has concluded its review and evaluation of the proposals submitted in response to the Summer 2009 RFP and has reported the results of the review and evaluation to the Operating Committee. ESI has received Entergy Operating Committee approval to move forward with five resources:

- *four acquisition proposals totaling approximately 2,800 MW, including the Ninemile self build option identified in the RFP; and*
- *one PPA proposal totaling approximately 500 MW.*

Subsequent to the RFP selections, one of the acquisition proposals that had been selected for award was withdrawn by the bidder. Nonetheless, even with the withdrawal of this acquisition proposal, the 1,550 MW of resource needs identified when the RFP was issued have been filled.

The Independent Monitor for ESI's Summer 2009 Long-Term RFP, Potomac Economics, has certified that the evaluation and analysis of the RFP proposals were fair and impartial, did not unfairly favor any proposal, including the self-build proposal, and were free from affiliate abuse. In addition, the IM has certified that the various processes established under the RFP to ensure protection of confidential information were followed accordingly. Further, the Independent Monitor has affirmed that the Operating Committee's resource selection is consistent with the RFP evaluation results.

ESI, on behalf of the Entergy Operating Companies, will be entering into discussions for the execution of definitive agreements associated with the selected proposals. All transactions will be contingent upon obtaining necessary regulatory approvals, including full cost recovery.

Additional information regarding ESI' RFP's can be obtained at the Entergy RFP Web site:

<https://emo-web.no.entergy.com/ENTRFP/index.htm>

108. Does ENO believe that adding some capacity close to the New Orleans load center (such as the Michoud site) would be desirable when new generation construction is required?

A. Yes, locating new generation close to load centers is preferable if all other attributes are equal. The Summer 2009 RFP For Long-Term Supply-Side Resources sought resources for the Amite South planning region, which includes the Downstream of Gypsy sub region. This RFP included a self-build option to construct a CCGT unit at the Ninemile site in Westwego, LA, which is in the Amite South region and Downstream of Gypsy sub region close to the New Orleans load center. Also see response to Question 107.

109. Please list and define the planning regions for which Entergy intends to complete integrated area plans in 2011. (2009 IRP Supplement, p. 4)

A. The Company intends to complete integrated area plans for the Amite South region including the Downstream of Gypsy sub region, West of the Atchafalaya Basin region including the Western sub region, Central region, and North Arkansas region.

110. Please specify the spending levels that ENO has incurred in 2008 - 2010 and anticipated for 2011 - 2013 to Maintain readiness of new nuclear and continue with on-going assessment. (2009 IRP Supplement, p. 4)

A. ENO has informed the Operating Committee that it is not interested in pursuing a new nuclear facility at this time, and as such ENO is not incurring any costs related to the development of potential new nuclear facilities at the River Bend or Grand Gulf sites. ENO does not have an option to participate in those projects, if they proceed.

111. Do the values in Figure ENOI-6 represent ENO's expectations (a) under current regulation or (b) assuming the Barriers to DSM Implementation (p. ENOI-16) are overcome?

A. Because Figure ENOI-6 shows ENO load requirements and generation capability for 2009, the intent of the question is not clear. However, the DSM planning assumption for incremental-utility sponsored DSM does assume that barriers to DSM are overcome such that all cost-effective DSM programs are fully funded and implemented and appropriate regulatory treatment is given to program costs, lost net margins, and shareholder incentives.

112. How much additional energy-efficiency can ENO achieve if the Barriers to DSM Implementation are overcome? (Or alternatively, how much less would ENO achieve if the Barriers to DSM Implementation are not overcome?)

A. The DSM potential study identified all market-achievable and cost-effective DSM, assuming barriers are overcome. An analysis of what ENO may achieve in an alternative scenario has not been performed.

113. Please describe ENO's efforts to date and future plans to overcome the Barriers to DSM Implementation.

A. ENO implemented an energy efficiency Quick Start Program in 2009 -2010 that helped to develop the contractor infrastructure needed to begin implementing energy efficiency programs. ENO also was instrumental in the development of a contractor training / certification program through Delgado College to help growth the energy efficiency contractor network. ENO has in the past and continues to educate customers through various channels on the benefits of energy efficiency. The Energy Smart Program will continue the process of developing the contractor network and the education process through the delivery of the Energy Smart programs. In addition, the regulatory barriers to DSM have been overcome through the Council's resolutions approving the Energy Smart programs.

114. Please provide any available analyses of the capital and operating costs of the nuclear uprates (p. ENOI-14).

A. Analyses of possible nuclear uprates are not yet publicly available.

115. The IRP executive summary states that ENOI is concerned with change, transition, uncertainties, and unpredictability. The ENOI IRP further states that the price and availability of natural gas is a key uncertainty yet also concludes that utility-scale solar PV economics are not attractive at this time. ENO's portfolio choice of heavily pursuing CCGT seems to contradict the goal of predictability because the historic cost of natural gas is anything but predictable (e.g. see NYMEX Henry Hub historic gas prices combined with price forecasts, and see Energy Information Administrations Annual Energy Outlook 2010) while the historic cost of solar PV has an undeniable trend toward increasing affordability (e.g. see U.S. Dept. of Energy Solar Energy Technologies Programs LCOE projections through the year 2030). It would seem that investing in solar PV would provide safe harbor from natural gas price volatility.

a. Did ENOI analyze at what point the steady decline of the levelized cost of solar PV would become more attractive than the volatility of the levelized cost of natural gas fuel?

b. Did ENOI consider the sensitivity to capital cost inflation for the construction of CCGT power plants?

c. Did ENOI consider the cost contained in the long lead times to construct a CCGT power plants versus solar PV utility projects?

A. Supply diversity is a strategy for mitigating risk, but it is not a strategy worth pursuing without regard to cost. At this time, solar technology does not appear to be an economically attractive alternative relative to CCGTs or, for that matter, most other

renewables. ENOI has not analyzed at what point the decline in solar cost make it more attractive than natural gas. However, the SRP analysis considered that the cost of supply alternatives may change over time and that the cost of some technologies, such as solar, are likely to decline. The results of the analysis indicated that even considering potential declines in cost, solar economics, while improving, remained relatively uneconomic in the later half of the planning horizon. It is important to recognize that solar technology, due to its intermittent nature, also is subject to volatility in cost. With respect to the capital cost associated with deploying CCGT technology, it should be noted that the economics of solar technology are more sensitive to changes in deployment cost than those of gas-fired CCGTs because the cost of deploying solar comprises a relatively larger portion of the cost of electricity. The analysis did consider the lead time associated with constructing a CCGT vs. a Photo Voltaic (“PV”) solar project. As with all assumptions reflected in the SRP, the assumptions regarding renewable resources are subject to continuing re-assessment through ongoing planning and procurement activities.

116. The ENOI PowerPoint slide titled Solar PV Intermittency During Peak Hours implies that solar generation is too unpredictable for inclusion in the ENOI portfolio. However, this slide does not clearly delineate the parameters and sources for its data. The conclusion that solar is too unpredictable does not seem to account for known solutions for smoothing the short-term variations in power generated on site.

- a. Did ENOI consider smoothing technology, such as flywheels, as a way to mitigate the short-term variations of solar-generated power?**
- b. Did ENOI consider smoothing technology, such as bulk storage (Nas batteries), as a way to mitigate the short-term variations of solar-generated power?**
- c. Did ENOI consider smoothing technology, such as Vanadium flow batteries, as a way to mitigate the short-term variations of solar-generated power?**
- d. Did ENOI consider smoothing technology, such as zinc bromide batteries, as a way to mitigate the short-term variations of solar-generated power?**
- e. Did ENOI consider smoothing technology, such as lithium-bromide batteries, as a way to mitigate the short-term variations of solar-generated power?**

A. The premise that the SRP has concluded that Solar generation is too unpredictable for inclusion in the ENOI portfolio is incorrect. The point of the referenced analysis is that solar is an intermittent resource and that intermittency negatively affects the economics of solar compared to other alternatives. Given current planning assumptions, solar technology does not appear to represent an economic alternative for meeting the power needs of ENOI’s customers. As with all assumptions reflected in the SRP, the assumptions regarding renewable resources are subject to continuing re-assessment through on-going planning and procurement activities. ENOI is unaware of any utility scale battery or new storage technology that is economically feasible at this time.

117. ENO’s IRP acknowledges environmental concerns to be a key uncertainty. However, that concern seems to be limited to be whether legislation will change the economics of supply alternatives. Recently, ENO’s parent company conducted a study that concluded the Mississippi Gulf Coast will suffer \$370 billion in losses to

global warming if power companies do not offset the amount of carbon they are putting into the environment. (see Jackson Free Press quoting Jeff Williams, director of Entergy's Climate Consulting division, released an Oct. 21 PowerPoint). Undoubtedly, ENO's ratepayers would bear a significant portion of those losses.

a. Did ENO consider the environmental cost to its customers from the choice to continue and/or increase CCGT technology (i.e. large-scale burning of fossil fuels) as a large portion of the portfolio?

A. Environmental considerations in the planning process are described on page 2-6 of the 2009 SRP. Also, the statement that CCGT technology makes up a large portion of ENO's portfolio is incorrect. In addition, Slide 8 to the "IRP Overview Presentation" presented at the October 26, 2010 IRP public meeting demonstrates that not only ENO, but all Entergy companies rank among the lowest emissions of CO2 per MWh when compared to neighboring utilities. The presentation can be found at www.entergy-neworleans.com/irp under the Integrated Resource Plan 2010 link.

118. The ICF report contracted by ENO states that transmission line losses amount to 7.4127% (Figure 17, ICF Potential Study, Appendix 9). If the IRP is intended to chart a prudent course for long-term and high-dollar investments, it would seem prudent to investigate ways to reduce this significant inefficiency.

a. Where in the IRP process is there any evidence of any effort on ENO's part--even a pilot project--to attempt to decrease these significant transmission line losses?

A. The IRP process addresses the issue of transmission losses implicitly through the Area Planning process as discussed in the response to question #21. Transmission losses are reduced when resources are located near load centers and within constrained areas. The Area Planning process attempts to identify the resource needs associated with load centers in order to mitigate any over-reliance on transmission and effectively limit losses resulting from moving power over long distances. The recent Summer 2009 Long-Term Resource RFP explicitly addressed the issue of transmission losses by quantifying the losses associated with moving power from resources located outside of the region. The value of these losses were considered in the economic evaluation of alternative resources. Although not specifically addressed in the IRP documents provided to the City Council of New Orleans, the goal of reducing transmission line losses is part of ENO's long-term integrated approach to planning. Two current projects by Entergy's Transmission Business Unit demonstrate steps that are being taken in this area. If these projects are determined to be cost effective, they can be replicated across the Entergy Transmission network for the benefit of customers.

1. Advanced Conductor Project

Entergy is currently carrying out a project which consists of the utilization of an advanced conductor to solve a reliability issue related with components overload at N-1 conditions.

The 230 kV Line 195 (Hartburg – Inland Orange – McLewis) in the Entergy’s system is one of the primary sources into the Beaumont/Port Arthur (Texas) area. The single contingency loss of 500 kV Line 547 (Cypress – Hartburg) causes thermal overloads of this line. To prevent from overload conditions and potential cascading effects the power transmitted over the 500 kV corridor has to be restricted, underutilizing the capacity of the corridor.

Entergy is implementing a solution to withstand overload under N-1 contingency without affecting transmission limits of the 500 kV corridor: 13 miles of the 230kV Line 195 (Hartburg – Inland Orange - McLewis) are being thermally upgrading by re-conductoring with ACCC/TW conductor. ACCC/TW is a low-sag (HTLS) advanced-technology conductor able to operate at high temperature without exceeding sag clearances, thus it is able to absorb the increase in the power flow due contingencies. Station equipment is also upgraded to achieve 797 MVA capacity along entire circuit. The project is expected to be in service in May 2011.

The improvement in the 500 kV corridor transmission capacity will certainly have a tremendous positive impact on the system economic operation. This will support the reduction of the industry’s carbon footprint by reducing congestion and facilitating transmission access to lower-emitting generation sources such as wind.

It may also contribute to improve transmission system efficiency by reducing losses. Indeed, the ACCC/TW conductor has less resistance than an ACSR conductor of the same diameter, when they operate at the same conditions. Thus, at normal operation there will be a saving in transmission losses. During the emergency conditions that the upgrading solution is designed for, the losses on the conductor will be high because it will operate at high temperature. However, because the occurrence of these conditions is of low probability, the effects of these short periods of high losses on the performance of the energy-efficiency solution will be small, and consequently there might be a net savings.

2. Voltage and Reactive Power Control Project

Voltages affect not only the flow of active power but also the flow of reactive power in the grid. Changes in the flows of reactive power have a strong influence on system losses. Thus, adjusting voltages can have a significant effect on losses. Also, appropriate management and control of reactive power in the grid allows maximization of the amount of real active power that can be transferred across congested transmission lines. Otherwise, reactive power (more than necessary) flows in the grid consuming transmission and generation capacity, hence limiting the system’s ability to move real active power.

Entergy, as in general, almost all North American grid operators, adjusts transmission voltages and reactive power flows principally in a decentralized fashion at the power plant/substation level. In the transmission control center, transmission system operators

provide the generator operators with hourly voltage schedules to maintain at high-side generator interconnecting transmission buses. Transmission operators also remotely switch transmission banks of shunt capacitors or reactors. The transmission operators' manual control actions are coordinated with automatic reactive power control actions such as automatic voltage (or VAR flow) controlled distribution and transmission capacitors, the action of on-load tap controllers, and flexible AC transmission system controllers.

One approach to enhance the existing voltage scheduling process by performing near-real-time optimal power flow simulations and using the results to send updated voltage set-points to on-line generators. In that way, optimal voltage profiles would be determined to more closely follow real-time variations in system operating conditions. One challenge of implementing a continually changing voltage schedule is the increased coordination required among the control center and numerous generators.

Entergy has teamed with the Electric Power Research Institute ("EPRI") to evaluate the technical feasibility, benefits, challenges, and limitations of implementing near-real-time optimal voltage control to help reduce transmission losses and improve overall reactive support. Off-line study with real system data will be performed to evaluate effectiveness of the strategy according to Entergy's requirement.

119. I did not see a lot of attention to the industrial DSM category. As this is the largest user of energy, what is the plan to reduce industrial client's DSM apart from curtailment?

A. Both ENO's Quick Start program and the proposed Energy Smart program allocate a significant portion of the total energy efficiency budget to the Commercial and Industrial markets for the implementation of programs targeted to reduce kwh usage. The budget for these programs were proportionate to the energy usage of these customer segments. This allocation process is described in greater detail in the July 2, 2010 Energy Smart Program filing which can be found on ENO's website at www.energy-neworleans.com/irp. In fact, the ENO Quick start Energy Efficiency programs for the large commercial and industrial segment were oversubscribed and surpassed their savings goals.

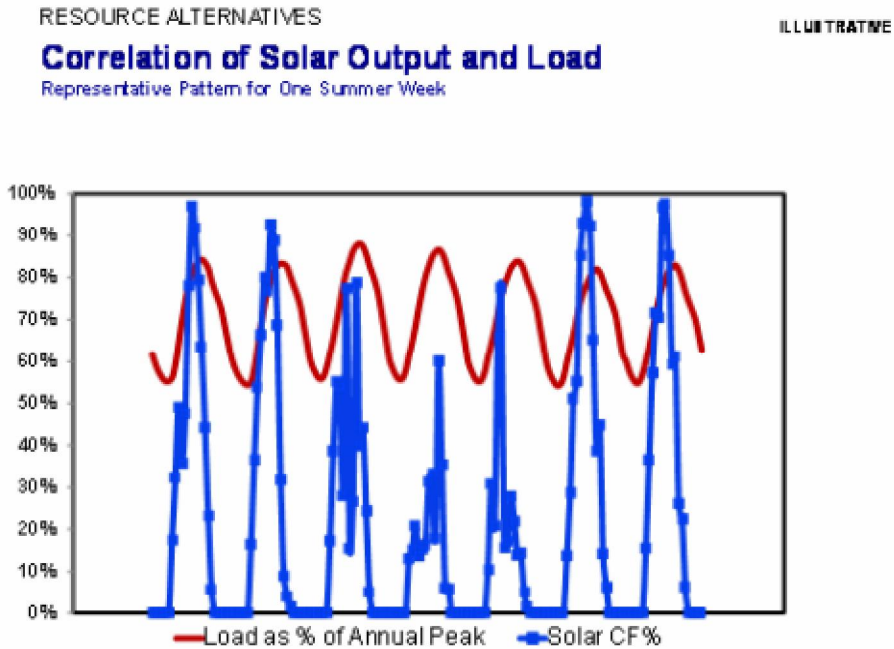
120. What do the employment numbers look like for the Energy Smart plan? Will ENO hire in house? If so, what type of pay scale and benefits will workers receive? Is there a job creation/ economic impact target? Will low income and/or locals receive the economic benefits of job creation.

A. ENO will oversee the Energy Smart programs utilizing its existing staff and will appoint an experienced Third Party Administrator to develop, manage and administer the

programs. However, the programs have specifically been designed to grow and develop a sustainable green workforce through its Participating Local Contractor network. The network will be comprised of local contractors who use the incentives from the Energy Smart program to develop and grow their businesses for energy audits and energy efficiency products and services. ENO projects that over 100 licensed and insured contractors will participate in increasing the energy efficiency of New Orleans homes and businesses through the Energy Smart programs. The third party administrator will be responsible for recruiting contractors with an emphasis on the inclusion of small and disadvantaged businesses.

121. Please represent the output of a Typical Solar PV Array on the same time and 0%-100% load scale as used for the "Correlation of Wind Output and Load" diagram in your recent presentation.

A. Below is a slide showing the correlation of load and solar output.



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122. What is the exact list of sources for your future natural gas pricing and availability? What is the natural gas price outlook when the global economy returns to pre-2008 growth levels, and how does this affect your LCOE analysis for CCGT?

A. The long term natural gas forecast used in the 2009 SRP was prepared in January of 2009 before the full effects of the global economic down turn and the remarkable production of domestic gas in spite of falling prices and recession-weakened demand were realized. This forecast considered information from NYMEX (as of 1/15/2009), Deutsche Bank (1/16/2009), PIRA (10/29/2008), Ventyx (Spring 2008 Release), Wood Mackenzie (1/23/2009), U.S. Department of Energy - Energy Information Agency (2008), IHS CERA (10/22/2008), and Energy Ventures Analysis (11/17/2008). The long

term natural gas forecast used in the SRP Refresh was about \$2.00/mmBtu lower in levelized, nominal dollars than the gas forecast used in the 2009 SRP Refresh Supplement. The updated forecast was prepared in May of 2010 and it reflected increased confidence in domestic non-conventional resources and the viability of technology innovations to bring large volumes of low cost gas to market. It was based on information from NYMEX (as of 3/31/2010), Deutsche Bank (3/31/2010), PIRA (4/16/2010), Ventyx (Fall 2009 Release), Wood Mackenzie (4/14/2010), U.S. Department of Energy - Energy Information Agency (2010), IHS CERA (11/16/2009), and Energy Ventures Analysis (4/7/2010). The lowered natural gas price of the SRP Refresh improves the relative economics of gas-fired resources.

123. What is Entergy's typical daily load profile in the summer months? Is Solar generation coincident with this, and how does Entergy reflect the Capacity value of Solar's generation profile?

A. This analysis has not been performed. However, for the purposes of determining the capacity value associated with a solar resource Entergy assesses the probability that the resource will be available during the top ten percent of peak hours.

124. Please explain how your analysis took into account the supply "smoothing" effects and increased reliability of multiple solar installations over a wider geographical area. For example, a Solar PV array in one area which has some temporary shading while another 20 miles away which does not.

A. While smoothing effects might reduce the level of flexible capability requirements the benefits of smoothing would not be that significant to solar's current overall economics.

125. How much solar incentives are included in the proposed IRP and what is their value? In this plan what is the approximate difference between creating a solar farm with Entergy New Orleans and creating one with a utility in California?

A. The IRP evaluates solar resources with and without incentives. The Reference Planning Scenario assumes the current investment tax credit for solar remains in place. It does not assume a federal or state mandate for renewables. The IRP process is flexible and the level of renewables can be adjusted to comply with any future federal, state or local renewable requirements or to take advantage of any future incentives or technology advances that would make a particular renewable resource economic. The economics of solar facilities are regionally dependent. Given that California is not interconnected with the Entergy Electric System, evaluating California solar economics would not be helpful. As such the analysis has not been performed.

126. What happens to the LCOE of Solar PV Generation when a more typical 30 Year Expected Life is used for the investment?

A. As noted in previous responses, the useful life of a PV solar plant is 25 years. ENOI has not performed the requested analysis, however, does not expect that extending the useful life from 25 to 30 years would materially improve solar's economics

127. As a freedom of information disclosure please post the full list of respondents to the IRP RFP. Please present a Net Present Value vs. program costs cost benefit analysis. In conjunction disclose the source where the program funds are budgeted from i.e. are the dollars debt, proceeds from the rate payees, federal subsidy dollars etc.

A. It is unclear which RFP the question is requesting data from, however, the confidentially agreements signed in all of the recent resource RFPs conducted by Entergy Services, Inc. ("ESI") for the benefit of the Entergy Operating Companies including ENO do not allow public disclose of RFP bid or evaluation data.

128. What concrete steps does Entergy New Orleans plan to take to leverage and enhance Energy Smart through collaboration with the Southeast Energy Efficiency Alliance energy efficiency program in New Orleans?

A. Energy Smart will provide information on all available energy efficiency programs and incentives to New Orleans residents so that residents can make informed decisions concerning energy efficiency upgrades, available incentives and financing options.

129. How is Entergy factoring in the supply cost risk factor of Natural Gas vs. that of Renewables? It would appear from the "Total Supply Cost/Risk" diagram in the presentation that a 4% reduction in cost between the "Max Green" and "Gas Centric" models results in a supply cost risk increase of over 15%.

A. The Portfolio Strategy Assessment assessed the risk of CO2 and Natural Gas price volatilities on portfolio cost. That assessment led to the conclusion that including some level of renewable generation within the portfolio might provide risk mitigation benefits. In order to develop the Reference Planning Scenario, the results of the Portfolio Strategy Assessment were considered in conjunction with other factors (both quantitative and qualitative) including, but not necessarily limited to:

- The uncertainty regarding deployment cost (greater for emerging technologies);
- Uncertainty relating to emerging technology performance;
- The potential effects of intermittent resources on System operations cost;
- The amount of renewable generation realistically deployable within the Entergy region given the regions natural resources
- The number of projects deployable over time.
- The potential for a federal or state imposed renewable portfolio standard

As with all assumptions reflected in the SRP, the assumptions regarding renewable resources are subject to continuing re-assessment through on-going planning and procurement activities.

Will the more thorough residential energy audits under Energy Smart be conducted by RESNET certified energy raters? If this is not yet determined, will you meet with the Energy Rater Roundtable prior to making a decision (or direct your Third Party Administrator to do so)?

A. There are two types of audits contemplated within the Energy Smart plan residential solutions program: Level 1 walk through audits and Level 2 whole house diagnostic audits. The Level one walk through audit described in the Company's proposed Residential Solutions program would be provided by a trained energy efficiency contractor who has signed a program participation agreement and undergone program training. For Level 2 energy audits, the auditor is expected to be either RESNET (Residential Energy Services Network-www.natresnet.org) or BPI (Building Performance Institute Inc. -www.bpi.org) certified. Contractors performing Level 2 audits must also sign program participation agreements and undergo program specific training to better understand for example, program elements, monitoring and incentives.

130. How does next year's rollout of more models of Electric Vehicle affect Entergy's demand forecasts? How does the potential for EV Battery energy access for peak capacity supply contribute to other peak capacity tools such as Time-of-Use Metering and Load Control?

A. The Reference Planning Scenario was evaluated against peak load and annual energy growth both higher and lower than the Reference Case including the High Load Factor Case which represented a scenario driven by energy efficiency, including penetration of plug-in hybrid electric and electric vehicles that charge off-peak. The potential for battery storage to contribute to peak capacity was not analyzed as part of the SRP, but it is an issue to watch.